KAREN KRUSE
503.290.2312 telephone
karen.kruse@troutmansanders.com

TROUTMAN SANDERS

TROUTMAN SANDERS LLP
Attorneys at Law
100 SW Main St., Suite 1000
Portland, Oregon 97204
503.290.2400 telephone
troutmansanders.com

May 25, 2016

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301

Attn: Filing Center

Re: Docket No. UM 1742 - Errata to PacifiCorp's Rebuttal Testimony

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing in the above-referenced docket the following errata to the Rebuttal Testimony of PacifiCorp:

- Exhibit PAC/107 – This e-mail contains attorney-client privileged communications and was inadvertently included as an exhibit to the testimony of Bruce W. Griswold. As a result, PacifiCorp is withdrawing this exhibit.

- PAC/100 – PacifiCorp is providing redacted and redline versions of pages from the Rebuttal Testimony of Bruce W. Griswold, which notes the removal of all references to Exhibit PAC/107 and any context associated with this exhibit. In particular, these revisions only impact one sentence on p. 76 of Mr. Griswold's testimony, and any changes made were merely to remove reference to Exhibit PAC/107 or context surrounding this exhibit. These redacted and redline pages were separately prepared for the Public Utility Commission of Oregon's (Commission) convenience and, thus, should <u>not</u> be filed in the above-referenced docket.

PacifiCorp has attached hereto a complete PDF filing package containing the updated Griswold testimony and exhibits, which reflects only the removal of Exhibit PAC/107 and any references thereto, as well as the Rebuttal Testimony and Exhibits of Richard A. Vail, as previously filed in this docket. PacifiCorp requests that this PDF replace the current document posted on the Commission's website and that any internal copies of the filing be replaced with this version in order to avoid any further, inadvertent disclosure of Exhibit PAC/107.

We apologize for the inconvenience and please contact me at (503) 290-2312 if you have any questions or concerns.

Sincerely,

/s/ *Karen Kruse*
Karen Kruse

Attorney for PacifiCorp

Enclosures

CERTIFICATE OF SERVICE

I certify that I served a true and accurate copy of PacifiCorp's corrected rebuttal testimony and exhibits in Docket No. UM 1742 on the parties listed below via e-mail and/or overnight delivery, in compliance with OAR 860-001-0180.

Irion A. Sanger
Sanger Law, PC
1117 SE 53rd Avenue
Portland, OR 97215
(503) 756-7533
irion@sanger-law.com

Bradley A. Kresge
Surprise Valley Electrification Corp.
516 U.S. Highway 395 E
Alturas, CA 96101
bradsvec@frontier.com

Dated this 25th day of May, 2016.

/s/ *Chris D. Zentz*
Chris D. Zentz
Troutman Sanders LLP

Attorney for PacifiCorp

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/100

CORRECTED REBUTTAL TESTIMONY OF BRUCE W. GRISWOLD

May 17, 2016

TABLE OF CONTENTS

TABLE OF EXHIBITS

Exhibit PAC/101	General Transfer Agreement between the United States of America Department of Energy acting by and through the Bonneville Power Administration and Pacific Power & Light Co.
Exhibit PAC/102	PacifiCorp Standard Power Purchase Agreement for On-System, Intermittent Qualifying Facilities (Less than 10,000 kW)
Exhibit PAC/103	PacifiCorp Standard Power Purchase Agreement for Off-System, Firm Qualifying Facilities (Less than 10,000 kW)
Exhibit PAC/104	PacifiCorp's Oregon Schedule 37 – Avoided Cost Prices and Process for Qualifying Facilities (Less than 10,000 kW)
Exhibit PAC/105	Direct Testimony of Stefan Brown, Docket No. UM 1129, Public Utility Commission of Oregon Staff Exhibit 2200 (March 24, 2006)
Exhibit PAC/106	Surprise Valley Electrification Corporation, "Paisley Geothermal Power Sales Concept Paper"
Exhibit PAC/107	[Intentionally Deleted]
Exhibit PAC/108	Email from B. Griswold to L. Culp, dated August 26, 2014
Exhibit PAC/109	Surprise Valley's May 20, 2014 Draft Power Purchase Agreement
Exhibit PAC/110	Surprise Valley's July 22, 2014 Draft Power Purchase Agreement
Exhibit PAC/111	Surprise Valley's June 22, 2015 Draft Power Purchase Agreement
Exhibit PAC/112	Email from J. Younie to L. Culp, dated November 6, 2013
Exhibit PAC/113	Emails between J. Younie and L. Culp, J. Portouw, and D. Meeuwsen, dated from November 20, 2013 through January 28, 2014
Exhibit PAC/114	Emails between J. Younie and L. Culp, from January 2014 through May 2014
Exhibit PAC/115	PacifiCorp's Response to Surprise Valley Data Request 1.8
Exhibit PAC/116	Surprise Valley's Supplemental Response to PacifiCorp's Data Request 2.3, including Attachment 2.3(c)
Exhibit PAC/117	Surprise Valley's Response to PacifiCorp's Data Request 3.10
Exhibit PAC/118	Surprise Valley's Response to PacifiCorp's Data Request 3.14, including Attachment 3.14

Exhibit PAC/119	Surprise Valley’s Response to PacifiCorp’s Data Request 3.15
Exhibit PAC/120	Surprise Valley’s Response to PacifiCorp’s Data Request 3.24
Exhibit PAC/121	Surprise Valley’s Response to PacifiCorp’s Data Request 3.30
Exhibit PAC/122	Surprise Valley’s Response to PacifiCorp’s Data Request 3.33
Exhibit PAC/123	Surprise Valley’s Response to PacifiCorp’s Data Request 3.34
Exhibit PAC/124	Surprise Valley’s Response to PacifiCorp’s Data Request 3.39
Exhibit PAC/125	Surprise Valley’s Response to PacifiCorp’s Data Request 3.48
Exhibit PAC/126	Surprise Valley’s Response to PacifiCorp’s Data Request 3.49
Exhibit PAC/127	Surprise Valley’s Response to PacifiCorp’s Data Request 3.50
Exhibit PAC/128	Surprise Valley’s Response to PacifiCorp’s Data Request 3.54
Exhibit PAC/129	Surprise Valley’s Response to PacifiCorp’s Data Request 3.55
Exhibit PAC/130	Surprise Valley’s Response to PacifiCorp’s Data Request 3.56
Exhibit PAC/131	Surprise Valley’s Response to PacifiCorp’s Data Request 3.64
Exhibit PAC/132	Surprise Valley’s Response to PacifiCorp’s Data Request 3.65, including Attachment 3.65
Exhibit PAC/133	Surprise Valley’s Response to PacifiCorp’s Data Request 3.75
Exhibit PAC/134	Surprise Valley’s Response to PacifiCorp’s Data Request 3.77
Exhibit PAC/135	Surprise Valley’s Response to PacifiCorp’s Data Request 3.79
Exhibit PAC/136	Surprise Valley’s Response to PacifiCorp’s Data Request 3.85
Exhibit PAC/137	Surprise Valley’s Response to PacifiCorp’s Data Request 3.92
Exhibit PAC/138	Surprise Valley’s Response to PacifiCorp’s Data Request 3.93
Exhibit PAC/139	Surprise Valley’s Response to PacifiCorp’s Data Request 4.1
Exhibit PAC/140	Surprise Valley’s Response to PacifiCorp’s Data Request 4.3
Exhibit PAC/141	Surprise Valley’s Response to PacifiCorp’s Data Request 4.5
Exhibit PAC/142	Surprise Valley’s Response to PacifiCorp’s Data Request 4.14

I. INTRODUCTION

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

A. My name is Bruce W. Griswold. My business address is 825 N. E. Multnomah, Suite 600, Portland, Oregon. I am employed by PacifiCorp as Director of Short-Term Origination and Qualifying Facility Contracts.

Q. Please describe your education qualifications.

A. I have Bachelor of Science and Master of Science degrees in Agricultural Engineering from Montana State and Oregon State, respectively. I have been employed with PacifiCorp for over thirty years and held various positions of responsibility in retail energy services, engineering, marketing, and wholesale energy services. I have also worked in the private industry and with an environmental firm as a project engineer. I currently work in the Energy Supply Management business unit of PacifiCorp (PacifiCorp or ESM), which is the name of PacifiCorp's merchant function (formerly Commercial and Trading or C&T).[1] My current responsibilities include the negotiation and management of wholesale power supply and resource acquisition through requests for proposals and responsibility for the Company's qualifying facility (QF) power purchase agreements (PPA).

Q. Have you testified in other Oregon Public Utility Commission (Commission) proceedings?

A. Yes, I have previously appeared as a witness on behalf of the Company before the Commission.

[1] I will refer to the Company's transmission function as "PacifiCorp Transmission."

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

My testimony addresses the parties' PPA negotiations, including the inability of Surprise Valley Electrification Corporation (Surprise Valley) to verifiably delivery QF power to PacifiCorp. In short, I demonstrate that Surprise Valley's fundamental proposal is for PacifiCorp and its customers to pay avoided cost prices for an unverifiable amount of BPA Power Administration (BPA) Tier 1 preference power, which is not required under Public Utility Regulatory Policies Act (PURPA).

Q. Please summarize your testimony.

A. I present testimony regarding the background and negotiations with Surprise Valley. My testimony summarizes how PPAs for QFs under the PURPA normally work and the ways in which Surprise Valley's project deviates from the standard. Additionally, I demonstrate how Surprise Valley's proposed theory of "delivery" for the net output of its QF project does not comport with PURPA, or the policies and requirements of the Federal Energy Regulatory Commission (FERC), or the policies and requirements of the Oregon Commission.

Surprise Valley recognizes that little or no power from the QF would physically flow to PacifiCorp's system, yet it insists on selling the full output of the plant to PacifiCorp. It has not been willing or able to make appropriate and verifiable delivery arrangements to account for the lack of physical delivery. PacifiCorp and Surprise Valley have not yet signed a PPA because Surprise Valley has been either unwilling or unable to agree to terms and conditions of a QF PPA that would allow PacifiCorp to verify that it receives power from the QF under that PPA.

I also testify that PacifiCorp has negotiated in good faith and worked with Surprise Valley to find contractual arrangements meeting both FERC and Commission policies and requirements. While there have been a number of misunderstandings by the parties during the course of negotiations, those negotiations were not conducted in bad faith. In the end, PacifiCorp is not willing to sign a PPA unless it can be sure that it will receive the power it pays for under that PPA.

Q. How is your testimony organized?

A. I provide an overview of a QF's delivery obligations under PURPA and under the Company's standard Oregon on- and off-system PPAs. I then describe initial discussions between PacifiCorp ESM and Surprise Valley and the delivery challenges that presented themselves regarding the QF's configuration. Finally, I address the allegations in Surprise Valley's complaint about validity of Surprise Valley's proposed delivery arrangements and the course of the parties' negotiations.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the exhibits identified in the Table of Exhibits above.

III. BACKGROUND

A. Description of the Parties

Q. Please describe PacifiCorp.

A. PacifiCorp is a vertically integrated utility serving approximately 1.8 million customers in six states. PacifiCorp is an indirect, wholly-owned subsidiary of Berkshire Hathaway Energy. PacifiCorp consists of three operating units: (1) Pacific Power; (2) PacifiCorp Transmission; and (3) Rocky Mountain Power. Relevant to the current proceeding, Pacific Power is responsible for delivering electricity to customers in Oregon, Washington, and California and manages PacifiCorp's renewable generation resources and energy supply management for all six states. Pacific Power includes ESM, PacifiCorp's marketing function. PacifiCorp Transmission manages PacifiCorp's transmission services, transmission planning and system operations for all six states, as well as PacifiCorp's transmission expansion projects.

Q. Please describe Surprise Valley.

A. Surprise Valley is a non-profit rural cooperative, owned by its customers in Oregon, California, and Nevada. Surprise Valley has constructed a small geothermal facility that it has named the Paisley Project (Paisley Project or Paisley). Surprise Valley has about 4,500 member customers, who are primarily comprised of agricultural-based businesses and customers.[2]

Q. Please describe the Paisley Project.

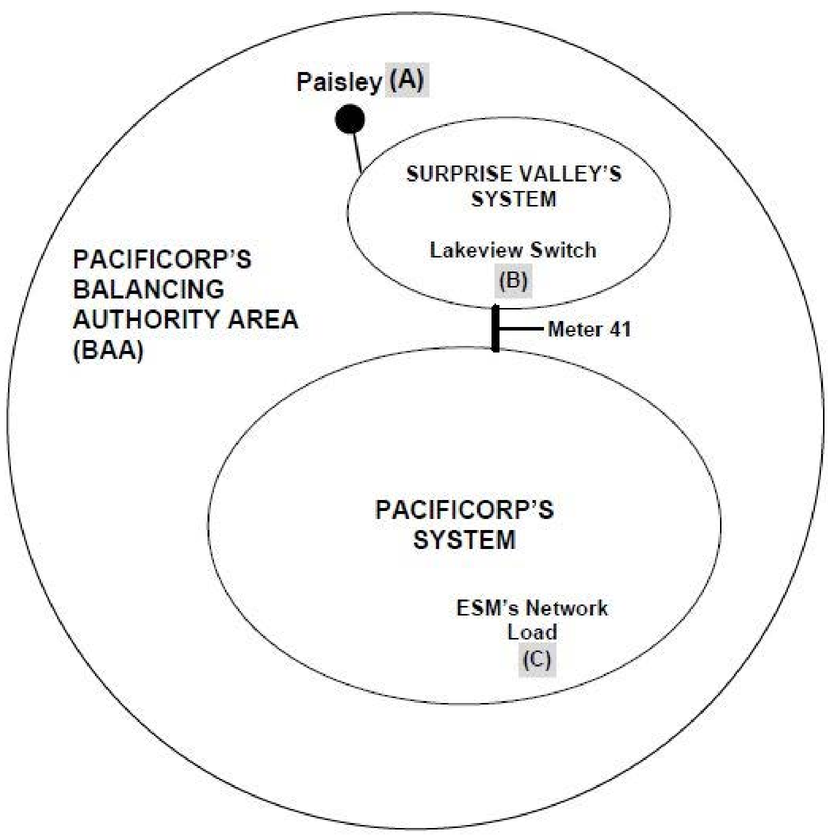
A. The Paisley Project is a geothermal electric generation facility that was constructed in Paisley, Oregon, with a rated output of 3,650 kilowatts (kW) and a maximum net output of 2,349 kW.[3] The Paisley Project is a QF as defined by PURPA.

[2] SVEC/100, Kresge/5.

[3] *See* Surprise Valley Complaint at 6; *see also* SVEC/400, Anderson/2-3.

Q. Is the Paisley Project directly interconnected to PacifiCorp's system?

A. No, it is interconnected to Surprise Valley's distribution system and in Surprise Valley's service territory. Surprise Valley's service territory in turn interconnects with PacifiCorp's transmission system at BPA Meter 41, which is also referred to as the Lakeview Switch. Below is a diagram illustrating the Paisley Project's location in relation to the Surprise Valley and PaciCorp transmission systems.



Q. Is the Paisley Project within PacifiCorp's Balancing Authority Area?

A. Yes. Surprise Valley is not its own Balancing Authority Area (BAA), so PacifiCorp serves as the Balancing Authority (BA) for Surprise Valley.

Q. Please describe Surprise Valley's electrical needs.

A. Surprise Valley's 2014 peak load was approximately 39 megawatts (MW), and its 2014 minimum load was approximately 14 MW.[4]

Q. How does Surprise Valley supply its electrical needs?

A. Surprise Valley is a full requirements customer of the BPA. This means that BPA has historically provided all of the power necessary to meet Surprise Valley's electrical needs.[5] The addition of the Paisley Project adds another resource that Surprise Valley can theoretically use to serve its load. In fact, the majority of Surprise Valley's load lies between the Paisley Project and the point of interconnection between Surprise Valley's electric system and PacifiCorp's electrical system. BPA delivers the majority of Surprise Valley's full requirements power across PacifiCorp's transmission system to Surprise Valley's system.[6]

Q. Under what agreement does PacifiCorp deliver BPA power to Surprise Valley?

A. PacifiCorp and BPA have a long-standing agreement referred to as the General Transfer Agreement (GTA).[7] Under this legacy agreement, BPA schedules power for delivery to a group of its preference power customers via the PacifiCorp Transmission system. PacifiCorp Transmission then delivers power to these BPA customers on BPA's behalf.

B. Overview of the Parties' Dispute

Q. Please provide an overview of the parties' dispute?

---

[4] SVEC/100, Kresge/6

[5] *Id.*

[6] *Id*.

[7] *See* General Transfer Agreement between the United States of America Department of Energy acting by and through the BPA Power Administration and Pacific Power & Light Co., attached as PAC/101.

A. For some time now, Surprise Valley has been seeking to sell the output of the Paisley Project to PacifiCorp in accordance with PacifiCorp's Oregon Schedule 37, *Avoided Cost Purchases from Qualifying Facilities of 10,000 KW or Less* (Schedule 37). From the outset, PacifiCorp asked Surprise Valley to agree to the terms and conditions of one of PacifiCorp's Commission-approved standard QF PPAs as a condition of receiving a PPA. If Surprise Valley had been willing to agree to those terms and conditions, PacifiCorp would have signed a QF PPA with Surprise Valley as early as 2014. But, Surprise Valley has refused to agree to the terms and conditions of any version of a standard QF PPA. Specifically, it has been either unwilling or unable to comply with the requirements for QF power delivery.

Although Surprise Valley's QF is classified as a "standard" QF, PacifiCorp has nevertheless spent significant time and effort entertaining and investigating non-standard and creative delivery proposals from Surprise Valley. None of Surprise Valley's delivery proposals, including the new variation offered in Surprise Valley's direct testimony in this case, would provide PacifiCorp with the firm, measurable delivery that is necessary for PacifiCorp to verify receipt of QF power and justify payment of standard avoided cost prices to Surprise Valley. In fact, the delivery proposals offered by Surprise Valley as early as April 2014, and the updated version articulated in Surprise Valley's March 15, 2016 direct testimony, simply would not allow PacifiCorp to verify how much power it is receiving from Surprise Valley.

Although the parties have expended much time and effort on these issues, Surprise Valley and PacifiCorp remain in disagreement about the terms and conditions of delivery required under PURPA. PacifiCorp clearly articulated its disagreement with

Surprise Valley's delivery proposals to Surprise Valley as early as August 2014 in response to Surprise Valley's "concept paper." Despite the parties' good-faith disagreement about the delivery arrangements required by law, Surprise Valley has accused PacifiCorp of acting in bad faith by refusing to execute a PPA.

Q. Is the point of disagreement between the parties about the terms and conditions of a QF PPA a minor one?

A. No. If PacifiCorp were to sign the QF PPA that Surprise Valley apparently wants it to sign, PacifiCorp would immediately be required to purchase the full net output of the Paisley Project without any way to verify that the QF power was actually being delivered to PacifiCorp's system.

Q. Why is that a problem?

A. If PacifiCorp cannot tell how much power it actually receives under a PPA with Surprise Valley, it has no way to accurately pay or enforce the minimum delivery requirements or any other rights or remedies contained in a PPA. The fact that there would be no way for PacifiCorp to seek financial recourse from the QF for any shortage is bad enough, but as I will explain in my testimony, because of the issues with Surprise Valley's delivery proposal, PacifiCorp would also need to cover any shortage of physical QF power delivery with PacifiCorp's own resources, then purchase that power back from Surprise Valley at avoided cost prices. This introduces incremental cost and risk for PacifiCorp's retail customers.

Q. Is PacifiCorp willing to enter into the PPA that Surprise Valley wants?

A. No. PacifiCorp is not willing to enter into a PPA that harms its retail customers.

Q. Do you have any other general comments about PacifiCorp's willingness to enter into a PPA with Surprise Valley?

A. Yes. Surprise Valley has accused PacifiCorp of acting in bad faith. While the parties have certainly disagreed about the terms and conditions of a PPA that would meet the requirements of PURPA, PacifiCorp is simply not willing to sign a PPA that harms customers. This is true whether the negotiations take months or whether they take years. PacifiCorp informed Surprise Valley as early as August 2014 that it was not willing to accept a "swap" type of delivery arrangement instead an actual delivery of QF power, yet to this day, Surprise Valley still proposes a variation of its original "swap" proposal. PacifiCorp has consistently maintained that it requires verifiable power delivery to its system. Surprise Valley could have filed a complaint as early as August 2014 seeking the Commission's view on the parties' dispute, in accordance with its rights under Schedule 37. Instead, Surprise Valley kept talking to PacifiCorp about arrangements that had fundamental flaws. Despite the passage of time, PacifiCorp does not believe it should be penalized for continuing to talk to Surprise Valley after PacifiCorp rejected Surprise Valley's delivery proposal, nor should it be penalized for continuing to refuse to accept a PPA that would harm its retail customers.

Q. Do you have any general comments about the parties' communications?

A. Yes. I believe most of the assertions in Surprise Valley's complaint about PacifiCorp's bad faith actions are attributable to some critical misunderstandings. I detail these misunderstandings in Section IV.C of my testimony. Surprise Valley appears to believe, for example, that PacifiCorp Transmission has the responsibility or plays a significant role in making arrangements for a QF to deliver QF power to PacifiCorp's system. This is a significant misunderstanding on Surprise Valley's part that distorts its interpretation of many of the parties' communications.

Q. Did you realize how pervasive these misunderstandings were before Surprise Valley filed its complaint?

A. No.

Q. Do you have any general comments about Surprise Valley's assertion that it is entitled to pre-August 20, 2014 avoided cost pricing because it established a legally enforceable obligation (LEO) at that time?

A. Yes. PacifiCorp does not believe that a QF is entitled to lock in rates under a standard PPA if a QF is not willing or able to agree to the terms of that PPA. Surprise Valley has never been willing (and remains unwilling) to agree to the terms and conditions of any standard QF PPA. Surprise Valley actually modified its own PPA with BPA in July 2015, *after* it filed its complaint, to help effectuate the unorthodox delivery method proposed in its direct testimony. These modifications appear intended to cure some of the deficiencies that PacifiCorp previously pointed out with Surprise Valley's proposed delivery method, and they preclude any conclusion that Surprise Valley had a LEO before August 20, 2014.

Q. What is your view of those post-complaint contract modifications?

A. They suggest that Surprise Valley ultimately recognized some of the deficiencies in its own pre-complaint power delivery proposals. PacifiCorp should not be penalized for refusing to accept any of those inadequate proposals.

Q. Have Surprise Valley's post-complaint actions cured the deficiencies in Surprise Valley's proposed delivery method?

A. No. Surprise Valley's post-complaint actions have mitigated some of the problems with Surprise Valley's early delivery proposals, but they have not solved the critical problem. Surprise Valley's delivery proposal, as described in Surprise Valley's March 15, 2016 testimony, would still leave PacifiCorp unable to verify how much power it receives under a PPA with Surprise Valley. I discuss Surprise Valley's post-complaint power delivery proposal in more detail in Section IV.B of my testimony.

Q. You stated that PacifiCorp would sign a standard QF PPA with Surprise Valley if Surprise Valley were willing to agree to the terms and conditions of a standard QF PPA. Would PacifiCorp be willing to enter into a *non-standard* QF PPA with Surprise Valley?

A. Yes. PacifiCorp is willing to negotiate a non-standard QF PPA with Surprise Valley so long as Surprise Valley cures the deficiencies in its delivery method to ensure PacifiCorp can verify firm delivery to the PacifiCorp system. A negotiated PPA, in contrast to a standard PPA, has a Commission-approved avoided cost pricing methodology that may affect the avoided cost price that Surprise Valley would receive, something Surprise Valley has stated that it will not accept. In fact, Surprise Valley filed the complaint specifically because PacifiCorp was not willing to guarantee pre-August 20, 2014 avoided cost pricing as part of a PPA. Surprise Valley wanted the published standard avoided cost prices of Schedule 37, but a negotiated non-standard PPA. PacifiCorp therefore has had difficulty negotiating a non-standard QF PPA with Surprise Valley.[8]

C. PURPA Obligations

Q. Are you familiar with PURPA?

[8] *See* Surprise Valley Complaint at 2-3, 27-28, 34; *see also* Surprise Valley's Response to PacifiCorp's Data Request 3.33 (attached hereto as PAC/122), 3.49 (attached hereto as PAC/126), and 3.50 (attached hereto as PAC/127).

A. Yes. I have worked extensively on PURPA contracts in my role at PacifiCorp. I have worked with QFs for the past twenty years and have participated as a witness in Commission proceedings addressing PURPA issues since 2006.

Q. What is PacifiCorp ESM's obligation to purchase power from QFs under PURPA?

A. PURPA generally requires a utility such as PacifiCorp to purchase the net output of the generation that is produced by a QF and is made available to the utility.

Q. Does PacifiCorp ordinarily have difficulty reaching agreement with QFs over QF PPAs?

A. No. It ordinarily takes about ninety to one hundred twenty days from the time a QF contacts the Company to reach a signed agreement. The biggest spike in disagreements correlates to pricing decreases when Schedule 37 avoided costs are updated. Aside from this issue, PacifiCorp is ordinarily able to reach agreement with QFs quickly, particularly when QFs like the Paisley Project are entitled to accept the terms of the Company's Commission-approved standard QF PPA.

Q. How many QF PPAs has PacifiCorp signed since Surprise Valley first contacted PacifiCorp about the Paisley Project in August 2013?

A. PacifiCorp has executed over 40 new or renewed QF PPAs since August 2013.

Q. How many QFs have filed complaints against PacifiCorp since that time?

A. One—Surprise Valley.

Q. If it is ordinarily straightforward to reach agreement on a standard QF PPA, why has PacifiCorp been unable to reach agreement with Surprise Valley?

A. Surprise Valley is either unwilling or unable to comply with the delivery requirements found in the Company's standard QF PPAs. PacifiCorp has engaged in discussions with

Surprise Valley about the possibility of negotiating a non-standard QF PPA, but Surprise Valley remains unwilling or unable to agree to commercially acceptable delivery terms. The delivery terms are a critical element of a QF PPA regardless of whether the PPA is standard or non-standard because they ensure PacifiCorp and its customers receive the power that they pay for.

Q. What benefit would PacifiCorp stand to gain by intentionally delaying signing a PPA with Surprise Valley?

A. None. This has been a difficult process and we have tried many times to resolve it, but PacifiCorp will not sign a PPA that it believes may harm customers.

1. Overview of QF Delivery Obligations

Q. What is your understanding of a QF's delivery obligations under PURPA?

A. Both federal and Oregon law require a QF to arrange for delivery of its power to a utility's system before that utility is obligated to purchase QF power.

Q. Is evidence of QF power delivery arrangements a prerequisite to entering into a Commission-approved off-system PPA?

A. Yes. The Commission has cited to the FERC order in *Pioneer Wind Park I, LLC* with approval,[9] where FERC held that a QF must "deliver[] energy to the point of interconnection . . . with that purchasing utility," at which point the purchasing utility must take the energy.[10]

Q. How is QF power delivery accomplished?

---

[9] *In re Investigation Into Qualifying Facility Contracting and Pricing*, Order No. 14-058, Docket No. UM 1610 at 21-22 (Feb. 24, 2014).

[10] *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215 at P 38 (2013).

A. QFs are required to deliver their power to PacifiCorp through one of two methods: (1) physical delivery of the power from the QF to PacifiCorp's system through a direct interconnection with PacifiCorp's system; or (2) delivery of the power from the QF to PacifiCorp's system through a commercially acceptable wheeling[11] arrangement.

Q. Are these methods consistent with PURPA regulations?

A. Yes.[12]

Q. Are these methods recognized by the Commission?

A. Yes. These methods are explicitly recognized by the QF delivery requirements in PacifiCorp's standard, Commission-approved QF PPAs.

2. QF's Delivery Obligations Under the Commission's Standard (Schedule 37) QF PPAs

Q. What is PacifiCorp's Schedule 37?

A. PacifiCorp's Schedule 37 applies to QFs that are 10,000 kW or less.[13] These QFs are referred to as "standard" QFs.

Q. What is a "standard" QF?

A. Standard QFs are a defined class of QFs that are deemed eligible under federal or state law to receive standard published avoided cost pricing.[14] Standard QFs willing to

[11] Wheeling is the use of the transmission or distribution facilities of one electrical system to transmit power to another electrical system.

[12] FERC's PURPA regulations at 18 C.F.R. § 292.303(d) provide, "If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission." (Emphasis added.)

[13] A 3,000 kW limit applies to solar QFs. *See In re PacifiCorp Application to Reduce the Qualifying Facility Standard Contract Eligibility Cap*, Docket No. UM 1734, Order No. 16-130 at 4 (Mar. 29, 2016).

[14] *In re Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket No. UM 1129, Order No. 05-584 at 12 (May 13, 2005).

execute a Commission-approved standard QF PPA will generally be entitled to the published avoided cost prices found in Schedule 37. The Company's standard QF PPAs contain a standard set of rates, terms, and conditions approved by the Commission that govern PacifiCorp's purchase of electrical power from QFs at avoided cost.[15]

Q. Are you familiar with the requirements of PacifiCorp's standard QF PPAs?

A. Yes. I sponsored testimony in docket UM 1129, when the standard PPAs were first adopted by the Commission. Since then, I have been involved in every Commission proceeding in which changes to the Company's standard QF PPAs have been adopted.

Q. How do a standard QF and PacifiCorp ESM negotiate a standard PPA?

A. Generally speaking, so long as the QF meets the requirements of a Schedule 37 and provides the information requested in Schedule 37, few negotiations are required. PacifiCorp's standard form PPAs are available for review online.[16]

Q. Are QFs or utilities permitted to alter the terms and conditions of standard QF PPAs?

A. Generally, no. The Commission has allowed some level of flexibility for parties to alter standard QF PPAs, but in general, the standard terms and conditions are to be followed. When the Commission adopted the standard QF PPAs, it stated:

> Standard contracts are designed to minimize the need for parties to engage in contract negotiations. Consequently, any flexibility in the terms and conditions of a standard contract should be specifically delineated and bounded. To the extent that a party

---

[15] *Id.*

[16] *See* PacifiCorp Standard PPA for On-System, Intermittent QF Resources Less than 10 MW, available at: https://www.pacificpower.net/content/dam/pacific_power/doc/Efficiency_Environment/Net_Metering_Customer_Generation/PacifiCorp_Schedule37_OR_Wind(MAG)_New_QF_PPA_Aug_20_2014.pdf, attached as PAC/102 (Standard On-System PPA); *see also* PacifiCorp Standard PPA for Off-System QFs Less than 10 MW, available at: https://www.pacificpower.net/content/dam/pacific_power/doc/Efficiency_Environment/Net_Metering_Customer_Generation/PacifiCorp_Schedule37_OR_Off-System_New_QF_PPA_Aug_20_2014.pdf, attached as PAC/103 (Standard Off-System PPA).

> anticipated the need for flexibility with regard to a particular standard contract term or condition, the specific issue should have been raised and examined in this proceeding. It is inappropriate to request that standard contracts be subject to potential negotiation to address project-specific characteristics.[17]

Q. Does PacifiCorp insist that a standard QF meet the terms and conditions of a standard QF PPA before it will purchase power from that QF?

A. Generally, yes. If a QF's issues with a standard PPA are minor and customers will not be harmed by minor changes, PacifiCorp will work with a QF to accommodate a QF's limitations. A QF owned by a public entity, for example, may require some minor adjustments to the security or insurance provisions due to restrictions imposed by public ownership. But by and large, PacifiCorp expects a standard QF to agree to the terms and conditions of a standard QF PPA.

Q. Are there different types of standard QF PPAs?

A. Yes. PacifiCorp has standard QF PPAs for various types of QFs. For purposes of QF power delivery, these PPAs fall into two categories—on-system QF PPAs and off-system QF PPAs.

Q. Has Surprise Valley been willing to agree to the terms and conditions of either type of standard QF PPA?

A. No.

a. Standard On-System QF PPA

Q. What is an on-system QF?

A. An on-system QF is a QF that is directly interconnected with PacifiCorp's system. This means that the QF generator is connected directly to and metered at PacifiCorp's

[17] Order 05-584 at 39.

transmission or distribution system. PacifiCorp's Schedule 37 explains how an on-system QF interconnects with PacifiCorp's system.

Q. How does an on-system QF deliver its power to PacifiCorp?

A. PacifiCorp measures the physical flow of power onto PacifiCorp's system at the point of delivery. And, under the terms of the PPA, PacifiCorp purchases the "amount of energy flowing through the Point of Delivery" up to the net output of the QF.[18]

Q. How is a QF made aware of this delivery obligation?

A. The steps needed for interconnection and metering to allow this type of delivery are discussed in the Company's Schedule 37 and in the standard on-system PPA. These are publicly available on the Company's website.[19]

Q. What is PacifiCorp's role in a QF's delivery of power under an on-system PPA?

A. PacifiCorp's role is described in the Company's Schedule 37. Generally, PacifiCorp ESM communicates with the QF about the terms and conditions of the PPA, ensures all information is collected, and ensures that the QF complies with the requirements of the on-system PPA. Schedule 37 explains that, separately, a QF is required to contact PacifiCorp Transmission regarding an interconnection agreement.[20] As Mr. Richard A. Vail explains in his testimony, PacifiCorp Transmission will address interconnection and

---

[18] PAC/102, Griswold/8 at § 1.30 ("For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the Point of Delivery.").

[19] *See* PacifiCorp's Oregon Schedule 37 – Avoided Cost Prices and Process for QFs Less than 10,000 KW, available at: https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/Oregon/Approved_Tariffs/PURPA_Power_Source_Agreement/Schedule_37_Avoided_Cost_Purchases_From_Qualifying_Facilities_of_10000_kW_or_Less.pdf, attached as PAC/104 (Schedule 37); *see also* SVEC/208 (including the Schedule 37 in effect as of March 2, 2011) (attached as PAC/111), PAC/102.

[20] *See* PAC/104, Griswold/9.

metering issues at the QF's request to allow the physical connection of the QF to the Company's system and to ensure that PacifiCorp's system can receive the QF's output.

Q. Is Surprise Valley willing to sign a standard on-system PPA under which PacifiCorp pays for the "amount of energy flowing through the Point of Delivery"?

A. No. Surprise Valley insists that PacifiCorp must purchase all of the Paisley Project's generation.[21] As I will explain, however, the Paisley Project's location on Surprise Valley's system means that most of the Paisley Project's generation will be consumed by Surprise Valley's own load, and little or no power will physically "flow through the Point of Delivery."[22]

Q. Is PacifiCorp willing to purchase something *other than* the "amount of energy flowing through the Point of Delivery" under a standard on-system PPA?

A. No. This measurement of physical flow across a meter is the only way PacifiCorp can determine the amount of power it receives from an on-system QF.

Q. Given these facts, is PacifiCorp willing to sign a standard on-system PPA with Surprise Valley for the output of the Paisley Project?

---

[21] *See* SVEC/100, Kresge/13 ("While I am not an expert on power contract matters, Surprise Valley has been willing to sign a PPA for the *full net output* of the Paisley Project") (emphasis added); SVEC/300, Saleba-Tabone/29 ("[No] scheduling or ancillary services would be required to make uninterruptible transfers of title and use of the QF's full net output to PacifiCorp."); Surprise Valley's Response to PacifiCorp's Data Request 3.10 ("Surprise Valley and PacifiCorp's power purchase agreement or other legally enforceable obligation make the entire net output of the QF available to PacifiCorp and provide PacifiCorp with legal title to that full net output.") (attached hereto as PAC/117); Surprise Valley's Response to PacifiCorp's Data Request 3.24 ("A contract or legally enforceable obligation can be entered into before the utility can verify that it receives the benefit of the full net output of the QF.") (attached hereto as PAC/120); Surprise Valley's Response to PacifiCorp's Data Request 4.40 ("If any metering points need to be changed in the PacifiCorp and BPA transmission agreement(s), then PacifiCorp is illegally refusing to make changes necessary to effectuate PacifiCorp ESM's purchase of the full net output of the Paisley Project.") (attached hereto as PAC/145); *see also* Surprise Valley Complaint at 24-27 (where Surprise Valley claims it is making the full net output of the Paisley Project available to PacifiCorp).

[22] SVEC/400, Anderson/4 ("[The] flow of electrical current into the PacifiCorp system at the [Point of Delivery] is likely to *only occur during limited light load hours*.") (emphasis added); Surprise Valley's Response to PacifiCorp's Data Request 3.15 ("The bi-directional meter #4123 installed at the [Point of Delivery] to measure any power flowing back into the PacifiCorp system in July 2014 has *not measured any flow into the PacifiCorp system in any month*.") (emphasis added) (attached hereto as PAC/119).

A. No. As stated above, however, PacifiCorp is willing to sign a standard on-system PPA with Surprise Valley for the amount of power physically flowing through the Lakeview point of delivery, up to the net output of the Paisley Project, as measured by Meter 41.

b. Standard Off-System QF PPA

Q. What is an off-system QF?

A. An off-system QF is not directly interconnected with PacifiCorp's system, but is instead interconnected with another utility's transmission or distribution system. An off-system QF wishing to sell power to PacifiCorp must wheel its generation to PacifiCorp across another utility's system to PacifiCorp's system before PacifiCorp can obtain (and purchase) the power.

Q. Does the Company's standard off-system PPA contain specific delivery requirements?

A. Yes. As further explained below, the Company's Commission-approved standard off-system PPA and Addendum W to that PPA contain specific delivery requirements.

Q. Who arranges for the wheel of QF power to PacifiCorp's system?

A. The QF.

Q. How is a QF made aware of its delivery requirements?

A. PacifiCorp's Schedule 37 makes clear that a QF that is not directly interconnected with PacifiCorp's system is required to make and pay for the transmission arrangements to deliver its power to PacifiCorp's system. Schedule 37 requires the QF to provide the "status of interconnection or transmission arrangements" as a prerequisite to obtaining a draft PPA from PacifiCorp.[23] Section II of PacifiCorp's Schedule 37 states as follows:

[23] *See* PAC/104, Griswold/8.

> NOTE: Section II [Interconnection] applies only to QFs connecting directly to PacifiCorp's electrical system. *An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.*[24]

Q. In this case, who is the Paisley Project's "local utility or transmission provider"?

A. Surprise Valley.

Q Does the Company's standard off-system PPA make clear that it is a QF's obligation to make transmission arrangements for delivery of its power to PacifiCorp's system?

A. Yes. For example, Addendum W's recitals indicate that the seller under the off-system PPA will "deliver Net Output from its QF Facility to PacifiCorp via one (or more) Transmitting Entities," meaning the seller must make transmission arrangements across an intervening transmission system to deliver the net output to PacifiCorp. Similarly, Section 1 of Addendum W clearly states, "*Seller* shall arrange for the Firm Delivery of Net Output to the Point of Delivery."[25]

Q. Please describe the delivery requirements in the Company's standard off-system PPA.

A. The off-system PPA's Addendum W defines "Firm Delivery" to mean "uninterruptible transmission service that is reserved and/or scheduled between the Point of Interconnection and the Point of Delivery pursuant to Seller's Transmission Agreement."[26] The PPA defines "Transmission Agreement" as "the agreement (or contemporaneous agreements) between Seller and the Transmitting Entity providing for

[24] *Id*. at 9 (emphasis added).

[25] PAC/103, Griswold/41-42.

[26] *Id.* at 41.

Seller's uninterruptible right to transmit Net Output to the Point of Delivery," and the "Transmission Entity" as "the (non-PacifiCorp) operator of the transmission system at the Point of Delivery."[27]

Q. What happens if the QF fails to arrange for firm delivery over the intervening system to the Point of Delivery?

A. If a QF fails to arrange for firm delivery of its power, then it cannot obtain standard avoided cost pricing. In particular, Addendum W states that, "Whenever Seller fails to provide for Firm Delivery of Net Output, all Net Output delivered via non-firm transmission rights shall be deemed Excess Output, and therefore subject to the payment provision in Section 5.4."[28]

Q. How do indirectly interconnected QFs ordinarily make transmission arrangements to deliver QF power to a utility's system?

A. An indirectly interconnected (or off-system) QF will ordinarily contract with a third-party transmission provider to deliver QF power to a utility's system. For example, PacifiCorp currently purchases power from seven Oregon off-system QFs that have point-to-point third-party transmission arrangements with BPA. As another example, a QF may be directly interconnected with Idaho Power but may wish to sell power to PacifiCorp. In that case, the QF would enter into a point-to-point transmission arrangement with Idaho Power, the intervening utility. Idaho Power would contract with the QF to ensure the power is delivered to PacifiCorp's system on a firm basis.

Q. What are some characteristics of those transmission arrangements?

---

[27] *Id*.

[28] *Id*. at 42.

A. These are ordinarily firm point-to-point transmission arrangements. A firm point-to-point transmission agreement provides transmission service that is reserved and/or scheduled between specified points of receipt and delivery, and includes specific terms and conditions commonly recognized in the energy industry as commercially necessary to ensure firm delivery of power through a wheel.

For instance, as is generally described in the Open Access Transmission Tariff (OATT), which, as noted above, governs the provision of transmission service for every other off-system QF delivery arrangement of which I'm aware, firm point-to-point transmission service must be supported by ancillary services and requires the submission of schedules. The types of ancillary services that must be purchased by an OATT transmission customer will vary depending on the details of the specific delivery arrangement, and on whether the transmission customer is self-supplying or purchasing certain ancillary services from a third party. Generally speaking, however, OATT transmission customers need to self-supply or arrange to purchase certain types of energy reserves and imbalance services in order to ensure the firmness and reliability of their delivery arrangement.

In the circumstances where the intervening utility does not have an OATT, an off-system QF's delivery arrangements should also be scheduled, as well as supported by the ancillary services needed to ensure the firmness of the delivery and maintain reliability within and among the BAA affected by the transmission service.[29]

Q. Does Addendum W include additional specific delivery requirements?

[29] *See, e.g,. id*. at 42-43.

A. Yes. Addendum W, is entitled the "Generation Scheduling Addendum,"[30] and is defined by the agreement as "providing for the measurement, scheduling, and delivery of Net Output from the Facility to the Point of Delivery via a non-PacifiCorp transmission provider."[31] Most importantly, as noted above, Addendum W states that the seller must arrange for the *firm* delivery of its net output to the point of delivery.[32]

Addendum W also discusses certain energy reserve requirements, stating that "The Transmitting Entity [Surprise Valley, here] shall provide all generation reserves as required by the WECC and/or as required by any other governing agency or industry standard to deliver the Net Energy to the Point of Delivery, at no cost to PacifiCorp."[33] Further, Addendum W includes certain scheduling requirements, stating that the QF "shall coordinate with the Transmitting Entity(s) to provide PacifiCorp with a schedule of the next Day's hourly scheduled Net Output deliveries at least 24 (twenty-four) hours prior to the beginning of the day being scheduled, and otherwise in accordance with the WECC Prescheduling Calendar."[34] Addendum W also requires the QF to procure energy imbalance service, which it states "is designed to correct a mismatch between energy scheduled by the QF and the actual real-time production by the QF."[35]

Q. Why does PacifiCorp's standard off-system PPA include these requirements?

---

[30] *Id*. at 41.

[31] *Id*. at 6.

[32] *Id*. at 42.

[33] *Id*.

[34] *Id*.

[35] *Id*. at 43.

A. PacifiCorp cannot rely on metering of "physical flow" to validate delivery of power from an off-system QF, so a utility requires evidence of commercially appropriate delivery arrangements to provide this validation.

Some of the requirements of the standard off-system PPA, such as the need for generation reserves, relate to firmness. A QF that commits to delivering its power on a firm basis is entitled to receive the Commission's standard published avoided cost pricing for that power, which includes, when appropriate, the value of capacity in the avoided cost pricing. Other requirements of the standard off-system PPA, such as the need for hourly scheduling, are needed to ensure PacifiCorp can verify that it is actually receiving the power—via a third-party transmission provider—that the QF is supposed to have generated and delivered under a PPA.

Q. Do QF transmission arrangements ordinarily comply with specific industry standards?

Yes. All of the QF transmission arrangements of which I am aware include specific standard industry protocols, as well as additional requirements found in the Company's off-system PPA and Addendum W, such as scheduling and reserve requirements with cost allocation of specific ancillary services to the QF.

Q. Why are these standard industry protocols important?

A. These standard industry protocols are needed to ensure that PacifiCorp receives and can validate the delivery of firm power under a QF PPA. They allow PacifiCorp ESM to know when QF power will be delivered to PacifiCorp's system so that PacifiCorp ESM can schedule that power for use to serve PacifiCorp's own load. They allow PacifiCorp ESM to know that it can rely on firm delivery of QF power, and therefore count on the power being there when the QF says it will be there. Importantly, the protocols also allow PacifiCorp ESM to verify through e-tagging and scheduling that it actually receives QF power that the QF has contractually committed to deliver, and informs PacifiCorp ESM of the timing and location of the QF power delivery.

Without these industry standard protocols, power generated by QFs would simply be pushed onto a transmission system where it could not be properly accounted for, scheduled for load service, or otherwise managed and used.

Q. What is PacifiCorp's role in a QF's delivery of power under an off-system PPA?

A. PacifiCorp's role is described in the Company's Schedule 37. Generally, PacifiCorp ESM communicates with the QF about the terms and conditions of the PPA and ensures all information is collected and that the QF complies with the requirements of the off-system PPA.

Q. Does either PacifiCorp ESM or PacifiCorp Transmission make wheeling arrangements for an off-system QF?

A. No. PacifiCorp ESM does not make transmission arrangements for a QF and is not a party to a QF's transmission arrangements. The arrangements are entirely the QF's responsibility. PacifiCorp ESM simply confirms that the QF has firm transmission arrangements in place that meet the requirements of the standard off-system QF PPA. As Mr. Vail explains, PacifiCorp Transmission does not own or operate the intervening transmission system needed to deliver an off-system QF's power to PacifiCorp's system. Again, the QF is responsible for making these arrangements.

Q. Does PacifiCorp Transmission have *any* role in the QF's delivery arrangements?

A. As Mr. Vail explains, if an off-system QF enters into a point-to-point transmission arrangement with another utility, that utility will need to coordinate with PacifiCorp Transmission to make sure PacifiCorp's system can accept the power.

Q. Once PacifiCorp Transmission determines that power can be safely and reliably *received* by PacifiCorp's system, does that mean the QF has made delivery arrangements that meet the requirements of a QF PPA?

A. No. Just because PacifiCorp Transmission determines that QF power can be *received* by PacifiCorp's system does not mean the QF has made appropriate arrangements to *deliver* that power or that it is, in fact, delivering any power at all.

Q. Has Surprise Valley been willing to agree to the terms and conditions of the Company's standard off-system QF PPA, including the delivery arrangements described in that PPA?

A. No. Surprise Valley has been either unable or unwilling to provide the delivery arrangements required by the Company's standard off-system PPA. For example, with respect to the ancillary services explicitly required by Addendum W of the off-system PPA, PacifiCorp asked Surprise Valley what ancillary services will be provided to ensure the Paisley Project's power is delivered to PacifiCorp's system. Surprise Valley stated, "[n]o ancillary services are required to ensure that the Paisley Project's power is delivered to PacifiCorp's system on a firm basis."[36] In addition to stating that ancillary services requirements do not apply to Surprise Valley, Surprise Valley does not concede

[36] *See, e.g.,* Surprise Valley's Response to PacifiCorp's Data Request 4.26, attached hereto as PAC/144.

that the scheduling requirements contained in the Company's standard PPAs apply to Surprise Valley.[37]

Q. Given these facts, is PacifiCorp willing to sign a standard off-system PPA with Surprise Valley for the output of the Paisley Project?

A. No. PacifiCorp will not sign an off-system QF PPA with Surprise Valley unless Surprise Valley provides evidence that it has made transmission arrangements that comply with the standard off-system PPA. These delivery requirements were litigated by multiple parties, approved by the Commission, and are a mandatory element of a standard off-system QF PPA. They ensure a QF makes commercially appropriate delivery arrangements so that PacifiCorp can obtain and meaningfully use the power it purchases under a PPA.

3. QF's Delivery Obligations Under the Commission's Non-Standard (Schedule 38) QF PPAs

Q. What is PacifiCorp's Schedule 38?

A. Schedule 38 generally applies to QFs that are larger than the eligible maximum capacity threshold in Schedule 37.[38] If a QF is not eligible for a standard contract, the QF must negotiate the rates, terms, and conditions of a PPA with the purchasing utility.

Q. How much are QFs paid for power under Schedule 38?

A. Avoided cost pricing under Schedule 38 is a negotiated price that takes into account the Commission-defined specific operating characteristics of the QF at issue. The standard

---

[37] *See, e.g.*, Surprise Valley's Response to PacifiCorp's Data Request 3.79, attached hereto as PAC/135.

[38] As noted previously, the maximum capacity threshold is 3,000 kW for solar and 10,000 kW for all other QF types.

avoided cost price specified in PacifiCorp's Schedule 37 serves as a starting point for negotiated pricing under Schedule 38.[39]

Q. If Surprise Valley is unwilling or unable to agree to the terms and conditions of a *standard* QF PPA, would PacifiCorp be willing to negotiate a *non-standard* QF PPA with Surprise Valley?

A. Yes. If Surprise Valley is unable or unwilling to agree to a standard QF PPA, PacifiCorp would be willing to negotiate the terms and conditions of a non-standard QF PPA. In fact, PacifiCorp has entertained proposals from Surprise Valley that fall outside of the terms of the Schedule 37 standard PPAs. That said, the Company would still require Surprise Valley to provide delivery arrangements that allow PacifiCorp to verify how much power it is receiving from Surprise Valley, as well as where that QF power will be delivered and how and when it will be delivered. So far, Surprise Valley has not proposed any delivery arrangements that meet these criteria.

Even if a non-standard delivery proposal provided verifiable delivery, PacifiCorp would need to assess the quality of that delivery to make sure it provided the level of firmness and customer indifference that the standard off-system PPA provides. If it does not, PacifiCorp would need to adjust the avoided cost price to reflect the value of that power, as delivered.

D. Initial Discussions with Surprise Valley

Q. How would you describe initial discussions with Surprise Valley about a potential QF PPA?

[39] The Commission recently issued an order in docket UM 1610 that addresses PacifiCorp's calculation of non-standard avoided cost pricing. PacifiCorp has not yet made a compliance filing in that docket. *See In re Investigation into Avoided Cost Contracting and Pricing,* Docket No. UM 1610, Order No. 16-174 (May 13, 2016).

A. The discussions started as a typical Schedule 37 standard QF PPA request. Surprise Valley submitted information consistent with Schedule 37 requirements for a standard off-system PPA but as information emerged around interconnection, location of the Paisley Project within Surprise Valley's electrical system, the BAA, and Surprise Valley's interest in selling 100% of the net output to PacifiCorp, the discussions became much more complicated, particularly regarding whether an off-system or an on-system PPA was the appropriate structure.

Q. When did Surprise Valley first contact PacifiCorp about obtaining a standard QF PPA for the Paisley Project?

A. Surprise Valley first contacted PacifiCorp about obtaining a standard QF PPA for the Paisley Project in August 2013.

Q. Was Surprise Valley eligible for a standard QF PPA?

A. Yes. The Commission defines a "standard" geothermal QF as a QF that is 10 MW or less. So long as Surprise Valley was willing to agree to the terms and conditions of a standard template QF PPA, the Paisley Project was entitled to sell power to PacifiCorp under a standard QF PPA.

Q. How are initial communications with a QF ordinarily handled?

A. When a QF approaches PacifiCorp to obtain a standard QF PPA, PacifiCorp assumes the QF will agree to the terms and conditions of the standard QF PPA, and that PacifiCorp will then be required to purchase power from that QF under the terms and conditions of that standard PPA.

Q. Can QFs review the terms and conditions of the Company's standard QF PPAs before they approach the Company?

A. Yes. The Company's standard QF PPAs are publicly available on the Company's website along with copies of Schedule 37 and Schedule 38. The Company assumes that a QF seeking to execute such a PPA is aware of those terms and conditions. If they have not reviewed the standard QF PPA, the Company generally points out the location of the PPAs on our website. PacifiCorp's Schedule 37 also provides specific information about obtaining a standard QF PPA that has been prepared specifically for the QF including all of the PPA requirements listed in Schedule 37.

Q. Who did Surprise Valley communicate with when it initially sought a standard QF PPA with PacifiCorp?

A. Surprise Valley initially communicated with John Younie, a PacifiCorp employee who, at the time, handled the first line of communications with Surprise Valley.

Q. Were you Mr. Younie's supervisor?

A. Yes.

Q. Did these communications go smoothly?

A. The communications went smoothly at first. But as time passed, PacifiCorp realized that there were problems with Surprise Valley's willingness or ability to agree to the terms and conditions of a standard QF PPA. Specifically, a number of complicating factors regarding the Paisley Project's configuration revealed themselves.

Q. How would you characterize those initial communications?

A. I would characterize them as initially friendly, but undermined by some misunderstandings about the requirements of the Company's standard QF PPAs on Surprise Valley's side, and some misunderstandings about the QF's configuration and Surprise Valley's intentions regarding power delivery on PacifiCorp's side.

Q. As those communications evolved, what did you learn about the Paisley Project?

A. As Mr. Younie reported back to me on the communications between the parties, it became clear to me that the Paisley Project did not meet the profile of any QF I have dealt with in the past. The configuration of the Paisley Project was unique and challenging. That configuration created significant problems in negotiating a PPA.

Q. Once the challenges became apparent, did you take over for Mr. Younie as the primary contact person with Surprise Valley?

A. Yes. Although I was involved in review of Mr. Younie's work as he progressed on the PPA, it became apparent by August 2014 that there were significant challenges with the Paisley Project, so I stepped in as the primary point of contact with Surprise Valley.

E. Delivery Challenges Posed by the Paisley Project's Configuration

Q. Where is the Paisley Project located?

A. As I have noted, the Paisley Project is a geothermal electric generation facility located in Paisley, Oregon, interconnected to Surprise Valley's distribution system and located in Surprise Valley's service territory. The Paisley generator itself is located in a remote area on the far side of the majority of Surprise Valley's load and roughly 50 miles from where Surprise Valley's service territory interconnects with PacifiCorp's transmission system at BPA's Meter 41, also referred to as the Lakeview Switch.[40]

Q. Why is the Paisley Project's configuration unusual?

A. There are a number of reasons the Paisley Project's configuration is unusual. First, the Paisley Project is owned by Surprise Valley, another utility. This is not typical of QFs

[40] *See* Surprise Valley Complaint at 7.

that I have dealt with. Moreover, it is a QF interconnected with its own electrical system, a non-PacifiCorp system within PacifiCorp's BAA.

Q. How does Surprise Valley's interconnection with and ownership of the Paisley Project affect the potential use of the Paisley Project's output?

A. Because Surprise Valley owns the Paisley Project, Surprise Valley could use the Paisley Project in a number of ways. It could use the Paisley Project as a generation resource to serve Surprise Valley's own retail load, in which case that generation could not be sold to anyone else. Alternatively, Surprise Valley's retail load could be served by *some other generation resource* and the Paisley Project's output could be sold to another entity like PacifiCorp. But the ownership and interconnection issues meant that PacifiCorp needed to make sure Surprise Valley was actually planning to sell and could physically deliver the QF power to PacifiCorp. PacifiCorp needed to make sure Surprise Valley was not going to use the Paisley Project's generation to serve its own load *and then* try to sell that same power to PacifiCorp.

Q. What concerns are raised by Surprise Valley's limited access to generation resources and its potential use of the Paisley Project to serve Surprise Valley's own load?

A. The ownership and configuration of the Paisley Project allow Surprise Valley to use the Paisley Project to serve its own cooperative's load. This makes it doubly important for PacifiCorp to ensure that Surprise Valley makes arrangements to deliver the QF's power to PacifiCorp in a manner that PacifiCorp can verify to avoid the problem where the same power is both used and "sold."

Q. Were there other factors that complicated PacifiCorp's assessment of whether it could verify power delivery from the Paisley Project?

A. Yes. As we looked into the issue more closely, it became apparent that additional factors made it challenging for Surprise Valley to execute a PPA that ensured PacifiCorp would physically receive any power from Surprise Valley.

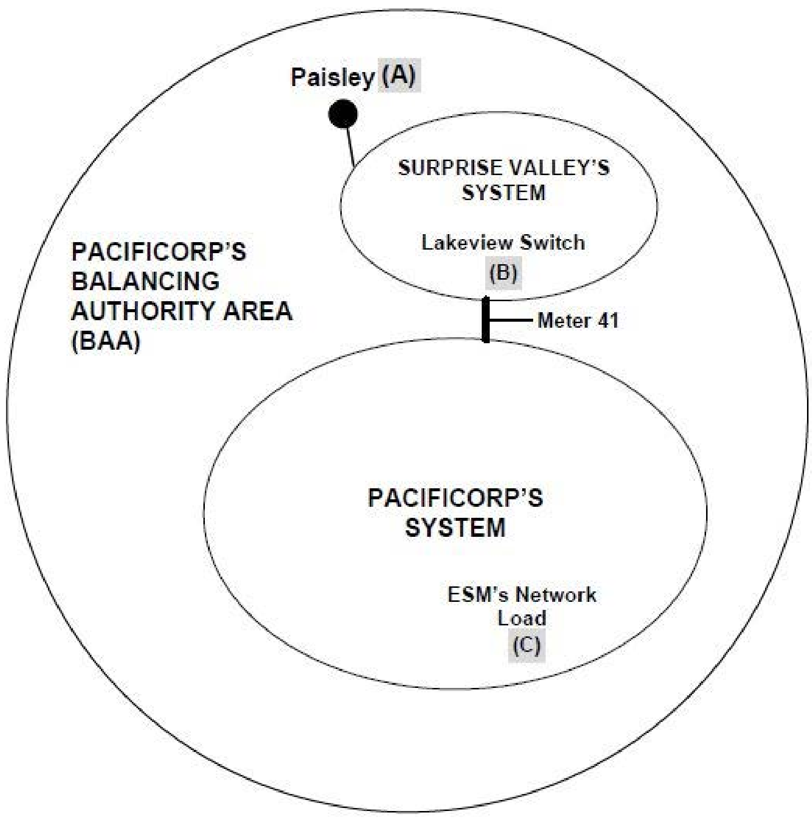
Q. What are those factors?

A. First, the location of the Paisley Project on Surprise Valley's system is problematic for Surprise Valley. Second, the fact the Paisley Project is interconnected with Surprise Valley's distribution system, rather than a more commercially sophisticated system, poses delivery challenges for Surprise Valley. Third, Surprise Valley's method of serving its load with BPA power raised serious issues about whether any power, let alone QF power, was available for sale to PacifiCorp. These problematic issues were compounded by the fact that Surprise Valley sought to rely on a non-standard, "swap" type of transaction for its delivery obligations, in no small part because that proposal relied on the GTA between BPA and PacifiCorp. During contract discussions and negotiations it appeared that PacifiCorp was being asked to sign a PPA that would obligate it to pay avoided cost prices for power it might never receive. Or in other words, to simply accept Surprise Valley's word that PacifiCorp gets the power from BPA via the proposed "swap" arrangements, introducing risk to PacifiCorp's retail customers.

1. Location of the Paisley Project

Q. Why is the location of the Paisley Project on Surprise Valley's system problematic for Surprise Valley?

A. The Paisley Project is located in Paisley, which is located on the far northeast side of Surprise Valley's system (A). Surprise Valley's retail load is located between the Paisley Project and the Lakeview Switch (B), where the Paisley Project intends to deliver power to PacifiCorp's system. This means that the Paisley Project's output would need to pass through Surprise Valley's own load before reaching PacifiCorp's system.



Q. As a practical matter, what does this mean?

A. It means that Surprise Valley cannot physically deliver the full output of the Paisley Project to PacifiCorp's system. After the generation leaves the plant, some amount of that generation will be consumed by Surprise Valley's retail load, and only the remainder will be physically delivered to PacifiCorp's system at the Lakeview switch point of delivery.

Q. Assuming Paisley were generating power, how much of Paisley's power would be physically delivered to PacifiCorp's system after Paisley's generation passes through Surprise Valley's load?

A. Very little. After the parties ran into difficulties with delivery issues, PacifiCorp conducted flow studies on Surprise Valley's system. Those flow studies confirmed that even if the Paisley Project were generating at full capacity, less than one percent of the generator output would actually reach PacifiCorp's system.

Q. Would PacifiCorp be willing to purchase the amount of power that is physically delivered by Surprise Valley to the Lakeview switch, up to the net output of the Paisley Project?

A. Yes. If Surprise Valley were willing to sign a standard on-system QF PPA, PacifiCorp would treat Surprise Valley's distribution system as a long tie-line interconnecting the QF with PacifiCorp's system, a viable option because of the Paisley Project's ownership. PacifiCorp would then purchase the amount of power that is physically delivered to PacifiCorp's system and verified by a meter between the systems, up to the net output of the Paisley Project.

Q. Is Surprise Valley willing to sign such an agreement?

A. No. Surprise Valley recognizes that little or no power would physically flow to PacifiCorp's system, yet it insists on selling the full output of the plant (minus station service and line losses). PacifiCorp will only purchase the metered flow under the on-system QF PPA, per the terms of that agreement. Yet Surprise Valley continues to assert that the standard, on-system QF PPA "allows Surprise Valley to sell the entire net output to PacifiCorp."[41]

Q. What options does this leave Surprise Valley?

A. If Surprise Valley is unwilling to sign a PPA that relies on metered flow between the parties' systems, but instead wishes to sell the full net output of the plant, Surprise Valley must find a way to verifiably transmit or wheel the Paisley Project's power to PacifiCorp's system.

2. The Paisley Project's Interconnection with Surprise Valley's Distribution System

Q. Why does the fact that the Paisley Project is interconnected with Surprise Valley's distribution system pose challenges for Surprise Valley?

A. Surprise Valley operates a non-FERC jurisdictional distribution system that does not seem to be set up to manage a commercially appropriate wheeling arrangement. If a QF cannot manage physical delivery of its power to a utility's system, as Surprise Valley cannot, a QF must make wheeling arrangements to deliver its power to a utility's system.

Q. Please explain.

A. Parties that are delivering physical power to other parties need to make appropriate commercial arrangements to ensure power is appropriately accounted for between each party's electrical systems. These commercial arrangements can include requirements like scheduling, e-tagging, procurement and provision of ancillary services, etc. Transmission providers like BPA, Avista, or PacifiCorp Transmission have systems and business practices in place that let them transmit power over their systems using these standard commercial indicia of reliability and verification. A small cooperative like Surprise

[41] *See, e.g.*, Surprise Valley's Response to PacifiCorp's Data Request 3.48, attached hereto as PAC/125.

Valley rarely undertakes such commercial deliveries and therefore may not be set up to meet the same industry standards for transmitting power as larger, FERC-jurisdictional utilities. This does not mean that Surprise Valley can simply ignore the industry standards or that PacifiCorp can or will accept an inferior or unacceptable method of delivery that puts its customers at risk for overpayment or under-delivery.

Q. Is Surprise Valley capable of making firm transmission arrangements that comply with industry delivery standards?

A. Based on my discussions with Surprise Valley, Surprise Valley does not appear to be willing or capable of doing so at this point in time, though it could presumably take steps to elevate its level of delivery service.

Q. How would Surprise Valley accomplish that?

A. That would be up to Surprise Valley. The QF is responsible for making and paying for the wheeling arrangements to deliver the power to PacifiCorp.[42] The acceptable firm transmission standards are well known in the industry and PacifiCorp believes that Surprise Valley should be responsible for providing them in return for receiving the published standard avoided cost pricing for the full net output of their QF. As I pointed out earlier, we currently have multiple off-system PPAs in Oregon, and several in other states as well. All of these off-system PPAs are currently either providing or securing the necessary wheeling arrangements to deliver firm power to PacifiCorp. PacifiCorp is not sure precisely what capabilities Surprise Valley has, but at this point in time, it does not appear that Surprise Valley is capable of providing or has taken the initiative to

[42] PAC/103 at Griswold/42.

understand the industry standard requirements identified in Addendum W of the off-system PPA.

Q. Is Surprise Valley willing to do so?

A. That is unclear. To this point, Surprise Valley has not been willing to provide PacifiCorp with evidence that it is willing to provide firm delivery of the Paisley Project's power to PacifiCorp's system. For example, during negotiations, Surprise Valley never explained how it would reserve capacity on its system to allow for firm delivery; how it would provide ancillary services, including generation reserves; or how it would comply with industry-standard hourly scheduling protocols. Instead, Surprise Valley has simply insisted that it wants a PPA for the full net output of the Paisley Project at full avoided cost, while drawing a line in the sand and stating that it is unwilling to "purchase unreasonably expensive 'transmission arrangements.'"[43] Assuming Surprise Valley considers it "unreasonably expensive" for Surprise Valley to make industry-standard transmission arrangements that allow PacifiCorp to verify how much power Surprise Valley is delivering to PacifiCorp's system, Surprise Valley would appear unwilling to provide those arrangements.

Q. Does it matter that the Paisley Project is owned by Surprise Valley? How can Surprise Valley make a delivery arrangement with itself?

A. Surprise Valley need not sign a contract with itself to be entitled to an off-system QF PPA, but it would nevertheless need to describe its firm delivery arrangements for PacifiCorp, obtain ancillary services supporting the delivery arrangement, arrange for hourly scheduling, and arrange for the ancillary services and other requirements of an off-

[43] PAC/126.

system PPA. Regardless of who owns a QF, the reason for requiring industry-standard wheeling arrangements for an indirectly interconnected QF remains the same. These industry standards provide indicia of verifiable delivery and passage of title that are necessary to make a PPA meaningful.

Q. Is it PacifiCorp's responsibility to ensure that a QF can make commercially appropriate QF arrangements to deliver QF power to a purchasing utility's system?

A. No. The delivery of power from a QF to a utility's system has always been a QF's responsibility. That said, PacifiCorp employees have spent an enormous amount of time and effort in discussions with Surprise Valley and behind the scenes trying to understand the implications of the Paisley Project's configuration and to make Surprise Valley's situation work, despite the fact that Surprise Valley has been unwilling or unable to make standard delivery arrangements.

Q. What do you view as the source of Surprise Valley's difficulties in delivering its power to PacifiCorp's system?

A. For the reasons explained above, Surprise Valley's siting of its project means that it cannot sell the entire net output of the plant through a direct interconnection. The location of the plant means that Surprise Valley must provide a commercially appropriate wheeling arrangement that allows PacifiCorp to verify receipt of QF power, which Surprise Valley has had trouble providing or has suggested are unreasonable and expensive.

Q. If Surprise Valley did not sell its power to PacifiCorp, how else could Surprise Valley use the Paisley Project's power?

A. Surprise Valley could use the Paisley Project to serve its load, as it currently appears to be doing, or it could force BPA to take the power as an offset to Surprise Valley's all-requirements contract with BPA.[44] Instead, it has chosen to sell the power to PacifiCorp to obtain a higher price for that power while securing the lower priced all-requirements deliveries from BPA. This is Surprise Valley's right, but it does require Surprise Valley to meet certain obligations and industry standards before the Paisley Project can enjoy the benefit of PacifiCorp's higher avoided cost pricing. Specifically, Surprise Valley first has to show that it is able to deliver the QF's power to PacifiCorp's system so that PacifiCorp and its customers actually get the benefit of that power and PacifiCorp is not just subsidizing Surprise Valley's customers so they retain their lower rates through their BPA all-requirements contract.

3. Surprise Valley's All-Requirements Contract with BPA

Q. Why did Surprise Valley's contractual arrangements for serving its own load raise concerns for PacifiCorp?

A. Surprise Valley has an all-requirements power supply contract with BPA. Under that contract, BPA supplies all of the power required to meet Surprise Valley's load.[45] When the parties were still in the midst of PPA discussions (before Surprise Valley filed its complaint), the all-requirements contract with BPA treated the Paisley Project as a load-serving resource.[46]

---

[44] Surprise Valley stated that it considered selling the power to BPA but BPA was "not interested in purchasing the net output." Surprise Valley's Response to PacifiCorp's Data Request 3.34, attached hereto as PAC/1.23.

[45] SVEC/100, Kresge/6 ("We are a full requirements customer of BPA. This means that BPA provides power to meet all of Surprise Valley's electric needs.").

[46] Surprise Valley's Response to PacifiCorp's Data Request 4.14 ("If the BPA and Surprise Valley power sale agreement had not been modified to reflect the existence of the Paisley Project, then it would appear that the Paisley Project served Surprise Valley's retail load. This would result in Surprise Valley's retail load appearing smaller. To ensure that the net output of the Paisley Project did not appear to serve Surprise Valley's retail load, the net output

Q. What concerns did this raise for PacifiCorp?

A. The fact that Surprise Valley's contract with BPA treated Paisley as a load-serving resource meant that if the Paisley Project were generating power, and that power were used to serve Surprise Valley's load (as Surprise Valley conceded it would), BPA would then be obligated to supply only the net retail load under its all-requirements contract with Surprise Valley and would schedule less power for delivery to Surprise Valley's system.

Q. How much would BPA's scheduled deliveries to Surprise Valley have been reduced under the contract?

A. In theory they would have been reduced by the amount of the Paisley Project's output.

Q Can you provide an example of how this might have affected the amount of power available on Surprise Valley's system?

A. Yes. Imagine that Surprise Valley's total load was 10 MW and the Paisley Project was not generating power. In this case, BPA would have been obligated to schedule 10 MW of power for delivery to Surprise Valley, the full amount of Surprise Valley's load needs. Now imagine that Surprise Valley's total load was 10 MW and the Paisley Project was generating 3 MW. In this case, BPA would have been obligated to deliver only 7 MW to Surprise Valley under Surprise Valley's all-requirements contract with BPA because Paisley would be serving the additional 3 MW of load.

Q. How would that have affected Surprise Valley's ability to sell the Paisley Project's output as a QF?

---

of the Paisley Project needed to be measured.") (attached hereto as PAC/142); Surprise Valley's Response to PacifiCorp's Data Request 4.71 ("Without the contract amendment, the Paisley Project would contractually serve Surprise Valley's load.") (attached hereto as PAC/150).

A. If PacifiCorp entered into a QF PPA to purchase the full net output of the Paisley Project (here, 3 MW), it would not have received that 3 MW. BPA would have provided 7 MW to Surprise Valley's system, and Paisley's 3 MW would have been used to serve Surprise Valley's remaining load. These are Surprise Valley's only resources, and they are required to meet Surprise Valley's load. Thus, in this scenario, there would be no "extra" power available for purchase by PacifiCorp.

Q. What is the significance of this power deficit in a situation where PacifiCorp cannot verify how much power it is (or is not) receiving under a QF PPA with Surprise Valley?

A. This deficit of power would not be an issue if Surprise Valley provided or acquired delivery services consistent with an off-system QF PPA that allowed PacifiCorp to verify how much power it was (or was not) receiving. PacifiCorp would know that it received no power, and it would not pay Surprise Valley for anything. On the other hand, if PacifiCorp could not verify physical power delivery under the PPA (because Surprise Valley failed to make verifiable delivery arrangements), but PacifiCorp was nevertheless required to purchase the amount of energy generated by the Paisley Project under a PPA, PacifiCorp would be paying for power that simply did not get to our system. This unacceptably introduces risk to PacifiCorp's retail customers.

Q. Did BPA get involved in these discussions?

A. Yes. BPA verbally agreed at one point to informally assist with what I will call the "contractual power deficit" problem.

Q. Was PacifiCorp ESM amenable to this offer?

A. Yes. If BPA had been willing to put the offer in writing and agree to provide Surprise-Valley specific hourly schedules for power delivery, PacifiCorp would have been willing to work with the offer. But BPA was not. After Surprise Valley filed its complaint against PacifiCorp, BPA and Surprise Valley appear to have amended their power sales agreement to eliminate the "contractual" use of Paisley as a load-serving resource. This solved one problem PacifiCorp identified with Surprise Valley's proposed delivery method during PPA negotiations, but it did not solve all of the problems. Critically, BPA continues to refuse to provide PacifiCorp with the type of granular schedules that would allow PacifiCorp to verify physical receipt of the Paisley Project's power. I will discuss this issue next.

4. PacifiCorp's General Transfer Agreement (GTA) with BPA

Q. Are there other complications caused by Surprise Valley's method of load service?

A. Yes. If Surprise Valley is unwilling or unable to make *standard* QF power delivery arrangements, which has been the case, the fact that BPA serves Surprise Valley's load through an agreement with PacifiCorp called the GTA is a complicating factor.

Q, What is the GTA?

A. The GTA[47] is a reciprocal transfer agreement between PacifiCorp and BPA that provides for the transfer of energy across PacifiCorp's transmission and distribution system to certain of BPA's wholesale power customers, including Surprise Valley. Under the agreement, BPA schedules power to PacifiCorp's system, and PacifiCorp Transmission delivers that power to certain of BPA's customers on BPA's behalf. BPA does the same in return for PacifiCorp. PacifiCorp schedules power to BPA's system, and BPA

[47] The GTA can be found at PAC/101.

delivers that power to certain of PacifiCorp's customers on PacifiCorp's behalf. At the end of each month, BPA and PacifiCorp true-up the transfer amounts between the two utilities.

Q. Does BPA serve Surprise Valley's load through the GTA?

A. Yes. Surprise Valley purchases all of its load needs from BPA. Under the GTA, PacifiCorp Transmission delivers this BPA power to Surprise Valley on BPA's behalf.

Q. Is the GTA relevant to Surprise Valley's attempt to obtain a PPA?

A. The GTA is a critical component for the success of the *non-standard* delivery proposals Surprise Valley has tendered to PacifiCorp since April 2014. It remains a critical element of the delivery proposals that form the basis of Surprise Valley's complaint, as well as the proposals in its direct testimony.

Q. Why do you say that Surprise Valley relies on "non-standard" delivery proposals?

As I noted above, Surprise Valley does not want to sign a *standard on-system* PPA because little or no power physically flows from the Paisley Project (or from Surprise Valley's system at all) to PacifiCorp's system. Surprise Valley has also historically been either unwilling or unable to make the commercially appropriate transmission arrangements required by a *standard off-system* PPA, which requires a QF to provide, among other things, industry-standard scheduling and ancillary services. Instead, since April of 2014, Surprise Valley has tendered "alternative" delivery arrangements to PacifiCorp seeking a PPA for the full output of the Paisley Project, which PacifiCorp has consistently rejected. These have been referred to as Surprise Valley's "concept paper," or "swap," and Surprise Valley's "displacement" or "offset" proposals.

At their most basic, these proposals would allow Surprise Valley to simply run the Paisley Project and use the QF generation to serve Surprise Valley's load. Surprise Valley would make no transmission arrangements whatsoever. PacifiCorp would then simply "keep" some of the power PacifiCorp Transmission was delivering to Surprise Valley on BPA's behalf under the GTA.

Q. Please explain how Surprise Valley's reliance on the GTA is problematic.

A. Surprise Valley's delivery proposal has a number of issues, some of them legal issues that will be addressed in briefing. The biggest problem is that PacifiCorp cannot verify how much power BPA will schedule to Surprise Valley's system under the GTA. Without that information, PacifiCorp cannot tell how much extra power the Paisley Project is actually delivering to PacifiCorp's system.

BPA schedules power for PacifiCorp Transmission to deliver to its customers under the GTA on an aggregated BAA.[48] It does not schedule power specifically to individual customers like Surprise Valley; rather, it takes historical meter data for each of its customers and rolls it up to a single large hourly schedule delivered daily to PacifiCorp's system.[49] BPA's aggregated scheduling makes it impossible for PacifiCorp's ESM to verify how much physical power is being over-scheduled from BPA that is attributable to the Paisley generation under Surprise Valley's various delivery proposals.

Q. Why does this create verification problems?

[48] Surprise Valley's Response to PacifiCorp's Data Request 3.39 (explaining that BPA treats Surprise Valley's load as part of its "aggregated loads" for all of its requirements customers) (attached hereto as PAC/124).

[49] *Id.*

A. Even without industry-standard delivery arrangements, PacifiCorp might be able to verify how much power it receives from the Paisley Project if it has three pieces of data it needs to "true up" the amount of QF power available for purchase under the PPA: (1) The generator output of the Paisley Project at the facility; (2) Surprise Valley's load at the Lakeview Switch; and (3) the amount of power scheduled by BPA to Surprise Valley's system. PacifiCorp has access to (1) and (2), but because of BPA's aggregate scheduling practices, PacifiCorp does not have access to (3).

Q. Do you think Surprise Valley is aware of this flaw in its delivery proposals?

A. I believe so. After PacifiCorp filed its answer to Surprise Valley's complaint in this docket, Surprise Valley moved to strike all of PacifiCorp's references to the GTA in PacifiCorp's answer.[50] This motion was denied, but it remains clear that Surprise Valley does not want PacifiCorp to talk about the GTA.

Q. Has Surprise Valley attempted to limit discussion of the GTA in other ways?

A. Yes. Surprise Valley consistently states that the Commission cannot address the GTA because it is outside of the Commission's jurisdiction. For example, Surprise Valley witness Brad Kresge's direct testimony asks the Commission to find that Surprise Valley has made "sufficient transmission arrangements" to enable a sale of the full net output of the Paisley Project, but then he drops a footnote stating that his counsel has explained that some of "PacifiCorp's transmission arrangements arguments" may be outside of the Commission's jurisdiction to address.[51]

Q Do you believe the "arguments" in Mr. Kresge's footnote refer to the GTA?

A. Yes.

[50] *See* Surprise Valley's Motion to Strike or Clarify Scope of Proceeding (Nov. 6, 2015)

[51] *See* SVEC/100, Kresge/2.

Q. How do you assess Surprise Valley's argument that the Commission should not discuss the GTA?

A. I think it is impossible for the Commission to "not discuss the GTA" in this case, because (1) Surprise Valley has made it an integral part of its conceptual power delivery proposal, and (2) the way Surprise Valley is trying to use it has fatal flaws that would prevent PacifiCorp and its customers from verifying that they receive any physical power from Surprise Valley/BPA under a PPA.

Q. How did PacifiCorp respond to Surprise Valley's assertion that the GTA cannot be discussed anywhere but FERC?

A. When PacifiCorp reviewed Surprise Valley's direct testimony, it became clear that Surprise Valley was going to rely heavily on the GTA as a critical element of delivery in this case. Yet Surprise Valley has consistently stated that the Commission cannot discuss the GTA, only FERC can do so. Consequently, on April 6, 2016, PacifiCorp moved to suspend the procedural schedule in this docket so PacifiCorp could seek guidance on Surprise Valley's delivery proposals, including the GTA element, at FERC.

Q. Did the Commission grant PacifiCorp's motion?

A. No. The Administrative Law Judge (ALJ) denied the motion. The ALJ held that preemption did not bar the Commission from ruling on the issues in this docket and that the Commission has authority to implement PURPA.[52]

Q. How do you interpret that ruling?

[52] *Surprise Valley Electrification Corp. v. PacifiCorp, d/b/a Pacific Power*, Ruling Denying Motion to Suspend Procedural Schedule and Hold Proceedings in Abeyance, Docket No. UM 1742 (Apr. 29, 2016).

A. I interpret that ruling to mean that the Commission is willing and able to address the issues in Surprise Valley's complaint and direct testimony, as well as PacifiCorp's arguments in response to Surprise Valley, *including arguments about the GTA.*

Q. How does Surprise Valley make the GTA a critical part of its delivery proposal?

A. Surprise Valley leaned heavily on the GTA for one of its delivery proposals as far back as April 2014, when it provided PacifiCorp with a "concept paper" that detailed its proposed delivery method. PacifiCorp was not sure to what extent Surprise Valley would continue to rely on the GTA in its testimony in this case, but its direct testimony confirms the critical nature of the GTA to Surprise Valley's arguments. For example, at Exhibit SVEC/300, Saleba-Tabone/3-4, witnesses Saleba and Tabone summarize Surprise Valley's power delivery proposal in several bullet points. One of those bullet points states that, under Surprise Valley's proposed delivery method, "a portion of the BPA power delivered to PacifiCorp on behalf of Surprise Valley will be retained by PacifiCorp for its own use."[53]

Q. Does this passage refer to the GTA?

A. Yes. The passage actually means, "a portion of the BPA power delivered to PacifiCorp on behalf of Surprise Valley ***under the GTA*** will be retained by PacifiCorp for its own use." And, to correct the statement, PacifiCorp does not deliver any power "on behalf of Surprise Valley." PacifiCorp delivers power on behalf of *BPA*, PacifiCorp's counterparty to the GTA.

Q. Why is this a problem?

[53] SVEC/300, Saleba-Tabone/3.

A. This "retention" of BPA power is the only way PacifiCorp would receive power under Surprise Valley's proposed PPA. This is problematic for numerous reasons, but the most critical flaw is that currently under the GTA, BPA gives PacifiCorp Transmission an aggregated schedule for a group of BPA's wholesale preference customers.[54] That power is delivered to a number of delivery points across PacifiCorp's western BAA. This means that PacifiCorp cannot know how much power BPA has actually scheduled for delivery to Surprise Valley's system at any time, or ever. Thus, even if Surprise Valley's delivery proposal somehow worked in theory—that is, even if it appropriately transferred title of power to PacifiCorp and otherwise complied with PURPA—it would still be a non-starter because it would leave PacifiCorp with no idea whether it was actually receiving physical power anywhere on its system under the proposed PPA.

Surprise Valley is trying to use PURPA to arbitrage low-cost Tier 1 BPA preference power for PacifiCorp's much more lucrative avoided cost pricing. At a minimum, PacifiCorp should be able to validate how much of that power it receives.[55]

Q. Is BPA willing to provide more granular, Surprise Valley-specific schedules?

A. No. My understanding is that Surprise Valley has asked for such schedules but BPA has consistently refused to provide them. As Mr. Vail explains in his testimony, PacifiCorp Transmission recently contacted BPA to make one last attempt to obtain Surprise Valley-specific schedules from BPA, but BPA refused.

IV. SURPRISE VALLEY'S COMPLAINT

Q. What does Surprise Valley allege in its complaint?

[54] PAC/124 (explaining that BPA treats Surprise Valley's load as part of its "aggregated loads" for all of its requirements customers).

[55] It should also be able to validate where and when it receives that power.

A. Surprise Valley makes two key assertions in its complaint. It argues that it committed to sell the Paisley Project's full net output to PacifiCorp before August 20, 2014, and that it therefore has a LEO that entitles it to pre-August 20, 2014 avoided cost rates for the full net output of the Paisley Project. It also argues that PacifiCorp acted in bad faith during negotiations and seeks penalties against PacifiCorp.

Q. Do you agree with these assertions?

A. No.

Q. Were you surprised by any of the allegations in Surprise Valley's complaint?

A. Yes. I was surprised by many of the allegations of bad faith, and by a number of Surprise Valley's assertions about promises PacifiCorp had made. I believe a number of Surprise Valley's statements are misunderstandings or are simply wrong.

Q. Do any particular misunderstandings stand out?

A. Yes. I disagree with many of Mr. Culp's and Mr. Kresge's assertions, but one misunderstanding throughout the testimony stands out. PacifiCorp did a number of studies during the course of the parties' negotiations to determine how PacifiCorp might receive the Paisley Project's net output in a way that would allow PacifiCorp to physically meter and measure that output. Surprise Valley consistently suggests that PacifiCorp's ability to "receive" Surprise Valley's net output equated to PacifiCorp accepting that Surprise Valley was "delivering" the net output.[56] These are two different things. PacifiCorp Transmission's ability to *receive* QF power on PacifiCorp's system

[56] SVEC/100, Kresge/16 ("PacifiCorp ESM made it clear that the purpose of this internal request for network transmission would be to identify and resolve all issues related to metering and measuring the Paisley Project's net output that would be required for PacifiCorp ESM to take delivery and title to the entire net output for its use."); SVEC/200, Culp/8 ("[The] system impact study that resulted from the network transmission request would show the system upgrades required in order to receive the Paisley Project into PacifiCorp's system."); SVEC/300, Saleba-Tabone/21 (same); Surprise Valley Complaint at 10 (same).

and measure its flow is not the same thing as a QF's ability to *deliver* that power. There are times of the year when Surprise Valley's loads are low and Paisley generation in excess of load would be received on PacifiCorp's system at Lakeview Switch; however, that is different than Paisley delivering the full net output to PacifiCorp. In fact, Surprise Valley has been extremely careful about the use of the word "receive" in this context, which suggests it may be aware of the difference.

A. Legal Construct in Surprise Valley's Complaint

Q. Given the flaws you have described in Surprise Valley's delivery proposals, how does Surprise Valley's complaint describe Surprise Valley's entitlement to a QF PPA?

A. Surprise Valley relies on two theories for its entitlement to a QF PPA in its complaint: First, it relies on what I will call FERC's Order No. 69 "offset" or "displacement" theory. Second, it relies on FERC's "simultaneous purchase and sale" construct.[57] Surprise Valley uses these theories to argue that it need not make traditional delivery arrangements for the Paisley Project's power.

Q. Do you agree that these constructs apply here?

A. No.

1. FERC's Order No. 69 Offset Construct

Q. What is FERC's Order No. 69 "Offset" construct?

A. As I understand it, FERC recognizes an extremely narrow "offset" alternative to an off-system QF's requirement to wheel its power to a purchasing utility.[58] FERC's Order

[57] Surprise Valley Complaint at 24-27.

[58] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. 12214, 12222 (1980) (Order No. 69).

No. 69 states that an all-requirements utility—like Surprise Valley—can use QF power to serve its own load, displacing the energy that would have been supplied *by its all-requirements supplier*—like BPA. That all-requirements supplier will be deemed to have purchased the QF power without receiving actual physical delivery or wheel of QF power.[59]

Q. Who would be Surprise Valley's all-requirements supplier in this context?

A. BPA.

Q Does Surprise Valley attempt to apply the "offset" construct to sell QF power to BPA?

A. No. It attempts to apply it to PacifiCorp, which does not work. Under FERC's description of the offset or displacement construct, Surprise Valley could use the Paisley Project's output to serve Surprise Valley's own load. That power would displace Surprise Valley's load requirements, and therefore would decrease the amount of electricity that Surprise Valley would otherwise purchase from BPA under Surprise Valley's all-requirements contract with BPA. The power would be "deemed" purchased by BPA. But at this point in the analysis, Surprise Valley veers away from Order 69, which would apply the offset to BPA, and attempts to apply the offset to PacifiCorp.

Q. Does this make sense?

A. No. This suggestion is not only impossible under the various parties' existing contractual arrangements, but also appears to be inconsistent with Order No. 69.

---

[59] Order No. 69 at 12219 ("Under paragraph (d), if the qualifying facility consents, an all-requirements utility which would otherwise be obligated to purchase energy or capacity from the qualifying facility would be permitted to transmit the energy or capacity to *its supplying utility.* In most instances, this transaction would actually take the form of the displacement of energy or capacity that would have been provided under the *all-requirements obligation*.") (emphasis added).

Q. Does PacifiCorp sell *any* wholesale power to Surprise Valley at all that could be the subject of such an "offset"?

A. No. PacifiCorp ESM, Surprise Valley's proposed counterparty under the PPA, makes no wholesale power sales to Surprise Valley. Even if FERC's Order 69 offset provision could theoretically apply to *any* party selling power to a cooperative (rather than limiting the construct to all-requirements sellers, as FERC does), the offset provision would still not apply to PacifiCorp.

Q. When PacifiCorp Transmission delivers power to Surprise Valley on behalf of BPA, what is its role?

A. PacifiCorp Transmission simply delivers BPA's power to Surprise Valley.[60]

Q. Has Surprise Valley tried to use the offset provision to "sell" Paisley's power to BPA, its all-requirements provider?

A. Surprise Valley states that it tried to sell the Paisley Project's output to BPA, but BPA was "not interested in purchasing the net output."[61]

2. FERC's Simultaneous Purchase and Sale Construct

Q. Does Surprise Valley make another Order 69 argument in its complaint?

A. Yes. Surprise Valley argues that it is entitled to a PPA for the full net output of the Paisley Project because a "QF may enter into a 'simultaneous purchase and sale' in which

[60] There are a multitude of reasons the theory does not apply to PacifiCorp Transmission, aside from the fact that it does not fit into the Order No. 69 construct. For example: (1) PacifiCorp Transmission has no legal title to the power it delivers on behalf of BPA—it cannot just "keep" it; (2) the applicable contracts—which Surprise Valley does not appear to understand—leave no "extra" power for PacifiCorp Transmission to "keep," so there is nothing to "keep"; and (3) PacifiCorp Transmission does not buy and sell power to serve load. Rather, it is BPA Tier 1 power sourced from BPA's power resources to serve BPA's own customers. Even if PacifiCorp Transmission could theoretically "keep" such power to serve customer load, which it cannot do for a host of reasons, PURPA does not obligate PacifiCorp to purchase BPA Tier 1 power at avoided cost rates when PacifiCorp cannot even verify delivery sufficient to cover the amount of the QFs net output.

[61] PAC/123.

the QF sells to the utility its entire net output, while simultaneously purchasing from the utility its full electric requirements at tariff rates."[62]

Q. Are you familiar with the concept of the "simultaneous purchase and sale" under PURPA?

A. Yes. Surprise Valley cites FERC Order 69 for the concept, but this Commission also addressed the concept in docket UM 1129 and adopted a related stipulation in Order No. 07-360. I participated in that docket as a witness and I am familiar with the concept.

Q. What is the "simultaneous purchase and sale" construct?

A. Under a "simultaneous purchase and sale," a QF sells its entire net output to a utility while simultaneously purchasing its full electrical requirements from that utility at tariffed retail rates.

Q. Does this concept apply to the Paisley Project?

A. Not insofar as PacifiCorp is concerned. Although the Paisley Project wants to sell its net output to PacifiCorp, it does not simultaneously purchase its electrical requirements from PacifiCorp.

Q. Why doesn't the Paisley Project purchase its electrical requirements from PacifiCorp?

A. The Paisley Project is not a PacifiCorp customer and it is not directly interconnected with PacifiCorp's system. Moreover, the electrical requirements of a QF are generally things like station service needed to power the QF, not, as Surprise Valley appears to assert here, load service for an entire cooperative.

[62] Surprise Valley's Complaint at 26 (citations omitted).

3. Conclusions about Order No. 69

Q. Does FERC Order 69 eliminate Surprise Valley's requirement to deliver its power to PacifiCorp's system?

A. No. PURPA, Oregon law, and the Commission's standard PPA require an off-system QF to wheel its power to an indirectly interconnected utility before that utility is required to purchase that power under PURPA. FERC Order 69 does not eliminate these requirements for parties like Surprise Valley and PacifiCorp under either of the theories put forth by Surprise Valley.

B. Delivery Proposal in Surprise Valley's Direct Testimony

Q. Please describe the QF power delivery proposal in Surprise Valley's direct testimony.

A. Surprise Valley's delivery proposal is described in Surprise Valley's "concept paper" and the testimonies of Saleba and Tabone (Exhibit SVEC/300) and Anderson (Exhibit SVEC/400). It is similar to the concept paper in the sense that, under Surprise Valley's most recent delivery proposal, the Paisley Project's power would be used to serve Surprise Valley's load and PacifiCorp would theoretically "keep" some of the power PacifiCorp delivers to Surprise Valley on BPA's behalf under the GTA. It basically states as follows:

- BPA schedules power to PacifiCorp Transmission (under the GTA) for delivery to Surprise Valley at the Lakeview Switch.
- BPA continues to supply Surprise Valley with its full load requirements under the all-requirements contract between BPA and Surprise Valley as if the Paisley Project generation were not serving any Surprise Valley load.

- When Paisley Project is generating, additional power will be added to PacifiCorp Transmission's system equal to the Paisley Project output less transmission line losses.
- PacifiCorp Transmission also delivers power to PacifiCorp retail customers in the area surrounding Surprise Valley's service territory sufficient to meet their load needs.
- The "excess" power will be supplied to PacifiCorp's retail customers and PacifiCorp generation serving PacifiCorp's Mile High substation will be reduced by the net output at the Paisley Project.
- PacifiCorp will pay Surprise Valley for this "excess" power at avoided cost prices in the QF PPA.

Q. Is this power delivery method consistent with the Company's Commission-approved on- or off-system PPAs?

A No.

Q. Does that mean the Company is unwilling to entertain the proposal?

A. The Company is willing to entertain any proposal under which a QF delivers physical power to PacifiCorp's system. If a QF's power delivery proposal is of a lower quality than the delivery required by PacifiCorp's standard PPA, it may affect the pricing of that power under Commission precedent.[63] But so long as a QF *verifiably* delivers physical QF power to PacifiCorp's system, PacifiCorp is willing to purchase that power under PURPA.

[63] Direct Testimony of Stefan Brown, Docket No. UM 1129, Staff Exhibit 2200 at 8 (March 24, 2006), attached as PAC/105 ("The utilities have proposed that their standard off-system QF contract specify the use of firm transmission. If a QF wants to use non-firm transmission to deliver its output to the purchasing utility it may do so, but it would not receive capacity payments and would have to execute a non-standard contract.").

1. Problems with Surprise Valley's Power Delivery Proposal

Q. Is PacifiCorp willing to accept the power delivery proposal in Surprise Valley's direct testimony?

A. No.

Q. Why not?

A. The primary reason is that, as with Surprise Valley's April 2014 "concept paper," the proposal in Surprise Valley's direct testimony does not allow PacifiCorp to verify how much physical power it would be receiving under a PPA with Surprise Valley.

Q. How would power be delivered to PacifiCorp's system under Surprise Valley's proposal?

A. Under Surprise Valley's proposed delivery method, the Paisley Project's generation would be consumed by Surprise Valley's load. The way PacifiCorp would supposedly obtain power under the PPA is by "keeping" some of the BPA power PacifiCorp Transmission delivers to Surprise Valley on BPA's behalf. As Surprise Valley explains, "a portion of the BPA power delivered to PacifiCorp on behalf of Surprise Valley will be retained by PacifiCorp for its own use."[64] I have already explained that PacifiCorp Transmission is delivering power on behalf of BPA under the GTA, not Surprise Valley. As far as I can tell, this "retention" of an unverifiable amount of BPA power is the only way PacifiCorp would obtain power, if any, under a PPA with Surprise Valley.

Q. Why couldn't PacifiCorp verify the amount of power it would receive under such a PPA?

[64] SVEC/300, Saleba-Tabone/3-4.

As I noted previously, BPA gives PacifiCorp Transmission an aggregated schedule for a group of BPA's wholesale preference customers under the GTA, scheduled to a number of delivery points.[65] This means that PacifiCorp cannot know how much power BPA has actually scheduled for delivery to Surprise Valley's system at any time. If PacifiCorp cannot know how much power BPA is scheduling to Surprise Valley, it cannot know how much it might be able to "keep." It is impossible to measure and BPA is unwilling to provide a Surprise-Valley specific schedule.

Q. What is the potential harm from this lack of verification?

A. First, there is no record of what was scheduled by BPA at the level needed to tie the amount to the Paisley Project because BPA will not provide a granular schedule. In other words, imagine BPA provides PacifiCorp Transmission a schedule aggregated at the BAA level that includes no power for Surprise Valley. This is not transparent to PacifiCorp Transmission, yet: (1) PacifiCorp ESM would theoretically purchase the full net output of the Paisley Project for power it never receives under Surprise Valley's delivery proposal;[66] and (2) PacifiCorp Transmission, as the BAA, is tasked with load following for Surprise Valley's system under the GTA, which means that PacifiCorp Transmission would need to make up for BPA's scheduling failure by purchasing extra power needed for Surprise Valley's system from PacifiCorp ESM, then deliver it to Surprise Valley's system to make up for the difference. PacifiCorp ESM would then be forced to buy that same power back from Surprise Valley under the QF PPA at

[65] PAC/124 (explaining that BPA treats Surprise Valley's load as part of its "aggregated loads" for all of its requirements customers).

[66] The Paisley Project's power is all consumed by Surprise Valley's load, so the only power available for "purchase" under this construct is the power scheduled from BPA to Surprise Valley's system. This assumes none is actually scheduled to Surprise Valley.

PacifiCorp's own avoided cost prices. This is why PacifiCorp needs granular schedules from BPA, not just the ability to measure "actual deliveries" to Surprise Valley's system, as Surprise Valley witness Mr. Anderson suggests.[67]

Q. Does Surprise Valley concede that if BPA under-schedules power delivery to Surprise Valley under the GTA, PacifiCorp would be required to provide the additional power necessary to serve Surprise Valley's load and then purchase the Paisley Project's power back at PacifiCorp's avoided cost?

A. Yes.[68]

Q. Does this make the QF responsible for its own power delivery?

A. No.

Q. Why is this a problem if PacifiCorp has already agreed to provide load following service on BPA's behalf under the GTA? Wouldn't PacifiCorp simply be carrying out the function it has always carried out under the GTA?

A. PacifiCorp's GTA with BPA is intended to allow reciprocal transfers of power for load service between PacifiCorp and BPA, and it is meant to net out in the end. It is not a slush fund for QF-sourced power sold to PacifiCorp at avoided cost, nor is it an insurance policy for QFs who cannot deliver power to PacifiCorp's system on a firm basis. In this case, Surprise Valley is essentially proposing to outsource its own QF power delivery

---

[67] *See, e.g.*, SVEC/400, Anderson/11.

[68] PAC/124 ("To the extent that PacifiCorp believes that BPA is not accurately scheduling and delivering energy necessary to serve Surprise Valley's loads, and is also not adequately compensating PacifiCorp for the imbalance-type service provided to BPA under the General Transfer Agreement, that is an issue that PacifiCorp must raise with BPA and/or FERC under that transmission agreement or the Federal Power Act; the dispute over the FERC-jurisdictional transmission agreement between PacifiCorp and BPA is not relevant to PacifiCorp's separate obligation to purchase the entire net output of Surprise Valley's QF made available to PacifiCorp."); Surprise Valley's Response to PacifiCorp's Data Request 4.17 ("On a contractual basis, the sale of power from the Paisley Project is entirely separate from the power sales contract between BPA and Surprise Valley. A failure of BPA to schedule enough power to serve Surprise Valley's full retail load is no different with or without the existence of the Paisley Project and is a matter between BPA and PacifiCorp.") (attached hereto as PAC/143).

obligations to PacifiCorp and BPA under the GTA, then require PacifiCorp to both provide and pay for any under-scheduling or under-delivery by BPA to Surprise Valley's system.

Q. If BPA failed to schedule sufficient power to meet Surprise Valley's load needs under the GTA, what remedies would PacifiCorp have against BPA?

A. None specific to Surprise Valley. The GTA provides a monthly true-up mechanism between BPA and PacifiCorp at the aggregate BAA level, so any under-scheduling by BPA to Surprise Valley's system would be lost in the aggregate amount.

Q. If BPA failed to schedule sufficient power to meet Surprise Valley's load needs under the GTA, what remedies would PacifiCorp have against Surprise Valley?

A. None. The contractual remedies in the standard off-system PPA for under-delivery are useless when the under-delivery cannot be measured.

Q. Even if BPA were willing to provide granular schedules to Surprise Valley's system, thereby solving one key problem with the transaction, why might Surprise Valley's avoided cost still need to be adjusted?

A. As I noted previously, under Surprise Valley's proposal, Surprise Valley would use the Paisley Project to serve its own load. It would outsource its power delivery obligations to BPA and PacifiCorp under the GTA. But the quality of power delivery under the GTA is not sufficient to support standard avoided cost pricing. PacifiCorp and BPA's reciprocal load service involves power that is fungible in nature, and the deliveries are not carefully tracked and tagged. Neither does BPA provide PacifiCorp with hourly delivery schedules (not even in the aggregate). This quality of delivery is appropriate for reciprocal load service, but it does not meet the standards required by the Company's standard off-system PPA for the purchase of QF power at avoided cost.

Q. In support of its argument for a LEO, Surprise Valley asserts that QF power purchase agreements are typically signed before interconnection and transmission issues are fully resolved.[69] How do you respond?

A. That can be the case in some instances, but not here. This is not a situation where the parties have reached agreement on all issues, including delivery, and are simply waiting for the QF and PacifiCorp Transmission to finalize an interconnection agreement.[70] To the contrary, Surprise Valley asserts that all of its delivery arrangements have already been made. It denies that it has to take any additional steps or to finalize anything at all. In other words, this is not a situation where we are simply waiting for interconnection issues to be finalized; it is an unresolved dispute over the key terms and conditions under which PacifiCorp is able to purchase power under a QF PPA.

2. Responses to Specific Assertions by Surprise Valley's Witnesses

Q. According to Surprise Valley witnesses Saleba and Tabone, PacifiCorp has "confused the issues of physical transmission with contract issues."[71] How do you respond?

A. I believe witnesses Saleba, Tabone, and Anderson all understand transmission, contractual delivery, and the movement of electrons on the transmission grid, but not

---

[69] *See, e.g.*, PAC/120.

[70] A QF seeking a direct interconnection with PacifiCorp Transmission may need to finalize those arrangements after a PPA is signed. A QF seeking to deliver under an off-system PPA must make transmission arrangements to deliver power to PacifiCorp's system *before* a PPA is signed.

[71] SVEC/300, Saleba-Tabone/3.

PURPA.[72] They do not seem to account for the legal requirements imposed by PURPA, as PacifiCorp will address in its legal briefing. This is not an ordinary power delivery—it is a PURPA transaction. Under PURPA, PacifiCorp is only required to purchase the net output generated by the QF and delivered to PacifiCorp's system, whether by direct interconnection or by firm transmission. Under PURPA, PacifiCorp is only required to pay for the net power received, as actually metered or scheduled, not some fungible contractual amount of generic power. In any case, Saleba and Tabone fail to account for BPA's lack of granular scheduling under the GTA.

Q. Witnesses Saleba and Tabone state that, "on a contractual basis, power flows from Paisley to PacifiCorp over Surprise Valley's lines. On a physical basis, a portion of BPA power delivered to PacifiCorp on behalf of Surprise Valley will be retained by PacifiCorp for its own use, which will be equivalent to Paisley's output."[73] Does this validate the proposed delivery method?

A. No. First, it is unclear how PacifiCorp ESM takes possession or ownership of this power in a manner that would allow it to account for that power, measure it, and use it to serve load. Any possession of that power is simply a transfer obligation by PacifiCorp Transmission. And because of BPA's aggregated schedules, PacifiCorp cannot measure the amount it supposedly would "retain." Mr. Anderson's conclusions about the

---

[72] Witnesses Saleba and Tabone concede in response to PacifiCorp Data Requests 4.1 and 4.3 that they have no experience assisting with PURPA contracts. They appear to be experts on transmission issues, but do not appear to be familiar with PURPA standard contracts. *See* Surprise Valley's Response to PacifiCorp Data Request 4.1 (attached hereto as PAC/139) and 4.3 (PAC/140). Similarly, Mr. Anderson concedes that his area of expertise is engineering, not PURPA or contract matters.

[73] SVEC/300, Saleba-Tabone/3.

adequacy of "meters" to determine the additional amount of power on PacifiCorp's system attributable to the Paisley Project have the same flaw.[74]

Q. Witnesses Saleba and Tabone assert that sufficient metering is in place to ensure PacifiCorp receives power equivalent to Paisley output.[75] Is this correct?

A. No. Without granular schedules from BPA specifically for Surprise Valley, there is no way for PacifiCorp to ensure it receives a net benefit of power on its system equivalent to the Paisley Project's net output. This is the issue with Mr. Anderson's testimony, as well. The crucial part of his testimony is his assertion that the metering in place can accurately measure the increased amount of electricity on PacifiCorp's system because, when Paisley operates, there will be current flow into PacifiCorp's system equal to the net output of Paisley, minus losses and station service.[76] But because PacifiCorp does not receive granular Surprise Valley-specific schedules, PacifiCorp cannot know whether BPA is scheduling an adequate amount of power to PacifiCorp's system to ensure there is, in fact, "additional" power on PacifiCorp's system in the amount of the Paisley Project's net output.

Q. According to Saleba and Tabone, because Surprise Valley does not plan to use Paisley to serve its own load, Paisley has no impact on the contracts with BPA, and BPA will still be obligated to supply and deliver Surprise Valley's total load requirements.[77] How do you respond?

---

[74] *See, e.g.,* SVEC/400, Anderson/12.

[75] SVEC/300, Saleba-Tabone/4.

[76] SVEC/400, Anderson/5.

[77] SVEC/300, Saleba-Tabone/6.

A. Even if BPA is now obligated by its contract with Surprise Valley to supply one hundred percent of Surprise Valley's load needs, it does not solve the problem of lack of verification of delivery of QF power in the amount of the net output of the plant due to the lack of granular schedules.

Q. Witnesses Saleba and Tabone argue that it is not unusual for there to be a difference between contractual and physical flow.[78] How do you respond?

A. I would agree with their statements. In fact, PacifiCorp's off-system QF PPA and Addendum W clearly spell out the true-up that occurs between physical output and scheduled delivery of QF power that reaches PacifiCorp's system. These requirements were vetted in docket UM 1129 and are in all of PacifiCorp's Commission-approved off-system QF PPAs.

Under PURPA, a utility pays only for power that a QF delivers to the utility's system either by physical delivery or by contractual schedule. If that power is over-scheduled, PacifiCorp buys what is actually generated, because anything over and above the QF's generation is not from the QF. If under-scheduled, PacifiCorp only pays for the contractual schedule because the QF power did not physically reach PacifiCorp's system.

None of their points, however, address the power verification problem that PacifiCorp faces due to BPA's scheduling practices. The witnesses simply ignore that critical point—PacifiCorp still needs to receive a verifiable schedule at the Surprise Valley level, not at the BAA level.

Q. According to Surprise Valley, the difference between what BPA delivers to PacifiCorp and what PacifiCorp delivers to Surprise Valley would be power made

[78] *Id.* at 6-7.

physically available for PacifiCorp's use under the PURPA contract that "can be tracked via metering."[79] Do you agree?

A. This could only be true if PacifiCorp were to obtain Surprise Valley-specific hourly schedules from BPA, which it cannot because BPA will not provide them.

Q. In their discussion of metering, Saleba and Tabone state, "[m]etering at the Paisley Project will also measure the amount of QF contract power sold to PacifiCorp."[80] Do you have thoughts about these statements?

A. Again, PacifiCorp cannot determine how much power it would "keep" under this arrangement without Surprise-Valley-specific schedules from BPA to compare to the meters they describe.

Q. Saleba and Tabone question whether Surprise Valley should be required to pay for that metering. What is your response?

A. Under Oregon law, the QF pays for metering.

Q. Saleba and Tabone, as well as Surprise Valley witness Mr. Anderson, assert that existing metering is sufficient to track physical increase in power on PacifiCorp's system when Paisley generates. They assert that the only things that may need to change are metering points in contracts between Surprise Valley and BPA, and between PacifiCorp and BPA.[81] Do you agree?

A. I disagree. None of these steps would solve the problem caused by a lack of granular, Surprise Valley-specific schedules from BPA, regardless of metering.

---

[79] *Id.* at 7.

[80] *Id.* at 8.

[81] *See, e.g., id.* at 10.

Let me try to provide an example using the 10 MW Surprise Valley load and the 3 MW Paisley generation values discussed above. Under that scenario, the net load at Lakeview Switch would show 7 MW, which is what PacifiCorp Transmission (as the load-following entity) would deliver to Surprise Valley. The 3 MW generated by Paisley would be measured, and the 7 MW of Surprise Valley's net load would be measured. Under the witnesses' theory, the two are added to make up the 10 MW all-requirement amount that BPA is scheduling to PacifiCorp for delivery to Surprise Valley under the GTA.

However, that theoretical 10 MW is included in an aggregate amount scheduled to PacifiCorp at the BAA level; it is not scheduled to Surprise Valley specifically, so the 10 MW is not visible. Imagine the aggregate amount scheduled by BPA under the GTA is 400 MW. Without the Surprise-Valley level schedule, there is no way for PacifiCorp to validate that the 3 MW attributed to the Paisley Project is in included in the aggregated 400 MW schedule.

Surprise Valley and their consultants are asking PacifiCorp customers to blindly accept that an amount attributable to the Paisley Project is included in the aggregate amount and it is correct in every hour. The inability to validate the transaction is an unacceptable risk for PacifiCorp's customers. It would be easily solved by BPA providing a specific Surprise Valley schedule showing the 3 MW attributable to the Paisley generation. Unfortunately, BPA refuses to provide this information and PacifiCorp cannot force BPA to provide it. Surprise Valley is unwilling or unable to provide alternative firm delivery arrangements to PacifiCorp.

Q. Saleba and Tabone assert that Surprise Valley has an adequate interconnection to deliver the Paisley Project's output to PacifiCorp directly, and that Surprise Valley does not need to purchase transmission from others or build a new direct generation intertie from Paisley to PacifiCorp because there is sufficient capacity on its own system to deliver power.[82] Is this correct?

A. Surprise Valley could provide industry-standard power delivery if it chose to do so. It could purchase or self-supply ancillary services required for firm delivery as well as the ancillary services required by the Company's off-system PPA, including generation reserves, and provide scheduling in line with industry standards. But it has not been willing to do so.

Q. Do you agree with Saleba and Tabone's assertion that Surprise Valley need not supply ancillary services as part of firm delivery?[83]

A. No. Without Surprise Valley-specific, granular schedules from BPA, Surprise Valley cannot rely on its proposed non-standard delivery method. Instead must comply with the standard delivery obligations in the standard QF PPAs.

I do not believe that Surprise Valley's power delivery proposal provides delivery that can be verified at all, let alone considered firm. Moreover, the Company's standard off-system PPA requires certain ancillary services to be provided by and paid for by the QF to maintain customer indifference to a QF power purchase. If the Paisley Project were to provide verifiable power delivery without providing some of the ancillary services required by the Company's standard off-system PPA, PacifiCorp may be able to purchase that power at an adjusted avoided cost price.

[82] *Id.* at 11.

[83] *Id.* at 13.

Q. Mr. Anderson notes that Surprise Valley and PacifiCorp have an agreement for transfer service (totally separate from the issues in this case) that does not include requirements for imbalance energy, schedules, any ancillary services, e-Tags, or OATT/wholesale distribution tariff. What is the relevance of this observation?

A. It is not relevant. Mr. Anderson may be suggesting that PacifiCorp's insistence on industry standard, QF-PPA-compliant delivery of the Paisley Project's power is somehow unnecessary. But this implication is completely wrong and demonstrates a failure to understand PURPA or commercial delivery requirements. QF power delivery needs to be firm, scheduled, verifiable, traceable to the QF generator, and trued up with the generator's net output. None of these things are critical for a generic reciprocal transfer agreement, which is not even a sales agreement. This is similar to the misunderstanding Surprise Valley has under the GTA.

Q. Please respond to Saleba and Tabone's assertion that PacifiCorp changed its mind various times about the need for Surprise Valley to provide transmission, scheduling, and ancillary services, as well as whether an on-system or off-system PPA was appropriate.[84]

A. This is a straightforward issue. If Surprise Valley wants to sell the amount of the Paisley Project's generation that is in excess of Surprise Valley's load, and which physically flows to PacifiCorp's system, an on-system PPA is appropriate. If Surprise Valley insists on selling the full net output of the plant, it needs to comply with the terms and conditions of PacifiCorp's off-system PPA by providing firm transmission arrangements, including ancillary services and scheduling to allow PacifiCorp to verify that it is actually

[84] *Id.* at 15.

receiving any amount of power. Because of BPA's scheduling protocols under the GTA, there is no other way for PacifiCorp to verify delivery of power under an off-system PPA.

Q. Saleba and Tabone note that your March 20, 2014 request for network resource status includes an attestation indicating PacifiCorp has committed to purchase the resource.[85] How do you react to the assertion that that attestation somehow equates to a promise to purchase the full net output of the plant without contingency?

A. I disagree. Surprise Valley misunderstands the purpose of the transmission service request and the related attestation. The purpose of the request was to identify what upgrades would be necessary for PacifiCorp to purchase the Paisley Project's full net output, to receive the Paisley Project's power on PacifiCorp's system, and to deliver it to PacifiCorp's load. Because PURPA contracts create a mandatory purchase obligation, PacifiCorp may in some instances issue a request to designate a QF as a designated network resource (DNR) before a PPA is signed, recognizing that it will purchase the delivered output of the QF subject to the conditions being met in the DNR request and subject to the QF complying with the Company's standard PPA requirements. Compliance is not ordinarily an issue, but Surprise Valley has been either unable or unwilling to agree to the terms and conditions of a standard QF PPA.

Q. Who are the parties to the transmission service request?

A. PacifiCorp ESM and PacifiCorp Transmission.

Q. Is the existence of the attestation a promise to Surprise Valley?

A. No.

[85] *See id.* at 27-28; *see also* SVEC/100, Kresge/3.

Q. Do you agree that the studies related to the transmission service request delayed the signing of a PPA with Surprise Valley?

A. No. As I noted, the transmission service request, as well as the construction agreement that came out of it, were actually done earlier than they are typically done in order to help move things along while the parties sorted out issues related to Surprise Valley's delivery proposals.

Q. The transmission service request was for the full net output of the plant. Does this mean that PacifiCorp was satisfied that Surprise Valley's delivery arrangements would result in delivery of the full net output of the Paisley Project's power to PacifiCorp's system?

A. No. When purchasing QF power, PacifiCorp ESM will make a transmission service request equal to the full nameplate capacity of the QF to ensure that, once the QF delivers its power to PacifiCorp's system, PacifiCorp ESM has adequate transmission capacity to accept the full output of the project and deliver it to load. This is true regardless of whether the intended purchase is a firm purchase of 100 percent of the output or purchases in excess of load served by the project first (here, via an "on-system" measurement of metered flow). This is because if load suddenly went to zero, PacifiCorp ESM would need access to transmission capacity equal to the maximum generation of the plant, or else PacifiCorp ESM would be responsible for purchasing point-to-point transmission to move the QF power to load. This is standard practice, and it can be demonstrated by examining firm Oregon QFs that elect to serve load first and ask PacifiCorp ESM to purchase only the excess delivered to PacifiCorp's system.

In this scenario, PacifiCorp assumed it would be purchasing some power from Surprise Valley, if only the metered flow onto PacifiCorp's system. As I noted, even if PacifiCorp purchases less than the full net output of a QF (excess only), PacifiCorp ESM nevertheless analyzes the QF purchase for full output of the generator to secure network transmission capacity.

Q. Witnesses Saleba and Tabone assert that, before Surprise Valley filed its complaint, PacifiCorp never communicated that Surprise Valley would need to acquire ancillary services. What is your response?

A. First of all, witnesses Saleba and Tabone have not been involved in these issues for very long and cannot have personal knowledge of the parties' prior communications. In any case, Addendum W to the Company's standard off-system PPA makes clear that a QF must provide and pay for certain ancillary services. That standard form PPA was provided to Surprise Valley as early as November 2013.

Q. Saleba and Tabone argue that because PacifiCorp is so much bigger than Surprise Valley, PacifiCorp should have made clear its preferences for how deliveries should be made to PacifiCorp's system. How do you respond?[86]

A. There is normally no guesswork involved in negotiating standard QF PPAs. That is the very point of the Commission-approved standard QF PPAs. They are simple and straightforward. Things became difficult when Surprise Valley could not (or would not) agree to or meet the terms of those PPAs. It engaged PacifiCorp in extended discussions regarding alternative delivery arrangements, including a swap of power with BPA that relies on the GTA's non-granular scheduling to complete delivery of QF power.

[86] SVEC/300, Saleba-Tabone/32.

Addendum W of the Company's off-system PPA has certain requirements. PacifiCorp has no "preference" except that those Commission-approved PPA requirements are met.

Q In their testimony, Saleba and Tabone argue that, because the parties spent time discussing "displacement" and "metering" solutions, it was reasonable for Surprise Valley to conclude there would be no need to schedule the power and secure ancillary services from PacifiCorp to deliver power to PacifiCorp.[87] Do you agree?

A No. The discussions always involved a scheduling component, it just depended on whether the schedule would be coming from Surprise Valley or BPA. This scheduling component is critical to a firm PURPA sale. As I have noted, BPA has refused to provide the scheduling PacifiCorp would need to verify *any* receipt of power under Surprise Valley's non-standard proposal, let alone firm delivery. For that reason, scheduling would appear to need to come from Surprise Valley as part of a delivery arrangement that complies with the Company's standard off-system PPA.

C. Allegations of Bad Faith

1. Allegations that PacifiCorp Unreasonably Refused to Sign a PPA with Surprise Valley Before August 20, 2014

Q. How do you respond to Surprise Valley's assertions that PacifiCorp unreasonably refused to sign a PPA with Surprise Valley before August 20, 2014?

A. I disagree with this assertion. During the course of the parties' negotiations, Surprise Valley consistently refused to agree to the terms and conditions of a standard QF PPA. Its proposals for a non-standard PPA would have required PacifiCorp to purchase all of the Paisley Project's generation blindly, with no ability to verify that it was receiving the power it was paying for. For that reason, they were unacceptable.

[87] *Id.* at 33.

Q. Does Surprise Valley state when, precisely, PacifiCorp should have signed a PPA with Surprise Valley?

A. Yes. According to Surprise Valley's testimony and its responses to PacifiCorp's data requests, Surprise Valley believes there were four critical points at which Surprise Valley was entitled to a PPA under PURPA.[88] These four points include: (1) following delivery of Surprise Valley's "concept paper" describing its metering arrangements for the Paisley Project; (2) following the May 20, 2014 draft PPA Surprise Valley edited and provided to PacifiCorp, which incorporated the metering and delivery arrangements explained in the "concept paper"; (3) following the July 22, 2014 draft PPA that Surprise Valley edited and provided to PacifiCorp; and (4) on June 22, 2015, when Surprise Valley apparently unilaterally signed a PPA, which also happens to be the same day it filed its complaint in this proceeding. The last one, I note, is not before August 20, 2014. I describe and respond to each of these points below.

a. April 14, 2014 Concept Paper

Q. Have you reviewed the portions of Surprise Valley's testimony regarding the "concept paper" it provided to PacifiCorp regarding its proposed delivery arrangements on April 14, 2014?[89]

A. Yes.

[88] *See* SVEC/100 at 19:6-20:13 and SVEC/200 at 10:14-11:16 (discussing the concept paper); SVEC/100 at 18:20-20:13 and SVEC/200 at 14:7-15:3 (discussing the May 20, 2014 draft PPA and Surprise Valley's willingness to sign that draft); SVEC/100 at 22:22-23:3 and SVEC/200 at 17:12-20:4 (discussing the July 22, 2014 draft PPA and, again, asserting Surprise Valley would sign that draft); *see also* PAC/122; Surprise Valley Response to PacifiCorp Data Requests 3.30 (attached hereto as PAC/121) and 4.50 (attached hereto as PAC/147). The "concept paper" can be found at SVEC/202, Culp/61-62, and attached as PAC/106.

[89] *See* SVEC/100, Kresge/19-20; *see also* SVEC/200, Culp/10; *see also* SVEC/202, Culp/61-62.

Q. Does Surprise Valley claim it was entitled to a PPA based on the proposed delivery arrangements detailed in the concept paper?

A. Yes. Surprise Valley's witness Brad Kresge testifies that, "[On] April 14, 2014, we provided a concept paper explaining our proposal regarding metering. *Our metering proposal and draft PPA provided on May 20, 2014 was based on what we believed PacifiCorp had previously communicated would be acceptable to the company*."[90] Similarly, Surprise Valley witness Lynn Culp testifies that Surprise Valley believed the approach described in the concept paper was acceptable to PacifiCorp when he states, "Our understanding was that PacifiCorp could purchase the additional power on its system that resulted from the Paisley Project generating power and displacing or offsetting BPA power wheeled by PacifiCorp. . . . We may not have continued working with PacifiCorp on the basic approach in the concept paper if PacifiCorp had flatly stated it was unacceptable."[91]

Q. Are there any other instances in which Surprise Valley suggests the concept paper warranted a PPA from PacifiCorp?

A. Yes. In addition to Surprise Valley's testimony, Surprise Valley's response to PacifiCorp's data requests suggests the concept paper was part of the PPA negotiation process, resulting in a PPA that Surprise Valley was willing to sign.[92]

Q. Please describe the concept paper.

A. As I have outlined earlier, the concept paper as submitted by Surprise Valley was simple and composed of the following statements and arrangements:

[90] SVEC/100, Kresge/19 (emphasis added).

[91] SVEC/200, Culp/11.

[92] PAC/121, PAC/147.

- BPA schedules power to PacifiCorp Transmission (under the GTA) for delivery to Surprise Valley at the Lakeview Switch.
- PacifiCorp Transmission also delivers power for PacifiCorp ESM to PacifiCorp retail customers in the area surrounding Surprise Valley's service territory sufficient to meet their load needs.
- BPA will continue to supply Surprise Valley with its full load requirements under the all-requirements contract between BPA and Surprise Valley as if the Paisley Project generation was not serving any Surprise Valley load.
- The result is that when Paisley Project is generating, additional power will be added to PacifiCorp Transmission's system equal to the Paisley Project output less transmission line losses.
- The "excess" power will be supplied to PacifiCorp's retail customers and PacifiCorp generation serving PacifiCorp's Mile High substation will be reduced by the net output at the Paisley Project.
- PacifiCorp will pay Surprise Valley for this "excess" power at avoided cost prices in the QF PPA.

Q. What is your impression of the concept paper?

A. The concept paper is flawed in many respects. First, it suggests that PacifiCorp should accept non-QF power from BPA somewhere on its system, which is basically a swap. The Paisley Project would generate behind Surprise Valley's load, and PacifiCorp would receive not the QF generation, but BPA power at a location somewhere else on the grid. Second, the concept paper makes the blind assumption that the power generated by the Paisley Project will equal the schedule delivered by BPA to Surprise Valley in every hour of every day, yet PacifiCorp has no way to validate BPA's actual hourly schedules to Surprise Valley. The concept paper would ask PacifiCorp's customers to accept the assumption of accurate hourly schedules at face value. Third, the GTA under which PacifiCorp Transmission delivers power to Surprise Valley on BPA's behalf is for one purpose only—to deliver power to Surprise Valley—not to deliver BPA power to PacifiCorp's retail customers.

The concept paper did not address the key components of the QF PPA, which must include a way to measure the output of the QF and verify Surprise Valley's schedule. In short, the concept paper gave PacifiCorp no way to determine whether PacifiCorp was getting any power from BPA that would be attributed to the Paisley Project, and no available schedule that would allow PacifiCorp to true up the actual generation against the scheduled delivery by BPA.

Q. What is your response to Surprise Valley's assertions that it thought PacifiCorp would accept the concept paper?

A. First, PacifiCorp did not communicate back to Surprise Valley that it accepted its proposal. Second, contrary to Surprise Valley's claims, I responded to Surprise Valley on August 26, 2014, and noted that PacifiCorp would not accept a "swap," as proposed by Surprise Valley in its concept paper.[93] These and other pieces of evidence in the record refute Surprise Valley's claim that the "concept paper" (and the May 20, 2014 PPA discussed below) were based on what was "acceptable" to PacifiCorp.

Q. Why did it take until August 26, 2014, to respond to the April 14, 2014 concept paper?

[93] Email from B. Griswold to L. Culp, dated August 26, 2014, attached as PAC/108.

A. The simple reason is that there were (and still are) a lot of moving parts and unknowns in this proposed structure. All of these took time to evaluate, including consideration of alternative ways to measure the output from the generator, investigating how to verify delivery through whatever delivery arrangements were made, and what parties needed to be involved in each alternative (*i.e.*, Surprise Valley, BPA, PacifiCorp Transmission, or PacifiCorp ESM). We were willing to investigate and spent a lot of time doing so. Ultimately, the issue boiled down to how PacifiCorp would verify the power delivery scheduled from BPA specifically allocated to Surprise Valley under the GTA, and how that scheduled delivery could be compared with the Paisley Project's generation. I advised Surprise Valley very clearly that PacifiCorp would not accept the concept paper proposal on August 26, 2014. During that time, PacifiCorp continued to work with Surprise Valley on a variety of PPA and operational issues, including exploring ways to allow them to generate to meet their Oregon Business Energy Tax Credit deadline, PacifiCorp ESM's request for a system impact study and facilities study from PacifiCorp Transmission to evaluate power flows and metering alternatives (which takes 60 days per study under the OATT), and continued review of draft PPA documents. The system impact study results were shared in July 2014 and required an additional facilities study.

Q. Do you believe the concept paper created a LEO?

A. No. The parties still disagreed about how the concept paper could be incorporated into the PPA, as well as key material terms and conditions of that PPA. It is one thing to provide a conceptual vision of how something should work, but it is another to turn it into a workable, mutually-acceptable agreement. Surprise Valley refused to accept the terms and conditions of a standard PPA and also failed to provide alternative terms and conditions that PacifiCorp could accept. In addition to the outstanding questions and issues noted in the draft PPA and the metering, measurement, and cost allocation issues, the parties had not reached agreement on the fundamental issue--the amount of power that Surprise Valley would actually deliver to PacifiCorp's system and how much PacifiCorp should be obligated to pay for that power based on the quality of the delivery.

b. May 20, 2014 Draft PPA

Q. Have you reviewed Surprise Valley's testimony regarding the May 20, 2014 draft PPA?

A. Yes, I have.

Q. Surprise Valley claims the May 20, 2014 PPA incorporated the terms it believed were "acceptable" to PacifiCorp.[94] Can you briefly explain the terms of this PPA?

A. This PPA was an on-system QF PPA edited by Surprise Valley to incorporate, among other things, the metering and delivery arrangements proposed in their concept paper as part of Exhibit B.[95] (Exhibit B is a description of the point of interconnection and point of delivery.) This Exhibit B effectively suggested that PacifiCorp would receive energy via a "swap" wherein PacifiCorp would keep some of the energy that PacifiCorp Transmission was required to transmit to Surprise Valley on BPA's behalf under the GTA, while Surprise Valley's Paisley Project generation would be wholly consumed by Surprise Valley's own load.

---

[94] SVEC/100, Kresge/19.

[95] SVEC/200, Culp/14 ("Exhibit B to the May 20, 2014 draft PPA included a description of the points of delivery that was based on the 'concept paper.' Surprise Valley considered the concerns PacifiCorp raised regarding deliveries and metering, and attempted to address them in the PPA."). The May 20, 2014 Draft PPA is at SVEC/206, Culp/3-46, and attached as PAC/109.

Although Surprise Valley claims that PacifiCorp indicated this approach was "acceptable" in oral discussions,[96] it has provided no evidence whatsoever to support this claim, and I disagree. PacifiCorp was willing to investigate Surprise Valley's proposals but never agreed to accept them if they proved unworkable, which they did.

Q. Please describe the terms and conditions of the May 20, 2014 draft PPA.

A. The May 20, 2014 PPA was a variation of an on-system PPA provided by PacifiCorp in February 2014 to accommodate the fact that Surprise Valley is in PacifiCorp's BAA. The draft PPA provided by PacifiCorp required Surprise Valley to provide transmission service to deliver the project's output to PacifiCorp. This accommodation was made by PacifiCorp in a continued effort to find alternative metering and delivery options that might work for Surprise Valley.

Surprise Valley made substantive changes to this draft PPA and delivered it back to PacifiCorp on May 20, 2014. PacifiCorp could not accept Surprise Valley's changes to the draft PPA. Surprise Valley's edits contained the same delivery flaws the concept paper contained. Other of the edits clearly indicated that Surprise Valley did not intend to comply with the PPA's delivery requirements. For example, where the standard PPA language states that a QF intends to "transmit" its net output to PacifiCorp, Surprise Valley deleted the word "transmit" and replaced it with the word "sell."[97] Another of my key observations is that the May 20, 2014 PPA included Addendum W, which outlines the requirements for scheduling, metering, and ancillary services by the QF to deliver firm power to PacifiCorp, yet it is clear that Surprise Valley did not actually intend to make those Addendum W delivery arrangements. At this point, at a minimum, Surprise

---

[96] Surprise Valley's Response to PacifiCorp DR 3.75, attached as PAC/133.

[97] SVEC/206, Culp/4.

Valley clearly should have known that PacifiCorp viewed those services as Surprise Valley's responsibility.

Q. Did you tell Surprise Valley that the terms of the May 20, 2014 draft PPA were acceptable to PacifiCorp?

A. No. I made it clear to Surprise Valley that its proposed arrangements were unacceptable.[98]

Q. Have you also reviewed Surprise Valley's testimony and responses to PacifiCorp's data requests regarding its willingness to sign the May 20, 2014 PPA?

A. Yes. I am familiar with Surprise Valley's testimony on this topic[99] and its responses to PacifiCorp Data requests 3.30, 3.32, 3.33, and 4.50 where Surprise Valley repeatedly asserts it was willing to sign the May 20, 2014 PPA.[100]

Q. What is your response to Surprise Valley's claims that it was ready to sign the May 20, 2014 PPA?

A. Surprise Valley has admitted that this PPA was not ready to be signed. Surprise Valley's response to PacifiCorp Data Request 3.64 admits that there were a number of open questions in the May 20, 2014 draft PPA.[101] And this is even more clear in the number of comments and questions included by Surprise Valley in the draft PPA.

---

[98] PAC/108 ("PacifiCorp merchant has made it clear from our beginning discussions that we were not going to do any PPA that could not be physically metered and measured as having been delivered to PacifiCorp's system.").

[99] SVEC/100, Kresge/18-19 ("Surprise Valley sent PacifiCorp ESM a complete draft PPA with all project specific information included on May 20, 2014. We stated that we were prepared to execute the draft PPA, we were concerned about the length of time it has taken to finalize the PPA, and timing was critical."); *see also* SVEC/200, Culp/14 ("On May 20, 2014, Surprise Valley informed PacifiCorp that we were prepared to enter into a standard QF power sales agreement with PacifiCorp, and to execute the May 20, 2014 draft PPA.").

[100] PAC/121, PAC/122 and PAC/147.

[101] Surprise Valley's Response to PacifiCorp DR 3.64 ("Q: Confirm or deny that [the May 20] draft PPA included a number of remaining questions from Surprise Valley regarding Addendum W. . . A. Confirmed. That draft PPA included a number of remaining questions from Surprise Valley regarding Addendum W.") (attached hereto as PAC/131).

Q. Have you also reviewed Surprise Valley's Response to PacifiCorp Data Request 3.65, which includes the communications allegedly demonstrating PacifiCorp's "acceptance" of the proposed delivery arrangements contained in the concept paper and memorialized in the May 20, 2014 draft PPA?

A. Yes.

Q. What is your response after reviewing these communications?

A. Surprise Valley has not provided any evidence that PacifiCorp accepted the delivery arrangements proposed in the May 20, 2014 draft PPA and the concept paper. The emails provided as Attachment 3.65 to Surprise Valley's data responses are emails between Surprise Valley, BPA, and Surprise Valley's consultants. There is nothing in these emails suggesting PacifiCorp agreed with Surprise Valley's proposal.[102] Furthermore, these emails—which are Surprise Valley's own *internal* communications—demonstrate that PacifiCorp had issues with Surprise Valley's delivery proposal from its concept paper.[103]

Q. What is your conclusion regarding Surprise Valley's willingness to sign the May 20, 2014 draft PPA?

A. In sum, Surprise Valley was not ready or willing to sign the May 20, 2014 draft PPA. Surprise Valley and PacifiCorp's communications, described above, as well as the PPA itself, indicate that there were numerous open issues that needed to be resolved before a PPA could be signed. Not the least of these issues included the unresolved nature of the delivery arrangements, outstanding questions and issues regarding Addendum W, and

[102] *See* Surprise Valley's Response to PacifiCorp DR 3.65, including Attachment 3.65 (both attached hereto as PAC/132).

[103] *Id.* ("In our meeting with PAC transmission last week, it cam[e] across that we need to prove to [PacifiCorp] that they are getting the energy.").

incomplete metering arrangements that were still under investigation by PacifiCorp Transmission.

Q. Do you believe the May 20, 2014 draft PPA created a LEO?

A. No. The same key outstanding issues and disputes existed with the May 20, 2014 PPA that existed with the concept paper.

Q. Mr. Kresge asserts that former Pacific Power President and CEO, Mr. Pat Reiten, assured Surprise Valley on June 6, 2014, that Surprise Valley would be entitled to pre-August 20, 2014 avoided cost prices. How do you respond?

A. I cannot verify Mr. Kresge's assertions. PacifiCorp ESM has no record of any discussion between Mr. Reiten and PacifiCorp ESM. I would note that Mr. Reiten did not oversee PacifiCorp's merchant function, which was part of PacifiCorp Energy at that time. PacifiCorp ESM follows specific internal protocols for approval of QF PPAs. These protocols ensure that PacifiCorp does not enter into QF PPAs unless it is appropriate to do so from both a legal and operational standpoint. Mr. Reiten did not inform PacifiCorp ESM about this conversation or otherwise notify me of any official "approval" of anything. Thus, even assuming Mr. Kresge is accurately reporting Mr. Reiten's statements, I assume they were merely part of an informal, friendly conversation. I assume that Mr. Reiten, like PacifiCorp, expected Surprise Valley to provide verifiable delivery arrangements that would allow PacifiCorp to sign a QF PPA with Surprise Valley.

Q. Mr. Kresge also states that he had a conversation with current Pacific Power President and CEO Mr. Stefan Bird on May 15, 2015. Can you briefly summarize Mr. Kresge's testimony on this point?

A. Mr. Kresge states that, "On May 15, 2015, *outside the context of the settlement negotiations*, Pacific Power's president [Stefan] Bird and I discussed the PPA. Mr. Bird stated that the company would make a path to accommodate this project, and purchase the entire net output at rates effective before August 2014."[104]

Q. Why do you think Mr. Kresge said the words "outside the context of settlement negotiations"?

A. I am not sure, because the parties were deeply involved in confidential settlement negotiations at the time.

Q. Do you recall what was happening in May 2015?

A. Yes. Surprise Valley sent PacifiCorp a demand letter on April 16, 2015, seeking the sale of the full net output of the Paisley Project. From April 16, 2015 until Surprise Valley filed its complaint in June 2015, the parties were engaged in settlement discussions. I will not discuss the details of the confidential settlement discussions, other than to say the parties spent a good deal of time talking, and to emphasize that PacifiCorp has never deviated from its assertion that it will not accept a PPA under which it cannot verify receipt of power.

Q. Do you believe Surprise Valley is legally entitled to pre-August 20, 2014 avoided cost pricing?

A. No. To this day, Surprise Valley continues to have issues with verifiable delivery of the Paisley Project's full net output to PacifiCorp's system.

c. July 22, 2014 Draft PPA

Q. Can you explain Surprise Valley's position regarding the July 22, 2014 draft PPA?

[104] SVEC/100 at 27 (emphasis added).

A. Yes. In its testimony, Surprise Valley repeatedly claims that the July 22, 2014 draft PPA it provided to PacifiCorp was also one that it was willing to sign and only included certain "non-substantive" edits to the May 20, 2014 draft.[105] Similarly, in its responses to PacifiCorp's data requests, Surprise Valley reiterates that it was willing to sign the July 22, 2014 draft PPA.[106]

Q. Do you agree with Surprise Valley that the July 22, 2014 draft PPA was ready to sign?

A. No.

Q. Why not?

A. First, this draft PPA suffers from the same deficiencies as the May 20, 2014 draft, which are described in further detail above. By Surprise Valley's own admissions, this draft did not contain any substantive revisions to address the open items in the May 20, 2014 draft. Second, Surprise Valley also admits that the July 22, 2014 draft contained significant flaws, which precluded either party from being ready or able to sign the draft PPA. For example, in response to PacifiCorp's Data Request 3.79, Surprise Valley states:

> Surprise Valley was willing to execute the agreement submitted on July 22, 2014 because it understood that PacifiCorp communicated that form of written agreement to be its preference. Surprise Valley intended to perform under the agreement, which contained the rates in effect at that time. Surprise Valley does not concede that the scheduling provisions contained in the July 22, 2014 agreement may be lawfully imposed upon Surprise Valley's QF, located within PacifiCorp's balancing authority, by PacifiCorp absent Surprise

---

[105] *See* SVEC/100, Kresge/22-23 ("On July 22, 2014, Surprise Valley provided PacifiCorp with a draft PPA incorporating the non-substantive changes and recommendations made by PacifiCorp at and after the July 11, 2014 meeting. The July 22, 2014 draft also included non-substantive edits to reflect that two months had passed since we sent the May 20, 2014 draft PPA."); *see also* SVEC/200, Culp/17 ("We were ready to sign this PPA, and optimistic that a PPA could be finalized. . ."); *see also* PAC/109.

[106] PAC/121, PAC/122 and PAC/147; Surprise Valley's Responses to PacifiCorp 3.77 (attached hereto as PAC/134) and 3.85 (attached hereto as PAC/136). The July 22, 2014 Draft PPA is available at SVEC/207, Culp/2-45, and attached as PAC/110.

> Valley's agreement. Surprise Valley's attempt to execute such an agreement in July 2014 in order to obtain PacifiCorp's signature on a contract is not a concession that PacifiCorp may lawfully limit its purchase of QF energy to scheduled QF energy or otherwise relieve PacifiCorp's obligation to purchase unscheduled QF net output made available to PacifiCorp within its balancing authority.[107]

As this response demonstrates, despite Surprise Valley's claims that it was willing to sign the July 22, 2014 draft PPA, it was simultaneously unwilling to agree that it was required to abide by its terms and disagreed that the scheduling provisions contained in this draft could be "lawfully imposed upon Surprise Valley's QF." Neither had Surprise Valley provided any evident of such arrangements, as required by Schedule 37 and Commission precedent. Therefore, Surprise Valley's claims of willingness to sign are merely illusory. Surprise Valley was *not* ready or willing to sign the July 22, 2014 draft PPA, despite its claims to the contrary.

Q. Please describe your August 26, 2014 email to Surprise Valley.

A. On August 26, 2014, I sent an email to Mr. Culp letting him know that PacifiCorp would not accept the concept paper or a "swap." I let him know we were still reviewing the latest draft PPA he had sent, but that there were serious issues with that draft, including outstanding issues regarding metering, true ups between actual generation and deliveries to PacifiCorp's system.[108] Because the communications had become so complicated, I also advised Mr. Culp that I should be Surprise Valley's point of contact going forward, rather than Mr. Younie.

Q. What led to that email?

[107] PAC/135, PAC/136.

[108] PAC/108.

A. By August 26, 2014, PacifiCorp had expended an incredible amount of effort trying to understand how the Company might make a non-standard PPA with unusual delivery provisions work for Surprise Valley. Keep in mind that Surprise Valley's unusual configuration led to legal questions about PURPA compliance; questions about whether we could physically meter the QF's output at various places that we ordinarily would not be able to meter due to the Paisley Project's location in PacifiCorp's BAA; issues to discuss with PacifiCorp Transmission regarding whether it could appropriately play a role in power delivery under Surprise Valley's proposed "swap" of QF power for BPA power; and questions for BPA regarding their potential role in these arrangements. None of these questions could be answered by the people who ordinarily handled routine QF contracting, and all of them required coordination with people both inside and outside of the Company. All of this took an inordinate amount of time. It required coordination and feedback and multiple meetings involving different parties at PacifiCorp ESM and Transmission, Surprise Valley, and BPA. But, by August 26, 2014, PacifiCorp had come to understand the deficiencies in the concept paper and the draft PPAs that stemmed from the concept paper.

Q. What, specifically, did you tell Mr. Culp?

A. I reminded Mr. Culp that PacifiCorp had spent significant effort attempting to assist Surprise Valley with a PPA—that PacifiCorp had held multiple meetings with Surprise Valley's team, with BPA, and with PacifiCorp's transmission and metering departments, in hopes of finding a solution for Surprise Valley to deliver power to PacifiCorp's system. I reminded Mr. Culp that PacifiCorp had looked at the Paisley Project being off-system (and scheduling delivery), as well as being an on-system to accommodate the BAA issue but still requiring Surprise Valley to provide scheduling and delivery services to move the power to PacifiCorp, and that PacifiCorp had initiated a transmission service request to enable the Company to do a system impact study to assess options for metering and measuring the project's actual delivery. All of this was done under the assumption that the Company could basically accept a physical swap of QF power for BPA power at an alternative location, even though nothing in PURPA required a swap. In the end, however, there was still no evidence that the Paisley Project's power would reach PacifiCorp's system.

Q What else did you clarify?

A I clarified that PacifiCorp was not going to sign a PPA unless the power sold under that PPA could be verifiably delivered to PacifiCorp's system. I also let Mr. Culp know that PacifiCorp was still in the process of conducting a system impact study and looking at metering issues that might allow measurement of physical flow, but that even those issues were outstanding because (1) PacifiCorp did not have final confirmation of the metering or its cost, (2) the parties had not yet reached agreement on payment for metering, and (3) it was still uncertain whether that metering would show that the Paisley Project was delivering power to PacifiCorp's system.

Q. Did these comments apply to the concept paper, the May 20, 2014 draft PPA, and the July 22, 2014 draft PPA?

A. Yes.

Q. After you clearly expressed PacifiCorp's unwillingness to accept Surprise Valley's delivery proposal, did Surprise Valley seek dispute resolution under the Company's PPA, as contemplated by PacifiCorp's Schedule 37?

A. No. Surprise Valley did not seek the Commission's view on PacifiCorp's position until nearly a year later, on June 22, 2015.

Q. Do you believe PacifiCorp should be penalized for failing to sign a PPA with a QF after PacifiCorp clearly expressed disagreement with the QF's delivery proposal?

A. No. If Surprise Valley disagreed with PacifiCorp's assessment, it could have sought review of that assessment at the Commission. PacifiCorp's position has not changed. PacifiCorp should not be penalized for continuing to talk to Surprise Valley yet refusing to sign a PPA, given the parties' clear disagreement on this point.

Q. Do you believe the July 22, 2014 draft PPA created a LEO?

A. No. The same key outstanding issues and disputes existed with the July 22, 2014 PPA that existed with the concept paper and the May 20, 2014 draft PPA.

d. June 22, 2015 Signed PPA

Q. Have you reviewed Surprise Valley's claims regarding the June 22, 2015 PPA that it signed?

A. Yes.

Q. Can you briefly summarize those claims?

A. Yes. Surprise Valley's testimony contains a copy of the unilaterally executed PPA that Surprise Valley signed and sent to PacifiCorp.[109] This PPA contains the same Addendum W and delivery and metering arrangement flaws that both the May 20, 2014 and July 22, 2014 draft PPAs contained.[110] Similarly, several of Surprise Valley's responses to PacifiCorp's data requests also state that the PPA executed on June 22, 2015, contained the delivery and metering arrangements identified in Surprise Valley's concept paper.

[109] SVEC/202, Culp/106; PAC/111.

[110] *Compare* PAC/109, PAC/110, and PAC/111 (all of which are materially identical).

Surprise Valley asserts that the delivery arrangements are described in the testimony of Mr. Anderson.[111]

Q. When did Surprise Valley file its complaint in this proceeding?

A. June 22, 2015.

Q. Do you have an alternative explanation?

A. Yes. It seems more plausible to me that Surprise Valley did not, and still does not, have a PPA that is ready for signature due to the fundamental delivery and metering issues described herein, as well as the open issues with Addendum W. Because of these significant issues, there is no way for the Paisley Project to perform under the PPA and, thus, no draft PPA produced to date was ready for either party's signature.

Q. Have you also reviewed Surprise Valley's responses to PacifiCorp Data Requests 4.14 and 4.64?

A. Yes.

Q. Can you briefly summarize those data requests and Surprise Valley's responses?

A. Yes. In these responses,[112] Surprise Valley explains that it was necessary to amend its power supply contract with BPA in order to make its proposed delivery and metering arrangements work. Specifically, Surprise Valley states:

> BPA and Surprise Valley amended the power supply contract to ensure proper metering and accounting for power deliveries, and *to ensure that the Paisley Project has no impact on the amount of power or obligations under Surprise Valley's power and transmission contracts with BPA. If the BPA and Surprise Valley power sale agreement had not been modified to reflect the existence of the Paisley Project, then it would appear that the Paisley Project served Surprise Valley's retail load*. This would result in Surprise Valley's retail load appearing smaller. To ensure that the net output of the Paisley Project did not

[111] PAC/121, PAC/122 and PAC/147.

[112] *See* PAC/142; Surprise Valley's Response to PacifiCorp Data Request 4.64 (attached hereto as PAC/148).

> appear to serve Surprise Valley's retail load, the net output of the Paisley Project needed to be measured.[113]

Additionally, Surprise Valley also indicated that the amendment to its BPA power sales agreement was necessary "To ensure that the Paisley Project is not used to serve Surprise Valley's retail load under the BPA contract."[114] Surprise Valley also concedes that, from its perspective, this contract amendment was necessary to ensure that the "physical flow of power" matches the "contractual sale of power" for purposes of Surprise Valley's sale of the Paisley Project's power to PacifiCorp.[115] Thus, it is clear from Surprise Valley's own statements that amendment of its BPA power sales agreement was a fundamental *requirement* for making its proposed delivery arrangements work.

Q. Do you know when BPA and Surprise Valley amended the power sales agreement?

A. According to Surprise Valley's response to PacifiCorp Data Request 4.64, the contract was revised effective July 1, 2015.[116]

Q. If the amendments needed to make Surprise Valley's delivery arrangements work were not effective until July 1, 2015, how can Surprise Valley claim it was ready to sign a PPA containing the necessary delivery arrangements before that date?

A. I do not believe it can. Without the amendment to the BPA power sales agreement, Surprise Valley's own admissions indicate that the Paisley Project would solely be used to serve Surprise Valley's own load.

---

[113] PAC/142 (emphasis added).

[114] PAC/148.

[115] *See* Surprise Valley's Response to PacifiCorp Data Request 4.67, attached as PAC/149.

[116] *See* PAC/148 and Surprise Valley's First Supplemental Response to PacifiCorp Data Request 2.3, including the Attachment 2.3(c) To ensure that the Paisley Project is not used to serve Surprise Valley's retail load under the BPA contract.") (attached hereto as PAC/116).

Q. What do you conclude about Surprise Valley's assertions that PacifiCorp should have signed a PPA with Surprise Valley before August 20, 2014?

A. I disagree with Surprise Valley. From the beginning of our discussions and negotiations around PPA structure, PacifiCorp has made it clear that PacifiCorp would not execute any PPA agreement that could not measure or verify the physical power delivered to our system.

Q. Do you believe the June 25, 2015 draft PPA created a LEO?

A. No. The same key outstanding issues and disputes existed with the June 25, 2015 PPA that existed with the concept paper, the May 20, 2014 draft PPA, and the July 22, 2014 draft PPA. In any case, this PPA would not have created a LEO for pre-August 20, 2014 pricing.

2. Allegations that PacifiCorp Unreasonably Delayed Negotiations

Q. What do you make of Surprise Valley's assertions that PacifiCorp unreasonably delayed negotiations?

A. I disagree that PacifiCorp intentionally delayed negotiations with Surprise Valley. I do believe there have been many miscommunications in this instance, more than with any QF I have dealt with in my lengthy career.

Q. Please describe the ongoing communication between PacifiCorp and Surprise Valley.

A. Between August and November 2013, John Younie and Mr. Culp exchanged over 25 emails in which PacifiCorp assisted Surprise Valley with a number of issues, including explaining various pieces of information needed under the PPA, helping Mr. Culp find Paisley's form 556 on FERC's website, etc. Mr. Culp did not know how to prepare a motive force plan, did not have an estimate of the generation from the project, and had other problems completing the information required. When all the required information was delivered on November 6, 2013, Mr. Younie provided the draft PPA *the same day*.[117]

Q. Did Surprise Valley indicate that it was unwilling or unable to provide the transmission arrangements at this time?

A. No. Surprise Valley and PacifiCorp exchanged several emails after the draft PPA was provided to Surprise Valley. Mr. Culp provided PacifiCorp with a list of questions about the PPA from their consultants, Power Engineers, and from BPA. PacifiCorp understood that Surprise Valley intended to wheel its power from the point of interconnection between the Paisley Project and Surprise Valley's system to a point on PacifiCorp's system. PacifiCorp thought BPA might be the wheeling entity. Surprise Valley also asked about how Addendum W worked.[118]

Q. Mr. Culp claims that sometime in December 2013, Surprise Valley stated that transmission arrangements with BPA would be unnecessary. According to Mr. Culp, PacifiCorp did not ask for Surprise Valley to make transmission arrangements "with itself" in response. How do you respond?

A. I can find no reference to this in the parties' correspondence, and Mr. Culp cites to no specific date or communication for this statement. I agree there was some confusion initially about whether BPA could provide transmission arrangements for Surprise Valley. But PacifiCorp's assumption was that Surprise Valley would comply with the

[117] *See* Email from J. Younie to L. Culp, dated November 6, 2013, attached as PAC/112.

[118] *See* Emails between J. Younie and L. Culp, J. Portouw, and D. Meeuwsen, dated from November 20, 2013 through January 28, 2014, and particularly, L. Culp email to J. Younie re Surprise Valley PPA, dated December 2, 2013 (containing a list of questions the parties needed to discuss regarding the November 6, 2013 draft PPA), attached as PAC/113.

terms of a Commission-approved off-system PPA, regardless of whether Surprise Valley or BPA was making the delivery. In addition, as I have explained, PacifiCorp has no problem allowing Surprise Valley to sell its power through a direct, on-system PPA. The limitation is that PacifiCorp will only purchase the amount of net output flowing through the point of delivery under such an agreement, not the full output of the generator. In Surprise Valle's case, unfortunately, this would be very little power.

Q. On December 3, 2013, Mr. Younie informed Mr. Culp that the Paisley Project would not be a QF if Surprise Valley used the net output to offset power purchased from BPA and that is transmitted to Surprise Valley by PacifiCorp. Please provide context for this statement.

A. PacifiCorp began to understand that Surprise Valley might be proposing a "swap" of power under which the QF would be used to serve load, and PacifiCorp might be asked to take BPA power somewhere else in PacifiCorp's BAA in lieu of QF power. I had concerns with this type of arrangement and so advised Mr. Younie, who relayed this message to Mr. Culp.

Q According to Mr. Culp, Surprise Valley then informed PacifiCorp that the Paisley Project would not be contractually serving load.[119] What effect did this have on Surprise Valley's delivery obligations?

A. None. Surprise Valley was obligated to deliver the Paisley Project's power to PacifiCorp's system. PacifiCorp would purchase the amount it could verify as delivered.

Q. On December 30, 2013, PacifiCorp had determined that the on-system PPA was the appropriate format for this deal, why is this?

[119] SVEC/200, Culp/7.

A. After conversation with PacifiCorp Transmission regarding the appropriate BAA, it was determined that Surprise Valley was located in PacifiCorp Transmission's BAA, which shifted the PPA from an off-system to an on-system. This would still require Surprise Valley to provide scheduling and ancillary services to move the full output of the Paisley Project to PacifiCorp's system.

Q. Mr. Culp asserts that all information requested by PacifiCorp was submitted to PacifiCorp by January 9, 2014.[120] Do you agree?

A. No. Surprise Valley continued to provide information at Mr. Younie's request through the month of January. On February 10, 2014, Mr. Younie sent a draft on-system PPA to Mr. Culp. Between January and May 2014, Mr. Younie and Mr. Culp exchanged a number of emails in which Mr. Younie requested information for the draft PPA.[121]

Q. On January 29, 2014, PacifiCorp determined that the form PPA should be a combination of on/off system PPA. Why?

A. This was essentially to address the fact that the off-system PPA contained provisions stating that the QF was outside of PacifiCorp's BAA. The change did not modify Paisley's obligation to deliver its power to PacifiCorp's system. Surprise Valley would still need to provide scheduling and ancillary services to move the full output of Paisley to PacifiCorp, thus the combination included an Addendum W to the on-system PPA. The combination PPA was now looking more like a non-standard PPA that would be negotiated under Oregon Schedule 38.

---

[120] SVEC/200, Culp/6.

[121] *See* Emails between J. Younie and L. Culp, from January 2014 through May 2014 (regarding information needed from Surprise Valley in order to complete a draft PPA), attached as PAC/114.

Q. Mr. Culp says that after numerous discussions, PacifiCorp "agreed in principle" that power could be purchased at then current Schedule 37 rates through offsetting, swapping, or displacing power. Is this accurate?

A. PacifiCorp was willing to consider Surprise Valley's delivery method, though it would not sign a PPA unless those delivery arrangements actually worked. As evidenced by the ongoing discussions of alternatives, PacifiCorp was willing to consider non-standard delivery arrangements if Surprise Valley complied with PURPA *and* allowed PacifiCorp to verify receipt of QF power. The delivery methods under consideration were a significant departure from a standard QF PPA.

Q. Did PacifiCorp agree with Surprise Valley that, when the Paisley Project operated, there would be more power on its system and that it would purchase that power?[122]

A. This would be true in theory if BPA scheduled sufficient power to Surprise Valley's system to make it true. The problem, in the end, was that PacifiCorp would not know whether "there would be more power on its system" as a result of the Paisley Project's generation, unless BPA provided scheduling under the GTA that would allow PacifiCorp to verify delivery. PacifiCorp did not know at this time whether BPA would be willing to provide such scheduling. In the end, they were not.

Q. Surprise Valley explains that in a July 11, 2014 meeting, PacifiCorp explained that "all it needed" was a way to meter and measure the additional power that would be on its system. What is your response?

A. This is accurate. PacifiCorp would be willing to purchase power from Surprise Valley if it could in fact meter and measure the additional power that would be on PacifiCorp's

[122] Mr. Culp says this was communicated to Surprise Valley in email correspondence and orally from John Younie, Bruce Griswold, and Pat Reiten between February and August.

system as a result of the QF. But as I have noted, under Surprise Valley's delivery proposal, the "measurement" aspect of the transaction presupposes that BPA will cooperate with Surprise Valley by providing granular schedules sufficient to allow PacifiCorp to verify the amount of power scheduled by BPA that PacifiCorp would then attribute to the Paisley Project.

Q. Would the studies being performed at the time allow PacifiCorp to verify receipt of QF power?

A. No. These studies were being done as part of an affected systems study to allow the Paisley Project to operate. They were not studies that would demonstrate how PacifiCorp might verify receipt of QF power. Schedules from BPA were a critical part of verifying that the Paisley Project's generation created "extra" power on PacifiCorp's system under Surprise Valley's proposals. I did not realize at the time that Mr. Culp so interpreted the studies.

Q. Mr. Culp states that PacifiCorp's calls and emails regarding the transmission service request led Surprise Valley to believe that Surprise Valley could offset, swap or displace power deliveries.[123] Do you have any comments on these statements?

A. Yes. PacifiCorp never stated that the metering would make a swap work. The metering would allow PacifiCorp to physically measure the output of the generator, measure the physical flow on to PacifiCorp's system, and compare that information to the amount of power BPA had scheduled to PacifiCorp's system for Surprise Valley. This last piece of information was necessary for the "true up," but it turned out to be impossible to obtain. And that was the point of my August 26, 2014 email. It turned out that PacifiCorp was

[123] SVEC/200, Culp/9.

not receiving the Paisley Project's power physically, nor did we have granular schedules from BPA. The only remaining way to verifiably deliver the project's full output to PacifiCorp was to go back to the original delivery requirements found in either the standard on-system or off-system PPA.

Q. Did you realize that Mr. Culp believed a transmission service request would advise the parties how Surprise Valley could *deliver* the full net output of the Paisley Project to PacifiCorp's system?

A. No.

Q. What discussions occurred on the July 11, 2014 call between PacifiCorp Transmission, PacifiCorp ESM, the parties' attorneys, Mr. Culp and Mr. Kresge?

A. The purpose of the call was to discuss the pending system impact study from the transmission service request to assess the metering and communication necessary to measure the output of the Paisley Project and the net load being served at the Lakeview Switch.

Q. Mr. Culp argues that you "reversed PacifiCorp's position" on many issues in your August 26, 2014 email. Is that correct?

A. No. I consistently told Surprise Valley that, from PacifiCorp ESM's perspective, PacifiCorp needed to verify physical delivery of the Paisley Project's generation through either metering or appropriate schedules.

Q. On a conference call on August 29, 2014, did you state that you believed that PacifiCorp had a method in place for metering and communications that would allow the company to sign a PPA, as Mr. Culp asserts?

A. Yes. Metering was identified in the System Impact Study that would measure the Paisley Project generator output and net load deliveries to Surprise Valley via PacifiCorp Transmission. The System Impact Study also determined that a Facility Study was necessary and in progress. However, as I explained in that call, we would still need the BPA hourly schedules for Surprise Valley. Those schedules were critical to a PPA for the full net output of the Paisley Project. Without them, the best PacifiCorp's metering could do is measure metered flow to PacifiCorp's system, which would allow PacifiCorp to sign a PPA for only a small amount of power.

Q. According to Mr. Culp, PacifiCorp agreed on a conference call on September 25, 2014, that it would take the entire net output of the Paisley Project, and that power flow issues had been resolved.[124] How would you respond?

A. The Facility Study was completed September 26, 2014, and shared with Surprise Valley on October 3, 2014. It confirmed the results of the System Impact Study, and fine-tuned the costs and schedule for metering and communications issues. As noted above, these served an important purpose, but it was indicated to Surprise Valley that PacifiCorp still would need the BPA schedules for Surprise Valley in order to verify receipt of the power from BPA attributed to the Paisley Project.

Q. Surprise Valley alleges that it had a non-productive meeting with PacifiCorp on November 24, 2014, after which PacifiCorp refused to communicate with Surprise Valley.[125] Is this your recollection?

A. I am not aware of the details of that meeting. However, PacifiCorp had a call with Surprise Valley on January 14, 2015. After that call, PacifiCorp ESM began working on

[124] SVEC/200, Culp/20.

[125] SVEC/200, Culp/21-22.

a draft reimbursement agreement which would reimburse PacifiCorp ESM for the costs of the metering and communication upgrades being implemented in the construction agreement between PacifiCorp ESM and PacifiCorp.

Q. What do you make of Surprise Valley's assertion that PacifiCorp has changed its position about the applicability of an off-system PPA?[126]

A. PacifiCorp has always been willing to sign a standard off-system PPA, and in fact sent Surprise Valley a standard off-system PPA in 2013. Standard QFs are entitled to standard QF PPAs, so long as they are willing to agree to the terms and conditions of those PPAs. QFs are generally aware of this fact and Surprise Valley's assertions to the contrary are not correct. PacifiCorp has always agreed to sign either a standard on-system or off-system PPA. Surprise Valley would never accept a PPA with standard on-system delivery provisions or standard off-system delivery provisions because they were not willing to accept the terms of either version or any combination thereof.

Q. Surprise Valley complains that the draft PPA sent to Surprise Valley contained a jury waiver provision that was not approved by the Commission. How do you respond?

A. PacifiCorp has asked QFs to agree to this provision until PacifiCorp can get it approved by the Commission, but is certainly willing to sign a standard PPA without it. I doubt that this issue delayed signing of a PPA in light of the fact that Surprise Valley still has not resolved its fundamental delivery issues.

Q. How do you respond to Surprise Valley's assertion that PacifiCorp delayed approval of the Paisley Project's test generation?[127]

[126] *See, e.g., id.* at 28-29.

A. Any delay was caused by a need to review system operational and safety issues. Once those were addressed, PacifiCorp approved test generation. This did not delay the signing of a PPA. The reason PacifiCorp still has not signed a PPA to this day is that Surprise Valley still has not resolved its fundamental delivery issues.

Q. Surprise Valley asserts PacifiCorp requested unnecessary information and did not do so quickly. How do you respond?

A. Surprise Valley did not provide the initial information requested, and it had to be educated about very basic contract terms. Moreover, assessment of Surprise Valley's situation took time in light of the unusual issues raised by Surprise Valley's request. The reason PacifiCorp still has not signed a PPA to this day is that Surprise Valley still has not resolved its fundamental delivery issues.

Q. How do you respond to Surprise Valley's assertion that the PPA negotiations were slowed down by PacifiCorp ESM's insistence that it would not sign an agreement until PacifiCorp Transmission approved the transmission service request studies, as well as the time Surprise Valley and BPA were required to expend to resolve PacifiCorp's transmission concerns?[128]

A. If the Paisley Project's delivery to PacifiCorp's system cannot be measured, yet PacifiCorp is obligated by a PPA to purchase the full net output of the plant, then PacifiCorp's customers may pay for power they never receive. These issues needed to be resolved before PacifiCorp would sign a PPA, whether that took months or years.

---

[127] *Id.* at 13.

[128] *Id.* at 9-12.

3. Other Issues

Q. How do you respond to Surprise Valley's assertion that PacifiCorp never told Surprise Valley it needed to make transmission arrangements until PacifiCorp filed its answer?[129]

A. The assertion is false. A QF's delivery requirements are clearly laid out in PacifiCorp's publicly available off-system QF PPA, which was provided to Surprise Valley in 2013. PacifiCorp provided Surprise Valley with all the same information and requirements for transmission service it provides other Schedule 37 QF projects, whether they are off-system or on-system. The delivery and scheduling issues were included in various of PacifiCorp's draft PPAs to Surprise Valley, and discussed with Surprise Valley at various meetings, as noted in my August 26, 2014 email to Mr. Culp.[130] Moreover, PacifiCorp's Schedule 37 advises any QF that is not connecting directly to PacifiCorp's system to "contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system."[131]

Surprise Valley's argument that it was never told it needed to make transmission arrangements requires the Commission to assume that Surprise Valley failed to read or consider the terms and conditions of the Company's standard QF PPAs, which is not a credible assumption to make. At a minimum, when confronted with delivery issues, Surprise Valley should have reviewed the standard PPAs. We know they eventually did so, because the marked-up draft PPAs that Surprise Valley sent to PacifiCorp in 2014

[129] *E.g.*, SVEC/100, Kresge/2, 13, 15, 22; SVEC/200, Culp/6, 28.

[130] PAC/108.

[131] PAC/104 at Griswold/9.

have the following edit: where the standard PPA language states that a QF will "transmit" its net output to PacifiCorp, Surprise Valley deleted the word "transmit" and replaced it with the word "sell."[132] PacifiCorp rejected the mark-up. Surprise Valley was well aware of the standard requirement to "transmit" its power to PacifiCorp; it just disagreed with PacifiCorp's assertion that, unless Surprise Valley could provide acceptable alternative arrangements, Surprise Valley was required to follow them.

Q. How do you respond to Surprise Valley's suggestions that PacifiCorp is required to tell a QF how to deliver its power to PacifiCorp's system?

A. Surprise Valley has consistently asked PacifiCorp how Surprise Valley is supposed to provide transmission service. First, it is not PacifiCorp's responsibility to tell Surprise Valley how to provide transmission service. It is Surprise Valley's system, and Surprise Valley's responsibility under PURPA to make the arrangements consistent with the off-system PPA and Addendum W or to demonstrate a verifiable method of power delivery. As I mentioned earlier, PacifiCorp has multiple off-system QF PPAs in Oregon and across its six-state system. None of those QFs asked PacifiCorp how to provide firm transmission service. Given the number of industry experts and consultants being used by Surprise Valley on the development of the Paisley Project,[133] it would seem that one of them would be able to determine how to meet the terms and conditions of the Commission-approved off-system PPA, assuming that is what Surprise Valley actually wanted to do.

---

[132] PAC/109.

[133] *See, e.g.*, Surprise Valley's Responses to PacifiCorp's Data Requests 3.54 (attached hereto at PAC/128), 3.55 (attached hereto at PAC/129), and 3.56 (attached hereto at PAC/130).

In my opinion, it would help if Surprise Valley had a wholesale distribution tariff that standardized Surprise Valley's delivery services and raised them to industry standards, but is not necessary. Neither does Surprise Valley need to provide an agreement "with itself." But Surprise Valley does need to provide evidence of firm transmission service for delivery of QF power to PacifiCorp's system, including scheduling and ancillary services, in order to qualify for a standard avoided cost rate and provide PacifiCorp with a verifiable schedule of the physical delivery to its system.

Q. Mr. Kresge states that test power generated by the Paisley Project between July 12, 2015, and September 30, 2015, benefitted PacifiCorp and suggested that Surprise Valley should be compensated for that power.[134] Do you agree?

A. No. I am not aware that any of the test power was delivered to PacifiCorp's system. My understanding is that all of the power was used to serve Surprise Valley's load and offset its deliveries from BPA. This was a specific condition agreed to by PacifiCorp ESM, PacifiCorp Transmission, and Surprise Valley back in April 2014 to allow Surprise Valley to run the Paisley Project for testing in order to meet the Oregon Business Energy Tax Credit deadline. In fact, my understanding is that Surprise Valley secured permission from BPA to run the Paisley Project to offset its own load during the noted period without impacting its all-requirements contract with BPA. If some power in excess of Surprise Valley's load reached PacifiCorp's system, that flow onto PacifiCorp's system would have been unauthorized use of PacifiCorp's transmission system, subject to penalty. To the extent any "extra" power ended up somewhere in PacifiCorp's BAA as a

[134] Surprise Valley reiterated this assertion in discovery, stating that "PacifiCorp is required to compensate Surprise Valley for the net output of the Paisley Project between July 12, 2015 and September 30, 2015." *See* Surprise Valley's Response to PacifiCorp Data Request 5.3, attached as PAC/151.

result of Surprise Valley's power generation that amount of power would not be measurable or valuable, its location would not be evident, and it could not be used by PacifiCorp ESM to serve load. In short, PacifiCorp ESM enjoyed no benefit whatsoever from Surprise Valley's test energy.

Q. Does Mr. Kresge's testimony about the "benefits" of test energy demonstrate the problem with Surprise Valley's position?

A. Yes. It demonstrates a complete lack of understanding of the type of commercially appropriate power delivery arrangements that would allow PacifiCorp ESM to account for QF power, measure it, and use it to serve load. Simply attaching a generator to a system in a BAA and turning it on does not benefit the merchant function in a BAA, and it certainly does not constitute "firm" power delivery that would allow a merchant function to count on and schedule that power for load service.

Q. What do you make of Surprise Valley's assertion that PacifiCorp's off-system PPA does not apply to Surprise Valley because the recitals to that standard PPA state that the QF is not located in PacifiCorp's BAA?

A. Surprise Valley is the first QF in PacifiCorp's BAA where their project is not directly interconnected with PacifiCorp but would require a wheeling arrangement to deliver and sell the full output to PacifiCorp. Other utilities that own QFs have agreed to on-system PPAs under which PacifiCorp purchases the amount of QF generation that flows through a meter to PacifiCorp's system, an arrangement PacifiCorp is willing to offer here. The recital at issue reflects the fact that it is unusual for a QF in PacifiCorp's BAA and *not* directly interconnected with PacifiCorp to seek a PPA for the full net output of the plant. PacifiCorp prepared a hybrid on/off system PPA to account for this fact, but nothing about the location of the Paisley Project eliminates Surprise Valley's firm, verifiable power delivery obligations.

D. Surprise Valley's Non-Analogous QF PPA Examples

Q. Surprise Valley's witnesses, particularly Mr. Dolan, analogize Surprise Valley's power swap/displacement proposal with other QF projects that they have heard of. Do you agree with their characterizations?

A. No. The examples provided are not analogous to the current situation and they are irrelevant to this discussion.

1. Kootenai's Fighting Creek QF

Q. Are you familiar with the testimony Surprise Valley's witnesses provided regarding Kootenai's Fighting Creek QF?

A. Yes, I am.

Q. Can you briefly summarize the Kootenai Fighting Creek QF?

A. Yes. Kootenai is an all requirements customer of BPA, but is directly connected to the distribution system of Avista. Therefore, Avista provides Kootenai with its all requirements power on behalf of BPA pursuant to Avista's OATT – FERC Electric Tariff Volume 8.

Q. Surprise Valley's witness Mr. Dolan states in his testimony that Kootenai is served via a general transfer agreement between Avista and BPA through Avista's 115 kV transmission system. Do you agree with his statement?

No. In fact, I am confused by his statement that Kootenai is served via a general transfer agreement between Avista and BPA. The "Interconnection and Operating Agreement" attached to the power purchase agreement between Kootenai and Avista specifically states in the recitals that the general transfer agreement expired December 31, 2005, and was replaced with Avista's OATT – FERC Electric Tariff Volume 8, whereby Avista provides network integration transmission service to BPA for delivery of power to Kootenai, and BPA purchases such services at tariff cost.

In other words, BPA is purchasing firm transmission service from Avista to serve Kootenai. This is very different than the GTA between PacifiCorp and BPA and presumably provides the verification needed to determine delivery.

Q. Does Mr. Dolan have personal knowledge of all of the agreements underlying Surprise Valley's proposed sale and delivery of QF power to PacifiCorp's system?

A. He concedes that he does not.[135]

Q. Does Mr. Dolan's testimony profess to speak to the dispute between Surprise Valley and PacifiCorp?

A. No. Mr. Dolan concedes that his testimony does not address the dispute between Surprise Valley and PacifiCorp.[136]

Q. Mr. Dolan describes the prior power sales arrangements for Kootenai Fighting Creek and indicates the output was sold to Avista under a PURPA QF contract.[137] What is your response?

A. Perhaps Mr. Dolan does not realize this because he is not sufficiently familiar with the current dispute, but the type of PURPA QF contract offered by Avista to Kootenai is far different than the one Surprise Valley is seeking from PacifiCorp. Aside from the obvious differences in the verifiability of delivery, the Avista PPA that was actually

[135] *See* Surprise Valley's Response to PacifiCorp Data Request 5.16, attached as PAC/155.

[136] SVEC/500, Dolan/2.

[137] *Id.* at 5-6.

executed was an as-available, non-firm contract, meaning that Avista only purchases energy when and if the energy gets to Avista's system at the point of interconnection between Kootenai and Avista, for the lower of 85 percent of the Dow Jones Mid-Columbia non-firm index price or Avista's avoided cost rates contained in the PPA.[138] Effectively, the Fighting Creek arrangements allowed Avista to purchase the QF's net output only when it was available and only when excess transmission (*i.e.,* non-firm) was available to deliver the output to Avista's system. This is very much different than the PPA demanded by Surprise Valley. The Kootenai agreement is a non-firm agreement which requires no minimum delivery obligations, no credit support, and therefore receives a discounted non-firm price. Surprise Valley wanted firm, fixed prices while asking PacifiCorp to blindly accept it was delivering the Paisley Project's full net output.

Q. Mr. Dolan also mentions an earlier, unsigned PPA whereby he claims Avista was willing to purchase the net output of Kootenai's Fighting Creek under a long-term agreement at full avoided cost rates.[139] Do you have any thoughts on this?

A. I would just note that the form agreement he provided is unsigned and an unsigned agreement is not effective.

Q. What is your response to Mr. Dolan's testimony that no contractual or scheduling changes were made with BPA to deliver Kootenai's all-requirements power when the Fighting Creek power was sold to Avista?

A. I was not involved in those negotiations, nor am I aware of the specifics of Kootenai's contract with BPA, so I am not qualified to discuss the specifics of that agreement.

[138] SVEC/502 at Dolan/10, § 7.3; *see also* Surprise Valley Responses to PacifiCorp's Data Requests 3.92 (attached hereto as PAC/137) and 3.93 (attached hereto as PAC/138).

[139] SVEC/500, Dolan/6.

However, as I noted above, Mr. Dolan states that the delivery from BPA to Avista is done via a general transfer agreement, when in fact, it appears to be delivered under Avista's OATT. That being said, the discussion of what Mr. Dolan suggests is a similar arrangement has no bearing on this dispute.

Q. Why do you say the Fighting Creek analogy raised by Surprise Valley has "no bearing" on this dispute?

A. We do not know why Avista entered into the PPA with Kootenai, and Mr. Dolan cannot confirm the reasons.[140] The question is whether Surprise Valley's arrangements are satisfactory. Because they would not allow PacifiCorp to verify receipt of power, they are not.

Q. What is your response to Mr. Dolan's testimony regarding the "delivery" arrangements accepted by Avista for the Fighting Creek QF's net output?

A. Mr. Dolan claims that Avista made "the necessary arrangements to accept title to such a 'delivery' without ancillary services, schedules, or e-tags provided by Kootenai,"[141] however, he provides no information on what these "necessary arrangements" were that Avista made. It should be noted again that the power purchase agreement was for as-available, non-firm deliveries, not for a firm QF sale to Avista. He also concedes he has no legal expertise, which makes it unclear how he could testify as to whether the arrangements at issue in that agreement complied with PURPA or whether they even pass title to Avista.

[140] Surprise Valley explained in discovery that the question of whether PURPA required Avista to accept the Kootenai arrangements is not something Mr. Dolan can speak to because it requires a "legal conclusion" *See* Surprise Valley's Response to PacifiCorp Data Requests 5.13 (attached hereto as PAC/152), 5.14 (attached hereto as PAC/153) and 5.15 (attached hereto as PAC/154).

[141] SVEC/500, Dolan/7-8.

2. Oregon Trail Cooperative's Co-Gen Co., Idaho Power, and Unnamed Parties' Transaction

Q. Surprise Valley's witness Mr. Kresge states that Idaho Power entered into an arrangement that is similar to Surprise Valley's proposed power swap/displacement with Co-Gen Co. that was located in the service territory of Oregon Trail Electric Cooperative.[142] What is your response?

A. Mr. Kresge states that he is "aware of" a supposedly similar transaction which Idaho Power participated in. First, without more information I cannot confirm that either the power swap/displacement proposal exists at all or in a similar format as Surprise Valley is proposing here, or that the PPA executed by the parties and the avoided cost rate are similar to what Surprise Valley is seeking. Second, even if they were, this does not mean that Surprise Valley's proposal satisfies the federal or Oregon requirements for PURPA transactions.

Q. Mr. Kresge also asserts that PacifiCorp has entered into PPAs with other QFs with net output that was smaller than the QF's load or smaller than the load of the QF's serving utility.[143] Mr. Kresge further asserts that in some of these instances, the power that PacifiCorp received was displaced BPA power that BPA would have otherwise delivered to serve its customers' load.[144] What is your response?

A. This is not a true statement. Mr. Kresge cites to PacifiCorp Response to Surprise Valley DR 1.8[145] for its support for this statement. In that request, Surprise Valley asked

[142] SVEC/100, Kresge/4.

[143] *Id.*

[144] *Id.* at 5 (*citing* PacifiCorp's Response to Surprise Valley DR 1.8 as support). PacifiCorp's Response to Surprise Valley DR 1.8 was provided at SVEC/203, Culp/11-12, and is also attached as PAC/115.

[145] *Id.*

PacifiCorp to identify its QF PPAs under which a portion or all of the QF's output is transmitted across a third parties' distribution or transmission system. PacifiCorp provided a list of these parties. These QF purchases are not power swap/displacement arrangements. The QFs at issue have either provided firm or non-firm delivery arrangements to PacifiCorp that allow for PacifiCorp to receive and take title to the QF power. The avoided cost pricing that each entity receives depends on the firmness of the power provided and whether or not they executed a standard or non-standard PPA with PacifiCorp. All of these agreements, unlike Surprise Valley's proposal, allow PacifiCorp to verify delivery of QF power.

Q. Why does Surprise Valley assert that these transactions are power displacement scenarios similar to the transaction they want to engage in?

A. Surprise Valley appears to be unable to provide the necessary delivery arrangements needed to satisfy the requirements of PacifiCorp's Commission-approved standard PPAs. Unable to provide the contractual arrangements needed, Surprise Valley is retreating to a position whereby it equates scenarios to Surprise Valley's position based on basic electrical engineering principles, ignoring the framework of contracts and laws that allow for the orderly operation of the transmission grid.

V. CONCLUSION

Q. Please summarize your conclusions.

A. Although Surprise Valley wishes to sell the full net output of the Paisley Project to PacifiCorp, Surprise Valley has not been willing or able to make appropriate and verifiable delivery arrangements to account for the lack of physical delivery of the Paisley Project's power to PacifiCorp's system. PacifiCorp has negotiated in good faith and worked with Surprise Valley to find contractual arrangements that meet both FERC and Commission policies and requirements. While there have been a number of misunderstandings by the parties during the course of negotiations, those negotiations were not conducted in bad faith. In the end, PacifiCorp is not willing to sign a PPA unless it can be sure that it will receive the power it pays for under that PPA.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/101

**GENERAL TRANSFER AGREEMENT
BETWEEN THE UNITED STATES OF AMERICA DEPARTMENT OF ENERGY
ACTING BY AND THROUGH THE BONNEVILLE POWER ADMINISTRATION AND
PACIFIC POWER & LIGHT CO.**

May 17, 2016

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. <u>Exhibits</u>. 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. <u>Revision of Exhibits</u>.

(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; 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.

Exhibit B, Table 1, Revision No. 1
Page 1 of 2
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.

Exhibit B, Table 1, Revision No. 1
Page 2 of 2
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. 3
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer: Benton Rural Electrification Association, Inc.
Effective 0000 hours on
March 24, 2006

Point of Delivery for Bonneville

This revision updates this exhibit to include a meter adjustment to account for the addition of load being served by Benton REA to Yakama Power on behalf of Bonneville Power.

WHITE SWAN POINT OF DELIVERY:

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

Voltage: 115 kV.

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

Meter Adjustment: The Benton White Swan meter reading will be adjusted by deducting Yakama Power's Hawk Road meter point, plus Benton REA assessed 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 Anne E. Draper

Name: Anne E. Draper, Manager,
Transmission Acquisition and Reserves

Date: ____________

PACIFICORP

By K Houston

Name: Kenneth Houston
Director, Transmission

Date: 3-22-06

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

<u>Point of Delivery for Bonneville</u>

This revision adds the Ariel Point of Delivery.

<u>ARIEL POINT OF DELIVERY</u>:

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

<u>Voltage</u>: 115 kV.

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

<u>Point of Replacement</u>: 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 ____________________
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)

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.

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
Coöperative, 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.

(WP-PCI-1185c)

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 ______________________

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

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

Contract No. DE-MS79-82BP90049
Transferor: PacifiCorp
Bonneville's Customer:
Surprise Valley Electrification Corporation
Effective Date: August 1, 1992

Points of Delivery for Bonneville

This Revision No. 3 establishes an effective date of August 1, 1992 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 the vicinity of Surprise Valley's Lakeview Switching Station where the 69 kV facilities of PacifiCorp and Suprise 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;

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.

Exhibit B, Table 19
Page 1 of 2
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Umatilla Electric
Cooperative Association
Effective at 2400 hours on
June 30, 1981

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.

Exhibit B, Table 19
Page 2 of 2
Contract No. DE-MS79-82BP90049
Transferor: Company
Bonneville's Customer:
Umatilla Electric
Cooperative Association
Effective at 2400 hours on
June 30, 1981

(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.

Exhibit B, Table 21, Revision No. 1

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.

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

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:
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

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

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.

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

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;

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

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. 21
TRANSFER CHARGES, SOLE USE-OF-FACILITIES CHARGES, AND LOSS FACTORS

This Exhibit D, Revision No. 21 updates the transfer charge associated with the Klondike 69 kV Point of Delivery.

EFFECTIVE DATE. This exhibit revision shall be retroactive to January 1, 2015.

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	1.1660[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 (Benton)	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
Looking Glass (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

---

[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 the Government passes Wasco's transfer charge through to the Company under the transfer charge for the Klondike 69 kV POD.

[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
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

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

PACIFICORP

By: Joseph P H

Name: Joseph Hoerner, Director
(Print/Type) Energy Supply Management

Title: PacifiCorp Power

Date: 07/08/15

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By: David Fitz

Name: David A. Fitzsimmons
(Print/Type)

Title: Manager, Transmission Sales

Date: 7/15/2015

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
Page 1 of 2
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

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. <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. 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	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: [signature]

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

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/102

PACIFICORP STANDARD
POWER PURCHASE AGREEMENT FOR
ON-SYSTEM
INTERMITTENT QUALIFYING FACILITIES
(LESS THAN 10,000 KW)

May 17, 2016

DRAFT

THIS WORKING DRAFT DOES NOT CONSTITUTE A BINDING OFFER, SHALL NOT FORM THE BASIS FOR AN AGREEMENT BY ESTOPPEL OR OTHERWISE, AND IS CONDITIONED UPON EACH PARTY'S RECEIPT OF ALL REQUIRED MANAGEMENT APPROVALS (INCLUDING FINAL CREDIT AND LEGAL APPROVAL). ANY ACTIONS TAKEN BY A PARTY IN RELIANCE ON THE TERMS SET FORTH IN THIS WORKING DRAFT OR ON STATEMENTS MADE DURING NEGOTIATIONS PURSUANT TO THIS WORKING DRAFT SHALL BE AT THAT PARTY'S OWN RISK. UNTIL THIS AGREEMENT IS NEGOTIATED, APPROVED BY MANAGEMENT, SIGNED AND DELIVERED, NO PARTY SHALL HAVE ANY OTHER LEGAL OBLIGATIONS, EXPRESSED OR IMPLIED, OR ARISING IN ANY OTHER MANNER UNDER THIS WORKING DRAFT OR IN THE COURSE OF NEGOTIATIONS.

POWER PURCHASE AGREEMENT

BETWEEN

____

[a new Firm Qualifying Facility with 10,000 kW Facility Capacity Rating, or Less and an Intermittent Resource with Mechanical Availability Guarantee]

AND

PACIFICORP

EXHIBIT A:	DESCRIPTION OF SELLER'S FACILITY
EXHIBIT B:	SELLER'S INTERCONNECTION FACILITIES
EXHIBIT C:	REQUIRED FACILITY DOCUMENTS
EXHIBIT D-1:	SELLER'S MOTIVE FORCE PLAN
EXHIBIT D-2:	ENGINEER'S CERTIFICATION OF MOTIVE FORCE PLAN
EXHIBIT E:	START-UP TESTING
EXHIBIT F:	SELLER AUTHORIZATION TO RELEASE GENERATION DATA TO PACIFICORP
EXHIBIT G:	SCHEDULE 37 AND PRICING SUMMARY TABLE
EXHIBIT H:	GREEN TAG ATTESTATION AND BILL OF SALE

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT, entered into this ____ day of ______________, 20____, is between _________________________, "**Seller**" and PacifiCorp (d/b/a Pacific Power & Light Company), an Oregon corporation acting in its regulated utility capacity, "**PacifiCorp**." (Seller and PacifiCorp are referred to individually as a "**Party**" or collectively as the "**Parties**").

RECITALS

A. Seller intends to construct, own, operate and maintain a _____________________ ______________________________________ [state type of facility] facility for the generation of electric power, including interconnection facilities, located in _____________________________ [City, County, State] with a Facility Capacity Rating of ___________ kilowatts (kW**)** _______ as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

B. Seller intends to commence delivery of Net Output under this Agreement, for the purpose of Start-up Testing, on __________________, 20____ ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on _________________, 20____ ("**Scheduled Commercial Operation Date**"); and

D. Seller estimates that the average annual Net Energy to be delivered by the Facility to PacifiCorp is __________ kilowatt-hours (kWh), which amount of energy PacifiCorp will include in its resource planning; and

E. Seller shall (choose one) ☐ sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp ☐ sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of this Agreement; and

F. This Agreement is a "New QF Contract" under the PacifiCorp Inter-Jurisdictional Cost Allocation Revised Protocol.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

Section 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 "**As-built Supplement**" shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 "**Availability**" means the percentage of time that the Facility is capable of producing Net Energy during a Contract Year. The percentage of time during a Contract Year that the Facility is available to produce power is calculated as follows:

% Availability ={[(H x N)-(Sum of Downtime Hrs for N Turbines)]/(H x N)} x 100%

where H is the number of hours in the Contract Year and N is the number of turbines comprising the Facility. Downtime Hours (calculated in 10 minute increments), for each individual unit includes minutes in which the unit is not in "run" status, or is in "run" status but faulted (including any delay in resetting a fault). Notwithstanding the previous sentence, Downtime Hours does not include minutes that a unit is unavailable due to (i) an event of Force Majeure; (ii) a default by PacifiCorp under this Agreement; (iii) Lack of Motive Force at times when the Facility would otherwise be available (including the normal amount of time required by the generating equipment to resume operations following a Lack of Motive Force); or (iv) outages scheduled at least 90 days in advance with PacifiCorp's written consent, up to 200 hours per unit per year.

1.3 "**Average Annual Generation**" shall have the meaning set forth in Section 4.2.

1.4 **"Billing Period"** means, unless otherwise agreed to, the time period between PacifiCorp's consecutive readings of its power purchase billing meter at the Facility in the normal course of PacifiCorp's business. Such periods typically range between twenty-seven (27) and thirty-four (34) days and may not coincide with calendar months.

1.5 "**CAMD**" means the Clean Air Markets Division of the Environmental Protection Agency or successor administrator, or any state or federal entity given jurisdiction over a program involving transferability of Green Tags.

1.6 **"Commercial Operation Date"** means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.6.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the

Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

1.6.2 The Facility has completed Start-Up Testing;

1.6.3 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating that, (a), in accordance with the Generation Interconnection Agreement, all required interconnection facilities and metering have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with PacifiCorp's electric system, and (b) if the Facility consists of multiple wind generation facilities on a common transmission line, the required metering equipment has been completed and tested in conformance with Section 8 of this Agreement (or if the Facility is interconnected with another electric utility that will wheel Net Output to PacifiCorp, all required interconnection facilities and metering equipment have been completed and tested and are in place to allow for such wheeling);

1.6.4 PacifiCorp has received a certificate addressed to PacifiCorp from an attorney in good standing in the State of Oregon stating that Seller has obtained all Required Facility Documents and if requested by PacifiCorp, in writing, has provided copies of any or all such requested Required Facility Documents. (Facilities over 200 kW only).

1.6.5 Seller has complied with the security requirements of Section 10.

1.6.6 PacifiCorp has received an executed copy of **Exhibit F**—Seller's Interconnection Request.

1.7 **"Commission"** means the Oregon Public Utilities Commission.

1.8 **"Contract Price"** means the applicable price for capacity or energy, or both capacity and energy, stated in Sections 5.1, 5.2, and 5.3.

1.9 **"Contract Year"** means a twelve (12)- month period commencing at 00:00 hours Pacific Prevailing Time ("PPT") on January 1 and ending on 24:00 hours PPT on December 31; *provided, however,* that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

1.10 "**Credit Requirements**" means a long-term credit rating (corporate or long-term senior unsecured debt) of (1) "Baa3" or greater by Moody's, or (2) "BBB-" or greater by S&P, or such other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment.

1.11 “**Cut-in Speed**” means the wind speed at which a stationary wind turbine begins producing Net Energy, as specified by the turbine manufacturer, and set forth in **Exhibit A**.

1.12 “**Default Security**”, unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at **[specify POD]** (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) 25% of the Average Annual Generation provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller’s average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

1.13 “**Effective Date**” shall have the meaning set forth in Section 2.1.

1.14 “**Energy Delivery Schedule**” shall have the meaning set forth in Section 4.4.

1.15 “**Environmental Attributes**” shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

1.16 “**Excess Output**” shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Capacity Rating.

1.17 **“Facility”** shall have the meaning set forth in Recital A.

1.18 “**Facility Capacity Rating**” means the sum of the Nameplate Capacity Ratings for all generators comprising the Facility.

1.19 “**FERC**” means the Federal Energy Regulatory Commission, or its successor.

1.20 “**Guaranteed Availability**” shall have the meaning set forth in Section 4.3.1.

1.21 **“Generation Interconnection Agreement”** means the generation interconnection agreement to be entered into separately between Seller and PacifiCorp’s transmission or distribution department, as applicable, providing for the construction, operation, and maintenance of PacifiCorp’s interconnection facilities required to accommodate deliveries of

Seller’s Net Output if the Facility is to be interconnected directly with PacifiCorp rather than another electric utility.

1.22 “**Green Tags**” means (1) the Environmental Attributes associated with all Net Output, together with (2) all WREGIS Certificates; and (3) the Green Tag Reporting Rights associated with such energy, Environmental Attributes and WREGIS Certificates, however commercially transferred or traded under any or other product names, such as "Renewable Energy Credits," "Green-e Certified", or otherwise. One (1) Green Tag represents the Environmental Attributes made available by the generation of one (1) MWh of energy from the Facility. Provided however, that “Green Tags” do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

1.23 “**Green Tag Reporting Rights”** means the exclusive right of a purchaser of Green Tags to report exclusive ownership of Green Tags in compliance with federal or state law, if applicable, and to federal or state agencies or other parties at such purchaser's discretion, and include reporting under Section 1605(b) of the Energy Policy Act of 1992, or under any present or future domestic, international, or foreign emissions trading program or renewable portfolio standard.

1.24 “**Lack of Motive Force**” means temporary lack, due to natural causes, of: sunlight (for a solar powered facility), water (for a hydropower facility), current or wave amplitude (for a wave energy facility), or Sufficient Wind (for a wind turbine facility). Lack of Motive Force does not include lack of any motive force due to voluntary actions taken by Seller (e.g. lease or sale of water rights).

1.25 **“Letter of Credit”** means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of “A” or greater from S&P or “A2” or greater from Moody’s, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

1.26 **“Licensed Professional Engineer”** means a person acceptable to PacifiCorp in its reasonable judgment who is licensed to practice engineering in the state of Oregon, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made.

1.27 “**Material Adverse Change**” means the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller’s ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement.

1.28 **“Nameplate Capacity Rating”** means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.29 "**Net Energy**" means the energy component, in kWh, of Net Output.

1.30 **"Net Output"** means all energy and capacity produced by the Facility, less station use and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the Point of Delivery.

1.31 "**Net Replacement Power Costs"** shall have the meaning set forth in Section 11.4.1.

1.32 **"Off-Peak Hours"** means all hours of the week that are not On-Peak Hours.

1.33 **"On-Peak Hours"** means the hours between 6 a.m. Pacific Prevailing Time ("**PPT**") and 10 p.m. PPT, Mondays through Saturdays, excluding all hours occurring on holidays as provided in Schedule 37.

1.34 "**Output Shortfall**" shall have the meaning set forth in Section 4.3.2

1.35 **"Point of Delivery"** means the high side of the Seller's step-up transformer(s) located at the point of interconnection between the Facility and PacifiCorp's distribution/ transmission system, as specified in the Generation Interconnection Agreement, or, if the Facility is not interconnected directly with PacifiCorp, the point at which another utility will deliver the Net Output to PacifiCorp as specified in **Exhibit B**.

1.36 **"Prime Rate"** means the publicly announced prime rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, New York, selected by the Party to whom interest based on the Prime Rate is being paid.

1.37 **"Prudent Electrical Practices"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

1.38 **"QF"** means "**Qualifying Facility,**" as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.39 **"Renewable Resource Deficiency Period"** means the period from________ through ________.

1.40 **"Renewable Resource Sufficiency Period"** means the period from _______ through ________.

1.41 **"Replacement Price"** means the price at which PacifiCorp, acting in a commercially reasonable manner, purchases for delivery at the Point of Delivery a replacement for any Net Output that Seller is required to deliver under this Agreement plus (i) costs reasonably incurred by PacifiCorp in purchasing such replacement Net Output, and (ii) additional transmission charges, if any, reasonably incurred by PacifiCorp in causing replacement energy to be delivered to the Point of Delivery. If PacifiCorp elects not to make such a purchase, the Replacement Price shall be the market price at the Mid-Columbia trading hub for such energy not delivered, plus any additional cost or expense incurred as a result of Seller's failure to deliver, as determined by PacifiCorp in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

1.42 **"Required Facility Documents"** means all licenses, permits, authorizations, and agreements, including a Generation Interconnection Agreement or equivalent, necessary for construction, operation, and maintenance of the Facility consistent with the terms of this Agreement, including without limitation those set forth in **Exhibit C.**

1.43 "**Schedule 37**" means the Schedule 37 of Pacific Power & Light Company's Commission-approved tariffs, providing pricing options for Qualifying Facilities of 10,000 kW or less, which is in effect on the Effective Date of this Agreement. A copy of that Schedule 37 is attached as **Exhibit G**.

1.44 **"Scheduled Commercial Operation Date"** shall have the meaning set forth in Recital C.

1.45 "**Scheduled Initial Delivery Date**" shall have the meaning set forth in Recital B.

1.46 **"Start-Up Testing"** means the completion of required factory and start-up tests as set forth in **Exhibit E** hereto.

1.47 "**Sufficient Wind**" means any hour during which the average wind speed is equal to or greater than the manufacturer's rated Cut-in Speed for the wind turbines comprising the Facility.

1.48 "**Termination Date**" shall have the meaning set forth in Section 2.4.

1.49 "**WREGIS**" means the Western Renewable Energy Generation Information System or successor organization in case WREGIS is ever replaced.

1.50 "**WREGIS Certificate**" means "Certificate" as defined by WREGIS in the WREGIS Operating Rules dated July 15, 2013.

1.51 "**WREGIS Operating Rules**" means the operating rules and requirements adopted by WREGIS, dated July 15, 2013.

Section 2: **TERM; COMMERCIAL OPERATION DATE**

2.1 This Agreement shall become effective after execution by both Parties ("**Effective Date**").

2.2 **Time is of the essence for this Agreement,** and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to deliver Net Output by the Scheduled Commercial Operation Date is critically important. Therefore,

2.2.1 By ______________________, Seller shall provide PacifiCorp with a copy of an executed Generation Interconnection Agreement, or wheeling agreement, as applicable, which shall be consistent with all material terms and requirements of this Agreement.

2.2.2 Upon completion of construction, Seller, in accordance with Section 6.1, shall provide PacifiCorp with an As-built Supplement acceptable to PacifiCorp;

2.2.3 By the date thirty (30) days after the Effective Date, Seller shall provide Default Security required under Sections 10.1 or 10.2, as applicable.

2.3 Seller shall cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date. If Commercial Operation occurs after the Scheduled Commercial Operation Date, Seller shall be in default, and liable for delay damages specified in Section 11.

2.4 Except as otherwise provided herein, this Agreement shall terminate on _____________ [enter Date that is no later than 20 years after the Scheduled Initial Delivery Date] ("**Termination Date**").

Section 3: **REPRESENTATIONS AND WARRANTIES**

3.1 PacifiCorp represents, covenants, and warrants to Seller that:

3.1.1 PacifiCorp is duly organized and validly existing under the laws of the State of Oregon.

3.1.2 PacifiCorp has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.

3.1.3 PacifiCorp has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.1.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on PacifiCorp or any valid order of any court, or any regulatory agency or other body having authority to which PacifiCorp is subject.

3.1.5 This Agreement is a valid and legally binding obligation of PacifiCorp, enforceable against PacifiCorp in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2 Seller represents, covenants, and warrants to PacifiCorp that:

3.2.1 Seller is a [corporation, partnership, or limited liability company] duly organized and validly existing under the laws of ______.

3.2.2 Seller has the requisite power and authority to enter into this Agreement and to perform according to the terms hereof, including all required regulatory authority to make wholesale sales from the Facility.

3.2.3 Seller has taken all actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.2.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.2.5 This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2.6 The Facility is and shall for the term of this Agreement continue to be a QF, and Seller will operate the Facility in a manner consistent with its FERC QF certification. Seller has provided to PacifiCorp the appropriate QF certification (which may include a FERC self-certification) prior to

PacifiCorp's execution of this Agreement. At any time during the term of this Agreement, PacifiCorp may require Seller to provide PacifiCorp with evidence satisfactory to PacifiCorp in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements and, if PacifiCorp is not satisfied that the Facility qualifies for such status, a written legal opinion from an attorney who is (a) in good standing in the state of Oregon, and (b) who has no economic relationship, association or nexus with the Seller or the Facility, stating that the Facility is a QF and providing sufficient proof (including copies of all documents and data as PacifiCorp may request) demonstrating that Seller has maintained and will continue to maintain the Facility as a QF.

3.2.7 Compliance with Ownership Requirements in Commission Proceedings No. UM 1129 and UM 1610. Seller will not make any changes in its ownership, control, or management during the term of this Agreement that would cause it to not be in compliance with the definition of a Small Cogeneration Facility or Small Power Production Facility provided in PacifiCorp's Schedule 37 tariff approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by PacifiCorp not more frequently than every 36 months, such documentation and information as reasonably may be required to establish Seller's continued compliance with such Definition. PacifiCorp agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PacifiCorp will provide all such confidential information the Public Utility Commission of Oregon upon the Commission's request. These ownership requirements, as well as the dispute resolution provision governing any disputes over a QF's entitlement to the standard rates and standard contract with respect to the requirements, are detailed in Schedule 37.

3.2.8 Additional Seller Creditworthiness Warranties. Seller need not post security under Section 10 for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following:

(a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.

(b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.

(c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.

(d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

(e) **[Applicable only to Seller's with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

_______ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

_______ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

Section 4: DELIVERY OF POWER AND PERFORMANCE GUARANTEE

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase (a) all Net Output from the Facility delivered to the Point of Delivery and (b) all Green Tags associated with the output or otherwise resulting from the generation of energy by the Facility (which shall come from the Facility and from no other source), for the periods during which the Green Tags are required to be transferred to PacifiCorp under the terms of Section 5.5.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, _______________ kWh per Contract Year ("**Average Annual Generation**"). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

4.3 Performance Guaranty.

4.3.1 Guaranteed Availability. Seller guarantees that the annual Availability of the Facility (the **"Guaranteed Availability"**) for (i) the first Contract Year shall be no less than 0.80, and (ii) for the second Contract Year shall be no less than 0.85. Beginning with the third Contract Year and for each Contract Year thereafter, the Guaranteed Availability for each Contract Year shall be 0.90, with such annual Availability to be calculated for purposes of this Section 4.3.1 for each Contract Year.

4.3.2 Liquidated Damages for Output Shortfall. If the Availability in any given Contract Year falls below the Guaranteed Availability for that Contract Year, the resulting shortfall shall be expressed in kWh as the **"Output Shortfall**." The Output Shortfall shall be calculated in accordance with the following formula:

Output Shortfall = (Guaranteed Availability – Availability) x Average Annual Generation

If an Output Shortfall occurs in any given Contract Year, Seller may owe PacifiCorp liquidated damages in accordance with Section 11. Each Party agrees and acknowledges that (a) the damages that PacifiCorp would incur due to the Facility's failure to achieve the Guaranteed Availability would be difficult or impossible to predict with certainty, and (b) the liquidated damages contemplated by Section 11 are a fair and reasonable calculation of such damages.

4.4 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility ("**Energy Delivery Schedule**"), incorporated into **Exhibit D**.

4.5 Transfer of Title to Green Tags; Documentation of Green Tags Transfers. Subject to the Green Tags ownership as defined in Section 5.5, title to the Green Tags shall pass from Seller to PacifiCorp immediately upon the generation of the Net Output at the Facility that gives rise to such Green Tags. The Parties shall execute all additional documents and instruments reasonably requested by PacifiCorp in order to further document the transfer of the Green Tags to PacifiCorp or its designees. Without limiting the generality of the foregoing, Seller shall, on or before the 10th day of each month, deliver to PacifiCorp a Green Tags Attestation and Bill of Sale in the form attached as **Exhibit H** for all Green Tags delivered to PacifiCorp hereunder in the preceding month, along with any attestation that is then-current with the Center for Resource Solution's Green-e program or successor organization in case the Center for Resource Solutions is replaced by another party over the life of the contract. Seller, at its own cost and expense, shall register with, pay all fees required by, and comply with, all reporting and other requirements of WREGIS relating to the Facility or Green Tags, except that when Seller is required to transfer Green Tags to PacifiCorp under Section 5.5, PacifiCorp will pay all fees required by WREGIS relating to the Green Tags. Seller shall ensure that the Facility will participate in and comply with, during the Term, all aspects of WREGIS. Seller will use WREGIS as required pursuant to the WREGIS Operating Rules to effectuate the transfer of WREGIS Certificates to PacifiCorp, and transfer such WREGIS Certificates to PacifiCorp, in accordance with WREGIS reporting protocols and WREGIS Operating Rules. Seller may either elect to enter into a Qualified Reporting Entity Services Agreement with PacifiCorp in a form approved by PacifiCorp, enter into a Qualified Reporting Entity Services Agreement with a third-party authorized to act as a Qualified Reporting Entity, or elect to act as its own WREGIS-defined Qualified Reporting Entity. Seller shall promptly give PacifiCorp copies of all documentation it submits to WREGIS. Further, in the event of the promulgation of a scheme involving Green Tags administered by CAMD, upon notification by CAMD that any transfer contemplated by this Agreement will not be recorded, the Parties shall promptly cooperate in taking all reasonable actions necessary so that such transfers can be recorded. Seller shall not report under Section 1605(b) of the Energy Policy Act of 1992 or under any applicable program that any of the Green Tags purchased by PacifiCorp hereunder belong to any person other than PacifiCorp. Without limiting the generality of PacifiCorp's ownership of the Green Tag Reporting Rights, PacifiCorp may report under such program that such Green Tags purchased hereunder belong to it. Each Party shall promptly give the other Party copies of all documents it submits to the CAMD to effectuate any transfer. Seller shall reasonably cooperate in any registration by PacifiCorp of the Facility in the renewable portfolio standard or equivalent program in all such further states and programs in which PacifiCorp may wish to register or maintain registration of the Facility by providing copies of all such information as PacifiCorp reasonably required for such registration.

Section 5: **PURCHASE PRICES**

5.1 Seller shall have the option to select one of three pricing options: Standard Fixed Avoided Cost Prices ("Fixed Price Standard"), Renewable Fixed Avoided Cost Prices ("Fixed Price Renewable"), or Firm Market Indexed Avoided Cost Prices ("Firm Electric Market"), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility's contract. Seller has selected the following (Seller to initial one):

_______ Fixed Price Standard
_______ Fixed Price Renewable
_______ Firm Electric Market

A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G.**

5.2 (Fixed Price Standard Seller Only). In the event Seller elects the Fixed Price Standard pricing method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller Firm Electric Market.

5.3 (Fixed Price Renewable Seller Only). In the event Seller elects the Fixed Price Renewable pricing method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller Firm Electric Market.

5.4 For all Excess Output and for all Net Output delivered prior to the Commercial Operation Date, PacifiCorp shall pay Seller 93 percent of a blended market index price for day-ahead firm energy at MidColumbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by the Intercontinental Exchange (ICE), for the On-Peak and Off-Peak periods. PacifiCorp shall document its calculation of the blended rate, upon request, to Seller. Such payment will be accomplished by adjustments pursuant to Section 9.2

5.5 Environmental Attributes

5.5.1 (Fixed Price Standard Seller Only): PacifiCorp waives any claim to Seller's ownership of Environmental Attributes under this Agreement throughout the Term.

5.5.2 (Fixed Price Renewable Seller Only): PacifiCorp waives any claim to Seller's ownership of Environmental Attributes during the Renewable Resource Sufficiency Period, and any period within the Term of this Agreement after completion of the first fifteen (15) years after the Scheduled Initial Delivery Date. Subject to the foregoing, Seller shall transfer the Green Tags to PacifiCorp in accordance with Section 4.5 during the Renewable Resource Deficiency Period.

Section 6: **OPERATION AND CONTROL**

6.1 As-Built Supplement. Upon completion of initial (and any subsequent) construction of the Facility, Seller shall provide PacifiCorp an As-Built Supplement to specify the actual Facility as built. The As-Built Supplement must be reviewed and approved by PacifiCorp, which approval shall not unreasonably be withheld, conditioned or delayed.

6.2 Incremental Utility Upgrades. At start-up (and at any other time upon at least six months' prior written notice), Seller may increase Net Output, if such increase is due to normal variances in estimated versus actual performance, changed Facility operations, or improvements in Facility efficiency. Seller may not increase Net Output under this Agreement by installing additional generating units. In the case of substantial upgrades, PacifiCorp may require Seller to comply with Section 3.2.8(e) (in the event that the Facility upgrade causes the Facility Capacity Rating to exceed 3,000 kW) and increase its Average Annual Generation in Section 4.2 (if appropriate). PacifiCorp may also update Seller's security obligation (if applicable). So long as the Facility Capacity Rating after the upgrade is 10,000 kW or less, Seller will continue to receive the Contract Price for the Net Output, as set forth in Sections 5.1, 5.2, and 5.3 of this Agreement. If Seller increases the Facility Capacity Rating above 10,000 kW, then (on a going forward basis) PacifiCorp shall pay Seller the Contract Price for the fraction of total Net Output equal to 10,000 kW divided by the Facility Capacity Rating of the upgraded Facility. For the remaining fraction of Net Output, PacifiCorp and Seller shall agree to a new negotiated rate. Seller shall be responsible for ensuring that any planned increase in the Facility Capacity Rating or the maximum instantaneous capacity of the Facility complies with Seller's Generation Interconnection Agreement and any other agreements with PacifiCorp.

6.3 Seller shall operate and maintain the Facility in a safe manner in accordance with the Generation Interconnection Agreement (if applicable), Prudent Electrical Practices and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code as such laws and code may be amended from time to time. PacifiCorp shall have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and PacifiCorp's electric system is disconnected, suspended or interrupted, in whole or in part, pursuant to the Generation Interconnection Agreement, or to the extent generation curtailment is required as a result of Seller's non-compliance with the Generation Interconnection Agreement. PacifiCorp shall have the right to inspect the Facility to confirm that Seller is operating the Facility in accordance with the provisions of this Section 6.3 upon reasonable notice to Seller. Seller is solely responsible for the operation and maintenance of the Facility. PacifiCorp shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.4 Scheduled Outages. Seller may cease operation of the entire Facility or individual units, if applicable, for maintenance or other purposes. Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp's request, if any, to reschedule such planned outage in order to accommodate PacifiCorp's need for Facility operation.

6.5 Unplanned Outages. In the event of an unscheduled outage or curtailment exceeding twenty-five (25) percent of the Facility Capacity Rating (other than curtailments due to lack of motive force), Seller immediately shall notify PacifiCorp of the necessity of such unscheduled outage or curtailment, the time when such has occurred or will occur and the anticipated duration. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled outage or curtailment, to limit the duration of such, and to perform unscheduled maintenance during Off-Peak hours.

Section 7: **FUEL/MOTIVE FORCE**

Prior to the Effective Date of this Agreement, Seller provided to PacifiCorp a fuel or motive force plan acceptable to PacifiCorp in its reasonable discretion and attached hereto as **Exhibit D-1,** together with a certification from a Licensed Professional Engineer to PacifiCorp attached hereto as **Exhibit D-2**, certifying that the implementation of the fuel or motive force plan can reasonably be expected to provide fuel or motive force to the Facility for the duration of this Agreement adequate to generate power and energy in quantities necessary to deliver the Average Annual Generation set forth by Seller in Section 4.

Section 8: **METERING**

8.1 Seller shall pay for, and PacifiCorp shall design, furnish, install, own, inspect, test, maintain and replace all metering equipment required pursuant to the Generation Interconnection Agreement, if applicable.

8.2 Seller shall pay for and design, furnish, install, own, inspect, test, maintain and replace all metering equipment required in order to calculate Availability of the Facility. Data required to calculate Availability include, but are not limited to: hourly average wind velocity measured at turbine hub height; and ambient air temperature. Seller shall make available all such data to PacifiCorp in electronic format per Section 8.5.

8.3 Metering shall be performed at the location and in a manner consistent with this Agreement and as specified in the Generation Interconnection Agreement, or, if the Facility is one of multiple wind generation facilities sharing a common transmission line, the required metering equipment has been completed and tested and is in place to correctly and accurately measure the amount of Net Output generated by the Facility and flowing into PacifiCorp's system at the Point of Delivery, or, if the Net Output is to be wheeled to PacifiCorp by another utility, metering will be performed in accordance with the terms of PacifiCorp's interconnection agreement with such other utility. All quantities of energy purchased hereunder shall be adjusted to account for electrical losses, if any between the point of metering and the Point of Delivery, so that the purchased amount reflects the net amount of energy flowing into PacifiCorp's system at the Point of Delivery.

8.4 PacifiCorp shall periodically inspect, test, repair and replace the metering equipment as provided in the Generation Interconnection Agreement, if applicable. If the Net Output is to be wheeled to PacifiCorp by another utility, meter inspection, testing, repair and replacement will be performed in accordance with the terms of PacifiCorp's interconnection agreement with such utility. If any of the inspections or tests discloses an error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) Billing Periods, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered following the repair of the meter.

Section 9: <u>**BILLINGS, COMPUTATIONS, AND PAYMENTS**</u>

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PacifiCorp shall send to Seller payment for Seller's deliveries of Net Output to PacifiCorp, together with computations supporting such payment. PacifiCorp may offset any such payment to reflect amounts owing from Seller to PacifiCorp pursuant to this Agreement, the Generation Interconnection Agreement, or any other agreement between the Parties.

9.2 Corrections. PacifiCorp shall have up to eighteen months to adjust any payment made pursuant to Section 9.1. In the event PacifiCorp determines it has overpaid Seller (for Excess Output or otherwise), PacifiCorp may adjust Seller's future payment accordingly in order to recapture any overpayment in a reasonable time.

9.3 Annual Invoicing for Output Shortfall. Beginning on the first January 31 occurring after the Commercial Operation Date, and continuing on January 31 of each Contract Year thereafter, PacifiCorp shall deliver to Seller an invoice showing PacifiCorp's computation of Net Output and Output Shortfall, if any, for the prior Contract Year and any resulting amount due PacifiCorp as liquidated damages. In preparing such invoices, PacifiCorp shall utilize the meter data provided to PacifiCorp for the Contract Year in question, but may also rely on historical averages and such other information as may be available to PacifiCorp at the time of invoice preparation, if the meter data for such Contract Year is then incomplete or otherwise not available. To the extent required, PacifiCorp shall true up any such invoice as promptly as practicable following its receipt of actual results for the relevant Contract Year. Seller shall pay to PacifiCorp, by wire transfer or by any other means agreed to by the Parties in writing, the amount set forth as due in such invoice.

9.4 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; *provided*, *however*, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

Section 10: **SECURITY**

Unless Seller has adopted the creditworthiness warranties contained in Section 3.2.8, Seller must provide security (if requested by PacifiCorp) in the form of a cash escrow, letter of credit, senior lien, or step-in rights. Seller hereby elects to provide, in accordance with the applicable terms of this Section 10, the following security (Seller to initial one selection only):

____ Cash Escrow

_____ Letter of Credit

_____ Senior Lien

_____ Step-in Rights

_____ Seller has adopted the Creditworthiness Warranties of Section 3.2.8.

In the event Seller's obligation to post default security (under Section 10 or Section 11.1.4) arises solely from Seller's delinquent performance of construction-related financial obligations, upon Seller's request, PacifiCorp will excuse Seller from such obligation in the event Seller has negotiated financial arrangements with its construction lenders that mitigate Seller's financial risks to PacifiCorp's reasonable satisfaction.

[SKIP THIS SECTION 10.1 UNLESS SELLER SELECTED CASH ESCROW ALTERNATIVE]

10.1 Cash Escrow Security. Seller shall deposit in an escrow account established by PacifiCorp in a banking institution acceptable to both Parties, the Default Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institution from time to time. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.2 UNLESS SELLER SELECTED LETTER OF CREDIT ALTERNATIVE]

10.2 Letter of Credit Security. Seller shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to PacifiCorp in its discretion, or (b) a Letter of Credit in favor of PacifiCorp. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.3 UNLESS SELLER SELECTED SENIOR LIEN ALTERNATIVE]

10.3 Senior Lien. Before the Scheduled Commercial Operation Date, Seller shall grant PacifiCorp a senior, unsubordinated lien on the Facility and its assets as security for performance of this Agreement by executing, acknowledging and delivering a security agreement and a deed of trust or a mortgage, in a recordable form (each in a form satisfactory to PacifiCorp in the reasonable exercise of its discretion). Pending delivery of the senior lien to PacifiCorp, Seller shall not cause or permit the Facility or its assets to be burdened by liens or other encumbrances that would be superior to PacifiCorp's, other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

[SKIP THIS SECTION 10.4 UNLESS SELLER SELECTED STEP-IN RIGHTS ALTERNATIVE]

10.4 Step-in Rights (Operation by PacifiCorp Following Event of Default of Seller).

10.4.1 Prior to any termination of this Agreement due to an Event of Default of Seller, as identified in Section 11, PacifiCorp shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this Agreement) during the period provided for herein. Seller shall not grant any person, other than the lending institution providing financing to the Seller for construction of the Facility ("Facility Lender"), a right to possess, assume control of, and operate the Facility that is equal to or superior to PacifiCorp's right under this Section 10.4.

10.4.2 PacifiCorp shall give Seller ten (10) calendar days notice in advance of the contemplated exercise of PacifiCorp's rights under this Section 10.4. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Electrical Practices. Upon such notice, PacifiCorp, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Facility for the purpose of constructing and/or operating the Facility. Seller hereby irrevocably appoints PacifiCorp as Seller's attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions as PacifiCorp may reasonably deem necessary or appropriate to exercise PacifiCorp's step-in rights under this Section 10.4.

10.4.3 During any period that PacifiCorp is in possession of and constructing and/or operating the Facility, no proceeds or other monies attributed to operation of the Facility shall be remitted to or otherwise provided to the account of Seller until all Events of Default of Seller have been cured.

10.4.4 During any period that PacifiCorp is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and PacifiCorp shall assume possession, operation, and control solely as agent for Seller.

(a) In the event PacifiCorp is in possession and control of the Facility for an interim period, Seller shall resume operation and PacifiCorp shall relinquish its right to operate when Seller demonstrates to PacifiCorp's reasonable satisfaction that it will remove those grounds that originally gave rise to PacifiCorp's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this Agreement, and (ii) has cured any Events of Default of Seller which allowed PacifiCorp to exercise its rights under this Section 10.4.

(b) In the event that PacifiCorp is in possession and control of the Facility for an interim period, the Facility Lender, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and PacifiCorp shall relinquish its right to operate when the Facility Lender or any nominee or transferee thereof, requests such relinquishment.

10.4.5 PacifiCorp's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by PacifiCorp of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility PacifiCorp elects to return such possession and operation to Seller, PacifiCorp shall provide Seller with at least fifteen (15) calendar days advance notice of the date PacifiCorp intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

Section 11: **DEFAULTS AND REMEDIES**

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.

11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Generation Interconnection Agreement) within the time allowed for a cure under such agreement or instrument.

11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;

11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.

11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy an Availability of forty percent (40%) or more for two (2) consecutive years; else Seller's failure to satisfy an Availability of fifty percent (50%) or more for one year.

11.2 Notice; Opportunity to Cure.

11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.

11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.

11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for the Average Annual Generation that Seller was otherwise obligated to provide at the Guaranteed Availability for a period of twenty-four (24) months from the date of termination, plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, plus the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any Output Shortfall (under Section 4.3) during the period of default ("**Net Replacement Power Costs**"); *provided, however,* that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

(a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.

(b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

Section 12: **INDEMNIFICATION AND LIABILITY**

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller's side of the Point of Delivery, (c) Seller's operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement 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. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. Except to the extent such damages are included in the liquidated damages, delay damages, cost to cover damages or other specified measure of damages expressly provided for in this Agreement, neither Party shall be liable to the other Party for special, punitive, indirect, exemplary or consequential damages, whether such damages are allowed or provided by contract, tort (including negligence), strict liability, statute or otherwise.

Section 13: **INSURANCE *(FACILITIES OVER 200KW ONLY)***

13.1 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system if delivery to PacifiCorp is to be accomplished by wheeling, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) (of "ACORD Form" or the equivalent) certifying Seller's compliance with the insurance requirements hereunder. Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate. If requested by PacifiCorp, a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company, shall be furnished to PacifiCorp.

13.2 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than “B+” by the A.M. Best Company the insurance coverage specified below:

13.2.1 Commercial General Liability insurance, to include contractual liability, with a minimum single limit of $1,000,000 to protect against and from all loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

13.2.2 All Risk Property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The Risk policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

13.3 The Commercial General Liability policy required herein shall include i) provisions or endorsements naming PacifiCorp, its Board of Directors, Officers and employees as additional insureds, and ii) cross liability coverage so that the insurance applies separately to each insured against whom claim is made or suit is brought, even in instances where one insured claims against or sues another insured.

13.4 All liability policies required by this Agreement shall include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and provisions that such policies shall not be canceled or their limits of liability reduced without 1) ten (10) days prior written notice to PacifiCorp if canceled for nonpayment of premium, or 2) thirty (30) days prior written notice to PacifiCorp if canceled for any other reason.

13.5 Insurance coverage provided on a "claims-made" basis shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

Section 14: **FORCE MAJEURE**

14.1 As used in this Agreement, “**Force Majeure**” or “**an event of Force Majeure**” means any cause beyond the reasonable control of the Seller or of PacifiCorp which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of fuel or motive force resources to operate the Facility or changes in market conditions that affect the price of energy or transmission. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the event of Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

14.1.1 the non-performing Party, shall, within two (2) weeks after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

14.1.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure; and

14.1.3 the non-performing Party uses its best efforts to remedy its inability to perform.

14.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the event of Force Majeure.

14.3 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.4 PacifiCorp may terminate the Agreement if Seller fails to remedy Seller's inability to perform, due to an event of Force Majeure, within six months after the occurrence of the event.

Section 15: **SEVERAL OBLIGATIONS**

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

Section 16: **CHOICE OF LAW**

This Agreement shall be interpreted and enforced in accordance with the laws of the State of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

Section 17: **PARTIAL INVALIDITY**

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

Section 18: **WAIVER**

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

Section 19: **GOVERNMENTAL JURISDICTIONS AND AUTHORIZATIONS**

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PacifiCorp.

Section 20: **REPEAL OF PURPA**

This Agreement shall not terminate upon the repeal of the PURPA, unless such termination is mandated by federal or state law.

Section 21: **SUCCESSORS AND ASSIGNS**

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent to a lender as part of a financing transaction or as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

Section 22: ENTIRE AGREEMENT

22.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PacifiCorp's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

22.2 By executing this Agreement, Seller releases PacifiCorp from any claims, known or unknown, that may have arisen prior to the Effective Date.

Section 23: NOTICES

23.1 All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested.

Notices	**PacifiCorp**	**Seller**
All Notices	PacifiCorp 825 NE Multnomah Street Portland, OR 97232 Attn: Contract Administration, Suite 600 Phone: (503) 813 - 5380 Facsimile: (503) 813 - 6291 Duns: 00-790-9013 Federal Tax ID Number: 93-0246090	
All Invoices:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Scheduling:	(same as street address above) Attn: Resource Planning, Suite 600 Phone: (503) 813 - 6090 Facsimile: (503) 813 – 6265	
Payments:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Wire Transfer:	Bank One N.A. ABA: ACCT: NAME: PacifiCorp Wholesale	
Credit and Collections	(same as street address above) Attn: Credit Manager, Suite 700 Phone: (503) 813 - 5684	

Notices	PacifiCorp	Seller
	Facsimile: (503) 813 – 5609	
With Additional Notices of an Event of Default or Potential Event of Default to:	(same as street address above) Attn: PacifiCorp General Counsel Phone: (503) 813-5029 Facsimile: (503) 813-7252	

23.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 23.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the date first above written.

PacifiCorp	Seller
By:____________________________	By:____________________________
Name:__________________________	Name:__________________________
Title:___________________________	Title: __________________________

EXHIBIT A

DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

Seller's Facility consists of ___________________________ generators manufactured by _________________. More specifically, each generator at the Facility is described as:

Type (synchronous or inductive):

Model:
Number of Phases:
Rated Output (kW): **Rated Output (kVA):**
Rated Voltage (line to line):
Rated Current (A): Stator: ____ A; Rotor: ______ A
Maximum kW Output: ____________ kW **Maximum kVA Output:** ______kVA
Minimum kW Output: _________ kW
Manufacturer's Guaranteed Cut-in Wind Speed [if applicable]:
Facility Capacity Rating: ____________ kW at ______________________________________
Identify the maximum output of the generator(s) and describe any differences between that output and the Nameplate Capacity Rating:

Station service requirements, and other loads served by the Facility, if any, are described as follows:
____

____.

Location of the Facility: The Facility is to be constructed in the vicinity of ____________ in _____________ County, _____________. The location is more particularly described as follows:

[legal description of parcel]

Power factor requirements:
Rated Power Factor (PF) or reactive load (kVAR):

EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

[Seller to provide its own diagram and description]

<u>POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES</u>

Instructions to Seller:

1. Include description of point of metering, and Point of Delivery
2. Provide interconnection single line drawing of Facility including any transmission facilities on Seller's side of the Point of Delivery.

EXHIBIT C

REQUIRED FACILITY DOCUMENTS

REQUIRED OF ALL FACILITIES:

- QF Certification
- Interconnection Agreement
- Fuel Supply Agreement, if applicable

REQUIRED IF SELLER ELECTS TO GRANT SENIOR LIEN OR STEP-IN RIGHTS:

- Deed or Lease to Facility Premises
- Preliminary Title Report of Premises
- Proof of ownership of Facility
- Off-take sale agreements, e.g. surplus heat sale contract, if applicable

REQUIRED OF ALL HYDRO FACILITIES:

- FERC License or documentation of an applicable exemption
- Power Generation Water Rights

Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be requested.

EXHIBIT D-1

SELLER'S MOTIVE FORCE PLAN

A. MONTHLY DELIVERY SCHEDULES AND SCHEDULED MAINTENANCE

Month	Average Energy (kWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Seller to provide an estimate of the average monthly Net Output of the Facility, and explain the basis for the estimate.

EXHIBIT D-2

**ENGINEER'S CERTIFICATION OF
MOTIVE FORCE PLAN**

Seller provide a written declaration from a Licensed Professional Engineer to PacifiCorp that the Facility is likely capable under average conditions foreseeable during the term of this Agreement of meeting Seller's estimated average, maximum, and minimum Net Output.

EXHIBIT E
START-UP TESTING

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable): **[Seller identify appropriate tests]**

1. Pressure tests of all steam system equipment;
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;
3. Operating tests of all valves, operators, motor starters and motor;
4. Alarms, signals, and fail-safe or system shutdown control tests;
5. Insulation resistance and point-to-point continuity tests;
6. Bench tests of all protective devices;
7. Tests required by manufacturer of equipment; and
8. Complete pre-parallel checks with PacifiCorp.

Required start-up tests are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PacifiCorp's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;
3. Brake tests;
4. Energization of transformers;
5. Synchronizing tests (manual and auto);
6. Stator windings dielectric test;
7. Armature and field windings resistance tests;
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load;
9. Heat runs;
10. Tests required by manufacturer of equipment;
11. Excitation and voltage regulation operation tests;
12. Open circuit and short circuit; saturation tests;
13. Governor system steady state stability test;
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;
15. Auto stop/start sequence;
16. Level control system tests; and
17. Completion of all state and federal environmental testing requirements.

EXHIBIT F

SELLER AUTHORIZATION TO RELEASE GENERATION DATA TO PACIFICORP

[Interconnection Customer Letterhead]

Transmission Services
Attn: Director, Transmission Services
825 NE Multnomah, Suite 1600
Portland, OR 97232

RE: ___________ Interconnection Request

Dear Sir:

________________ hereby voluntarily authorizes PacifiCorp's Transmission business unit to share ____________________'s generator interconnection information and generator meter data with Marketing Affiliate employees of PacifiCorp Energy, including, but not limited to those in the Commercial and Trading group. _________________ acknowledges that PacifiCorp did not provide it any preferences, either operational or rate-related, in exchange for this voluntary consent.

____
Name

____
Title

____
Date

EXHIBIT G

SCHEDULE 37 AND PRICING SUMMARY TABLE

EXHIBIT H

GREEN TAG ATTESTATION AND BILL OF SALE

Subject to Green Tags ownership as defined in Section 5.5, from the period commencing on ____ and ending on _____, _____________________ ("Seller") hereby sells, transfers and delivers to PacifiCorp the Green Tags (including all Green Tag Reporting Rights) associated with the generation of Net Output under the Power Purchase Agreement (Renewable Energy) between Seller and PacifiCorp dated [_________] (the "PPA"), as described below, in the amount of one Green Tag for each megawatt hour generated. Defined terms used in this Green Tag Attestation and Bill of Sale (as indicated by initial capitalization) shall have the meaning set forth in the PPA.

Facility name and location: _________________________ Fuel Type: _____________

Capacity (MW): _________________ Operational Date: ________________________

Energy Admin. ID no.: ________

Dates	MWh generated
__________	________

Seller further attests, warrants and represents, under penalty of perjury, as follows:

i) to the best of its knowledge, the information provided herein is true and correct;

ii) its sale to PacifiCorp is its one and only sale of the Green Tags referenced herein;

iii) the Facility generated Output in the amount indicated above; and

iv) to the best of Seller's knowledge, each of the Green Tags associated with the generation Output have been generated and sold by the Facility.

This Green Tag Attestation and Bill of Sale confirms, in accordance with the PPA, the transfer from Seller to PacifiCorp all of Seller's right, title and interest in and to the Green Tags (including Green Tag Reporting Rights), as set forth above.

Seller's Contact Person: [_________________________________]

WITNESS MY HAND,

____

a ____

By _______________________

Its _______________________

Date: _______________________

This Attestation may be disclosed by Seller and PacifiCorp to others, including the Center for Resource Solutions and the public utility commissions having jurisdiction over PacifiCorp, to substantiate and verify the accuracy of PacifiCorp's advertising and public communication claims, as well as in PacifiCorp's advertising and other public communications.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/103

**PACIFICORP STANDARD
POWER PURCHASE AGREEMENT FOR
OFF-SYSTEM
FIRM QUALIFYING FACILITIES
(LESS THAN 10,000 KW)**

May 17, 2016

DRAFT

THIS WORKING DRAFT DOES NOT CONSTITUTE A BINDING OFFER, SHALL NOT FORM THE BASIS FOR AN AGREEMENT BY ESTOPPEL OR OTHERWISE, AND IS CONDITIONED UPON EACH PARTY'S RECEIPT OF ALL REQUIRED MANAGEMENT APPROVALS (INCLUDING FINAL CREDIT AND LEGAL APPROVAL). ANY ACTIONS TAKEN BY A PARTY IN RELIANCE ON THE TERMS SET FORTH IN THIS WORKING DRAFT OR ON STATEMENTS MADE DURING NEGOTIATIONS PURSUANT TO THIS WORKING DRAFT SHALL BE AT THAT PARTY'S OWN RISK. UNTIL THIS AGREEMENT IS NEGOTIATED, APPROVED BY MANAGEMENT, SIGNED AND DELIVERED, NO PARTY SHALL HAVE ANY OTHER LEGAL OBLIGATIONS, EXPRESSED OR IMPLIED, OR ARISING IN ANY OTHER MANNER UNDER THIS WORKING DRAFT OR IN THE COURSE OF NEGOTIATIONS.

POWER PURCHASE AGREEMENT

BETWEEN

____

[Firm Qualifying Facility (new or existing) located in non-PacifiCorp Control Area, interconnecting to non-PacifiCorp system, with 10,000 kW Facility Capacity Rating, or Less, and uninterruptible transmission to the Point of Delivery]

AND

PACIFICORP

DRAFT

EXHIBIT A:	DESCRIPTION OF SELLER'S FACILITY
EXHIBIT B:	SELLER'S INTERCONNECTION FACILITIES
EXHIBIT C:	REQUIRED FACILITY DOCUMENTS
EXHIBIT D-1:	SELLER'S MOTIVE FORCE PLAN
EXHIBIT D-2:	ENGINEER'S CERTIFICATION OF MOTIVE FORCE PLAN
EXHIBIT E:	START-UP TESTING
EXHIBIT F:	SELLER AUTHORIZATION TO RELEASE GENERATION DATA TO PACIFICORP
EXHIBIT G:	SCHEDULE 37 AND PRICING SUMMARY TABLE
EXHIBIT H:	GREEN TAG ATTESTATION AND BILL OF SALE
ADDENDUM W:	GENERATION SCHEDULING ADDENDUM

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT ("**Agreement**"), entered into this ____day of ______________, 20____, is between _________________________, "**Seller**" and PacifiCorp (d/b/a Pacific Power & Light Company), an Oregon corporation acting in its regulated utility capacity, "**PacifiCorp**." (Seller and PacifiCorp are referred to individually as a "**Party**" or collectively as the "**Parties**").

RECITALS

A. **[New QFs Only:]** Seller intends to construct, own, operate and maintain a _____ _______________________________________ [state type of facility] facility for the generation of electric power, including interconnection facilities, located in _____________________________ [City, County, State] with a Facility Capacity Rating of ______ -kilowatts (kW**)** as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

A. **[Existing QFs Only:]** Seller owns, operates, and maintains a _______________ ______________________[state type of facility] facility for the generation of electric power, including interconnection facilities, located in _____________________________ [City, County, State] with a Facility Capacity Rating of __________ kilowatts (kW) as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

B. Seller intends to commence delivery of Net Output under this Power Purchase Agreement, for the purpose of Start-up Testing, on __________________, 20______ ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on _________________, 20____ ("**Scheduled Commercial Operation Date**"); and

D. Seller estimates that the average annual Net Energy to be delivered by the Facility to PacifiCorp is __________ kilowatt-hours (kWh), which amount of energy PacifiCorp will include in its resource planning; and

E. Seller shall sell and PacifiCorp shall purchase all Net Output from the Facility in accordance with the terms and conditions of this Agreement; and

F. This Agreement is a "New QF Contract" under the PacifiCorp Inter-Jurisdictional Cost Allocation Revised Protocol.

G. Seller intends to transmit Net Output to PacifiCorp via transmission facilities operated by a third party, and PacifiCorp intends to accept scheduled firm delivery of Seller's Net Output, under the terms of this Agreement, including the Generation Scheduling Addendum attached as **Addendum W** and incorporated contemporaneously herewith.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 **"As-built Supplement"** shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 "**Average Annual Generation"** shall have the meaning set forth in Section 4.2.

1.3 **"Billing Period"** means calendar months.

1.4 **"CAMD"** means the Clean Air Markets Division of the Environmental Protection Agency or successor administrator, or any state or federal entity given jurisdiction over a program involving transferability of Green Tags.

1.5 **"Commercial Operation Date"** means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.5.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

1.5.2 The Facility has completed Start-Up Testing (applies to new Facilities and new upgrades only);

1.5.3 PacifiCorp has received a certificate addressed to PacifiCorp from an attorney in good standing in the State of Oregon stating that Seller has obtained all Required Facility Documents (Facilities over 200 kW only) and, if requested by PacifiCorp, in writing, has provided copies of any or all such requested Required Facility Documents.

1.5.4 Seller has complied with the security requirements of Section 10.

1.5.5 PacifiCorp has received an executed copy of **Exhibit F** - Seller's Interconnection Request.

1.6 **"Commission"** means the Oregon Public Utilities Commission.

1.7 **"Contract Price"** means the applicable price for Net Output stated in Sections 5.1, 5.2, and 5.3.

1.8 **"Contract Year"** means a twelve (12) month period commencing at 00:00 hours Pacific Prevailing Time ("**PPT**") on January 1 and ending on 24:00 hours PPT on December 31; *provided, however,* that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

1.9 "**Credit Requirements**" means a long-term credit rating (corporate or long-term senior unsecured debt) of (1) "Baa3" or greater by Moody's, or (2) "BBB-" or greater by S&P, or such other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment.

1.10 "**Default Security**", unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at ________________**[specify POD]** (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery; provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller's average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

1.11 "**Effective Date**" shall have the meaning set forth in Section 2.1.

1.12 "**Energy Delivery Schedule**" shall have the meaning set forth in Section 4.5.

1.13 "**Environmental Attributes**" shall mean any and all claims, credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, resulting from the avoidance of the emission of any gas, chemical, or other substance to the air, soil or water. Environmental Attributes include but are not limited to: (1) any avoided emissions of pollutants to the air, soil, or water such as (subject to the foregoing) sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), and other pollutants; and (2) any avoided emissions of carbon dioxide (C02), methane (CH4), and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere.

1.14 “**Excess Output**” shall mean any increment of Net Output produced at a rate, on an hourly basis, exceeding the Facility Capacity Rating.

1.15 “**Facility**” shall have the meaning set forth in Recital A.

1.16 “**Facility Capacity Rating**” means the sum of the Nameplate Capacity Ratings for all generators comprising the Facility.

1.17 “**FERC**” means the Federal Energy Regulatory Commission, or its successor.

1.18 “**Generation Scheduling Addendum**” means **Addendum W**, the portion of this Agreement providing for the measurement, scheduling, and delivery of Net Output from the Facility to the Point of Delivery via a non-PacifiCorp transmission provider.

1.19 “**Green Tags**” means (1) the Environmental Attributes associated with all Net Output, together with (2) all WREGIS Certificates; and (3) the Green Tag Reporting Rights associated with such energy, Environmental Attributes and WREGIS Certificates, however commercially transferred or traded under any or other product names, such as "Renewable Energy Credits," "Green-e Certified", or otherwise. One (1) Green Tag represents the Environmental Attributes made available by the generation of one (1) MWh of energy from the Facility. Provided however, that “Green Tags” do not include Environmental Attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity.

1.20 “**Green Tag Reporting Rights”** means the exclusive right of a purchaser of Green Tags to report exclusive ownership of Green Tags in compliance with federal or state law, if applicable, and to federal or state agencies or other parties at such purchaser's discretion, and include reporting under Section 1605(b) of the Energy Policy Act of 1992, or under any present or future domestic, international, or foreign emissions trading program or renewable portfolio standard.

1.21 “**Interconnected Utility**” means ____, the operator of the electric utility system at the Point of Interconnection.

1.22 “**Interconnection Agreement**” means the agreement (or contemporaneous agreements) between Seller and the Interconnected Utility governing interconnection of Seller’s Facility at the Point of Interconnection and associated use of the Interconnected Utility’s system.

1.23 “**Letter of Credit**” means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of “A” or greater from S&P or “A2” or greater from Moody’s, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

1.24 "**Licensed Professional Engineer**" means a person acceptable to PacifiCorp in its reasonable judgment who is licensed to practice engineering in the state of Oregon, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made.

1.25 "**Material Adverse Change**" means the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller's ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement

1.26 "**Maximum Annual Delivery**" shall have the meaning set forth in Section 4.3.

1.27 "**Minimum Annual Delivery**" shall have the meaning set forth in Section 4.3.

1.28 "**Nameplate Capacity Rating**" means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.29 "**Net Energy**" means the energy component, in kWh, of Net Output.

1.30 "**Net Output**" means all energy and capacity produced by the Facility, less station use and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any, up to and including the Point of Interconnection. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the Point of Interconnection, less any station use not provided by the Facility.

1.31 "**Net Replacement Power Costs**" shall have the meaning set forth in Section 11.4.1.

1.32 "**Off-Peak Hours**" means all hours of the week that are not On-Peak Hours.

1.33 "**On-Peak Hours**" means the hours between 6 a.m. Pacific Prevailing Time ("**PPT**") and 10 p.m. PPT, Mondays through Saturdays, excluding all hours occurring on holidays as provided in Schedule 37.

1.34 "**Point of Delivery**" means the location in PacifiCorp's system where PacifiCorp has agreed to receive Seller's Net Energy, as specified in **Exhibit B.**

1.35 "**Point of Interconnection**" means the point of interconnection between Seller's Facility and the Transmitting Entity's system, if applicable, as specified in **Exhibit B**.

1.36 "**Prime Rate**" means the publicly announced prime rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, New York, selected by the Party to whom interest based on the Prime Rate is being paid.

1.37 "**Prudent Electrical Practices**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

1.38 "**QF**" means "**Qualifying Facility,**" as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.39 **"Renewable Resource Deficiency Period"** means the period from________ through ________.

1.40 **"Renewable Resource Sufficiency Period"** means the period from _______ through ________.

1.41 "**Replacement Price**" means the price at which PacifiCorp, acting in a commercially reasonable manner, purchases for delivery at the Point of Delivery a replacement for any Net Output that Seller is required to deliver under this Agreement plus (i) costs reasonably incurred by PacifiCorp in purchasing such replacement Net Output, and (ii) additional transmission charges, if any, reasonably incurred by PacifiCorp in causing replacement energy to be delivered to the Point of Delivery. If PacifiCorp elects not to make such a purchase, the Replacement Price shall be the market price at the Mid-Columbia trading hub for such energy not delivered, plus any additional cost or expense incurred as a result of Seller's failure to deliver, as determined by PacifiCorp in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

1.42 "**Required Facility Documents**" means all licenses, permits, authorizations, and agreements, including an Interconnection Agreement and Transmission Agreement(s), necessary for construction, operation and maintenance of the Facility, and delivery of Facility output, consistent with the terms of this Agreement. The Required Facility Documents are set forth in **Exhibit C.**

1.43 “**Schedule 37**” means the Schedule 37 of Pacific Power & Light Company’s Commission-approved tariffs, providing pricing options for Qualifying Facilities of 10,000 kW or less, which is in effect on the Effective Date of this Agreement. A copy of that Schedule 37 is attached as **Exhibit G**.

1.44 “**Scheduled Commercial Operation Date**” shall have the meaning set forth in Recital C.

1.45 “**Scheduled Initial Delivery Date**” shall have the meaning set forth in Recital B.

1.46 “**Start-Up Testing**” means the completion of required factory and start-up tests as set forth in **Exhibit E** hereto.

1.47 “**Termination Date**” shall have the meaning set forth in Section 2.4.

1.48 “**Transmission Agreement**” means the agreement (or contemporaneous agreements) between Seller and the Transmitting Entity providing for Seller’s uninterruptible right to transmit Net Output to the Point of Delivery.

1.49 “**Transmitting Entity(s)**” means ______________________________________, the (non-PacifiCorp) operator of the transmission system at the Point of Delivery.

1.50 “**WREGIS**” means the Western Renewable Energy Generation Information System or successor organization in case WREGIS is ever replaced.

1.51 “**WREGIS Certificate**” means “Certificate” as defined by WREGIS in the WREGIS Operating Rules dated July 15, 2013.

1.52 “**WREGIS Operating Rules**” means the operating rules and requirements adopted by WREGIS, dated July 15, 2013.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement shall become effective after execution by both Parties (“**Effective Date**”).

2.2 **Time is of the essence for this Agreement,** and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to deliver Net Output by the Scheduled Commercial Operation Date is critically important. Therefore,

2.2.1 By _____________________, Seller shall provide PacifiCorp with a copy of an executed Interconnection Agreement and an executed Transmission Agreement, which shall be consistent with all material terms and requirements of this Agreement.

2.2.2 Upon completion of construction, Seller, in accordance with Section 6.1, shall provide PacifiCorp with an As-built Supplement acceptable to PacifiCorp;

2.2.3 By the date thirty (30) days after the Effective Date, Seller shall provide Default Security required under Sections 10.1 or 10.2, as applicable.

2.3 Seller shall cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date. If Commercial Operation occurs after the Scheduled Commercial Operation Date, Seller shall be in default, and liable for delay damages specified in Section 11.

2.4 Except as otherwise provided herein, this Agreement shall terminate on ______________________________________ [enter Date that is no later than 20 years after the Scheduled Initial Delivery Date] ("**Termination Date**").

SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1 PacifiCorp represents, covenants, and warrants to Seller that:

3.1.1 PacifiCorp is duly organized and validly existing under the laws of the State of Oregon.

3.1.2 PacifiCorp has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.

3.1.3 PacifiCorp has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.1.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on PacifiCorp or any valid order of any court, or any regulatory agency or other body having authority to which PacifiCorp is subject.

3.1.5 This Agreement is a valid and legally binding obligation of PacifiCorp, enforceable against PacifiCorp in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2 Seller represents, covenants, and warrants to PacifiCorp that:

3.2.1 Seller is a [corporation, partnership, or limited liability company] duly organized and validly existing under the laws of _____________.

3.2.2 Seller has the requisite power and authority to enter into this Agreement and to perform according to the terms hereof, including all required regulatory authority to make wholesale sales from the Facility.

3.2.3 Seller has taken all actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.2.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.2.5 This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2.6 The Facility is and shall for the term of this Agreement continue to be a QF, and Seller will operate the Facility in a manner consistent with its FERC QF certification. Seller has provided to PacifiCorp the appropriate QF certification (which may include a FERC self-certification) prior to PacifiCorp's execution of this Agreement. At any time during the term of this Agreement, PacifiCorp may require Seller to provide PacifiCorp with evidence satisfactory to PacifiCorp in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements and, if PacifiCorp is not satisfied that the Facility qualifies for such status, a written legal opinion from an attorney who is (a) in good standing in the state of Oregon, and (b) who has no economic relationship, association or nexus with the Seller or the Facility, stating that the Facility is a QF and providing sufficient proof (including copies of all documents and data as PacifiCorp may request) demonstrating that Seller has maintained and will continue to maintain the Facility as a QF.

3.2.7 <u>Compliance with Ownership Requirements in Commission Proceedings No. UM 1129 and UM 1610</u>. Seller will not make any changes in its ownership, control, or management during the term of this Agreement that would cause it to not be in compliance with the definition of a Small Cogeneration Facility or Small Power Production Facility provided in PacifiCorp's Schedule 37 tariff approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by PacifiCorp not more frequently than every 36 months, such documentation and information as reasonably may be required to establish Seller's continued compliance with such Definition. PacifiCorp agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PacifiCorp will provide all such confidential information the Public Utility Commission of Oregon upon the Commission's request. These ownership requirements, as well as the dispute resolution provision governing any disputes over a QF's entitlement to the standard rates and standard contract with respect to the requirements, are detailed in Schedule 37.

3.2.8 Additional Seller Creditworthiness Warranties. Seller need not post security under Section 10 for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following:

(a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.

(b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.

(c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.

(d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

(e) **[Applicable only to Sellers with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

_______ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

_______ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase (a) all Net Output from the Facility delivered to the Point of Delivery and (b) all Green Tags associated with the output or otherwise resulting from the generation of energy by the Facility (which shall come from the Facility and from no other source), for the periods during which the Green Tags are required to be transferred to PacifiCorp under the terms of Section 5.5.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, _______________ kWh per Contract Year ("**Average Annual Generation**"). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

4.3 Minimum and Maximum Delivery. Seller shall deliver (or cause to be delivered) from the Facility a minimum of ___________ kWh of Net Output during each Contract Year, provided that such minimum for the first Contract Year shall be reduced *pro rata* to reflect the Commercial Operation Date, and further provided that such minimum delivered Net Output shall be reduced on a *pro rata* basis for any periods during a Contract Year that the Facility was prevented from generating or delivering electricity for reasons of Force Majeure ("**Minimum Annual Delivery**"). Seller estimates, for informational purposes, that it will deliver from the Facility a maximum of __________ kWh of Net Output during each Contract Year ("**Maximum Annual Delivery**"). Seller's basis for determining the Minimum and Maximum Annual Delivery amounts is set forth in **Exhibit D.**

4.4 Deliveries in Deficit of Delivery Obligation. Seller's failure to deliver the Minimum Annual Delivery in any Contract Year (prorated if necessary) shall be a default, and Seller shall be liable for damages in accordance with Section 11.

4.5 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility ("**Energy Delivery Schedule**"), incorporated into **Exhibit D**.

4.6 Transfer of Title to Green Tags; Documentation of Green Tags Transfers. Subject to the Green Tags ownership as defined in Section 5.5, title to the Green Tags shall pass from Seller to PacifiCorp immediately upon the generation of the Net Output at the Facility that gives rise to such Green Tags. The Parties shall execute all additional documents and instruments reasonably requested by PacifiCorp in order to further document the transfer of the Green Tags to PacifiCorp or its designees. Without limiting the generality of the foregoing, Seller shall, on or before the 10th day of each month, deliver to PacifiCorp a Green Tags Attestation and Bill of Sale in the form attached as **Exhibit H** for all Green Tags delivered to PacifiCorp hereunder in the preceding month, along with any attestation that is then-current with the Center for Resource Solution's Green-e program or successor organization in case the Center for Resource Solutions is replaced by another party over the life of the contract. Seller, at its own cost and expense, shall register with, pay all fees required by, and comply with, all reporting and other requirements of WREGIS relating to the Facility or Green Tags, except that when Seller is required to transfer Green Tags to PacifiCorp under Section 5.5, PacifiCorp will pay all fees required by WREGIS relating to the Green Tags. Seller shall ensure that the Facility will participate in and comply with, during the Term, all aspects of WREGIS. Seller will use WREGIS as required pursuant to the WREGIS Operating Rules to effectuate the transfer of WREGIS Certificates to PacifiCorp, and transfer such WREGIS Certificates to PacifiCorp, in accordance with WREGIS reporting protocols and WREGIS Operating Rules. Seller may either elect to enter into a Qualified Reporting Entity Services Agreement with PacifiCorp in a form approved by PacifiCorp, enter into a Qualified Reporting Entity Services Agreement with a third-party authorized to act as a Qualified Reporting Entity, or elect to act as its own WREGIS-defined Qualified Reporting Entity. Seller shall promptly give PacifiCorp copies of all documentation it submits to WREGIS. Further, in the event of the promulgation of a scheme involving Green Tags administered by CAMD, upon notification by CAMD that any transfer contemplated by this Agreement will not be recorded, the Parties shall promptly cooperate in taking all reasonable actions necessary so that such transfers can be recorded. Seller shall not report under Section 1605(b) of the Energy Policy Act of 1992 or under any applicable program that any of the Green Tags purchased by PacifiCorp hereunder belong to any person other than PacifiCorp. Without limiting the generality of PacifiCorp's ownership of the Green Tag Reporting Rights, PacifiCorp may report under such program that such Green Tags purchased hereunder belong to it. Each Party shall promptly give the other Party copies of all documents it submits to the CAMD to effectuate any transfer. Seller shall reasonably cooperate in any registration by PacifiCorp of the Facility in the renewable portfolio standard or equivalent program in all such further states and programs in which PacifiCorp may wish to register or maintain registration of the Facility by providing copies of all such information as PacifiCorp reasonably required for such registration.

SECTION 5: PURCHASE PRICES

5.1 Seller shall have the option to select one of three pricing options: Standard Fixed Avoided Cost Prices ("Fixed Price Standard"), Renewable Fixed Avoided Cost Prices ("Fixed Price Renewable"), or Firm Market Indexed Avoided Cost Prices ("Firm Electric Market"), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility's contract. Seller has selected the following (Seller to initial one):

_______ Fixed Price Standard
_______ Fixed Price Renewable
_______ Firm Electric Market

A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G.**

5.2 (Fixed Price Standard Seller Only). In the event Seller elects the Fixed Price Standard pricing method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller Firm Electric Market.

5.3 (Fixed Price Renewable Seller Only). In the event Seller elects the Fixed Price Renewable pricing method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller Firm Electric Market.

5.4 For all Excess Output and for all Net Output delivered prior to the Commercial Operation Date, PacifiCorp shall pay Seller 93 percent of a blended market index price for day-ahead firm energy at MidColumbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by the Intercontinental Exchange (ICE), for the On-Peak and Off-Peak periods. PacifiCorp shall document its calculation of the blended rate, upon request, to Seller. Such payment will be accomplished by adjustments pursuant to Section 9.2.

5.5 Environmental Attributes.

5.5.1 (Fixed Price Standard Seller Only): PacifiCorp waives any claim to Seller's ownership of Environmental Attributes under this Agreement throughout the Term.

5.5.2 (Fixed Price Renewable Seller Only): PacifiCorp waives any claim to Seller's ownership of Environmental Attributes during the Renewable Resource Sufficiency Period, and any period within the Term of this Agreement after completion of the first fifteen (15) years after the Scheduled Initial Delivery Date. Subject to the foregoing, Seller shall transfer the Green Tags to PacifiCorp in accordance with Section 4.5 during the Renewable Resource Deficiency Period.

SECTION 6: OPERATION AND CONTROL

6.1 As-Built Supplement. Upon completion of initial (and any subsequent) construction affecting the Facility, Seller shall provide PacifiCorp an As-built Supplement to specify the actual Facility as built. The As-built Supplement must be reviewed and approved by PacifiCorp, which approval shall not unreasonably be withheld, conditioned or delayed.

6.2 Incremental Utility Upgrades. At start-up (and at any other time upon at least six months' prior written notice), Seller may increase Net Output, if such increase is due to normal variances in estimated versus actual performance, changed Facility operations, or improvements in Facility efficiency. Seller may not increase Net Output under this Agreement by installing additional generating units. In the case of substantial upgrades, PacifiCorp may require Seller to comply with Section 3.2.8(e) (in the event that the Facility upgrade causes the Facility Capacity Rating to exceed 3,000 kW) and increase its Minimum Annual Delivery obligation in Section 4.3 (if appropriate). PacifiCorp may also update Seller's security obligation (if applicable). So long as the Facility Capacity Rating after the upgrade is 10,000 kW or less, Seller will continue to receive the Contract Price for the Net Output, as set forth in Sections 5.1, 5.2, and 5.3 of this Agreement. If Seller increases the Facility Capacity Rating above 10,000 kW, then (on a going forward basis) PacifiCorp shall pay Seller the Contract Price for the fraction of total Net Output equal to 10,000 kW divided by the Facility Capacity Rating of the upgraded Facility. For the remaining fraction of Net Output, PacifiCorp and Seller shall agree to a new negotiated rate. Seller shall be responsible for ensuring that any planned increase in the Facility Capacity Rating or the maximum instantaneous capacity of the Facility complies with Seller's Interconnection Agreement, Transmission Agreement and any other relevant agreements.

6.3 Seller shall operate and maintain the Facility in a safe manner in accordance with this Agreement, the Interconnection Agreement, Prudent Electrical Practices and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code as such laws and code may be amended from time to time. PacifiCorp shall have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and the Point of Delivery is disconnected, suspended or interrupted, in whole or in part, pursuant to the Interconnection Agreement or Transmission Agreement(s), or to the extent generation curtailment is required as a result of Seller's non-compliance with the Interconnection Agreement or Transmission Agreement(s). PacifiCorp shall have the right to inspect the Facility to confirm that Seller is operating the Facility in accordance with the provisions of this Section 6.3 upon reasonable notice to Seller. Seller is solely responsible for the operation and maintenance of the Facility. PacifiCorp shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.4 Scheduled Outages. Seller may cease operation of the entire Facility or individual units, if applicable, for maintenance or other purposes. Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp's request, if any, to reschedule such planned outage in order to accommodate PacifiCorp's need for Facility operation.

6.5 Unplanned Outages. In the event of an unscheduled outage or curtailment exceeding twenty-five (25) percent of the Facility Capacity Rating (other than curtailments due to lack of motive force), Seller immediately shall notify PacifiCorp of the necessity of such unscheduled outage or curtailment, the time when such has occurred or will occur and the anticipated duration. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled outage or curtailment, to limit the duration of such, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: FUEL/MOTIVE FORCE

Prior to the Effective Date of this Agreement, Seller provided to PacifiCorp a fuel or motive force plan acceptable to PacifiCorp in its reasonable discretion and attached hereto as **Exhibit D-1,** together with a certification from a Licensed Professional Engineer to PacifiCorp attached hereto as **Exhibit D-2**, certifying that the implementation of the fuel or motive force plan can reasonably be expected to provide fuel or motive force to the Facility for the duration of this Agreement adequate to generate power and energy in quantities necessary to deliver the Minimum Annual Delivery set forth by Seller in Section 4.

SECTION 8: METERING AT THE POINT OF INTERCONNECTION

8.1 Metering shall be performed at the location and in a manner consistent with this Agreement, as specified in **Exhibit B**. Seller shall provide to PacifiCorp metered Facility Net Output in hourly increments, and any other energy measurements required to administer this Agreement. If the Transmitting Entity requires Seller to telemeter data, PacifiCorp shall be entitled to receive the same data Seller provides to the Transmitting Entity, if such data is useful to PacifiCorp's administration of this Agreement. All quantities of energy purchased hereunder shall be adjusted to account for electrical losses, if any, between the point of metering and the Point of Interconnection. The loss adjustment shall be ___% of the kWh energy production recorded on the Facility output meter.

8.2 Seller shall pay for the installation, testing, and maintenance of any metering required by Section 8.1, and shall provide reasonable access to such meters. PacifiCorp shall have reasonable access to inspection, testing, repair and replacement of the metering equipment. If any of the inspections or tests discloses a measurement error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) Billing Periods, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered following the repair of the meter.

SECTION 9: BILLINGS, COMPUTATIONS, AND PAYMENTS

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PacifiCorp shall send to Seller payment for Seller's deliveries of Net Output to PacifiCorp, together with computations supporting such payment. PacifiCorp may offset any such payment to reflect amounts owing from Seller to PacifiCorp pursuant to this Agreement or any other agreement between the Parties.

9.2 Corrections. PacifiCorp shall have up to eighteen months to adjust any payment made pursuant to Section 9.1. In the event PacifiCorp determines it has overpaid Seller (for Excess Output or otherwise), PacifiCorp may adjust Seller's future payment accordingly in order to recapture any overpayment in a reasonable time.

9.3 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; *provided*, *however*, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 10: SECURITY

Unless Seller has adopted the creditworthiness warranties contained in Section 3.2.8, Seller must provide security (if requested by PacifiCorp) in the form of a cash escrow, letter of credit, senior lien, or step-in rights. Seller hereby elects to provide, in accordance with the applicable terms of this Section 10, the following security (Seller to initial one selection only):

____ Cash Escrow

_____ Letter of Credit

_____ Senior Lien

_____ Step-in Rights

_____ Seller has adopted the Creditworthiness Warranties of Section 3.2.8.

In the event Seller's obligation to post default security (under Section 10 or Section 11.1.4) arises solely from Seller's delinquent performance of construction-related financial obligations, upon Seller's request, PacifiCorp will excuse Seller from such obligation in the event Seller has negotiated financial arrangements with its construction lenders that mitigate Seller's financial risks to PacifiCorp's reasonable satisfaction.

[SKIP THIS SECTION 10.1 UNLESS SELLER SELECTED CASH ESCROW ALTERNATIVE]

10.1 Cash Escrow Security. Seller shall deposit in an escrow account established by PacifiCorp in a banking institution acceptable to both Parties, the Default Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institution from time to time. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.2 UNLESS SELLER SELECTED LETTER OF CREDIT ALTERNATIVE]

10.2 Letter of Credit Security. Seller shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to PacifiCorp in its discretion, or (b) a Letter of Credit in favor of PacifiCorp. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.3 UNLESS SELLER SELECTED SENIOR LIEN ALTERNATIVE]

10.3 Senior Lien. Before the Scheduled Commercial Operation Date, Seller shall grant PacifiCorp a senior, unsubordinated lien on the Facility and its assets as security for performance of this Agreement by executing, acknowledging and delivering a security agreement and a deed of trust or a mortgage, in a recordable form (each in a form satisfactory to PacifiCorp in the reasonable exercise of its discretion). Pending delivery of the senior lien to PacifiCorp, Seller shall not cause or permit the Facility or its assets to be burdened by liens or other encumbrances that would be superior to PacifiCorp's, other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

[SKIP THIS SECTION 10.4 UNLESS SELLER SELECTED STEP-IN RIGHTS ALTERNATIVE]

10.4 Step-in Rights (Operation by PacifiCorp Following Event of Default of Seller).

10.4.1 Prior to any termination of this Agreement due to an Event of Default of Seller, as identified in Section 11, PacifiCorp shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this Agreement) during the period provided for herein. Seller shall not grant any person, other than the lending institution providing financing to the Seller for construction of the Facility ("Facility

Lender"), a right to possess, assume control of, and operate the Facility that is equal to or superior to PacifiCorp's right under this Section 10.4.

10.4.2 PacifiCorp shall give Seller ten (10) calendar days notice in advance of the contemplated exercise of PacifiCorp's rights under this Section 10.4. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Electrical Practices. Upon such notice, PacifiCorp, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Facility for the purpose of constructing and/or operating the Facility. Seller hereby irrevocably appoints PacifiCorp as Seller's attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions as PacifiCorp may reasonably deem necessary or appropriate to exercise PacifiCorp's step-in rights under this Section 10.4.

10.4.3 During any period that PacifiCorp is in possession of and constructing and/or operating the Facility, no proceeds or other monies attributed to operation of the Facility shall be remitted to or otherwise provided to the account of Seller until all Events of Default of Seller have been cured.

10.4.4 During any period that PacifiCorp is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and PacifiCorp shall assume possession, operation, and control solely as agent for Seller.

(a) In the event PacifiCorp is in possession and control of the Facility for an interim period, Seller shall resume operation and PacifiCorp shall relinquish its right to operate when Seller demonstrates to PacifiCorp's reasonable satisfaction that it will remove those grounds that originally gave rise to PacifiCorp's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this Agreement, and (ii) has cured any Events of Default of Seller which allowed PacifiCorp to exercise its rights under this Section 10.4.

(b) In the event that PacifiCorp is in possession and control of the Facility for an interim period, the Facility Lender, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and PacifiCorp shall relinquish its right to operate when the Facility Lender or any nominee or transferee thereof, requests such relinquishment.

10.4.5 PacifiCorp's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by PacifiCorp of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility PacifiCorp elects to return such possession and operation to Seller, PacifiCorp shall provide Seller with at least fifteen (15) calendar days advance notice of the date PacifiCorp intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

SECTION 11: DEFAULTS AND REMEDIES

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.

11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Interconnection Agreement and any Transmission Agreement) within the time allowed for a cure under such agreement or instrument.

11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;

11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.

11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for two (2) consecutive years; else Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for one year.

11.2 Notice; Opportunity to Cure.

11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.

11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.

11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the sum of the Replacement Price for the Minimum Annual Delivery that Seller was otherwise obligated to provide for a period of twenty-four (24) months from the date of termination plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, and the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any energy and capacity that Seller was otherwise obligated (under Section 4.3) to provide during the period of default ("**Net Replacement Power Costs**"); *provided, however,* that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

(a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.

(b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

SECTION 12: INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller's side of the Point of Delivery, (c) Seller's operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement 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. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. EXCEPT TO THE EXTENT SUCH DAMAGES ARE INCLUDED IN THE LIQUIDATED DAMAGES, DELAY DAMAGES, COST TO COVER DAMAGES OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE.

SECTION 13: INSURANCE *(FACILITIES OVER 200KW ONLY)*

13.1 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) (of "ACORD Form" or the equivalent) certifying Seller's compliance with the insurance requirements hereunder. Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate. If requested by PacifiCorp, a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company, shall be furnished to PacifiCorp.

13.2 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "B+" by the A.M. Best Company the insurance coverage specified below:

13.2.1 Commercial General Liability insurance, to include contractual liability, with a minimum single limit of $1,000,000 to protect against and from all loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

13.2.2 All Risk Property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The Risk policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

13.3 The Commercial General Liability policy required herein shall include i) provisions or endorsements naming PacifiCorp, its Board of Directors, Officers and employees as additional insureds, and ii) cross liability coverage so that the insurance applies separately to each insured against whom claim is made or suit is brought, even in instances where one insured claims against or sues another insured.

13.4 All liability policies required by this Agreement shall include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and provisions that such policies shall not be canceled or their limits of liability reduced without 1) ten (10) days prior written notice to PacifiCorp if canceled for nonpayment of premium, or 2) thirty (30) days prior written notice to PacifiCorp if canceled for any other reason.

13.5 Insurance coverage provided on a "claims-made" basis shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

SECTION 14: FORCE MAJEURE

14.1 As used in this Agreement, "**Force Majeure**" or "**an event of Force Majeure**" means any cause beyond the reasonable control of the Seller or of PacifiCorp which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of fuel or motive force resources to operate the Facility or changes in market conditions that affect the price of energy or transmission. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the event of Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

14.1.1 the non-performing Party, shall, within two (2) weeks after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

14.1.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure; and

14.1.3 the non-performing Party uses its best efforts to remedy its inability to perform.

14.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the event of Force Majeure.

14.3 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.4 PacifiCorp may terminate the Agreement if Seller fails to remedy Seller's inability to perform, due to an event of Force Majeure, within six months after the occurrence of the event.

SECTION 15: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 16: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the State of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 17: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

SECTION 18: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 19: GOVERNMENTAL JURISDICTIONS AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PacifiCorp.

SECTION 20: REPEAL OF PURPA

This Agreement shall not terminate upon the repeal of the PURPA, unless such termination is mandated by federal or state law.

SECTION 21: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent to a lender as part of a financing transaction or as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 22: ENTIRE AGREEMENT

22.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PacifiCorp's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

22.2 By executing this Agreement, Seller releases PacifiCorp from any claims, known or unknown, that may have arisen prior to the Effective Date.

SECTION 23: NOTICES

23.1 All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested.

Notices	PacifiCorp	Seller
All Notices	PacifiCorp 825 NE Multnomah Street Portland, OR 97232 Attn: Contract Administration, Suite 600 Phone: (503) 813 - 5380 Facsimile: (503) 813 - 6291 Duns: 00-790-9013 Federal Tax ID Number: 93-0246090	
All Invoices:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Scheduling:	(same as street address above) Attn: Resource Planning, Suite 600 Phone: (503) 813 - 6090 Facsimile: (503) 813 – 6265	
Payments:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Wire Transfer:	Bank One N.A. ABA: ACCT: NAME: PacifiCorp Wholesale	
Credit and Collections:	(same as street address above) Attn: Credit Manager, Suite 700 Phone: (503) 813 - 5684 Facsimile: (503) 813 – 5609	
With Additional Notices of an Event of Default or Potential Event of Default to:	(same as street address above) Attn: PacifiCorp General Counsel Phone: (503) 813-5029 Facsimile: (503) 813-7252	

23.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 23.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the date first above written.

PacifiCorp	Seller
By:_____________________________	By:____________________________
Name:___________________________	Name:_________________________
Title:____________________________	Title: __________________________

EXHIBIT A

DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

Seller's Facility consists of ___________________________ generators manufactured by _________________. More specifically, each generator at the Facility is described as:

A. <u>Manufacturer's Nameplate Data:</u>
Type (synchronous or inductive):

Model:
Number of Phases:
Rated Output (kW): **Rated Output (kVA):**
Rated Voltage (line to line):
Rated Current (A): Stator: ____ A; Rotor: ______ A
Power factor requirements:
Rated Power Factor (PF) or reactive load (kVAR):

B. <u>Seller's Estimate of Facility Output Under Ideal (Maximum) or Worst (Minimum) Conditions</u>
Maximum kW Output: ____________ kW **Maximum kVA Output:** ______kVA
Minimum kW Output: _________ kW
Manufacturer's Guaranteed Cut-in Wind Speed [if applicable]:

Facility Capacity Rating: ____________ kW at _____________________________________
Identify the maximum output of the generator(s) and describe any differences between that output and the Nameplate Capacity Rating:

Station service requirements, and other loads served by the Facility, if any, are described as follows:
____

____.

C: <u>Location of the Facility</u>: The Facility is to be constructed in the vicinity of ____________ in _____________ County, _____________. The location is more particularly described as follows:

[legal description of parcel]

EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

[Seller to provide its own diagram and description]

POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES

Instructions to Seller:

1. Describe the point(s) of metering, including the type of meter(s), and the owner of the meter(s).

2. Provide single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection,

3. Specify the Point of Delivery, and any transmission facilities on Seller's side of the Point of Delivery used to deliver Net Output.

EXHIBIT C

REQUIRED FACILITY DOCUMENTS

REQUIRED OF ALL FACILITIES:

QF Certification
Interconnection Agreement
Fuel Supply Agreement, if applicable

REQUIRED IF SELLER ELECTS TO GRANT SENIOR LIEN OR STEP-IN RIGHTS:

Deed or Lease to Facility Premises
Preliminary Title Report of Premises
Proof of ownership of Facility
Off-take sale agreements, e.g. surplus heat sale contract, if applicable

Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be requested.

EXHIBIT D-1

SELLER'S MOTIVE FORCE PLAN

A. **MONTHLY DELIVERY SCHEDULES AND SCHEDULED MAINTENANCE**

Month	Average Energy (kWh)
January	
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Seller provide an estimate of the average monthly Net Output of the Facility, and explain the basis for the estimate.

B. **MINIMUM ANNUAL DELIVERY CALCULATION**

Seller specify the Minimum Annual Delivery of the Facility, and explain the basis for the estimate. NOTE: The Minimum Annual Delivery should be based on the most adverse natural motive force conditions reasonably expected and should take into account unscheduled repairs or maintenance and Seller's load (if any).

C. **MAXIMUM ANNUAL DELIVERY CALCULATION**

Seller specify the estimated Maximum Annual Delivery of the Facility, and explain the basis for the estimate.

EXHIBIT D-2

ENGINEER'S CERTIFICATION OF MOTIVE FORCE PLAN

Seller provide a written declaration from a Licensed Professional Engineer to PacifiCorp that the Facility is likely capable under average conditions foreseeable during the term of this Agreement of meeting Seller's estimated average, maximum, and minimum Net Output.

EXHIBIT E

START-UP TESTING

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable): **[Seller identify appropriate tests]**

1. Pressure tests of all steam system equipment;
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;
3. Operating tests of all valves, operators, motor starters and motor;
4. Alarms, signals, and fail-safe or system shutdown control tests;
5. Insulation resistance and point-to-point continuity tests;
6. Bench tests of all protective devices;
7. Tests required by manufacturer of equipment; and
8. Complete pre-parallel checks with PacifiCorp.

Required start-up tests are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PacifiCorp's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;
3. Brake tests;
4. Energization of transformers;
5. Synchronizing tests (manual and auto);
6. Stator windings dielectric test;
7. Armature and field windings resistance tests;
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load;
9. Heat runs;
10. Tests required by manufacturer of equipment;
11. Excitation and voltage regulation operation tests;
12. Open circuit and short circuit; saturation tests;
13. Governor system steady state stability test;
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;
15. Auto stop/start sequence;
16. Level control system tests; and
17. Completion of all state and federal environmental testing requirements.

EXHIBIT F

SELLER AUTHORIZATION TO RELEASE GENERATION DATA TO PACIFICORP

[Interconnection Customer Letterhead]

Transmission Services
Attn: Director, Transmission Services
825 NE Multnomah, Suite 1600
Portland, OR 97232

RE: ___________ Interconnection Request

Dear Sir:

_________________ hereby voluntarily authorizes PacifiCorp's Transmission business unit to share _____________________'s generator interconnection information and generator meter data with Marketing Affiliate employees of PacifiCorp Energy, including, but not limited to those in the Commercial and Trading group. _________________ acknowledges that PacifiCorp did not provide it any preferences, either operational or rate-related, in exchange for this voluntary consent.

____
Name

____
Title

____
Date

EXHIBIT G

SCHEDULE 37 AND PRICING SUMMARY TABLE

EXHIBIT H

GREEN TAG ATTESTATION AND BILL OF SALE

Subject to Green Tags ownership as defined in Section 5.5, from the period commencing on ____ and ending on _____, _____________________ ("Seller") hereby sells, transfers and delivers to PacifiCorp the Green Tags (including all Green Tag Reporting Rights) associated with the generation of Net Output under the Power Purchase Agreement (Renewable Energy) between Seller and PacifiCorp dated [_________] (the "PPA"), as described below, in the amount of one Green Tag for each megawatt hour generated. Defined terms used in this Green Tag Attestation and Bill of Sale (as indicated by initial capitalization) shall have the meaning set forth in the PPA.

Facility name and location: ________________________ Fuel Type: _____________

Capacity (MW): _________________ Operational Date: _______________________

Energy Admin. ID no.: ________

Dates	MWh generated
__________	________

Seller further attests, warrants and represents, under penalty of perjury, as follows:

i) to the best of its knowledge, the information provided herein is true and correct;

ii) its sale to PacifiCorp is its one and only sale of the Green Tags referenced herein;

iii) the Facility generated Output in the amount indicated above; and

iv) to the best of Seller's knowledge, each of the Green Tags associated with the generation Output have been generated and sold by the Facility.

This Green Tag Attestation and Bill of Sale confirms, in accordance with the PPA, the transfer from Seller to PacifiCorp all of Seller's right, title and interest in and to the Green Tags (including Green Tag Reporting Rights), as set forth above.

Seller's Contact Person: [______________________________]

WITNESS MY HAND,

____

a ______________________________________

By ____________________

Its ____________________

Date: ____________________

This Attestation may be disclosed by Seller and PacifiCorp to others, including the Center for Resource Solutions and the public utility commissions having jurisdiction over PacifiCorp, to substantiate and verify the accuracy of PacifiCorp's advertising and public communication claims, as well as in PacifiCorp's advertising and other public communications.

ADDENDUM W

GENERATION SCHEDULING ADDENDUM

WHEREAS, Seller's Facility is not located within the control area of PacifiCorp;

WHEREAS, Seller's Facility will not interconnect directly to PacifiCorp's System;

WHEREAS, Seller and PacifiCorp have not executed, and will not execute, a Generation Interconnection Agreement in conjunction with the Power Purchase Agreement;

WHEREAS, Seller has elected to exercise its right under PURPA to deliver Net Output from it's QF Facility to PacifiCorp via one (or more) Transmitting Entities.

WHEREAS, PacifiCorp desires that Seller schedule delivery of Net Output on a firm, hourly basis;

WHEREAS, PacifiCorp does not intend to buy, and Seller does not intend to deliver, more or less than Net Output from the Facility (except as expressly provided, below);

THEREFORE, Seller and PacifiCorp do hereby agree to the following, which shall become part of their Power Purchase Agreement:

DEFINITIONS

The meaning of the terms defined in the Power Purchase Agreement and this **Addendum W** shall apply to this Generation Scheduling Addendum:

"Day" means midnight to midnight, prevailing local time at the Point of Delivery, or any other mutually agreeable 24-hour period.

"Energy Imbalance Accumulation," or "**EIA,**" means the accumulated difference between Seller's Net Output and the energy actually delivered at the Point of Delivery. A positive accumulated difference indicates Seller's net delivery of Supplemented Output to PacifiCorp.

"Firm Delivery" means uninterruptible transmission service that is reserved and/or scheduled between the Point of Interconnection and the Point of Delivery pursuant to Seller's Transmission Agreement.

"Settlement Period" means one month.

"Supplemented Output" means any increment of scheduled hourly energy or capacity delivered to the Point of Delivery in excess of the Facility's Net Output during that same hour.

ADDENDUM W-ctd.

"**Surplus Delivery**" means any energy delivered by the Facility in excess of hourly Net Output that is not offset by the delivery of energy in deficit of hourly Net Output during the Settlement Period. PacifiCorp shall accept Surplus Delivery, but shall not pay for it.

SELLER'S OBLIGATIONS IN LIEU OF THOSE CONTAINED IN A GENERATION INTERCONNECTION AGREEMENT.

1. **Seller's Responsibility to Arrange for Delivery of Net Output to Point of Delivery**. Seller shall arrange for the Firm Delivery of Net Output to the Point of Delivery. Seller shall comply with the terms and conditions of the Transmission Agreement(s) between the Seller and the Transmitting Entity(s). Whenever Seller fails to provide for Firm Delivery of Net Output, all Net Output delivered via non-firm transmission rights shall be deemed Excess Output, and therefore subject to the payment provision in Section 5.4.

2. **Seller's Responsibility to Schedule Delivery.** Seller shall coordinate with the Transmitting Entity(s) to provide PacifiCorp with a schedule of the next Day's hourly scheduled Net Output deliveries at least 24 (twenty-four) hours prior to the beginning of the day being scheduled, and otherwise in accordance with the WECC Prescheduling Calendar (which is updated annually and may be downloaded at: http://www.wecc.biz/.

3. **Seller's Responsibility to Maintain Interconnection Facilities**. PacifiCorp shall have no obligation to install or maintain any interconnection facilities on Seller's side of the Point of Interconnection. PacifiCorp shall not pay any costs arising from Seller interconnecting its Facility with the Transmitting Entity(s).

4. **Seller's Responsibility to Pay Transmission Costs**. Seller shall make all arrangements for, and pay all costs associated with, transmitting Net Output to PacifiCorp, scheduling energy into the PacifiCorp system and any other costs associated with delivering the Seller's Net Output to the Point of Delivery.

5. **Energy Reserve Requirements.** The Transmitting Entity shall provide all generation reserves as required by the WECC and/or as required by any other governing agency or industry standard to deliver the Net Energy to the Point of Delivery, at no cost to PacifiCorp.

6. **Seller's Responsibility to Report Net Output.** On or before the tenth ($10^{th)}$ day following the end of each Billing Period, Seller shall send a report documenting hourly station service, Excess Output, and Net Output from the Facility during the previous Billing Period, in columnar format substantially similar to the attached **Example 1**. If requested, Seller shall provide an electronic copy of the data used to calculate Net Output, in a standard format specified by PacifiCorp. For each day Seller is late delivering the certified report, PacifiCorp shall be entitled to postpone its payment deadline in Section 9 of this Power Purchase Agreement by one day. Seller hereby grants PacifiCorp the right to audit its certified reports of hourly Net Output. In the event of discovery of a billing error resulting in underpayment or overpayment, the Parties agree to limit recovery to a period of three years from the date of discovery.

ADDENDUM W-ctd.

7. **Seller's Supplemental Representations and Warranties.** In addition to the Seller's representations and warranties contained in Section 3 of this Agreement, Seller warrants that:

(a) Seller's Supplemented Output, if any, results from Seller's purchase of some form of energy imbalance ancillary service;

(b) The Transmitting Entity(s) requires Seller to procure the service, above, as a condition of providing transmission service;

(c) The Transmitting Entity requires Seller to schedule deliveries of Net Output in increments of no less than one (1) megawatt;

(d) Seller is not attempting to sell PacifiCorp energy or capacity in excess of its Net Output; and

(e) The energy imbalance service, above, is designed to correct a mismatch between energy scheduled by the QF and the actual real-time production by the QF.

8. **Seller's Right to Deliver Supplemented Output**. In reliance upon Seller's warranties in Section 5, above, PacifiCorp agrees to accept and pay for Supplemented Output; *provided, however, that* Seller agrees to achieve an EIA of zero (0) kilowatt-hours during On-Peak Hours and zero (0) kilowatt-hours during Off-Peak Hours at the end of each Settlement Period.

(a) **Remedy for Seller's Failure to Achieve zero EIA**. In the event Seller does not achieve zero EIA at the end of each Settlement Period, PacifiCorp will declare any positive balance to be Surplus Delivery, and Seller's EIA will be reset to zero. PacifiCorp will include an accounting of Surplus Delivery in each monthly statement provided to Seller pursuant to Section 9.1 of this Agreement.

(b) **Negative Energy Imbalance Accumulations**. Any negative EIA (indicating that the Transmitting Entity has delivered less than Seller's Net Output), will be reset to zero at the end of each Settlement Period without any corresponding compensation by PacifiCorp.

(c) **PacifiCorp's Option to Change EIA Settlement Period**. In the event PacifiCorp reasonably determines that doing so likely will have a *de minimis* net effect upon the cost of Seller's Net Output to PacifiCorp, it may elect to enlarge the Settlement Period, up to a maximum of one Contract Year. Conversely, if PacifiCorp reasonably determines, based on the QF's performance during the current year, that reducing the Settlement Period likely will significantly lower the net cost of Seller's Net Output to PacifiCorp, it shall have the right to shorten Seller's EIA settlement period beginning the first day of the following Contract Year. However, in no case shall the Settlement Period be less than one month.

DRAFT

ADDENDUM W—Example 1

Example of Seller's Output Reporting Requirement

Day	Hour ending (HE)	**A** Meter Reading[Ψ] at Point of Interconnection (MWh)	**B** Meter reading at Station Power Meter* (MWh)	**C (=A-B)** Net Output (MWh)	**D** Facility Capacity Rating (MW)	**E (=Max (0, C-D))** Excess Output (MWh)
1	7:00	0.50	0.01	0.49	1.50	
1	8:00	0.50	0.02	0.48	1.50	
1	9:00	0.50	0.01	0.49	1.50	
1	10:00	0.50	0.01	0.49	1.50	
1	11:00	0.50	0.01	0.49	1.50	
1	12:00	1.60	0.01	1.59	1.50	0.09
1	13:00	1.70	0.01	1.69	1.50	0.19
1	14:00	1.60	0.01	1.59	1.50	0.09
1	15:00	1.50	0.01	1.49	1.50	
1	16:00	1.50	0.01	1.50	1.50	
1	17:00	1.50	0.00	1.50	1.50	
1	18:00	1.50	0.01	1.49	1.50	
1	19:00	0.50	0.02	0.48	1.50	
1	20:00	0.50	0.01	0.49	1.50	

Ψ Seller shall show adjustment of Meter Reading for losses, if any, between point of metering and the Point of Interconnection, in accordance with Section 8.1.

* Does not apply if Station Service is provided from the gross output of the Facility.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/104

PacifiCorp's Oregon Schedule 37
Avoided Cost Prices and Process for Qualifying Facilities
(Less than 10,000 kW)

May 17, 2016

Available

To owners of Qualifying Facilities making sales of electricity to the Company in the State of Oregon.

Applicable

For power purchased from Qualifying Facilities with a nameplate capacity of 10,000 kW or less or that, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a nameplate capacity of 10,000 kW or less. Owners of these Qualifying Facilities will be required to enter into a written power sales contract with the Company.

Definitions

Cogeneration Facility

A facility which produces electric energy together with steam or other form of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying Facilities

Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Qualifying Electricity

Electricity that meets the requirements of "qualifying electricity" set forth in the Oregon Renewable Portfolio Standards: ORS 469A.010, 469A.020, and 469A.025.

Renewable Qualifying Facility

A Qualifying Facility that generates Qualifying Electricity.

Wind Qualifying Facility

A Renewable Qualifying Facility that generates Qualifying Electricity using wind as its motive force.

Baseload Renewable Qualifying Facility

A Renewable Qualifying Facility that generates Qualifying Electricity using any qualifying resource other than wind or solar.

Small Power Production Facility

A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

On-Peak Hours or Peak Hours

On-Peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

(continued)

Definitions (continued)

Off-Peak Hours
All hours other than On-Peak.

Excess Output
Excess Output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Nameplate Capacity. PacifiCorp shall pay Seller the Off-Peak Price as described and calculated under pricing option 4 (Non-Firm Market Index Avoided Cost Price) for all Excess Output.

Same Site
Generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and standard contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought.

Person(s) or Affiliated Person(s)
A natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a “passive investor” whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a “passive investor” in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Shared Interconnection and Infrastructure
QFs otherwise meeting the separate ownership test and thereby qualified for entitlement to the standard rates and standard contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for the standard rates and standard contract so long as the use of the shared interconnection complies with the interconnecting utility’s safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility’s approved standard contract.

Dispute Resolution
Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and standard contract.

(continued)

Dispute Resolution (continued)

Any dispute concerning a QF's entitlement to the standard rates and standard contract shall be presented to the Commission for resolution.

Self Supply Option

Owner shall elect to sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp or sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of the power purchase agreement and the appropriate retail service.

Pricing Options

1. Standard Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Standard Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price,
The Standard Fixed Avoided Cost pricing option is available to all Qualifying Facilities. The Standard Fixed Avoided Cost Price for Wind Qualifying Facilities will reflect integration costs as set forth on page 5.

2. Renewable Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Renewable Qualifying Facility and the Company and will not change during the term of the contract. Renewable Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price. The Renewable Fixed Avoided Cost pricing option is available only to Renewable Qualifying Facilities. A Renewable Qualifying Facility choosing the Renewable Fixed Avoided Cost pricing option must cede all Green Tags generated by the facility, as defined in the standard contract, to the Company during the Renewable Resource Deficiency Period identified on page 6, except that a Renewable Qualifying Facility retains ownership of all Environmental Attributes generated by the facility, as defined in the standard contract, during the Renewable Resource Sufficiency Period identified on page 6 and during any period after the first 15 years of a longer term contract (up to 20 years).

3. Firm Market Indexed Avoided Cost Prices

Firm Market Index Avoided Cost Prices are available to Qualifying Facilities that contract to deliver firm power. Monthly on-peak / off-peak prices paid are a blending of Intercontinental Exchange (ICE) Day Ahead Power Price Report at market hubs for on-peak and off-peak prices. The monthly blending matrix is available upon request.

4. Non-Firm Market Index Avoided Cost Prices

Non-Firm Market Index Avoided Cost Prices are available to Qualifying Facilities that do not elect to provide firm power. Qualifying Facilities taking this option will have contracts that do not include minimum delivery requirements, default damages for construction delay or, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are 93 percent of a blending of ICE Day Ahead Power Price Report at market hubs for on-peak and off-peak firm index prices. The monthly blending matrix is available upon request. The Non-Firm Market Index Avoided Cost pricing option is available to all Qualifying Facilities. The Non-Firm Market Index Avoided Cost Price for Wind Qualifying Facilities will reflect integration costs.

(continued)

Monthly Payments

A Qualifying Facility shall select the option of payment at the time of signing the contract under one of the Pricing Options specified above. Once an option is selected the option will remain in effect for the duration of the Facility's contract.

Renewable or Standard Fixed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the renewable or standard fixed prices as provided in this schedule. On-Peak and Off-Peak are defined in the definitions section of this schedule.

Firm Market Indexed and Non-Firm Market Index Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the market prices calculated at the time of delivery. On-Peak and Off-Peak are defined in the definitions section of this schedule.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

OREGON
SCHEDULE 37

AVOIDED COST PURCHASES FROM
QUALIFYING FACILITIES OF 10,000 KW OR LESS

Avoided Cost Prices

Standard Fixed Avoided Cost Prices

Fixed Prices ¢/kWh

Deliveries During Calendar Year	Base Load QF (1) On-Peak Energy Price (a)	Base Load QF (1) Off-Peak Energy Price (b)	Wind QF (2) On-Peak Energy Price (c)	Wind QF (2) Off-Peak Energy Price (d)	Solar QF On-Peak Energy Price (e)	Solar QF Off-Peak Energy Price (f)
2015	2.77	2.19	2.51	1.93	2.77	2.19
2016	2.87	2.20	2.60	1.93	2.87	2.20
2017	3.13	2.43	2.86	2.16	3.13	2.43
2018	3.38	2.54	3.10	2.26	3.38	2.54
2019	3.55	2.73	3.26	2.45	3.55	2.73
2020	3.82	2.93	3.53	2.64	3.82	2.93
2021	4.11	3.18	3.81	2.88	4.11	3.18
2022	4.41	3.44	4.10	3.14	4.41	3.44
2023	4.72	3.69	4.41	3.38	4.72	3.69
2024	6.16	3.06	2.87	2.74	3.48	3.06
2025	6.35	3.18	2.99	2.86	3.61	3.18
2026	6.41	3.18	2.98	2.84	3.62	3.18
2027	6.61	3.31	3.11	2.97	3.76	3.31
2028	6.98	3.61	3.40	3.26	4.07	3.61
2029	7.15	3.71	3.50	3.36	4.18	3.71
2030	7.30	3.79	3.58	3.43	4.27	3.79
2031	7.62	4.03	3.82	3.67	4.52	4.03
2032	7.80	4.14	3.92	3.76	4.64	4.14
2033	7.93	4.20	3.97	3.81	4.71	4.20
2034	8.15	4.34	4.11	3.95	4.86	4.34
2035	8.40	4.51	4.27	4.11	5.04	4.51
2036	8.59	4.62	4.38	4.21	5.16	4.62
2037	8.82	4.76	4.52	4.35	5.31	4.76
2038	9.05	4.91	4.65	4.48	5.47	4.91
2039	9.25	5.02	4.76	4.58	5.59	5.02
2040	9.51	5.19	4.93	4.74	5.78	5.19
2041	9.71	5.30	5.03	4.85	5.90	5.30

(1) Capacity Contribution to Peak for Avoided Proxy Resource and Base Load Qualifying Facility resource are assumed 100%.

(2) The standard avoided cost price for wind is reduced by an integration charge of $2.55/MWh ($2012). If Wind Qualifying Facility is not in PacifiCorp's balancing authority area, then no reduction is required.

(continued)

Avoided Cost Prices (Continued)

Renewable Fixed Avoided Cost Prices

Fixed Prices ¢/kWh

Deliveries During Calendar Year (1)	Renewable Base Load QF (2)		Wind QF (3,4)		Solar QF (5)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)	(e)	(f)
2015	2.77	2.19	2.51	1.93	2.77	2.19
2016	2.87	2.20	2.60	1.93	2.87	2.20
2017	3.13	2.43	2.86	2.16	3.13	2.43
2018	3.38	2.54	3.10	2.26	3.38	2.54
2019	3.55	2.73	3.26	2.45	3.55	2.73
2020	3.82	2.93	3.53	2.64	3.82	2.93
2021	4.11	3.18	3.81	2.88	4.11	3.18
2022	4.41	3.44	4.10	3.14	4.41	3.44
2023	4.72	3.69	4.41	3.38	4.72	3.69
2024	11.96	7.05	8.67	6.73	9.28	7.05
2025	12.19	7.24	8.83	6.92	9.46	7.24
2026	12.36	7.51	8.93	7.18	9.56	7.51
2027	12.59	7.71	9.09	7.37	9.73	7.71
2028	12.82	7.91	9.24	7.57	9.91	7.91
2029	13.05	8.11	9.40	7.76	10.07	8.11
2030	13.27	8.32	9.55	7.96	10.24	8.32
2031	13.47	8.59	9.67	8.22	10.37	8.59
2032	13.78	8.75	9.90	8.37	10.62	8.75
2033	13.97	9.05	10.01	8.67	10.74	9.05
2034	14.17	9.36	10.13	8.97	10.88	9.36
2035	14.47	9.55	10.34	9.15	11.11	9.55
2036	14.85	9.65	10.63	9.25	11.42	9.65
2037	15.06	9.98	10.76	9.57	11.56	9.98
2038	15.58	9.94	11.19	9.51	12.00	9.94
2039	16.04	10.01	11.55	9.58	12.38	10.01
2040	16.38	10.22	11.80	9.77	12.65	10.22
2041	16.66	10.51	11.98	10.05	12.85	10.51

(1) For the purpose of determining: (i) when the Renewable Qualifying Facility is entitled to renewable avoided cost prices; and (ii) the ownership of Environmental Attributes and the transfer of Green Tags to PacifiCorp, the Renewable Resource Sufficiency Period ends December 31, 2023, and the Renewable Resource Deficiency Period begins January 1, 2024.

(2) The renewable avoided cost price during the Renewable Resource Deficiency Period (2024-2040) has been increased by an integration charge of $2.55/MWh ($2012).

(3) During the Renewable Resource Deficiency Period, the renewable avoided cost price for a Wind Qualifying Facility will be adjusted by adding the difference between the avoided integration costs and the Qualifying Facility's integration costs. If the Wind Qualifying Facility is in PacifiCorp's balancing authority area (BAA), the adjustment is zero (integration costs cancel each other out). If the Wind Qualifying Facility is not in PacifiCorp's BAA, $2.55/MWh ($2012) will be added for avoided integration charges.

(4) During Renewable Resource Sufficiency Period, the renewable avoided cost price for a Wind Qualifying Facility has been reduced by an integration charge of $2.55/MWh ($2012) for Wind Qualifying Facilities located in PacifiCorp's BAA (in-system). If a Wind Qualifying Facility is not in PacifiCorp's BAA, $2.55/MWh ($2012) will be added for avoided integration charges.

(5) The renewable avoided cost payment during the Renewable Resource Deficiency Period (2024-2040) has been increased by an integration charge of $2.55/MWh ($2012).

(continued)

Qualifying Facilities Contracting Procedure

Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading).

It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to allow time for studies, negotiation of agreements, engineering, procurement, and construction of the required interconnection facilities. Early application for interconnection will help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

1. **Qualifying Facilities up to 10,000 kW**

APPLICATION: To owners of existing or proposed QFs with a design capacity less than or equal to 10,000 kW who desire to make sales to the Company in the state of Oregon. Such owners will be required to enter into a written power purchase agreement with the Company pursuant to the procedures set forth below.

I. **Process for Completing a Power Purchase Agreement**

A. **Communications**

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

PacifiCorp
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information.

(continued)

B. Procedures

1. The Company's approved generic or standard form power purchase agreements may be obtained from the Company's website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

2. In order to obtain a project specific draft power purchase agreement the owner must provide in writing to the Company, general project information required for the completion of a power purchase agreement, including, but not limited to:

   (a) demonstration of ability to obtain QF status;
   (b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
   (c) generation technology and other related technology applicable to the site;
   (d) proposed site location;
   (e) schedule of monthly power deliveries;
   (f) calculation or determination of minimum and maximum annual deliveries;
   (g) motive force or fuel plan;
   (h) proposed on-line date and other significant dates required to complete the milestones;
   (i) proposed contract term and pricing provisions as defined in this Schedule (i.e.,standard fixed price, renewable fixed price);
   (j) status of interconnection or transmission arrangements;
   (k) point of delivery or interconnection;

3. The Company shall provide a draft power purchase agreement when all information described in Paragraph 2 above has been received in writing from the QF owner. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Public Utility Commission of Oregon in this Schedule 37.

4. If the owner desires to proceed with the power purchase agreement after reviewing the Company's draft power purchase agreement, it may request in writing that the Company prepare a final draft power purchase agreement. In connection with such request, the owner must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft power purchase agreement. Within 15 business days following receipt of all information requested by the Company in this paragraph 4, the Company will provide the owner with a final draft power purchase agreement.

(continued)

B. Procedures (continued)

5 After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

6. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

II. Process for Negotiating Interconnection Agreements

[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (including but not limited to PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (including but not limited to PacifiCorp's Commercial and Trading Group).

(continued)

II. Process for Negotiating Interconnection Agreements (continued)

A. Communications

Initial communications regarding interconnection agreements should be directed to the Company in writing as follows:

PacifiCorp
Director – Transmission Services
825 NE Multnomah St, Suite 1600
Portland, Oregon 97232

Based on the project size and other characteristics, the Company will direct the QF owner to the appropriate individual within the Company's transmission function who will be responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.

B. Procedures

Generally, the interconnection process involves (1) initiating a request for interconnection, (2) undertaking studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) executing an interconnection agreement to address facility construction, testing, acceptance, ownership, operation and maintenance issues. Consistent with PURPA and Oregon Public Utility Commission regulations, the owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis. For interconnections impacting the Company’s Transmission and Distribution System, the Company will process the interconnection application through PacifiCorp Transmission Services.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/105

Direct Testimony of Stefan Brown,
Docket No. UM 1129,
Public Utility Commission of Oregon Staff Exhibit 2200
(March 24, 2006)

May 17, 2016

CASE: UM 1129
WITNESS: Brown

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 2200

Direct Testimony

March 24, 2006

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Dr. Stefan Brown. My business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/2201.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses Issue 14 and Issue 3.b. dealing with provisions of PacifiCorp's and Portland General Electric's (PGE's) contracts for purchase of off-system Qualifying Facility (QF) power.

Q. DID YOU PREPARE AN EXHIBIT FOR THIS DOCKET?

A. Yes, I prepared Staff Exhibit 2202.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

ISSUE 14, TARIFF PROVISIONS FOR PURCHASES FROM OFF-SYSTEM QFS

Q. ARE THE METERING PROVISIONS IN PACIFICORP'S POWER PURCHASE AGREEMENT FOR OFF-SYSTEM QFS APPROPRIATE?

A. Yes. PacifiCorp circulated among the parties a revised Purchase Power Agreement on March 22, 2006, that requires a QF provide PacifiCorp with metered hourly Facility Net Output and other energy measurements required to administer the agreement. The QF must also provide telemeter data if required by the Transmitting Entity and the data are useful to administer the agreement.[1] The data are readily available from the necessary metering equipment, and are necessary to verify that PacifiCorp is only paying for the energy it receives.

Section 8.1 also states, "energy purchased … shall be adjusted to account for electrical losses, if any, between the point of metering and the Point of Interconnection." This provision is acceptable if the intention is to not charge a QF for losses when the QF generates and delivers energy to the transmission provider/owner (TO) to offset losses. In this case, the net output of the facility should be reduced by the amount of energy the QF generates to offset losses that are returned in kind to the TO.

[1] See Section 8.1. Staff understands that PacifiCorp will officially file the final version of the agreement, which PacifiCorp has represented will be the same as the draft it earlier circulated, in this docket on March 24, 2006.

Q. ARE THE METERING PROVISIONS IN PGE'S POWER PURCHASE AGREEMENT FOR OFF-SYSTEM QFS APPROPRIATE?

A. PGE's off-system QF tariff does not include metering provisions. QFs are required, under Section 4.5 to maintain and provide PGE access to at least two years of records of Net Output and imbalance information. The records should be sufficient to allow PGE to verify the amount of energy that a QF has generated and delivered.

Q. ARE THE TELEMETRY PROVISIONS IN PACIFICORP'S POWER PURCHASE AGREEMENT FOR OFF-SYSTEM QFS APPROPRIATE?

A. Yes. Section 8.1 states that PacifiCorp is entitled to telemeter data if the Transmitting Entity requires it and the data are useful to PacifiCorp's administration of the agreement. This requirement should not impose unnecessary metering costs on the QF.

Q. ARE THE TELEMETRY PROVISIONS IN PGE'S POWER PURCHASE AGREEMENT FOR OFF-SYSTEM QFS APPROPRIATE?

A. PGE's tariff does not include any telemetry provisions. Telemetry provisions are not necessary for off-system QFs for which PGE is neither providing ancillary services nor dispatching the unit.

Q. ARE THE DATA EXCHANGE PROVISIONS IN PACIFICORP'S POWER PURCHASE AGREEMENT FOR OFF-SYSTEM QFS APPROPRIATE?

A. Yes. PacifiCorp should be able to require that QFs submit data in a format that is readily accessible and usable by the company. Section 6, page 2 of Addendum W deals with net output reporting requirements. PacifiCorp is asking for hourly station service, Excess Output[2] and Net Output[3] in columnar format. In addition, the company is asking to be provided with an electronic copy upon request. These conditions seem reasonable and appropriate because they will allow PacifiCorp to verify the amount of energy that a QF has generated, delivered and should be paid for. Further, the data should be readily available as output from the facility's metering equipment.

Q. ARE THE DATA EXCHANGE PROVISIONS IN PGE'S POWER PURCHASE AGREEMENT FOR OFF-SYSTEM QFS APPROPRIATE?

A. Yes. Section 4.5 of Appendix 2 requires that a QF provide a preschedule for all deliveries of energy on the last business day prior to the scheduled delivery date, and that parties coordinate hourly real-time schedules. In the absence of real-time schedule changes, the preschedule will be considered final. Both PGE and the QF will maintain records of hourly energy schedules with the final E-Tag[4] being the controlling evidence. Further, the QF needs to maintain records for at least two years of hourly Net Output. These provisions appear sufficient to ensure that PGE will have the data necessary to pay the QF for its scheduled and delivered net output. Further, the data should be readily available as output from the facility's metering equipment.

[2] See PacifiCorp Power Purchase Agreement, Section 1.12.
[3] See PacifiCorp Power Purchase Agreement, Section 1.24.

[4] An E-Tag or "Electronic Tag" is an electronic record that includes the Point of Receipt, the Point of Delivery, the MW to be delivered, the start and end time of the transaction.

Q. ARE THE PRODUCTION BALANCING PROVISIONS IN PACIFICORP'S POWER PURCHASE AGREEMENT FOR OFF-SYSTEM QFS APPROPRIATE?

A. Yes. Under federal PURPA, utilities are required to purchase the net output of a QF, but no more than the net output, at avoided cost. While scheduling convention only allows for scheduling whole megawatts, facilities do not generate energy in one-MW unit increments. Additionally, the nameplate rating of facilities is not necessarily in whole megawatts. As a result, there may be a mismatch between scheduled output and actual generation. This is especially problematic for small facilities.

In its proposed standard contract for off-system QFs, PacifiCorp has included an Energy Imbalance Accumulation (EIA) that provides the opportunity for a QF to match its scheduled deliveries with its actual net output during off peak and on peak periods across the Settlement Period. The QF would net the differences between the hourly transmission schedule and net output over the Settlement Period. The Settlement Period is initially one month, but it may be expanded up to one year at PacifiCorp's discretion.

Another provision of the EIA is that PacifiCorp will pay for the lesser of delivered energy and actual net output for on peak and off peak hours summed across the Settlement Period. Utilities are required to purchase the net output, but not more than net output, of QFs. If actual energy deliveries exceed net output during the Settlement Period, the utility should only be required to pay for the QF's net output— the maximum amount of energy that PURPA requires the utilities to purchase. If, instead, net output exceeds energy deliveries during the Settlement Period, the utility should only be required to pay for energy deliveries because that is the amount of power that it receives from the transmitting utility. This provision is designed to protect PacifiCorp and its customers from paying avoided costs for energy it either does not receive or that is in excess of QF net output. In addition, it provides an incentive for a QF to accurately schedule its output across the settlement period.

While the excess energy may not be worth the on peak price, it is not without value. Therefore, while not required by PURPA, I recommend that PacifiCorp consider modifying its agreement by adding a provision that states that the company will pay QFs the off-peak price for energy delivered in excess of actual net output in the settlement period.

Q. ARE THE PRODUCTION BALANCING PROVISIONS IN PGE'S POWER PURCHASE AGREEMENT FOR OFF-SYSTEM QFS APPROPRIATE?

A. Yes, but the language in Schedule 201 should be clarified. While PGE's contract does not include specific balancing provisions, the contract does implicitly include them. In Appendix 2, Section 1.2, PGE defines the "Billing Period" as a calendar month. In addition, Section 4.5 of Appendix 2 requires that the "seller shall make commercially reasonable efforts to schedule in any hour an amount equal to its expected Net Output for such hour."

From these two provisions and an e-mail response by PGE witness Mr. Doug Kuns[5] I conclude that PGE will allow a QF to follow scheduling convention by

[5] See Staff Exhibit 2202.

scheduling in whole units even when its expected net output is not in whole units, and that PGE will pay for the scheduled and delivered energy generated by the QF. In the e-mail response, Mr. Kuns stated that it is PGE's "intent as stated in Section 4.5, that the QF will be able to use commercially reasonable efforts to schedule and deliver its Net Output to PGE" and "the scheduling requirements for whole MW increments is acceptable within our proposed agreement, even if the QF production may be higher or lower than the scheduled amount in an hour." *See* Staff/2202.

However, I conclude that there is a conflict in the language between the proposed standard contract for off-system QFs and Schedule 201. Section 1.6 of the Standard Contract defines Contract Price as "the applicable price for Delivered Net Output…" This definition applies to the pricing options in Sections 5.1, 5.2 and 5.3. In contrast, in Schedule 201, page 4, PGE states that "pricing options represent the purchase price per MWh the Company will pay for electricity delivered … up to the nameplate rating of the QF in any hour. Any energy delivered in excess of the nameplate rating shall be purchased at the applicable Off-Peak Prices for the selected pricing option." This implies that PGE will not pay avoided costs for scheduled delivery in an hour greater than nameplate rating.

For example, assume that a QF has a nameplate rating of 3.5 MW, generates 3.5 MW in each hour, and schedules 3 MW in half of the hours and 4 MW in the remaining hours in the billing period (ignoring on-peak and off-peak periods for purposes of this example). On average, over the billing period the QF would have scheduled and generated, and the TO would have delivered, 3.5 MW per hour. Therefore, the QF may reasonably expect to be paid avoided cost for all of its output. The language in Schedule 201 implies that PGE would pay the avoided cost for 3.5 MW per hour, but would only pay the off-peak price for the "extra" 0.5.MW that was delivered in hours when 4 MW was scheduled and delivered. This apparent conflict in language should be resolved, and the tariff should make clear that PGE will allow balancing within the billing period.

Q. IS IT REASONABLE FOR A UTILITY TO REQUIRE AN OFF-SYSTEM QF TO USE FIRM TRANSMISSION FOR DELIVERY OF POWER UNDER A STANDARD CONTRACT FOR OFF-SYSTEM QFS?

A. Yes. The utilities have proposed that their standard off-system QF contracts specify the use of firm transmission. If a QF wants to use non-firm transmission to deliver its output to the purchasing utility it may do so, but it would not receive capacity payments and would have to execute a non-standard contract.

ISSUE 3b, COST AND CONTRACTUAL PROVISIONS NECESSARY TO PURCHASE OFF-SYSTEM QF POWER

Q. ARE THE COST AND CONTRACTUAL PROVISIONS IN PGE'S AND PACIFICORP'S POWER PURCHASE AGREEMENTS FOR OFF-SYSTEM QFS APPROPRIATE?

A. Some of the provisions are not appropriate. PGE's implicit balancing provisions are not appropriate as written. However, PGE has clarified its intention in an e-mail to Staff.[6] I recommend that PGE modify the language in Schedule 201 to clarify its intent to allow for netting of differences between Net Output and delivered energy across the billing period.

Also, consistent with my recommendation under Issue 14 earlier, while not required by PURPA, I recommend PacifiCorp consider modifying its agreement by adding a provision that states the company will pay QFs the off-peak price for energy delivered in excess of actual net output in the settlement period.

Q. WILL STAFF BE SUBMITTING A BRIEF DISCUSSING THE COMMISSION'S JURISDICTION TO APPROVE THESE CONTRACTS?

A. No, staff understands that no party is challenging the Commission's jurisdiction to approve these contracts. As such, staff will not be filing a brief concerning the Commission's jurisdiction to review and approve these contracts.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

---

[6] See Staff Exhibit 2202.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/106

PAISLEY GEOTHERMAL POWER SALES CONCEPT PAPER

May 17, 2016

Paisley Geothermal Power Sales Concept Paper

Surprise Valley Electrification Corp. (SVEC) is a full requirements utility customer of the Bonneville Power Administration (BPA). The power supplied by BPA to serve SVEC's load requirements is transported to SVEC through the PacifiCorp (PAC) transmission system. SVEC has developed a geothermal resource on the Colahan Ranch near Paisley Oregon for the production of electrical power (Paisley Plant). The Paisley Plant nameplate rating is 3.6MW. The gross production based on the volume and temperature of the geothermal fluid delivered to the plant is 3.1 MW and the net output is 2.4MW.

BACKGROUND

The Paisley Plant is located near Paisley Oregon within the service territory of SVEC and within the PAC Balancing Area. The net output of the Paisley Plant will be metered at the plant with a BPA revenue meter. PAC will monitor generation through a SCADA system connection. SVEC will also have a meter at the plant. The electricity produced by the plant will be interconnected to the grid at the SVEC 69 Kv transmission line at the Paisley substation. This substation is located approximately one mile from the Paisley Plant.

SVE proposes to sell the net output to PAC under a PURPA contract. The point of delivery for this transaction is at the Lakeview Switch 940 (see attached one line drawing) where BPA has a revenue meter and SVEC interconnects with PAC. SVEC has a 44 mile 69 Kv transmission line from the point of interconnect to the point of delivery. SVEC's service territory is served from this transmission line.

PROPOSED CONTRACTUAL ARRANGEMENT

PAC transmission delivers and SVEC receives its BPA power at Lakeview Switch 940. PAC transmission also delivers all of the power needs for PAC retail customers in the area surrounding SVEC's service territory. BPA will continue to supply SVEC with its full load requirements. Consequently, there will be additional power in the PAC transmission system because the Paisley Plant is generating. This excess amount will be equal to the amount of power generated by the Paisley Plant less some predetermined amount allowing for transmission line losses. This power will be available for use by PAC retail customers. In other words, the amount of power generated by the Paisley Plant will effectively be serving PAC retail customer loads in this remote part of the PAC Balancing Area. The PAC resources serving the PAC Mile High substation will be correspondingly reduced by the net output (minus transmission line loss) at the Paisley Plant.

Under this conceptual understanding, PAC will pay SVEC for the amount of power generated at the Paisley Plant, less some predetermined amount for transmission line losses, at the rates set forth in the PURPA contract entered into between SVEC and PAC.

Member Service Manager
Surprise Valley Electric
530.233.3511 office
530.640.2666 cell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/107

[INTENTIONALLY DELETED]

May 25, 2016

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP., Complainant v. PACIFICORP, d/b/a PACIFIC POWER, Respondent.

EXHIBIT PAC/108

E-MAIL FROM B. GRISWOLD TO L. CULP, DATED AUGUST 26, 2014

May 17, 2016

From: Griswold, Bruce {Mkt Function}
To: Lynn Culp
Cc: Reid, Michael; Kirk Gibson; Brad Kresge; Erb, Jeff; Till, Dustin; Link, Rick {Mkt Function}; Younie, John
Subject: RE: SVE PPA Concern
Date: Tuesday, August 26, 2014 9:09:05 PM

Lynn
Going forward, please address your concerns on the PPA to me directly. John is addressing other QF PPA issues at the time. While I understand your issue,I want to be clear on the status of your requested Schedule 37 PPA. From the beginning of your request, PacifiCorp has attempted to address your ability to be qualified as a Schedule 37 PPA. We have held multiple meetings with your team, with BPA, with our transmission business and our metering department to find a solution for you actually physically delivering power to PacifiCorp's system. We have looked at your project being off-sytem and scheduling delivery, we have initiated a transmission service request with our transmission business to do a system impact study to assess options for metering and measuring your actual delivery under the assumption that the company can basically accept a physical swap of power at an alternative location. Nothing in PURPA obligates us to do a swap however we have expended a large effort to find a physical means to show that your project's generated power reaches our system. It does not. PacifiCorp is accommodating your generation through a swap with power that is coming from BPA to serve your load that we are delivering on BPA's behalf. PacifiCorp merchant has made it clear from our beginning discussions that we were not going to do any PPA that could not be physically metered and measured as having been delivered to PacifiCorp's system. That is the purpose of the system impact study and the involvement of our metering. As of today, we do not have a final confirmation on the metering, the cost of the metering, agreement in place on who pays for metering and whether that metering schemes without a doubt clearly shows that your project is delivering power to our system.

Regarding the status of the PPA. We have a redline from you. It is still in draft form and we have not agreed to final commercial terms and conditions to address metering and power true-up or the final form of the PPA with SVEC. There are outstanding items on metering, true ups between actual generation and deliveries to our system. We are reviewing the Oregon commission order from August 19 2014 with our attorneys and will respond on the status of your agreement relative to the August 19 2014 order in the near future. In the interim, we will continue moving forward to ensure that our customers are receiving your physical power.

If you have questions, call me at 503-813-5218.

Bruce Griswold
PacifiCorp C&T
503.813.5218 Office
503.702.1445 Cell

From: Lynn Culp [lynnsvec@frontier.com]
Sent: Tuesday, August 26, 2014 8:05 PM
To: Younie, John
Cc: Griswold, Bruce {Mkt Function}; Reid, Michael; Kirk Gibson; Brad Kresge
Subject: SVE PPA Concern

Hello John,
We understand that PacifiCorp reached an agreement on their Schedule 37 and has initiated the new rates effective 8/20. In our discussions with PacifiCorp throughout the Spring and Summer months this year, PacifiCorp represented that there was no concern whether the power supplied by the Paisley Project would be under the rate schedule then in effect (in place before this recent rate change). As you know we have been working on the PPA with PacifiCorp for many, many months now and numerous times SVEC has been made to wait for PacifiCorp to respond. The most recent revised agreement (sent to you on July 22) was sent with the collective understanding that it needed to be completed quickly because of the proposed rate change. I am sure you will recall the concerns raised by GM Brad Kresge's regarding the SVEC Board's questions surrounding the importance of receiving the rates that were in place when SVEC committed to the arrangement with PacifiCorp. The lack of response to our July 22 submittal of the agreement following the earlier discussions is disconcerting in light of the news of the approved rate change.

It is important that SVEC understand whether we still on track to execute the PPA with the Schedule 37 rates that were in place during all of our discussions. Please clarify PacifiCorp's position regarding the rates that will apply to the PPA with SVEC for the power generated by the Paisley Project as soon as practicable.

Thank you,
Lynn

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/109

SURPRISE VALLEY'S MAY 20, 2014
DRAFT POWER PURCHASE AGREEMENT

May 17, 2016

POWER PURCHASE AGREEMENT

BETWEEN

SURPRISE VALLEY ELECTRIFICATION CORPORATION

[Firm Qualifying Facility with 10,000 kW Facility Capacity Rating, or Less, and uninterruptible transmission to the Point of Delivery]

AND

PACIFICORP

Deleted: 6
Deleted: 9
Deleted: 12
Deleted: 12
Deleted: 13
Deleted: 13
Deleted: 16
Deleted: 20
Deleted: 21
Deleted: 22
Deleted: 22
Deleted: 22
Deleted: 22
Deleted: 22
Deleted: 23
Deleted: 23
Deleted: 23
Deleted: 23

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT, entered into this ____day of ______________, 20____, is between Surprise Valley Electrification Corp., "**Seller**" and PacifiCorp (d/b/a Pacific Power & Light Company), an Oregon corporation acting in its regulated utility capacity, "**PacifiCorp**." (Seller and PacifiCorp are referred to individually as a "**Party**" or collectively as the "**Parties**").

Deleted: Corporation

RECITALS

A. Seller intends to construct, own, operate and maintain a geothermal facility for the generation of electric power, including interconnection facilities, located in Paisley, Lake County, Oregon with a Facility Capacity Rating of 3,650 -kilowatts (kW**)** as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

B. Seller intends to commence delivery of Net Output under this Power Purchase Agreement, for the purpose of Start-up Testing, on May 31, 2014 ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on July 31, 2014 ("**Scheduled Commercial Operation Date**"); and

D. Seller estimates that the average annual Net Energy to be delivered by the Facility to PacifiCorp is 18,285,671 kilowatt-hours (kWh), which amount of energy PacifiCorp will include in its resource planning; and

Deleted: 18,880,048

E. Seller shall (choose one) X☐ sell all Net Output to PacifiCorp and purchase its full electric requirements from Bonneville Power Administration ☐ sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from Bonneville Power Administration, in accordance with the terms and conditions of this Agreement; and

F. This Agreement is a "New QF Contract" under the PacifiCorp Inter-Jurisdictional Cost Allocation Revised Protocol.

G. Seller intends to sell Net Output to PacifiCorp, and PacifiCorp intends to accept scheduled firm delivery of Seller's Net Output, under the terms of this Agreement, including the Generation Scheduling Addendum attached as **Addendum W** and Sellers Interconnection Facilities attached as Exhibit B which are incorporated contemporaneously herewith.

Deleted: transmit

Formatted: Highlight

Deleted: via transmission facilities operated by Seller

Formatted: Highlight

Formatted: Highlight

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 **"As-built Supplement"** shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 "**Average Annual Generation"** shall have the meaning set forth in Section 4.2.

1.3 **"Billing Period"** means calendar months.

1.4 **"Commercial Operation Date"** means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.4.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

1.4.2 The Facility has completed Start-Up Testing;

1.4.3 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating that, (a), in accordance with the Interconnection Agreement, if applicable, all required interconnection facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with PacifiCorp's electric system, or (b) if the Facility is interconnected with another electric utility that will wheel Net Output to PacifiCorp, all required interconnection facilities have been completed and tested and are in place to allow for such wheeling;

1.4.4 PacifiCorp has received a certificate addressed to PacifiCorp from an attorney in good standing in the State of Oregon stating that Seller has obtained all Required Facility Documents (Facilities over 200 kW only) and, if requested by PacifiCorp, in writing, has provided copies of any or all such requested Required Facility Documents.

1.4.5 Seller has complied with the security requirements of Section 10.

1.4.6 PacifiCorp has received an executed copy of **Exhibit F** - Seller's Interconnection Request.

1.5 **“Commission”** means the Oregon Public Utilities Commission.

1.6 **“Contract Price”** means the applicable price for capacity or energy, or both capacity and energy, stated in Sections 5.1 and 5.2.

1.7 **"Contract Year”** means a twelve (12) month period commencing at 00:00 hours Pacific Prevailing Time (“**PPT**”) on January 1 and ending on 24:00 hours PPT on December 31; *provided, however,* that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

1.8 “**Credit Requirements**” means a long-term credit rating (corporate or long-term senior unsecured debt) of (1) “Baa3” or greater by Moody’s, or (2) “BBB-” or greater by S&P, or such other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment.

1.9 “**Default Security**”, unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at Mid-C (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery; provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller’s average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

1.10 “**Effective Date**” shall have the meaning set forth in Section 2.1.

1.11 “**Energy Delivery Schedule**” shall have the meaning set forth in Section 4.5.

1.12 “**Environmental Attributes**” shall have the meaning set forth in Section 5.5.

1.13 “**Excess Output**” shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Capacity Rating.

1.14 “**Facility**” shall have the meaning set forth in Recital A.

1.15 “**Facility Capacity Rating**” means the sum of the Nameplate Capacity Ratings for all generators comprising the Facility.

1.16 “**FERC**” means the Federal Energy Regulatory Commission, or its successor.

1.17 “**Generation Scheduling Addendum**” means **Addendum W**, the portion of this Agreement providing for the measurement, scheduling, and delivery of Seller’s Net Output from the Facility to the Point of Delivery via a non-PacifiCorp transmission providers.

Formatted: Font:12 pt, Highlight

1.18 **Interconnected Utility**" means Surprise Valley Electrification Corp. and/or Bonneville Power Administration, the operators of the electric utility system at a Points of Interconnection.

1.19 "**Interconnection Agreement**" means the agreement (or contemporaneous agreements) between the Interconnected Utility and PacifiCorp governing interconnection of Interconnected Utility at a Point of Delivery and associated use of the Interconnected Utility's system.

1.20 "**Letter of Credit**" means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of "A" or greater from S&P or "A2" or greater from Moody's, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

1.21 "**Licensed Professional Engineer**" means a person acceptable to PacifiCorp in its reasonable judgment who is licensed to practice engineering in the state of Oregon, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made.

1.22 "**Material Adverse Change**" means the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller's ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement

1.23 "**Maximum Annual Delivery**" shall have the meaning set forth in Section 4.3.

1.24 "**Minimum Annual Delivery**" shall have the meaning set forth in Section 4.3.

1.25 "**Nameplate Capacity Rating**" means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units. Usually indicated on a nameplate attached to the individual machine or device.

1.26 "**Net Energy**" means the energy component, in kWh, of Net Output.

1.27 "**Net Output**" means an amount equal to all energy and capacity produced by the Facility, less station use and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any, up to and including the Point of Delivery. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the Points of Interconnection, adjusted as set forth in this paragraph.

Deleted: "

Formatted: Indent: Left: 0.63", No bullets or numbering

Deleted: oration

Formatted: Highlight

Formatted: Highlight

Deleted: the

Formatted: Highlight

Deleted: the

Formatted: Highlight

Formatted: Highlight

Deleted: excluding pumping load attributable to the extraction and transportation functions the pumps perform

Formatted: Highlight

1.28 "**Net Replacement Power Costs**" shall have the meaning set forth in Section 11.4.1.

1.29 "**Off-Peak Hours**" means all hours of the week that are not On-Peak Hours.

1.30 "**On-Peak Hours**" means the hours between 6 a.m. Pacific Prevailing Time ("**PPT**") and 10 p.m. PPT, Mondays through Saturdays, excluding all hours occurring on holidays as provided in Schedule 37.

1.31 "**Point of Delivery**" means the Point or Points of Interconnection between a Transmitting Entity's system and PacifiCorp's distribution/transmission systemas specified in **Exhibit B.**

1.32 "**Point of Interconnection**" means the point(s) of interconnection between a Transmitting Entity's system and PacifiCorp's distribution/transmission system, as specified in **Exhibit B**.

1.33 "**Prime Rate**" means the publicly announced prime rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, New York, selected by the Party to whom interest based on the Prime Rate is being paid.

1.34 "**Prudent Electrical Practices**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

1.35 "**QF**" means "**Qualifying Facility,**" as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.36 "**Replacement Price**" means the price at which PacifiCorp, acting in a commercially reasonable manner, purchases for delivery at the Point of Delivery a replacement for any Net Output that Seller is required to deliver under this Agreement plus (i) costs reasonably incurred by PacifiCorp in purchasing such replacement Net Output, and (ii) additional transmission charges, if any, reasonably incurred by PacifiCorp in causing replacement energy to be delivered to the Point of Delivery. If PacifiCorp elects not to make such a purchase, the Replacement Price shall be the market price at the Mid-Columbia trading hub for such energy not delivered, plus any additional cost or expense incurred as a result of Seller's failure to deliver, as determined by PacifiCorp in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

1.37 "**Required Facility Documents**" means all licenses, permits, authorizations, and agreements, including an Interconnection Agreement or equivalent, and any Transmission

Deleted: p
Deleted: i
Deleted: the
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Deleted: , the point at which another utility will deliver the Net Output to PacifiCorp,
Formatted: Highlight
Deleted: Seller's Facility and the
Formatted: Highlight
Formatted: Highlight

Agreement(s), necessary for construction, operation and maintenance of the Facility consistent with the terms of this Agreement. The Required Facility Documents are set forth in **Exhibit C.**

1.38 “**Schedule 37**” means the Schedule 37 of Pacific Power & Light Company’s Commission-approved tariffs, providing pricing options for Qualifying Facilities of 10,000 kW or less, which is in effect on the Effective Date of this Agreement. A copy of that Schedule 37 is attached as **Exhibit G**.

1.39 “**Scheduled Commercial Operation Date**” shall have the meaning set forth in Recital C.

1.40 “**Scheduled Initial Delivery Date**” shall have the meaning set forth in Recital B.

1.41 “**Start-Up Testing**” means the completion of required factory and start-up tests as set forth in **Exhibit E** hereto.

1.42 “**Termination Date**” shall have the meaning set forth in Section 2.4.

1.43 “**Transmission Agreement**” means the agreement (or contemporaneous agreements) between Seller and the Transmitting Entity providing for Seller’s uninterruptible right to transmit Net Output to the Point of Delivery.

1.44 “**Transmitting Entity(s)**” means Surprise Valley Electrification Corp. and Bonneville Power Administration, the (non-PacifiCorp) operators of the transmission systems at the Points of Delivery.

Deleted: oration
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight
Formatted: Highlight

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement shall become effective after execution by both Parties (“**Effective Date**”).

2.2 **Time is of the essence for this Agreement,** and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to deliver Net Output by the Scheduled Commercial Operation Date is critically important. Therefore,

2.2.1 By NEED Transmission Agreement ASAP__________________, Seller shall provide PacifiCorp with a copy of an executed Interconnection Agreement and an executed Transmission Agreement, if applicable, which shall be consistent with all material terms and requirements of this Agreement.

Deleted: __
Formatted: Not Highlight
Formatted: Not Highlight

2.2.2 Upon completion of construction, Seller, in accordance with Section 6.1, shall provide PacifiCorp with an As-built Supplement acceptable to PacifiCorp;

2.2.3 By the date thirty (30) days after the Effective Date, Seller shall provide Default Security required under Sections 10.1 or 10.2, as applicable.

2.3 Seller shall cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date. If Commercial Operation occurs after the Scheduled Commercial Operation Date, Seller shall be in default, and liable for delay damages specified in Section 11.

2.4 Except as otherwise provided herein, this Agreement shall terminate on May 30, 2020 ("**Termination Date**").

Deleted: enter Date that is no later than 20 years after the Scheduled Initial Delivery Date]

SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1 PacifiCorp represents, covenants, and warrants to Seller that:

3.1.1 PacifiCorp is duly organized and validly existing under the laws of the State of Oregon.

3.1.2 PacifiCorp has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.

3.1.3 PacifiCorp has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.1.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on PacifiCorp or any valid order of any court, or any regulatory agency or other body having authority to which PacifiCorp is subject.

3.1.5 This Agreement is a valid and legally binding obligation of PacifiCorp, enforceable against PacifiCorp in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2 Seller represents, covenants, and warrants to PacifiCorp that:

3.2.1 Seller is a corporation duly organized and validly existing under the laws of _______California______.

3.2.2 Seller has the requisite power and authority to enter into this Agreement and to perform according to the terms hereof, including all required regulatory authority to make wholesale sales from the Facility.

3.2.3 Seller has taken all actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.2.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.2.5 This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2.6 The Facility is and shall for the term of this Agreement continue to be a QF, and Seller will operate the Facility in a manner consistent with its FERC QF certification. Seller has provided to PacifiCorp the appropriate QF certification (which may include a FERC self-certification) prior to PacifiCorp's execution of this Agreement. At any time during the term of this Agreement, PacifiCorp may require Seller to provide PacifiCorp with evidence satisfactory to PacifiCorp in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements and, if PacifiCorp is not satisfied that the Facility qualifies for such status, a written legal opinion from an attorney who is (a) in good standing in the state of Oregon, and (b) who has no economic relationship, association or nexus with the Seller or the Facility, stating that the Facility is a QF and providing sufficient proof (including copies of all documents and data as PacifiCorp may request) demonstrating that Seller has maintained and will continue to maintain the Facility as a QF.

3.2.7 Compliance with Partial Stipulation in Commission Proceeding No. UM-1129. Seller will not make any changes in its ownership, control, or management during the term of this Agreement that would cause it to not be in compliance with the definition of a Small Cogeneration Facility or Small Power Production Facility provided in PacifiCorp's Schedule 37 tariff approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by PacifiCorp not more frequently than every 36 months, such documentation and information as reasonably may be required to establish Seller's continued compliance with such Definition. PacifiCorp agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PacifiCorp will provide all such confidential information the Public Utility Commission of Oregon upon the Commission's request.

3.2.8 Additional Seller Creditworthiness Warranties. Seller need not post security under Section 10 for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following:

(a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.

(b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.

(c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.

(d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

(e) **[Applicable only to Sellers with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

____X___ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

______ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase all Net Output from the Facility delivered to the Point of Delivery.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, 18,285,671 kWh per Contract Year ("**Average Annual Generation**"). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

Deleted: 18,880,048

4.3 Minimum and Maximum Delivery. Seller shall deliver (or cause to be delivered) from the Facility a minimum of 12,197,102 kWh of Net Output during each Contract Year, provided that such minimum for the first Contract Year shall be reduced *pro rata* to reflect the Commercial Operation Date, and further provided that such minimum delivered Net Output shall be reduced on a *pro rata* basis for any periods during a Contract Year that the Facility was prevented from generating or delivering electricity for reasons of Force Majeure ("**Minimum Annual Delivery**"). Seller estimates, for informational purposes, that it will deliver from the Facility a maximum of 19,391,369 kWh of Net Output during each Contract Year ("**Maximum Annual Delivery**"). Seller's basis for determining the Minimum and Maximum Annual Delivery amounts is set forth in **Exhibit D.**

Deleted: 12,594,025

Deleted: 20,021,187

4.4 Deliveries in Deficit of Delivery Obligation. Seller's failure to deliver the Minimum Annual Delivery in any Contract Year (prorated if necessary) shall be a default, and Seller shall be liable for damages in accordance with Section 11.

4.5 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility ("**Energy Delivery Schedule**"), incorporated into **Exhibit D**.

SECTION 5: PURCHASE PRICES

5.1 Seller shall have the option to select one of four pricing options: Fixed Avoided Cost Prices ("Fixed Price"), Firm Market Indexed Avoided Cost Prices ("Firm Electric Market"), Gas Market Indexed Avoided Cost Prices ("Gas Market"), or Banded Gas Market Indexed Avoided Cost Prices ("Banded Gas Market"), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility's contract. Seller has selected the following (Seller to initial one):

___X___	Fixed Price
_______	Firm Electric Market
_______	Gas Market
_______	Banded Gas Market

A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G.**

5.2 (Applies only to "Fixed Price" Contracts Greater than 15 Years). In the event Seller elects the Fixed Price payment method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller market-based rates, using the following pricing option (Seller to initial one):

_______	Firm Electric Market
_______	Gas Market
_______	Banded Gas Market

5.3 If the Seller elects a gas market indexed price option, the index shall be the Opal Gas Market Index as provided in Schedule 37. In the event that Platt ceases to publish the Opal Gas Market Index, the Company shall replace the index with a similar gas index.

5.4 For all Excess Output and for all Net Output delivered prior to the Commercial Operation Date, PacifiCorp shall pay Seller a blended market index price for day-ahead non-firm energy at Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by Dow Jones, for the On-Peak and Off-Peak periods. PacifiCorp shall document its calculation of the blended rate, upon request, to Seller. Such payment will be accomplished by adjustments pursuant to Section 9.2.

5.5 Environmental Attributes. PacifiCorp waives any claim to Seller's ownership of Environmental Attributes under this Agreement. Environmental Attributes include, but are not limited to, Green Tags, Green Certificates, Renewable Energy Credits (RECs) and Tradable Renewable Certificates (TRCs) (as those terms are commonly used in the regional electric utility industry) directly associated with the production of energy from the Seller's Facility.

SECTION 6: OPERATION AND CONTROL

6.1 As-Built Supplement. Upon completion of initial (and any subsequent) construction of the Facility, Seller shall provide PacifiCorp an As-built Supplement to specify the actual Facility as built. The As-built Supplement must be reviewed and approved by PacifiCorp, which approval shall not unreasonably be withheld, conditioned or delayed.

6.2 Incremental Utility Upgrades. At start-up (and at any other time upon at least six months prior written notice), Seller may increase Net Output, if such increase is due to normal variances in estimated versus actual performance, changed Facility operations, or improvements in Facility efficiency. Seller may not increase Net Output under this Agreement by installing additional generating units. In the case of substantial upgrades, PacifiCorp may require Seller to comply with Section 3.2.8(e) (in the event that the Facility upgrade causes the Facility Capacity Rating to exceed 3,000 kW) and increase its Minimum Annual Delivery obligation in Section 4.3 (if appropriate). PacifiCorp may also update Seller's security obligation (if applicable). So long as the Facility Capacity Rating after the upgrade is 10,000 kW or less, Seller will continue to receive the Contract Price for the Net Output, as set forth in Sections 5.1 and 5.2 of this Agreement. If Seller increases the Facility Capacity Rating above 10,000 kW, then (on a going forward basis) PacifiCorp shall pay Seller the Contract Price for the fraction of total Net Output equal to 10,000 kW divided by the Facility Capacity Rating of the upgraded Facility. For the remaining fraction of Net Output, PacifiCorp and Seller shall agree to a new negotiated rate. Seller shall be responsible for ensuring that any planned increase in the Facility Capacity Rating or the maximum instantaneous capacity of the Facility complies with Seller's Interconnection Agreement, Transmission Agreement and any other relevant agreements.

Deleted: '

6.3 Seller shall operate and maintain the Facility in a safe manner in accordance with this Agreement, the Interconnection Agreement, Prudent Electrical Practices and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code as such laws and code may be amended from time to time. PacifiCorp shall have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and the Point of Delivery is disconnected, suspended or interrupted, in whole or in part, pursuant to the Interconnection Agreement or Transmission Agreement(s), or to the extent generation curtailment is required as a result of Seller's non-compliance with the Interconnection Agreement or Transmission Agreement(s). PacifiCorp shall have the right to inspect the Facility to confirm that Seller is operating the Facility in accordance with the provisions of this Section 6.3 upon reasonable notice to Seller. Seller is solely responsible for the operation and maintenance of the Facility. PacifiCorp shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.4 Scheduled Outages. Seller may cease operation of the entire Facility or individual units, if applicable, for maintenance or other purposes. Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp's request, if any, to reschedule such planned outage in order to accommodate PacifiCorp's need for Facility operation.

6.5 Unplanned Outages. In the event of an unscheduled outage or curtailment exceeding twenty-five (25) percent of the Facility Capacity Rating (other than curtailments due to lack of motive force), Seller immediately shall notify PacifiCorp of the necessity of such unscheduled outage or curtailment, the time when such has occurred or will occur and the anticipated duration. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled outage or curtailment, to limit the duration of such, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: FUEL/MOTIVE FORCE

Prior to the Effective Date of this Agreement, Seller provided to PacifiCorp a fuel or motive force plan acceptable to PacifiCorp in its reasonable discretion and attached hereto as **Exhibit D-1,** together with a certification from a Licensed Professional Engineer to PacifiCorp attached hereto as **Exhibit D-2**, certifying that the implementation of the fuel or motive force plan can reasonably be expected to provide fuel or motive force to the Facility for the duration of this Agreement adequate to generate power and energy in quantities necessary to deliver the Minimum Annual Delivery set forth by Seller in Section 4.

SECTION 8: METERING AT THE POINT OF INTERCONNECTION

8.1 Metering shall be performed at the locations and in a manner consistent with this Agreement, as specified in **Exhibit B**. Seller shall provide to PacifiCorp metered Facility Net Output in hourly increments, and any other energy measurements required to administer this Agreement. If the Transmitting Entity requires Seller to telemeter data, PacifiCorp shall be entitled to receive the same data Seller provides to the Transmitting Entity, if such data is useful to PacifiCorp's administration of this Agreement. All quantities of energy purchased hereunder shall be adjusted to account for electrical losses, if any, between the point of Interconnection and the Point of Delivery. The loss adjustment shall be 1.9___% of the kWh energy production recorded on the Facility output meter.

Formatted: Highlight

8.2 Seller shall pay for the installation, testing, and maintenance of any metering required by Section 8.1, and shall provide reasonable access to such meters. PacifiCorp shall have reasonable access to inspection, testing, repair and replacement of the metering equipment. If any of the inspections or tests discloses a measurement error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) Billing Periods, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered following the repair of the meter.

<u>SECTION 9: BILLINGS, COMPUTATIONS, AND PAYMENTS</u>

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PacifiCorp shall send to Seller payment for Seller's deliveries of Net Output to PacifiCorp, together with computations supporting such payment. PacifiCorp may offset any such payment to reflect amounts owing from Seller to PacifiCorp pursuant to this Agreement, the Interconnection Agreement, or any other agreement between the Parties.

9.2 <u>Corrections</u>. PacifiCorp shall have up to eighteen months to adjust any payment made pursuant to Section 9.1. In the event PacifiCorp determines it has overpaid Seller (for Excess Output or otherwise), PacifiCorp may adjust Seller's future payment accordingly in order to recapture any overpayment in a reasonable time.

9.3 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; *provided*, *however*, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

<u>SECTION 10: SECURITY</u>

Unless Seller has adopted the creditworthiness warranties contained in Section 3.2.8, Seller must provide security (if requested by PacifiCorp) in the form of a cash escrow, letter of credit, senior lien, or step-in rights. Seller hereby elects to provide, in accordance with the applicable terms of this Section 10, the following security (Seller to initial one selection only):

____ Cash Escrow - $236,404

_____ Letter of Credit - $236,404

_____ Senior Lien

_____ Step-in Rights

___X__ Seller has adopted the Creditworthiness Warranties of Section 3.2.8.

In the event Seller's obligation to post default security (under Section 10 or Section 11.1.4) arises solely from Seller's delinquent performance of construction-related financial obligations, upon Seller's request, PacifiCorp will excuse Seller from such obligation in the event Seller has negotiated financial arrangements with its construction lenders that mitigate Seller's financial risks to PacifiCorp's reasonable satisfaction.

[SKIP THIS SECTION 10.1 UNLESS SELLER SELECTED CASH ESCROW ALTERNATIVE]

10.1 <u>Cash Escrow Security</u>. Seller shall deposit in an escrow account established by PacifiCorp in a banking institution acceptable to both Parties, the Default Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institution from time to time. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.2 UNLESS SELLER SELECTED LETTER OF CREDIT ALTERNATIVE]

10.2 Letter of Credit Security. Seller shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to PacifiCorp in its discretion, or (b) a Letter of Credit in favor of PacifiCorp. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.3 UNLESS SELLER SELECTED SENIOR LIEN ALTERNATIVE]

10.3 Senior Lien. Before the Scheduled Commercial Operation Date, Seller shall grant PacifiCorp a senior, unsubordinated lien on the Facility and its assets as security for performance of this Agreement by executing, acknowledging and delivering a security agreement and a deed of trust or a mortgage, in a recordable form (each in a form satisfactory to PacifiCorp in the reasonable exercise of its discretion). Pending delivery of the senior lien to PacifiCorp, Seller shall not cause or permit the Facility or its assets to be burdened by liens or other encumbrances that would be superior to PacifiCorp's, other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

[SKIP THIS SECTION 10.4 UNLESS SELLER SELECTED STEP-IN RIGHTS ALTERNATIVE]

10.4 Step-in Rights (Operation by PacifiCorp Following Event of Default of Seller).

10.4.1 Prior to any termination of this Agreement due to an Event of Default of Seller, as identified in Section 11, PacifiCorp shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this Agreement) during the period provided for herein. Seller shall not grant any person, other than the lending institution providing financing to the Seller for construction of the Facility ("Facility Lender"), a right to possess, assume control of, and operate the Facility that is equal to or superior to PacifiCorp's right under this Section 10.4.

10.4.2 PacifiCorp shall give Seller ten (10) calendar days' notice in advance of the contemplated exercise of PacifiCorp's rights under this Section 10.4. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the

Facility in accordance with Prudent Electrical Practices. Upon such notice, PacifiCorp, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Facility for the purpose of constructing and/or operating the Facility. Seller hereby irrevocably appoints PacifiCorp as Seller's attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions as PacifiCorp may reasonably deem necessary or appropriate to exercise PacifiCorp's step-in rights under this Section 10.4.

10.4.3 During any period that PacifiCorp is in possession of and constructing and/or operating the Facility, no proceeds or other monies attributed to operation of the Facility shall be remitted to or otherwise provided to the account of Seller until all Events of Default of Seller have been cured.

10.4.4 During any period that PacifiCorp is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and PacifiCorp shall assume possession, operation, and control solely as agent for Seller.

(a) In the event PacifiCorp is in possession and control of the Facility for an interim period, Seller shall resume operation and PacifiCorp shall relinquish its right to operate when Seller demonstrates to PacifiCorp's reasonable satisfaction that it will remove those grounds that originally gave rise to PacifiCorp's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this Agreement, and (ii) has cured any Events of Default of Seller which allowed PacifiCorp to exercise its rights under this Section 10.4.

(b) In the event that PacifiCorp is in possession and control of the Facility for an interim period, the Facility Lender, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and PacifiCorp shall relinquish its right to operate when the Facility Lender or any nominee or transferee thereof, requests such relinquishment.

10.4.5 PacifiCorp's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by PacifiCorp of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility PacifiCorp elects to return such possession and operation to Seller, PacifiCorp shall provide Seller with at least fifteen (15) calendar days advance notice of the date PacifiCorp intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

SECTION 11: DEFAULTS AND REMEDIES

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.

11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Interconnection Agreement and any Transmission Agreement) within the time allowed for a cure under such agreement or instrument.

11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;

11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.

11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for two (2) consecutive years; else Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for one year.

11.2 Notice; Opportunity to Cure.

11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.

11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.

11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the sum of the Replacement Price for the Minimum Annual Delivery that Seller was otherwise obligated to provide for a period of twenty-four (24) months from the date of termination plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, and the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any energy and capacity that Seller was otherwise obligated (under Section 4.3) to provide during the period of default ("**Net Replacement Power Costs**"); *provided, however,* that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

(a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.

(b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

SECTION 12: INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller's side of the Point of Delivery, (c) Seller's operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement 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. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. EXCEPT TO THE EXTENT SUCH DAMAGES ARE INCLUDED IN THE LIQUIDATED DAMAGES, DELAY DAMAGES, COST TO COVER DAMAGES OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE.

SECTION 13: INSURANCE
(FACILITIES OVER 200KW ONLY)

13.1 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) (of "ACORD Form" or the equivalent) certifying Seller's compliance with the insurance requirements hereunder. Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate. If requested by PacifiCorp, a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company, shall be furnished to PacifiCorp.

13.2 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "B+" by the A.M. Best Company the insurance coverage specified below:

13.2.1 Commercial General Liability insurance, to include contractual liability, with a minimum single limit of $1,000,000 to protect against and from all loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

13.2.2 All Risk Property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The Risk policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

13.3 The Commercial General Liability policy required herein shall include i) provisions or endorsements naming PacifiCorp, its Board of Directors, Officers and employees as additional insureds, and ii) cross liability coverage so that the insurance applies separately to each insured against whom claim is made or suit is brought, even in instances where one insured claims against or sues another insured.

13.4 All liability policies required by this Agreement shall include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and provisions that such policies shall not be canceled or their limits of liability reduced without 1) ten (10) days prior written notice to PacifiCorp if canceled for nonpayment of premium, or 2) thirty (30) days prior written notice to PacifiCorp if canceled for any other reason.

13.5 Insurance coverage provided on a "claims-made" basis shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

SECTION 14: FORCE MAJEURE

14.1 As used in this Agreement, "**Force Majeure**" or "**an event of Force Majeure**" means any cause beyond the reasonable control of the Seller or of PacifiCorp which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of fuel or motive force resources to operate the Facility or changes in market conditions that affect the price of energy or transmission. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the event of Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

14.1.1 the non-performing Party, shall, within two (2) weeks after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

14.1.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure; and

14.1.3 the non-performing Party uses its best efforts to remedy its inability to perform.

14.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the event of Force Majeure.

14.3 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.4 PacifiCorp may terminate the Agreement if Seller fails to remedy Seller's inability to perform, due to an event of Force Majeure, within six months after the occurrence of the event.

SECTION 15: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 16: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the State of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 17: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

SECTION 18: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 19: GOVERNMENTAL JURISDICTIONS AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PacifiCorp.

SECTION 20: REPEAL OF PURPA

This Agreement shall not terminate upon the repeal of the PURPA, unless such termination is mandated by federal or state law.

SECTION 21: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent to a lender as part of a financing transaction or as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 22: ENTIRE AGREEMENT

22.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PacifiCorp's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

22.2 By executing this Agreement, Seller releases PacifiCorp from any claims, known or unknown, that may have arisen prior to the Effective Date.

SECTION 23: NOTICES

23.1 All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested.

Notices	**PacifiCorp**	**Seller**
All Notices	PacifiCorp 825 NE Multnomah Street Portland, OR 97232 Attn: Contract Administration, Suite 600 Phone: (503) 813 - 5380 Facsimile: (503) 813 - 6291 Duns: 00-790-9013	Surprise Valley Electrification Corp 516 US Hwy 395 E Alturas, CA 96101 Phone: (530) 233-3511 Facsimile: (530) 233-2190

Notices	PacifiCorp	Seller
	Federal Tax ID Number: 93-0246090	Duns: ___004770020______ Federal Tax ID Number: _94-0912124_______
All Invoices:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Scheduling:	(same as street address above) Attn: Resource Planning, Suite 600 Phone: (503) 813 - 6090 Facsimile: (503) 813 – 6265	
Payments:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Wire Transfer:	Bank One N.A. ABA: ACCT: NAME: PacifiCorp Wholesale	
Credit and Collections:	(same as street address above) Attn: Credit Manager, Suite 1900 Phone: (503) 813 - 5684 Facsimile: (503) 813 – 5609	
With Additional Notices of an Event of Default or Potential Event of Default to:	(same as street address above) Attn: PacifiCorp General Counsel Phone: (503) 813-5029 Facsimile: (503) 813-7252	

Deleted: _

23.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 23.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the date first above written.

PacifiCorp

By:_____________________________

Name: Bruce Griswold
____

Seller

By:____________________________

Name:_Craig Joiner

Title: Director, Short Term Origination and QF Contracts

Title: President of the Board of Directors

EXHIBIT A
DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

Seller's Facility consists of One (1) generator manufactured by Hyundai Ideal Electric Co. More specifically, each generator at the Facility is described as: Generator

A. Manufacturer's Nameplate Data:
Type (synchronous or inductive): Synchronous

Model: Synchronous Generator S/N 1210094 1800 RPM
Number of Phases: 3
Rated Output (kW): 3,650 **Rated Output (kVA):** 4,055
Rated Voltage (line to line):
Rated Current (A): Stator: 563 A; Rotor: 98 A
Power factor requirements:
Rated Power Factor (PF) or reactive load (kVAR): 0.90 P.F.

B. Seller's Estimate of Facility Output Under Ideal (Maximum) or Worst (Minimum) Conditions
Maximum kW Output: _2349___________ kW **Maximum kVA Output:** +/- .9 PF 2610 kVA
Minimum kW Output: ___1644______ kW
Manufacturer's Guaranteed Cut-in Wind Speed [if applicable]:

Facility Capacity Rating: ____2349_______ kW at ________ +/- .9 PF

Identify the maximum output of the generator(s) and describe any differences between that output and the Nameplate Capacity Rating: limited by geothermal resource.

Station service requirements, and other loads served by the Facility, if any, are described as follows: Parasitic load list attached

Deleted: EXHIBIT A ... [1]

EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

[Seller to provide its own diagram and description]

POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES

Instructions to Seller:

Describe the point(s) of metering, including the type of meter(s), and the owner of the meter(s).

Deleted: 1.

The Paisley Plant is located near Paisley Oregon within the service territory of SVEC and within the PacifiCorp Balancing Area. The net output of the Paisley Plant will be metered at the plant with a PacifiCorp revenue meter. SVEC also has a meter at the plant. The electricity produced by the plant will be interconnected to the grid at the SVEC 69 Kv transmission line at the Paisley substation. This substation is located approximately one mile from the Paisley Plant.

The Points of Delivery for this transaction are at the Lakeview Switch 940 where BPA has a revenue meter and SVEC interconnects with PacifiCorp Transmission) and at the point near structure 47/5 in the BPA's La Pine- Chiloquin 230 kV transmission line, where 230 kV facilities of BPA and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012). SVEC has a 44 mile 69 kV transmission line from the point of interconnect to the Lakeview 940 switch Point of Delivery to PacifiCorp Transmission at Lakeview. SVEC's service territory is served from this transmission line. BPA serves the Yamsay 230 kV with a 230 kV transmission line to this Point of Delivery with PacifiCorp Transmission

PacifiCorp transmission delivers and SVEC receives its BPA power at Lakeview Switch 940. PacifiCorp transmission also delivers all of the power needs for PacifiCorp retail customers in the area surrounding SVEC's service territory. BPA will continue to supply SVEC with its full load requirements. Consequently, there will be additional power in the PacifiCorp transmission system because the Paisley Plant is generating. This excess amount will be equal to the amount of power generated by the Paisley Plant less the predetermined amount allowing for transmission line losses as determined by the meter readings at the Yamsay 230 kV Delivery Point less the deliveries to SVEC by PacifiCorp Transmission (on behalf of BPA). This power will be delivered into PacifiCorp Transmission's system and be available for use by PacifiCorp retail customers. In other words, the amount of power generated by the Paisley Plant will effectively be serving PacifiCorp retail customer loads in this remote part of the PacifiCorp Balancing Area. The PacifiCorp resources serving the PAC Mile High substation will be correspondingly reduced by the net output (minus transmission line loss) at the Paisley Plant.

Under this conceptual understanding, PacifiCorp will pay SVEC for the amount of power generated at the Paisley Plant, less the predetermined amount for transmission line losses, at the rates set forth in this contract entered into between SVEC and PacifiCorp.

2. Provide single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection,

3. Specify the Point of Delivery, and any transmission facilities on Seller's side of the Point of Delivery used to deliver Net Output.

The Points of Delivery for this transaction are at the Lakeview Switch 940 where BPA has a revenue meter and SVEC interconnects with PacifiCorp Transmission and at the point near structure 47/5 in BPA's La Pine- Chiloquin 230 kV transmission line, and where the 230 kV facilities of BPA and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012). SVEC has a 44 mile 69 kV transmission line from the point of interconnect to the Lakeview Switch 940 Point of Delivery to PacifiCorp Transmission at Lakeview. SVEC's service territory is served from this transmission line. BPA serves the Yamsay 230 kV with a 230 kV transmission line to the Point of Delivery with PacifiCorp Transmission

EXHIBIT C
REQUIRED FACILITY DOCUMENTS

Deleted: Section Break (Next Page)

REQUIRED OF ALL FACILITIES:
QF Certification : QF13-276-000
Interconnection Agreement NEED ASAP
Fuel Supply Agreement, if applicable
Land Lease

REQUIRED IF SELLER ELECTS TO GRANT SENIOR LIEN OR STEP-IN RIGHTS:
Deed or Lease to Facility Premises
Preliminary Title Report of Premises
Proof of ownership of Facility
Off-take sale agreements, e.g. surplus heat sale contract, if applicable

NOT REQUIRED

Formatted: Font:Bold

Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be requested.

Exhibit D-1 Motive Force Plan

A. MONTHLY DELIVERY SCHEDULES AND SCHEDULED MAINTENANCE

The following table summarizes the estimated monthly energy sales based on plant gross output, plant parasitic load consumption and assumed annual availability.

Annual Monthly Energy		
	Monthly kWh	Monthly Average kW
January	1,704,725	2,291
February	1,536,615	2,286
March	1,680,082	2,258
April	1,601,097	2,223
May	1,521,422	2,045
June	1,380,508	1,917
July	1,316,967	1,770
August	1,371,325	1,843
September	1,464,407	2,034
October	1,649,095	2,216
November	1,632,560	2,267
December	1,426,869	1,918
TOTAL	**18,285,671**	**2,087**

The estimated monthly output is based on the Net Output of the plant considering the following:

- Gross output of the plant at the generator terminals, considering average ambient wet-bulb temperature conditions
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Estimated plant degradation due to scaling/plant wear – first 2 years operation
- Annual 5 day planned maintenance shutdown (scheduled for December)
- Unplanned outages (1%)
- Transmission system outages (20 hours/year)

B. MINIMUM ANNUAL DELIVERY CALCULATION

The plant will operate as a base load facility. The minimum annual delivery is based on the expected worst case conditions of operation and availability. The Minimum Net Output is 12,197,102 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions + 5^{0}F elevated temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Five year, 14 day, major maintenance shutdown (scheduled for December)
- Estimated plant degradation 2X estimated annual average
- Unplanned outages (2%)

- Major unplanned outage – 3 months – production pump, well or plant failure (allocated across each operating month)

C. MAXIMUM DELIVERY CALCULATION

The maximum delivery is based on optimal operating conditions and availability. The Maximum Net Output is 19,391,369 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions - 5^{0}F reduced temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Annual 5 day planned maintenance shutdown (scheduled for December)
- No plant operational degradation
- No unplanned outages

Deleted: EXHIBIT D-1
Average Energy (kWh) ... [2]

Deleted: EXHIBIT D-2 ... [3]

EXHIBIT D-2
ENGINEER'S CERTIFICATION
OF
MOTIVE FORCE PLAN

Seller provide a written declaration from a Licensed Professional Engineer to PacifiCorp that the Facility is likely capable under average conditions foreseeable during the term of this Agreement of meeting Seller's estimated average, maximum, and minimum Net Output.

After reviewing the documentation provided to me by Surprise Valley Electric Corporation I have determined that the power plant is likely to meet the power estimates represented in the table below provided that the following qualifications are met.

Minimum	12,197,102 KWh/ year
Average	18,285,671 KWh/year
Maximum	19,391,369 KWh/year

Qualifications:

1. Power output will depend on the plant's ability to maintain 3000 GPM of 232°F geothermal well water
2. These power estimates do not include the parasitic load of the geothermal well pumps
3. Plant availability factor for the average output case stays at 97.4% or better

Signed/Stamped:

Formatted: Font:12 pt, Expanded by 2.2 pt, Lowered by 119.5 pt

Date: May 15, 2014

Formatted: Font:Not Italic, No underline

EXHIBIT E

START-UP TESTING

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable): **[Seller identify appropriate tests]TAS-Turbine Air System to complete during start up and commissioning procedures**

1. Pressure tests of all steam system equipment; TAS
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;TAS
3. Operating tests of all valves, operators, motor starters and motor;TAS
4. Alarms, signals, and fail-safe or system shutdown control tests;TAS
5. Insulation resistance and point-to-point continuity tests;TAS
6. Bench tests of all protective devices;In Factory
7. Tests required by manufacturer of equipment;TAS and
8. Complete pre-parallel checks with PacifiCorp. TAS will support this scope but needs to understand the requirements.

Required start-up tests are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PacifiCorp's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;TAS. Vibration only.
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;TAS
3. Brake tests;NA
4. Energization of transformers;TAS
5. Synchronizing tests (manual and auto);TAS
6. Stator windings dielectric test ; Determining who to perform
7. Armature and field windings resistance tests;TAS
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load; TAS plant is not designed to island mode or survive load rejection. TAS will perform plant trip testing from above load l levels.
9. Heat runs;NA
10. Tests required by manufacturer of equipment;TAS
11. Excitation and voltage regulation operation tests;TAS
12. Open circuit and short circuit; saturation tests;to be determined
13. Governor system steady state stability test;TAS
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;TAS

Deleted: test;

Deleted:

15. Auto stop/start sequence;TAS
16. Level control system tests; andTAS
17. Completion of all state and federal environmental testing requirementsNA

Formatted: Left, Indent: Left: 0.19", Hanging: 0.81"

Deleted: .

EXHIBIT F
Seller Authorization to Release Generation Data to PacifiCorp
See attached letter

EXHIBIT G
SCHEDULE 37 and PRICING SUMMARY TABLE

W - 2

ADDENDUM W

GENERATION SCHEDULING ADDENDUM

WHEREAS, Seller's Facility is located within the control area of PacifiCorp;

Deleted: not

WHEREAS, Seller's Facility will not interconnect directly to PacifiCorp's System;

WHEREAS, Seller and PacifiCorp have not executed, and will not execute, a Generation Interconnection Agreement in conjunction with the Power Purchase Agreement;

WHEREAS, Seller has elected to exercise its right under PURPA to deliver Net Output from it's QF Facility to PacifiCorp via one (or more) Transmitting Entities.

WHEREAS, PacifiCorp desires that Seller schedule delivery of Net Output on a firm, hourly basis;

WHEREAS, PacifiCorp does not intend to buy, and Seller does not intend to deliver, more or less than Net Output from the Facility (except as expressly provided, below);

THEREFORE, Seller and PacifiCorp do hereby agree to the following, which shall become part of their Power Purchase Agreement:

DEFINITIONS

The meaning of the terms defined in the Power Purchase Agreement and this **Addendum W** shall apply to this Generation Scheduling Addendum:

"Day" means midnight to midnight, prevailing local time at the Point of Delivery, or any other mutually agreeable 24-hour period.

"Energy Imbalance Accumulation," or "**EIA,**" means the accumulated difference between Seller's Net Output and the energy actually delivered at the Point of Delivery. A positive accumulated difference indicates Seller's net delivery of Supplemented Output to PacifiCorp.

"Firm Delivery" means uninterruptible transmission service that is reserved and/or scheduled between the Point of Interconnection and the Points of Delivery pursuant to Transmission Agreements with Transmitting Entities.

Formatted: Highlight

Deleted: Seller's

Formatted: Highlight

Formatted: Highlight

"Settlement Period" means one month.

"Supplemented Output" means any increment of scheduled hourly energy or capacity delivered to the Point of Delivery in excess of the Facility's Net Output during that same hour.

"**Surplus Delivery"** means any energy delivered by the Facility in excess of hourly Net Output that is not offset by the delivery of energy in deficit of hourly Net Output during the Settlement Period. PacifiCorp shall accept Surplus Delivery, but shall not pay for it.

ADDENDUM W-ctd.

SELLER'S OBLIGATIONS IN LIEU OF THOSE CONTAINED IN A GENERATION INTERCONNECTION AGREEMENT.

1. **Seller's Responsibility to Arrange for Delivery of Net Output to Point of Delivery**. Seller shall arrange for the Firm Delivery of Net Output to the Point of Delivery. Seller shall comply with the terms and conditions of the Transmission Agreement(s) between the Seller and the Transmitting Entity(s). Whenever Seller fails to provide for Firm Delivery of Net Output, all Net Output delivered via non-firm transmission rights shall be deemed Excess Output, and therefore subject to the payment provision in Section 5.4 of the Power Purchase Agreement.

2. **Seller's Responsibility to Schedule Delivery.** Seller shall coordinate with the Transmitting Entity(s) to provide PacifiCorp with a schedule of the next Day's hourly scheduled Net Output deliveries at least 24 (twenty-four) hours prior to the beginning of the day being scheduled, and otherwise in accordance with the WECC Prescheduling Calendar (which is updated annually and may be downloaded at: http://www.wecc.biz/.

3. **Seller's Responsibility to Maintain Interconnection Facilities**. PacifiCorp shall have no obligation to install or maintain any interconnection facilities on Seller's side of the Point of Delivery. PacifiCorp shall not pay any costs arising from Seller interconnecting its Facility with the Transmitting Entity(s).

4. **Seller's Responsibility to Pay Transmission Costs**. Seller shall make all arrangements for, and pay all costs associated with, transmitting Net Output to PacifiCorp, scheduling energy into the PacifiCorp system and any other costs associated with delivering the Seller's Net Output to the Point of Delivery.

5. **Energy Reserve Requirements.** The Transmitting Entity shall provide all generation reserves as required by the WECC and/or as required by any other governing agency or industry standard to deliver the Net Energy to the Point of Delivery, at no cost to PacifiCorp.

6. **Seller's Responsibility to Report Net Output.** On or before the tenth ($10^{th)}$ day following the end of each Billing Period, Seller shall send a report documenting hourly station service, Excess Output, and Net Output from the Facility during the previous Billing Period, in columnar format substantially similar to the attached **Example 1**. If requested, Seller shall provide an electronic copy of the data used to calculate Net Output, in a standard format specified by PacifiCorp. For each day Seller is late delivering the certified report, PacifiCorp shall be entitled to postpone its payment deadline in Section 9 of this Power Purchase Agreement by one day. Seller hereby grants PacifiCorp the right to audit its certified reports of hourly Net Output. In the event of discovery of a billing error resulting in underpayment or overpayment, the Parties agree to limit recovery to a period of three years from the date of discovery.

7. **Seller's Supplemental Representations and Warranties**. In addition to the Seller's representations and warranties contained in Section 3 of this Agreement, Seller warrants that:

(a) Seller's Supplemented Output, if any, results from Seller's purchase of some form of energy imbalance ancillary service;

Comment [1]: Who provides this service? PAC since we are in their balancing authority?

ADDENDUM W-ctd.

(b) The Transmitting Entity(s) requires Seller to procure the service, above, as a condition of providing transmission service;

Comment [2]: Is SVE the transmitting entity? And SVE is seller.

Comment [3]: Is this true with respect to BPA? Not true with respect to SVEC.

(c) The Transmitting Entity requires Seller to schedule deliveries of Net Output in increments of no less than one (1) megawatt;

(d) Seller is not attempting to sell PacifiCorp energy or capacity in excess of its Net Output; and

(e) The energy imbalance service, above, is designed to correct a mismatch between energy scheduled by the QF and the actual real-time production by the QF.

8. **Seller's Right to Deliver Supplemented Output**. In reliance upon Seller's warranties in Section 5, above, PacifiCorp agrees to accept and pay for Supplemented Output; *provided, however, that* Seller agrees to achieve an EIA of zero (0) kilowatt-hours during On-Peak Hours and zero (0) kilowatt-hours during Off-Peak Hours at the end of each Settlement Period.

(a) **Remedy for Seller's Failure to Achieve zero EIA**. In the event Seller does not achieve zero EIA at the end of each Settlement Period, PacifiCorp will declare any positive balance to be Surplus Delivery, and Seller's EIA will be reset to zero. PacifiCorp will include an accounting of Surplus Delivery in each monthly statement provided to Seller pursuant to Section 9.1 of this Agreement.

(b) **Negative Energy Imbalance Accumulations**. Any negative EIA (indicating that the Transmitting Entity has delivered less than Seller's Net Output), will be reset to zero at the end of each Settlement Period without any corresponding compensation by PacifiCorp.

(c) **PacifiCorp's Option to Change EIA Settlement Period**. In the event PacifiCorp reasonably determines that doing so likely will have a *de minimis* net effect upon the cost of Seller's Net Output to PacifiCorp, it may elect to enlarge the Settlement Period, up to a maximum of one Contract Year. Conversely, if PacifiCorp reasonably determines, based on the QF's performance during the current year, that reducing the Settlement Period likely will significantly lower the net cost of Seller's Net Output to PacifiCorp, it shall have the right to shorten Seller's EIA settlement period beginning the first day of the following Contract Year. However, in no case shall the Settlement Period be less than one month.

ADDENDUM W—Example 1

Example of Seller's Output Reporting Requirement

Day	Hour ending (HE)	**A** Meter Reading at Point of Delivery (MWh)	**B** Meter reading at Station Power Meter* (MWh)	**C (=A-B)** Net Output (MWh)	**D** Facility Capacity Rating (MW)	**E (=Max (0, C-D))** Excess Output (MWh)
1	7:00	0.50	0.01	0.49	1.50	
1	8:00	0.50	0.02	0.48	1.50	
1	9:00	0.50	0.01	0.49	1.50	
1	10:00	0.50	0.01	0.49	1.50	
1	11:00	0.50	0.01	0.49	1.50	
1	12:00	1.60	0.01	1.59	1.50	0.09
1	13:00	1.70	0.01	1.69	1.50	0.19
1	14:00	1.60	0.01	1.59	1.50	0.09
1	15:00	1.50	0.01	1.49	1.50	
1	16:00	1.50	0.01	1.50	1.50	
1	17:00	1.50	0.00	1.50	1.50	
1	18:00	1.50	0.01	1.49	1.50	
1	19:00	0.50	0.02	0.48	1.50	
1	20:00	0.50	0.01	0.49	1.50	

Seller shall show adjustment of Meter Reading for losses, if any, between point of metering and the Point of Delivery, in accordance with Section 8.1.

* Does not apply if Station Service is provided from the gross output of the Facility.

Formatted: Centered, Indent: First line: 0.5", Line spacing: single

ADDENDUM A

JURY TRIAL WAIVER

Deleted: PacifiCorp and Surprise Valley Electrification Corp ("SVEC") are parties to that certain Power Purchase Agreement executed the date last written below (the "PPA"). This Addendum A to the PPA is entered into by and between PacifiCorp and SVEC and is intended to be interpreted and applied to the PPA.
and QF Contracts

Deleted: and QF Contracts

ADDENDUM W—Example 1

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/110

SURPRISE VALLEY'S JULY 22, 2014
DRAFT POWER PURCHASE AGREEMENT

May 17, 2016

Draft 7-22-14

POWER PURCHASE AGREEMENT

BETWEEN

SURPRISE VALLEY ELECTRIFICATION CORPORATION

[Firm Qualifying Facility with 10,000 kW Facility Capacity Rating, or Less, and uninterruptible transmission to the Point of Delivery]

AND

PACIFICORP

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT, entered into this ____day of July, 2014, is between Surprise Valley Electrification Corp., "**Seller**" and PacifiCorp (d/b/a Pacific Power & Light Company), an Oregon corporation acting in its regulated utility capacity, "**PacifiCorp**." (Seller and PacifiCorp are referred to individually as a "**Party**" or collectively as the "**Parties**").

RECITALS

A. Seller intends to construct, own, operate and maintain a geothermal facility for the generation of electric power, including interconnection facilities, located in Paisley, Lake County, Oregon with a Facility Capacity Rating of 3,650 kilowatts (kW) as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

B. Seller intends to commence delivery of Net Output under this Power Purchase Agreement, for the purpose of Start-up Testing, on August 29, 2014 ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on or before November 1, 2014 ("**Scheduled Commercial Operation Date**") depending on the date of receipt of the Facilities Study being prepared by PacifiCorp Transmission; and

D. Seller estimates that the average annual Net Energy to be delivered by the Facility to PacifiCorp is 18,285,671 kilowatt-hours (kWh), which amount of energy PacifiCorp will include in its resource planning; and

E. Seller shall (choose one) X☐ sell all Net Output to PacifiCorp and purchase its full electric requirements from Bonneville Power Administration ☐ sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from Bonneville Power Administration, in accordance with the terms and conditions of this Agreement; and

F. This Agreement is a "New QF Contract" under the PacifiCorp Inter-Jurisdictional Cost Allocation Revised Protocol.

G. Seller intends to sell Net Output to PacifiCorp, and PacifiCorp intends to accept scheduled firm delivery of Seller's Net Output, under the terms of this Agreement, including the Generation Scheduling Addendum attached as **Addendum W** and incorporated contemporaneously herewith.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 **"As-built Supplement"** shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 "**Average Annual Generation"** shall have the meaning set forth in Section 4.2.

1.3 **"Billing Period"** means calendar months.

1.4 **"Commercial Operation Date"** means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.4.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

1.4.2 The Facility has completed Start-Up Testing;

1.4.3 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating that, (a), in accordance with the Interconnection Agreement, if applicable, all required interconnection facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with PacifiCorp's electric system, or (b) if the Facility is interconnected with another electric utility that will wheel Net Output to PacifiCorp, all required interconnection facilities have been completed and tested and are in place to allow for such wheeling;

1.4.4 PacifiCorp has received a certificate addressed to PacifiCorp from an attorney in good standing in the State of Oregon stating that Seller has obtained all Required Facility Documents (Facilities over 200 kW only) and, if requested by PacifiCorp, in writing, has provided copies of any or all such requested Required Facility Documents.

1.4.5 Seller has complied with the security requirements of Section 10.

1.4.6 PacifiCorp has received an executed copy of **Exhibit F** - Seller's Interconnection Request.

1.5 **"Commission"** means the Oregon Public Utilities Commission.

1.6 **"Contract Price"** means the applicable price for capacity or energy, or both capacity and energy, stated in Sections 5.1 and 5.2.

1.7 **"Contract Year"** means a twelve (12) month period commencing at 00:00 hours Pacific Prevailing Time ("**PPT**") on January 1 and ending on 24:00 hours PPT on December 31; *provided, however,* that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

1.8 "**Credit Requirements**" means a long-term credit rating (corporate or long-term senior unsecured debt) of (1) "Baa3" or greater by Moody's, or (2) "BBB-" or greater by S&P, or such other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment.

Seller shall provide to PacifiCorp within five Business Days of receipt of a written request all reasonable financial records, including but not limited to three years of audited financial statements prepared in accordance with generally accepted accounting principles, necessary for PacifiCorp to confirm that Seller satisfies the Credit Requirements during the Term of this Agreement.

1.9 "**Default Security**", unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at Mid-C (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery; provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller's average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

1.10 "**Effective Date**" shall have the meaning set forth in Section 2.1.

1.11 "**Energy Delivery Schedule**" shall have the meaning set forth in Section 4.5.

1.12 "**Environmental Attributes**" shall have the meaning set forth in Section 5.5.

1.13 "**Excess Output**" shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Capacity Rating.

1.14 "**Facility**" shall have the meaning set forth in Recital A.

1.15 "**Facility Capacity Rating**" means the sum of the Nameplate Capacity Ratings for all generators comprising the Facility.

1.16 "**FERC**" means the Federal Energy Regulatory Commission, or its successor.

1.17 "**Generation Scheduling Addendum**" means **Addendum W**, the portion of this Agreement providing for the measurement, scheduling, and delivery of Seller's Net Output from the Facility to the Point of Delivery via non-PacifiCorp transmission providers.

1.18 **Interconnected Utility**" means Surprise Valley Electrification Corp. and/or Bonneville Power Administration, the operators of the electric utility system at a Point of Interconnection.

1.19 "**Interconnection Agreement**" means the agreement (or contemporaneous agreements) between the Interconnected Utility and PacifiCorp governing interconnection of Interconnected Utility at a Point of Delivery and associated use of the Interconnected Utility's system.

1.20 "**Letter of Credit**" means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of "A" or greater from S&P or "A2" or greater from Moody's, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

1.21 "**Licensed Professional Engineer**" means a person acceptable to PacifiCorp in its reasonable judgment who is licensed to practice engineering in the state of Oregon, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made.

1.22 "**Material Adverse Change**" means the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller's ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement

1.23 "**Maximum Annual Delivery**" shall have the meaning set forth in Section 4.3.

1.24 "**Minimum Annual Delivery**" shall have the meaning set forth in Section 4.3.

1.25 "**Nameplate Capacity Rating**" means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units that are usually indicated on a nameplate attached to the individual machine or device.

1.26 “**Net Energy**” means the energy component, in kWh, of Net Output.

1.27 “**Net Output”** means an amount equal to all energy and capacity produced by the Facility, less station use excluding pumping load attributable to the extraction and transportation functions the pumps perform and less transformation and transmission losses and other adjustments (e.g., Seller’s load other than station use), if any, up to and including the Point of Delivery. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the revenue metering at SVEC’s Paisley generator generation substation, adjusted as set forth in this paragraph.

1.28 “**Net Replacement Power Costs**” shall have the meaning set forth in Section 11.4.1.

1.29 “**Off-Peak Hours**” means all hours of the week that are not On-Peak Hours.

1.30 “**On-Peak Hours**” means the hours between 6 a.m. Pacific Prevailing Time (“**PPT**”) and 10 p.m. PPT, Mondays through Saturdays, excluding all hours occurring on holidays as provided in Schedule 37.

1.31 “**Point of Delivery**” means the Point or Points of Interconnection between a Transmitting Entity’s system and PacifiCorp’s distribution/transmission system as specified in **Exhibit B.**

1.32 “**Point of Interconnection**” means the point(s) of interconnection between a Transmitting Entity’s system and PacifiCorp’s distribution/transmission system, as specified in **Exhibit B**.

1.33 “**Prime Rate**” means the publicly announced prime rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, New York, selected by the Party to whom interest based on the Prime Rate is being paid.

1.34 “**Prudent Electrical Practices**” means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

1.35 “**QF**” means “**Qualifying Facility,**” as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.36 “**Replacement Price**” means the price at which PacifiCorp, acting in a commercially reasonable manner, purchases for delivery at the Point of Delivery a replacement for any Net Output that Seller is required to deliver under this Agreement plus (i) costs reasonably incurred by PacifiCorp in purchasing such replacement Net Output, and (ii) additional transmission charges, if any, reasonably incurred by PacifiCorp in causing replacement energy to be delivered to the Point of Delivery. If PacifiCorp elects not to make such a purchase, the Replacement Price shall be the market price at the Mid-Columbia trading hub for such energy not delivered, plus any additional cost or expense incurred as a result of Seller's failure to deliver, as determined by PacifiCorp in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

1.37 "**Required Facility Documents**" means all licenses, permits, authorizations, and agreements, including an Interconnection Agreement or equivalent, and any Transmission Agreement(s), necessary for construction, operation and maintenance of the Facility consistent with the terms of this Agreement. The Required Facility Documents are set forth in **Exhibit C.**

1.38 "**Schedule 37**" means the Schedule 37 of Pacific Power & Light Company's Commission-approved tariffs, providing pricing options for Qualifying Facilities of 10,000 kW or less, which is in effect on the Effective Date of this Agreement. A copy of that Schedule 37 is attached as **Exhibit G**.

1.39 "**Scheduled Commercial Operation Date**" shall have the meaning set forth in Recital C.

1.40 "**Scheduled Initial Delivery Date**" shall have the meaning set forth in Recital B.

1.41 "**Start-Up Testing**" means the completion of required factory and start-up tests as set forth in **Exhibit E** hereto.

1.42 "**Termination Date**" shall have the meaning set forth in Section 2.4.

1.43 "**Transmission Agreement**" means the agreement (or contemporaneous agreements) between Seller and the Transmitting Entity providing for Seller's uninterruptible right to transmit Net Output to the Point of Delivery.

1.44 "**Transmitting Entity(s)**" means Surprise Valley Electrification Corp. and Bonneville Power Administration, the (non-PacifiCorp) operators of the transmission systems at a Points of Delivery.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement shall become effective after execution by both Parties ("**Effective Date**").

2.2 **Time is of the essence for this Agreement,** and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to deliver Net Output by the Scheduled Commercial Operation Date is critically important. Therefore, 2.2.1 By October 31, 2014, Seller shall provide PacifiCorp with a copy of an executed Interconnection Agreement and an executed Transmission Agreement, if either applicable, which shall be consistent with all material terms and requirements of this Agreement.

2.2.2 Upon completion of construction, Seller, in accordance with Section 6.1, shall provide PacifiCorp with an As-built Supplement acceptable to PacifiCorp;

2.2.3 By the date thirty (30) days after the Effective Date, Seller shall provide Default Security required under Sections 10.1 or 10.2, as applicable.

2.3 Seller shall cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date. If Commercial Operation occurs after the Scheduled Commercial Operation Date, Seller shall be in default, and liable for delay damages specified in Section 11.

2.4 This Agreement shall terminate on May 30, 2020, ("**Termination Date**") except as otherwise provided herein,.

SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1 PacifiCorp represents, covenants, and warrants to Seller that:

3.1.1 PacifiCorp is duly organized and validly existing under the laws of the State of Oregon.

3.1.2 PacifiCorp has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.

3.1.3 PacifiCorp has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.1.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on PacifiCorp or any valid order of any court, or any regulatory agency or other body having authority to which PacifiCorp is subject.

3.1.5 This Agreement is a valid and legally binding obligation of PacifiCorp, enforceable against PacifiCorp in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2 Seller represents, covenants, and warrants to PacifiCorp that:

3.2.1 Seller is a corporation duly organized and validly existing under the laws of California.

3.2.2 Seller has the requisite power and authority to enter into this Agreement and to perform according to the terms hereof, including all required regulatory authority to make wholesale sales from the Facility.

3.2.3 Seller has taken all actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.2.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.2.5 This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2.6 The Facility is and shall for the term of this Agreement continue to be a QF, and Seller will operate the Facility in a manner consistent with its FERC QF certification. Seller has provided to PacifiCorp the appropriate QF certification (which may include a FERC self-certification) prior to PacifiCorp's execution of this Agreement. At any time during the term of this Agreement, PacifiCorp may require Seller to provide PacifiCorp with evidence satisfactory to PacifiCorp in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements and, if PacifiCorp is not satisfied that the Facility qualifies for such status, a written legal opinion from an attorney who is (a) in good standing in the state of Oregon, and (b) who has no economic relationship, association or nexus with the Seller or the Facility, stating that the Facility is a QF and providing sufficient proof (including copies of all documents and data as

PacifiCorp may request) demonstrating that Seller has maintained and will continue to maintain the Facility as a QF.

3.2.7 Compliance with Partial Stipulation in Commission Proceeding No. UM-1129. Seller will not make any changes in its ownership, control, or management during the term of this Agreement that would cause it to not be in compliance with the definition of a Small Cogeneration Facility or Small Power Production Facility provided in PacifiCorp's Schedule 37 tariff approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by PacifiCorp not more frequently than every 36 months, such documentation and information as reasonably may be required to establish Seller's continued compliance with such Definition. PacifiCorp agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PacifiCorp will provide all such confidential information the Public Utility Commission of Oregon upon the Commission's request.

3.2.8 Additional Seller Creditworthiness Warranties. Seller need not post security under Section 10 for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following:

(a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.

(b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.

(c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.

(d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

(e) **[Applicable only to Sellers with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

____X___ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

______ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase all Net Output from the Facility delivered to the Point of Delivery.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, 18,285,671 kWh per Contract Year ("**Average Annual Generation**"). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

4.3 Minimum and Maximum Delivery. Seller shall deliver (or cause to be delivered) from the Facility a minimum of 12,197,102 kWh of Net Output during each Contract Year, provided that such minimum for the first Contract Year shall be reduced *pro rata* to reflect the Commercial Operation Date, and further provided that such minimum delivered Net Output shall be reduced on a *pro rata* basis for any periods during a Contract Year that the Facility was prevented from generating or delivering electricity for reasons of Force Majeure ("**Minimum Annual Delivery**"**)**. Seller estimates, for informational purposes, that it will deliver from the Facility a maximum of 19,391,369 kWh of Net Output during each Contract Year ("**Maximum Annual Delivery"**). Seller's basis for determining the Minimum and Maximum Annual Delivery amounts is set forth in **Exhibit D.**

4.4 Deliveries in Deficit of Delivery Obligation. Seller's failure to deliver the Minimum Annual Delivery in any Contract Year (prorated if necessary) shall be a default, and Seller shall be liable for damages in accordance with Section 11.

4.5 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility ("**Energy Delivery Schedule**"), incorporated into **Exhibit D**.

SECTION 5: PURCHASE PRICES

5.1 Seller shall have the option to select one of four pricing options: Fixed Avoided Cost Prices ("Fixed Price"), Firm Market Indexed Avoided Cost Prices ("Firm Electric Market"), Gas Market Indexed Avoided Cost Prices ("Gas Market"), or Banded Gas Market Indexed Avoided Cost Prices ("Banded Gas Market"), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility's contract. Seller has selected the following (Seller to initial one):

___X___ Fixed Price
_______ Firm Electric Market
_______ Gas Market
_______ Banded Gas Market

A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G.**

5.2 (Applies only to "Fixed Price" Contracts Greater than 15 Years). In the event Seller elects the Fixed Price payment method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller market-based rates, using the following pricing option (Seller to initial one):

_______ Firm Electric Market
_______ Gas Market
_______ Banded Gas Market

5.3 If the Seller elects a gas market indexed price option, the index shall be the Opal Gas Market Index as provided in Schedule 37. In the event that Platt ceases to publish the Opal Gas Market Index, the Company shall replace the index with a similar gas index.

5.4 For all Excess Output and for all Net Output delivered prior to the Commercial Operation Date, PacifiCorp shall pay Seller a blended market index price for day-ahead non-firm energy at Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by Dow Jones, for the On-Peak and Off-Peak periods. PacifiCorp shall document its calculation of the blended rate, upon request, to Seller. Such payment will be accomplished by adjustments pursuant to Section 9.2.

5.5 Environmental Attributes. PacifiCorp waives any claim to Seller's ownership of Environmental Attributes under this Agreement. Environmental Attributes include, but are not limited to, Green Tags, Green Certificates, Renewable Energy Credits (RECs) and Tradable

Renewable Certificates (TRCs) (as those terms are commonly used in the regional electric utility industry) directly associated with the production of energy from the Seller's Facility.

SECTION 6: OPERATION AND CONTROL

6.1 As-Built Supplement. Upon completion of initial (and any subsequent) construction of the Facility, Seller shall provide PacifiCorp an As-built Supplement to specify the actual Facility as built. The As-built Supplement must be reviewed and approved by PacifiCorp, which approval shall not unreasonably be withheld, conditioned or delayed.

6.2 Incremental Utility Upgrades. At start-up (and at any other time upon at least six months prior written notice), Seller may increase Net Output, if such increase is due to normal variances in estimated versus actual performance, changed Facility operations, or improvements in Facility efficiency. Seller may not increase Net Output under this Agreement by installing additional generating units. In the case of substantial upgrades, PacifiCorp may require Seller to comply with Section 3.2.8(e) (in the event that the Facility upgrade causes the Facility Capacity Rating to exceed 3,000 kW) and increase its Minimum Annual Delivery obligation in Section 4.3 (if appropriate). PacifiCorp may also update Seller's security obligation (if applicable). So long as the Facility Capacity Rating after the upgrade is 10,000 kW or less, Seller will continue to receive the Contract Price for the Net Output, as set forth in Sections 5.1 and 5.2 of this Agreement. If Seller increases the Facility Capacity Rating above 10,000 kW, then (on a going forward basis) PacifiCorp shall pay Seller the Contract Price for the fraction of total Net Output equal to 10,000 kW divided by the Facility Capacity Rating of the upgraded Facility. For the remaining fraction of Net Output, PacifiCorp and Seller shall agree to a new negotiated rate. Seller shall be responsible for ensuring that any planned increase in the Facility Capacity Rating or the maximum instantaneous capacity of the Facility complies with Seller's Interconnection Agreement, Transmission Agreement and any other relevant agreements.

6.3 Seller shall operate and maintain the Facility in a safe manner in accordance with this Agreement, the Interconnection Agreement, Prudent Electrical Practices and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code as such laws and code may be amended from time to time. PacifiCorp shall have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and the Point of Delivery is disconnected, suspended or interrupted, in whole or in part, pursuant to the Interconnection Agreement or Transmission Agreement(s), or to the extent generation curtailment is required as a result of Seller's non-compliance with the Interconnection Agreement or Transmission Agreement(s). PacifiCorp shall have the right to inspect the Facility to confirm that Seller is operating the Facility in accordance with the provisions of this Section 6.3 upon reasonable notice to Seller. Seller is solely responsible for the operation and maintenance of the Facility. PacifiCorp shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.4 Scheduled Outages. Seller may cease operation of the entire Facility or individual units, if applicable, for maintenance or other purposes. Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp's request, if any, to reschedule such planned outage in order to accommodate PacifiCorp's need for Facility operation.

6.5 Unplanned Outages. In the event of an unscheduled outage or curtailment exceeding twenty-five (25) percent of the Facility Capacity Rating (other than curtailments due to lack of motive force), Seller immediately shall notify PacifiCorp of the necessity of such unscheduled outage or curtailment, the time when such has occurred or will occur and the anticipated duration. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled outage or curtailment, to limit the duration of such, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: FUEL/MOTIVE FORCE

Prior to the Effective Date of this Agreement, Seller provided to PacifiCorp a fuel or motive force plan acceptable to PacifiCorp in its reasonable discretion and attached hereto as **Exhibit D-1,** together with a certification from a Licensed Professional Engineer to PacifiCorp attached hereto as **Exhibit D-2**, certifying that the implementation of the fuel or motive force plan can reasonably be expected to provide fuel or motive force to the Facility for the duration of this Agreement adequate to generate power and energy in quantities necessary to deliver the Minimum Annual Delivery set forth by Seller in Section 4.

SECTION 8: METERING AT THE POINT OF INTERCONNECTION

8.1 Metering shall be performed at the locations and in a manner consistent with this Agreement, as specified in **Exhibit B**. Seller shall provide to PacifiCorp metered Facility Net Output in hourly increments, and any other energy measurements required to administer this Agreement. If the Transmitting Entity requires Seller to telemeter data, PacifiCorp shall be entitled to receive the same data Seller provides to the Transmitting Entity, if such data is useful to PacifiCorp's administration of this Agreement. All quantities of energy purchased hereunder shall be adjusted to account for electrical losses, if any, between the point of Interconnection and the Point of Delivery. The loss adjustment shall be 1.9% of the kWh energy production recorded on the Facility output meter.

8.2 Seller shall pay for the installation, testing, and maintenance of any metering required by Section 8.1, and shall provide reasonable access to such meters. PacifiCorp shall have reasonable access to inspection, testing, repair and replacement of the metering equipment. If any of the inspections or tests discloses a measurement error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) Billing Periods, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered following the repair of the meter.

SECTION 9: BILLINGS, COMPUTATIONS, AND PAYMENTS

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PacifiCorp shall send to Seller payment for Seller's deliveries of Net Output to PacifiCorp, together with computations supporting such payment. PacifiCorp may offset any such payment to reflect amounts owing from Seller to PacifiCorp pursuant to this Agreement, the Interconnection Agreement, or any other agreement between the Parties.

9.2 Corrections. PacifiCorp shall have up to eighteen months to adjust any payment made pursuant to Section 9.1. In the event PacifiCorp determines it has overpaid Seller (for Excess Output or otherwise), PacifiCorp may adjust Seller's future payment accordingly in order to recapture any overpayment in a reasonable time.

9.3 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; *provided*, *however*, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 10: SECURITY

Unless Seller has adopted the creditworthiness warranties contained in Section 3.2.8, Seller must provide security (if requested by PacifiCorp) in the form of a cash escrow, letter of credit, senior lien, or step-in rights. Seller hereby elects to provide, in accordance with the applicable terms of this Section 10, the following security (Seller to initial one selection only):

____ Cash Escrow - $236,404

_____ Letter of Credit - $236,404

_____ Senior Lien

_____ Step-in Rights

___X__ Seller has adopted the Creditworthiness Warranties of Section 3.2.8.

In the event Seller's obligation to post default security (under Section 10 or Section 11.1.4) arises solely from Seller's delinquent performance of construction-related financial obligations, upon Seller's request, PacifiCorp will excuse Seller from such obligation in the event Seller has negotiated financial arrangements with its construction lenders that mitigate Seller's financial risks to PacifiCorp's reasonable satisfaction.

[SKIP THIS SECTION 10.1 UNLESS SELLER SELECTED CASH ESCROW ALTERNATIVE]

10.1 Cash Escrow Security. Seller shall deposit in an escrow account established by PacifiCorp in a banking institution acceptable to both Parties, the Default Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institution from time to time. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.2 UNLESS SELLER SELECTED LETTER OF CREDIT ALTERNATIVE]

10.2 Letter of Credit Security. Seller shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to PacifiCorp in its discretion, or (b) a Letter of Credit in favor of PacifiCorp. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.3 UNLESS SELLER SELECTED SENIOR LIEN ALTERNATIVE]

10.3 Senior Lien. Before the Scheduled Commercial Operation Date, Seller shall grant PacifiCorp a senior, unsubordinated lien on the Facility and its assets as security for performance of this Agreement by executing, acknowledging and delivering a security agreement and a deed of trust or a mortgage, in a recordable form (each in a form satisfactory to PacifiCorp in the reasonable exercise of its discretion). Pending delivery of the senior lien to PacifiCorp, Seller shall not cause or permit the Facility or its assets to be burdened by liens or other encumbrances that would be superior to PacifiCorp's, other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

[SKIP THIS SECTION 10.4 UNLESS SELLER SELECTED STEP-IN RIGHTS ALTERNATIVE]

10.4 Step-in Rights (Operation by PacifiCorp Following Event of Default of Seller).

10.4.1 Prior to any termination of this Agreement due to an Event of Default of Seller, as identified in Section 11, PacifiCorp shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this Agreement) during the period provided for herein. Seller shall not grant any person, other than the lending institution providing financing to the Seller for construction of the Facility ("Facility

Lender"), a right to possess, assume control of, and operate the Facility that is equal to or superior to PacifiCorp's right under this Section 10.4.

10.4.2 PacifiCorp shall give Seller ten (10) calendar days' notice in advance of the contemplated exercise of PacifiCorp's rights under this Section 10.4. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Electrical Practices. Upon such notice, PacifiCorp, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Facility for the purpose of constructing and/or operating the Facility. Seller hereby irrevocably appoints PacifiCorp as Seller's attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions as PacifiCorp may reasonably deem necessary or appropriate to exercise PacifiCorp's step-in rights under this Section 10.4.

10.4.3 During any period that PacifiCorp is in possession of and constructing and/or operating the Facility, no proceeds or other monies attributed to operation of the Facility shall be remitted to or otherwise provided to the account of Seller until all Events of Default of Seller have been cured.

10.4.4 During any period that PacifiCorp is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and PacifiCorp shall assume possession, operation, and control solely as agent for Seller.

(a) In the event PacifiCorp is in possession and control of the Facility for an interim period, Seller shall resume operation and PacifiCorp shall relinquish its right to operate when Seller demonstrates to PacifiCorp's reasonable satisfaction that it will remove those grounds that originally gave rise to PacifiCorp's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this Agreement, and (ii) has cured any Events of Default of Seller which allowed PacifiCorp to exercise its rights under this Section 10.4.

(b) In the event that PacifiCorp is in possession and control of the Facility for an interim period, the Facility Lender, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and PacifiCorp shall relinquish its right to operate when the Facility Lender or any nominee or transferee thereof, requests such relinquishment.

10.4.5 PacifiCorp's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by PacifiCorp of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility PacifiCorp elects to return such possession and operation to Seller, PacifiCorp shall provide Seller with at least fifteen (15) calendar days advance notice of the date PacifiCorp intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

SECTION 11: DEFAULTS AND REMEDIES

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.

11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Interconnection Agreement and any Transmission Agreement) within the time allowed for a cure under such agreement or instrument.

11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;

11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.

11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy the minimum delivery obligation of

Section 4.3 for two (2) consecutive years; else Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for one year.

11.2 Notice; Opportunity to Cure.

11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.

11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.

11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the sum of the Replacement Price for the Minimum Annual Delivery that Seller was otherwise obligated to provide for a period of twenty-four (24) months from the date of termination plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, and the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any energy and capacity that Seller was otherwise obligated (under Section 4.3) to provide during the period of default ("**Net Replacement Power Costs**"); *provided, however,* that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

(a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.

(b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

SECTION 12: INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller's side of the Point of Delivery, (c) Seller's operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement 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. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. EXCEPT TO THE EXTENT SUCH DAMAGES ARE INCLUDED IN THE LIQUIDATED DAMAGES, DELAY DAMAGES, COST TO COVER DAMAGES OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE.

SECTION 13: INSURANCE
(FACILITIES OVER 200KW ONLY)

13.1 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) (of "ACORD Form" or the equivalent) certifying Seller's compliance with the insurance requirements hereunder. Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate. If requested by PacifiCorp, a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company, shall be furnished to PacifiCorp.

13.2 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "B+" by the A.M. Best Company the insurance coverage specified below:

13.2.1 Commercial General Liability insurance, to include contractual liability, with a minimum single limit of $1,000,000 to protect against and from all loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

13.2.2 All Risk Property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The Risk policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

13.3 The Commercial General Liability policy required herein shall include i) provisions or endorsements naming PacifiCorp, its Board of Directors, Officers and employees as additional insureds, and ii) cross liability coverage so that the insurance applies separately to each insured against whom claim is made or suit is brought, even in instances where one insured claims against or sues another insured.

13.4 All liability policies required by this Agreement shall include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and provisions that such policies shall not be canceled or their limits of liability reduced without 1) ten (10) days prior written notice to PacifiCorp if canceled for nonpayment of premium, or 2) thirty (30) days prior written notice to PacifiCorp if canceled for any other reason.

13.5 Insurance coverage provided on a "claims-made" basis shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

SECTION 14: FORCE MAJEURE

14.1 As used in this Agreement, "**Force Majeure**" or "**an event of Force Majeure**" means any cause beyond the reasonable control of the Seller or of PacifiCorp which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of fuel or motive force resources to operate the Facility or changes in market conditions that affect the price of energy or transmission. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the event of Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

14.1.1 the non-performing Party, shall, within two (2) weeks after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

14.1.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure; and

14.1.3 the non-performing Party uses its best efforts to remedy its inability to perform.

14.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the event of Force Majeure.

14.3 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.4 PacifiCorp may terminate the Agreement if Seller fails to remedy Seller's inability to perform, due to an event of Force Majeure, within six months after the occurrence of the event.

SECTION 15: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 16: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the State of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 17: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

SECTION 18: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 19: GOVERNMENTAL JURISDICTIONS AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PacifiCorp.

SECTION 20: REPEAL OF PURPA

This Agreement shall not terminate upon the repeal of the PURPA, unless such termination is mandated by federal or state law.

SECTION 21: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party’s consent to a lender as part of a financing transaction or as part of (a) a sale of all or substantially all of the assigning Party’s assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 22: ENTIRE AGREEMENT

22.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PacifiCorp's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

22.2 By executing this Agreement, Seller releases PacifiCorp from any claims, known or unknown, that may have arisen prior to the Effective Date.

SECTION 23: NOTICES

23.1 All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested.

Notices	PacifiCorp	Seller
All Notices	PacifiCorp 825 NE Multnomah Street Portland, OR 97232 Attn: Contract Administration, Suite 600 Phone: (503) 813 - 5380 Facsimile: (503) 813 - 6291 Duns: 00-790-9013 Federal Tax ID Number: 93-0246090	Surprise Valley Electrification Corp 516 US Hwy 395 E Alturas, CA 96101 Phone: (530) 233-3511 Facsimile: (530) 233-2190 Duns: ___004770020______ Federal Tax ID Number: _94-0912124_______
All Invoices:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Scheduling:	(same as street address above) Attn: Resource Planning, Suite 600 Phone: (503) 813 - 6090 Facsimile: (503) 813 – 6265	
Payments:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Wire Transfer:	Bank One N.A. ABA: ACCT: NAME: PacifiCorp Wholesale	
Credit and Collections:	(same as street address above) Attn: Credit Manager, Suite 1900 Phone: (503) 813 - 5684 Facsimile: (503) 813 – 5609	
With Additional Notices of an Event of Default or Potential Event of Default to:	(same as street address above) Attn: PacifiCorp General Counsel Phone: (503) 813-5029 Facsimile: (503) 813-7252	

23.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 23.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the date first above written.

PacifiCorp	Seller
By:______________________________	By:______________________________
Name: Bruce Griswold ________________________	Name:_Craig Joiner
Title: Director, Short Term Origination and QF Contracts	Title: __President of the Board of Directors________________________

EXHIBIT A
DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

Seller's Facility consists of One (1) generator manufactured by Hyundai Ideal Electric Co. More specifically, each generator at the Facility is described as: Generator

A. Manufacturer's Nameplate Data:
Type (synchronous or inductive): Synchronous

Model: Synchronous Generator S/N 1210094 1800 RPM
Number of Phases: 3
Rated Output (kW): 3,650 **Rated Output (kVA):** 4,055
Rated Voltage (line to line):
Rated Current (A): Stator: 563 A; Rotor: 98 A
Power factor requirements:
Rated Power Factor (PF) or reactive load (kVAR): 0.90 P.F.

B. Seller's Estimate of Facility Output Under Ideal (Maximum) or Worst (Minimum) Conditions
Maximum kW Output: _2349___________ kW **Maximum kVA Output:** +/- .9 PF 2610 kVA
Minimum kW Output: ___1644______ kW
Manufacturer's Guaranteed Cut-in Wind Speed [if applicable]:

Facility Capacity Rating: ____2349_______ kW at ________+/- .9 PF ____________________________

Identify the maximum output of the generator(s) and describe any differences between that output and the Nameplate Capacity Rating: limited by geothermal resource.

Station service requirements, and other loads served by the Facility, if any, are described as follows: Parasitic load list attached

____

____.

EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES

Description of the point(s) of metering, including the type of meter(s), and the owner of the meter(s).

The Paisley Plant is located near Paisley Oregon within the service territory of SVEC and within the PacifiCorp Balancing Area. The electricity produced by the Paisley Plant will be interconnected to the SVEC electric system at SVEC's 69 kV transmission line at the Paisley generator generation substation.

There will be two sets of meters used to measure the generating quantities under this agreement. The generation quantities received and delivered of the Paisley Plant will be metered at SVEC's Paisley generator generation substation with two PacifiCorp revenue grade meters (primary and back-up). The primary meter will be used for SCADA, which will include: bi-directional MWH and MVARH quantities, MW, MVAR, and per phase volts and amps. The back-up meter will be used for telemetry MW data to the Alternate Control Center. Both meters will be capable of: (i) being accessed by PacifiCorp's transmission's MV-90 data acquisition system; and (ii) equipped with digital and analog option cards that conform to current standards as will be outlined in a Facilities Study. The second set of revenue metering will be at SVEC's Lakeview Switch 940 (Bonneville Power Administration's Meter 41) . Two PacifiCorp revenue grade meters (primary and back-up) will be installed at Bonneville Power Administration's (BPA) Meter 41 Substation located near PacifiCorp's Mile Hi Substation to measure generation quantities received and retail quantities delivered to SVEC.

The specific type and model of meters will be determined as a product of the Facilities Study.

2. A single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection shall be provided,

Please see the single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection is attached.

3. Specification of the Point of Delivery, and any transmission facilities on Seller's side of the Point of Delivery used to deliver Net Output.

Seller will deliver energy from the Paisley Project at the Bonneville Power Administration's Meter 41 (SVEC's Lakeview Switch 940)located near PacifiCorp's Mile Hi Substation where Seller's electric system interconnects with PacifiCorp Transmission. Bonneville Power Administration will deliver energy at the point near structure 47/5 in Bonneville Power Administration's La Pine- Chiloquin 230 kV transmission line, and where the 230 kV facilities of Bonneville Power Administration and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012).

EXHIBIT C
REQUIRED FACILITY DOCUMENTS

REQUIRED OF ALL FACILITIES:
QF Certification : QF13-276-000
Interconnection Agreement
Fuel Supply Agreement, if applicable
Land Lease

REQUIRED IF SELLER ELECTS TO GRANT SENIOR LIEN OR STEP-IN RIGHTS:
Deed or Lease to Facility Premises
Preliminary Title Report of Premises
Proof of ownership of Facility
Off-take sale agreements, e.g. surplus heat sale contract, if applicable

Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be requested.

Exhibit D-1 Motive Force Plan

A. MONTHLY DELIVERY SCHEDULES AND SCHEDULED MAINTENANCE

The following table summarizes the estimated monthly energy sales based on plant gross output, plant parasitic load consumption and assumed annual availability.

Annual Monthly Energy		
	Monthly kWh	Monthly Average kW
January	1,704,725	2,291
February	1,536,615	2,286
March	1,680,082	2,258
April	1,601,097	2,223
May	1,521,422	2,045
June	1,380,508	1,917
July	1,316,967	1,770
August	1,371,325	1,843
September	1,464,407	2,034
October	1,649,095	2,216
November	1,632,560	2,267
December	1,426,869	1,918
TOTAL	**18,285,671**	**2,087**

The estimated monthly output is based on the Net Output of the plant considering the following:

- Gross output of the plant at the generator terminals, considering average ambient wet-bulb temperature conditions
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Estimated plant degradation due to scaling/plant wear – first 2 years operation
- Annual 5 day planned maintenance shutdown (scheduled for December)
- Unplanned outages (1%)
- Transmission system outages (20 hours/year)

B. MINIMUM ANNUAL DELIVERY CALCULATION

The plant will operate as a base load facility. The minimum annual delivery is based on the expected worst case conditions of operation and availability. The Minimum Net Output is 12,197,102 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions + 5^0F elevated temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Five year, 14 day, major maintenance shutdown (scheduled for December)
- Estimated plant degradation 2X estimated annual average
- Unplanned outages (2%)
- Major unplanned outage – 3 months – production pump, well or plant failure (allocated across each operating month)

C. MAXIMUM DELIVERY CALCULATION

The maximum delivery is based on optimal operating conditions and availability. The Maximum Net Output is 19,391,369 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions - 5^0F reduced temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Annual 5 day planned maintenance shutdown (scheduled for December)
- No plant operational degradation
- No unplanned outages

EXHIBIT D-2
ENGINEER'S CERTIFICATION
OF
MOTIVE FORCE PLAN

Seller provide a written declaration from a Licensed Professional Engineer to PacifiCorp that the Facility is likely capable under average conditions foreseeable during the term of this Agreement of meeting Seller's estimated average, maximum, and minimum Net Output.

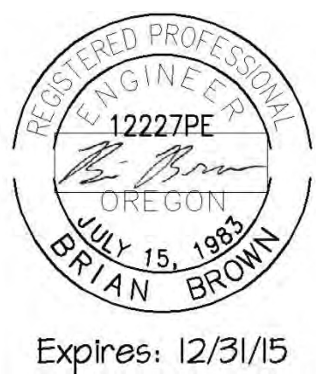
After reviewing the documentation provided to me by Surprise Valley Electric Corporation I have determined that the power plant is likely to meet the power estimates represented in the table below provided that the following qualifications are met.

Minimum	12,197,102 KWh/ year
Average	18,285,671 KWh/year
Maximum	19,391,369 KWh/year

Qualifications:

1. Power output will depend on the plant's ability to maintain 3000 GPM of 232°F geothermal well water
2. These power estimates do not include the parasitic load of the geothermal well pumps
3. Plant availability factor for the average output case stays at 97.4% or better

Signed/Stamped:



Date: May 15, 2014

EXHIBIT E

START-UP TESTING

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable): **[Seller identify appropriate tests]TAS-Turbine Air System to complete during start up and commissioning procedures**

1. Pressure tests of all steam system equipment; TAS
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;TAS
3. Operating tests of all valves, operators, motor starters and motor;TAS
4. Alarms, signals, and fail-safe or system shutdown control tests;TAS
5. Insulation resistance and point-to-point continuity tests;TAS
6. Bench tests of all protective devices;In Factory
7. Tests required by manufacturer of equipment;TAS and
8. Complete pre-parallel checks with PacifiCorp. TAS will support this scope but needs to understand the requirements.

Required start-up tests are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PacifiCorp's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;TAS. Vibration only.
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;TAS
3. Brake tests;NA
4. Energization of transformers;TAS
5. Synchronizing tests (manual and auto);TAS
6. Stator windings dielectric test ; Determining who to perform
7. Armature and field windings resistance tests;TAS
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load; TAS plant is not designed to island mode or survive load rejection. TAS will perform plant trip testing from above load l levels.
9. Heat runs;NA
10. Tests required by manufacturer of equipment;TAS
11. Excitation and voltage regulation operation tests;TAS
12. Open circuit and short circuit; saturation tests;to be determined
13. Governor system steady state stability test;TAS
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;TAS

15. Auto stop/start sequence;TAS
16. Level control system tests; andTAS
17. Completion of all state and federal environmental testing requirements NA

EXHIBIT F
Seller Authorization to Release Generation Data to PacifiCorp
See attached letter

EXHIBIT G
SCHEDULE 37 and PRICING SUMMARY TABLE

ADDENDUM W

GENERATION SCHEDULING ADDENDUM

WHEREAS, Seller's Facility is located within the control area of PacifiCorp;

WHEREAS, Seller's Facility will not interconnect directly to PacifiCorp's System;

WHEREAS, Seller and PacifiCorp have not executed, and will not execute, a Generation Interconnection Agreement in conjunction with the Power Purchase Agreement;

WHEREAS, Seller has elected to exercise its right under PURPA to deliver Net Output from its QF Facility to PacifiCorp via one (or more) Transmitting Entities.

WHEREAS, PacifiCorp desires that Seller schedule delivery of Net Output on a firm, hourly basis;

WHEREAS, PacifiCorp does not intend to buy, and Seller does not intend to deliver, more or less than Net Output from the Facility (except as expressly provided, below);

THEREFORE, Seller and PacifiCorp do hereby agree to the following, which shall become part of their Power Purchase Agreement:

DEFINITIONS

The meaning of the terms defined in the Power Purchase Agreement and this **Addendum W** shall apply to this Generation Scheduling Addendum:

"Day" means midnight to midnight, prevailing local time at the Point of Delivery, or any other mutually agreeable 24-hour period.

"Energy Imbalance Accumulation," or "**EIA,**" means the accumulated difference between Seller's Net Output and the energy actually delivered at the Point of Delivery. A positive accumulated difference indicates Seller's net delivery of Supplemented Output to PacifiCorp.

"Firm Delivery" means uninterruptible transmission service that is reserved and/or scheduled between the Point of Interconnection and the Points of Delivery pursuant to Transmission Agreements with Transmitting Entities.

"Settlement Period" means one month.

"Supplemented Output" means any increment of scheduled hourly energy or capacity delivered to the Point of Delivery in excess of the Facility's Net Output during that same hour.

"**Surplus Delivery"** means any energy delivered by the Facility in excess of hourly Net Output that is not offset by the delivery of energy in deficit of hourly Net Output during the Settlement Period. PacifiCorp shall accept Surplus Delivery, but shall not pay for it.

ADDENDUM W-ctd.

SELLER'S OBLIGATIONS IN LIEU OF THOSE CONTAINED IN A GENERATION INTERCONNECTION AGREEMENT.

1. **Seller's Responsibility to Arrange for Delivery of Net Output to Point of Delivery**. Seller shall arrange for the Firm Delivery of Net Output to a Point of Delivery. Seller shall comply with the terms and conditions of the Transmission Agreement(s) between the Seller and the Transmitting Entity(s). Whenever Seller fails to provide for Firm Delivery of Net Output, all Net Output delivered via non-firm transmission rights shall be deemed Excess Output, and therefore subject to the payment provision in Section 5.4 of the Power Purchase Agreement.

2. **Seller's Responsibility to Schedule Delivery.** Seller shall coordinate with the Transmitting Entity(s) to provide PacifiCorp with a schedule of the next Day's hourly scheduled Net Output deliveries at least 24 (twenty-four) hours prior to the beginning of the day being scheduled, and otherwise in accordance with the WECC Prescheduling Calendar (which is updated annually and may be downloaded at: http://www.wecc.biz/.

3. **Seller's Responsibility to Maintain Interconnection Facilities**. PacifiCorp shall have no obligation to install or maintain any interconnection facilities on Seller's side of the Point of Delivery. PacifiCorp shall not pay any costs arising from Seller interconnecting its Facility with the Transmitting Entity(s).

4. **Seller's Responsibility to Pay Transmission Costs**. Seller shall make all arrangements for, and pay all costs associated with, transmitting Net Output to PacifiCorp, scheduling energy into the PacifiCorp system and any other costs associated with delivering the Seller's Net Output to the Point of Delivery.

5. **Energy Reserve Requirements.** The Transmitting Entity shall provide all generation reserves as required by the WECC and/or as required by any other governing agency or industry standard to deliver the Net Energy to the Point of Delivery, at no cost to PacifiCorp.

6. **Seller's Responsibility to Report Net Output.** On or before the tenth ($10^{th)}$ day following the end of each Billing Period, Seller shall send a report documenting hourly station service, Excess Output, and Net Output from the Facility during the previous Billing Period, in columnar format substantially similar to the attached **Example 1**. If requested, Seller shall provide an electronic copy of the data used to calculate Net Output, in a standard format specified by PacifiCorp. For each day Seller is late delivering the certified report, PacifiCorp shall be entitled to postpone its payment deadline in Section 9 of this Power Purchase Agreement by one day. Seller hereby grants PacifiCorp the right to audit its certified reports of hourly Net Output. In the event of discovery of a billing error resulting in underpayment or overpayment, the Parties agree to limit recovery to a period of three years from the date of discovery.

7. **Seller's Supplemental Representations and Warranties**. In addition to the Seller's representations and warranties contained in Section 3 of this Agreement, Seller warrants that:

(a) Seller's Supplemented Output, if any, results from Seller's purchase of some form of energy imbalance ancillary service;

ADDENDUM W-ctd.

(b) The Transmitting Entity(s) requires Seller to procure the service, above, as a condition of providing transmission service;

(c) The Transmitting Entity requires Seller to schedule deliveries of Net Output in increments of no less than one (1) megawatt;

(d) Seller is not attempting to sell PacifiCorp energy or capacity in excess of its Net Output; and

(e) The energy imbalance service, above, is designed to correct a mismatch between energy scheduled by the QF and the actual real-time production by the QF.

8. **Seller's Right to Deliver Supplemented Output**. In reliance upon Seller's warranties in Section 5, above, PacifiCorp agrees to accept and pay for Supplemented Output; *provided, however, that* Seller agrees to achieve an EIA of zero (0) kilowatt-hours during On-Peak Hours and zero (0) kilowatt-hours during Off-Peak Hours at the end of each Settlement Period.

(a) **Remedy for Seller's Failure to Achieve zero EIA**. In the event Seller does not achieve zero EIA at the end of each Settlement Period, PacifiCorp will declare any positive balance to be Surplus Delivery, and Seller's EIA will be reset to zero. PacifiCorp will include an accounting of Surplus Delivery in each monthly statement provided to Seller pursuant to Section 9.1 of this Agreement.

(b) **Negative Energy Imbalance Accumulations**. Any negative EIA (indicating that the Transmitting Entity has delivered less than Seller's Net Output), will be reset to zero at the end of each Settlement Period without any corresponding compensation by PacifiCorp.

(c) **PacifiCorp's Option to Change EIA Settlement Period**. In the event PacifiCorp reasonably determines that doing so likely will have a *de minimis* net effect upon the cost of Seller's Net Output to PacifiCorp, it may elect to enlarge the Settlement Period, up to a maximum of one Contract Year. Conversely, if PacifiCorp reasonably determines, based on the QF's performance during the current year, that reducing the Settlement Period likely will significantly lower the net cost of Seller's Net Output to PacifiCorp, it shall have the right to shorten Seller's EIA settlement period beginning the first day of the following Contract Year. However, in no case shall the Settlement Period be less than one month.

ADDENDUM W—Example 1

Example of Seller's Output Reporting Requirement

Day	Hour ending (HE)	**A** Meter Reading▿ at Point of Delivery (MWh)	**B** Meter reading at Station Power Meter* (MWh)	**C (=A-B)** Net Output (MWh)	**D** Facility Capacity Rating (MW)	**E (=Max (0, C-D))** Excess Output (MWh)
1	7:00	0.50	0.01	0.49	1.50	
1	8:00	0.50	0.02	0.48	1.50	
1	9:00	0.50	0.01	0.49	1.50	
1	10:00	0.50	0.01	0.49	1.50	
1	11:00	0.50	0.01	0.49	1.50	
1	12:00	1.60	0.01	1.59	1.50	0.09
1	13:00	1.70	0.01	1.69	1.50	0.19
1	14:00	1.60	0.01	1.59	1.50	0.09
1	15:00	1.50	0.01	1.49	1.50	
1	16:00	1.50	0.01	1.50	1.50	
1	17:00	1.50	0.00	1.50	1.50	
1	18:00	1.50	0.01	1.49	1.50	
1	19:00	0.50	0.02	0.48	1.50	
1	20:00	0.50	0.01	0.49	1.50	

▿ Seller shall show adjustment of Meter Reading for losses, if any, between point of metering and the Point of Delivery, in accordance with Section 8.1.

* Does not apply if Station Service is provided from the gross output of the Facility.

ADDENDUM A

JURY TRIAL WAIVER

[Addendum A under SVEC Review] PacifiCorp and Surprise Valley Electrification Corp ("SVEC") are parties to that certain Power Purchase Agreement executed the date last written below (the "PPA"). This Addendum A to the PPA is entered into by and between PacifiCorp and SVEC and is intended to be interpreted and applied to the PPA.

Whereas, the Parties for their respective business purposes have an interest in not presenting a dispute to a jury for trial should a dispute arise between the Parties;

NOW, THEREFORE, for independent consideration, the receipt and sufficiency of which is acknowledged by both Parties, the Parties do hereby declare and agree as follows:

TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

This Addendum A to the PPA is executed and made effective this __ day of August, 2014.

PacifiCorp	Surprise Valley Electrification Corp.
By:______________________________	By:____________________________
Name: Bruce Griswold	Name: Brad Kresge
Title: Director, Short-Term Origination and QF Contracts	Title: General Manager

ADDENDUM W—Example 1

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP., Complainant v. PACIFICORP, d/b/a PACIFIC POWER, Respondent.

EXHIBIT PAC/111

SURPRISE VALLEY'S JUNE 22, 2015
DRAFT POWER PURCHASE AGREEMENT

May 17, 2016

POWER PURCHASE AGREEMENT

BETWEEN

SURPRISE VALLEY ELECTRIFICATION CORPORATION

[Firm Qualifying Facility with 10,000 kW Facility Capacity Rating, or Less, and uninterruptible transmission to the Point of Delivery]

AND

PACIFICORP

POWER PURCHASE AGREEMENT

THIS POWER PURCHASE AGREEMENT, entered into this 22nd day of June, 2015, is between Surprise Valley Electrification Corp., "**Seller**" and PacifiCorp (d/b/a Pacific Power & Light Company), an Oregon corporation acting in its regulated utility capacity, "**PacifiCorp**." (Seller and PacifiCorp are referred to individually as a "**Party**" or collectively as the "**Parties**").

RECITALS

A. Seller intends to construct, own, operate and maintain a geothermal facility for the generation of electric power, including interconnection facilities, located in Paisley, Lake County, Oregon with a Facility Capacity Rating of 3,650 kilowatts (kW) as further described in **Exhibit A** and **Exhibit B ("Facility")**; and

B. Seller intends to commence delivery of Net Output under this Power Purchase Agreement, for the purpose of Start-up Testing, on July 27, 2015 ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on or before September 10, 2015 ("**Scheduled Commercial Operation Date**") depending on the date of receipt of the Facilities Study being prepared by PacifiCorp Transmission; and

D. Seller estimates that the average annual Net Energy to be delivered by the Facility to PacifiCorp is 18,285,671 kilowatt-hours (kWh), which amount of energy PacifiCorp will include in its resource planning; and

E. Seller shall (choose one) X☐ sell all Net Output to PacifiCorp and purchase its full electric requirements from Bonneville Power Administration ☐ sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from Bonneville Power Administration, in accordance with the terms and conditions of this Agreement; and

F. This Agreement is a "New QF Contract" under the PacifiCorp Inter-Jurisdictional Cost Allocation Revised Protocol.

G. Seller intends to sell Net Output to PacifiCorp, and PacifiCorp intends to accept scheduled firm delivery of Seller's Net Output, under the terms of this Agreement, including the Generation Scheduling Addendum attached as **Addendum W** and incorporated contemporaneously herewith.

AGREEMENT

NOW, THEREFORE, the Parties mutually agree as follows:

SECTION 1: DEFINITIONS

When used in this Agreement, the following terms shall have the following meanings:

1.1 **"As-built Supplement"** shall be a supplement to **Exhibit A** and **Exhibit B**, provided by Seller following completion of construction of the Facility, describing the Facility as actually built.

1.2 "**Average Annual Generation"** shall have the meaning set forth in Section 4.2.

1.3 **"Billing Period"** means calendar months.

1.4 **"Commercial Operation Date"** means the date that the Facility is deemed by PacifiCorp to be fully operational and reliable, which shall require, among other things, that all of the following events have occurred:

1.4.1 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating (a) the Facility Capacity Rating of the Facility at the anticipated Commercial Operation Date; and (b) that the Facility is able to generate electric power reliably in amounts required by this Agreement and in accordance with all other terms and conditions of this Agreement;

1.4.2 The Facility has completed Start-Up Testing;

1.4.3 PacifiCorp has received a certificate addressed to PacifiCorp from a Licensed Professional Engineer stating that, (a), in accordance with the Interconnection Agreement, if applicable, all required interconnection facilities have been constructed, all required interconnection tests have been completed and the Facility is physically interconnected with PacifiCorp's electric system, or (b) if the Facility is interconnected with another electric utility that will wheel Net Output to PacifiCorp, all required interconnection facilities have been completed and tested and are in place to allow for such wheeling;

1.4.4 PacifiCorp has received a certificate addressed to PacifiCorp from an attorney in good standing in the State of Oregon stating that Seller has obtained all Required Facility Documents (Facilities over 200 kW only) and, if requested by PacifiCorp, in writing, has provided copies of any or all such requested Required Facility Documents.

1.4.5 Seller has complied with the security requirements of Section 10.

1.4.6 PacifiCorp has received an executed copy of **Exhibit F** - Seller's Interconnection Request.

1.5 **"Commission"** means the Oregon Public Utilities Commission.

1.6 **"Contract Price"** means the applicable price for capacity or energy, or both capacity and energy, stated in Sections 5.1 and 5.2.

1.7 **"Contract Year"** means a twelve (12) month period commencing at 00:00 hours Pacific Prevailing Time ("**PPT**") on January 1 and ending on 24:00 hours PPT on December 31; *provided, however,* that the first Contract Year shall commence on the Commercial Operation Date and end on the next succeeding December 31, and the last Contract Year shall end on the Termination Date.

1.8 "**Credit Requirements**" means a long-term credit rating (corporate or long-term senior unsecured debt) of (1) "Baa3" or greater by Moody's, or (2) "BBB-" or greater by S&P, or such other indicia of creditworthiness acceptable to PacifiCorp in its reasonable judgment.

Seller shall provide to PacifiCorp within five Business Days of receipt of a written request all reasonable financial records, including but not limited to three years of audited financial statements prepared in accordance with generally accepted accounting principles, necessary for PacifiCorp to confirm that Seller satisfies the Credit Requirements during the Term of this Agreement.

1.9 "**Default Security**", unless otherwise agreed to by the Parties in writing, means the amount of either a Letter of Credit or cash placed in an escrow account sufficient to replace twelve (12) average months of replacement power costs over the term of this Agreement, and shall be calculated by taking the average, over the term of this Agreement, of the positive difference between (a) the monthly forward power prices at Mid-C (as determined by PacifiCorp in good faith using information from a commercially reasonable independent source), multiplied by 110%, minus (b) the average of the Fixed Avoided Cost Prices specified in Schedule 37, and multiplying such difference by (c) the Minimum Annual Delivery; provided, however, the amount of Default Security shall in no event be less than the amount equal to the payments PacifiCorp would make for three (3) average months based on Seller's average monthly volume over the term of this Agreement and utilizing the average Fixed Avoided Cost Prices specified in Schedule 37. Such amount shall be fixed at the Effective Date of this Agreement.

1.10 "**Effective Date**" shall have the meaning set forth in Section 2.1.

1.11 "**Energy Delivery Schedule**" shall have the meaning set forth in Section 4.5.

1.12 "**Environmental Attributes**" shall have the meaning set forth in Section 5.5.

1.13 "**Excess Output**" shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Capacity Rating.

1.14 “**Facility**” shall have the meaning set forth in Recital A.

1.15 “**Facility Capacity Rating**” means the sum of the Nameplate Capacity Ratings for all generators comprising the Facility.

1.16 “**FERC**” means the Federal Energy Regulatory Commission, or its successor.

1.17 “**Generation Scheduling Addendum**” means **Addendum W**, the portion of this Agreement providing for the measurement, scheduling, and delivery of Seller’s Net Output from the Facility to the Point of Delivery via non-PacifiCorp transmission providers.

1.18 **Interconnected Utility**” means Surprise Valley Electrification Corp. and/or Bonneville Power Administration, the operators of the electric utility system at a Point of Interconnection.

1.19 “**Interconnection Agreement**” means the agreement (or contemporaneous agreements) between the Interconnected Utility and PacifiCorp governing interconnection of Interconnected Utility at a Point of Delivery and associated use of the Interconnected Utility’s system.

1.20 “**Letter of Credit**” means an irrevocable standby letter of credit, from an institution that has a long-term senior unsecured debt rating of “A” or greater from S&P or “A2” or greater from Moody’s, in a form reasonably acceptable to PacifiCorp, naming PacifiCorp as the party entitled to demand payment and present draw requests thereunder.

1.21 “**Licensed Professional Engineer**” means a person acceptable to PacifiCorp in its reasonable judgment who is licensed to practice engineering in the state of Oregon, who has no economic relationship, association, or nexus with the Seller, and who is not a representative of a consulting engineer, contractor, designer or other individual involved in the development of the Facility, or of a manufacturer or supplier of any equipment installed in the Facility. Such Licensed Professional Engineer shall be licensed in an appropriate engineering discipline for the required certification being made.

1.22 “**Material Adverse Change**” means the occurrence of any event of default under any material agreement to which Seller is a party and of any other development, financial or otherwise, which would have a material adverse effect on Seller, the Facility or Seller’s ability to develop, construct, operate, maintain or own the Facility as provided in this Agreement

1.23 “**Maximum Annual Delivery**” shall have the meaning set forth in Section 4.3.

1.24 “**Minimum Annual Delivery**” shall have the meaning set forth in Section 4.3.

1.25 “**Nameplate Capacity Rating**” means the full-load electrical quantities assigned by the designer to a generator and its prime mover or other piece of electrical equipment, such as transformers and circuit breakers, under standardized conditions, expressed in amperes, kilovoltamperes, kilowatts, volts, or other appropriate units that are usually indicated on a nameplate attached to the individual machine or device.

1.26 "**Net Energy**" means the energy component, in kWh, of Net Output.

1.27 "**Net Output"** means an amount equal to all energy and capacity produced by the Facility, less station use excluding pumping load attributable to the extraction and transportation functions the pumps perform and less transformation and transmission losses and other adjustments (e.g., Seller's load other than station use), if any, up to and including the Point of Delivery. For purposes of calculating payment under this Agreement, Net Output of energy shall be the amount of energy flowing through the revenue metering at SVEC's Paisley generator generation substation, adjusted as set forth in this paragraph.

1.28 "**Net Replacement Power Costs**" shall have the meaning set forth in Section 11.4.1.

1.29 "**Off-Peak Hours**" means all hours of the week that are not On-Peak Hours.

1.30 "**On-Peak Hours**" means the hours between 6 a.m. Pacific Prevailing Time ("**PPT**") and 10 p.m. PPT, Mondays through Saturdays, excluding all hours occurring on holidays as provided in Schedule 37.

1.31 "**Point of Delivery**" means the Point or Points of Interconnection between a Transmitting Entity's system and PacifiCorp's distribution/transmission system as specified in **Exhibit B.**

1.32 "**Point of Interconnection**" means the point(s) of interconnection between a Transmitting Entity's system and PacifiCorp's distribution/transmission system, as specified in **Exhibit B**.

1.33 "**Prime Rate**" means the publicly announced prime rate for commercial loans to large businesses with the highest credit rating in the United States in effect from time to time quoted by Citibank, N.A. If a Citibank, N.A. prime rate is not available, the applicable Prime Rate shall be the announced prime rate for commercial loans in effect from time to time quoted by a bank with $10 billion or more in assets in New York City, New York, selected by the Party to whom interest based on the Prime Rate is being paid.

1.34 "**Prudent Electrical Practices**" means any of the practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry or any of the practices, methods or acts, which, in the exercise of reasonable judgment in the light of the facts known at the time a decision is made, could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Electrical Practices is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts.

1.35 "**QF**" means "**Qualifying Facility,**" as that term is defined in the FERC regulations (codified at 18 CFR Part 292) in effect on the Effective Date.

1.36 "**Replacement Price**" means the price at which PacifiCorp, acting in a commercially reasonable manner, purchases for delivery at the Point of Delivery a replacement for any Net Output that Seller is required to deliver under this Agreement plus (i) costs reasonably incurred by PacifiCorp in purchasing such replacement Net Output, and (ii) additional transmission charges, if any, reasonably incurred by PacifiCorp in causing replacement energy to be delivered to the Point of Delivery. If PacifiCorp elects not to make such a purchase, the Replacement Price shall be the market price at the Mid-Columbia trading hub for such energy not delivered, plus any additional cost or expense incurred as a result of Seller's failure to deliver, as determined by PacifiCorp in a commercially reasonable manner (but not including any penalties, ratcheted demand or similar charges).

1.37 "**Required Facility Documents**" means all licenses, permits, authorizations, and agreements, including an Interconnection Agreement or equivalent, and any Transmission Agreement(s), necessary for construction, operation and maintenance of the Facility consistent with the terms of this Agreement. The Required Facility Documents are set forth in **Exhibit C.**

1.38 "**Schedule 37**" means the Schedule 37 of Pacific Power & Light Company's Commission-approved tariffs, providing pricing options for Qualifying Facilities of 10,000 kW or less, which is in effect prior to August 20, 2014. A copy of that Schedule 37 is attached as **Exhibit G**.

1.39 "**Scheduled Commercial Operation Date**" shall have the meaning set forth in Recital C.

1.40 "**Scheduled Initial Delivery Date**" shall have the meaning set forth in Recital B.

1.41 "**Start-Up Testing**" means the completion of required factory and start-up tests as set forth in **Exhibit E** hereto.

1.42 "**Termination Date**" shall have the meaning set forth in Section 2.4.

1.43 "**Transmission Agreement**" means the agreement (or contemporaneous agreements) between Seller and the Transmitting Entity providing for Seller's uninterruptible right to transmit Net Output to the Point of Delivery.

1.44 "**Transmitting Entity(s)**" means Surprise Valley Electrification Corp. and Bonneville Power Administration, the (non-PacifiCorp) operators of the transmission systems at a Points of Delivery.

SECTION 2: TERM; COMMERCIAL OPERATION DATE

2.1 This Agreement shall become effective after execution by both Parties ("**Effective Date**").

2.2 **Time is of the essence for this Agreement,** and Seller's ability to meet certain requirements prior to the Commercial Operation Date and to deliver Net Output by the Scheduled Commercial Operation Date is critically important. Therefore,

2.2.1 By October 31, 2014, Seller shall provide PacifiCorp with a copy of an executed Interconnection Agreement and an executed Transmission

Agreement, if either applicable, which shall be consistent with all material terms and requirements of this Agreement.

2.2.2 Upon completion of construction, Seller, in accordance with Section 6.1, shall provide PacifiCorp with an As-built Supplement acceptable to PacifiCorp;

2.2.3 By the date thirty (30) days after the Effective Date, Seller shall provide Default Security required under Sections 10.1 or 10.2, as applicable.

2.3 Seller shall cause the Facility to achieve Commercial Operation on or before the Scheduled Commercial Operation Date. If Commercial Operation occurs after the Scheduled Commercial Operation Date, Seller shall be in default, and liable for delay damages specified in Section 11.

2.4 This Agreement shall terminate on May 30, 2020, ("**Termination Date**") except as otherwise provided herein,.

SECTION 3: REPRESENTATIONS AND WARRANTIES

3.1 PacifiCorp represents, covenants, and warrants to Seller that:

3.1.1 PacifiCorp is duly organized and validly existing under the laws of the State of Oregon.

3.1.2 PacifiCorp has the requisite corporate power and authority to enter into this Agreement and to perform according to the terms of this Agreement.

3.1.3 PacifiCorp has taken all corporate actions required to be taken by it to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.1.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on PacifiCorp or any valid order of any court, or any regulatory agency or other body having authority to which PacifiCorp is subject.

3.1.5 This Agreement is a valid and legally binding obligation of PacifiCorp, enforceable against PacifiCorp in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2 Seller represents, covenants, and warrants to PacifiCorp that:

3.2.1 Seller is a corporation duly organized and validly existing under the laws of California.

3.2.2 Seller has the requisite power and authority to enter into this Agreement and to perform according to the terms hereof, including all required regulatory authority to make wholesale sales from the Facility.

3.2.3 Seller has taken all actions required to authorize the execution, delivery and performance of this Agreement and the consummation of the transactions contemplated hereby.

3.2.4 The execution and delivery of this Agreement does not contravene any provision of, or constitute a default under, any indenture, mortgage, or other material agreement binding on Seller or any valid order of any court, or any regulatory agency or other body having authority to which Seller is subject.

3.2.5 This Agreement is a valid and legally binding obligation of Seller, enforceable against Seller in accordance with its terms (except as the enforceability of this Agreement may be limited by bankruptcy, insolvency, bank moratorium or similar laws affecting creditors' rights generally and laws restricting the availability of equitable remedies and except as the enforceability of this Agreement may be subject to general principles of equity, whether or not such enforceability is considered in a proceeding at equity or in law).

3.2.6 The Facility is and shall for the term of this Agreement continue to be a QF, and Seller will operate the Facility in a manner consistent with its FERC QF certification. Seller has provided to PacifiCorp the appropriate QF certification (which may include a FERC self-certification) prior to PacifiCorp's execution of this Agreement. At any time during the term of this Agreement, PacifiCorp may require Seller to provide PacifiCorp with evidence satisfactory to PacifiCorp in its reasonable discretion that the Facility continues to qualify as a QF under all applicable requirements and, if PacifiCorp is not satisfied that the Facility qualifies for such status, a written legal opinion from an attorney who is (a) in good standing in the state of Oregon, and (b) who has no economic relationship, association or nexus with the Seller or the Facility, stating that the Facility is a QF and providing sufficient proof (including copies of all documents and data as PacifiCorp may request) demonstrating that Seller has maintained and will continue to maintain the Facility as a QF.

3.2.7 Compliance with Partial Stipulation in Commission Proceeding No. UM-1129. Seller will not make any changes in its ownership, control, or management during the term of this Agreement that would cause it to not be in compliance with the definition of a Small Cogeneration Facility or Small Power Production Facility provided in PacifiCorp's Schedule 37 tariff approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by PacifiCorp not more frequently than every 36 months, such documentation and information as reasonably may be required to establish Seller's continued compliance with such Definition. PacifiCorp agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except PacifiCorp will provide all such confidential information the Public Utility Commission of Oregon upon the Commission's request.

3.2.8 Additional Seller Creditworthiness Warranties. Seller need not post security under Section 10 for PacifiCorp's benefit in the event of Seller default, provided that Seller warrants all of the following:

(a) Neither the Seller nor any of its principal equity owners is or has within the past two (2) years been the debtor in any bankruptcy proceeding, is unable to pay its bills in the ordinary course of its business, or is the subject of any legal or regulatory action, the result of which could reasonably be expected to impair Seller's ability to own and operate the Facility in accordance with the terms of this Agreement.

(b) Seller has not at any time defaulted in any of its payment obligations for electricity purchased from PacifiCorp.

(c) Seller is not in default under any of its other agreements and is current on all of its financial obligations, including construction related financial obligations.

(d) Seller owns, and will continue to own for the term of this Agreement, all right, title and interest in and to the Facility, free and clear of all liens and encumbrances other than liens and encumbrances related to third-party financing of the Facility.

(e) **[Applicable only to Sellers with a Facility having a Facility Capacity Rating greater than 3,000 kW]** Seller meets the Credit Requirements.

Seller hereby declares (Seller initial one only):

____X___ Seller affirms and adopts all warranties of this Section 3.2.8, and therefore is not required to post security under Section 10; or

______ Seller does not affirm and adopt all warranties of this Section 3.2.8, and therefore Seller elects to post the security specified in Section 10.

3.3 Notice. If at any time during this Agreement, any Party obtains actual knowledge of any event or information which would have caused any of the representations and warranties in this Section 3 to have been materially untrue or misleading when made, such Party shall provide the other Party with written notice of the event or information, the representations and warranties affected, and the action, if any, which such Party intends to take to make the representations and warranties true and correct. The notice required pursuant to this Section shall be given as soon as practicable after the occurrence of each such event.

SECTION 4: DELIVERY OF POWER

4.1 Commencing on the Commercial Operation Date, unless otherwise provided herein, Seller will sell and PacifiCorp will purchase all Net Output from the Facility delivered to the Point of Delivery.

4.2 Average Annual Generation. Seller estimates that the Facility will generate, on average, 18,285,671 kWh per Contract Year ("**Average Annual Generation**"). Seller may, upon at least six months prior written notice, modify the Average Annual Generation every other Contract Year.

4.3 Minimum and Maximum Delivery. Seller shall deliver (or cause to be delivered) from the Facility a minimum of 12,197,102 kWh of Net Output during each Contract Year, provided that such minimum for the first Contract Year shall be reduced *pro rata* to reflect the Commercial Operation Date, and further provided that such minimum delivered Net Output shall be reduced on a *pro rata* basis for any periods during a Contract Year that the Facility was prevented from generating or delivering electricity for reasons of Force Majeure ("**Minimum Annual Delivery**"**)**. Seller estimates, for informational purposes, that it will deliver from the Facility a maximum of 19,391,369 kWh of Net Output during each Contract Year ("**Maximum Annual Delivery"**). Seller's basis for determining the Minimum and Maximum Annual Delivery amounts is set forth in **Exhibit D.**

4.4 Deliveries in Deficit of Delivery Obligation. Seller's failure to deliver the Minimum Annual Delivery in any Contract Year (prorated if necessary) shall be a default, and Seller shall be liable for damages in accordance with Section 11.

4.5 Energy Delivery Schedule. Seller has provided a monthly schedule of Net Energy expected to be delivered by the Facility ("**Energy Delivery Schedule**"), incorporated into **Exhibit D**.

SECTION 5: PURCHASE PRICES

5.1 Seller shall have the option to select one of four pricing options: Fixed Avoided Cost Prices (“Fixed Price”), Firm Market Indexed Avoided Cost Prices (“Firm Electric Market”), Gas Market Indexed Avoided Cost Prices (“Gas Market”), or Banded Gas Market Indexed Avoided Cost Prices (“Banded Gas Market”), as published in Schedule 37. Once an option is selected the option will remain in effect for the duration of the Facility’s contract. Seller has selected the following (Seller to initial one):

___X___ Fixed Price

_______ Firm Electric Market

_______ Gas Market

_______ Banded Gas Market

A copy of Schedule 37, and a table summarizing the purchase prices under the pricing option selected by Seller, is attached as **Exhibit G.**

5.2 (Applies only to “Fixed Price” Contracts Greater than 15 Years). In the event Seller elects the Fixed Price payment method, PacifiCorp shall pay Seller the applicable On-Peak and Off-Peak rates specified in **Schedule 37** during the first fifteen (15) years after the Scheduled Initial Delivery Date. Thereafter, PacifiCorp shall pay Seller market-based rates, using the following pricing option (Seller to initial one):

_______ Firm Electric Market

_______ Gas Market

_______ Banded Gas Market

5.3 If the Seller elects a gas market indexed price option, the index shall be the Opal Gas Market Index as provided in Schedule 37. In the event that Platt ceases to publish the Opal Gas Market Index, the Company shall replace the index with a similar gas index.

5.4 For all Excess Output and for all Net Output delivered prior to the Commercial Operation Date, PacifiCorp shall pay Seller a blended market index price for day-ahead non-firm energy at Mid-Columbia, California Oregon Border (COB), Four Corners and Palo Verde market indices as reported by Dow Jones, for the On-Peak and Off-Peak periods. PacifiCorp shall document its calculation of the blended rate, upon request, to Seller. Such payment will be accomplished by adjustments pursuant to Section 9.2.

5.5 Environmental Attributes. PacifiCorp waives any claim to Seller’s ownership of Environmental Attributes under this Agreement. Environmental Attributes include, but are not limited to, Green Tags, Green Certificates, Renewable Energy Credits (RECs) and Tradable Renewable Certificates (TRCs) (as those terms are commonly used in the regional electric utility industry) directly associated with the production of energy from the Seller’s Facility.

SECTION 6: OPERATION AND CONTROL

6.1 As-Built Supplement. Upon completion of initial (and any subsequent) construction of the Facility, Seller shall provide PacifiCorp an As-built Supplement to specify the actual Facility as built. The As-built Supplement must be reviewed and approved by PacifiCorp, which approval shall not unreasonably be withheld, conditioned or delayed.

6.2 Incremental Utility Upgrades. At start-up (and at any other time upon at least six months prior written notice), Seller may increase Net Output, if such increase is due to normal variances in estimated versus actual performance, changed Facility operations, or improvements in Facility efficiency. Seller may not increase Net Output under this Agreement by installing additional generating units. In the case of substantial upgrades, PacifiCorp may require Seller to comply with Section 3.2.8(e) (in the event that the Facility upgrade causes the Facility Capacity Rating to exceed 3,000 kW) and increase its Minimum Annual Delivery obligation in Section 4.3 (if appropriate). PacifiCorp may also update Seller's security obligation (if applicable). So long as the Facility Capacity Rating after the upgrade is 10,000 kW or less, Seller will continue to receive the Contract Price for the Net Output, as set forth in Sections 5.1 and 5.2 of this Agreement. If Seller increases the Facility Capacity Rating above 10,000 kW, then (on a going forward basis) PacifiCorp shall pay Seller the Contract Price for the fraction of total Net Output equal to 10,000 kW divided by the Facility Capacity Rating of the upgraded Facility. For the remaining fraction of Net Output, PacifiCorp and Seller shall agree to a new negotiated rate. Seller shall be responsible for ensuring that any planned increase in the Facility Capacity Rating or the maximum instantaneous capacity of the Facility complies with Seller's Interconnection Agreement, Transmission Agreement and any other relevant agreements.

6.3 Seller shall operate and maintain the Facility in a safe manner in accordance with this Agreement, the Interconnection Agreement, Prudent Electrical Practices and in accordance with the requirements of all applicable federal, state and local laws and the National Electric Safety Code as such laws and code may be amended from time to time. PacifiCorp shall have no obligation to purchase Net Output from the Facility to the extent the interconnection between the Facility and the Point of Delivery is disconnected, suspended or interrupted, in whole or in part, pursuant to the Interconnection Agreement or Transmission Agreement(s), or to the extent generation curtailment is required as a result of Seller's non-compliance with the Interconnection Agreement or Transmission Agreement(s). PacifiCorp shall have the right to inspect the Facility to confirm that Seller is operating the Facility in accordance with the provisions of this Section 6.3 upon reasonable notice to Seller. Seller is solely responsible for the operation and maintenance of the Facility. PacifiCorp shall not, by reason of its decision to inspect or not to inspect the Facility, or by any action or inaction taken with respect to any such inspection, assume or be held responsible for any liability or occurrence arising from the operation and maintenance by Seller of the Facility.

6.4 Scheduled Outages. Seller may cease operation of the entire Facility or individual units, if applicable, for maintenance or other purposes. Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp's request, if any, to reschedule such planned outage in order to accommodate PacifiCorp's need for Facility operation.

6.5 Unplanned Outages. In the event of an unscheduled outage or curtailment exceeding twenty-five (25) percent of the Facility Capacity Rating (other than curtailments due to lack of motive force), Seller immediately shall notify PacifiCorp of the necessity of such unscheduled outage or curtailment, the time when such has occurred or will occur and the anticipated duration. Seller shall take all reasonable measures and exercise its best efforts to avoid unscheduled outage or curtailment, to limit the duration of such, and to perform unscheduled maintenance during Off-Peak hours.

SECTION 7: FUEL/MOTIVE FORCE

Prior to the Effective Date of this Agreement, Seller provided to PacifiCorp a fuel or motive force plan acceptable to PacifiCorp in its reasonable discretion and attached hereto as **Exhibit D-1,** together with a certification from a Licensed Professional Engineer to PacifiCorp attached hereto as **Exhibit D-2**, certifying that the implementation of the fuel or motive force plan can reasonably be expected to provide fuel or motive force to the Facility for the duration of this Agreement adequate to generate power and energy in quantities necessary to deliver the Minimum Annual Delivery set forth by Seller in Section 4.

SECTION 8: METERING AT THE POINT OF INTERCONNECTION

8.1 Metering shall be performed at the locations and in a manner consistent with this Agreement, as specified in **Exhibit B**. Seller shall provide to PacifiCorp metered Facility Net Output in hourly increments, and any other energy measurements required to administer this Agreement. If the Transmitting Entity requires Seller to telemeter data, PacifiCorp shall be entitled to receive the same data Seller provides to the Transmitting Entity, if such data is useful to PacifiCorp's administration of this Agreement. All quantities of energy purchased hereunder shall be adjusted to account for electrical losses, if any, between the point of Interconnection and the Point of Delivery. The loss adjustment shall be 1.9% of the kWh energy production recorded on the Facility output meter.

8.2 Seller shall pay for the installation, testing, and maintenance of any metering required by Section 8.1, and shall provide reasonable access to such meters. PacifiCorp shall have reasonable access to inspection, testing, repair and replacement of the metering equipment. If any of the inspections or tests discloses a measurement error exceeding two percent (2%), either fast or slow, proper correction, based upon the inaccuracy found, shall be made of previous readings for the actual period during which the metering equipment rendered inaccurate measurements if that period can be ascertained. If the actual period cannot be ascertained, the proper correction shall be made to the measurements taken during the time the metering equipment was in service since last tested, but not exceeding three (3) Billing Periods, in the amount the metering equipment shall have been shown to be in error by such test. Any correction in billings or payments resulting from a correction in the meter records shall be made in the next monthly billing or payment rendered following the repair of the meter.

SECTION 9: BILLINGS, COMPUTATIONS, AND PAYMENTS

9.1 On or before the thirtieth (30th) day following the end of each Billing Period, PacifiCorp shall send to Seller payment for Seller's deliveries of Net Output to PacifiCorp, together with computations supporting such payment. PacifiCorp may offset any such payment to reflect amounts owing from Seller to PacifiCorp pursuant to this Agreement, the Interconnection Agreement, or any other agreement between the Parties.

9.2 Corrections. PacifiCorp shall have up to eighteen months to adjust any payment made pursuant to Section 9.1. In the event PacifiCorp determines it has overpaid Seller (for Excess Output or otherwise), PacifiCorp may adjust Seller's future payment accordingly in order to recapture any overpayment in a reasonable time.

9.3 Any amounts owing after the due date thereof shall bear interest at the Prime Rate plus two percent (2%) from the date due until paid; *provided*, *however*, that the interest rate shall at no time exceed the maximum rate allowed by applicable law.

SECTION 10: SECURITY

Unless Seller has adopted the creditworthiness warranties contained in Section 3.2.8, Seller must provide security (if requested by PacifiCorp) in the form of a cash escrow, letter of credit, senior lien, or step-in rights. Seller hereby elects to provide, in accordance with the applicable terms of this Section 10, the following security (Seller to initial one selection only):

____ Cash Escrow - $236,404

_____ Letter of Credit - $236,404

_____ Senior Lien

_____ Step-in Rights

___X__ Seller has adopted the Creditworthiness Warranties of Section 3.2.8.

In the event Seller's obligation to post default security (under Section 10 or Section 11.1.4) arises solely from Seller's delinquent performance of construction-related financial obligations, upon Seller's request, PacifiCorp will excuse Seller from such obligation in the event Seller has negotiated financial arrangements with its construction lenders that mitigate Seller's financial risks to PacifiCorp's reasonable satisfaction.

[SKIP THIS SECTION 10.1 UNLESS SELLER SELECTED CASH ESCROW ALTERNATIVE]

10.1 Cash Escrow Security. Seller shall deposit in an escrow account established by PacifiCorp in a banking institution acceptable to both Parties, the Default Security. Such sum shall earn interest at the rate applicable to money market deposits at such banking institution from time to time. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.2 UNLESS SELLER SELECTED LETTER OF CREDIT ALTERNATIVE]

10.2 Letter of Credit Security. Seller shall post and maintain in an amount equal to the Default Security: (a) a guaranty from a party that satisfies the Credit Requirements, in a form acceptable to PacifiCorp in its discretion, or (b) a Letter of Credit in favor of PacifiCorp. To the extent PacifiCorp receives payment from the Default Security, Seller shall, within fifteen (15) days, restore the Default Security as if no such deduction had occurred.

[SKIP THIS SECTION 10.3 UNLESS SELLER SELECTED SENIOR LIEN ALTERNATIVE]

10.3 Senior Lien. Before the Scheduled Commercial Operation Date, Seller shall grant PacifiCorp a senior, unsubordinated lien on the Facility and its assets as security for performance of this Agreement by executing, acknowledging and delivering a security agreement and a deed of trust or a mortgage, in a recordable form (each in a form satisfactory to PacifiCorp in the reasonable exercise of its discretion). Pending delivery of the senior lien to PacifiCorp, Seller shall not cause or permit the Facility or its assets to be burdened by liens or other encumbrances that would be superior to PacifiCorp's, other than workers', mechanics', suppliers' or similar liens, or tax liens, in each case arising in the ordinary course of business that are either not yet due and payable or that have been released by means of a performance bond posted within eight (8) calendar days of the commencement of any proceeding to foreclose the lien.

[SKIP THIS SECTION 10.4 UNLESS SELLER SELECTED STEP-IN RIGHTS ALTERNATIVE]

10.4 Step-in Rights (Operation by PacifiCorp Following Event of Default of Seller).

10.4.1 Prior to any termination of this Agreement due to an Event of Default of Seller, as identified in Section 11, PacifiCorp shall have the right, but not the obligation, to possess, assume control of, and operate the Facility as agent for Seller (in accordance with Seller's rights, obligations, and interest under this Agreement) during the period provided for herein. Seller shall not grant any person, other than the lending institution providing financing to the Seller for construction of the Facility ("Facility Lender"), a right to possess, assume control of, and operate the Facility that is equal to or superior to PacifiCorp's right under this Section 10.4.

10.4.2 PacifiCorp shall give Seller ten (10) calendar days' notice in advance of the contemplated exercise of PacifiCorp's rights under this Section 10.4. Upon such notice, Seller shall collect and have available at a convenient, central location at the Facility all documents, contracts, books, manuals, reports, and records required to construct, operate, and maintain the Facility in accordance with Prudent Electrical Practices. Upon such notice, PacifiCorp, its employees, contractors, or designated third parties shall have the unrestricted right to enter the Facility for the purpose of constructing and/or operating the Facility. Seller hereby irrevocably appoints PacifiCorp as Seller's attorney-in-fact for the exclusive purpose of executing such documents and taking such other actions as PacifiCorp may reasonably deem necessary or appropriate to exercise PacifiCorp's step-in rights under this Section 10.4.

10.4.3 During any period that PacifiCorp is in possession of and constructing and/or operating the Facility, no proceeds or other monies attributed to operation of the Facility shall be remitted to or otherwise provided to the account of Seller until all Events of Default of Seller have been cured.

10.4.4 During any period that PacifiCorp is in possession of and operating the Facility, Seller shall retain legal title to and ownership of the Facility and PacifiCorp shall assume possession, operation, and control solely as agent for Seller.

(a) In the event PacifiCorp is in possession and control of the Facility for an interim period, Seller shall resume operation and PacifiCorp shall relinquish its right to operate when Seller demonstrates to PacifiCorp's reasonable satisfaction that it will remove those grounds that originally gave rise to PacifiCorp's right to operate the Facility, as provided above, in that Seller (i) will resume operation of the Facility in accordance with the provisions of this Agreement, and (ii) has cured any Events of Default of Seller which allowed PacifiCorp to exercise its rights under this Section 10.4.

(b) In the event that PacifiCorp is in possession and control of the Facility for an interim period, the Facility Lender, or any nominee or transferee thereof, may foreclose and take possession of and operate the Facility and PacifiCorp shall relinquish its right to operate when the Facility Lender or any nominee or transferee thereof, requests such relinquishment.

10.4.5 PacifiCorp's exercise of its rights hereunder to possess and operate the Facility shall not be deemed an assumption by PacifiCorp of any liability attributable to Seller. If at any time after exercising its rights to take possession of and operate the Facility PacifiCorp elects to return such possession and operation to Seller, PacifiCorp shall provide Seller with at least fifteen (15) calendar days advance notice of the date PacifiCorp intends to return such possession and operation, and upon receipt of such notice Seller shall take all measures necessary to resume possession and operation of the Facility on such date.

SECTION 11: DEFAULTS AND REMEDIES

11.1 Events of Default. The following events shall constitute defaults under this Agreement:

11.1.1 Breach of Material Term. Failure of a Party to perform any material obligation imposed upon that Party by this Agreement (including but not limited to failure by Seller to meet any deadline set forth in Section 2) or breach by a Party of a representation or warranty set forth in this Agreement.

11.1.2 Default on Other Agreements. Seller's failure to cure any default under any commercial or financing agreements or instrument (including the Interconnection Agreement and any Transmission Agreement) within the time allowed for a cure under such agreement or instrument.

11.1.3 Insolvency. A Party (a) makes an assignment for the benefit of its creditors; (b) files a petition or otherwise commences, authorizes or acquiesces in the commencement of a proceeding or cause of action under any bankruptcy or similar law for the protection of creditors, or has such a petition filed against it and such petition is not withdrawn or dismissed within sixty (60) days after such filing; (c) becomes insolvent; or (d) is unable to pay its debts when due.

11.1.4 Material Adverse Change. A Material Adverse Change has occurred with respect to Seller and Seller fails to provide such performance assurances as are reasonably requested by PacifiCorp, including without limitation the posting of additional Default Security, within thirty (30) days from the date of such request;

11.1.5 Delayed Commercial Operations. Seller's failure to achieve the Commercial Operation Date by the Scheduled Commercial Operation Date.

11.1.6 Underdelivery. If Seller's Facility has a Facility Capacity Rating of 100 kW or less, Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for two (2) consecutive years; else Seller's failure to satisfy the minimum delivery obligation of Section 4.3 for one year.

11.2 Notice; Opportunity to Cure.

11.2.1 Notice. In the event of any default hereunder, the non-defaulting Party must notify the defaulting Party in writing of the circumstances indicating the default and outlining the requirements to cure the default.

11.2.2 Opportunity to Cure. A Party defaulting under Section 11.1.1 or 11.1.5 shall have thirty (30) days to cure after receipt of proper notice from the non-defaulting Party. This thirty (30) day period shall be extended by an additional ninety (90) days if (a) the failure cannot reasonably be cured within the thirty (30) day period despite diligent efforts, (b) the default is capable of being cured within the additional ninety (90) day period, and (c) the defaulting Party commences the cure within the original thirty (30) day period and is at all times thereafter diligently and continuously proceeding to cure the failure.

11.2.3 Seller Default Under Other Agreements. Seller shall cause any notices of default under any of its commercial or financing agreements or instruments to be sent by the other party to such agreements or instruments, or immediately forwarded, to PacifiCorp as a notice in accordance with Section 23.

11.2.4 Seller Delinquent on Construction-related Financial Obligations. Seller promptly shall notify PacifiCorp (or cause PacifiCorp to be notified) anytime it becomes delinquent under any construction related financing agreement or instrument related to the Facility. Such delinquency may constitute a Material Adverse Change, subject to Section 11.1.4.

11.3 Termination.

11.3.1 Notice of Termination. If a default described herein has not been cured within the prescribed time, above, the non-defaulting Party may terminate this Agreement at its sole discretion by delivering written notice to the other Party and may pursue any and all legal or equitable remedies provided by law or pursuant to this Agreement; *provided, however* that PacifiCorp shall not terminate: (a) for a default under Section 11.1.5 unless PacifiCorp is in a resource deficient state during the period Commercial Operation is delayed; or (b) for a default under Section 11.1.6, unless such default is material. The rights provided in Section 10 and this Section 11 are cumulative such that the exercise of one or more rights shall not constitute a waiver of any other rights. Further, the Parties may by mutual written agreement amend this Agreement in lieu of a Party's exercise of its right to terminate.

11.3.2 In the event this Agreement is terminated because of Seller's default and Seller wishes to again sell Net Output to PacifiCorp following such termination, PacifiCorp in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price, until the Termination Date (as set forth in Section 2.4). At such time Seller and PacifiCorp agree to execute a written document ratifying the terms of this Agreement.

11.3.3 Damages. If this Agreement is terminated as a result of Seller's default, Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the sum of the Replacement Price for the Minimum Annual Delivery that Seller was otherwise obligated to provide for a period of twenty-four (24) months from the date of termination plus any cost incurred for transmission purchased to deliver the replacement power to the Point of Delivery, and the estimated administrative cost to the utility to acquire replacement power. Amounts owed by Seller pursuant to this paragraph shall be due within five (5) business days after any invoice from PacifiCorp for the same.

11.3.4 If this Agreement is terminated because of Seller's default, PacifiCorp may foreclose upon any security provided pursuant to Section 10 to satisfy any amounts that Seller owes PacifiCorp arising from such default.

11.4 Damages.

11.4.1 Failure to Deliver Net Output. In the event of Seller default under Subsection 11.1.5 or Subsection 11.1.6, then Seller shall pay PacifiCorp the positive difference, if any, obtained by subtracting the Contract Price from the Replacement Price for any energy and capacity that Seller was otherwise obligated (under Section 4.3) to provide during the period of default ("**Net Replacement Power Costs**"); *provided, however,* that the positive difference obtained by subtracting the Contract Price from the Replacement Price shall not exceed the Contract Price, and the period of default under this Section 11.4.1 shall not exceed one Contract Year.

11.4.2 Recoupment of Damages.

(a) Default Security Available. If Seller has posted Default Security, PacifiCorp may draw upon that security to satisfy any damages, above.

(b) Default Security Unavailable. If Seller has not posted Default Security, or if PacifiCorp has exhausted the Default Security, PacifiCorp may collect any remaining amount owing by partially withholding future payments to Seller over a reasonable period of time, which period shall not be less than the period over which the default occurred. PacifiCorp and Seller shall work together in good faith to establish the period, and monthly amounts, of such withholding so as to avoid Seller's default on its commercial or financing agreements necessary for its continued operation of the Facility.

SECTION 12: INDEMNIFICATION AND LIABILITY

12.1 Indemnities.

12.1.1 Indemnity by Seller. Seller shall release, indemnify and hold harmless PacifiCorp, its directors, officers, agents, and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with (a) the energy delivered by Seller under this Agreement to and at the Point of Delivery, (b) any facilities on Seller's side of the Point of Delivery, (c) Seller's operation and/or maintenance of the Facility, or (d) arising from this Agreement, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property belonging to PacifiCorp, Seller or others, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of PacifiCorp, its directors, officers, employees, agents or representatives.

12.1.2 Indemnity by PacifiCorp. PacifiCorp shall release, indemnify and hold harmless Seller, its directors, officers, agents, Lenders and representatives against and from any and all loss, fines, penalties, claims, actions or suits, including costs and attorney's fees, both at trial and on appeal, resulting from, or arising out of or in any way connected with the energy delivered by Seller under this Agreement after the Point of Delivery, including without limitation any loss, claim, action or suit, for or on account of injury, bodily or otherwise, to, or death of, persons, or for damage to, or destruction or economic loss of property, excepting only such loss, claim, action or suit as may be caused solely by the fault or gross negligence of Seller, its directors, officers, employees, agents, Lenders or representatives.

12.2 No Dedication. Nothing in this Agreement 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. No undertaking by one Party to the other under any provision of this Agreement shall constitute the dedication of that Party's system or any portion thereof to the other Party or to the public, nor affect the status of PacifiCorp as an independent public utility corporation or Seller as an independent individual or entity.

12.3 No Consequential Damages. EXCEPT TO THE EXTENT SUCH DAMAGES ARE INCLUDED IN THE LIQUIDATED DAMAGES, DELAY DAMAGES, COST TO COVER DAMAGES OR OTHER SPECIFIED MEASURE OF DAMAGES EXPRESSLY PROVIDED FOR IN THIS AGREEMENT, NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR SPECIAL, PUNITIVE, INDIRECT, EXEMPLARY OR CONSEQUENTIAL DAMAGES, WHETHER SUCH DAMAGES ARE ALLOWED OR PROVIDED BY CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, STATUTE OR OTHERWISE.

SECTION 13: INSURANCE *(FACILITIES OVER 200KW ONLY)*

13.1 Certificates. Prior to connection of the Facility to PacifiCorp's electric system, or another utility's electric system, Seller shall secure and continuously carry insurance in compliance with the requirements of this Section. Seller shall provide PacifiCorp insurance certificate(s) (of "ACORD Form" or the equivalent) certifying Seller's compliance with the insurance requirements hereunder. Commercial General Liability coverage written on a "claims-made" basis, if any, shall be specifically identified on the certificate. If requested by PacifiCorp, a copy of each insurance policy, certified as a true copy by an authorized representative of the issuing insurance company, shall be furnished to PacifiCorp.

13.2 Required Policies and Coverages. Without limiting any liabilities or any other obligations of Seller under this Agreement, Seller shall secure and continuously carry with an insurance company or companies rated not lower than "B+" by the A.M. Best Company the insurance coverage specified below:

13.2.1 Commercial General Liability insurance, to include contractual liability, with a minimum single limit of $1,000,000 to protect against and from all loss by reason of injury to persons or damage to property based upon and arising out of the activity under this Agreement.

13.2.2 All Risk Property insurance providing coverage in an amount at least equal to the full replacement value of the Facility against "all risks" of physical loss or damage, including coverage for earth movement, flood, and boiler and machinery. The Risk policy may contain separate sub-limits and deductibles subject to insurance company underwriting guidelines. The Risk Policy will be maintained in accordance with terms available in the insurance market for similar facilities.

13.3 The Commercial General Liability policy required herein shall include i) provisions or endorsements naming PacifiCorp, its Board of Directors, Officers and employees as additional insureds, and ii) cross liability coverage so that the insurance applies separately to each insured against whom claim is made or suit is brought, even in instances where one insured claims against or sues another insured.

13.4 All liability policies required by this Agreement shall include provisions that such insurance is primary insurance with respect to the interests of PacifiCorp and that any other insurance maintained by PacifiCorp is excess and not contributory insurance with the insurance required hereunder, and provisions that such policies shall not be canceled or their limits of liability reduced without 1) ten (10) days prior written notice to PacifiCorp if canceled for nonpayment of premium, or 2) thirty (30) days prior written notice to PacifiCorp if canceled for any other reason.

13.5 Insurance coverage provided on a "claims-made" basis shall be maintained by Seller for a minimum period of five (5) years after the completion of this Agreement and for such other length of time necessary to cover liabilities arising out of the activities under this Agreement.

SECTION 14: FORCE MAJEURE

14.1 As used in this Agreement, "**Force Majeure**" or "**an event of Force Majeure**" means any cause beyond the reasonable control of the Seller or of PacifiCorp which, despite the exercise of due diligence, such Party is unable to prevent or overcome. By way of example, Force Majeure may include but is not limited to acts of God, fire, flood, storms, wars, hostilities, civil strife, strikes, and other labor disturbances, earthquakes, fires, lightning, epidemics, sabotage, restraint by court order or other delay or failure in the performance as a result of any action or inaction on behalf of a public authority which by the exercise of reasonable foresight such Party could not reasonably have been expected to avoid and by the exercise of due diligence, it shall be unable to overcome, subject, in each case, to the requirements of the first sentence of this paragraph. Force Majeure, however, specifically excludes the cost or availability of fuel or motive force resources to operate the Facility or changes in market conditions that affect the price of energy or transmission. If either Party is rendered wholly or in part unable to perform its obligation under this Agreement because of an event of Force Majeure, that Party shall be excused from whatever performance is affected by the event of Force Majeure to the extent and for the duration of the event of Force Majeure, after which such Party shall re-commence performance of such obligation, provided that:

14.1.1 the non-performing Party, shall, within two (2) weeks after the occurrence of the Force Majeure, give the other Party written notice describing the particulars of the occurrence; and

14.1.2 the suspension of performance shall be of no greater scope and of no longer duration than is required by the event of Force Majeure; and

14.1.3 the non-performing Party uses its best efforts to remedy its inability to perform.

14.2 No obligations of either Party which arose before the Force Majeure causing the suspension of performance shall be excused as a result of the event of Force Majeure.

14.3 Neither Party shall be required to settle any strike, walkout, lockout or other labor dispute on terms which, in the sole judgment of the Party involved in the dispute, are contrary to the Party's best interests.

14.4 PacifiCorp may terminate the Agreement if Seller fails to remedy Seller's inability to perform, due to an event of Force Majeure, within six months after the occurrence of the event.

SECTION 15: SEVERAL OBLIGATIONS

Nothing contained in this Agreement shall ever be construed to create an association, trust, partnership or joint venture or to impose a trust or partnership duty, obligation or liability between the Parties. If Seller includes two or more parties, each such party shall be jointly and severally liable for Seller's obligations under this Agreement.

SECTION 16: CHOICE OF LAW

This Agreement shall be interpreted and enforced in accordance with the laws of the State of Oregon, excluding any choice of law rules which may direct the application of the laws of another jurisdiction.

SECTION 17: PARTIAL INVALIDITY

It is not the intention of the Parties to violate any laws governing the subject matter of this Agreement. If any of the terms of the Agreement are finally held or determined to be invalid, illegal or void as being contrary to any applicable law or public policy, all other terms of the Agreement shall remain in effect. If any terms are finally held or determined to be invalid, illegal or void, the Parties shall enter into negotiations concerning the terms affected by such decision for the purpose of achieving conformity with requirements of any applicable law and the intent of the Parties to this Agreement.

SECTION 18: WAIVER

Any waiver at any time by either Party of its rights with respect to a default under this Agreement or with respect to any other matters arising in connection with this Agreement must be in writing, and such waiver shall not be deemed a waiver with respect to any subsequent default or other matter.

SECTION 19: GOVERNMENTAL JURISDICTIONS AND AUTHORIZATIONS

This Agreement is subject to the jurisdiction of those governmental agencies having control over either Party or this Agreement. Seller shall at all times maintain in effect all local, state and federal licenses, permits and other approvals as then may be required by law for the construction, operation and maintenance of the Facility, and shall provide upon request copies of the same to PacifiCorp.

SECTION 20: REPEAL OF PURPA

This Agreement shall not terminate upon the repeal of the PURPA, unless such termination is mandated by federal or state law.

SECTION 21: SUCCESSORS AND ASSIGNS

This Agreement and all of the terms hereof shall be binding upon and inure to the benefit of the respective successors and assigns of the Parties. No assignment hereof by either Party shall become effective without the written consent of the other Party being first obtained and such consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, either Party may assign this Agreement without the other Party's consent to a lender as part of a financing transaction or as part of (a) a sale of all or substantially all of the assigning Party's assets, or (b) a merger, consolidation or other reorganization of the assigning Party.

SECTION 22: ENTIRE AGREEMENT

22.1 This Agreement supersedes all prior agreements, proposals, representations, negotiations, discussions or letters, whether oral or in writing, regarding PacifiCorp's purchase of Net Output from the Facility. No modification of this Agreement shall be effective unless it is in writing and signed by both Parties.

22.2 By executing this Agreement, Seller releases PacifiCorp from any claims, known or unknown, that may have arisen prior to the Effective Date.

SECTION 23: NOTICES

23.1 All notices except as otherwise provided in this Agreement shall be in writing, shall be directed as follows and shall be considered delivered if delivered in person or when deposited in the U.S. Mail, postage prepaid by certified or registered mail and return receipt requested.

Notices	PacifiCorp	Seller
All Notices	PacifiCorp 825 NE Multnomah Street Portland, OR 97232 Attn: Contract Administration, Suite 600 Phone: (503) 813 - 5380 Facsimile: (503) 813 - 6291 Duns: 00-790-9013 Federal Tax ID Number: 93-0246090	Surprise Valley Electrification Corp 516 US Hwy 395 E Alturas, CA 96101 Phone: (530) 233-3511 Facsimile: (530) 233-2190 Duns: ___004770020______ Federal Tax ID Number: _94-0912124_______
All Invoices:	(same as street address above) Attn: Back Office, Suite 700 Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Scheduling:	(same as street address above) Attn: Resource Planning, Suite 600 Phone: (503) 813 - 6090 Facsimile: (503) 813 – 6265	
Payments:	(same as street address above) Attn: Back Office, Suite 700	

Notices	PacifiCorp	Seller
	Phone: (503) 813 - 5578 Facsimile: (503) 813 – 5580	
Wire Transfer:	Bank One N.A. ABA: ACCT: NAME: PacifiCorp Wholesale	
Credit and Collections:	(same as street address above) Attn: Credit Manager, Suite 1900 Phone: (503) 813 - 5684 Facsimile: (503) 813 – 5609	
With Additional Notices of an Event of Default or Potential Event of Default to:	(same as street address above) Attn: PacifiCorp General Counsel Phone: (503) 813-5029 Facsimile: (503) 813-7252	

23.2 The Parties may change the person to whom such notices are addressed, or their addresses, by providing written notices thereof in accordance with this Section 23.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names as of the date first above written.

PacifiCorp	Seller
By:________________________	By: [signature]
Name: Bruce Griswold	Name:_Craig Joiner
Title: Director, Short Term Origination and QF Contracts	Title: __President of the Board of Directors____________________

EXHIBIT A
DESCRIPTION OF SELLER'S FACILITY

[Seller to Complete]

Seller's Facility consists of One (1) generator manufactured by Hyundai Ideal Electric Co. More specifically, each generator at the Facility is described as: Generator

A. Manufacturer's Nameplate Data:
Type (synchronous or inductive): Synchronous

Model: Synchronous Generator S/N 1210094 1800 RPM
Number of Phases: 3
Rated Output (kW): 3,650 **Rated Output (kVA):** 4,055
Rated Voltage (line to line):
Rated Current (A): Stator: 563 A; Rotor: 98 A
Power factor requirements:
Rated Power Factor (PF) or reactive load (kVAR): 0.90 P.F.

B. Seller's Estimate of Facility Output Under Ideal (Maximum) or Worst (Minimum) Conditions
Maximum kW Output: _2349___________ kW **Maximum kVA Output:** +/- .9 PF 2610 kVA
Minimum kW Output: ___1644______ kW
Manufacturer's Guaranteed Cut-in Wind Speed [if applicable]:

Facility Capacity Rating: ____2349_______ kW at ________+/- .9 PF ____________________________

Identify the maximum output of the generator(s) and describe any differences between that output and the Nameplate Capacity Rating: limited by geothermal resource.

Station service requirements, and other loads served by the Facility, if any, are described as follows: Parasitic load list attached
____

____.

EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES

Description of the point(s) of metering, including the type of meter(s), and the owner of the meter(s).

The Paisley Plant is located near Paisley Oregon within the service territory of SVEC and within the PacifiCorp Balancing Area. The electricity produced by the Paisley Plant will be interconnected to the SVEC electric system at SVEC's 69 kV transmission line at the Paisley generator generation substation.

There will be two sets of meters used to measure the generating quantities under this agreement. The generation quantities received and delivered of the Paisley Plant will be metered at SVEC's Paisley generator generation substation with two PacifiCorp revenue grade meters (primary and back-up). The primary meter will be used for SCADA, which will include: bi-directional MWH and MVARH quantities, MW, MVAR, and per phase volts and amps. The back-up meter will be used for telemetry MW data to the Alternate Control Center. Both meters will be capable of: (i) being accessed by PacifiCorp's transmission's MV-90 data acquisition system; and (ii) equipped with digital and analog option cards that conform to current standards as will be outlined in a Facilities Study. The second set of revenue metering will be at SVEC's Lakeview Switch 940 (Bonneville Power Administration's Meter 41) . Two PacifiCorp revenue grade meters (primary and back-up) will be installed at Bonneville Power Administration's (BPA) Meter 41 Substation located near PacifiCorp's Mile Hi Substation to measure generation quantities received and retail quantities delivered to SVEC.

The specific type and model of meters will be determined as a product of the Facilities Study.

2. A single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection shall be provided,

Please see the single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection is attached.

3. Specification of the Point of Delivery, and any transmission facilities on Seller's side of the Point of Delivery used to deliver Net Output.

Seller will deliver energy from the Paisley Project at the Bonneville Power Administration's Meter 41 (SVEC's Lakeview Switch 940)located near PacifiCorp's Mile Hi Substation where Seller's electric system interconnects with PacifiCorp Transmission. Bonneville Power Administration will deliver energy at the point near structure 47/5 in Bonneville Power Administration's La Pine- Chiloquin 230 kV transmission line, and where the 230 kV facilities of

Bonneville Power Administration and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012).

EXHIBIT C
REQUIRED FACILITY DOCUMENTS

REQUIRED OF ALL FACILITIES:
QF Certification : QF13-276-000
Interconnection Agreement
Fuel Supply Agreement, if applicable
Land Lease

REQUIRED IF SELLER ELECTS TO GRANT SENIOR LIEN OR STEP-IN RIGHTS:
Deed or Lease to Facility Premises
Preliminary Title Report of Premises
Proof of ownership of Facility
Off-take sale agreements, e.g. surplus heat sale contract, if applicable

Depending upon the type of Facility and its specific characteristics, additional Required Facility Documents may be requested.

Exhibit D-1 Motive Force Plan

A. MONTHLY DELIVERY SCHEDULES AND SCHEDULED MAINTENANCE

The following table summarizes the estimated monthly energy sales based on plant gross output, plant parasitic load consumption and assumed annual availability.

Annual Monthly Energy		
	Monthly kWh	Monthly Average kW
January	1,704,725	2,291
February	1,536,615	2,286
March	1,680,082	2,258
April	1,601,097	2,223
May	1,521,422	2,045
June	1,380,508	1,917
July	1,316,967	1,770
August	1,371,325	1,843
September	1,464,407	2,034
October	1,649,095	2,216
November	1,632,560	2,267
December	1,426,869	1,918
TOTAL	**18,285,671**	**2,087**

The estimated monthly output is based on the Net Output of the plant considering the following:

- Gross output of the plant at the generator terminals, considering average ambient wet-bulb temperature conditions
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Estimated plant degradation due to scaling/plant wear – first 2 years operation
- Annual 5 day planned maintenance shutdown (scheduled for December)
- Unplanned outages (1%)
- Transmission system outages (20 hours/year)

B. MINIMUM ANNUAL DELIVERY CALCULATION

The plant will operate as a base load facility. The minimum annual delivery is based on the expected worst case conditions of operation and availability. The Minimum Net Output is 12,197,102 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions + 5^0F elevated temperature

- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Five year, 14 day, major maintenance shutdown (scheduled for December)
- Estimated plant degradation 2X estimated annual average
- Unplanned outages (2%)
- Major unplanned outage – 3 months – production pump, well or plant failure (allocated across each operating month)

C. MAXIMUM DELIVERY CALCULATION

The maximum delivery is based on optimal operating conditions and availability. The Maximum Net Output is 19,391,369 kWh based on the following assumptions:

- Plant output is based on estimated average wet bulb conditions - 5^0F reduced temperature
- Plant parasitic load losses (cycle feed pumps, cooling tower, make up water pump, transformer losses, etc.)
- Annual 5 day planned maintenance shutdown (scheduled for December)
- No plant operational degradation
- No unplanned outages

EXHIBIT D-2
ENGINEER'S CERTIFICATION
OF
MOTIVE FORCE PLAN

Seller provide a written declaration from a Licensed Professional Engineer to PacifiCorp that the Facility is likely capable under average conditions foreseeable during the term of this Agreement of meeting Seller's estimated average, maximum, and minimum Net Output.

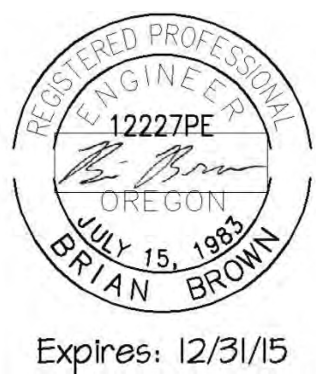
After reviewing the documentation provided to me by Surprise Valley Electric Corporation I have determined that the power plant is likely to meet the power estimates represented in the table below provided that the following qualifications are met.

Minimum	12,197,102 KWh/ year
Average	18,285,671 KWh/year
Maximum	19,391,369 KWh/year

Qualifications:

1. Power output will depend on the plant's ability to maintain 3000 GPM of 232°F geothermal well water
2. These power estimates do not include the parasitic load of the geothermal well pumps
3. Plant availability factor for the average output case stays at 97.4% or better

Signed/Stamped:



Date: May 15, 2014

EXHIBIT E

START-UP TESTING

Required factory testing includes such checks and tests necessary to determine that the equipment systems and subsystems have been properly manufactured and installed, function properly, and are in a condition to permit safe and efficient start-up of the Facility, which may include but are not limited to (as applicable): **[Seller identify appropriate tests]TAS- Turbine Air System to complete during start up and commissioning procedures**

1. Pressure tests of all steam system equipment; TAS
2. Calibration of all pressure, level, flow, temperature and monitoring instruments;TAS
3. Operating tests of all valves, operators, motor starters and motor;TAS
4. Alarms, signals, and fail-safe or system shutdown control tests;TAS
5. Insulation resistance and point-to-point continuity tests;TAS
6. Bench tests of all protective devices;In Factory
7. Tests required by manufacturer of equipment;TAS and
8. Complete pre-parallel checks with PacifiCorp. TAS will support this scope but needs to understand the requirements.

Required start-up tests are those checks and tests necessary to determine that all features and equipment, systems, and subsystems have been properly designed, manufactured, installed and adjusted, function properly, and are capable of operating simultaneously in such condition that the Facility is capable of continuous delivery into PacifiCorp's electrical system, which may include but are not limited to (as applicable):

1. Turbine/generator mechanical runs including shaft, vibration, and bearing temperature measurements;TAS. Vibration only.
2. Running tests to establish tolerances and inspections for final adjustment of bearings, shaft run-outs;TAS
3. Brake tests;NA
4. Energization of transformers;TAS
5. Synchronizing tests (manual and auto);TAS
6. Stator windings dielectric test ; Determining who to perform
7. Armature and field windings resistance tests;TAS
8. Load rejection tests in incremental stages from 5, 25, 50, 75 and 100 percent load; TAS plant is not designed to island mode or survive load rejection. TAS will perform plant trip testing from above load l levels.
9. Heat runs;NA
10. Tests required by manufacturer of equipment;TAS
11. Excitation and voltage regulation operation tests;TAS
12. Open circuit and short circuit; saturation tests;to be determined
13. Governor system steady state stability test;TAS
14. Phase angle and magnitude of all PT and CT secondary voltages and currents to protective relays, indicating instruments and metering;TAS

15. Auto stop/start sequence;TAS
16. Level control system tests; andTAS
17. Completion of all state and federal environmental testing requirements NA

EXHIBIT F
Seller Authorization to Release Generation Data to PacifiCorp
See attached letter

SURPRISE VALLEY
ELECTRIFICATION CORP.
516 U.S. HWY 395E ALTURAS, CA 96101
PHONE (530) 233-3511 FAX (530) 233-2190

Seller Authorization to Release Generation Data to PacifiCorp

Transmission Services
Attn: Senior Vice President, Transmission Services
825 NE Multnomah, Suite 1600
Portland, OR 97232

RE: Surprise Valley Electrification Corp. Interconnection Request

Dear Sir:

Surprise Valley Electrification Corp. hereby voluntarily authorizes PacifiCorp's Transmission business unit to share Surprise Valley Electrification Corp.'s generator interconnection information and generator meter data with Marketing Affiliate employees of PacifiCorp Energy, including, but not limited to those in the Commercial and Trading group. Surprise Valley Electrification Corp. acknowledges that PacifiCorp did not provide it any preferences, either operational or rate-related, in exchange for this voluntary consent.

C. James Hays
C. James Hays

General Manager
Title

August 13, 2013
Date

EXHIBIT G
SCHEDULE 37 and PRICING SUMMARY TABLE

Available

To owners of Qualifying Facilities making sales of electricity to the Company in the State of Oregon.

Applicable

For power purchased from Qualifying Facilities with a nameplate capacity of 10,000 kW or less or that, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a nameplate capacity of 10,000 kW or less. Owners of these Qualifying Facilities will be required to enter into a written power sales contract with the Company.

Definitions

Cogeneration Facility
A facility which produces electric energy together with steam or other form of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying Facilities
Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Small Power Production Facility
A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

On-Peak Hours or Peak Hours
On-peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005, the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April and for the period between the last Sunday in October and the first Sunday in November.

Off-Peak Hours
All hours other than On-Peak.

West Side Gas Market Index
The monthly indexed gas price shall be the average of the price indexes published by Platts in “Inside FERC’s Gas Market Report” monthly price report for Northwest Pipeline Corp. Rock Mountains, Northwest Pipeline Corp. Canadian Border, and Rockies/Northwest Stanfield, OR.

Excess Output
Excess output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Nameplate Capacity. PacifiCorp shall pay Seller the Off-peak Price as described and calculated under pricing option 5 for all Excess Output.

(continued)

Same Site
Generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and standard contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought.

Person(s) or Affiliated Person(s)
A natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a “passive investor” whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit. A unit of Oregon local government may also be a “passive investor” if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Shared Interconnection and Infrastructure
QFs otherwise meeting the separate ownership test and thereby qualified for entitlement to the standard rates and standard contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for the standard rates and standard contract so long as the use of the shared interconnection complies with the interconnecting utility’s safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility’s approved standard contract.

Dispute Resolution
Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and standard contract. Any dispute concerning a QF’s entitlement to the standard rates and standard contract shall be presented to the Commission for resolution.

Self Supply Option
Owner shall elect to sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp or sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of the power purchase agreement and the appropriate retail service.

(continued)

Pricing Options

1. Fixed Avoided Cost Prices
Prices are fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under either the Firm Market Indexed, the Banded Gas Market Indexed or the Gas Market Indexed Avoided Cost pricing option.

2. Gas Market Indexed Avoided Cost Prices
Fixed prices apply during the resource sufficiency period (2012 through 2015), thereafter a portion of avoided cost prices are indexed to actual monthly West Side Gas Market Index prices. The remaining portion of avoided cost prices will be fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Prices are available for a term of up to 20 years.

3. Banded Gas Market Indexed Avoided Cost Prices
Fixed prices apply during the resource sufficiency period (2012 through 2015), thereafter a portion of avoided cost prices are indexed to actual monthly West Side Gas Market Index prices. The remaining portion of avoided cost prices will be fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. The gas indexed portion of the avoided cost prices are banded to limit the amount that prices can vary with changes in gas prices. Prices are available for a term of up to 20 years.

4. Firm Market Indexed Avoided Cost Prices
Firm market index avoided cost prices are available to Qualifying Facilities that contract to deliver firm power. Monthly on-peak / off-peak prices paid are a blending of Intercontinental Exchange (ICE) Day Ahead Power Price Report at market hubs for on-peak and off-peak prices. The monthly blending matrix is available upon request.

5. Non-firm Market Index Avoided Cost Prices
Non- Firm market index avoided cost prices are available to Qualifying Facilities that do not elect to provide firm power. Qualifying Facilities taking this option will have contracts that do not include minimum delivery requirements, default damages for construction delay, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are a blending of ICE Day Ahead Power Price Report at market hubs for on-peak and off-peak prices. The monthly blending matrix is available upon request.

(continued)

Monthly Payments

A Qualifying Facility shall select the option of payment at the time of signing the contract under one of three Pricing Options as specified above. Once an option is selected the option will remain in effect for the duration of the Facility's contract.

Fixed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the fixed prices as provided in this tariff. The definition of On-Peak and Off-Peak is as defined in the definitions section of this tariff.

Gas Market Indexed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at On-Peak and Off-Peak prices calculated each month.

To calculate the Off-Peak price, multiply the West Side Gas Market Index price in $/MMBtu by 0.696 to get actual gas price in cents/kWh. The Off-Peak Energy Adder is added to the actual gas price to get the Off-Peak Price.

The On-Peak price is the Off-Peak price plus the On-Peak Capacity Adder.

Banded Gas Indexed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at On-Peak and Off-Peak prices calculated each month.

To calculate the Off-Peak price, multiply the West Side Gas Market Index price in $/MMBtu by 0.696 to get actual gas price in cents/kWh. This price is banded such that the actual gas price shall be no lower than the Gas Market Index Floor nor greater than the Gas Market Index Ceiling as listed in the price section of this tariff. The Off-Peak Energy Adder is added to the actual gas price to get the Off-Peak Price.

The On-Peak price is the Off-Peak price plus the On-Peak Capacity Adder.

Firm Market Indexed and Non-firm Market Index Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the market prices calculated at the time of delivery. The definition of On-Peak and Off-Peak is as defined in the definitions section of this tariff.

(continued)

Avoided Cost Prices

Pricing Option 1 – Fixed Avoided cost Prices ¢/kWh

Deliveries During Calendar Year	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)
2012	3.09	2.32
2013	3.72	2.62
2014	4.13	2.80
2015	4.39	2.99
2016	6.04	3.69
2017	6.32	3.91
2018	6.66	4.21
2019	6.99	4.50
2020	6.94	4.41
2021	7.23	4.65
2022	7.67	5.04
2023	7.92	5.24
2024	7.89	5.16
2025	8.09	5.32
2026	8.39	5.57
2027	8.66	5.78
2028	8.88	5.95
2029	9.07	6.09
2030	9.20	6.16

(continued)

Avoided Cost Prices (Continued)

Pricing Option 2 – Gas Market Indexed Avoided Cost Prices ¢/kWh

Deliveries During Calendar Year	Fixed Prices		Gas Market Index		Forecast	Estimated Prices (3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Capacity Adder (1)	Off-Peak Energy Adder	West Side Gas Market Index Price (2) $/MMBtu	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
			Avoided Firm Capacity Costs / (0.876 * 88.6% * 57%)	Total Avoided Energy Costs - ((e) * 0.696)		(g) + (c)	((e) * 0.696) + (d)
2012	3.09	2.32	Market Based Prices 2012 through 2015				
2013	3.72	2.62					
2014	4.13	2.80					
2015	4.39	2.99					
2016			2.36	0.44	$4.66	6.042	3.685
2017			2.40	0.47	$4.95	6.316	3.914
2018			2.45	0.47	$5.38	6.660	4.212
2019			2.49	0.47	$5.79	6.988	4.496
2020			2.53	0.47	$5.66	6.943	4.409
2021			2.58	0.48	$5.98	7.225	4.645
2022			2.63	0.50	$6.53	7.667	5.041
2023			2.67	0.52	$6.78	7.916	5.242
2024			2.72	0.53	$6.66	7.885	5.163
2025			2.77	0.54	$6.87	8.093	5.322
2026			2.82	0.55	$7.21	8.385	5.565
2027			2.87	0.57	$7.49	8.655	5.781
2028			2.93	0.60	$7.69	8.877	5.948
2029			2.98	0.62	$7.85	9.070	6.086
2030			3.04	0.64	$7.92	9.197	6.156
2031			3.10	0.64	$8.06	9.348	6.246
2032			3.16	0.65	$8.21	9.526	6.365
2033			3.22	0.66	$8.37	9.705	6.484
2034			3.29	0.68	$8.53	9.902	6.616

(1) Avoided Firm Capacity Costs are equal to the fixed costs of a SCCT as identified in the Company's 2011 IRP.
(2) A heat rate of 0.696 is used to adjust gas prices from $/MMBtu to ¢/kWh
(3) Estimated avoided cost prices based upon forecast West Side Gas Market Index prices.
Actual prices will be calculated each month using actual index gas prices.

(continued)

Avoided Cost Prices (Continued)

Pricing Option 3 – Banded Gas Market Indexed Avoided Cost Prices ¢/kWh

Deliveries During Calendar Year	Fixed Prices On-Peak Energy Price	Fixed Prices Off-Peak Energy Price	Banded Gas Market Index On-Peak Capacity Adder (1)	Banded Gas Market Index Off-Peak Energy Adder	Gas Market Index Floor 90%	Gas Market Index Ceiling 110%	Forecast West Side Gas Market Index Price (2) $/MMBtu	Estimated Prices (3) On-Peak Energy Price	Estimated Prices (3) Off-Peak Energy Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
			Avoided Firm Capacity Costs / (0.876 * 88.6% * 57%)	Total Avoided Energy Costs - ((e) * 0.696)	(g) * 0.696 * 90%	(g) * 0.696 * 110%		(i) + (c)	MIN(MAX(((g) * 0.696) , (e)) , (f)) + (d)
2012	3.09	2.32	Market Based Prices 2010 through 2013						
2013	3.72	2.62							
2014	4.13	2.80							
2015	4.39	2.99							
2016			2.36	0.44	2.92	3.57	$4.66	6.04	3.69
2017			2.40	0.47	3.10	3.79	$4.95	6.32	3.91
2018			2.45	0.47	3.37	4.12	$5.38	6.66	4.21
2019			2.49	0.47	3.63	4.43	$5.79	6.99	4.50
2020			2.53	0.47	3.55	4.33	$5.66	6.94	4.41
2021			2.58	0.48	3.75	4.58	$5.98	7.23	4.65
2022			2.63	0.50	4.09	5.00	$6.53	7.67	5.04
2023			2.67	0.52	4.25	5.19	$6.78	7.92	5.24
2024			2.72	0.53	4.17	5.10	$6.66	7.89	5.16
2025			2.77	0.54	4.30	5.26	$6.87	8.09	5.32
2026			2.82	0.55	4.52	5.52	$7.21	8.39	5.57
2027			2.87	0.57	4.69	5.73	$7.49	8.66	5.78
2028			2.93	0.60	4.82	5.89	$7.69	8.88	5.95
2029			2.98	0.62	4.92	6.01	$7.85	9.07	6.09
2030			3.04	0.64	4.96	6.06	$7.92	9.20	6.16
2031			3.10	0.64	5.05	6.17	$8.06	9.35	6.25
2032			3.16	0.65	5.14	6.29	$8.21	9.53	6.37
2033			3.22	0.66	5.24	6.41	$8.37	9.71	6.48
2034			3.29	0.68	5.34	6.53	$8.53	9.90	6.62

(1) Avoided Firm Capacity Costs are equal to the fixed costs of a SCCT as identified in the Company's 2011 IRP.

(2) A heat rate of 0.696 is used to adjust gas prices from $/MMBtu to ¢/kWh

(3) Estimated avoided cost prices based upon forecast West Side Gas Market Index prices. Actual prices will be calculated each month using actual index gas prices.

(continued)

Example of Gas Pricing Options available to the Qualifying Facility
An example of the two gas pricing options using different assumed gas prices is provided at the end of this tariff.

Qualifying Facilities Contracting Procedure
Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading).

It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to allow time for studies, negotiation of agreements, engineering, procurement, and construction of the required interconnection facilities. Early application for interconnection will help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

1. Qualifying Facilities up to 10,000 kW

APPLICATION: To owners of existing or proposed QFs with a design capacity less than or equal to 10,000 kW who desire to make sales to the Company in the state of Oregon. Such owners will be required to enter into a written power purchase agreement with the Company pursuant to the procedures set forth below.

I. Process for Completing a Power Purchase Agreement

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

PacifiCorp
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information.

(continued)

B. Procedures

1. The Company's approved generic or standard form power purchase agreements may be obtained from the Company's website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

2. In order to obtain a project specific draft power purchase agreement the owner must provide in writing to the Company, general project information required for the completion of a power purchase agreement, including, but not limited to:

   (a) demonstration of ability to obtain QF status;
   (b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
   (c) generation technology and other related technology applicable to the site;
   (d) proposed site location;
   (e) schedule of monthly power deliveries;
   (f) calculation or determination of minimum and maximum annual deliveries;
   (g) motive force or fuel plan;
   (h) proposed on-line date and other significant dates required to complete the milestones;
   (i) proposed contract term and pricing provisions (i.e.,fixed, deadband, gas indexed);
   (j) status of interconnection or transmission arrangements;
   (k) point of delivery or interconnection;

3. The Company shall provide a draft power purchase agreement when all information described in Paragraph 2 above has been received in writing from the QF owner. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Oregon Public Utilities Commission in this Schedule 37.

4. If the owner desires to proceed with the power purchase agreement after reviewing the Company's draft power purchase agreement, it may request in writing that the Company prepare a final draft power purchase agreement. In connection with such request, the owner must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft power purchase agreement. Within 15 business days following receipt of all information requested by the Company in this paragraph 4, the Company will provide the owner with a final draft power purchase agreement.

(continued)

B. Procedures (continued)

5 After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

6. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

II. Process for Negotiating Interconnection Agreements

[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (including but not limited to PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (including but not limited to PacifiCorp's Commercial and Trading Group).

(continued)

II. Process for Negotiating Interconnection Agreements (continued)

A. Communications

Initial communications regarding interconnection agreements should be directed to the Company in writing as follows:

PacifiCorp
Director – Transmission Services
825 NE Multnomah St, Suite 1600
Portland, Oregon 97232

Based on the project size and other characteristics, the Company will direct the QF owner to the appropriate individual within the Company's transmission function who will be responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.

B. Procedures

Generally, the interconnection process involves (1) initiating a request for interconnection, (2) undertaking studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) executing an interconnection agreement to address facility construction, testing, acceptance, ownership, operation and maintenance issues. Consistent with PURPA and Oregon Public Utility Commission regulations, the owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis. For interconnections impacting the Company's Transmission and Distribution System, the Company will process the interconnection application through PacifiCorp Transmission Services.

(continued)

PACIFIC POWER
A DIVISION OF PACIFICORP

Example of Gas Pricing Options given Assumed Gas Prices ¢/kWh

Banded Gas Market Index

Year	Prices Listed in the Tariff				Example using assumed Gas Prices						Compared to Fixed Prices	
	On-Peak Capacity Adder	Off-Peak Energy Adder	Gas Market Index Floor 90%	Gas Market Index Ceiling 110%	Assumed Gas Price $/MMBtu	Actual Energy Price	Fuel Index Floor / Ceiling Component	Fuel Index Type of Price	Price Paid to QF Off-Peak Price	Price Paid to QF On-Peak Price	Off-Peak Price	On-Peak Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
						(e) x 0.696			(b) + (g)	(a) + (i)		
2016	2.36	0.44	2.92	3.57	$2.00	1.39	2.92	Floor	3.36	5.72	3.69	6.04
					$4.00	2.78	2.92	Floor	3.36	5.72		
					$5.00	3.48	3.48	Actual	3.92	6.28		
					$7.00	4.87	3.57	Ceiling	4.01	6.37		
					$10.00	6.96	3.57	Ceiling	4.01	6.37		

Gas Market Method

Year	Prices Listed in the Tariff				Example using assumed Gas Prices						Compared to Fixed Prices	
	On-Peak Capacity Adder	Off-Peak Energy Adder	Fuel Index Floor 90%	Fuel Index Ceiling 110%	Assumed Gas Price $/MMBtu	Actual Energy Price	Fuel Index Floor / Ceiling Component	Fuel Index Type of Price	Price Paid to QF Off-Peak Price	Price Paid to QF On-Peak Price	Off-Peak Price	On-Peak Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
						(e) x 0.696			(b) + (f)	(a) + (i)		
2016	2.36	0.44	Not Relevant		$2.00	1.39	Not Relevant		1.83	4.19	3.69	6.04
					$4.00	2.78			3.22	5.58		
					$5.00	3.48			3.92	6.28		
					$7.00	4.87			5.31	7.67		
					$10.00	6.96			7.40	9.76		

ADDENDUM W

GENERATION SCHEDULING ADDENDUM

WHEREAS, Seller's Facility is located within the control area of PacifiCorp;

WHEREAS, Seller's Facility will not interconnect directly to PacifiCorp's System;

WHEREAS, Seller and PacifiCorp have not executed, and will not execute, a Generation Interconnection Agreement in conjunction with the Power Purchase Agreement;

WHEREAS, Seller has elected to exercise its right under PURPA to deliver Net Output from its QF Facility to PacifiCorp via one (or more) Transmitting Entities.

WHEREAS, PacifiCorp desires that Seller schedule delivery of Net Output on a firm, hourly basis;

WHEREAS, PacifiCorp does not intend to buy, and Seller does not intend to deliver, more or less than Net Output from the Facility (except as expressly provided, below);

THEREFORE, Seller and PacifiCorp do hereby agree to the following, which shall become part of their Power Purchase Agreement:

DEFINITIONS

The meaning of the terms defined in the Power Purchase Agreement and this **Addendum W** shall apply to this Generation Scheduling Addendum:

"Day" means midnight to midnight, prevailing local time at the Point of Delivery, or any other mutually agreeable 24-hour period.

"Energy Imbalance Accumulation," or "**EIA,**" means the accumulated difference between Seller's Net Output and the energy actually delivered at the Point of Delivery. A positive accumulated difference indicates Seller's net delivery of Supplemented Output to PacifiCorp.

"Firm Delivery" means uninterruptible transmission service that is reserved and/or scheduled between the Point of Interconnection and the Points of Delivery pursuant to Transmission Agreements with Transmitting Entities.

"Settlement Period" means one month.

"Supplemented Output" means any increment of scheduled hourly energy or capacity delivered to the Point of Delivery in excess of the Facility's Net Output during that same hour.

"**Surplus Delivery"** means any energy delivered by the Facility in excess of hourly Net Output that is not offset by the delivery of energy in deficit of hourly Net Output during the Settlement Period. PacifiCorp shall accept Surplus Delivery, but shall not pay for it.

ADDENDUM W-ctd.

SELLER'S OBLIGATIONS IN LIEU OF THOSE CONTAINED IN A GENERATION INTERCONNECTION AGREEMENT.

1. **Seller's Responsibility to Arrange for Delivery of Net Output to Point of Delivery**. Seller shall arrange for the Firm Delivery of Net Output to a Point of Delivery. Seller shall comply with the terms and conditions of the Transmission Agreement(s) between the Seller and the Transmitting Entity(s). Whenever Seller fails to provide for Firm Delivery of Net Output, all Net Output delivered via non-firm transmission rights shall be deemed Excess Output, and therefore subject to the payment provision in Section 5.4 of the Power Purchase Agreement.

2. **Seller's Responsibility to Schedule Delivery.** Seller shall coordinate with the Transmitting Entity(s) to provide PacifiCorp with a schedule of the next Day's hourly scheduled Net Output deliveries at least 24 (twenty-four) hours prior to the beginning of the day being scheduled, and otherwise in accordance with the WECC Prescheduling Calendar (which is updated annually and may be downloaded at: http://www.wecc.biz/.

3. **Seller's Responsibility to Maintain Interconnection Facilities**. PacifiCorp shall have no obligation to install or maintain any interconnection facilities on Seller's side of the Point of Delivery. PacifiCorp shall not pay any costs arising from Seller interconnecting its Facility with the Transmitting Entity(s).

4. **Seller's Responsibility to Pay Transmission Costs**. Seller shall make all arrangements for, and pay all costs associated with, transmitting Net Output to PacifiCorp, scheduling energy into the PacifiCorp system and any other costs associated with delivering the Seller's Net Output to the Point of Delivery.

5. **Energy Reserve Requirements.** The Transmitting Entity shall provide all generation reserves as required by the WECC and/or as required by any other governing agency or industry standard to deliver the Net Energy to the Point of Delivery, at no cost to PacifiCorp.

6. **Seller's Responsibility to Report Net Output.** On or before the tenth ($10^{th)}$ day following the end of each Billing Period, Seller shall send a report documenting hourly station service, Excess Output, and Net Output from the Facility during the previous Billing Period, in columnar format substantially similar to the attached **Example 1**. If requested, Seller shall provide an electronic copy of the data used to calculate Net Output, in a standard format specified by PacifiCorp. For each day Seller is late delivering the certified report, PacifiCorp shall be entitled to postpone its payment deadline in Section 9 of this Power Purchase Agreement by one day. Seller hereby grants PacifiCorp the right to audit its certified reports of hourly Net Output. In the event of discovery of a billing error resulting in underpayment or overpayment, the Parties agree to limit recovery to a period of three years from the date of discovery.

7. **Seller's Supplemental Representations and Warranties**. In addition to the Seller's representations and warranties contained in Section 3 of this Agreement, Seller warrants that:

(a) Seller's Supplemented Output, if any, results from Seller's purchase of some form of energy imbalance ancillary service;

ADDENDUM W-ctd.

(b) The Transmitting Entity(s) requires Seller to procure the service, above, as a condition of providing transmission service;

(c) The Transmitting Entity requires Seller to schedule deliveries of Net Output in increments of no less than one (1) megawatt;

(d) Seller is not attempting to sell PacifiCorp energy or capacity in excess of its Net Output; and

(e) The energy imbalance service, above, is designed to correct a mismatch between energy scheduled by the QF and the actual real-time production by the QF.

8. **Seller's Right to Deliver Supplemented Output**. In reliance upon Seller's warranties in Section 5, above, PacifiCorp agrees to accept and pay for Supplemented Output; *provided, however, that* Seller agrees to achieve an EIA of zero (0) kilowatt-hours during On-Peak Hours and zero (0) kilowatt-hours during Off-Peak Hours at the end of each Settlement Period.

(a) **Remedy for Seller's Failure to Achieve zero EIA**. In the event Seller does not achieve zero EIA at the end of each Settlement Period, PacifiCorp will declare any positive balance to be Surplus Delivery, and Seller's EIA will be reset to zero. PacifiCorp will include an accounting of Surplus Delivery in each monthly statement provided to Seller pursuant to Section 9.1 of this Agreement.

(b) **Negative Energy Imbalance Accumulations**. Any negative EIA (indicating that the Transmitting Entity has delivered less than Seller's Net Output), will be reset to zero at the end of each Settlement Period without any corresponding compensation by PacifiCorp.

(c) **PacifiCorp's Option to Change EIA Settlement Period**. In the event PacifiCorp reasonably determines that doing so likely will have a *de minimis* net effect upon the cost of Seller's Net Output to PacifiCorp, it may elect to enlarge the Settlement Period, up to a maximum of one Contract Year. Conversely, if PacifiCorp reasonably determines, based on the QF's performance during the current year, that reducing the Settlement Period likely will significantly lower the net cost of Seller's Net Output to PacifiCorp, it shall have the right to shorten Seller's EIA settlement period beginning the first day of the following Contract Year. However, in no case shall the Settlement Period be less than one month.

ADDENDUM W—Example 1

Example of Seller's Output Reporting Requirement

Day	Hour ending (HE)	A Meter Reading▿ at Point of Delivery (MWh)	B Meter reading at Station Power Meter* (MWh)	C (=A-B) Net Output (MWh)	D Facility Capacity Rating (MW)	E (=Max (0, C-D)) Excess Output (MWh)
1	7:00	0.50	0.01	0.49	1.50	
1	8:00	0.50	0.02	0.48	1.50	
1	9:00	0.50	0.01	0.49	1.50	
1	10:00	0.50	0.01	0.49	1.50	
1	11:00	0.50	0.01	0.49	1.50	
1	12:00	1.60	0.01	1.59	1.50	0.09
1	13:00	1.70	0.01	1.69	1.50	0.19
1	14:00	1.60	0.01	1.59	1.50	0.09
1	15:00	1.50	0.01	1.49	1.50	
1	16:00	1.50	0.01	1.50	1.50	
1	17:00	1.50	0.00	1.50	1.50	
1	18:00	1.50	0.01	1.49	1.50	
1	19:00	0.50	0.02	0.48	1.50	
1	20:00	0.50	0.01	0.49	1.50	

▿ Seller shall show adjustment of Meter Reading for losses, if any, between point of metering and the Point of Delivery, in accordance with Section 8.1.

* Does not apply if Station Service is provided from the gross output of the Facility.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/112

E-MAIL FROM J. YOUNIE TO L. CULP,
DATED NOVEMBER 6, 2013

May 17, 2016

From: Younie, John
To: lynnsvec@frontier.com
Subject: Surprise Valley Off-system Draft PPA 11062013.doc
Date: Wednesday, November 06, 2013 9:36:00 AM
Attachments: Surprise Valley Off-system Draft PPA 11062013.doc

Lynn,

Attached is a draft PPA updated with the motive force information you provided. Highlighted in yellow are blanks that I still need information. Could you please fill in the blanks and return the redline draft to me. Thanks for your help.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP.,
Complainant
v.
PACIFICORP, d/b/a PACIFIC POWER,
Respondent.

EXHIBIT PAC/113

E-MAILS BETWEEN
J. YOUNIE AND L. CULP, J. PORTOUW, AND D. MEEUWSEN,
DATED FROM NOVEMBER 20, 2013 THROUGH JANUARY 28, 2014

May 17, 2016

From: Younie, John
To: "lynn culp"
Subject: RE: Surprise Valley Off-system Draft PPA 11062013.doc
Date: Wednesday, November 20, 2013 3:06:00 PM

My phone number is: 503-813-5960.

From: lynn culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, November 20, 2013 2:36 PM
To: Younie, John
Subject: Re: Surprise Valley Off-system Draft PPA 11062013.doc

Hi John, I have some questions I would like to discuss with you. What is your phone number? Thanks, Lynn

From: Younie, John
Sent: Wednesday, November 06, 2013 9:36 AM
To: lynnsvec@frontier.com
Subject: Surprise Valley Off-system Draft PPA 11062013.doc

Lynn,

Attached is a draft PPA updated with the motive force information you provided. Highlighted in yellow are blanks that I still need information. Could you please fill in the blanks and return the redline draft to me. Thanks for your help.

From: Lynn Culp
To: Younie, John
Cc: Jim Hays; Brad Kresge
Subject: Fw: Surprise Valley Off-system Draft PPA 11062013.doc
Date: Saturday, November 23, 2013 5:09:46 PM

Hello John, See below. I'd like to have a phone conversation with one of your metering folks and BPA and us. Could you find out who that would be and get them in contact with me.
Thanks, Lynn

From: Vassallo,Gregory L (BPA) - TPCV-ALVEY
Sent: Thursday, November 21, 2013 8:48 AM
To: lynn culp ; Taylor,Eric K (BPA) - TSE-TPP-2
Cc: Jim Hays ; Brad Kresge ; Russell,Glenn A (BPA) - TPCV-TPP-4 ; Baker,Kevlyn D (BPA) - TPCV-TPP-4
Subject: RE: Surprise Valley Off-system Draft PPA 11062013.doc

Lynn,

Both BPA and SVEC metering meet BPA specifications for revenue metering so they should meet PACW requirements. I would suggest that PACW be invited to witness the in-service meter tests when they are performed at the site next year. PACW could be allowed access to Paisley meter data via our Metering Data Management Reporting (MDMR) system.

Greg Vassallo
Electrical Engineer - TPCV/Alvey
Customer Service Engineering & Planning
Bonneville Power Administration
541-988-7422 | glvassallo@bpa.gov

From: lynn culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, November 20, 2013 2:46 PM
To: Vassallo,Gregory L (BPA) - TPCV-ALVEY; Taylor,Eric K (BPA) - TSE-TPP-2
Cc: Jim Hays; Brad Kresge
Subject: Fw: Surprise Valley Off-system Draft PPA 11062013.doc

Hello Greg and Eric:

Please see the attached draft PPA with Pacific. Could you look at section 8, pg13 and exhibit B. Will the BPA revenue metering meet the requirements specified here? Please advise.
Thanks, Lynn

From: Younie, John
Sent: Wednesday, November 06, 2013 9:36 AM
To: lynnsvec@frontier.com
Subject: Surprise Valley Off-system Draft PPA 11062013.doc

Lynn,

Attached is a draft PPA updated with the motive force information you provided. Highlighted in yellow are blanks that I still need information. Could you please fill in the blanks and return the redline draft to me. Thanks for your help.

From:	Lynn Culp
To:	Younie, John
Cc:	Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann
Subject:	Re: Surprise Valley PPA
Date:	Monday, December 02, 2013 9:26:46 AM

Hello John, I hope you had a nice Thanksgiving holiday.
Following are the items in the draft PPA we would like to discuss tomorrow. We wanted to provide them to you so you could know what we are looking at and be prepared for the call.

1. Clause 1.27 – Net Output - We are interconnecting and metering the plant at the 69 kV line adjacent to the Paisley Plant. We assume that this is the point that Net Output should be based on. Please confirm.

2. Clause 1.31 – Point of Delivery – We would like to discuss the Point of Delivery and Interconnection Point. We are assuming that this is the same location at the 69 kV line adjacent to the plant.

3. Clause 1.36 – Replacement Price – Please provide clarification on how the quantity of replacement energy will be determined. Is this calculated based on the Exhibit D-1 projection or is this amount calculated based on the Energy Imbalance Accumulation determined under the Settlement Period in Addendum W?

4. Clause 4.5 – Energy Delivery Schedule – Please provide clarification on the purpose of developing the Net Energy schedule in Exhibit D. Based on Addendum D, Seller will be developing a day ahead hourly forecast with Settlement over a one month period. Which of these monthly forecasts will be used to determine positive or negative energy balance?

5. Clause 4.2 and Clause 6.2 – Clause 4.2 notes that the Average Annual Generation can be modified, upon six month notice, every other Contract year. Clause 6.2 allows Seller to increase Net Output at any time upon at least six month notice. We want to discuss the requirements behind these requirements and impact on increase/decrease of projected generation.

6. Clause 5.4 – We would like to discuss the payment of Excess Output in relationship to the facility operation. Excess Output is defined as Net Output produced in excess of the Facility Capacity Rating. Facility Capacity Rating is defined as the nameplate capacity rating of the generator. We are unclear on how the unit can generate in excess of a nameplate rating.

7. Addendum W – We would appreciate PacifiCorp discussion on the monthly settlement process and how positive and negative balances are settled.

a. Surplus Delivery – Please clarify the relationship between Addendum W definition and Clause 5.4. We would like to discuss the statement that PacifiCorp will accept Surplus Delivery, but shall not pay for it.
b. Section 8c – We would like to discuss the option of revising the Settlement Period to one year.

Thank you. Talk to you tomorrow. Lynn

Lynn Culp
Member Service Manager
Surprise Valley Electric
530.233.3511 office
530.640.2666 cell

From: Younie, John
Sent: Wednesday, November 27, 2013 3:01 PM
To: Lynn Culp
Cc: Mike Long ; Chun Chin ; Jim Hays ; Brad Kresge
Subject: RE: Surprise Valley PPA

Tuesday works best for me.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, November 27, 2013 2:39 PM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge
Subject: Surprise Valley PPA

Hello John,

I would like to have a phone conversation with you along with a couple of the gentlemen from Power Engineers who are assisting us with this project. We have a number of questions and clarifications with the PPA that we would like to discuss with you.

Are you available next Monday or Tuesday (11-1pm PT) or Wed (9-1pm PT). Any of those dates/times work for you?

Thank you. Looking forward to speaking with you. Have a great Thanksgiving. Lynn

From: Younie, John
To: "Lynn Culp"
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann
Subject: RE: Surprise Valley PPA
Date: Tuesday, December 03, 2013 11:28:00 AM

Lynn,

Bruce reminded me that if you were using your generation to off-set your BPA delivery you would not be a QF. In order for you to be a QF you must deliver the net output of your generator to PacifiCorp, we cannot do an accounting transaction. In this case BPA will be required to deliver your generation to PacifiCorp's system either through at Transmission Service Agreement or a Use-of-Facilities Agreement. If expensive improvements are required at Mile High in order to receive your generation we may ask that the power be delivered somewhere else on our system. I will ask our Transmission Desk if Mile High is an acceptable delivery point. In the meantime you need to initiate the delivery process with BPA.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, December 02, 2013 11:23 AM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann
Subject: Re: Surprise Valley PPA

See attached. Lynn

From: Younie, John
Sent: Monday, December 02, 2013 11:03 AM
To: Lynn Culp
Cc: Mike Long ; Chun Chin ; Jim Hays ; Brad Kresge ; Jeff Mann
Subject: RE: Surprise Valley PPA

Lynn,

Could you send me a one-line diagram that shows the generator, metering, and point of delivery?

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, December 02, 2013 9:27 AM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge; Jeff Mann
Subject: Re: Surprise Valley PPA

Hello John, I hope you had a nice Thanksgiving holiday.
Following are the items in the draft PPA we would like to discuss tomorrow. We wanted to provide them to you so you could know what we are looking at and be prepared for the call.

Clause 1.27 – Net Output - We are interconnecting and metering the plant at the 69 kV line adjacent to the Paisley Plant. We assume that this is the point that Net Output should be based on. Please confirm.

Clause 1.31 – Point of Delivery – We would like to discuss the Point of Delivery and Interconnection Point. We are assuming that this is the same location at the 69 kV line adjacent to the plant.

Clause 1.36 – Replacement Price – Please provide clarification on how the quantity of replacement energy will be determined. Is this calculated based on the Exhibit D-1 projection or is this amount calculated based on the Energy Imbalance Accumulation determined under the Settlement Period in Addendum W?

Clause 4.5 – Energy Delivery Schedule – Please provide clarification on the purpose of developing the Net Energy schedule in Exhibit D. Based on Addendum D, Seller will be developing a day ahead hourly forecast with Settlement over a one month period. Which of these monthly forecasts will be used to determine positive or negative energy balance?

Clause 4.2 and Clause 6.2 – Clause 4.2 notes that the Average Annual Generation can be modified, upon six month notice, every other Contract year. Clause 6.2 allows Seller to increase Net Output at any time upon at least six month notice. We want to discuss the requirements behind these requirements and impact on increase/decrease of projected generation.

Clause 5.4 – We would like to discuss the payment of Excess Output in relationship to the facility operation. Excess Output is defined as Net Output produced in excess of the Facility Capacity Rating. Facility Capacity Rating is defined as the nameplate capacity rating of the generator. We are unclear on how the unit can generate in excess of a nameplate rating.

Addendum W – We would appreciate PacifiCorp discussion on the monthly settlement process and how positive and negative balances are settled.

Surplus Delivery – Please clarify the relationship between Addendum W definition and Clause 5.4. We would like to discuss the statement that PacifiCorp will accept Surplus Delivery, but shall not pay for it.
Section 8c – We would like to discuss the option of revising the Settlement Period to one year.

Thank you. Talk to you tomorrow. Lynn

Lynn Culp
Member Service Manager
Surprise Valley Electric
530.233.3511 office
530.640.2666 cell

From: Younie, John

Sent: Wednesday, November 27, 2013 3:01 PM
To: Lynn Culp
Cc: Mike Long ; Chun Chin ; Jim Hays ; Brad Kresge
Subject: RE: Surprise Valley PPA

Tuesday works best for me.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Wednesday, November 27, 2013 2:39 PM
To: Younie, John
Cc: Mike Long; Chun Chin; Jim Hays; Brad Kresge
Subject: Surprise Valley PPA

Hello John,

I would like to have a phone conversation with you along with a couple of the gentlemen from Power Engineers who are assisting us with this project. We have a number of questions and clarifications with the PPA that we would like to discuss with you.

Are you available next Monday or Tuesday (11-1pm PT) or Wed (9-1pm PT). Any of those dates/times work for you?

Thank you. Looking forward to speaking with you. Have a great Thanksgiving. Lynn

From: Younie, John
To: Portouw, Jim; Meeuwsen, Doug
Subject: Surprise Valley Electric Corp
Date: Tuesday, December 03, 2013 11:36:00 AM

Jim and Doug,

It looks like BPA will be delivering approximately 3 MW of SVEC generation to our system at Mile High. Do you see any issues with taking delivery there? Is there a better delivery point?

From: Lynn Culp
To: Younie, John
Subject: Re: SVEC - SCADA
Date: Monday, January 20, 2014 11:15:54 AM

Hi John, I'm following up on this question with our engineer. What do you mean by real time "signal"? Is that a meter reading or some other signal? Lynn

From: Younie, John
Sent: Thursday, January 09, 2014 9:47 AM
To: lynnsvec@frontier.com
Subject: SVEC - SCADA

Lynn,

PacifiCorp will need to have a real time signal from the generator. Are you installing SCADA at the facility?

From: Lynn Culp
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin
Subject: Paisely Geothermal Signal
Date: Tuesday, January 28, 2014 10:24:58 AM

Hello John, What are Pacific's requirements for the "real time signal" required with the PPA? You have asked if we planned to install scada. We did not have that in our plans as we do not have scada on any of our system. Is there individuals in your group we could conference call with to discuss and determine how we can meet this requirement?

Also, I was speaking with Eric Birch of PacifiCorp Transmission group. He said that PacifiCorp Energy typically requests a transmission service request, which includes an impact study (100 days) and a facility study (an additional 60 days). Are these studies required for our PPA and have they been initiated with the transmission group? Do they have to be completed before the PPA can be signed and before the plant is operational?

Thanks, Lynn

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/114

E-MAILS BETWEEN
J. YOUNIE AND L. CULP,
FROM JANUARY 2014 THROUGH MAY 2014

May 17, 2016

From: Younie, John
To: lynnsvec@frontier.com
Subject: SVEC PPA
Date: Thursday, January 09, 2014 8:56:00 AM

Lynn,

Could you provide a breakdown of the generation that excludes the extraction and transmission loads but includes the reinjection loads? We will need each load identified. Also, provide net output on a monthly basis that includes maintenance downtime. Thanks for your help.

From: Younie, John
To: lynnsvec@frontier.com
Subject: SVEC - SCADA
Date: Thursday, January 09, 2014 9:47:00 AM

Lynn,

PacifiCorp will need to have a real time signal from the generator. Are you installing SCADA at the facility?

From:	Lynn Culp
To:	Younie, John
Cc:	Kirk Gibson; Brad Kresge; Mike Long
Subject:	Surprise Valley Net Output
Date:	Thursday, January 09, 2014 12:04:54 PM
Attachments:	SVEC Net output0113.xlsx

Hello John, Attached is the net output for the SVE Paisley plant including average, minimum and maximum output. Loads to extract and transport geothermal production fluid are not included in the data. There are no pumps at the injection well. Thanks, Lynn

From:	Younie, John
To:	Lynn Culp
Cc:	Brad Kresge; Mike Long
Subject:	RE: Surprise Valley Net Output
Date:	Friday, January 10, 2014 11:01:00 AM

Lynn – Thanks for the capacity's. I will need your assumptions and calculations for your generation estimates, especially for the super low minimum. I will also need your engineer to certify the motive force plan.

Below are the initial delivery date and the COD from the previous PPA. Could you please update these dates? I know we will not be ready to sign the PPA until sometime in March at the earliest. Thanks.

B. Seller intends to commence delivery of Net Output under this Power Purchase Agreement, for the purpose of Start-up Testing, on February 11, 2014 ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on March 31, 2014 ("**Scheduled Commercial Operation Date**");

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Thursday, January 09, 2014 9:01 PM
To: Younie, John
Cc: Brad Kresge; Mike Long
Subject: Re: Surprise Valley Net Output

Hi John, Here are the net outputs including kwh and kw (capacity) for ave/min/max generation. Thanks, Lynn

From: Younie, John
Sent: Thursday, January 09, 2014 1:32 PM
To: Lynn Culp
Subject: RE: Surprise Valley Net Output

Lynn,

A follow-up to the previous email. We need the capacity being delivered for Ave/Min/Max generation. We need these numbers as soon as possible, in order to make a transmission service request. Thanks

---

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Thursday, January 09, 2014 12:04 PM
To: Younie, John
Cc: Kirk Gibson; Brad Kresge; Mike Long
Subject: Surprise Valley Net Output

Hello John, Attached is the net output for the SVE Paisley plant including average, minimum and maximum output. Loads to extract and transport geothermal production fluid are not included in the data. There are no pumps at the injection well. Thanks, Lynn

From: Lynn Culp
To: Younie, John
Cc: Brad Kresge; Mike Long
Subject: Re: Surprise Valley Net Output
Date: Monday, January 20, 2014 11:12:10 AM

Hi John, Lets make the Commercial operation date May 26, 2013. Put the term at 6 years. Thanks, Lynn

From: Younie, John
Sent: Friday, January 10, 2014 11:01 AM
To: Lynn Culp
Cc: Brad Kresge ; Mike Long
Subject: RE: Surprise Valley Net Output

Lynn – Thanks for the capacity's. I will need your assumptions and calculations for your generation estimates, especially for the super low minimum. I will also need your engineer to certify the motive force plan.

Below are the initial delivery date and the COD from the previous PPA. Could you please update these dates? I know we will not be ready to sign the PPA until sometime in March at the earliest. Thanks.

B. Seller intends to commence delivery of Net Output under this Power Purchase Agreement, for the purpose of Start-up Testing, on February 11, 2014 ("**Scheduled Initial Delivery Date**"); and

C. Seller intends to operate the Facility as a Qualifying Facility, commencing commercial operations on March 31, 2014 ("**Scheduled Commercial Operation Date**");

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Thursday, January 09, 2014 9:01 PM
To: Younie, John
Cc: Brad Kresge; Mike Long
Subject: Re: Surprise Valley Net Output

Hi John, Here are the net outputs including kwh and kw (capacity) for ave/min/max generation. Thanks, Lynn

From: Younie, John
Sent: Thursday, January 09, 2014 1:32 PM
To: Lynn Culp
Subject: RE: Surprise Valley Net Output

Lynn,

A follow-up to the previous email. We need the capacity being delivered for Ave/Min/Max generation. We need these numbers as soon as possible, in order to make a transmission service request. Thanks

From: Lynn Culp [mailto:lynnsvec@frontier.com]

Sent: Thursday, January 09, 2014 12:04 PM
To: Younie, John
Cc: Kirk Gibson; Brad Kresge; Mike Long
Subject: Surprise Valley Net Output

Hello John, Attached is the net output for the SVE Paisley plant including average, minimum and maximum output. Loads to extract and transport geothermal production fluid are not included in the data. There are no pumps at the injection well. Thanks, Lynn

From: Younie, John
To: Lynn Culp
Subject: RE: SVEC - SCADA
Date: Tuesday, January 21, 2014 9:41:00 AM

PacifiCorp will want to see information from the generator on a real time basis. KW at the generator. We will also need an estimate of line and transformation losses from the generator to the point of delivery.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, January 20, 2014 11:15 AM
To: Younie, John
Subject: Re: SVEC - SCADA

Hi John, I'm following up on this question with our engineer. What do you mean by real time "signal"? Is that a meter reading or some other signal? Lynn

From: Younie, John
Sent: Thursday, January 09, 2014 9:47 AM
To: lynnsvec@frontier.com
Subject: SVEC - SCADA

Lynn,

PacifiCorp will need to have a real time signal from the generator. Are you installing SCADA at the facility?

From: Lynn Culp
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin
Subject: Paisely Geothermal Signal
Date: Tuesday, January 28, 2014 10:24:58 AM

Hello John, What are Pacific's requirements for the "real time signal" required with the PPA? You have asked if we planned to install scada. We did not have that in our plans as we do not have scada on any of our system. Is there individuals in your group we could conference call with to discuss and determine how we can meet this requirement?

Also, I was speaking with Eric Birch of PacifiCorp Transmission group. He said that PacifiCorp Energy typically requests a transmission service request, which includes an impact study (100 days) and a facility study (an additional 60 days). Are these studies required for our PPA and have they been initiated with the transmission group? Do they have to be completed before the PPA can be signed and before the plant is operational?

Thanks, Lynn

From: Lynn Culp
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin
Subject: Re: Paisely Geothermal Signal
Date: Wednesday, January 29, 2014 9:11:31 PM

Thanks John

From: Younie, John
Sent: Wednesday, January 29, 2014 2:51 PM
To: Lynn Culp
Cc: Brad Kresge ; Jeff Mann ; Kirk Gibson ; Chun Chin
Subject: RE: Paisely Geothermal Signal

Lynn,

We are still reviewing the PPA, it is a combination of on/off system PPA. I hope to have a draft to share with you next week.

SCADA – I talked to one of PacifiCorp's SCADA experts the policy is if there is a generator larger than 3 MW connected to our system we need SCADA. I will let you know when I have more information.

Transmission Service Request – Last week we made the request. I will let you know if we will sign the PPA without completion of the SIS and Facilities Study.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Tuesday, January 28, 2014 10:24 AM
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin
Subject: Paisely Geothermal Signal

Hello John, What are Pacific's requirements for the "real time signal" required with the PPA? You have asked if we planned to install scada. We did not have that in our plans as we do not have scada on any of our system. Is there individuals in your group we could conference call with to discuss and determine how we can meet this requirement?

Also, I was speaking with Eric Birch of PacifiCorp Transmission group. He said that PacifiCorp Energy typically requests a transmission service request, which includes an impact study (100 days) and a facility study (an additional 60 days). Are these studies required for our PPA and have they been initiated with the transmission group? Do they have to be completed before the PPA can be signed and before the plant is operational?

Thanks, Lynn

From: Lynn Culp
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin; Dick Wanderscheid
Subject: Re: Paisely Geothermal Signal
Date: Thursday, February 20, 2014 11:20:05 PM
Attachments: InterconnectStudy.pdf

Hi John,

My understanding was that a System Impact Study was completed by PacifiCorp. Please see attached document dated October 30, 2013 from PacifiCorp's Transmission services.
Is this the same as the SIS and Facility Study?
Appreciate your explanation. Thanks, Lynn

From: Younie, John
Sent: Monday, February 10, 2014 1:43 PM
To: Lynn Culp
Cc: Brad Kresge ; Jeff Mann ; Kirk Gibson ; Chun Chin ; Dick Wanderscheid
Subject: RE: Paisely Geothermal Signal

Lynn,

Here is a draft PPA for your geothermal project. This PPA is still being reviewed by management and is subject to change.

My supervisor told me that he would not execute this PPA until the transmission service request was approved.

Could you let me know what the losses are between the point of interconnection and the point of delivery?

Let me know if you have any questions.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, February 10, 2014 1:16 PM
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin; Dick Wanderscheid
Subject: Re: Paisely Geothermal Signal

Hello John, Just checking in with you to see when we can expect the draft of the PPA.
Thanks! Lynn

From: Younie, John
Sent: Wednesday, January 29, 2014 2:51 PM
To: Lynn Culp
Cc: Brad Kresge ; Jeff Mann ; Kirk Gibson ; Chun Chin
Subject: RE: Paisely Geothermal Signal

Lynn,

We are still reviewing the PPA, it is a combination of on/off system PPA. I hope to have a draft to share with you next week.

SCADA – I talked to one of PacifiCorp's SCADA experts the policy is if there is a generator larger than 3 MW connected to our system we need SCADA. I will let you know when I have more information.

Transmission Service Request – Last week we made the request. I will let you know if we will sign the PPA without completion of the SIS and Facilities Study.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Tuesday, January 28, 2014 10:24 AM
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin
Subject: Paisely Geothermal Signal

Hello John, What are Pacific's requirements for the "real time signal" required with the PPA? You have asked if we planned to install scada. We did not have that in our plans as we do not have scada on any of our system. Is there individuals in your group we could conference call with to discuss and determine how we can meet this requirement?

Also, I was speaking with Eric Birch of PacifiCorp Transmission group. He said that PacifiCorp Energy typically requests a transmission service request, which includes an impact study (100 days) and a facility study (an additional 60 days). Are these studies required for our PPA and have they been initiated with the transmission group? Do they have to be completed before the PPA can be signed and before the plant is operational?

Thanks, Lynn

From:	Lynn Culp
To:	Younie, John
Cc:	Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin; Mike Long
Subject:	Re: PPA IE
Date:	Tuesday, February 25, 2014 3:33:18 PM

Thanks John

From: Younie, John
Sent: Tuesday, February 25, 2014 2:45 PM
To: Lynn Culp
Cc: Brad Kresge ; Jeff Mann ; Kirk Gibson ; Chun Chin ; Mike Long
Subject: RE: PPA IE

Lynn:

PacifiCorp will accept Bill Bold and Brian Brown as independent engineers.

The SIS and Facilities Study you provided last week identifies the impacts and upgrades for SVEC to operate the generator on its system without exporting any power to PacifiCorp. It does not provide the system upgrades required in order to receive power from your generator. On January 27 PacifiCorp Merchant requested Network Resource status for your generator from PacifiCorp Transmission. A result of the Network Resource request will be a system impact study that shows the system upgrades required in order to receive your generation into PacifiCorp's system. One of the potential upgrades could be a SCADA requirement. After the request is made PacifiCorp Transmission has 90 days to complete their report.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Tuesday, February 25, 2014 1:52 PM
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin; Mike Long
Subject: PPA IE

Hi John, We are working through the PPA internally.
We have some items we want to address. we will put the items/questions in a logical format and provide to you in the next few days.

In the mean time we have made arrangements with Independent Engineers, Bill Bold and Brian Brown, to provide the Engineer's Certification for Exhibit D-2. Please see attached qualifications. Section 1.22 of the agreement states that the engineer must be acceptable to PacifiCorp.

Do you have any update on the question concerning the SIS and Facility study, which we posed last week?

Thanks! Lynn

From: Younie, John

Sent: Monday, February 10, 2014 1:43 PM
To: Lynn Culp
Cc: Brad Kresge ; Jeff Mann ; Kirk Gibson ; Chun Chin ; Dick Wanderscheid
Subject: RE: Paisely Geothermal Signal

Lynn,

Here is a draft PPA for your geothermal project. This PPA is still being reviewed by management and is subject to change.

My supervisor told me that he would not execute this PPA until the transmission service request was approved.

Could you let me know what the losses are between the point of interconnection and the point of delivery?

Let me know if you have any questions.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, February 10, 2014 1:16 PM
To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin; Dick Wanderscheid
Subject: Re: Paisely Geothermal Signal

Hello John, Just checking in with you to see when we can expect the draft of the PPA. Thanks! Lynn

From: Younie, John
Sent: Wednesday, January 29, 2014 2:51 PM
To: Lynn Culp
Cc: Brad Kresge ; Jeff Mann ; Kirk Gibson ; Chun Chin
Subject: RE: Paisely Geothermal Signal

Lynn,

We are still reviewing the PPA, it is a combination of on/off system PPA. I hope to have a draft to share with you next week.

SCADA – I talked to one of PacifiCorp's SCADA experts the policy is if there is a generator larger than 3 MW connected to our system we need SCADA. I will let you know when I have more information.

Transmission Service Request – Last week we made the request. I will let you know if we will sign the PPA without completion of the SIS and Facilities Study.

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Tuesday, January 28, 2014 10:24 AM

To: Younie, John
Cc: Brad Kresge; Jeff Mann; Kirk Gibson; Chun Chin
Subject: Paisely Geothermal Signal

Hello John, What are Pacific's requirements for the "real time signal" required with the PPA? You have asked if we planned to install scada. We did not have that in our plans as we do not have scada on any of our system. Is there individuals in your group we could conference call with to discuss and determine how we can meet this requirement?

Also, I was speaking with Eric Birch of PacifiCorp Transmission group. He said that PacifiCorp Energy typically requests a transmission service request, which includes an impact study (100 days) and a facility study (an additional 60 days). Are these studies required for our PPA and have they been initiated with the transmission group? Do they have to be completed before the PPA can be signed and before the plant is operational?

Thanks, Lynn

From:	Lynn Culp
To:	Younie, John
Cc:	Brad Kresge; Kirk Gibson; Jane
Subject:	SVE PPA Credit requirements
Date:	Tuesday, March 04, 2014 11:24:50 AM

Hi John,

As you are aware, Surprise Valley is a well-established operating utility. Surprise Valley is in strong financial condition, but does not currently maintain a long-term credit rating on its debt. Section 1.8 requires a certain credit rating from Moody's, or S&P, ***or such other indicia of credit worthiness acceptable to PacifiCorp…"***

Surprise Valley would like to have representatives from PacifiCorp's financial group review and evaluate Surprise Valley's financial condition as an operating utility for the purpose of Surprise Valley: 1) satisfying the credit worthiness of requirements of Section 1.8 of the PPA; and 2) making the warranty required by Section 3.28(e) of the PPA.

Kindly let me know who the financial folks at Surprise Valley should contact at PacifiCorp to address this matter.

Thanks, Lynn

From: janesvec@frontier.com
To: Lynn Culp; Younie, John
Cc: Brad Kresge; Kirk Gibson
Subject: Re: SVE PPA Credit requirements
Date: Thursday, May 01, 2014 2:17:06 PM
Attachments: FS 2011 FINAL COPY.pdf
FS 2012 FINAL COPY.pdf
FS 2013 Final Copy.pdf

John,
Here are three years of financial statements for Surprise Valley Electrification Corp.
for review under the PPA Credit Requirements.
Jane

Jane Eaton
Finance Manager
Surprise Valley Electrification Corp.
530-233-3511

From: Griswold, Bruce {Mkt Function}
To: Reid, Michael
Cc: Erb, Jeff; Younie, John; Link, Rick {Mkt Function}
Subject: FW: Surprise Valley Electric PPA
Date: Tuesday, May 20, 2014 4:26:51 PM
Attachments: SVEC On System PPA 02042014 Annotated 052014.docx

Michael

It is highly unlikely we will have this PPA finalized and approved for execution by May 31, 2014. There are a number of outstanding commercial and legal items and issues with this PPA that are not resolved at this time. Frankly, this project should be treated more as a negotiated Schedule 38 PPA because it is not standard and requires a number of concessions and assumptions on both sides. The bigger issue is what is our legal risk of not executing the PPA and SVEC missing their BETC deadline?

Bruce Griswold
PacifiCorp C&T
503.813.5218 Office
503.702.1445 Cell

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Tuesday, May 20, 2014 3:54 PM
To: Younie, John; Reid, Michael
Cc: Kirk Gibson; Brad Kresge; Griswold, Bruce {Mkt Function}
Subject: Surprise Valley Electric PPA

John/Michael

As we discussed during the last call, the Paisley Project is entering into the final phase of construction activities and start-up testing is due to commence within the next week.

SVEC appreciates the considerations discussed by PacifiCorp Transmission representatives regarding its ability to accommodate the Project's start-up activities. We are working to confirm that accommodation so the Project can maintain the established development schedule.

SVEC is prepared to enter into a standard PURPA power sales agreement with PacifiCorp. To that end, SVEC has considered some of the concerns voiced by PacifiCorp regarding the evidencing of the actual deliveries into the PacifiCorp system and SVEC has addressed those concerns in this version of the PPA. Please see the attached annotated version of the PPA that PacifiCorp forwarded in February. I have included both Bruce and Michael on this email to expedite their receipt of the attached PPA edits. Please note that the changes that are shaded in aqua are inserted in the PPA to provide language to address the SVEC Sales Concept. All other edits are red-lined for your convenience of review. SVEC is prepared to execute the PPA attached.

SVEC is prepared to move forward on the following matters, but needs some input from PacifiCorp:

1. **Interconnection Agreement** – As you are aware, SVEC has an interconnection arrangement with PacifiCorp at Lakeview substation and BPA has an interconnection agreement with PacifiCorp at Yamsay 230 kV. These are the two locations where deliveries will be made under the SVEC Sales Concept (See Exhibit B). There are existing interconnection agreements at these Delivery Points and therefore SVEC believes there is no further documentation required. Please confirm that these documents evidencing interconnection at the delivery points be used for the purposes of the PPA between SVEC and PacifiCorp and simply referenced in the PPA? Please advise.

2. **Finalizing determination that SVEC meets PacifiCorp's credit worthiness requirements** – Financial records were forwarded to PacifiCorp on May 1st. Please confirm PacifiCorp's determination. Please note that the attached PPA is prepared in a way which assumes that SVEC meets PacifiCorp's credit worthiness requirements for the Paisley Project obligations.

3. **Project As Built Drawings** – These will be forwarded under a separate cover for PacifiCorp's review in accordance with Section 6.1. Please advise as to who should receive these documents.

As noted above, SVEC is prepared to execute the PPA attached to this email. SVEC is concerned about the length of time it is taking to finalize the arrangements to be captured in the PPA for the Paisley Project output. SVEC offers the services of its attorney, Kirk Gibson, to PacifiCorp in order to assist in addressing any drafting and/or conceptual issues that may remain in finalization of the PPA (to customize the standard PPA language to accommodate SVEC's Sales Concept for the Paisley) that is not captured in the attached PPA. In addition, please be advised that SVEC is willing to consider the language in the proposed PPAs filed by PacifiCorp in its recent PURPA filing. Please indicate which proposed standard PPA in the recent filing that PacifiCorp filed would be applicable to the Paisley Project. As soon as PacifiCorp identifies the appropriate PPA, SVEC will review and determine whether it can accept any differences. SVEC may also be willing to accommodate PacifiCorp with other benefits of this project for PacifiCorp's immediate attention to this important issue of finalizing the PPA.

Too much time has elapsed since SVEC came to PacifiCorp with its Paisley Project. The timing of these activities is crucial for SVEC. SVEC is working with ODOE concerning achieving BETC certification for the Paisley Project. ODOE review of SVEC's eligibility for BETCs covering the Paisley Project is scheduled for next week.

Please let me know if there is anything that PacifiCorp is waiting for from SVEC and I will personally see to it that it gets resolved/delivered immediately. Additional delays could jeopardize SVEC's ability to achieve BETCs. I will be contacting you soon to set up a meeting where the issues related to the PPA can be finalized and the PPA executed.

Please do not hesitate to contact me should you have any questions or desire further information. Thank you.

Sincerely,

Lynn

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP., Complainant v. PACIFICORP, d/b/a PACIFIC POWER, Respondent.

EXHIBIT PAC/115

PACIFICORP'S RESPONSE TO
SURPRISE VALLEY DATA REQUEST 1.8

May 17, 2016

UM 1742 / PacifiCorp
October 26, 2015
SVEC Data Request 1.8

SVEC Data Request 1.8

Please identify all PacifiCorp's QF purchase power agreements in which a portion or all of the net output is transmitted across a third parties' distribution or transmission system. Please identify whether the third party has an open access transmission tariff, wholesale distribution tariff, or other method of tracking and transferring energy across its own distribution or transmission system.

Response to SVEC Data Request 1.8

PacifiCorp objects to this request as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence in that it asks for qualifying facility (QF) power purchase agreements (PPA) outside of Oregon and/or information that is publically available to Surprise Valley. Without waiving its objection, PacifiCorp responds as follows:

PacifiCorp has off-system QF PPAs with the following QF projects in Oregon:

QF Project	**Transmission Provider**
Farm Power Misty Meadow	Bonneville Power Administration (BPA)
Finley BioEnergy LLC	BPA
Mariah Wind	Columbia Basin Electric Cooperative (CBEC) and BPA
Middle Fork Irrigation District	BPA
Orem Family Wind	CBEC and BPA
Three Sisters Irrigation District	Central Electric Cooperative and BPA

The PPAs for the above named QFs can be accessed from the Public Utility Commission of Oregon's (OPUC) website under Docket RE 142.

A link to the OPUC website; specifically Docket RE 142, is provided below:

http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19097

UM 1742 / PacifiCorp
November 25, 2015
SVEC Data Request 1.8 – 1st Supplemental

SVEC Data Request 1.8

Please identify all PacifiCorp's QF purchase power agreements in which a portion or all of the net output is transmitted across a third parties' distribution or transmission system. Please identify whether the third party has an open access transmission tariff, wholesale distribution tariff, or other method of tracking and transferring energy across its own distribution or transmission system.

1st Supplemental Response to SVEC Data Request 1.8

PacifiCorp has off-system qualifying facility (QF) power purchase agreements with the following QF projects:

QF Project	Transmission Provider	Transmission Service
Farm Power Misty Meadow	Bonneville Power Administration (BPA)	BPA – Open Access Transmission Tariff (OATT)
Finley BioEnergy LLC	BPA	BPA - OATT
Mariah Wind	Columbia Basin Electric Cooperative (CBEC) and BPA	BPA - OATT
Middle Fork Irrigation District	BPA	BPA - OATT
Orem Family Wind	CBEC and BPA	BPA - OATT
Three Sisters Irrigation District	Central Electric Cooperative and BPA	BPA - OATT
Lower Valley Energy	BPA	BPA – OATT
Shosone Irrigation District (PPA expired in 2014)	Tri-State Generation and Transmission Association (Tri-State G&T)	TriState - OATT

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/116

SURPRISE VALLEY'S SUPPLEMENTAL RESPONSE TO PACIFICORP'S DATA REQUEST 2.3, INCLUDING ATTACHMENT 2.3(C)

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
March 21, 2016
SVEC First Supplemental Response to PacifiCorp Data Request 2.3

PacifiCorp Data Request 2.3

On page 6 of Surprise Valley's Reply to PacifiCorp's Response to Motion to Strike or Clarify Scope of Proceeding (Nov. 30, 2015), Surprise Valley stated:

> Surprise Valley is *willing, able, and ready to provide firm transmission service* over its own transmission system in a manner that is consistent with Commission and FERC precedent, as well as the firm transmission service that Surprise Valley provides to PacifiCorp. (Emphasis added.)

(a) Describe with specificity the details and mechanics of the "firm transmission service" Surprise Valley refers to in this statement. Specifically identify the ancillary services that Surprise Valley considers necessary to support firm delivery and would provide as part of the "firm transmission service," as well as the source of those services.
(b) Describe with specificity how PacifiCorp will be able to measure the exact amount of the net output of the Paisley Project that is delivered to PacifiCorp's system, identifying the specific data required and the source(s) of such data.
(b) Provide a copy of all agreements supporting Surprise Valley's response to this data request.

First Supplemental Response to PacifiCorp Data Request 2.3

Other than the objection regarding the filing of testimony, Surprise Valley reiterates the objections in its March 1, 2016 response to PacifiCorp Data Request 2.3.

Notwithstanding these objections and in addition to the March 1, 2016 response, Surprise Valley provides the following:

a. Surprise Valley's direct testimony provides the details and mechanics of the firm transmission service. Please refer to the direct testimony of Brad Kresge at pages 2, 7, 13-14, Gary Saleba and Gail Tabone at pages 2-3, 7-15, 17-18, 20-23, 28-35, and Stephen Anderson at pages 10-11.

Surprise Valley does not consider any ancillary services necessary to support firm delivery. Surprise Valley may be willing to provide additional transmission arrangements, once PacifiCorp identifies what transmission arrangements and metering it would like Surprise Valley to provide.

b. Surprise Valley's direct testimony provides the details and mechanics of the firm transmission service and how deliveries will be measured. Please refer to the direct testimony of Lynn Culp at pages 10-12, 13-15, 18, Gary Saleba and Gail Tabone at pages 4, 8-11, and Stephen Anderson at pages 2-12, 14-15. Surprise Valley may be willing to provide additional transmission arrangements, once PacifiCorp identifies what transmission arrangements and metering it would like Surprise Valley to provide.

c. Based on the discovery conference with Administrative Law Judge Michael Grant on March 17, 2016, Surprise Valley provides the following additional contracts in Attachment 2.3(c).

Surprise Valley may be willing to provide additional transmission arrangements, once PacifiCorp identifies what transmission arrangements and metering it would like Surprise Valley to provide.

Contract No. 09PB-13110

POWER SALES AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

SURPRISE VALLEY ELECTRIFICATION CORPORATION

Table of Contents

DEC 2 2 2008

This POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and SURPRISE VALLEY ELECTRIFICATION CORPORATION (Surprise Valley), hereinafter individually referred to as "Party" and collectively referred to as the "Parties". Surprise Valley is a non-profit corporation, organized and authorized under the laws of the State of California, to purchase and distribute electric power to serve retail consumers from its distribution system within its service area.

RECITALS

Surprise Valley's current power sales agreement (Contract No. 00PB-12074) continues through September 30, 2011, and will be replaced by this Agreement on October 1, 2011.

BPA has functionally separated its organization in order to separate the administration and decision-making activities of BPA's power and transmission functions. References in this Agreement to Power Services or Transmission Services are solely for the purpose of clarifying which BPA function is responsible for administrative activities that are jointly performed.

BPA is authorized to market federal power to qualified entities that are eligible to purchase such power. Under section 5(b)(1) of the Northwest Power Act, BPA is obligated to offer a power sales agreement to eligible customers for the sale and purchase of federal power to serve their retail consumer load in the Region that is not met by the customer's use of its non-federal resources.

BPA has proposed the adoption of a tiered rate pricing methodology for federal power sold to meet BPA's obligations under section 5(b) of the Northwest Power Act to eligible customers, in order to provide more efficient pricing signals and encourage the timely development of regional power resource infrastructure to meet regional consumer loads under this Agreement.

To effect that purpose, in this Agreement BPA establishes a Contract High Water Mark for Surprise Valley that will define the amounts of power Surprise Valley may purchase from BPA at the Tier 1 Rate, as defined in BPA's Tiered Rate Methodology.

The Parties agree:

1. **TERM**

This Agreement takes effect on the date signed by the Parties and expires on September 30, 2028, subject to approval of the United States Department of Agriculture Rural Utilities Service. Performance by BPA and Surprise Valley shall commence on October 1, 2011, with the exception of those actions required prior to that date that are included in:

(1) sections 3.3 through 3.7 of section 3, Power Purchase Obligation;

(2) section 9, Elections to Purchase Power Priced at Tier 2 Rates;

(3) section 14, Delivery;

(4) section 17, Information Exchange and Confidentiality;

(5) section 18, Conservation and Renewables;

(6) section 19, Resource Adequacy;

(7) section 22, Governing Law and Dispute Resolution;

(8) section 25, Termination;

(9) Exhibit A, Net Requirements and Resources;

(10) Exhibit B, High Water Marks and Contract Demand Quantities;

(11) Exhibit C, Purchase Obligations;

(12) section 2 of Exhibit D, Additional Products and Special Provisions; and

(13) Exhibit G, Principles of Non-Federal Transfer Service.

Until October 1, 2011, section 22, Governing Law and Dispute Resolution will only apply to the extent there is a dispute regarding actions required in the above referenced sections and exhibits.

2. DEFINITIONS

Capitalized terms below shall have the meaning stated. Capitalized terms that are not listed below are either defined within the section or exhibit in which the term is used, or if not so defined, shall have the meaning stated in BPA's applicable Wholesale Power Rate Schedules, including the General Rate Schedule Provisions (GRSPs). Definitions in **bold** indicate terms that are defined in the TRM and that the Parties agree should conform to the TRM as it may be revised. The Parties agree that if such definitions are revised pursuant to the TRM, they shall promptly amend this Agreement to incorporate such revised definitions from the TRM, to the extent they are applicable.

2.1 "5(b)/9(c) Policy" means BPA's Policy on Determining Net Requirements of Pacific Northwest Utility Customers Under sections 5(b)(1) and 9(c) of the Northwest Power Act issued May 23, 2000, and its revisions or successors.

2.2 "**7(i) Process**" means a public process conducted by BPA to establish rates for the sale of power and other products pursuant to section 7(i) of the Northwest Power Act or its successor.

2.3 "**Above-RHWM Load**" means forecast annual Total Retail Load, less Existing Resources, NLSLs, and Surprise Valley's RHWM, as determined in the RHWM Process, except for the FY 2012-2013 Rate Period, when Above-RHWM Load will be determined differently, as specified in the TRM.

2.4 "Annexed Load" means existing load, distribution system, or service territory Surprise Valley acquires after the Effective Date from another utility, by means of annexation, merger, purchase, trade, or other acquisition of rights, the acquisition of which has been authorized by a final state, regulatory or court action. The Annexed Load must be served from distribution facilities that are owned or acquired by Surprise Valley.

2.5 "Average Megawatts" or "aMW" means the amount of electric energy in megawatt-hours (MWh) during a specified period of time divided by the number of hours in such period.

2.6 "**Balancing Authority**" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

2.7 "**Balancing Authority Area**" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority.

2.8 "**Business Days**" means every Monday through Friday except Federal holidays.

2.9 "Carbon Credit" shall have the meaning as defined in section 1 of Exhibit H.

2.10 "**CHWM Contract**" means the power sales contract between a customer and BPA that contains a Contract High Water Mark (CHWM), and under which the customer purchases power from BPA at rates established by BPA in accordance with the TRM.

2.11 "Consumer-Owned Resource" means a Generating Resource connected to Surprise Valley's distribution system that is owned by a retail consumer, has a nameplate capability greater than 200 kilowatts, is operated or applied to load, and is not operated occasionally or intermittently as a back-up energy source at times of maintenance or forced outage. Consumer-Owned Resource does not include a resource where the owner of the resource is a retail consumer that exists solely for the purpose of selling wholesale power and for which Surprise Valley only provides incidental service to provide energy for local use at the retail consumer's generating plant for lighting, heat and the operation of auxiliary equipment.

2.12 "Contract Demand Quantity" or "CDQ" shall have the meaning as defined in the TRM, the definition of which is recited in section 6.6.1.

2.13 "Contract High Water Mark" or "CHWM" shall have the meaning as defined in the TRM, the definition of which is recited in section 6.6.1.

2.14 "Contract Resource" means any source or amount of electric power that Surprise Valley acquires from an identified or unidentified electricity-producing unit or units by contract purchase, and for which the amount received by Surprise Valley does not depend on the actual production from an identified Generating Resource.

2.15 "Dedicated Resource" means a Specified Resource or an Unspecified Resource Amount listed in Exhibit A that Surprise Valley is required by statute to provide or obligates itself to provide under this Agreement for use to serve its Total Retail Load.

2.16 "Diurnal" means the division of hours within a month between Heavy Load Hours (HLH) and Light Load Hours (LLH).

2.17 "Diurnal Flattening Service" or "DFS" means a service that makes a resource that is variable or intermittent, or that portion of such resource that is variable or intermittent, equivalent to a resource that is flat within each of the 24 HLH and LLH periods of a year.

2.18 "Due Date" shall have the meaning as described in section 16.2.

2.19 "Effective Date" means the date on which this Agreement has been signed by Surprise Valley and BPA.

2.20 "Eligible Annexed Load" shall have the meaning as defined in section 3.5.6.

2.21 "Environmental Attribute" shall have the meaning as defined in section 1 of Exhibit H.

2.22 "Environmentally Preferred Power RECS" or "EPP RECs" shall have the meaning as defined in section 1 of Exhibit H.

2.23 "Existing Resource" means a Specified Resource listed in section 2 of Exhibit A that Surprise Valley was obligated by contract or statute to use to serve Surprise Valley's Total Retail Load prior to October 1, 2006.

2.24 "FERC" means the Federal Energy Regulatory Commission, or its successor.

2.25 "Firm Requirements Power" means federal power that BPA sells under this Agreement and makes continuously available to Surprise Valley to meet BPA's obligations to Surprise Valley under section 5(b) of the Northwest Power Act.

2.26 "**Fiscal Year**" or "FY" means the period beginning each October 1 and ending the following September 30.

2.27 "Flat Annual Shape" means a distribution of energy having the same Average Megawatt value of energy in each month of the year.

2.28 "Flat Within-Month Shape" means a distribution of energy having the same Average Megawatt value of energy in each Diurnal period of the month.

2.29 "**Forced Outage Reserve Service**" or "FORS" means a service that provides an agreed-to amount of capacity and energy to load during the forced outages of a resource.

2.30 "Forecast Year" means the Fiscal Year ending one full year prior to the commencement of a Rate Period.

2.31 "Generating Resource" means any source or amount of electric power from an identified electricity-producing unit, and for which the amount of power received by Surprise Valley or Surprise Valley's retail consumer is determined by the power produced from such identified electricity-producing unit. Such unit may be owned by Surprise Valley or Surprise Valley's retail consumer in whole or in part, or all or any part of the output from such unit may be owned for a defined period by contract.

2.32 "Heavy Load Hours (HLH)" means hours ending 0700 through 2200 hours Pacific Prevailing Time (PPT), Monday through Saturday, excluding holidays as designated by the North American Electric Reliability Corporation (NERC). BPA may update this definition as necessary to conform to standards of the Western Electricity Coordinating Council (WECC), North American Energy Standards Board (NAESB), or NERC.

2.33 "HLH Diurnal Shape" means a distribution of energy between the Diurnal periods in which more megawatt-hours per hour are applied in the Heavy Load Hour (HLH) periods than megawatt-hours per hour applied in the Light Load Hour (LLH) periods. Such distributions are determined by Surprise Valley consistent with section 8.2 of Exhibit A.

2.34 "Integrated Network Segment" shall have the meaning as defined in section 14.1.

2.35 "Interchange Points" means the points where Balancing Authority Areas interconnect and at which the interchange of energy between Balancing Authority Areas is monitored and measured.

2.36 "Issue Date" shall have the meaning as described in section 16.1.

2.37 "Light Load Hours (LLH)" means: (1) hours ending 0100 through 0600 and 2300 through 2400 hours PPT, Monday through Saturday, and (2) all hours on Sundays and holidays as designated by NERC. BPA may update this definition as necessary to conform to standards of the WECC, NAESB, or NERC.

2.38 "Net Requirement" means the amount of federal power that Surprise Valley is entitled to purchase from BPA to serve its Total Retail Load minus amounts of Surprise Valley's Dedicated Resources shown in Exhibit A, as determined consistent with section 5(b)(1) of the Northwest Power Act.

2.39 "New Large Single Load" or "NLSL" has the meaning specified in section 3(13) of the Northwest Power Act and in BPA's NLSL policy.

2.40 "New Resource" means (1) a Specified Resource listed in section 2 of Exhibit A that Surprise Valley was or is first obligated by contract, or was or is obligated by statute, to use to serve Surprise Valley's Total Retail Load after September 30, 2006, and (2) any Unspecified Resource Amounts listed in Exhibit A.

2.41 "Northwest Power Act" means the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §839, Public Law No. 96-501, as amended.

2.42 "Notice Deadlines" means the dates established in section 9.1.1.

2.43 "Onsite Consumer Load" means the electric load of an identified retail consumer of Surprise Valley that is directly interconnected or electrically interconnected on the same portion of Surprise Valley's distribution system with a Consumer-Owned Resource of that same identified retail consumer such that no transmission schedule is needed to deliver the generation from the Consumer-Owned Resource to the consumer load.

2.44 "Operating Year" means the period, beginning each August 1 and ending the following July 31, that is designated under the Pacific Northwest

Coordination Agreement (PNCA) for resource planning and operational purposes.

2.45 "Pacific Northwest Coordination Agreement" or "PNCA" means Contract No. 97PB-10130, as such agreement may be amended or replaced, among BPA, the U.0S. Army Corps of Engineers, the Bureau of Reclamation, and certain generating utilities in the Region that sets forth the terms and conditions for the coordinated operation of generating resources in the Region.

2.46 "PNCA Update Shape" means the monthly shape of a Specified Resource that is a hydro resource that will be revised each Fiscal Year based on the monthly amounts for such resource that are in the final PNCA planning hydro-regulation study published for the Operating Year that began on the August 1 immediately preceding the Fiscal Year. If the final study is not published 30 days prior to the beginning of the Fiscal Year, then the monthly shape of Surprise Valley's Specified Resource that is a hydro resource will be revised based on the monthly amounts for such resource that are in the modified PNCA study published for the same Operating Year. The August and September amounts published for the Operating Year will be used as the August and September amounts for the Fiscal Year.

2.47 "Point of Delivery" or "POD" means the point where power is transferred from a transmission provider to Surprise Valley.

2.48 "Point of Metering" or "POM" means the point at which power is measured.

2.49 "Power Services" means the organization, or its successor organization, within BPA that is responsible for the management and sale of Federal power.

2.50 "Primary Points of Receipt" shall have the meaning as defined in section 14.1.

2.51 "Purchase Periods" means the time periods established in section 9.1.1.

2.52 "Rate Case Year" means the Fiscal Year ending prior to the commencement of a Rate Period. The Rate Case Year immediately follows the Forecast Year and is the year in which the 7(i) Process for the next Rate Period is conducted.

2.53 **"Rate Period"** means the period of time during which a specific set of rates established by BPA pursuant to the TRM is intended to remain in effect.

2.54 "Rate Period High Water Mark" or "RHWM" shall have the meaning as defined in the TRM, the definition of which is recited in section 6.6.1.

2.55 "Region" means the Pacific Northwest as defined in section 3(14) of the Northwest Power Act.

2.56 "Renewable Energy Certificates" or "RECs" shall have the meaning as defined in section 1 of Exhibit H.

2.57 "Resource Diurnal Shape" means a distribution of energy within each Diurnal period that a Generating Resource is expected to produce, as agreed to by the Parties in accordance with section 3.4.1(1).

2.58 "Resource Monthly Shape" means a distribution of energy within each month that a Generating Resource is expected to produce, as agreed to by the Parties in accordance with section 3.4.1(1).

2.59 "Resource Support Services" or "RSS" means the Diurnal Flattening Service, Forced Outage Reserve Service, Transmission Curtailment Management Service, and Secondary Crediting Service. BPA may in the future include other related services that are priced in the applicable 7(i) Process.

2.60 "Scheduling Points of Receipt" shall have the meaning as defined in section 14.1.

2.61 "**Secondary Crediting Service**" or "SCS" means the optional service offered by BPA that provides a monetary credit for the secondary output from an Existing Resource that has a firm critical energy component and a secondary energy component.

2.62 "Small Non-Dispatchable Resource" means a Specified Resource connected to Surprise Valley's distribution system the output of which cannot be shifted between Diurnal periods or days by the resource owner or operator. Such resource is further defined as:

(1) an Existing Resource that has a nameplate capability less than or equal to three megawatts, or

(2) a New Resource that has a nameplate capability less than or equal to one megawatt.

2.63 "Specified Resource" means a Generating Resource or Contract Resource that has a nameplate capability or maximum hourly purchase amount greater than 200 kilowatts, that Surprise Valley is required by statute or has agreed to use to serve its Total Retail Load. Each such resource is identified as a specific Generating Resource or as a specific Contract Resource with identified parties and is listed in sections 2 and 4 of Exhibit A.

2.64 "Statement of Intent" shall have the meaning as defined in section 2.3 of Exhibit C.

2.65 "Submitted Schedule" shall have the meaning as defined in section 3.7.

2.66 "Super Peak Credit" means a reduction in Surprise Valley's demand billing determinants equal to the amount of additional energy provided by a

Dedicated Resource, during a Super Peak Period, over the amount of energy that would have been provided by an equivalent amount of energy delivered flat across the monthly HLH period.

2.67 "Super Peak Period" means the hours BPA defines for each Rate Period in accordance with section 3.4.4.1 into which Surprise Valley must reshape its HLH energy from its Dedicated Resources to receive a Super Peak Credit. The hours BPA establishes for the Super Peak Period may vary by month and will be either two 3-hour periods each day or a single 6-hour period each day.

2.68 "Surplus Firm Power" means firm power that is in excess of BPA's obligations, including those incurred under sections 5(b), 5(c), and 5(d) of the Northwest Power Act, as available.

2.69 "Third Party Transmission Provider" means a transmission provider other than BPA that delivers power to Surprise Valley.

2.70 "Tier 1 Rate" means the Tier 1 Rate as defined in the TRM.

2.71 "Tier 1 RECs" shall have the meaning as defined in section 1 of Exhibit H.

2.72 "**Tier 2 Cost Pools**" means all of the Cost Pools to which Tier 2 Costs (as defined in the TRM) will be allocated by BPA.

2.73 "Tier 2 Load Growth Rate" means a Tier 2 Rate at which Load Following customers may elect to purchase Firm Requirements Power in accordance with section 2.2 of Exhibit C.

2.74 "Tier 2 Rate" means the Tier 2 Rate as defined in the TRM.

2.75 "Tier 2 RECs" shall have the meaning as defined in section 1 of Exhibit H.

2.76 "Tier 2 Short-Term Rate" means a Tier 2 Rate at which customers may elect to purchase Firm Requirements Power in accordance with section 2.4 of Exhibit C.

2.77 "Tier 2 Vintage Rate" means a Tier 2 Rate at which customers may elect to purchase Firm Requirements Power in accordance with section 2.3 of Exhibit C.

2.78 "Tiered Rate Methodology" or "TRM" means the long-term methodology established by BPA in a Northwest Power Act section 7(i) hearing as the Tiered Rate Methodology to implement the Policy (as defined in the TRM) construct of tiering BPA's Priority Firm Power rates for serving load under CHWM Contracts.

2.79 "Total Retail Load" means all retail electric power consumption, including electric system losses, within Surprise Valley's electrical system excluding:

(1) those loads BPA and Surprise Valley have agreed are nonfirm or interruptible loads,

(2) transfer loads of other utilities served by Surprise Valley, and

(3) any loads not on Surprise Valley's electrical system or not within Surprise Valley's service territory, unless specifically agreed to by BPA.

2.80 "Total Retail Load Monthly Shape" means the distribution among months as listed in the table in section 8.1 of Exhibit A. The FY 2010 Total Retail Load Monthly Shape from the table will apply for the FY 2012-2014 and FY 2015-2019 Purchase Periods; the FY 2015 Total Retail Load Monthly Shape will apply for the FY 2020-FY 2024 Purchase Period; and the FY 2020 Total Retail Load Monthly Shape will apply for the FY 2025-2028 Purchase Period.

2.81 "Transfer Service" means the transmission, distribution and other services provided by a Third Party Transmission Provider to deliver electric energy and capacity over its transmission system.

2.82 "**Transmission Curtailment Management Service**" or "TCMS" means the service Power Services may provide to back up a qualifying resource when a transmission curtailment occurs between such resource and the customer load.

2.83 "Transmission Services" means the organization, or its successor organization, within BPA that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System.

2.84 "Uncontrollable Force" shall have the meaning as defined in section 21.

2.85 "Unspecified Resource Amount" means an amount of firm energy, listed in sections 3 and 4 of Exhibit A, that Surprise Valley has agreed to supply and use to serve its Total Retail Load. Such amount is not attributed to a Specified Resource.

3. LOAD FOLLOWING POWER PURCHASE OBLIGATION

3.1 Purchase Obligation

From October 1, 2011, and continuing through September 30, 2028, BPA shall sell and make available, and Surprise Valley shall purchase, Firm Requirements Power in hourly amounts equal to Surprise Valley's hourly Total Retail Load minus the hourly firm energy from each of Surprise Valley's Dedicated Resources as listed in Exhibit A. Surprise Valley shall determine the hourly firm energy from each of its Dedicated Resources pursuant to section 3.3. Such amounts of energy are subject to change pursuant to section 3.5 and section 10.

3.2 **Take or Pay**
Surprise Valley shall pay for the amount of Firm Requirements Power it has committed to purchase under section 3.1, and that BPA makes available at the rates BPA establishes pursuant to the TRM, as applicable to such power, whether or not Surprise Valley took actual delivery of such power.

3.3 **Application of Dedicated Resources**
Surprise Valley agrees to serve a portion of its Total Retail Load with the Dedicated Resources listed in Exhibit A as follows:

(1) Specified Resources that are Generating Resources, except Small, Non-Dispatchable Resources, shall be listed in section 2.1 of Exhibit A,

(2) Specified Resources that are Contract Resources shall be listed in section 2.2 of Exhibit A,

(3) Specified Resources that are Small Non-Dispatchable Resources shall be listed in section 2.3 of Exhibit A, and

(4) Unspecified Resource Amounts shall be listed in section 3.1 of Exhibit A.

Surprise Valley shall use its Dedicated Resources to serve its Total Retail Load, and specify amounts of its Dedicated Resources in the tables shown in Exhibit A, as stated below for each specific resource and type. BPA shall use the amounts listed in Exhibit A in determining Surprise Valley's Net Requirement. The amounts listed are not intended to govern how Surprise Valley shall operate its Specified Resources, except for those resources that are Small Non-Dispatchable Resources and those resources supported with DFS or SCS from BPA.

3.3.1 **Specified Resources**

3.3.1.1 **Application of Specified Resources**
Surprise Valley shall apply the output of all Specified Resources, listed in section 2 of Exhibit A, to Surprise Valley's Total Retail Load in predefined hourly amounts consistent with section 3.7, except for Small Non-Dispatchable Resources and Specified Resources Surprise Valley is supporting with DFS or SCS from BPA. Surprise Valley shall apply all Specified Resources supported with DFS or SCS from BPA to Surprise Valley's Total Retail Load consistent with section 2 of Exhibit D. Surprise Valley shall apply all of the output as it is generated from its Small Non-Dispatchable Resources, listed in section 2.3 of Exhibit A, to Surprise Valley's Total Retail Load.

3.3.1.2 **Determining Specified Resource Amounts**
Surprise Valley shall state, for each Specified Resource listed in section 2 of Exhibit A, firm energy amounts for each Diurnal period and peak amounts for each month beginning with the later of the date the resource was dedicated to load or October 1, 2011, through the earlier of the date the resource will be permanently removed or September 30, 2028. BPA in consultation with Surprise Valley shall determine the firm energy amounts for each Diurnal period and peak amounts for each month for each Specified Resource consistent with the 5(b)/9(c) Policy, and using the allowable shapes established in section 3.4.

3.3.2 **Unspecified Resource Amounts**

3.3.2.1 **Application of Unspecified Resource Amounts**
To serve Above-RHWM Load that Surprise Valley commits to meet with Dedicated Resources in Exhibit C, Surprise Valley shall provide and use Unspecified Resource Amounts to meet any amounts not met with its Specified Resources during each Purchase Period. Surprise Valley shall apply its Unspecified Resource Amounts, listed in section 3 of Exhibit A, to Surprise Valley's Total Retail Load in predefined hourly amounts consistent with section 3.7.

3.3.2.2 **Determining Unspecified Resource Amounts**
By March 31 of each Rate Case Year, the Parties shall calculate, and BPA shall fill in the table in section 3.1.2 of Exhibit A with, Surprise Valley's Unspecified Resource Amounts for each of the years of the upcoming Rate Period consistent with Surprise Valley's elections for service to its Above-RHWM Load. Such Unspecified Resource Amounts shall be calculated using the monthly and Diurnal shapes listed in section 3.1.1 of Exhibit A. Upon termination or expiration of this Agreement any Unspecified Resource Amounts listed in Exhibit A shall expire, and Surprise Valley shall have no further obligation to apply Unspecified Resource Amounts.

3.4 **Shaping of Dedicated Resources**
Surprise Valley's Dedicated Resource amounts shall be shaped as follows:

3.4.1 **Initial Monthly and Diurnal Resource Shapes**
The amounts for each Dedicated Resource shall be first listed in Exhibit A with one of the following shapes:

(1) Generating Resources in the amount of energy within each month and Diurnal period of a year each resource is expected to generate output as agreed to by the Parties.

(2) Contract Resources in equal megawatt amounts for each hour in a year.

(3) Small Non-Dispatchable Resources in the amount of energy within each month and Diurnal period of a year each resource is expected to generate output as agreed to by the Parties.

(4) Unspecified Resource Amounts in equal megawatt amounts for each hour in a year.

3.4.2 **Reshaping Dedicated Resources**
By each Notice Deadline Surprise Valley may elect in writing, pursuant to section 3.4.3, to reshape its amounts of Dedicated Resources listed in sections 2.1, 2.2, and 3.1 of Exhibit A, except for those Specified Resources Surprise Valley is supporting with DFS or SCS from BPA, for the corresponding Purchase Period. After BPA receives such notice from Surprise Valley for the first Notice Deadline (November 1, 2009), BPA shall, by March 31, 2011, revise Exhibit A to reflect such written elections. After BPA receives such written notice from Surprise Valley for any subsequent Notice Deadline, BPA shall, by the following March 31, revise Exhibit A to reflect such election.

If Surprise Valley elects the PNCA Update Shape for a hydro resource, then BPA shall update the shape of such resource annually, in accordance with such election, to be completed no later than September 15 preceding the start of the applicable Fiscal Year.

3.4.3 **Monthly and Diurnal Reshaping Options**
Consistent with section 3.4.2, Surprise Valley may elect to reshape one or more of its Dedicated Resources using the allowable monthly and Diurnal shapes described below. If Surprise Valley elects to reshape its Dedicated Resources, then Surprise Valley shall elect both a monthly and a Diurnal shape for each Dedicated Resource that is reshaped.

3.4.3.1 **Generating Resources**
For each Generating Resource listed in section 2.1 of Exhibit A Surprise Valley may elect to apply each resource in any of the following shapes:

(1) Monthly Shapes: (A) Total Retail Load Monthly Shape; (B) Resource Monthly Shape; (C) Flat Annual Shape; or (D) PNCA Update Shape if the resource is a hydro resource and is designated as a PNCA resource in section 2.1 of Exhibit A.

(2) Diurnal Shapes: (A) Resource Diurnal Shape; (B) Flat Within-Month Shape; or (C) HLH Diurnal Shape.

3.4.3.2 **Contract Resources**
For each Contract Resource listed in section 2.2 of Exhibit A Surprise Valley may elect to apply each resource in any of the following shapes:

(1) Monthly Shapes: (A) Total Retail Load Monthly Shape; or (B) Flat Annual Shape.

(2) Diurnal Shapes: (A) Flat Within-Month Shape; or (B) HLH Diurnal Shape.

3.4.3.3 **Unspecified Resource Amounts**
Surprise Valley may elect to apply its Unspecified Resource Amounts, listed in section 3.1 of Exhibit A in any of the following shapes:

(1) Monthly Shapes: (A) Total Retail Load Monthly Shape; or (B) Flat Annual Shape.

(2) Diurnal shapes: (A) Flat Within-Month Shape; or (B) HLH Diurnal Shape.

3.4.4 **Super Peak Credit**

3.4.4.1 **Super Peak Period**
By September 30 of each Forecast Year BPA shall notify Surprise Valley in writing of the Super Peak Period for the upcoming Rate Period.

3.4.4.2 **Super Peak Amounts**
By October 31 of each Rate Case Year Surprise Valley shall notify BPA in writing of the monthly megawatt amounts of additional energy Surprise Valley elects to apply to its Total Retail Load for the upcoming Rate Period, for which Surprise Valley shall receive a Super Peak Credit. Surprise Valley shall establish such amounts from its Dedicated Resources consistent with section 9 of Exhibit A. After BPA receives such notification from Surprise Valley BPA shall revise the table in section 9 of Exhibit A, by March 31 of the same Rate Case Year, to reflect monthly amounts Surprise Valley submitted to BPA.

3.4.5 **Hourly Resource Shape**
Surprise Valley's Dedicated Resources listed in sections 2.1, 2.2, and 3.1 of Exhibit A, except for those Specified Resources Surprise Valley is supporting with DFS or SCS from BPA, shall be provided in equal megawatt amounts during all LLH of a month and in equal megawatt amounts during all HLH of a month, unless Surprise Valley reshapes

its HLH amounts pursuant to section 3.4.4. If Surprise Valley reshapes its HLH amounts pursuant to section 3.4.4, then Surprise Valley's Dedicated Resources shall be provided in (1) equal megawatt amounts during all LLH of a month, (2) equal megawatt amounts during all HLH of a month that are not in the Super Peak Period, and (3) equal megawatt amounts during all HLH of a month that are in the Super Peak Period. The hourly amounts provided in the Super Peak Period shall reflect the additional energy amounts listed in section 9 of Exhibit A.

3.5 **Changes to Dedicated Resources**

3.5.1 **Specified Resource Additions to Meet Above-RHWM Load**
By written notice to BPA, Surprise Valley may elect to add Specified Resources to section 2 of Exhibit A to meet any obligation Surprise Valley may have in Exhibit C to serve its Above-RHWM Load with Dedicated Resources. Subject to the following:

3.5.1.1 By any Notice Deadline, Surprise Valley may elect to add a Specified Resource to section 2 of Exhibit A with amounts effective at the start of the corresponding Purchase Period. The following applies for such Specified Resources:

(1) Surprise Valley shall determine amounts for such Specified Resources in accordance with section 3.3.1.2.

(2) Surprise Valley may elect to reshape such Specified Resources in accordance with section 3.4.3 or may elect to purchase DFS from BPA to support such Specified Resources.

3.5.1.2 After any Notice Deadline, and if Surprise Valley notifies BPA of its election in writing by October 31 of a Rate Case Year, then Surprise Valley may add Specified Resources to section 2 of Exhibit A with amounts effective at the start of the upcoming Rate Period. The following apply for such Specified Resources:

(1) Surprise Valley shall determine amounts for such Specified Resources in accordance with section 3.3.1.2.

(2) The shape of such resources shall either be in the shape selected in section 3.1.1 of Exhibit A for any Unspecified Resource Amounts for the applicable Purchase Period, or Surprise Valley may purchase DFS from BPA to support the Specified Resource pursuant to section 2.2 of Exhibit D.

3.5.1.3 BPA shall revise Exhibit A consistent with Surprise Valley's elections by March 31 following Surprise Valley's elections under sections 3.5.1.1 or 3.5.1.2.

3.5.2 **Resource Additions for a BPA Insufficiency Notice**
If BPA provides Surprise Valley a notice of insufficiency and reduces its purchase obligation, in accordance with section 23.2, then Surprise Valley may add Dedicated Resources to replace amounts of Firm Requirements Power BPA will not be providing due to insufficiency. The Parties shall revise Exhibit A to reflect such additions.

3.5.3 **Decrements for 9(c) Export**
If BPA determines, in accordance with section 23.6, that an export of a Specified Resource listed in section 2 of Exhibit A requires a reduction in the amount of Firm Requirements Power BPA sells Surprise Valley then BPA shall notify Surprise Valley of the amount and duration of the reduction in Surprise Valley's Firm Requirements Power purchases from BPA. Within 20 days of such notification Surprise Valley may add a Specified Resource to section 2 of Exhibit A in the amount of such decrement. If Surprise Valley does not add a Specified Resource to meet such decrement, then within 30 days of such notification BPA shall add Unspecified Resource Amounts to section 3.2 of Exhibit A in the amount and for the duration of such decrement.

3.5.4 **Temporary Resource Removal**
By March 31 of each Rate Case Year, BPA shall revise Surprise Valley's Dedicated Resource amounts listed in the tables of Exhibit A consistent with Surprise Valley's resource removal elections made in accordance with section 10.

3.5.5 **Permanent Discontinuance of Resources**
Surprise Valley may permanently remove a Specified Resource listed in section 2 of Exhibit A, consistent with the 5(b)/9(c) Policy on statutory discontinuance for permanent removal. If BPA makes a determination that Surprise Valley's Specified Resource has met BPA's standards for a permanent removal, then BPA shall revise Exhibit A accordingly. If Surprise Valley does not replace such resource with another Dedicated Resource, then Surprise Valley's additional Firm Requirements Power purchases under this Agreement, as a result of such a resource removal, may be subject to additional rates or charges as established in the Wholesale Power Rate Schedules and GRSPs.

3.5.6 **Resource Additions for Annexed Loads**
If Surprise Valley acquires an Annexed Load, in addition to any resources assigned by the other utility to serve the Annexed Load, Surprise Valley may add Dedicated Resources to Exhibit A, subject to sections 3.5.6.1 and 3.5.6.2 below, to serve amounts of such Annexed

Load that are Eligible Annexed Load. "Eligible Annexed Load" means an Annexed Load: (1) that is added after the Effective Date, and (2) for which Surprise Valley did not receive a CHWM addition pursuant to section 1.2.2 of Exhibit B.

3.5.6.1 During the Rate Period in which Surprise Valley acquires an Eligible Annexed Load, Surprise Valley may serve such load for the remainder of that Rate Period with Dedicated Resources in the shape of the load, as negotiated by the Parties, or with additional power purchased from BPA. If Surprise Valley elects to serve such load with Dedicated Resources, then Surprise Valley shall apply such resources for the remainder of the Rate Period and in accordance with applicable terms stated in Exhibit D. If Surprise Valley elects to purchase additional power from BPA for the Annexed Load, then during that Rate Period such power purchases may be subject to additional rates or charges as established in the Wholesale Power Rate Schedules and GRSPs and as applicable to the shape of the Eligible Annexed Load.

3.5.6.2 For all Rate Periods after the Rate Period when Surprise Valley acquires an Eligible Annexed Load, Surprise Valley may serve such load with Dedicated Resources pursuant to Surprise Valley's elections to apply Dedicated Resources or Purchase Firm Requirements Power at Tier 2 Rates during the applicable Purchase Period as stated in Exhibit C.

3.5.7 Resource Additions/Removals for NLSLs

3.5.7.1 To serve an NLSL listed in Exhibit D that is added after the Effective Date, Surprise Valley may add Dedicated Resources to section 4 of Exhibit A. Surprise Valley may discontinue serving its NLSL with the Dedicated Resources listed in section 4 of Exhibit A if BPA determines that Surprise Valley's NLSL is no longer an NLSL in Surprise Valley's service territory.

3.5.7.2 If Surprise Valley elects to serve an NLSL with Dedicated Resources, then Surprise Valley shall specify in section 4 of Exhibit A the maximum monthly and Diurnal Dedicated Resource amounts that Surprise Valley plans to use to serve the NLSL. Surprise Valley shall establish such firm energy amounts for each month beginning with the date the resource was dedicated to load through the earlier of the date the resource will be removed or September 30, 2028. Surprise Valley shall serve the actual load of the NLSL up to such maximum amounts with such Dedicated Resource amounts. To the extent that the NLSL load is less than the maximum amount in any monthly or Diurnal period, Surprise Valley shall have no right or obligation to use such amounts to serve the non-NLSL portion of its Total Retail Load. Specific arrangements to match such resources to the NLSL on an hourly basis shall be established in Exhibit D.

3.5.8 **PURPA Resources**
If Surprise Valley is required by the Public Utility Regulatory Policies Act (PURPA) to acquire output from a Generating Resource, then such output shall be added as a Specified Resource pursuant to Exhibit A. Surprise Valley shall purchase DFS from BPA (or equivalent service if DFS is unavailable) to support such resources for the term of this Agreement.

3.6 **Consumer-Owned Resources**
Except for any Consumer-Owned Resources serving an NLSL, which Surprise Valley has applied to load consistent with section 23.3.7, Surprise Valley shall apply the output of its Consumer-Owned Resources as follows:

3.6.1 **Existing Consumer-Owned Resources**
Surprise Valley has designated, in sections 7.1, 7.2, or 7.3 of Exhibit A, the extent that each existing Consumer-Owned Resource as of the Effective Date will or will not serve Onsite Consumer Load. Such designation shall apply for the term of this Agreement.

3.6.2 **New Consumer-Owned Resources**
Surprise Valley shall designate the extent that each Consumer-Owned Resource commencing commercial operation after the Effective Date will or will not serve Onsite Consumer Load. Surprise Valley shall make such designation to BPA in writing within 120 days of the first production of energy by such resource. Such designation shall apply for the term of this Agreement.

Consistent with Surprise Valley's designations, BPA shall list Consumer-Owned Resources serving Onsite Consumer Load in section 7.1 of Exhibit A, Consumer-Owned Resources not serving Onsite Consumer Load in section 7.2 of Exhibit A, and Consumer-Owned Resources serving both Onsite Consumer Load and load other than Onsite Consumer Load in section 7.3 of Exhibit A.

3.6.3 **Application of Consumer-Owned Resources Serving Onsite Consumer Load**
Power generated from Consumer-Owned Resources listed in section 7.1 of Exhibit A shall serve Surprise Valley's Onsite Consumer Load. Surprise Valley shall receive no compensation from BPA for excess power generated on any hour from such resources.

3.6.4 **Application of Consumer-Owned Resources Serving Load Other than Onsite Consumer Load**
Surprise Valley shall ensure that power generated from Consumer-Owned Resources listed in section 7.2 of Exhibit A is scheduled for delivery and either (1) sold to another utility in the Region to serve its Total Retail Load, (2) purchased by Surprise Valley to serve its Total Retail Load (consistent with section 3.3), (3) marketed as an export, or (4) any combination of (1), (2), and (3) above.

3.6.5 **Application of Consumer-Owned Resources Serving Both Onsite Consumer Load and Load Other than Onsite Consumer Load**
If Surprise Valley designates a Consumer-Owned Resource to serve both Onsite Consumer Load and load other than Onsite Consumer Load then Surprise Valley shall select either Option A or Option B below.

3.6.5.1 **Option A: Maximum Amounts Serving Onsite Consumer Load**
If Surprise Valley selects this Option A, then Surprise Valley shall specify, in section 7.3 of Exhibit A, the maximum hourly amounts of an identified Onsite Consumer Load that are to be served with power generated by an identified Consumer-Owned Resource. Such amounts shall be specified as Diurnal megawatt amounts, by month, and shall apply in all years for the term of this Agreement. Such amounts are not subject to change in accordance with section 3.6.6.

On any hour that the Onsite Consumer Load is less than the specified maximum hourly amounts, all such Onsite Consumer Load shall be served by Surprise Valley with the identified Consumer-Owned Resource or with power other than Firm Requirements Power. Any hourly amounts of the identified Onsite Consumer Load in excess of the specified maximum hourly amounts shall be served with Firm Requirements Power. Any power generated from the identified Consumer-Owned Resource in excess of the specified maximum hourly amounts shall be applied to load other than Onsite Consumer Load in accordance with section 3.6.4.

3.6.5.2 **Option B: Maximum BPA-Served Onsite Consumer Load**
If Surprise Valley selects this Option B, then Surprise Valley shall specify, in section 7.3 of Exhibit A, the maximum hourly amounts of an identified Onsite Consumer Load that are to be served with Firm Requirements Power. Such amounts shall be specified as Diurnal megawatt amounts, by month, and shall apply in all years for the term of this Agreement.

Such amounts are not subject to change in accordance with section 3.6.6.

On any hour that Onsite Consumer Load is less than the specified maximum hourly amounts, all such Onsite Consumer Load shall be served with Firm Requirements Power. Surprise Valley shall serve any hourly amounts of the identified Onsite Consumer Load in excess of the specified maximum hourly amounts with power generated by the identified Consumer-Owned Resource or with power other than Firm Requirements Power. Any power generated from the identified Consumer-Owned Resource in excess of the amounts required to be used to serve the Onsite Consumer Load shall be applied to load other than Onsite Consumer Load in accordance with section 3.6.4.

3.6.6 **Changes to Consumer-Owned Resources**
Prior to each Fiscal Year Surprise Valley shall notify BPA in writing of any changes in ownership, expected resource output, or other characteristic of Consumer-Owned Resources identified in section 7 of Exhibit A. If a Consumer-Owned Resource has permanently ceased operation and Surprise Valley notifies BPA of such cessation, then BPA shall revise section 7 of Exhibit A to reflect such change as long as BPA agrees the determination is reasonable.

3.6.7 **Data Requirements for Consumer-Owned Resources**
Surprise Valley shall meter all Consumer-Owned Resources listed in section 7 of Exhibit A and shall provide such meter data to BPA pursuant to section 17.3.

3.7 **Hourly Dedicated Resource Schedule**
By June 30 of each Rate Case Year, Surprise Valley shall provide BPA an aggregated hourly schedule, in whole megawatt amounts consistent with section 3.7.3 and in the format described in section 3.7.2, for its Dedicated Resources with amounts in each hour, calculated pursuant to section 3.7.1, for each year of the upcoming Rate Period ("Submitted Schedule"). Surprise Valley shall schedule such hourly amounts to its Total Retail Load consistent with section 13.

3.7.1 **Schedule Amounts**
The amounts in the Submitted Schedule shall equal the sum of all monthly and Diurnal Dedicated Resource amounts listed in the tables in sections 2 and 3 of Exhibit A except for those Small Non-Dispatchable Resources listed in section 2.3 of Exhibit A, and those Specified Resources supported with DFS or SCS listed in section 2 of Exhibit D. The hourly amounts in the Submitted Schedule shall be determined in accordance with section 3.4.5.

If the amounts in the Submitted Schedule change in accordance with sections 3.4.4 and/or 3.5, then Surprise Valley shall send BPA a revised Submitted Schedule using the updated amounts within five Business Days of such amounts being updated in Exhibit A.

3.7.2 **Schedule Format**
Surprise Valley shall provide the Submitted Schedule to BPA electronically in a comma-separated-value (csv) format with the time/date stamp in the first column and load amounts, with units of measurement specified, in the following column.

3.7.3 **Whole Megawatt Amounts**
If Surprise Valley's Submitted Schedule would otherwise have amounts in fractional megawatts-per-hour, Surprise Valley shall vary its hourly amounts by one megawatt in some hours so that over the course of the applicable month the amounts as scheduled in whole megawatts sum to the appropriate total. If Surprise Valley's Dedicated Resource amounts are less than one megawatt-per-hour in any Diurnal period of a month, then Surprise Valley shall schedule one megawatt starting with the first hour of the Diurnal period of that month, and schedule one megawatt in each subsequent hour of the Diurnal period until the appropriate amount has been scheduled for that Diurnal period of such month.

4. THIS SECTION INTENTIONALLY LEFT BLANK

5. THIS SECTION INTENTIONALLY LEFT BLANK

6. TIERED RATE METHODOLOGY

6.1 BPA has proposed the TRM to FERC for either confirmation and approval for a period of 20 years (through September 30, 2028) or a declaratory order that the TRM meets cost recovery standards. The then-effective TRM shall apply in accordance with its terms and shall govern BPA's establishment, review and revision pursuant to section 7(i) of the Northwest Power Act, of all rates for power sold under this Agreement.

6.2 In the event that FERC approves the TRM for a period less than through September 30, 2028, or issues a declaratory order that the TRM meets cost recovery standards for a period less than through September 30, 2028, BPA shall, before the approved period of the TRM expires: (1) propose continuation of the TRM in a hearing conducted pursuant to section 7(i) of the Northwest Power Act or its successor; and then (2) resubmit the TRM to FERC for approval or declaratory affirmation of cost recovery standards through September 30, 2028.

6.3 The recitation of language from the TRM in this Agreement is not intended to incorporate such language into this Agreement. The TRM's language may be revised, but only in accordance with the requirements of TRM sections 12 and

13. If language of the TRM is revised, then any such language recited in this Agreement shall be modified accordingly, and the Amendment process of section 24.1 herein shall not apply to any such modifications.

6.4 Any disputes over the meaning of the TRM or rates or whether the Administrator is correctly implementing the TRM or rates, including but not limited to matters of whether the Administrator is correctly interpreting, applying, and otherwise adhering or conforming to the TRM or rate, shall (1) be resolved pursuant to any applicable procedures set forth in the TRM; (2) if resolved by the Administrator as part of a proceeding under section 7(i) of the Northwest Power Act, be reviewable as part of the United States Court of Appeals for the Ninth Circuit's review under section 9(e)(5) of the Northwest Power Act of the rates or rate matters determined in such section 7(i) proceeding (subject to any further review by the United States Supreme Court); and (3) if resolved by the Administrator outside such a section 7(i) proceeding, be reviewable as a final action by the United States Court of Appeals for the Ninth Circuit under section 9(e)(5) of the Northwest Power Act (subject to any further review by the United States Supreme Court). The remedies available to Surprise Valley through such judicial review shall be Surprise Valley's sole and exclusive remedy for such disputes, except as provided in the next paragraph.

Any knowing failure of BPA to abide by the TRM, or any BPA repudiation of its obligation here and under the TRM to revise the TRM only in accordance with the TRM sections 12 and 13 procedures for revision, would be a matter of contract to be resolved as would any other claim of breach of contract under this Agreement. For purposes of this paragraph, when there is a dispute between BPA and Surprise Valley concerning what the TRM means or requires, a "knowing failure" shall occur only in the event the United States Court of Appeals for the Ninth Circuit or, upon further review, the United States Supreme Court rules against BPA on its position as to what the TRM means or requires and BPA thereafter persists in its prior position.

6.5 BPA shall not publish a Federal Register Notice regarding BPA rates or the TRM that prohibits, limits, or restricts Surprise Valley's right to submit testimony or brief issues on rate matters regarding the meaning or implementation of the TRM or establishment of BPA rates pursuant to it, provided however for purposes of BPA's conformance to this paragraph a "rate matter" shall not include budgetary and program level issues.

6.6 The TRM established by BPA as of the Effective Date includes, among other things, the following:

6.6.1 Definitions (from Definitions section of the TRM):

"**Contract High Water Mark**" or "**CHWM**" means the amount (expressed in Average Megawatts), computed for each customer in accordance with section 4 of the TRM. For each customer with a CHWM Contract, the CHWM is used to calculate each customer's

RHWM in the RHWM Process for each applicable Rate Period. The CHWM Contract specifies the CHWM for each customer.

"**Rate Period High Water Mark**" or "**RHWM**" means the amount, calculated by BPA in each RHWM Process (as defined in the TRM) pursuant to the formula in section 4.2.1 of the TRM and expressed in Average Megawatts, that BPA establishes for each customer based on the customer's CHWM and the RHWM Tier 1 System Capability (as defined in the TRM). The maximum planned amount of power a customer may purchase under Tier 1 Rates each Fiscal Year of the Rate Period is equal to the RHWM for Load Following customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block customers.

"**Contract Demand Quantity**" or "**CDQ**" means the monthly quantity of demand (expressed in kilowatts) included in each customer's CHWM Contract that is subtracted from the Customer System Peak (as defined in the TRM) as part of the process of determining the customer's Demand Charge Billing Determinant (as defined in the TRM), as calculated in accordance with section 5.3.5 of the TRM.

6.6.2 Rate Period High Water Mark Calculation (from section 4.2.1 of the TRM):

Expressed as a formula, the RHWM will be calculated by BPA for each customer as follows:

$$RHWM = \frac{CHWM}{\Sigma CHWM} \times T1SC$$

where:

RHWM = Rate Period High Water Mark, expressed in Average Megawatts

CHWM = Contract High Water Mark

ΣCHWM = sum of all customers' Contract High Water Marks, including those for customers without a CHWM Contract

T1SC = forecast RHWM Tier 1 System Capability (as defined in the TRM), averaged for the Rate Period

7. HIGH WATER MARKS AND CONTRACT DEMAND QUANTITIES

7.1 Contract High Water Mark (CHWM)

BPA shall establish Surprise Valley's CHWM in the manner defined in section 4.1 of the TRM that was current as of the Effective Date. Surprise Valley's CHWM and the circumstances under which it can change are stated in Exhibit B.

7.2 Rate Period High Water Mark (RHWM)

Surprise Valley's CHWM shall also be Surprise Valley's RHWM for FY 2012 and FY 2013. BPA shall establish Surprise Valley's RHWM for the next Rate Period by September 30, 2012, and for subsequent Rate Periods by September 30 of each Forecast Year thereafter. BPA shall establish Surprise Valley's RHWM in the manner defined in section 4.2 of the TRM that was current as of the Effective Date.

7.3 Contract Demand Quantities (CDQs)

BPA shall establish Surprise Valley's CDQs pursuant to the TRM. Surprise Valley's CDQs are listed in Exhibit B.

8. APPLICABLE RATES

Purchases under this Agreement are subject to the following rate schedules, or their successors: Priority Firm Power (PF), New Resource Firm Power (NR), and Firm Power Products and Services (FPS), as applicable. Billing determinants for any purchases will be included in each rate schedule. Power purchases under this Agreement are subject to BPA's Wholesale Power Rate Schedules, established in accordance with the TRM, as applicable, and its GRSPs (or their successors).

8.1 Priority Firm Power (PF) Rates

BPA shall establish its PF power rates that apply to purchases under this Agreement pursuant to section 7 of the Northwest Power Act, and in accordance with the TRM. BPA shall establish PF rates that include rate schedules for purchase amounts at Tier 1 Rates and purchase amounts at Tier 2 Rates. Surprise Valley's purchase of Firm Requirements Power shall be priced as follows:

(1) Tier 1 Rates shall apply to Firm Requirements Power that Surprise Valley purchases under this Agreement, less: (a) amounts of Firm Requirements Power priced at Tier 2 Rates elected by Surprise Valley in section 2 of Exhibit C, and (b) any amounts purchased for NLSLs.

(2) Tier 2 Rates shall apply to planned annual amounts of Firm Requirements Power that Surprise Valley purchases to serve its Above-RHWM Load that remains after applying Surprise Valley's New Resources. The details of this calculation, including the use of a forecasted RHWM for FY 2012 and FY 2013, are established in the TRM.

8.2 **New Resource Firm Power (NR) Rate**
Except for the application of section 23.3.7.1 Renewable Resource/Cogeneration Exception, any amounts of Firm Requirements Power provided to Surprise Valley from BPA for service to an NLSL that is listed in Exhibit D shall be purchased at the NR Rate.

8.3 **Firm Power Products and Services (FPS) Rate**
Services sold under this Agreement to Surprise Valley at the FPS rate, if any, are listed in Exhibit D.

8.4 **Additional Charges**
The Resource Shaping Charge shall apply to Surprise Valley's New Resources that are used to serve Total Retail Load in an amount other than equal megawatt amounts for each hour of the year. Surprise Valley may incur additional charges or penalty charges as provided in the Wholesale Power Rate Schedules and GRSPs, including the Unauthorized Increase Charge or its successors.

8.5 **Resource Support Services (RSS)**
For Surprise Valley's Specified Resources, Surprise Valley may elect to purchase RSS products under this Agreement. Such purchases shall be listed in Exhibit D.

9. ELECTIONS TO PURCHASE POWER PRICED AT TIER 2 RATES

9.1 **Determination and Notice to Serve Above-RHWM Load**
Surprise Valley shall determine and provide notice, as described below, to BPA whether Surprise Valley shall serve its Above-RHWM Load that is greater than or equal to 8,760 megawatt-hours with either: (1) Firm Requirements Power purchased from BPA at a Tier 2 Rate or rates, (2) Dedicated Resources, or (3) a specific combination of both (1) and (2). Surprise Valley shall make such determination and provide such notice as follows:

9.1.1 **Notice Deadlines and Purchase Periods**
Notice Deadlines and corresponding Purchase Periods are as follows:

Notice Deadline		Purchase Period
November 1, 2009	For	FY 2012 – FY 2014
September 30, 2011	For	FY 2015 – FY 2019
September 30, 2016	For	FY 2020 – FY 2024
September 30, 2021	For	FY 2025 – FY 2028

9.1.2 **Elections to Purchase at Tier 2 Rates**
By each Notice Deadline, Surprise Valley shall elect in writing to purchase, or not to purchase, Firm Requirements Power at Tier 2 Rates for at least the upcoming Purchase Period. If Surprise Valley elects to purchase Firm Requirements Power at Tier 2 Rates, then

Surprise Valley shall make such election pursuant to sections 2.2 through 2.4 of Exhibit C. BPA shall update Exhibit C to state Surprise Valley's Tier 2 Rate purchase elections.

9.1.3 **Elections Not to Purchase at Tier 2 Rates**
If Surprise Valley elects under section 9.1.2 not to purchase Firm Requirements Power at Tier 2 Rates to serve Above-RHWM Load for a Purchase Period, BPA shall update section 2.1 of Exhibit C to indicate such election. Such election shall not eliminate any existing obligation that extends into the Purchase Period or beyond to purchase Firm Requirements Power at Tier 2 Rates.

9.1.4 **Failure to Make an Election**
If Surprise Valley makes no election by a Notice Deadline in section 9.1.1 for the corresponding Purchase Period Surprise Valley shall be deemed to have purchased Firm Requirements Power at Tier 2 Short-Term Rates to serve Above-RHWM Load under Alternative A in section 2.4.1 of Exhibit C with zero Dedicated Resource amounts listed in the table in section 2.4.1.1(2) of Exhibit C, except for any existing obligation to apply Dedicated Resources that extends into the Purchase Period or beyond.

9.2 **Tier 2 Rate Alternatives**
Subject to the requirements of this section 9 and those stated in Exhibit C, Surprise Valley shall have the right to purchase Firm Requirements Power at Tier 2 Load Growth Rates, Tier 2 Vintage Rates, and Tier 2 Short-Term Rates.

9.3 **Flat Block**
Amounts of Firm Requirements Power priced at Tier 2 Rates and purchased by Surprise Valley shall be equal in all hours of the year.

10. TIER 2 REMARKETING AND RESOURCE REMOVAL

10.1 **Resource Removal and Remarketing of Tier 2 Purchase Amounts for Each Rate Period**
If Surprise Valley's Above-RHWM Load as forecast for an upcoming Rate Period is less than the sum of (1) Surprise Valley's Tier 2 Rate purchase amounts, as stated in Exhibit C, and (2) Surprise Valley's New Resource amounts, as stated in Exhibit A, then by October 31 of each Rate Case Year, Surprise Valley may notify BPA of the order and associated amounts of Surprise Valley's Tier 2 Rate purchase amounts that BPA shall remarket and the New Resources Surprise Valley shall remove for each Fiscal Year in the upcoming Rate Period to the extent necessary to comply with section 10.2. If compliance with the requirements of section 10.2 would cause Surprise Valley to remove part or all of any New Resource that Surprise Valley uses to fulfill a state or federal renewable resource standard or other comparable legal obligation, then Surprise Valley shall have the right to substitute its right to remove New Resources for the same amount of Existing Resources to

the extent necessary to comply with section 10.2, provided that the hourly, monthly, and Diurnal amounts so removed shall be equal to the hourly, monthly, and Diurnal amounts provided by the New Resources that Surprise Valley would have otherwise been obligated to remove.

If Surprise Valley does not provide BPA with such timely notice in accordance with the preceding paragraph, then BPA shall determine the order and associated amounts of Tier 2 remarketing and removal of New Resources to the extent necessary to comply with section 10.2.

10.2 **Extent of Removal**
Tier 2 remarketing and removal of New Resources pursuant to section 10.1 shall apply until:

(1) the remarketed Tier 2 Rate purchase amounts plus the removed New Resource amounts equal the amount by which Surprise Valley's Tier 2 Rate purchase amounts plus its New Resources exceed its Above-RHWM Load, or

(2) all of Surprise Valley's Tier 2 Rate purchase amounts are remarketed and all of its New Resources are removed.

10.3 **Partial Resource Removal**
When only a portion of a Specified Resource or Unspecified Resource Amounts is being removed pursuant to section 10.1, such resources shall be removed proportionally to maintain the same annual shape for the resource that Surprise Valley has established in Exhibit A.

10.4 **Remarketing of Power Priced at Tier 2 Rates**
Consistent with rates established under the TRM, Surprise Valley shall be subject to applicable charges or credits associated with BPA's remarketing of purchase amounts of Firm Requirements Power at Tier 2 Rates. Except as specified in section 10.5, Surprise Valley shall be responsible for remarketing of any amounts of its Dedicated Resources, Specified or Unspecified, that are removed pursuant to section 10.1.

10.5 **Removal of Resources Taking DFS**
The following shall apply for any Dedicated Resources: (1) for which Surprise Valley is purchasing DFS under this Agreement, and (2) that are partially or entirely removed pursuant to section 10.1.

10.5.1 Surprise Valley shall continue to apply the entire amount of any such resources to load consistent with applicable provisions stated in Exhibit D.

10.5.2 BPA shall remarket the amounts of any such resources that are removed pursuant to section 10.1 in the same manner BPA remarkets Tier 2 Rate purchase amounts in section 10.4. BPA shall continue to provide DFS in accordance with applicable provisions in Exhibit D to any amounts of such resources that remain after resource removal.

11. RIGHT TO CHANGE PURCHASE OBLIGATION

11.1 One-Time Right to Change Purchase Obligation

Subject to this section 11.1, Surprise Valley shall have a one-time right to change its purchase obligation, identified in section 3, to another purchase obligation available from BPA, including Block or Slice/Block. If Surprise Valley chooses to change its purchase obligation, then Surprise Valley shall first provide notice to BPA of its intent and then confirm its decision as established below. Any elections of Tier 2 Rate alternatives, Dedicated Resource additions, or other notices given to BPA under this Agreement shall continue to be applicable under the new purchase obligation, provided that BPA may update such terms and conditions consistent with the then-current terms of the new purchase obligation, and additional costs may apply for service under the new purchase obligation as described in section 11.1.3.

11.1.1 Notice to Change

By May 31, 2016, Surprise Valley may provide written notice to BPA that it is requesting to change its purchase obligation effective October 1, 2019, subject to confirmation described in section 11.1.4. Surprise Valley's notice shall state the type of service requested. If such service is the Slice/Block purchase obligation, then Surprise Valley shall state a range of Slice amounts between a specified minimum and maximum amount of Slice that Surprise Valley will accept, provided that the maximum amount of Slice shall not exceed 70% of Surprise Valley's CHWM.

11.1.2 Limitations Due to Peak Load Increase

By July 31, 2016, BPA shall assess the aggregate effect of all requests to change purchase obligations on BPA's forecast of its total monthly firm coincident peak loads in the first year the changes become effective. If the increase in this peak load in any one month exceeds 300 megawatts, then BPA may, after consulting with Surprise Valley and other customers with a CHWM Contract, do one of the following to reduce the increase in such peak load to 300 megawatts: (1) deny Surprise Valley's request to change its purchase obligation, or (2) approve Surprise Valley's request but defer the date on which Surprise Valley's new purchase obligation change becomes effective.

11.1.3 Charge to Change Purchase Obligation

In addition to the limitations established in section 11.1.2, Surprise Valley may be subject to charges, in addition to the rates for the new service, as a result of changing its purchase obligation. Such additional charges shall recover all additional costs that: (1) will be incurred by BPA to serve Surprise Valley under its new purchase obligation compared to its existing purchase obligation, and (2) would otherwise result in a rate impact on all other customers receiving service under a CHWM Contract. If Surprise Valley makes a request to change its purchase obligation, then by September 30, 2016, BPA shall determine and present Surprise Valley with any such additional charges. BPA shall not be required to make a payment to Surprise Valley as a result of Surprise Valley changing its purchase obligation.

11.1.4 **Change Confirmation**
Within 30 days of BPA's presentation to Surprise Valley of the additional charges determined in section 11.1.3, Surprise Valley shall provide BPA with written notice whether it wishes to proceed with its request to change its purchase obligation. If Surprise Valley is requesting a change to the Slice/Block purchase obligation, then such confirmation constitutes agreement that Surprise Valley shall purchase an amount of Slice within Surprise Valley's specified range of acceptable Slice amounts, if made available by BPA. If Surprise Valley does not provide BPA with such confirmation, then Surprise Valley's existing purchase obligation identified in section 3 shall continue to apply.

11.1.5 **Slice Amount**
If Surprise Valley requests a change to a Slice/Block purchase obligation, then BPA shall determine Surprise Valley's specific amount of Slice as follows:

(1) BPA shall determine the total amount of Slice available for purchase by all customers requesting a change to Slice/Block. Such amount shall be the sum of any unsubscribed amount of Slice as of October 1, 2011, plus any amount of Slice made available by customers switching from the Slice/Block purchase obligation.

(2) If such amount is sufficient to meet the requested maximum amount of Slice from all customers requesting a change to Slice/Block, then BPA shall provide to Surprise Valley its requested maximum amount of Slice as part of the new purchase obligation.

(3) If such amount is insufficient to meet the requested maximum amount of Slice from all customers requesting a change to Slice/Block, then BPA shall reduce individual Slice amounts of customers requesting a change to Slice/Block pro rata based on the requested maximum amount of Slice. If Surprise Valley's individual Slice amount is below its specified minimum, then Surprise Valley shall retain its current purchase obligation.

11.1.6 **Amendment to Reflect New Purchase Obligation**
Following Surprise Valley's confirmation of its decision to change its purchase obligation, the Parties shall amend this Agreement to replace the terms of Surprise Valley's current purchase obligation

with the terms of the new purchase obligation. Such amendment shall include, but not be limited to, revising the peak amounts for each of Surprise Valley's Specified Resources listed in section 2 of Exhibit A. The Parties shall revise such peak amounts using BPA's peak standard applicable to Surprise Valley's new purchase obligation. The amended Agreement shall be effective no later than October 1, 2019.

11.2 **This Section Intentionally Left Blank**

12. BILLING CREDITS AND RESIDENTIAL EXCHANGE

12.1 **Billing Credits**
If Surprise Valley develops a Generating Resource to serve its loads, then Surprise Valley agrees that it shall forego any request for, and BPA is not obligated to include, billing credits, as defined in section 6(h) of the Northwest Power Act, on Surprise Valley's bills under this Agreement. This section does not apply to any billing credit contracts in effect as of the Effective Date.

12.2 **Agreement to Limit Exchange Costs of Existing Resources**
Surprise Valley agrees it will not seek and shall not receive residential exchange benefits pursuant to section 5(c) of the Northwest Power Act other than pursuant to Section IV(G) of BPA's 2008 Average System Cost Methodology or its successor. Surprise Valley recognizes that the quantity of residential load will be determined in a subsequent policy or rate determination. Surprise Valley's agreement in this section 12.2 is a material precondition to BPA offering and executing this Agreement.

13. SCHEDULING

From October 1, 2011, through September 30, 2028, Power Services shall provide and Surprise Valley shall purchase Transmission Scheduling Service. The Parties shall administer Surprise Valley's Transmission Scheduling Service consistent with Exhibit F.

14. DELIVERY

14.1 **Definitions**

14.1.1 "Integrated Network Segment" means those facilities of the Federal Columbia River Transmission System that are required for the delivery of bulk power supplies, the costs for which are recovered through generally applicable transmission rates, and that are identified as facilities in the Integrated Network Segment, or its successor, in the BPA segmentation study for the applicable transmission rate period as determined in a hearing establishing or revising BPA's transmission rates pursuant to section 7(i) of the Northwest Power Act.

14.1.2 "Primary Points of Receipt" means the points on the Pacific Northwest transmission system where Firm Requirements Power is forecasted to be made available by Power Services to Surprise Valley for purposes of obtaining a long-term firm transmission contract.

14.1.3 "Scheduling Points of Receipt" means the points on the Pacific Northwest transmission system where Firm Requirements Power is made available by Power Services to Surprise Valley for purposes of transmission scheduling.

14.2 **Transmission Service**

14.2.1 Surprise Valley is responsible for delivery of power from the Scheduling Points of Receipt, except as provided under section 14.6.

14.2.2 Surprise Valley shall provide at least 60 days' notice to Power Services prior to changing Balancing Authority Areas.

14.2.3 At Surprise Valley's request, Power Services shall provide Surprise Valley with Primary Points of Receipt and other information needed to enable Surprise Valley to obtain long-term firm transmission for delivery of power sold under this Agreement. If required by Transmission Services for purposes of transmission scheduling, then Power Services shall provide Surprise Valley with Scheduling Points of Receipt. Power Services has the right to provide power to Surprise Valley at Scheduling Points of Receipt that are different than the Primary Points of Receipt. If BPA does provide power to Surprise Valley at Scheduling Points of Receipt that are different than the Primary Points of Receipt, then BPA shall reimburse Surprise Valley for any incremental, direct, non-administrative costs incurred by Surprise Valley to comply with delivering Firm Requirements Power from such a Scheduling Point of Receipt to Surprise Valley's load if the following conditions, as outlined in (1) or (2) below, have been met:

(1) If Surprise Valley has long-term Point to Point (PTP) transmission service (as defined in BPA's Open Access Transmission Tariff) for delivery of Firm Requirements Power to its load:

(A) Surprise Valley has requested long-term firm transmission service to deliver its Firm Requirements Power using the Primary Points of Receipt and other information provided by Power Services; and

(B) Surprise Valley has submitted a request to redirect its long-term firm PTP transmission service to deliver Firm Requirements Power from the Scheduling Point of Receipt on a firm basis, but that request was not granted; and

(C) Surprise Valley's transmission schedule was curtailed due to non-firm status under PTP transmission service or Surprise Valley can provide proof of the reimbursable costs incurred to replace the curtailed schedule.

(2) If Surprise Valley has long-term Network Integration Transmission Service (as defined in BPA's Open Access Transmission Tariff) for delivery of Firm Requirements Power to its load:

(A) Surprise Valley has requested long-term firm transmission service to deliver its Firm Requirements Power using the Primary Points of Receipt and other information provided by Power Services; and

(B) Surprise Valley's transmission schedule was curtailed due to non-firm status under its secondary service status and Surprise Valley can provide proof of the reimbursable costs incurred to replace the curtailed schedule.

14.3 **Liability for Delivery**
Surprise Valley waives any claims against BPA arising under this Agreement for non-delivery of power to any points beyond the applicable Scheduling Points of Receipt, except for reimbursement of costs as described in section 14.2.3. BPA shall not be liable under this Agreement for any third-party claims related to the delivery of power after it leaves the Scheduling Points of Receipt. Neither Party shall be liable under this Agreement to the other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply regardless of whether or not this Agreement provides for Transfer Service.

14.4 **Real Power Losses**
BPA is responsible for the real power losses necessary to deliver Firm Requirements Power to Surprise Valley's PODs listed in Exhibit E.

14.5 **Metering Losses**
BPA shall adjust measured amounts of power to account for losses, if any, that occur between Surprise Valley's PODs and the respective POMs, as specified in Exhibit E.

14.6 **Delivery by Transfer**
Subject to the limitations in this section, BPA agrees to acquire and pay for Transfer Service to deliver Firm Requirements Power and Surplus Firm Power to Surprise Valley's PODs, as listed in Exhibit E, in an amount not to exceed Surprise Valley's Total Retail Load on an hourly basis. In the event that a conflict exists between the provisions of this Agreement and the

Agreement Regarding Transfer Service (ARTS) Contract No. 05EO-40026, this Agreement shall govern.

14.6.1 **Ancillary Services**
BPA shall acquire and pay for Ancillary Services, as defined in BPA's Open Access Transmission Tariff, needed for Surprise Valley's Transfer Service subject to the following limitations:

(1) Surprise Valley shall reimburse BPA for load regulation service or its replacement at the applicable Transmission Services rate, or its successor.

(2) BPA shall pay for the Ancillary Service(s) charged by a Third-Party Transmission Provider to deliver Firm Requirements Power to the PODs listed in Exhibit E, only if Surprise Valley is also purchasing such Ancillary Service(s) from Transmission Services to deliver Firm Requirements Power to the PODs in Exhibit E. If at any time Surprise Valley is not purchasing Ancillary Service(s) from Transmission Services to deliver Firm Requirements Power to one or more of the PODs listed in Exhibit E, then Surprise Valley shall reimburse BPA for the Ancillary Service(s) charges BPA has incurred from the Third Party Transmission Provider to deliver power to such POD(s), at the applicable or equivalent Transmission Services Ancillary Services rate.

14.6.2 **Low Voltage Delivery**
Low Voltage Delivery is service over the Low Voltage Segment by any Third Party Transmission Provider's system. "Low Voltage Segment" means the facilities of a Third-Party Transmission Provider that are equivalent to the voltage level of the facilities excluded by Transmission Services from the Integrated Network Segment. For Low Voltage Delivery, Surprise Valley shall pay Power Services the applicable General Transfer Agreement (GTA) Delivery Charge, or its successor rate, consistent with the applicable BPA Wholesale Power Rate Schedules and GRSPs. The Parties shall list Surprise Valley's PODs that require Low Voltage Delivery in Exhibit E.

14.6.3 **Direct Assignment Costs**
Surprise Valley shall pay BPA for all directly assigned costs, including but not limited to: facility or system studies costs, construction costs, upgrade costs, and expansion costs, or other capital costs for facilities directly associated with service to any Surprise Valley PODs assessed by the Third Party Transmission Provider to BPA. Such costs shall be consistent with Transmission Services' "Guidelines for Direct Assignment Facilities," and the "Final Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements" included in BPA's Long Term Regional Dialogue Final

Policy, July 2007, or any other revision of that policy, or as established in a BPA 7(i) Process.

14.6.4 **Penalties Assessed By the Third Party Transmission Provider**
BPA has the right to directly pass through to Surprise Valley any penalty charges assessed by the Third Party Transmission Provider that are associated with BPA's acquisition of Transfer Service to the PODs identified in Exhibit E. Such charges may include, but are not limited to, power factor penalties or excessive energy imbalance penalties.

14.6.5 **Removal of PODs**
BPA may terminate deliveries at a POD if Surprise Valley consents to the termination or if the Parties determine that Surprise Valley's requirements for power at such point may be adequately supplied under reasonable conditions and circumstances at different POD(s): (1) directly from the Federal Columbia River Transmission System, (2) indirectly from the facilities of another transmission owner/operator, or (3) both.

14.6.6 **Annexed Loads**
BPA shall arrange and pay for Transfer Service for federal power deliveries to serve Surprise Valley's Annexed Load. Surprise Valley shall provide BPA written notice of any Annexed Load acquired greater than one Average Megawatt no later than 90 days prior to the commencement of service to the Annexed Load. However, BPA's obligation to provide Transfer Service to Surprise Valley's Annexed Load shall be limited by the megawatt caps and process for Annexed Load and new public customers set forth in BPA's Long Term Regional Dialogue Final Policy, July 2007, or any revision of that policy.

14.6.7 **Non-Federal Deliveries**
If Surprise Valley has a non-federal resource or is acquiring a non-federal resource necessary to serve its Above-RHWM Load, and Surprise Valley has requested that BPA assist in the acquisition of transmission services for such resource, then BPA shall offer Surprise Valley a separate agreement for specific terms and conditions under which BPA will obtain Transfer Service on a Third Party Transmission Provider's system for delivery of that resource to Surprise Valley's system. The terms of the agreement BPA offers to Surprise Valley shall not be subject to section 22, Governing Law and Dispute Resolution. BPA shall develop the agreement consistent with the principles of service specified in Exhibit G.

14.7 **Delivery of New Resources Over Multiple Transmission Systems**

14.7.1 **Determination of Surprise Valley's Baseline Load Percentages**
If Surprise Valley is applying New Resources to serve its Above-RHWM Load and its load is located on multiple transmission systems,

then BPA shall by July 31, 2010 and by July 31 of every Forecast Year through the term of this Agreement:

(1) calculate Surprise Valley's baseline delivery percentages and amounts for the upcoming Rate Period. Such percentages and amounts shall be based on BPA's forecast Total Retail Load for Surprise Valley for use in the applicable RHWM process, and shall serve as the basis from which BPA calculates any cost shifts, pursuant to section 14.7.3 below. BPA shall calculate Surprise Valley's load growth on each applicable transmission system by comparing forecast Total Retail Load on each applicable transmission system to Total Retail Load in 2010 on each applicable transmission system. BPA shall then calculate Surprise Valley's baseline delivery percentages by comparing Surprise Valley's load growth on each applicable transmission system and Surprise Valley's load growth on all transmission systems. BPA shall then calculate Surprise Valley's baseline delivery amounts by applying Surprise Valley's baseline delivery percentage for each transmission system to Surprise Valley's Above-RHWM Load; and

(2) revise Exhibit D to list Surprise Valley's baseline delivery percentages and amounts.

14.7.2 **De Minimis Load**
If, when BPA calculates Surprise Valley's baseline delivery percentages and amounts, Surprise Valley's Above-RHWM Load served over a transmission system is forecasted to be less than 8,760 megawatt-hours, then Surprise Valley's delivery amount for that system shall be zero, and the load deemed de minimis shall be added to the delivery amount of the other transmission system(s).

14.7.3 **Delivery of New Resources at Percentages Different than Baseline**

14.7.3.1 **Notification of Proposed Delivery Option**
Surprise Valley may notify BPA by August 15, 2010, and by August 15 of every Forecast Year through the term of this Agreement, of Surprise Valley's proposed option for delivering its New Resources and non-federal resources which Surprise Valley is seeking to include as a New Resource to its Above-RHWM Loads. In such notice, Surprise Valley shall provide BPA a table that includes the monthly amounts of each New Resource and non-federal resource which Surprise Valley is seeking to include as a New Resource, in megawatt-hours, and that it proposes to deliver over each transmission system to its load(s) for the upcoming Rate Period. Surprise Valley's proposed delivery amount over a transmission system shall be no more than the

minimum forecast load served over such transmission system during any hour of the upcoming Rate Period.

14.7.3.2 **Cost Shift Calculations**

Once BPA receives notification from Surprise Valley with its proposed delivery amounts, BPA shall compare the baseline delivery amounts and Surprise Valley's proposed delivery amounts to calculate the costs BPA determines would be shifted between the Surprise Valley and Tier 1 Rates by such a proposal.

In its calculation of Surprise Valley's cost shifts, BPA shall:

(1) include any reasonable cost shifts from Surprise Valley to Tier 1 Rates;

(2) include any reasonable benefits of Surprise Valley's delivery proposal that offset costs to BPA; and

(3) not include any costs to Surprise Valley attributable to future BPA resource acquisition decisions.

Such categories of costs shall include, but are not limited to, losses, risk of increased curtailments, ancillary services, and increased costs of delivering remote BPA resources that BPA is acquiring at the time that Surprise Valley's non-federal resource is first included in Surprise Valley's delivery option. Once BPA, in consultation with Surprise Valley, determines the categories of costs for each New Resource and non-federal resource which Surprise Valley is seeking to include as a New Resource that will apply in BPA's cost shift calculation, BPA shall not add any additional categories of costs into its calculations as long as the resource remains committed to serve load interconnected to the same transmission system.

14.7.3.3 **Notification of Costs and Exhibit D Revision**

BPA shall notify Surprise Valley of such costs by September 15, 2010 and by September 15 of every Forecast Year through the term of this Agreement.

If the Parties agree to mutually acceptable delivery options that are different than the baseline delivery percentages, the Parties shall, by September 30, 2010, revise Exhibit D to include the details of such delivery options. If there are any changes to Surprise Valley's New Resources, significant changes to load, significant changes to transmission conditions, or other changes that directly affect the cost shift categories since the previous cost shift calculation, then the Parties shall revise Exhibit D to reflect such changes by

September 30 of every Forecast Year through the term of this Agreement.

14.7.4 **Delivery of New Resources at the Baseline Delivery Percentages**
Unless the Parties have agreed otherwise pursuant to section 14.7.3 above, Surprise Valley shall apply its New Resources to serve its Above-RHWM Load consistent with the baseline delivery percentages listed in Exhibit D.

15. METERING

15.1 Measurement

By September 30, 2010, the Parties shall ensure that meters are installed on all PODs listed in Exhibit E, consistent with the requirements of this section 15. The amount of power measured by such meters shall be used by BPA for billing purposes. If the Parties agree that metering is economically or technologically impractical, then:

(1) the Parties shall use scheduled amounts to measure the amount of power purchased if such power is scheduled into or out of Surprise Valley's service territory; or

(2) the Parties shall use mutually acceptable load profiles to measure the amount of power purchased if such power is not scheduled.

If the metering equipment associated with the meters listed in Exhibit E fails to properly measure or record the interval readings, then BPA shall apply the procedure set out in the Meter Usage Data Estimations provision of the Wholesale Power Rate Schedules and GRSPs to determine the appropriate billing adjustment.

The rights to locate meters and access facilities granted to BPA pursuant to this section 15 are subject to the terms of any applicable agreement between Surprise Valley and Transmission Services addressing the location, cost responsibility, access, maintenance, testing, and liability of the Parties with respect to meters.

15.2 Existing BPA Owned Meters

At BPA's expense, BPA shall operate, maintain, and replace, as necessary, all existing metering equipment owned by BPA that is needed to plan, schedule, and bill for power. Surprise Valley authorizes BPA to maintain and replace any metering equipment on Surprise Valley's facilities that is reasonably necessary to forecast, plan, schedule, and bill for power. With reasonable notice from BPA, and for the purpose of implementing this provision, Surprise Valley shall grant BPA reasonable physical access to BPA owned meters at BPA's request.

BPA shall give Surprise Valley access to meter data from the BPA owned meters listed in Exhibit E.

If, at any time, BPA or Surprise Valley determines that a BPA owned meter is defective or inaccurate, then BPA shall adjust, repair, or replace the meter to provide accurate metering as soon as practical.

15.3 **Non-BPA Owned Meters**

15.3.1 **Customer Owned Meters**
Surprise Valley shall operate, maintain, and replace, as necessary at Surprise Valley's expense, all non-BPA metering equipment owned by Surprise Valley that is needed by BPA to forecast, plan, schedule, and bill for power for:

(1) points of interconnection between Surprise Valley's system and parties other than BPA;

(2) all loads that require separate measurement for purposes of forecasting, planning, scheduling, or billing for power; and

(3) Generating Resources listed in Exhibit A that are interconnected to Surprise Valley's system.

Surprise Valley shall give BPA direct, electronic access to meter data from all Surprise Valley owned meters that are capable of being accessed electronically. For the purpose of inspection, Surprise Valley shall grant BPA reasonable physical access to Surprise Valley meters at BPA's request.

If, at any time, BPA or Surprise Valley determines that a Surprise Valley owned meter listed in Exhibit E is defective or inaccurate, then Surprise Valley shall adjust, repair, or replace the meter, or shall make commercially reasonable efforts to arrange for the completion of such actions, to provide accurate metering as soon as practical. BPA shall have the right to witness any meter tests on Surprise Valley owned meters listed in Exhibit E and, with reasonable advance notice, BPA may conduct tests on such meters. Surprise Valley shall have the right to witness any meter tests conducted by BPA.

15.3.2 **Non-BPA Owned Meters Not Owned by Surprise Valley**
For non-BPA owned meters not owned by Surprise Valley needed by BPA to forecast, plan, schedule and bill for power under this Agreement, Surprise Valley shall make commercially reasonable efforts to arrange for such meters to be operated, maintained and replaced, as necessary, for the measurements described above in sections 15.3.1(1) and 15.3.1(2) and for any Generating Resources listed in Exhibit A that require metering.

If, at any time, it is determined that a non-BPA owned meter not owned by Surprise Valley listed in Exhibit E is defective or inaccurate, then Surprise Valley shall make commercially reasonable efforts to arrange to adjust, repair, or replace the meter, to provide accurate metering as soon as practical. To the extent possible, BPA may witness any meter tests on non-BPA owned meters not owned by Surprise Valley listed in Exhibit E and, with reasonable advance notice, BPA may conduct tests on such meters. Surprise Valley shall have the right to witness any meter tests conducted by BPA.

15.3.3 **Non-BPA Owned Meters Owned by Third-Party Transmission Provider**
This section 15.3 shall not apply to non-BPA owned meters that are owned by a Third-Party Transmission Provider with which BPA holds a transmission contract for service to Surprise Valley load. In these cases the metering arrangements shall be between BPA and the Third-Party Transmission Provider.

15.4 **New Meters**
A separate agreement addressing the location, cost responsibility, access, maintenance, testing, and liability of the Parties with respect to new meters shall be between Surprise Valley and Transmission Services.

All new and replaced meters shall meet American National Standard Institute standards, including, but not limited to C12.20, Electricity Meters--0.2 and 0.5 Accuracy Classes, and the Institute of Electrical and Electronics Engineers, Inc. standard C57.13, Requirements for Instrument Transformers, or their successors. Any new and replaced meters shall be able to record meter data hourly and store data for a minimum of 45 days.

15.5 **Metering an NLSL**
Any loads that are monitored by BPA for an NLSL determination and any NLSLs shall be metered pursuant to section 23.3.4.

15.6 **Metering Exhibit**
Surprise Valley shall provide meter data specified in section 17.3 and shall notify BPA of any changes to PODs, POMs, Interchange Points and related information for which it is responsible. BPA shall list Surprise Valley's PODs and meters in Exhibit E.

16. BILLING AND PAYMENT

16.1 **Billing**
BPA shall bill Surprise Valley monthly for all products and services provided during the preceding month(s). BPA may send Surprise Valley an estimated bill followed by a final bill. The Issue Date is the date BPA electronically sends the bill to Surprise Valley. If electronic transmittal of the entire bill is not practical, then BPA shall transmit a summary electronically, and send the entire bill by United States mail.

16.2 **Payment**
Surprise Valley shall pay all bills electronically in accordance with instructions on the bill. Payment of all bills, whether estimated or final, must be received by the 20th day after the Issue Date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or federal holiday, then the Due Date is the next Business Day.

If Surprise Valley has made payment on an estimated bill then:

(1) if the amount of the final bill exceeds the amount of the estimated bill, then Surprise Valley shall pay BPA the difference between the estimated bill and final bill by the final bill's Due Date; or

(2) if the amount of the final bill is less than the amount of the estimated bill, then BPA shall pay Surprise Valley the difference between the estimated bill and final bill by the 20th day after the final bill's Issue Date. If the 20th day is a Saturday, Sunday, or federal holiday, BPA shall pay the difference by the next Business Day.

16.3 **Late Payments**
After the Due Date, a late payment charge equal to the higher of:

(1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus four percent, divided by 365; or

(2) the Prime Rate times 1.5, divided by 365;

shall be applied each day to any unpaid balance.

16.4 **Termination**
If Surprise Valley has not paid its bill in full by the Due Date, it shall have 45 days to cure its nonpayment by making payment in full. If Surprise Valley does not provide payment within three Business Days after receipt of an additional written notice from BPA, and BPA determines in its sole discretion that Surprise Valley is unable to make the payments owed, then BPA may terminate this Agreement. Written notices sent under this section 16.4 must comply with section 20.

16.5 **Disputed Bills**

16.5.1 If Surprise Valley disputes any portion of a charge or credit on Surprise Valley's estimated or final bills, Surprise Valley shall provide written notice to BPA with a copy of the bill noting the disputed amounts. Notwithstanding whether any portion of the bill is in dispute, Surprise Valley shall pay the entire bill by the Due Date. This section 16.5.1 does not allow Surprise Valley to challenge the validity of any BPA rate.

16.5.2 Unpaid amounts on a bill (including both disputed and undisputed amounts) are subject to the late payment charges provided above. Notice of a disputed charge on a bill does not constitute BPA's agreement that a valid claim under contract law has been stated.

16.5.3 If the Parties agree, or if after a final determination of a dispute pursuant to section 22, Surprise Valley is entitled to a refund of any portion of the disputed amount, then BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate shall equal the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) divided by 365.

17. INFORMATION EXCHANGE AND CONFIDENTIALITY

17.1 General Requirements

Upon request, each Party shall provide the other Party with any information that is necessary to administer this Agreement and to forecast Surprise Valley's Total Retail Load, forecast BPA system load, comply with NERC reliability standards, prepare bills, resolve billing disputes, administer Transfer Service, and otherwise implement this Agreement. For example, this obligation includes transmission and power scheduling information and load and resource metering information (such as one-line diagrams, metering diagrams, loss factors, etc.). In addition, Surprise Valley shall provide information BPA requests about Dedicated Resources for purposes of meeting BPA's statutory obligations under section 7(b) of the Northwest Power Act. Information requested under this section 17.1 shall be provided in a timely manner. If Surprise Valley fails to provide BPA with information Surprise Valley is required to provide pursuant to this Agreement and the absence of such information makes it impossible for BPA to perform a calculation, make a determination, or take an action required under this Agreement, then BPA may suspend its obligation to perform such calculation, make such determination, or take such action until Surprise Valley has provided such information to BPA.

17.2 Reports

17.2.1 Within 30 days after final approval of Surprise Valley's annual financial report and statements by Surprise Valley's authorized officer, Surprise Valley shall either e-mail them to BPA at kslf@bpa.gov or, if any of the information is publicly available, then Surprise Valley shall notify BPA of its availability.

17.2.2 Within 30 days after its submittal to the Energy Information Administration (EIA), or its successor, Surprise Valley shall e-mail a copy of its Annual Form EIA-861 Reports to BPA at kslf@bpa.gov. If

Surprise Valley is not required to submit such reports to the EIA, then this requirement does not apply.

17.3 **Meter Data**

17.3.1 In accordance with section 15 and Exhibit E, the Parties shall notify each other of any changes to PODs, POMs, Interchange Points and related information for which it is responsible. Surprise Valley shall ensure BPA has access to all data from load and resource meters that BPA determines is necessary to forecast, plan, schedule, and bill under this Agreement. Access to this data shall be on a schedule determined by BPA. Meter data shall be in hourly increments for all meters that record hourly data. Meter data includes, but is not limited to: Surprise Valley's actual amounts of energy used or expended for loads and resources, and the physical attributes of Surprise Valley's meters.

17.3.2 Surprise Valley consents to allow Power Services to receive the following information from Transmission Services or BPA's metering function: (1) Surprise Valley's meter data, as specified in section 17.3.1, section 15, and Exhibit E, and (2) notification of outages or load shifts.

17.3.3 At least 15 calendar days in advance, Surprise Valley shall e-mail BPA at: (1) mdm@bpa.gov and (2) the contact shown in section 20 when the following events are planned to occur on Surprise Valley's system that will affect the load measured by the meters listed in Exhibit E: (1) installation of a new meter, (2) changes or updates to an existing meter not owned by BPA, (3) any planned line or planned meter outages, and (4) any planned load shifts from one POD to another. This section 17.3.3 is not intended to apply to retail meters not listed in Exhibit E.

17.3.4 If an unplanned load shift or outage occurs, materially affecting the load measured by the meters listed in Exhibit E, then Surprise Valley shall e-mail BPA at: (1) mdm@bpa.gov, and (2) the contact shown in section 20 within 72 hours after the event.

17.4 **Data for Determining CHWM and CDQs**

Upon request, Surprise Valley shall provide to BPA any load and resource information that BPA determines is reasonably necessary to calculate Surprise Valley's CHWM and CDQs. This may include historical load data not otherwise available to BPA and other data necessary to allow BPA to adjust for weather normalization.

17.5 **Transparency of Net Requirements Process**

By July 31 of each Forecast Year, BPA shall make the following information publicly available to Surprise Valley and all other BPA regional utility customers with a CHWM:

(1) Surprise Valley's measured Total Retail Load data for the previous two Fiscal Years in monthly energy amounts and monthly customer-system peak amounts, and

(2) Surprise Valley's Dedicated Resources for the previous two Fiscal Years in monthly energy and peak amounts as listed in section 5 of Exhibit A.

Surprise Valley waives all claims of confidentiality regarding the data described above.

17.6 **Confidentiality**
Before Surprise Valley provides information to BPA that is confidential, or is otherwise subject to privilege, or nondisclosure, Surprise Valley shall clearly designate such information as confidential. BPA shall notify Surprise Valley as soon as practicable of any request received under the Freedom of Information Act (FOIA), or under any other federal law or court or administrative order, for any confidential information. BPA shall only release such confidential information to comply with FOIA or if required by any other federal law or court or administrative order. BPA shall limit the use and dissemination of confidential information within BPA to employees who need it for purposes of administering this Agreement.

17.7 **Resources Not Used to Serve Total Retail Load**
Surprise Valley shall list in section 6 of Exhibit A all Generating Resources and Contract Resources Surprise Valley owns that are (1) not Specified Resources listed in section 2 of Exhibit A, and (2) greater than 200 kilowatts of nameplate capability. At BPA's request Surprise Valley shall provide BPA with additional data if needed to verify the information listed in section 6 of Exhibit A.

18. CONSERVATION AND RENEWABLES

18.1 Conservation

18.1.1 Evaluations

At BPA's expense, BPA may conduct, and Surprise Valley shall cooperate in, conservation impact and project implementation process evaluations to assess the amount, cost-effectiveness, and reliability of conservation in BPA's or Surprise Valley's service area.

BPA shall select the timing, frequency, and type of such evaluations. BPA shall do so with reasonable consideration of Surprise Valley's and Surprise Valley's consumers' needs.

18.1.2 **Reporting Requirements**

18.1.2.1 This section 18.1.2.1 does not apply if Surprise Valley's Total Retail Load from the most recent prior Fiscal Year is 25 annual Average Megawatts or less, or if Surprise Valley purchases all of its power from BPA to serve its Total Retail Load. Beginning June 1, 2010, and no later than June 1 every two years thereafter, Surprise Valley shall submit a ten-year conservation plan stating Surprise Valley's projection of planned conservation, including biennial conservation targets. This requirement may be satisfied by submitting any plans Surprise Valley prepares in the normal course of business if the plans include, or are supplemented by, the information required above. This includes plans required under state law (such as the Washington State Energy Independence Act (RCW 19.285)).

18.1.2.2 Surprise Valley shall verify and report all cost-effective (as defined by section 3(4) of the Northwest Power Act) non-BPA-funded conservation measures and projects savings achieved by Surprise Valley through the Regional Technical Forum's Planning, Tracking and Reporting System or its successor tool. Verification protocols of conservation measures and projects, reporting timelines and documentation requirements shall comply with BPA's Energy Efficiency Implementation Manual or its successor.

18.2 **Renewable Resources**

18.2.1 **Renewable Energy Certificates**
BPA shall transfer Renewable Energy Certificates (RECs), or their successors, to Surprise Valley in accordance with Exhibit H.

18.2.2 **Reporting Requirements**
This section 18.2.2 does not apply if Surprise Valley's Total Retail Load is 25 annual Average Megawatts or less or if Surprise Valley purchases all of its power from BPA to serve its Total Retail Load. If Surprise Valley's Total Retail Load is above 25 annual Average Megawatts, the following requirements may be satisfied by submitting plans and reports Surprise Valley prepares in the normal course of business as long as such plans and reports include the information required below.

Beginning September 1, 2012, and by September 1 every year thereafter, Surprise Valley shall provide BPA with the following:

(1) updated information on power forecasted to be generated over the forthcoming calendar year by renewable resources with nameplate capabilities greater than 200 kilowatts, including

net metered renewable resources operating behind the BPA meter, used by Surprise Valley to serve its Total Retail Load, under Exhibit A. Such information shall include: project name, fuel type(s), location, date power purchase contract signed, project energization date, capacity, capacity factor, remaining term of purchase (or if direct ownership remaining life of the project), and the percentage of output that will be used to serve Surprise Valley's Total Retail Load that calendar year. Where resources are jointly owned by Surprise Valley and other customers that have a CHWM Contract, Surprise Valley may either submit a report on behalf of all owners or identify the customer that will submit the report;

(2) the amount of all purchases of RECs used to meet requirements under state or federal law for the forthcoming calendar year; and

(3) if Surprise Valley is required under state law or by Transmission Services to prepare long-term integrated resource plans or resource forecasts, then Surprise Valley shall provide Power Services with updated copies of such or authorize Transmission Services to provide them directly to Power Services.

19. RESOURCE ADEQUACY

By November 30, 2010, and by November 30 each year thereafter, Surprise Valley shall provide to the Pacific Northwest Utilities Conference Committee (PNUCC), or its successor, forecasted loads and resources data to facilitate a region-wide assessment of loads and resources in a format, length of time, and level of detail specified in PNUCC's Northwest Regional Forecast Data Request.

After consultation with the Regional Resource Adequacy Forum, or a successor, BPA may require Surprise Valley to submit additional data to the Northwest Power and Conservation Council (Council) that BPA determines is necessary for the Council to perform a regional resource adequacy assessment.

The requirements of this section 19 are waived if Surprise Valley purchases from BPA all of its power to serve its Total Retail Load.

20. NOTICES AND CONTACT INFORMATION

Any notice required under this Agreement that requires such notice to be provided under the terms of this section shall be provided in writing to the other Party in one of the following ways:

(1) delivered in person;

(2) by a nationally recognized delivery service with proof of receipt;

(3) by United States Certified Mail with return receipt requested;

(4) electronically, if both Parties have means to verify the electronic notice's origin, date, time of transmittal and receipt; or

(5) by another method agreed to by the Parties.

Notices are effective when received. Either Party may change the name or address for delivery of notice by providing notice of such change or other mutually agreed method. The Parties shall deliver notices to the following person and address:

If to Surprise Valley:

Surprise Valley Electrification Corp.
22595 Highway 395 North
P.O. Box 691
Alturas, CA 96101
Attn: Daniel Silveria
General Manager
Phone: 530-233-3511
FAX: 530-233-2190
E-Mail: svec@hdo.net

If to BPA:

Bonneville Power Administration
1011 S.W. Emkay Drive, Suite 211
Bend, OR 97702

Attn: Daniel E. Bloyer - PSE
Account Executive
Phone: 541-318-1680
FAX: 541-318-1681
E-Mail: debloyer@bpa.gov

21. UNCONTROLLABLE FORCES

21.1 A Party shall not be in breach of an obligation under this Agreement to the extent its failure to fulfill the obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control, and without the fault or negligence, of the Party claiming the Uncontrollable Force, that prevents that Party from performing its obligations under this Agreement and which that Party could not have avoided by the exercise of reasonable care, diligence and foresight. Uncontrollable Forces include each event listed below, to the extent it satisfies the foregoing criteria, but are not limited to these listed events:

(1) any curtailment or interruption of firm transmission service on BPA's or a Third Party Transmission Provider's System that prevents delivery of Firm Requirements Power sold under this Agreement to Surprise Valley;

(2) any failure of Surprise Valley's distribution or transmission facilities that prevents Surprise Valley from delivering power to end-users;

(3) strikes or work stoppage;

(4) floods, earthquakes, other natural disasters, or terrorist acts; and

(5) final orders or injunctions issued by a court or regulatory body having subject matter jurisdiction which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court having subject matter jurisdiction.

21.2 Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

21.3 If an Uncontrollable Force prevents a Party from performing any of its obligations under this Agreement, such Party shall:

(1) immediately notify the other Party of such Uncontrollable Force by any means practicable and confirm such notice in writing as soon as reasonably practicable;

(2) use commercially reasonable efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable;

(3) keep the other Party apprised of such efforts on an ongoing basis; and

(4) provide written notice of the resumption of performance.

Written notices sent under this section must comply with section 20.

22. GOVERNING LAW AND DISPUTE RESOLUTION

This Agreement shall be interpreted consistent with and governed by federal law. Surprise Valley and BPA shall identify issue(s) in dispute arising out of this Agreement and make a good faith effort to negotiate a resolution of such disputes before either may initiate litigation or arbitration. Such good faith effort shall include discussions or negotiations between the Parties' executives or managers. Pending resolution of a contract dispute or contract issue between the Parties or through formal dispute resolution of a contract dispute arising out of this Agreement, the Parties shall continue performance under this Agreement unless to do so would be impossible or impracticable. Unless the Parties engage in binding arbitration as provided for in this section 22, the Parties reserve their rights to individually seek judicial resolution of any dispute arising under this Agreement.

22.1 Judicial Resolution

Final actions subject to section 9(e) of the Northwest Power Act are not subject to arbitration under this Agreement and shall remain within the exclusive jurisdiction of the United States Court of Appeals for the Ninth Circuit. Such final actions include, but are not limited to, the establishment and the implementation of rates and rate methodologies. Any dispute regarding any rights or obligations of Surprise Valley or BPA under any rate or rate methodology, or BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. For purposes of this section 22, BPA policy means any written document adopted by BPA as a final action in a decision record or record of decision that establishes a policy of general application or makes a determination under an applicable statute or regulation. If BPA determines that a dispute is excluded from arbitration under this section 22, then Surprise Valley may apply to the federal court having jurisdiction for an order determining whether such dispute is subject to nonbinding arbitration under this section 22.

22.2 **Arbitration**
Any contract dispute or contract issue between the Parties arising out of this Agreement, which is not excluded by section 22.1 above, shall be subject to arbitration, as set forth below.

Surprise Valley may request that BPA engage in binding arbitration to resolve any dispute. If Surprise Valley requests such binding arbitration and BPA determines in its sole discretion that binding arbitration of the dispute is appropriate under BPA's Binding Arbitration Policy or its successor, then BPA shall engage in such binding arbitration, provided that the remaining requirements of this section 22.2 and sections 22.3 and 22.4 are met. BPA may request that Surprise Valley engage in binding arbitration to resolve any dispute. In response to BPA's request, Surprise Valley may agree to binding arbitration of such dispute, provided that the remaining requirements of this section 22.2 and sections 22.3 and 22.4 are met. Before initiating binding arbitration, the Parties shall draft and sign an agreement to engage in binding arbitration, which shall set forth the precise issue in dispute, the amount in controversy and the maximum monetary award allowed, pursuant to BPA's Binding Arbitration Policy or its successor.

Nonbinding arbitration shall be used to resolve any dispute arising out of this contract that is not excluded by section 21.1 above and is not resolved via binding arbitration, unless Surprise Valley notifies BPA that it does not wish to proceed with nonbinding arbitration.

22.3 **Arbitration Procedure**
Any arbitration shall take place in Portland, Oregon, unless the Parties agree otherwise. The Parties agree that a fundamental purpose for arbitration is the expedient resolution of disputes; therefore, the Parties shall make best efforts to resolve an arbitrable dispute within one year of initiating arbitration. The rules for arbitration shall be agreed to by the Parties.

22.4 **Arbitration Remedies**
The payment of monies shall be the exclusive remedy available in any arbitration proceeding pursuant to this section 22. This shall not be interpreted to preclude the Parties from agreeing to limit the object of arbitration to the determination of facts. Under no circumstances shall specific performance be an available remedy against BPA.

22.5 **Finality**

22.5.1 In binding arbitration, the arbitration award shall be final and binding on the Parties, except that either Party may seek judicial review based upon any of the grounds referred to in the Federal Arbitration Act, 9 U.S.C. §1-16 (1988). Judgment upon the award rendered by the arbitrator(s) may be entered by any court having jurisdiction thereof.

22.5.2 In nonbinding arbitration, the arbitration award is not binding on the Parties. Each Party shall notify the other Party within 30 calendar days, or such other time as the Parties otherwise agreed to, whether it accepts or rejects the arbitration award. Subsequent to nonbinding arbitration, if either Party rejects the arbitration award, either Party may seek judicial resolution of the dispute, provided that such suit is brought no later than 395 calendar days after the date the arbitration award was issued.

22.6 **Arbitration Costs**
Each Party shall be responsible for its own costs of arbitration, including legal fees. Unless otherwise agreed to by the Parties, the arbitrator(s) may apportion all other costs of arbitration between the Parties in such manner as the arbitrator(s) deem reasonable taking into account the circumstances of the case, the conduct of the Parties during the proceeding, and the result of the arbitration.

23. STATUTORY PROVISIONS

23.1 **Retail Rate Schedules**
Surprise Valley shall make its retail rate schedules available to BPA, as required by section 5(a) of the Bonneville Project Act, P.L. 75-329, within 30 days of each of Surprise Valley's retail rate schedule effective dates. This requirement may be satisfied by Surprise Valley informing BPA of its public website where such information is posted and kept current.

23.2 **Insufficiency and Allocations**
If BPA determines, consistent with section 5(b) of the Northwest Power Act and other applicable statutes, that it will not have sufficient resources on a planning basis to serve its loads after taking all actions required by applicable laws then BPA shall give Surprise Valley a written notice that BPA may restrict service to Surprise Valley. Such notice shall be consistent with BPA's insufficiency and allocations methodology, published in the Federal Register on March 20, 1996, and shall state the effective date of the restriction, the amount of Surprise Valley's load to be restricted and the expected duration of the restriction. BPA shall not change that methodology without the written agreement of all public body, cooperative, federal agency and investor-owned utility customers in the Region purchasing federal power from BPA under section 5(b) of the Northwest Power Act. Such restriction

shall take effect no sooner than five years after BPA provides notice to Surprise Valley. If BPA imposes a restriction under this provision then the amount of Firm Requirements Power that BPA is obligated to provide and that Surprise Valley is obligated to purchase pursuant to section 3 and Exhibit C shall be reduced to the amounts available under such allocation methodology for restricted service.

23.3 **New Large Single Loads and CF/CTs**

23.3.1 **Determination of an NLSL**
In accordance with BPA's NLSL Policy, BPA may determine that a load is an NLSL as follows:

23.3.1.1 BPA shall determine an increase in production load to be an NLSL if any load associated with a new facility, an existing facility, or an expansion of an existing facility, which is not contracted for, or committed to (CF/CT), as determined by the Administrator, by a public body, cooperative, investor-owned utility, or federal agency customer prior to September 1, 1979, and which will result in an increase in power requirements of such customer of ten Average Megawatts (87,600,000 kilowatt-hours) or more in any consecutive 12-month period.

23.3.1.2 For the sole purpose of computing the increase in energy consumption between any two consecutive 12-month periods of comparison under this section 23.3.1, reductions in the end-use consumer's load associated with a facility during the first 12-month period of comparison due to unusual events reasonably beyond the control of the end-use consumer shall be determined by BPA, and the energy consumption shall be computed as if such reductions had not occurred.

23.3.1.3 The Parties may agree that the installed production equipment at a facility will exceed ten Average Megawatts consumption over any 12 consecutive months and such agreement shall constitute a binding NLSL determination.

23.3.2 **Determination of a Facility**
BPA shall make a written determination as to what constitutes a single facility, for the purpose of identifying an NLSL, based on the following criteria:

(1) whether the load is operated by a single end-use consumer;

(2) whether the load is in a single location;

(3) whether the load serves a manufacturing process which produces a single product or type of product;

(4) whether separable portions of the load are interdependent;

(5) whether the load is contracted for, served or billed as a single load under Surprise Valley's customary billing and service policy;

(6) consideration of the facts from previous similar situations; and

(7) any other factors the Parties determine to be relevant.

23.3.3 **Administrative Obligations and Rights**

23.3.3.1 Surprise Valley's CF/CT loads and NLSLs are listed in Exhibit D.

23.3.3.2 Surprise Valley shall provide reasonable notice to BPA of any expected increase in a single load that may qualify as an NLSL. The Parties shall list any such potential NLSLs in Exhibit D. If BPA determines that any load associated with a single facility is capable of growing ten Average Megawatts or more in a consecutive 12-month period, then such load shall be subject to monitoring as determined necessary by BPA.

23.3.3.3 When BPA makes a request, Surprise Valley shall provide physical access to its substations and other service locations where BPA needs to perform inspections or gather information for purposes of implementing section 3(13) of the Northwest Power Act, including but not limited to making a final NLSL, facility, or CF/CT determination. Surprise Valley shall make a request to the end-use consumer to provide BPA, at reasonable times, physical access to inspect a facility for these purposes.

23.3.3.4 Unless the Parties agree pursuant to section 23.3.1.3 above, BPA shall determine whether a new load or an increase in existing load at a facility is an NLSL. If BPA determines that the load is an NLSL, BPA shall notify Surprise Valley and the Parties shall add the NLSL to Exhibit D to reflect BPA's determination.

23.3.4 **Metering an NLSL**
For any loads that are monitored by BPA for an NLSL determination, and for any loads at any facility that is determined by BPA to be an NLSL, BPA may, in its sole discretion, install BPA owned meters. If the Parties agree otherwise, Surprise Valley may install meters meeting the exact specification BPA provides to Surprise Valley. Surprise Valley and BPA shall enter into a separate agreement for the location, ownership, cost responsibility, access, maintenance, testing,

replacement and liability of the Parties with respect to such meters. Surprise Valley shall arrange for metering locations that allow accurate measurement of the facility's load. Surprise Valley shall arrange for BPA to have physical access to such meters and Surprise Valley shall ensure BPA has access to all NLSL meter data that BPA determines is necessary to forecast, plan, schedule, and bill for power.

23.3.5 **Undetermined NLSLs**

If BPA does not determine at the outset that an increase in load is an NLSL, then the Parties shall install metering equipment as required by section 23.3.4 above, and BPA shall bill Surprise Valley for the increase in load at the applicable PF rate during any consecutive twelve-month monitoring period. If BPA later determines that the increase in load is an NLSL, then BPA shall revise Surprise Valley's bill to reflect the difference between the applicable PF rate and the applicable NR rate in effect for the monitoring period in which the increase takes place. Surprise Valley shall pay that bill with simple interest computed from the start of the monitoring period to the date the payment is made. The daily interest rate shall equal the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which the monitoring period began) divided by 365.

If BPA concludes in its sole judgment that Surprise Valley has not fulfilled its obligations, or has not been able to obtain access or information from the end-use consumer under sections 23.3.3 and 23.3.4, BPA may determine any load subject to NLSL monitoring to be an NLSL, in which case Surprise Valley shall be billed and pay in accordance with the last two sentences of the preceding paragraph. Such NLSL determination shall be final unless Surprise Valley proves to BPA's satisfaction that the applicable load did not exceed ten Average Megawatts in any 12-month monitoring period.

23.3.6 **Service Election for an NLSL**

Before the Parties add an NLSL to Exhibit D, Surprise Valley shall elect, in writing, to:

(1) have BPA serve the NLSL at the NR rate; or

(2) serve the NLSL with a Dedicated Resource in Exhibit A that is not already being used to serve Surprise Valley's firm consumer load in the region.

This election shall be binding on Surprise Valley for the remaining term of this Agreement.

23.3.7 **Consumer-Owned Resources Serving an NLSL**

23.3.7.1 **Renewable Resource/Cogeneration Exception**
An end-use consumer served by Surprise Valley, with a facility whose load is, in whole or in part, an NLSL, may reduce its NLSL to less than ten Average Megawatts in a consecutive 12-month period by applying an onsite renewable resource or onsite cogeneration behind Surprise Valley's meter to its facility load. Surprise Valley shall ensure that such resource is continuously applied to serve the NLSL, consistent with BPA's "Renewables and On-Site Cogeneration Option under the NLSL Policy" portion of its Policy for Power Supply Role for Fiscal Years 2007-2011, adopted February 4, 2005, and the NLSL policy included in BPA's Long Term Regional Dialogue Final Policy, July 2007, as amended or replaced. If the NLSL end-use consumer meets the qualification for the exception, then the Parties shall: (1) list the Consumer-Owned Resource serving the NLSL in section 7.4 of Exhibit A and (2) amend Exhibit D to add the onsite renewable resource or cogeneration facility and the requirements for such service.

23.3.7.2 **Consumer-Owned Resources that are not Renewable Resources/Cogeneration**
If Surprise Valley serves an NLSL with a Consumer-Owned Resource that does not qualify for the renewable resource or cogeneration exception, the Parties shall list such Consumer-Owned Resource serving the NLSL in section 7.4 of Exhibit A.

23.4 **Priority of Pacific Northwest Customers**
The provisions of sections 9(c) and 9(d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. Surprise Valley, together with other customers in the Region, shall have priority to BPA power consistent with such provisions.

23.5 **Prohibition on Resale**
Surprise Valley shall not resell Firm Requirements Power except to serve Surprise Valley's Total Retail Load or as otherwise permitted by federal law.

23.6 **Use of Regional Resources**

23.6.1 Within 60 days prior to the start of each Fiscal Year, Surprise Valley shall provide notice to BPA of any Firm Power from a Generating Resource, or a Contract Resource during its term, that has been used to serve firm consumer load in the Region and that Surprise Valley plans to export for sale outside the Region in the next Fiscal Year. For purposes of this section 23.6, "Firm Power" means electric power which is continuously made available from Surprise Valley's operation of generation or from its purchased power, which is able to meet its Total Retail Load, except when such generation or power is curtailed or restricted due to an Uncontrollable Force. Firm Power includes firm energy and firm peaking energy or both.

BPA may request and Surprise Valley shall provide within 30 days of such request, additional information on Surprise Valley's sales and dispositions of non-federal resources if BPA has information that Surprise Valley may have made such an export and not notified BPA. BPA may request and Surprise Valley shall provide within 30 days of such request, information on the planned use of any or all of Surprise Valley Generating and Contract Resources.

During any Purchase Period that Surprise Valley has no purchase obligation for Firm Requirements Power under section 3, Surprise Valley shall have no obligation to notify BPA of its exports under this section; provided, however, Surprise Valley shall provide notification of all applicable exports in Purchase Periods when it has a purchase obligation.

23.6.2 Surprise Valley shall be responsible for monitoring any Firm Power from Generating Resources and Contract Resources it sells in the Region to ensure such Firm Power is planned to be used to serve firm consumer load in the Region.

23.6.3 If Surprise Valley fails to report to BPA in accordance with section 23.6.1, above, any of its planned exports for sale outside the Region of Firm Power from a Generating Resource or a Contract Resource that has been used to serve firm consumer load in the Region, and BPA makes a finding that an export which was not reported was made, BPA shall decrement the amount of its Firm Requirements Power sold under this Agreement by the amount of the export that was not reported and by any continuing export amount. Decrements under the preceding sentence shall be first to power that would otherwise be provided at Tier 1 Rates. When applicable, such decrements shall be identified in section 3.2 of Exhibit A.

23.6.4 For purposes of this section 23.6, an export for sale outside the Region means a contract for the sale or disposition of Firm Power from a Generating Resource or a Contract Resource during its term that has been used to serve firm consumer load in the Region, which contract will be performed in a manner that such output is no longer used or not planned to be used solely to serve firm consumer load in the Region. Delivery of Firm Power outside the Region under a seasonal exchange agreement that is made consistent with BPA's 5(b)/9(c) Policy will not be considered an export. Firm Power from a Generating Resource or a Contract Resource used to serve firm consumer load in the Region means the firm generating or load carrying capability of a Generating Resource or a Contract Resource as established under PNCA resource planning criteria, or other resource planning criteria generally used for such purposes within the Region.

23.7 **BPA Appropriations Refinancing**
The Parties agree that the provisions of section 3201(i) of the Bonneville Power Administration Refinancing section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (BPA Refinancing Act), P.L. 104-134, 110 Stat. 1321, 350, as stated in the United States Code on the Effective Date, are incorporated by reference and are a material term of this Agreement.

24. STANDARD PROVISIONS

24.1 **Amendments**
Except where this Agreement explicitly allows for one Party to unilaterally amend a provision or exhibit, no amendment of this Agreement shall be of any force or effect unless set forth in writing and signed by authorized representatives of each Party.

24.2 **Entire Agreement and Order of Precedence**
This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties with respect to the subject matter of this Agreement. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

24.3 **Assignment**
This Agreement is binding on any successors and assigns of the Parties. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without (1) the other Party's written consent, which shall not be unreasonably withheld; and (2) the written consent of the United States Department of Rural Utilities Service. Such consent shall not be unreasonably withheld. Without limiting the foregoing, BPA's refusal to consent to assignment shall not be considered unreasonable if, in BPA's sole discretion: (1) the sale of power by BPA to the assignee would violate any applicable statute, or (2) such sale might adversely affect the tax-exempt status of bonds issued as part of an issue that finances or refinances the Columbia Generating Station or that such sale might limit the ability to issue future tax-exempt bonds to finance or refinance the Columbia Generating Station. Surprise Valley may not transfer or assign this Agreement to any of its retail consumers.

24.4 **No Third-Party Beneficiaries**
This Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

24.5 **Waivers**
No waiver of any provision or breach of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party, and any such waiver shall not be deemed a waiver of any other provision of this Agreement or of any other breach of this Agreement.

24.6 **BPA Policies**
Any reference in this Agreement to BPA policies, including any revisions, does not constitute agreement of Surprise Valley to such policy by execution of this Agreement, nor shall it be construed to be a waiver of the right of Surprise Valley to seek judicial review of any such policy.

24.7 **Rate Covenant and Payment Assurance**
Surprise Valley agrees that it shall establish, maintain and collect rates or charges sufficient to assure recovery of its costs for power and energy and other services, facilities and commodities sold, furnished or supplied by it through any of its electric utility properties. BPA may require additional forms of payment assurance if: (1) BPA determines that such rates and charges may not be adequate to provide revenues sufficient to enable Surprise Valley to make the payments required under this Agreement, or (2) BPA identifies in a letter to Surprise Valley that BPA has other reasonable grounds to conclude that Surprise Valley may not be able to make the payments required under this Agreement. If Surprise Valley does not provide payment assurance satisfactory to BPA, then BPA may terminate this Agreement. Written notices sent under this section must comply with section 20.

24.8 **Bond Assurances**
BPA has advised Surprise Valley that: (1) the Columbia Generating Station has been financed and refinanced in large part by bonds that are intended to bear interest that is exempt from federal income tax under section 103 of the Internal Revenue Code of 1954, as amended, and Title XIII of the Tax Reform Act of 1986, and (2) the tax-exempt status of those bonds and other bonds issued together with those bonds might be jeopardized if Surprise Valley or any other nongovernmental person has a contract to purchase additional amounts of the output of the Columbia Generating Station.

Consequently, Surprise Valley shall notify BPA at least 90 days before Surprise Valley acquires an Annexed Load, or Surprise Valley is acquired, in whole or in part, as an Annexed Load. Surprise Valley hereby acknowledges and agrees that BPA shall have the right to reduce Surprise Valley's CHWM in connection with any such Annexed Load to the extent the aggregate CHWM, including the Annexed Load, (or the aggregate CHWM, including the Annexed Load, of related entities) otherwise would result in a nongovernmental customer with a CHWM share of the Tier 1 System Resources that exceeds 2.8 percent.

25. TERMINATION

25.1 BPA's Right to Terminate

BPA may terminate this Agreement if:

(1) Surprise Valley fails to make payment as required by section 16.4, or

(2) Surprise Valley fails to provide payment assurance satisfactory to BPA as required by section 24.7.

Such termination is without prejudice to any other remedies available to BPA under law.

25.2 Customer's Right to Terminate

Surprise Valley may provide written notice to terminate this Agreement not later than 60 days after: (1) a Final FERC Order is issued declining to approve the Tiered Rate Methodology (if BPA seeks FERC's confirmation and approval of it), (2) FERC issues a final declaratory order finding that the TRM does not meet cost recovery standards, or (3) FERC issues a Final FERC Order that determines rates established consistent with the TRM cannot be approved because the TRM precludes the establishment of rates consistent with cost recovery. The notice shall include a date of termination not later than 90 days after the date of such notice. For purposes of this section 25.2, "Final FERC Order" means a dispositive order by FERC on the merits, and does not include any interim order. A dispositive order on the merits is, for purposes of this section, final when issued and there is no need to await a FERC order on rehearing before the decision is considered final.

26. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for which they sign.

SURPRISE VALLEY ELECTRIFICATION CORPORATION		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By	Daniel Silveria	By	Daniel E. Bloyer
Name	Daniel Silveria (Print/Type)	Name	Daniel E. Bloyer (Print/Type)
Title	General Manager	Title	Account Executive
Date	11/25/08	Date	12/1/2008

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Exhibit A
NET REQUIREMENTS AND RESOURCES

1. NET REQUIREMENTS

Surprise Valley's Net Requirement equals its Total Retail Load minus Surprise Valley's Dedicated Resources determined pursuant to section 3.3 of the body of this Agreement and listed in sections 2, 3, and 4 of this exhibit. The Parties shall not add or remove resource amounts to change Surprise Valley's purchase obligations from BPA under section 3.1 of the body of this Agreement except in accordance with sections 3.5 and 10 of the body of this Agreement.

2. LIST OF SPECIFIED RESOURCES

2.1 Generating Resources

Surprise Valley does not have any Generating Resources that are Specified Resources at this time.

2.2 Contract Resources

Surprise Valley does not have any Contract Resources that are Specified Resources at this time.

2.3 Small Non-Dispatchable Resources

Surprise Valley does not have any Small Non-Dispatchable Resources at this time. If Surprise Valley adds Small Non-Dispatchable Resources to this section and if the aggregate nameplate capability of such Small Non-Dispatchable Resources that are also New Resources exceeds one megawatt, then BPA shall consider the impacts of the aggregate shape of such New Resources and may require the application of DFS to account for the impact of the aggregate shape on Surprise Valley's load.

3. UNSPECIFIED RESOURCE AMOUNTS

3.1 Unspecified Resource Amounts Used to Serve Total Retail Load

3.1.1 Shape of Unspecified Resource Amounts

Surprise Valley's Unspecified Resource Amounts shall be calculated using the selected monthly and Diurnal shapes listed below. BPA shall update the table below consistent with section 3.4.2 of the body of this Agreement.

Shape of Unspecified Resource Amounts				
	Monthly Shape Choice		Diurnal Shape Choice	
Purchase Period	Total Retail Load Monthly Shape	Flat Annual Shape	HLH Diurnal Shape	Flat Within-Month Shape
FY 2012 - FY 2014		X		X
FY 2015 – FY 2019		X		X
FY 2020 – FY 2024		X		X
FY 2025 – FY 2028		X		X

3.1.2 **Unspecified Resource Amounts**
Surprise Valley does not have any Unspecified Resource Amounts at this time.

3.2 **Unspecified Resource Amounts for 9(c) Export Decrements**
BPA shall insert a table below pursuant to section 3.5.3 of the body of this Agreement.

4. DEDICATED RESOURCE AMOUNTS FOR AN NLSL
Surprise Valley does not have any Dedicated Resource amounts serving an NLSL at this time, in accordance with section 3.5.7 of the body of this Agreement.

5. TOTAL DEDICATED RESOURCE AMOUNTS
Surprise Valley does not have any Dedicated Resource amounts at this time.

6. LIST OF RESOURCES NOT USED TO SERVE TOTAL RETAIL LOAD
Pursuant to section 17 of the body of this Agreement, Surprise Valley does not own any Generating Resources or Contract Resources that are (1) not Specified Resources listed in section 2 of Exhibit A, and (2) greater than 200 kilowatts of nameplate capability.

7. **LIST OF CONSUMER-OWNED RESOURCES**

7.1 **Consumer-Owned Resources Serving Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving Onsite Consumer Load at this time.

7.2 **Consumer-Owned Resources Serving Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving load other than Onsite Consumer Load at this time.

7.3 **Consumer-Owned Resources Serving Both Onsite Consumer Load and Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving both Onsite Consumer Load and load other than Onsite Consumer Load at this time.

7.4 **Consumer-Owned Resources Serving an NLSL**
Pursuant to section 23.3.7 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving an NLSL at this time.

8. TABLES FOR ALLOWABLE DEDICATED RESOURCE SHAPES

8.1 **Total Retail Load Monthly Shape**
By March 31 immediately following each of the Fiscal Years 2010, 2015, and 2020, BPA shall fill in the table below with Surprise Valley's Total Retail Load Monthly Shape, in accordance with section 3.4.2 of the body of this Agreement. Surprise Valley's Total Retail Load Monthly Shape shall be calculated by dividing Surprise Valley's Total Retail Load (in megawatt-hours) in each month of Fiscal Years 2010, 2015, and 2020 by the Fiscal Year total of Surprise Valley's Total Retail Load (in megawatt-hours). BPA shall weather-normalize Surprise Valley's Total Retail Load data, prior to calculating the Total Retail Load Monthly Shape, using the same weather-normalization procedures set forth in section 4.1.1 of the TRM.

Total Retail Load Monthly Shape (%)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
FY 2010													100.0
FY 2015													100.0
FY 2020													100.0
Note: Fill in the table above with percents rounded to the nearest one decimal place													

8.2 **HLH Diurnal Shape**

8.2.1 **Specified Resources**
If Surprise Valley elects the HLH Diurnal Shape for its Specified Resources, Surprise Valley shall fill in a table with monthly LLH and HLH amounts for each year of the upcoming Purchase Period for each Specified Resource. The monthly LLH and HLH distributions shall be the same across all years of a Purchase Period. Surprise Valley shall submit the tables to BPA when Surprise Valley makes its reshaping elections. BPA shall update the appropriate Dedicated Resource amounts pursuant to Surprise Valley's submitted elections and consistent with section 3.4.2 of the body of this Agreement.

8.2.2 **Unspecified Resource Amounts**
If Surprise Valley elects the HLH Diurnal Shape for its Unspecified Resource Amounts, then Surprise Valley shall submit to BPA in writing its elected ratios of megawatt-hours per hour in HLH to

megawatt-hours per hour in LLH by the Notice Deadline. Surprise Valley shall submit to BPA twelve monthly ratios and such monthly ratios shall apply for all years of the corresponding Purchase Period. BPA shall update the table below pursuant to Surprise Valley's submitted elections and consistent with section 3.4.2 of the body of this Agreement. BPA shall calculate Surprise Valley's Unspecified Resource Amounts using the ratios in the table below.

HLH Diurnal Shape for Unspecified Resource Amounts												
	HLH to LLH Ratios (HLH:LLH)											
Purchase Period	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
FY 2012 – FY 2014												
FY 2015 – FY 2019												
FY 2020 – FY 2024												
FY 2025 – FY 2028												

9. SUPER PEAK AMOUNTS

Surprise Valley may reshape some or all of its HLH Dedicated Resource amounts for its (1) Specified Resources listed in section 2 of this exhibit, except for any Small Non-Dispatchable Resources and any Specified Resources Surprise Valley is supporting with DFS or SCS from BPA; and (2) Unspecified Resource Amounts listed in section 3.1.2 of this exhibit; into the Super Peak Period to receive a Super Peak Credit. BPA shall update the table below consistent with section 3.4.4 of the body of this Agreement.

Super Peak Amounts (MW)												
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												
Note: Fill in the table above with megawatts rounded to the nearest three decimal places.												

10. REVISIONS

BPA shall revise this exhibit to reflect (1) Surprise Valley's elections regarding the application and use of all resources owned by Surprise Valley and Surprise Valley's retail consumers and (2) BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Exhibit B
HIGH WATER MARKS AND CONTRACT DEMAND QUANTITIES

1. CONTRACT HIGH WATER MARK (CHWM)

1.1 CHWM Amount

By September 15, 2011, BPA shall fill in the table below with Surprise Valley's CHWM. Once established, Surprise Valley's CHWM shall not change for the term of this Agreement except as allowed in section 1.2 of this exhibit.

CHWM (annual aMW):	
Note: BPA shall round the number in the table above to three decimal places.	

1.2 Changes to CHWM

If a change is made to Surprise Valley's CHWM pursuant to this section 1.2, then BPA shall determine and notify Surprise Valley of the date such change will be effective as follows:

1.2.1 If a load included in Surprise Valley's Measured 2010 Load, as defined in the TRM, is later found to have been an NLSL in FY 2010, then BPA shall reduce Surprise Valley's CHWM by the amount of the NLSL. BPA shall notify Surprise Valley 30 days prior to when the updated CHWM will become effective. Surprise Valley shall be liable for payment of any charges to adjust for the ineligible Tier 1 PF rate purchases dating back to October 1, 2011.

1.2.2 If Surprise Valley acquires an Annexed Load from a utility that has a CHWM, then BPA shall increase Surprise Valley's CHWM by adding part of the other utility's CHWM to Surprise Valley's CHWM. The CHWM increase shall be effective on the date that Surprise Valley begins service to the Annexed Load. BPA shall establish the amount of the CHWM addition as follows:

(1) If Surprise Valley and the other utility involved in the annexation agree on the amount of the CHWM addition, then BPA shall adopt that amount if BPA determines such amount is reasonable.

(2) If Surprise Valley and the other utility cannot agree on the amount of the CHWM addition, or if BPA determines the amount agreed to in 1.2.2(1) of this exhibit is unreasonable, then the amount of the CHWM addition shall equal the calculated amount below; provided however, BPA may adjust the calculated amount below to reflect the division of Dedicated Resources between the utilities and other pertinent information advanced by Surprise Valley and the other utility:

$$\left[\frac{\text{Annexed Load minus annexed NLSLs, if any}}{\text{Other utility's pre-annexation Total Retail Load minus total NLSLs, if any}} \right] \times \left[\text{Other utility's pre-annexation CHWM} \right]$$

Any change to Surprise Valley's CHWM related to the acquisition of an Annexed Load is subject to section 24.8 of the body of this Agreement.

1.2.3 If another utility with a CHWM annexes load of Surprise Valley, then BPA shall reduce Surprise Valley's CHWM by adding part of Surprise Valley's CHWM to the other utility's CHWM. The CHWM reduction shall be effective on the date that the other utility begins service to the Annexed Load. BPA shall establish the amount of the CHWM reduction as follows:

(1) If Surprise Valley and the other utility involved in the annexation agree on the amount of the CHWM reduction, then BPA shall adopt that amount if BPA determines such amount is reasonable.

(2) If Surprise Valley and the other utility cannot agree on the amount of the CHWM reduction, or if BPA determines the amount agreed to in 1.2.3(1) of this exhibit is unreasonable, then the amount of the CHWM reduction shall equal the calculated amount below; provided however, BPA may adjust the calculated amount below to reflect the division of Dedicated Resources between the utilities and other pertinent information advanced by Surprise Valley and the other utility:

$$\left[\frac{\text{Annexed Load minus annexed NLSLs, if any}}{\text{Surprise Valley's pre-annexation Total Retail Load minus total NLSLs, if any}} \right] \times \left[\text{Surprise Valley's pre-annexation CHWM} \right]$$

1.2.4 BPA may change Surprise Valley's CHWM if BPA's Administrator determines that BPA is required by court order about an Annexed Load to make such changes. BPA shall determine the effective date of such a change and shall update this exhibit with the changed CHWM.

2. CONTRACT DEMAND QUANTITIES (CDQs)

2.1 CDQ Amounts

By September 15, 2011, BPA shall fill in the table below with Surprise Valley's monthly CDQs. Calculation of such CDQs is established in the TRM. Surprise Valley's monthly CDQs shall not change for the term of this Agreement except as allowed below.

Monthly Contract Demand Quantities												
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
kW												
Note: BPA shall round the amounts in the table above to the nearest whole kilowatt.												

2.2 **Changes Due to Annexation**
The Parties shall determine when changes to Surprise Valley's CDQs, as allowed below, will become effective.

2.2.1 If Surprise Valley acquires an Annexed Load from a utility that has monthly CDQs, then BPA shall increase Surprise Valley's CDQ for each month by adding the portion of the other utility's monthly CDQ that is attributable to such Annexed Load. For each month, the sum of Surprise Valley's and the other utility's post-annexation CDQs shall not exceed the sum of the pre-annexation CDQs for such utilities. BPA shall establish the amount of the CDQ additions as follows:

(1) If Surprise Valley and the other utility involved in the annexation agree on the amounts of the CDQ additions, then BPA shall adopt those amounts.

(2) If Surprise Valley and the other utility cannot agree on the amounts of the CDQ additions, then BPA shall determine the amounts based on the monthly load factors of the Annexed Load.

2.2.2 If another utility with monthly CDQs annexes load of Surprise Valley, then BPA shall reduce Surprise Valley's CDQ for each month by removing the portion of Surprise Valley's monthly CDQ that is attributable to the load that was annexed. For each month, the sum of Surprise Valley's and the other utility's post-annexation CDQs shall not exceed the sum of the pre-annexation CDQs for such utilities. BPA shall establish the amount of the CDQ reductions as follows:

(1) If Surprise Valley and the other utility involved in the annexation agree on the amounts of the CDQ reductions, then BPA shall adopt those amounts.

(2) If Surprise Valley and the other utility cannot agree on the amounts of the CDQ reductions, then BPA shall determine the amounts based on the monthly load factors of the Annexed Load.

3. REVISIONS

BPA may revise this exhibit to the extent allowed in sections 1 and 2 of this exhibit. All other changes shall be made by mutual agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Exhibit C
PURCHASE OBLIGATIONS

1. FIRM REQUIREMENTS POWER AT TIER 1 RATES

The portion of Surprise Valley's purchase obligation that is priced at Tier 1 Rates is established in section 8.1(1) of the body of this Agreement.

2. FIRM REQUIREMENTS POWER AT TIER 2 RATES

2.1 Notice to Purchase Zero Amounts at Tier 2 Rates

If Surprise Valley elects not to purchase Firm Requirements Power at Tier 2 Rates for a Purchase Period, then by March 31 immediately following the corresponding Notice Deadline, BPA shall update this exhibit to indicate such election by adding an "X" to the applicable cell in the following table. Such election means that for the Purchase Period specified below, Surprise Valley shall: (1) purchase zero amounts of Firm Requirements Power at Tier 2 Rates, and (2) serve all of its Above-RHWM Load that is greater than or equal to 8,760 megawatt-hours with power other than Firm Requirements Power. Surprise Valley may serve its Above-RHWM Load that is less than 8,760 megawatt-hours with power other than Firm Requirements Power.

Zero Tier 2	Purchase Period
	FY 2012 - FY 2014
	FY 2015 - FY 2019
	FY 2020 - FY 2024
	FY 2025 - FY 2028

2.2 Tier 2 Load Growth Rate

2.2.1 First Election Opportunity

If Surprise Valley elects by the first Notice Deadline (November 1, 2009) to purchase Firm Requirements Power at Tier 2 Load Growth Rates starting October 1, 2011, then in its election Surprise Valley shall elect one of the three Tier 2 Load Growth Rate options listed in section 2.2.3 of this exhibit. If Surprise Valley elects Option 3, then Surprise Valley shall state the amounts to be listed in the table in section 2.2.3.3 of this exhibit and Surprise Valley's Tier 2 Short-Term Rate election pursuant to section 2.4.1 of this exhibit. BPA shall amend this exhibit by March 31, 2010, to indicate Surprise Valley's election by adding an "X" to the "1st Notice Deadline" box next to the applicable option below. If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates by the first Notice Deadline, then Surprise Valley shall not have the right to purchase Firm Requirements Power at Tier 2 Load Growth Rates during the first Purchase Period.

2.2.2 **Second Election Opportunity**

2.2.2.1 If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates starting the first Purchase Period, then Surprise Valley may purchase Firm Requirements Power at Tier 2 Load Growth Rates starting October 1, 2014, provided:

(1) any elections of Tier 2 Rate alternatives or additions of New Resources under this Agreement that extend beyond the initial Purchase Period shall continue to apply for their term, and

(2) the Tier 2 Load Growth Rate applicable under this election may be different than the Tier 2 Load Growth Rate that was available during the first Purchase Period.

2.2.2.2 If Surprise Valley elects by the second Notice Deadline (September 30, 2011) to purchase Firm Requirements Power at Tier 2 Load Growth Rates, then in its election Surprise Valley shall elect one of the three Tier 2 Load Growth Rate options listed in section 2.2.3 of this exhibit. In such case, Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates under such elected option starting October 1, 2014.

2.2.2.3 If Surprise Valley elects Option 3, described in section 2.2.3.3 of this exhibit, then Surprise Valley shall state the amounts to be listed in the table in section 2.2.3.3 of this exhibit and Surprise Valley's Tier 2 Short-Term Rate election pursuant to section 2.4.1 of this exhibit. If Surprise Valley has prior elections of rate alternatives or resource additions that extend beyond the first Purchase Period, then Surprise Valley shall not have the right to elect Options 1 or 2 below. In such case, the amounts listed in the table in section 2.2.3.3 of this exhibit shall not be less than the sum of Surprise Valley's prior elections for each year.

2.2.2.4 BPA shall amend this exhibit by March 31, 2012, to indicate Surprise Valley's election by adding an "X" to the "2nd Notice Deadline" box next to the applicable option below. If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates by the second Notice Deadline, then Surprise Valley shall not purchase Firm Requirements Power at Tier 2 Load Growth Rates for the term of this Agreement.

2.2.3 **Tier 2 Load Growth Rate Options**

1st Notice Deadline ☐ 2nd Notice Deadline ☐ 2.2.3.1 **Option 1 - Full Tier 2 Load Growth Rate**
If Surprise Valley elects this option, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load.

1st Notice Deadline ☐ 2nd Notice Deadline ☐ 2.2.3.2 **Option 2 - Shared Rate Plan**

(1) **Obligation**
If Surprise Valley elects this option, provided that BPA determines Surprise Valley qualifies under the limit for the Shared Rate Plan as established in section 7 of the TRM, then Surprise Valley shall pay rates under the Shared Rate Plan for Firm Requirements Power purchased under this Agreement. If BPA determines Surprise Valley does not qualify under such limit, then Surprise Valley shall not have the right to elect this option and Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates under Option 1 as established in section 2.2.3.1 of this exhibit. For the second election opportunity stated in section 2.2.2 of this exhibit, availability under the limit for the Shared Rate Plan established in section 7 of the TRM shall equal such limit minus the amounts used by other customers who elected this Option 2 by the first Notice Deadline.

(2) **Terminating Participation**
Surprise Valley may terminate participation in the Shared Rate Plan by providing BPA notice in writing by March 31 of a Forecast Year. In such case, the change shall be effective the next Rate Period. If Surprise Valley stops participation in the Shared Rate Plan, then Surprise Valley shall not have the right to resume participation. Surprise Valley shall continue to purchase Firm Requirements Power priced at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load.

1st Notice Deadline ☐ 2nd Notice Deadline ☐ 2.2.3.3 **Option 3 - Partial Tier 2 Load Growth Rate**
If Surprise Valley elects this option, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load minus the amounts stated in the table below that Surprise Valley elects are not subject to Tier 2 Load Growth Rates. Surprise Valley shall establish such amounts at the time Surprise Valley elects this option and such amounts shall not change for the term of this Agreement. Surprise Valley may serve such amounts with

Dedicated Resources or with Firm Requirements Power purchased at other Tier 2 Rates. BPA shall update the table below by March 31 immediately following Surprise Valley's election of this option.

Load Amounts Not Subject To Tier 2 Load Growth Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW									
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

2.2.4 Modification to Tier 2 Load Growth Rate Election

2.2.4.1 Notice

Surprise Valley shall have the right to stop purchasing Firm Requirements Power at Tier 2 Load Growth Rates effective the upcoming Rate Period, except for the amount established in section 2.2.4.2 of this exhibit. If Surprise Valley chooses to modify its purchases at Tier 2 Load Growth Rates in this manner, then Surprise Valley shall notify BPA in writing by October 31 of a Rate Case Year.

2.2.4.2 Continued Purchase Amount

For the remaining term of this Agreement, Surprise Valley shall continue to purchase at Tier 2 Load Growth Rates the amount of Firm Requirements Power that Surprise Valley purchased at Tier 2 Load Growth Rates the year before the modification described above is effective.

2.2.4.3 Obligation to Apply Dedicated Resources

If Surprise Valley provides notice to modify its purchases at Tier 2 Load Growth Rates under section 2.2.4.1 of this exhibit, then for the remainder of the effective Purchase Period and all of the next Purchase Period, Surprise Valley shall apply Dedicated Resources to serve all of its Above-RHWM Load that is in excess of its commitment to purchase at Tier 2 Load Growth Rates pursuant to 2.2.4.2.

2.2.4.4 Charges to Modify Tier 2 Load Growth Rate Purchase

Surprise Valley shall be liable for payment of any costs that apply as a result of Surprise Valley modifying its Tier 2 Load Growth Rate purchase obligation under this section 2.2.4. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley at Tier 2 Load Growth Rates as a result of the modification, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, during the 7(i) Process that follows Surprise Valley's notice. If BPA determines that Surprise Valley owes payment for such costs, then Surprise Valley shall pay the entire amount to BPA in no more than 24 equal monthly amounts starting the first month of the upcoming Rate Period. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley modifying its Tier 2 Load Growth Rate purchase obligation under this section 2.2.4.

2.2.4.5 **Exhibit Update**
By March 31 following Surprise Valley's notice, BPA shall indicate Surprise Valley's election to modify its Tier 2 Load Growth Rate purchase by filling in the table below. As established in section 2.2.4.2 of this exhibit, Surprise Valley shall continue to purchase the following amounts of Firm Requirements Power at Tier 2 Load Growth Rates:

Continuing Tier 2 Load Growth Rates Purchase Obligation					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
aMW					
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
aMW					
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
aMW					
Fiscal Year	**2027**	**2028**			
aMW					
Note: Fill in the table above with annual Average Megawatts, rounded to three decimal places, for each year that follows Surprise Valley's modification beginning with the effective year of modification					

2.3 **Tier 2 Vintage Rates**
If Surprise Valley elects Option 1 or 2 in section 2.2.3 of this exhibit, then this section shall not apply. Otherwise:

2.3.1 **Election Process**

2.3.1.1 **Right to Convert**
Subject to the amounts of power BPA makes available at one or more Tier 2 Vintage Rates, Surprise Valley shall have the right to convert some or all of the amounts of Firm Requirements Power it has elected to purchase at Tier 2 Short-Term Rates, as stated in section 2.4 of this exhibit, to an equal purchase amount at Tier 2 Vintage Rates.

2.3.1.2 **Statement of Intent**
If Surprise Valley elects to purchase Firm Requirements Power from BPA at Tier 2 Vintage Rates, then Surprise Valley shall sign a Statement of Intent offered by BPA. "Statement of Intent" means a statement prepared by BPA

and signed by Surprise Valley that describes the approach and cost structure that will be used for a specific Tier 2 Cost Pool. If BPA establishes a Tier 2 Cost Pool for a Tier 2 Vintage Rate consistent with the Statement of Intent, then Surprise Valley agrees to have the portion of its Tier 2 Rate power purchase specified in the Statement of Intent priced at that rate. If BPA is unable to establish the Tier 2 Cost Pool for the specific Tier 2 Vintage Rate, then Surprise Valley agrees to purchase such amount of Firm Requirements Power at Tier 2 Short-Term Rates, except as stated in section 2.3.1.5 of this exhibit.

2.3.1.3 **Insufficient Availability**
The Statement of Intent shall include procedures to allocate between competing applications for a specific Tier 2 Cost Pool if requests exceed amounts available.

2.3.1.4 **Conversion Costs**
Upon establishment of a Tier 2 Vintage Rate for which Surprise Valley signed a Statement of Intent, Surprise Valley shall be liable for payment of any outstanding costs under Tier 2 Short-Term Rates that apply to Surprise Valley. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley under Tier 2 Short-Term Rates as a result of the conversion, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, in the first 7(i) Process that establishes the applicable Tier 2 Vintage Rate. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley's conversion of purchase amounts at Tier 2 Short-Term Rates to purchase amounts at Tier 2 Vintage Rates.

2.3.1.5 **Additional Offerings**
In addition to the right to convert to Tier 2 Vintage Rates established in section 2.3.1.1 of this exhibit, Surprise Valley may have the opportunity to purchase Firm Requirements Power at Tier 2 Vintage Rates regardless of whether Surprise Valley is purchasing at Tier 2 Short-Term Rates if:

(1) BPA determines, in its sole discretion, that all requests for service at Tier 2 Vintage Rates by purchasers of Firm Requirements Power at Tier 2 Short-Term Rates are able to be satisfied, and

(2) BPA determines, in its sole discretion, to offer Surprise Valley a Statement of Intent that would provide Surprise Valley the opportunity to purchase Firm Requirements at Tier 2 Vintage Rates.

If Surprise Valley signs a Statement of Intent offered by BPA pursuant to this section 2.3.1.5, and if BPA is unable to establish the Tier 2 Cost Pool for the applicable Tier 2 Vintage Rate, then Surprise Valley's current elections for service to its Above-RHWM Load shall continue to apply.

Except as provided in this section 2.3.1, any election by Surprise Valley to purchase Firm Requirements Power at Tier 2 Vintage Rates shall not relieve Surprise Valley of any obligation to purchase Firm Requirements Power at another Tier 2 Rate.

2.3.1.6 **Exhibit Updates**
By September 15 immediately following the establishment of a Tier 2 Vintage Rate for which Surprise Valley signed a Statement of Intent, BPA shall amend this exhibit to show Surprise Valley's Tier 2 Vintage Rate purchases and remove Surprise Valley's Tier 2 Short-Term Rate purchases by the amounts purchased at the Tier 2 Vintage Rate, if Surprise Valley is converting to the Tier 2 Vintage Rate from the Tier 2 Short-Term Rate. BPA shall insert applicable tables, terms, and conditions for each Tier 2 Vintage Rate in section 2.3.2 of this exhibit.

2.3.2 **Vintage Rate Elections**
Surprise Valley has no Tier 2 Vintage Rate elections at this time.

2.4 **Tier 2 Short-Term Rate**
If Surprise Valley elects Option 1 or 2 in section 2.2.3 of this exhibit, then this section shall not apply. Otherwise:

2.4.1 **Short-Term Rate Purchases**
Unless Surprise Valley elects, in section 2.1 of this exhibit, not to purchase Firm Requirements Power at Tier 2 Rates for a given Purchase Period, by each Notice Deadline Surprise Valley shall elect in writing either Alternative A or B below for the duration of the corresponding Purchase Period. If Surprise Valley elects Alternative A and elects to apply Dedicated Resources to serve its Above-RHWM Load, then Surprise Valley shall state the amounts to be listed in the table in section 2.4.1.1(2) of this exhibit. If Surprise Valley elects Alternative B, then Surprise Valley shall state the amounts to be listed in the table in section 2.4.1.3 of this exhibit. By March 31 immediately following each Notice Deadline, BPA shall update the tables in this section 2.4.1 to show Surprise Valley's Tier 2 Short-Term Rate election for the corresponding Purchase Period.

2.4.1.1 **Alternative A – Customer Planned Load Not Otherwise Served**
If Surprise Valley elects this alternative, then Surprise Valley shall purchase Firm Requirements Power priced at Tier 2 Short-Term Rates to serve all of Surprise Valley's Above-RHWM Load that Surprise Valley has not otherwise agreed to serve with:

(1) Firm Requirements Power purchased at other Tier 2 Rates, or

(2) the amounts of Dedicated Resources, stated in the table below, that Surprise Valley shall apply during the Purchase Period to serve its Above-RHWM Load. If Surprise Valley purchases power at Tier 2 Load Growth Rates, then these Dedicated Resource amounts shall not exceed the amounts stated in the table in section 2.2.3.3 of this exhibit.

Purchase Period non-Federal Resource Elections					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
Election					
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
Election					
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
Election					
Fiscal Year	**2027**	**2028**			
Election					
Note: Insert amounts in Average Megawatts rounded to three decimal places for each year of the applicable Purchase Period.					

2.4.1.2 **Alternative B – Limited Amounts**
If Surprise Valley elects this alternative, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Short-Term Rates to serve Surprise Valley's Above-RHWM Load that Surprise Valley has not otherwise agreed to serve with Firm Requirements Power purchased at other Tier 2 Rates; provided however, that amounts purchased at Tier 2 Short-Term Rates shall not exceed the amounts (including zero amounts) stated in the table in section 2.4.1.3 of this exhibit. Surprise Valley agrees to serve any of its remaining Above-RHWM Load with power other than Firm Requirements Power.

2.4.1.3 **Tier 2 Short-Term Rate Elections**
If Surprise Valley elects Alternative A above, then BPA shall indicate that election by adding an "X" to the table below for

each year of the applicable Purchase Period. If Surprise Valley elects Alternative B above, then BPA shall indicate that election by adding amounts (in Average Megawatts rounded to three decimal places) to the table below for each year of the applicable Purchase Period.

Tier 2 Short-Term Rate Table					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
Election					
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
Election					
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
Election					
Fiscal Year	**2027**	**2028**			
Election					

2.4.2 Right to Reduce Tier 2 Short-Term Rate Purchase Amounts

2.4.2.1 Notice

If Surprise Valley notifies BPA in writing by October 31 of a Rate Case Year, then Surprise Valley may reduce, in equal amounts for all hours of the year, some or all of the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates. The reduction may take effect in either year of the upcoming Rate Period and shall be effective for the remaining duration of the applicable Purchase Period(s). In its written notice, Surprise Valley shall state the amount of the reduction and the date the reduction shall take effect. Surprise Valley shall replace all reduced Tier 2 Short-Term Rate purchase amounts with amounts of Dedicated Resources applied pursuant to section 3.3 of the body of this Agreement.

2.4.2.2 Charges to Reduce Purchase Amounts

Surprise Valley shall be liable for payment of any costs that apply as a result of Surprise Valley reducing, under section 2.4.2.1 of this exhibit, the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley under Tier 2 Short-Term Rates as a result of the reduction, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, during the 7(i) Process that follows Surprise Valley's notice. If BPA determines that Surprise Valley owes payment for such costs, then Surprise Valley shall pay the entire amount to BPA in no more than 24 equal monthly amounts starting the first month of the upcoming Rate Period. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley reducing the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates.

2.4.2.3 **Exhibit Updates**
By March 31 following Surprise Valley's notice, BPA shall revise this exhibit and Exhibit A to show Surprise Valley's reduced Tier 2 Short-Term Rate purchase amounts and Surprise Valley's Dedicated Resource additions.

2.5 Amounts of Power to be Billed at Tier 2 Rates

2.5.1 Treatment for FY 2012 – FY 2013
By March 31, 2010, BPA shall update the table in section 2.5.2 of this exhibit, consistent with Surprise Valley's elections, with amounts of Firm Requirements Power which Surprise Valley shall purchase at applicable Tier 2 Rates for the FY 2012 – FY 2013 Rate Period.

2.5.2 Amounts of Power for Subsequent Rate Periods
For each Rate Period after the FY 2012 – FY 2013 Rate Period, BPA shall establish for the upcoming Rate Period consistent with Surprise Valley's elections: (1) the planned annual average amounts of Firm Requirements Power which Surprise Valley shall purchase at applicable Tier 2 Rates, and (2) any remarketed Tier 2 Rate purchase amounts in accordance with section 10 of the body of this Agreement. By March 31, 2013, and by March 31 of each Rate Case Year thereafter, BPA shall update the table below with such amounts for each year of the upcoming Rate Period.

Annual Amounts Priced at Tier 2 Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
No Tier 2 at this time									
Remarketed Amounts									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
No Tier 2 at this time									
Remarketed Amounts									

Notes:
1. List each applicable Tier 2 rate in the table above. For the first applicable Tier 2 rate replace **No Tier 2 at this time** with the name of the applicable Tier 2 rate. For each additional Tier 2 rate, add a new row above the **Remarketed Amounts** row. If Surprise Valley elects not to purchase at Tier 2 rates, then leave **No Tier 2 at this time** in the table and leave the remainder of the table blank.
2. Fill in the table above with annual Average Megawatts rounded to three decimal places.

3. **MONTHLY PF RATES**
Applicable monthly Tier 1 and Tier 2 Rates are specified in BPA Wholesale Power Rate Schedules and GRSPs.

4. **REVISIONS**
BPA shall revise this exhibit to reflect Surprise Valley's elections regarding service to its Above-RHWM Load and BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Exhibit D
ADDITIONAL PRODUCTS AND SPECIAL PROVISIONS

1. CF/CT AND NEW LARGE SINGLE LOADS

1.1 CF/CT Loads
Surprise Valley has no loads identified that were contracted for, or committed to (CF/CT), as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act.

1.2 Potential NLSLs
Surprise Valley has no identified potential NLSLs.

1.3 Existing NLSLs
Surprise Valley has no existing NLSLs.

2. RESOURCE SUPPORT SERVICES

2.1 BPA shall develop the RSS products to support applicable Specified Resources listed in section 2 of Exhibit A for the FY 2012-2014 Purchase Period and offer such as a revision to this exhibit by August 1, 2009. Prior to that date, BPA shall provide Surprise Valley a reasonable opportunity to provide input into the development of the products and the related contract provisions. If Surprise Valley requests that BPA provide such service, then the Parties shall execute a revision to this exhibit by the November 1, 2009, Notice Deadline. By each Notice Deadline thereafter, Surprise Valley may purchase RSS from BPA to support applicable Specified Resources listed in section 2 of Exhibit A for the corresponding Purchase Period.

2.2 If Surprise Valley adds a new Specified Resource within a Purchase Period to meet its obligations to serve Above-RHWM Load with Dedicated Resources, consistent with section 3.5.1 of the body of this Agreement, Surprise Valley may purchase RSS from BPA to support such resource. Such purchase shall be for the remainder of the Purchase Period and for the following Purchase Period. Surprise Valley shall notify BPA of its decision to purchase RSS for a new Specified Resource by October 31 of a Rate Case Year and the elected RSS will be effective at the start of the upcoming Rate Period.

3. IRRIGATION RATE MITIGATION
Subject to the terms specified in BPA's applicable Wholesale Power Rate Schedules and GRSPs:

3.1 for billing purposes, in the months listed below for each year during the term of this Agreement, BPA shall apply Irrigation Rate Mitigation to the lesser of the corresponding amount purchased at the Tier 1 Rate in the month or the energy amount in the table below:

Irrigation Amounts (kWh)

May	Jun	Jul	Aug	Sept	Annual Total
6,464,252	9,066,424	11,421,596	11,671,642	7,586,987	46,210,901

3.2 after the end of each irrigation season, the Parties shall administer a true-up process to ensure Surprise Valley's irrigation load meets or exceeds the total eligible irrigation amount (in kilowatt-hours) listed above; and

3.3 Surprise Valley shall be responsible for implementing cost-effective conservation measures on irrigation systems in their service territories. Surprise Valley shall verify and report all conservation measures and project savings consistent with section 18.1.2 of the body of this Agreement.

4. REVISIONS

This exhibit shall be revised by mutual agreement of the Parties to reflect additional products Surprise Valley purchases during the term of this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Exhibit E
METERING

1. METERING

1.1 Directly Connected Points of Delivery and Load Metering
None.

1.2 Transfer Points of Delivery and Load Metering

(1) **BPA POD Name:** Alturas 12.5 kV;
BPA POD Number: 817;
WECC Balancing Authority: PACW;

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

Voltage: 12.5 kV;

Metering: adjacent to PacifiCorp's Alturas Substation in the Surprise Valley's equipment yard 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Alturas Out;
BPA Meter Point Number: 244;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: The potential and current transformers are owned by Surprise Valley.

(2) **BPA POD Name:** Austin 69 kV;
BPA POD Number: 41;
WECC Balancing Authority: PACW;

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 flows;

BPA Meter Point Name: Austin Out;
BPA Meter Point Number: 132;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley

Metering Loss Adjustment: None;

Exception: The potential and current transformers are owned by BPA.

(3) **BPA POD Name:** Canby 69 kV;
BPA POD Number: 104;
WECC Balancing Authority: BPAT;

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

Voltage: 69 kV;

Metering: in Surprise Valley's Canby Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Canby Out (SVEC);
BPA Meter Point Number: 44;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: None.

(4) **BPA POD Name:** Cedarville Junction 69-SURP;
BPA POD Number: 117;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of BPA's Cedarville Junction Switching Station where the 69 kV facilities of Surprise Valley and BPA are connected;

Voltage: 69 kV;

Metering:

(A) in BPA's Cedarville Junction Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville Out;
BPA Meter Point Number: 65;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

(B) in Surprise Valley's Cedarville Substation in the 12.47 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville (PP&L) Out;
BPA Meter Point Number: 861;
Direction for PF Billing Purposes: Negative;
Manner of Service: Transfer, BPA to Surprise Valley to PacifiCorp;

Metering Loss Adjustment: BPA shall adjust for losses between the POD and the Cedarville (PP&L) Out POM. Such adjustments shall be specified in writing between BPA and Surprise Valley;

Exception: None.

(5) **BPA POD Name:** Davis Creek 12.5 kV;
BPA POD Number: 169;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Davis Creek Substation where the 12.5 kV facilities of Surprise Valley and BPA are connected;

Voltage: 12.5 kV;

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

BPA Meter Point Name: Davis Creek Out;
BPA Meter Point Number: 259;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) The potential transformers in the 12.5 kV meter installation are owned by Surprise Valley;

(B) BPA shall have unrestricted use, at no charge, of Surprise Valley's Davis Creek 115 kV Substation and tapline facilities.

(6) **BPA POD Name:** Lakeview 69 kV;
BPA POD Number: 383;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Lakeview Switching Station where the 69 kV facilities of PacificCorp 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 flows;

BPA Meter Point Name: Lakeview Out;
BPA Meter Point Number: 41;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacificCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: The potential transformers in the 69 kV meter installation are owned by Surprise Valley.

1.3 **Resource Locations and Metering**
None.

2. **REVISIONS**
Each Party shall notify the other in writing if updates to this exhibit are necessary to accurately reflect the actual characteristics of POD and meter information described in this exhibit. The Parties shall revise this exhibit to reflect such changes. The Parties shall mutually agree on any such exhibit revisions and agreement shall not be unreasonably withheld or delayed. The effective date of any exhibit revision shall be the date the actual circumstances described by the revision occur.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Exhibit F
TRANSMISSION SCHEDULING SERVICE

1. PURPOSE AND PARAMETERS

1.1 Purpose

Transmission Scheduling Service is provided by Power Services to help Surprise Valley manage certain aspects of its BPA Network Integration Transmission Service Agreement (BPA NT Agreement), to allow BPA to use the inherent resource flexibilities of Surprise Valley's network rights in combination with other network customers rights to manage BPA's power resources efficiently, and to provide seamless scheduling for Transfer Service customers.

1.2 Parameters of Transmission Scheduling Service

Beginning October 1, 2011, and through the term of this Agreement, Power Services shall provide and Surprise Valley shall purchase Transmission Scheduling Service. Power Services shall schedule Surprise Valley's federal and Dedicated Resources to Surprise Valley's Total Retail Load under Surprise Valley's BPA NT Agreement and/or other transmission agreement(s). Power Services shall not provide Transmission Scheduling Service for anything other than delivery to Surprise Valley's Total Retail Load.

Power Services shall perform all necessary prescheduling and real-time scheduling functions, and make other arrangements and adjustments consistent with any RSS products Surprise Valley is purchasing from Power Services. Surprise Valley shall continue to be responsible for all non-scheduling provisions of its transmission agreement(s) used to serve Surprise Valley's Total Retail Load including, but not limited to, the designation and undesignation of Network Resources, as defined by the applicable OATT.

Transmission Scheduling Service shall be subject to the rates, terms and conditions specified in BPA's applicable Wholesale Power Rate Schedules and GRSPs.

2. ASSIGNMENT OF SCHEDULING RIGHTS

Prior to commencement of Transmission Scheduling Service, Surprise Valley shall:

(1) notify Transmission Services that Power Services is the scheduling entity for service taken under Surprise Valley's BPA NT Agreement;

(2) assign Power Services the right to acquire and manage secondary service pursuant to section 28.4 of the BPA OATT as necessary to fulfill BPA's obligations under this Agreement; and

(3) provide copies of Surprise Valley's transmission agreement(s) used to serve Surprise Valley's Total Retail Load.

Additionally, over the term of this Agreement, Surprise Valley shall provide Power Services with any additional transmission agreements Surprise Valley enters into which are used for service to its Total Retail Load and all amendments and modifications to current copies of Surprise Valley's transmission agreement(s).

3. LOAD FORECAST

If a daily load forecast is required by Surprise Valley's transmission agreement(s), then BPA shall develop the daily and hourly load forecasts for Surprise Valley's Total Retail Load. Surprise Valley shall cooperate with BPA in all load forecasting. If any load specific information is needed for developing daily or hourly load forecast, then Surprise Valley shall provide such information in a timely manner.

4. SCHEDULING OF SURPRISE VALLEY'S DEDICATED RESOURCES

4.1 Prescheduling

Surprise Valley shall submit a delivery schedule to Power Services for its Dedicated Resources for delivery to its Total Retail Load which shall include information such as the source, the point of receipt, any OASIS reservation reference numbers needed for the delivery of non-federal power, the daily megawatt profile and all purchasing selling entities in the path. This delivery schedule shall be submitted to Power Services before the earliest of:

(1) 0800 hours Pacific Prevailing Time (PPT) on preschedule day, or

(2) one hour prior to the earliest of the transmission prescheduling deadlines associated with Surprise Valley's transmission agreement(s) delivery of power to Surprise Valley's Total Retail Load.

Surprise Valley shall submit all required prescheduled information in a format specified by Power Services.

At Power Services' request, Surprise Valley shall provide Power Services information on real power losses associated with Surprise Valley's transmission agreement(s).

4.2 Real-Time Scheduling

Power Services shall accept megawatt adjustments to Surprise Valley's Dedicated Resource schedule(s) up to the earliest of 45 minutes prior to the hour of delivery or 25 minutes prior to the earliest of the transmission real-time scheduling deadlines associated with delivery of power to Surprise Valley's Total Retail Load.

Surprise Valley shall submit all required real-time scheduling information in a format specified by Power Services.

4.3 Transmission Curtailments and Generation Outages

This section 4.3 shall not apply to Surprise Valley if Surprise Valley has acquired Forced Outage Reserve Service or the Transmission Curtailment Management Service from Power Services.

Surprise Valley shall notify BPA whether it wants to receive either an electronic copy of the E-Tag or an e-mail of a transmission curtailment that impacts any of Surprise Valley's Dedicated Resources. If Surprise Valley chooses notification of transmission curtailments by e-mail, then Surprise Valley shall provide BPA a single e-mail address for BPA to send such notifications to, and the Parties shall revise this exhibit to include the e-mail address. BPA shall notify Surprise Valley within ten minutes of the transmission curtailment.

(1) If a transmission curtailment or generation outage occurs prior to 45 minutes before the hour of delivery, then Surprise Valley shall be responsible for securing replacement energy, arranging delivery to the BPA Balancing Authority Area in which Surprise Valley is located, and notifying Power Services of the revised delivery schedule prior to 45 minutes before the hour of delivery.

If Power Services is unable to secure secondary network transmission for the replacement resource because Surprise Valley did not notify Power Services of the revised delivery schedule prior to 45 minutes prior to the hour of delivery or secondary network transmission is unavailable, then Surprise Valley shall be subject to charges consistent with the provisions of this Agreement and all related products and BPA's rate schedules, including UAI charges.

(2) Power Services shall not accept replacement delivery schedules for transmission curtailments or generation outages that occur after 45 minutes before the delivery hour. Surprise Valley shall be subject to charges consistent with the provisions of this Agreement and all related products and BPA's rate schedules, including UAI charges.

5. E-TAGS

To the extent E-Tags are required by transmission provider(s), Power Services shall create all E-Tags necessary for delivery of energy to Surprise Valley's Total Retail Load.

6. GENERATION IMBALANCE

Surprise Valley shall be responsible for costs associated with deviations between the scheduled Dedicated Resources for an hour and the actual generation produced across such hour; provided, however, if Surprise Valley submits a delivery schedule consistent with all provisions of this exhibit and BPA receives that delivery schedule, and a generation imbalance results from the BPA error, then BPA shall accept responsibility for the generation imbalance associated with the BPA scheduling error.

7. PENALTIES

If Surprise Valley fails to submit prescheduling or real-time scheduling information to BPA as required and by the deadlines in section 4 of this exhibit, then Surprise

Valley may be subject to applicable UAI charges, consistent with BPA's applicable Wholesale Power Rate Schedules and GRSPs.

8. AFTER THE FACT

BPA and Surprise Valley agree to reconcile all transactions, schedules and accounts at the end of each month (as early as possible within the first ten calendar days of the next month). BPA and Surprise Valley shall verify all transactions pursuant to this Agreement as to product or type of service, hourly amounts, daily and monthly totals, and related charges.

9. REVISIONS

BPA may unilaterally revise this exhibit:

(1) to implement changes that BPA determines are necessary to allow it to meet its power and scheduling obligations under this Agreement, or

(2) to comply with requirements of WECC, NAESB, or NERC, or their successors or assigns.

BPA shall provide a draft of any material revisions of this exhibit to Surprise Valley, with a reasonable time for comment, prior to BPA providing written notice of the revision. Revisions are effective 45 days after BPA provides written notice of the revisions to Surprise Valley unless, in BPA's sole judgment, less notice is necessary to comply with an emergency change to the requirements of WECC, NAESB, NERC, or their successors or assigns. In this case, BPA shall specify the effective date of such revisions.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Exhibit G
PRINCIPLES OF NON-FEDERAL TRANSFER SERVICE

As provided by section 14.6.7 of the body of this Agreement and BPA's Long-Term Regional Dialogue Final Policy, July 2007, or any other later revision of that policy, if Surprise Valley acquires non-federal resources to serve its retail load above its established RHWM, then BPA's support and assistance to Surprise Valley regarding transfer service for its non-federal resources shall be consistent with the following principles:

1. **ESTABLISHED CAPS AND LIMITATIONS**
BPA shall provide financial support for the transmission capacity associated with non-federal resource purchases to all Transfer Service customers up to a maximum of 41 megawatts per fiscal year, cumulative over the duration of this Agreement. This cumulative megawatt limit is shown in the table below.

Fiscal Year	Per Year MW Limit	Cumulative MW Limit
FY 2012	41	41
FY 2013	41	82
FY 2014	41	123
FY 2015	41	164
FY 2016	41	205
FY 2017	41	246
FY 2018	41	287
FY 2019	41	328
FY 2020	41	369
FY 2021	41	410
FY 2022	41	451
FY 2023	41	492
FY 2024	41	533
FY 2025	41	574
FY 2026	41	615
FY 2027	41	656
FY 2028	41	697

2. Application of section 14.6.7 of the body of this Agreement shall be on a first come, first served basis in each year based on the date each request is received by BPA. Requests not met, in whole or in part, in any Fiscal Year will have priority over subsequent requests the following year. Once granted, BPA shall honor such request for the duration of the resource acquisition period, not to exceed the term of this Agreement.

3. **PROCESS AND PARAMETERS FOR INITIALLY CHOOSING A NON-FEDERAL RESOURCE**

   3.1 BPA obtains Transfer Service from Third Party Transmission Providers pursuant to OATT Network Integration Transmission Service. Additionally, BPA acquires firm transmission for all load service obligations incurred.

Therefore, BPA shall, on behalf of Surprise Valley, pursue Network Resource designation, as defined in the FERC OATT for Surprise Valley's non-federal resource. BPA shall provide all information the Third Party Transmission Provider requires to evaluate the Network Resource designation request. Surprise Valley shall provide all relevant information BPA determines is required to submit an application for designation of the resource as a Network Resource per section 29 of the OATT, or its successor.

3.2 Surprise Valley shall notify BPA of its intent and/or actions to acquire or purchase a non-federal resource at least one year prior to delivery. Such acquisition or purchase shall be for a period of no less than one year in duration.

3.3 If BPA's existing Transfer Service to Surprise Valley is pursuant to a non-OATT contractual arrangement, then BPA shall pursue all reasonable arrangements, including but not limited to OATT service, sufficient to enable Surprise Valley to utilize the non-federal resource to serve its load.

3.4 BPA shall not be liable to Surprise Valley in the event that Network Resource designation cannot be obtained.

3.5 BPA shall only obtain or pay for Transfer Service for Surprise Valley's non-federal resource if it is designated as a Network Resource under the Third Party Transmission Provider's OATT with a commitment of at least one year. The limitations in this principle 3 do not pertain to market purchases and the use of secondary network transmission, which are addressed below in principle 15.

4. Surprise Valley shall provide BPA all information BPA determines is reasonably necessary to administer firm network transmission service over the Third Party Transmission Provider's system.

5. BPA shall pay only the capacity costs associated with transmission service to Surprise Valley over transmission facilities of the Third Party Transmission Provider that either (1) interconnect directly to Surprise Valley's facilities or (2) interconnect to BPA transmission facilities which subsequently interconnect with Surprise Valley's facilities. Surprise Valley shall arrange for, and pay any costs associated with, the delivery of non-federal power to an interconnection point with the Third Party Transmission Provider, including obtaining and paying for firm transmission across all intervening transmission systems.

6. Surprise Valley shall pay a portion of the costs of all Ancillary Services necessary to deliver any non-federal resource to serve its load. The Ancillary Service costs imposed by the Third Party Transmission Provider shall be apportioned between BPA and Surprise Valley based on either:

(1) metered/scheduled quantities of the non-federal resource, expressed as a percentage of total load, multiplied by the total costs assessed BPA by the Third Party Transmission Provider; or

(2) actual charges assessed by the Third Party Transmission Provider.

However, BPA shall treat the cost of load regulation service consistent with the load regulation service cost as described in section 14.6.1(1) of the body of this Agreement. BPA shall be responsible for the cost of generation supplied reactive power, and Surprise Valley shall be responsible for any generation imbalance costs, if any, related to Surprise Valley's non-federal resource.

7. Surprise Valley shall be responsible for the costs of all other transmission services for non-federal deliveries not included in principles 5 and 6 above, including, but not limited to: redispatch, congestion management costs, system and facility study costs associated with adding the non-federal generation as a Network Resource, direct assigned system upgrades, distribution and low-voltage charges, if applicable and real power losses.

8. Surprise Valley shall be responsible for all costs of interconnecting generation to a transmission system.

9. Surprise Valley shall be responsible for acquiring transmission services from BPA, including wheeling for non-federal resources. If Surprise Valley does not require transmission services from BPA for wheeling non-federal resources, then Surprise Valley shall be responsible for a pro rata share of the Third Party Transmission Provider transmission costs that BPA incurs to serve Surprise Valley.

10. Surprise Valley shall be responsible for all integration services to support its non-federal resources:

(1) in accordance with all requirements of the host Balancing Authority and/or Third Party Transmission Provider, and

(2) which are necessary for designation of the non-federal resource as a Network Resource.

11. As necessary, Surprise Valley shall meet all resource metering requirements including compliance with BPA standards and any requirements of the generation host Balancing Authority and/or Third Party Transmission Provider.

12. The Parties shall cooperate to establish the protocols, procedures, data exchanges or other arrangements the Parties deem reasonably necessary to support the transmission of Surprise Valley's non-federal resource.

13. Unless otherwise agreed, Surprise Valley shall be responsible for managing any non-federal resource consistent with Exhibit F.

14. BPA shall have no obligation to pay for Transfer Service for non-federal power to serve any portion of Surprise Valley's retail load that Surprise Valley is obligated to serve with federal power pursuant to this Agreement.

15. Once Surprise Valley's non-federal resource has been designated as a Network Resource, BPA will not undesignate Surprise Valley's Network Resource for marketing purposes. Also, once such Network Resource designation has been made, Surprise Valley may make market purchases to displace the Network Resource, which BPA shall schedule on secondary network service, provided that:

(1) such market purchases are at least one day in duration;

(2) the megawatt amount of the market purchase does not exceed the amount of the designated Network Resource that Surprise Valley would have scheduled to its load;

(3) such market purchases are only scheduled in preschedule consistent with section 4.1 of Exhibit F;

(4) Surprise Valley does not, under any circumstances, remarket its designated Network Resource or perform any other operation that would cause BPA to be in violation of its obligations under the Third Party Transmission Provider's OATT;

(5) Surprise Valley is responsible for any additional energy imbalance, redispatch, and/or UAI charges that result from a transmission curtailment that impacts the resulting secondary network schedule; and

(6) any RSS products that Surprise Valley has purchased from BPA are not applied to the market purchase(s).

16. These principles will be the basis for a separate agreement BPA shall offer to Surprise Valley to support the Transfer Service of Surprise Valley's non-federal resource. BPA shall include terms specific to a particular non-federal resource in exhibits to the separate agreement, with a separate exhibit for each non-federal resource. Surprise Valley is under no obligation to accept this separate agreement or the exhibit for the particular non-federal resource and BPA is not bound to acquire or pay for Transfer Service for non-federal resources if Surprise Valley does not accept the separate agreement or the exhibit for the particular non-federal resource.

17. BPA shall recover the costs associated with any agreements with Surprise Valley reached under these principles pursuant to BPA's Wholesale Power Rate Schedules and GRSPs.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Exhibit H
RENEWABLE ENERGY CERTIFICATES AND CARBON ATTRIBUTES

1. DEFINITIONS

1.1 "Carbon Credit" means an Environmental Attribute consisting of greenhouse gas emission credits, certificates, or similar instruments.

1.2 "Environmental Attributes" means the current or future credits, benefits, emission reductions, offsets and allowances attributable to the generation of energy from a resource. Environmental Attributes do not include the tax credits associated with such resource. One megawatt-hour of energy generation from a resource is associated with one megawatt-hour of Environmental Attributes.

1.3 "Environmentally Preferred Power RECS" or "EPP RECs" means the portion of BPA's Tier 1 RECs that is equal to an amount of up to 130 percent of the annual average of equivalent environmentally preferred power (EPP) contracted for as of October 1, 2009, for FYs 2010 and 2011 under Subscription power sales contracts containing rights to Environmental Attributes through FY 2016, as determined by BPA to be necessary to administer such rights.

1.4 "Renewable Energy Certificates" or "RECs" means the certificates, documentation, or other evidence that demonstrates, in the tracking system selected under section 5 of this exhibit, the ownership of Environmental Attributes.

1.5 "Tier 1 RECs" means the RECs composed of a blend, by fuel source, based on annual generation of the resources listed in or pursuant to section 2 of this exhibit.

1.6 "Tier 2 RECs" means the RECs associated with generation of the resources whose costs are allocated to a given Tier 2 Cost Pool in accordance with the TRM.

2. BPA'S TIER 1 REC INVENTORY

BPA's Tier 1 REC inventory shall include all RECs that BPA has determined are associated with resources whose output is used to establish Tier 1 System Capability, as Tier 1 System Capability is defined in the TRM. The disposition of any Carbon Credits that BPA determines are associated with resources listed in, or in accordance with, this section 2 shall be as described in section 3 of this exhibit. The disposition of any Carbon Credits that BPA determines are associated with resources not listed in, or in accordance with, this section 2 shall be consistent with section 7 of this exhibit. As of the Effective Date, BPA has determined that the following resources have RECs associated with them that will be included in the Tier 1 REC inventory: Foote Creek I, Foote Creek II, Stateline, Condon, Klondike I, Klondike III, and Ashland Solar. BPA shall maintain this list on a publicly accessible BPA website and shall periodically update this list to include any then-current resources that BPA has determined have Tier 1 RECs associated with them. BPA shall calculate its inventory of Tier 1 RECs annually and after the fact based on energy generated by listed resources during the previous calendar year.

3. **SURPRISE VALLEY'S SHARE OF TIER 1 RECS**
Beginning April 15, 2012, and by April 15 every year thereafter over the term of this Agreement, BPA shall:

(1) transfer to Surprise Valley, or manage in accordance with section 5 of this exhibit, at no additional charge or premium beyond Surprise Valley's payment of the otherwise applicable Tier 1 Rate, a pro rata share of Tier 1 RECs based on Surprise Valley's RHWM divided by the total RHWMs of all holders of CHWM Contracts; and

(2) for transferred RECs, provide Surprise Valley with a letter assigning title of such Tier 1 RECs to Surprise Valley.

The amount of Tier 1 RECs available to BPA to transfer or manage shall be subject to available Tier 1 REC inventory, excluding amounts of Tier 1 REC inventory used to provide EPP RECs.

4. **TIER 2 RECS**
If Surprise Valley chooses to purchase Firm Requirements Power at a Tier 2 Rate, and there are RECs which BPA has determined are associated with the resources whose costs are allocated to the Tier 2 Cost Pool for such rate, then beginning April 15 of the year immediately following the first Fiscal Year in which Surprise Valley's Tier 2 purchase obligation commences, and by April 15 every year thereafter for the duration of Surprise Valley's Tier 2 purchase obligation, BPA shall, based on Surprise Valley's election pursuant to section 5 of this exhibit, transfer to or manage for Surprise Valley a pro rata share of applicable Tier 2 RECs generated during the previous calendar year. The pro rata share of Tier 2 RECs BPA transfers to Surprise Valley shall be the ratio of Surprise Valley's amount of power purchased at the applicable Tier 2 Rate to the total amount of purchases under that Tier 2 Rate.

5. **TRANSFER, TRACKING, AND MANAGEMENT OF RECS**
Subject to BPA's determination that the commercial renewable energy tracking system WREGIS is adequate as a tracking system, BPA shall transfer Surprise Valley's share of Tier 1 RECs, and Tier 2 RECs if applicable, to Surprise Valley via WREGIS or its successor. If, during the term of this Agreement, BPA determines in consultation with customers that WREGIS is not adequate as a tracking system, then BPA may change commercial tracking systems with one year advance notice to Surprise Valley. In such case, the Parties shall establish a comparable process for BPA to provide Surprise Valley its RECs.

Starting on July 15, 2011, and by July 15 prior to each Rate Period through the term of this Agreement, Surprise Valley shall notify BPA which one of the following three options it chooses for the transfer and management of Surprise Valley's share of Tier 1 RECs, and Tier 2 RECs if applicable, for each upcoming Rate Period:

(1) BPA shall transfer Surprise Valley's RECs into Surprise Valley's own WREGIS account, which shall be established by Surprise Valley; or

(2) BPA shall transfer Surprise Valley's RECs into a BPA-managed WREGIS subaccount. Such subaccount shall be established by BPA on Surprise Valley's behalf and the terms and conditions of which shall be determined by the Parties in a separate agreement; or

(3) Surprise Valley shall give BPA the authority to market Surprise Valley's RECs on Surprise Valley's behalf. BPA shall annually credit Surprise Valley for Surprise Valley's pro rata share of all revenues generated by sales of RECs from the same rate pool on its April bill, issued in May.

If Surprise Valley fails to notify BPA of its election by July 15 before the start of each Rate Period, then Surprise Valley shall be deemed to have elected the option in section 5(3) of this exhibit.

Any RECs BPA transfers to Surprise Valley on April 15 of each year shall be limited to those generated January 1 through December 31 of the prior year, except that any RECs BPA transfers to Surprise Valley by April 15, 2012, shall be limited to those generated October 1, 2011, through December 31, 2011.

6. FEES

BPA shall pay any reasonable fees associated with (1) the provision of Surprise Valley's RECs and (2) the establishment of any subaccounts in Surprise Valley's name pursuant to sections 5(1) and 5(2) of this exhibit. Surprise Valley shall pay all other fees associated with any WREGIS or successor commercial tracking system, including WREGIS retirement, reserve, and export fees.

7. CARBON CREDITS

In the absence of carbon regulations or legislation directly affecting BPA, BPA intends to convey the value of any future Carbon Credits associated with resources whose costs are recovered in Tier 1 or Tier 2 Rates to Surprise Valley on a pro rata basis in the same manner as described for Tier 1 RECs and Tier 2 RECs in sections 3 and 4 of this exhibit. This value may be conveyed as: (1) the Carbon Credits themselves; (2) a revenue credit after BPA markets such Carbon Credits; or (3) the ability to claim that power purchases at the applicable PF rate are derived from certain federal resources.

8. BPA'S RIGHT TO TERMINATE SURPRISE VALLEY'S RECS AND/OR CARBON CREDITS

To the extent necessary to comply with any federal regulation or legislation which addresses Carbon Credits or any other form of Environmental Attribute(s) and includes compliance costs applicable to BPA, BPA may, upon reasonable notice to Surprise Valley, terminate Surprise Valley's contract rights to Tier 1 RECs under section 3 of this exhibit and/or Surprise Valley's pro rata share of Carbon Credits under section 7 of this exhibit.

9. RATEMAKING TREATMENT

Notwithstanding the transfer, sharing, management, conveyance, marketing or crediting of RECs and Carbon Credits, or the value of any or all of them, pursuant to this Exhibit H, BPA reserves any ratemaking authority it otherwise possesses to determine and factor in a share of the value and/or cost of any or all of the RECs and Carbon Credits for the purpose of: (1) determining applicable wholesale rates pursuant to section 7(c)(2) of the Northwest Power Act; and (2) establishing the rate(s) applicable to BPA sales pursuant to section 5(c) of the Northwest Power Act in a manner that BPA determines provides an appropriate sharing of the benefits and/or costs of the federal system and comparably reflects treatment of RECs and Carbon Credits in the calculation of a utility's average system cost of resources. BPA further reserves its ratemaking authority to recover any costs resulting from such ratemaking actions through rates, including rates applicable to Surprise Valley. This paragraph does not constitute Surprise Valley's agreement to statutory ratemaking authority BPA does not otherwise have.

10. REVISIONS

BPA shall revise this Exhibit H to reflect BPA's determinations relevant to this exhibit and made in accordance with this Agreement. Any other revisions to this Exhibit H shall be by mutual agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110.DOC) 09/09/08

Resolution No. 08-02 of the Board of Directors
Surprise Valley Electrification Corp.
Authorizing the General Manager to execute a Power
Sales Agreement between the Bonneville Power Administration (BPA) and
Surprise Valley Electrification Corp. (SVEC).

WHEREAS, the current Full Service Power Sales Agreement (Contract No. 00PB-12074) dated July 27, 2000 between BPA and SVEC is scheduled to expire September 30, 2011.

WHEREAS, SVEC wishes to continue purchasing wholesale power from BPA under a new BPA contract offer No. 09PB-13110 for a period of 20 years to expire on September 30, 2028.

NOW THEREFORE BE IT RESOLVED, that the General Manager of SVEC, Daniel W. Silveria, does hereby have the authority to execute contract No. 09PB-13110 between BPA and SVEC on behalf of Surprise Valley Electrification Corp. and its Board of Directors.

Signature of the Secretary

I, Raymond J. Cloud, certify that I am the Secretary of the Surprise Valley Electrification Corp. Board of Directors. I further certify that the above is a true excerpt from the minutes of a Board Meeting of this Board of Directors on the 25th day of November, 2008, at which a quorum was present and that the above portion of the minutes has not been modified or rescinded.

Raymond J. Cloud

Raymond J. Cloud, Secretary

RECEIVED
NOV 26 2008

Revision No. 1, Exhibit A
NET REQUIREMENTS AND RESOURCES
Effective July 1, 2015

AUTHENTICATED

This revision updates section 6 to add the Paisley Geothermal Power Plant resource.

1. NET REQUIREMENTS

Surprise Valley's Net Requirement equals its Total Retail Load minus Surprise Valley's Dedicated Resources determined pursuant to section 3.3 of the body of this Agreement and listed in sections 2, 3, and 4 of this exhibit. The Parties shall not add or remove resource amounts to change Surprise Valley's purchase obligations from BPA under section 3.1 of the body of this Agreement except in accordance with sections 3.5 and 10 of the body of this Agreement.

2. LIST OF SPECIFIED RESOURCES

2.1 Generating Resources

Surprise Valley does not have any Generating Resources that are Specified Resources at this time.

2.2 Contract Resources

Surprise Valley does not have any Contract Resources that are Specified Resources at this time.

2.3 Small Non-Dispatchable Resources

Surprise Valley does not have any Small Non-Dispatchable Resources at this time. If Surprise Valley adds Small Non-Dispatchable Resources to this section and if the aggregate nameplate capability of such Small Non-Dispatchable Resources that are also New Resources exceeds one megawatt, then BPA shall consider the impacts of the aggregate shape of such New Resources and may require the application of DFS to account for the impact of the aggregate shape on Surprise Valley's load.

3. UNSPECIFIED RESOURCE AMOUNTS

3.1 Unspecified Resource Amounts Used to Serve Total Retail Load

3.1.1 Shape of Unspecified Resource Amounts

Surprise Valley's Unspecified Resource Amounts shall be calculated using the selected monthly and Diurnal shapes listed below. BPA shall update the table below consistent with section 3.4.2 of the body of this Agreement.

Shape of Unspecified Resource Amounts				
	Monthly Shape Choice		Diurnal Shape Choice	
Purchase Period	**Total Retail Load Monthly Shape**	**Flat Annual Shape**	**HLH Diurnal Shape**	**Flat Within-Month Shape**
FY 2012 – FY 2014		X		X
FY 2015 – FY 2019		X		X
FY 2020 – FY 2024		X		X
FY 2025 – FY 2028		X		X

3.1.2 **Unspecified Resource Amounts**
Surprise Valley does not have any Unspecified Resource Amounts at this time.

3.2 **Unspecified Resource Amounts for 9(c) Export Decrements**
BPA shall insert a table below pursuant to section 3.5.3 of the body of this Agreement.

4. DEDICATED RESOURCE AMOUNTS FOR AN NLSL
Surprise Valley does not have any Dedicated Resource amounts serving an NLSL at this time, in accordance with section 3.5.7 of the body of this Agreement.

5. TOTAL DEDICATED RESOURCE AMOUNTS
Surprise Valley does not have any Dedicated Resource amounts at this time.

6. LIST OF RESOURCES NOT USED TO SERVE TOTAL RETAIL LOAD
Pursuant to section 17 of the body of this Agreement, all Generating Resources and Contract Resources Surprise Valley owns that are: (1) not Specified Resources listed in section 2 of Exhibit A, and (2) greater than 200 kilowatts of nameplate capability, are listed below.

(1) **Paisley Geothermal Power Plant (Paisley Geothermal)**

(A) Resource Profile

	Type of Resource			
Fuel Type	**Generating Resource**	**Contract Resource**	**Percent of Resource Not Used to Serve Load**	**Nameplate Capability (MW)**
Geothermal	X		100%	3.65

(B) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	N/A	N/A	N/A	2.087	2.082	2.087	2.087	2.087	2.082
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	2.087	2.087	2.087	2.082	2.087	2.087	2.087	2.082	
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places. Note: For FY 15, BPA has allowed Surprise Valley to temporarily apply the Paisley Geothermal resource to load that would otherwise be served at the Tier 1 Rate. See Exhibit D for the terms and conditions of such temporary application.									

7. LIST OF CONSUMER-OWNED RESOURCES

7.1 **Consumer-Owned Resources Serving Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving Onsite Consumer Load at this time.

7.2 **Consumer-Owned Resources Serving Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving load other than Onsite Consumer Load at this time.

7.3 **Consumer-Owned Resources Serving Both Onsite Consumer Load and Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving both Onsite Consumer Load and load other than Onsite Consumer Load at this time.

7.4 **Consumer-Owned Resources Serving an NLSL**
Pursuant to section 23.3.7 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving an NLSL at this time.

8. TABLES FOR ALLOWABLE DEDICATED RESOURCE SHAPES

8.1 **Total Retail Load Monthly Shape**
By March 31 immediately following each of the Fiscal Years 2010, 2015, and 2020, BPA shall fill in the table below with Surprise Valley's Total Retail Load Monthly Shape, in accordance with section 3.4.2 of the body of this Agreement. Surprise Valley's Total Retail Load Monthly Shape shall be calculated by dividing Surprise Valley's Total Retail Load (in megawatt-hours) in each month of Fiscal Years 2010, 2015, and 2020 by the Fiscal Year total of Surprise Valley's Total Retail Load (in megawatt-hours). BPA shall weather-normalize Surprise Valley's Total Retail Load data, prior to calculating the Total Retail Load Monthly Shape, using the same weather-normalization procedures set forth in section 4.1.1 of the TRM.

Total Retail Load Monthly Shape (%)													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
FY 2010													100.0
FY 2015													100.0
FY 2020													100.0
Note: Fill in the table above with percents rounded to the nearest one decimal place													

8.2 **HLH Diurnal Shape**

8.2.1 **Specified Resources**
If Surprise Valley elects the HLH Diurnal Shape for its Specified Resources, Surprise Valley shall fill in a table with monthly LLH and HLH amounts for each year of the upcoming Purchase Period for each Specified Resource. The monthly LLH and HLH distributions shall be the same across all years of a Purchase Period. Surprise Valley shall submit the tables to BPA when Surprise Valley makes its reshaping elections. BPA shall update the appropriate Dedicated Resource amounts pursuant to Surprise Valley's submitted elections and consistent with section 3.4.2 of the body of this Agreement.

8.2.2 **Unspecified Resource Amounts**
If Surprise Valley elects the HLH Diurnal Shape for its Unspecified Resource Amounts, then Surprise Valley shall submit to BPA in writing its elected ratios of megawatt-hours per hour in HLH to megawatt-hours per hour in LLH by the Notice Deadline. Surprise Valley shall submit to BPA twelve monthly ratios and such monthly ratios shall apply for all years of the corresponding Purchase Period. BPA shall update the table below pursuant to Surprise Valley's submitted elections and consistent with section 3.4.2 of the body of this Agreement. BPA shall calculate Surprise Valley's Unspecified Resource Amounts using the ratios in the table below.

HLH Diurnal Shape for Unspecified Resource Amounts												
	HLH to LLH Ratios (HLH:LLH)											
Purchase Period	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
FY 2012 – FY 2014												
FY 2015 – FY 2019												
FY 2020 – FY 2024												
FY 2025 – FY 2028												

9. SUPER PEAK AMOUNTS

Surprise Valley may reshape some or all of its HLH Dedicated Resource amounts for its (1) Specified Resources listed in section 2 of this exhibit, except for any Small Non-Dispatchable Resources and any Specified Resources Surprise Valley is supporting with DFS or SCS from BPA; and (2) Unspecified Resource Amounts listed in section 3.1.2 of this exhibit; into the Super Peak Period to receive a Super Peak Credit. BPA shall update the table below consistent with section 3.4.4 of the body of this Agreement.

Super Peak Amounts (MW)												
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												
Note: Fill in the table above with megawatts rounded to the nearest three decimal places.												

10. REVISIONS

BPA shall revise this exhibit to reflect (1) Surprise Valley's elections regarding the application and use of all resources owned by Surprise Valley and Surprise Valley's retail consumers and (2) BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110 Exh A R1.DOC) 06/23/15

Revision No. 2, Exhibit A
NET REQUIREMENTS AND RESOURCES
Effective October 1, 2015

AUTHENTICATED

This revision updates the note in the Paisley Geothermal Power Plant resource table in section 6.

1. NET REQUIREMENTS

Surprise Valley's Net Requirement equals its Total Retail Load minus Surprise Valley's Dedicated Resources determined pursuant to section 3.3 of the body of this Agreement and listed in sections 2, 3, and 4 of this exhibit. The Parties shall not add or remove resource amounts to change Surprise Valley's purchase obligations from BPA under section 3.1 of the body of this Agreement except in accordance with sections 3.5 and 10 of the body of this Agreement.

2. LIST OF SPECIFIED RESOURCES

2.1 **Generating Resources**

Surprise Valley does not have any Generating Resources that are Specified Resources at this time.

2.2 **Contract Resources**

Surprise Valley does not have any Contract Resources that are Specified Resources at this time.

2.3 **Small Non-Dispatchable Resources**

Surprise Valley does not have any Small Non-Dispatchable Resources at this time. If Surprise Valley adds Small Non-Dispatchable Resources to this section and if the aggregate nameplate capability of such Small Non-Dispatchable Resources that are also New Resources exceeds one megawatt, then BPA shall consider the impacts of the aggregate shape of such New Resources and may require the application of DFS to account for the impact of the aggregate shape on Surprise Valley's load.

3. UNSPECIFIED RESOURCE AMOUNTS

3.1 **Unspecified Resource Amounts Used to Serve Total Retail Load**

3.1.1 **Shape of Unspecified Resource Amounts**

Surprise Valley's Unspecified Resource Amounts shall be calculated using the selected monthly and Diurnal shapes listed below. BPA shall update the table below consistent with section 3.4.2 of the body of this Agreement.

Shape of Unspecified Resource Amounts				
	Monthly Shape Choice		Diurnal Shape Choice	
Purchase Period	**Total Retail Load Monthly Shape**	**Flat Annual Shape**	**HLH Diurnal Shape**	**Flat Within-Month Shape**
FY 2012 – FY 2014		X		X
FY 2015 – FY 2019		X		X
FY 2020 – FY 2024		X		X
FY 2025 – FY 2028		X		X

3.1.2 **Unspecified Resource Amounts**
Surprise Valley does not have any Unspecified Resource Amounts at this time.

3.2 **Unspecified Resource Amounts for 9(c) Export Decrements**
BPA shall insert a table below pursuant to section 3.5.3 of the body of this Agreement.

4. DEDICATED RESOURCE AMOUNTS FOR AN NLSL

Surprise Valley does not have any Dedicated Resource amounts serving an NLSL at this time, in accordance with section 3.5.7 of the body of this Agreement.

5. TOTAL DEDICATED RESOURCE AMOUNTS

Surprise Valley does not have any Dedicated Resource amounts at this time.

6. LIST OF RESOURCES NOT USED TO SERVE TOTAL RETAIL LOAD

Pursuant to section 17 of the body of this Agreement, all Generating Resources and Contract Resources Surprise Valley owns that are: (1) not Specified Resources listed in section 2 of Exhibit A, and (2) greater than 200 kilowatts of nameplate capability, are listed below.

(1) **Paisley Geothermal Power Plant (Paisley Geothermal)**

(A) Resource Profile

	Type of Resource		Percent of Resource Not Used to Serve Load	Nameplate Capability (MW)
Fuel Type	**Generating Resource**	**Contract Resource**		
Geothermal	X		100%	3.65

(B) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	N/A	N/A	N/A	2.087	2.082	2.087	2.087	2.087	2.082
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	2.087	2.087	2.087	2.082	2.087	2.087	2.087	2.082	
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places. Note: For FY 16, BPA has allowed Surprise Valley to temporarily apply the Paisley Geothermal resource to load that would otherwise be served at the Tier 1 Rate. See Exhibit D for the terms and conditions of such temporary application.									

7. LIST OF CONSUMER-OWNED RESOURCES

7.1 **Consumer-Owned Resources Serving Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving Onsite Consumer Load at this time.

7.2 **Consumer-Owned Resources Serving Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving load other than Onsite Consumer Load at this time.

7.3 **Consumer-Owned Resources Serving Both Onsite Consumer Load and Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving both Onsite Consumer Load and load other than Onsite Consumer Load at this time.

7.4 **Consumer-Owned Resources Serving an NLSL**
Pursuant to section 23.3.7 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving an NLSL at this time.

8. TABLES FOR ALLOWABLE DEDICATED RESOURCE SHAPES

8.1 **Total Retail Load Monthly Shape**
By March 31 immediately following each of the Fiscal Years 2010, 2015, and 2020, BPA shall fill in the table below with Surprise Valley's Total Retail Load Monthly Shape, in accordance with section 3.4.2 of the body of this Agreement. Surprise Valley's Total Retail Load Monthly Shape shall be calculated by dividing Surprise Valley's Total Retail Load (in megawatt-hours) in each month of Fiscal Years 2010, 2015, and 2020 by the Fiscal Year total of Surprise Valley's Total Retail Load (in megawatt-hours). BPA shall weather-normalize Surprise Valley's Total Retail Load data, prior to calculating the Total Retail Load Monthly Shape, using the same weather-normalization procedures set forth in section 4.1.1 of the TRM.

Total Retail Load Monthly Shape (%)													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
FY 2010													100.0
FY 2015													100.0
FY 2020													100.0
Note: Fill in the table above with percents rounded to the nearest one decimal place													

8.2 **HLH Diurnal Shape**

8.2.1 **Specified Resources**
If Surprise Valley elects the HLH Diurnal Shape for its Specified Resources, Surprise Valley shall fill in a table with monthly LLH and HLH amounts for each year of the upcoming Purchase Period for each Specified Resource. The monthly LLH and HLH distributions shall be the same across all years of a Purchase Period. Surprise Valley shall submit the tables to BPA when Surprise Valley makes its reshaping elections. BPA shall update the appropriate Dedicated Resource amounts pursuant to Surprise Valley's submitted elections and consistent with section 3.4.2 of the body of this Agreement.

8.2.2 **Unspecified Resource Amounts**
If Surprise Valley elects the HLH Diurnal Shape for its Unspecified Resource Amounts, then Surprise Valley shall submit to BPA in writing its elected ratios of megawatt-hours per hour in HLH to megawatt-hours per hour in LLH by the Notice Deadline. Surprise Valley shall submit to BPA twelve monthly ratios and such monthly ratios shall apply for all years of the corresponding Purchase Period. BPA shall update the table below pursuant to Surprise Valley's submitted elections and consistent with section 3.4.2 of the body of this Agreement. BPA shall calculate Surprise Valley's Unspecified Resource Amounts using the ratios in the table below.

HLH Diurnal Shape for Unspecified Resource Amounts												
	HLH to LLH Ratios (HLH:LLH)											
Purchase Period	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
FY 2012 – FY 2014												
FY 2015 – FY 2019												
FY 2020 – FY 2024												
FY 2025 – FY 2028												

9. SUPER PEAK AMOUNTS

Surprise Valley may reshape some or all of its HLH Dedicated Resource amounts for its (1) Specified Resources listed in section 2 of this exhibit, except for any Small Non-Dispatchable Resources and any Specified Resources Surprise Valley is supporting with DFS or SCS from BPA; and (2) Unspecified Resource Amounts listed in section 3.1.2 of this exhibit; into the Super Peak Period to receive a Super Peak Credit. BPA shall update the table below consistent with section 3.4.4 of the body of this Agreement.

Super Peak Amounts (MW)												
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												
Note: Fill in the table above with megawatts rounded to the nearest three decimal places.												

10. REVISIONS

BPA shall revise this exhibit to reflect (1) Surprise Valley's elections regarding the application and use of all resources owned by Surprise Valley and Surprise Valley's retail consumers and (2) BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110 Exh A R2 .DOC) 09/01/15

Revision No. 1, Exhibit B
HIGH WATER MARKS AND CONTRACT DEMAND QUANTITIES
Effective September 15, 2011

This revision updates: (1) section 1.1 to include Surprise Valley's CHWM and (2) section 2.1 to include Surprise Valley's monthly CDQs.

1. CONTRACT HIGH WATER MARK (CHWM)

1.1 CHWM Amount

By September 15, 2011, BPA shall fill in the table below with Surprise Valley's CHWM. Once established, Surprise Valley's CHWM shall not change for the term of this Agreement except as allowed in section 1.2 of this exhibit.

CHWM (annual aMW):	16.677
Note: BPA shall round the number in the table above to three decimal places.	

1.2 Changes to CHWM

If a change is made to Surprise Valley's CHWM pursuant to this section 1.2, then BPA shall determine and notify Surprise Valley of the date such change will be effective as follows:

1.2.1 If a load included in Surprise Valley's Measured 2010 Load, as defined in the TRM, is later found to have been an NLSL in FY 2010, then BPA shall reduce Surprise Valley's CHWM by the amount of the NLSL. BPA shall notify Surprise Valley 30 days prior to when the updated CHWM will become effective. Surprise Valley shall be liable for payment of any charges to adjust for the ineligible Tier 1 PF rate purchases dating back to October 1, 2011.

1.2.2 If Surprise Valley acquires an Annexed Load from a utility that has a CHWM, then BPA shall increase Surprise Valley's CHWM by adding part of the other utility's CHWM to Surprise Valley's CHWM. The CHWM increase shall be effective on the date that Surprise Valley begins service to the Annexed Load. BPA shall establish the amount of the CHWM addition as follows:

(1) If Surprise Valley and the other utility involved in the annexation agree on the amount of the CHWM addition, then BPA shall adopt that amount if BPA determines such amount is reasonable.

(2) If Surprise Valley and the other utility cannot agree on the amount of the CHWM addition, or if BPA determines the amount agreed to in 1.2.2(1) of this exhibit is unreasonable, then the amount of the CHWM addition shall equal the calculated amount below; provided however, BPA may adjust

AUG 2 3 2011

the calculated amount below to reflect the division of Dedicated Resources between the utilities and other pertinent information advanced by Surprise Valley and the other utility:

$$\left[\frac{\text{Annexed Load minus annexed NLSLs, if any}}{\text{Other utility's pre-annexation Total Retail Load minus total NLSLs, if any}} \right] \times \left[\text{Other utility's pre-annexation CHWM} \right]$$

Any change to Surprise Valley's CHWM related to the acquisition of an Annexed Load is subject to section 24.8 of the body of this Agreement.

1.2.3 If another utility with a CHWM annexes load of Surprise Valley, then BPA shall reduce Surprise Valley's CHWM by adding part of Surprise Valley's CHWM to the other utility's CHWM. The CHWM reduction shall be effective on the date that the other utility begins service to the Annexed Load. BPA shall establish the amount of the CHWM reduction as follows:

(1) If Surprise Valley and the other utility involved in the annexation agree on the amount of the CHWM reduction, then BPA shall adopt that amount if BPA determines such amount is reasonable.

(2) If Surprise Valley and the other utility cannot agree on the amount of the CHWM reduction, or if BPA determines the amount agreed to in 1.2.3(1) of this exhibit is unreasonable, then the amount of the CHWM reduction shall equal the calculated amount below; provided however, BPA may adjust the calculated amount below to reflect the division of Dedicated Resources between the utilities and other pertinent information advanced by Surprise Valley and the other utility:

$$\left[\frac{\text{Annexed Load minus annexed NLSLs, if any}}{\text{Surprise Valley's pre-annexation Total Retail Load minus total NLSLs, if any}} \right] \times \left[\text{Surprise Valley's pre-annexation CHWM} \right]$$

1.2.4 BPA may change Surprise Valley's CHWM if BPA's Administrator determines that BPA is required by court order about an Annexed Load to make such changes. BPA shall determine the effective date of such a change and shall update this exhibit with the changed CHWM.

2. CONTRACT DEMAND QUANTITIES (CDQs)

2.1 CDQ Amounts

By September 15, 2011, BPA shall fill in the table below with Surprise Valley's monthly CDQs. Calculation of such CDQs is established in the TRM.

Surprise Valley's monthly CDQs shall not change for the term of this Agreement except as allowed below.

Monthly Contract Demand Quantities												
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
kW	**2268**	**4354**	**3607**	**3738**	**3681**	**3288**	**4153**	**5566**	**5437**	**1651**	**522**	**5281**
Note: BPA shall round the amounts in the table above to the nearest whole kilowatt.												

2.2 **Changes Due to Annexation**
The Parties shall determine when changes to Surprise Valley's CDQs, as allowed below, will become effective.

2.2.1 If Surprise Valley acquires an Annexed Load from a utility that has monthly CDQs, then BPA shall increase Surprise Valley's CDQ for each month by adding the portion of the other utility's monthly CDQ that is attributable to such Annexed Load. For each month, the sum of Surprise Valley's and the other utility's post-annexation CDQs shall not exceed the sum of the pre-annexation CDQs for such utilities. BPA shall establish the amount of the CDQ additions as follows:

(1) If Surprise Valley and the other utility involved in the annexation agree on the amounts of the CDQ additions, then BPA shall adopt those amounts.

(2) If Surprise Valley and the other utility cannot agree on the amounts of the CDQ additions, then BPA shall determine the amounts based on the monthly load factors of the Annexed Load.

2.2.2 If another utility with monthly CDQs annexes load of Surprise Valley, then BPA shall reduce Surprise Valley's CDQ for each month by removing the portion of Surprise Valley's monthly CDQ that is attributable to the load that was annexed. For each month, the sum of Surprise Valley's and the other utility's post-annexation CDQs shall not exceed the sum of the pre-annexation CDQs for such utilities. BPA shall establish the amount of the CDQ reductions as follows:

(1) If Surprise Valley and the other utility involved in the annexation agree on the amounts of the CDQ reductions, then BPA shall adopt those amounts.

(2) If Surprise Valley and the other utility cannot agree on the amounts of the CDQ reductions, then BPA shall determine the amounts based on the monthly load factors of the Annexed Load.

3. REVISIONS

BPA may revise this exhibit to the extent allowed in sections 1 and 2 of this exhibit. All other changes shall be made by mutual agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110 Exh B R 1.DOC) 07/25/11

Revision No. 2, Exhibit C
PURCHASE OBLIGATIONS
Effective March 31, 2012

This revision updates sections 2.4.1.1 and 2.4.1.3 to add Surprise Valley's election regarding service to its Above-RHWM Load for the second Purchase Period (FY 2015 - FY 2019).

1. FIRM REQUIREMENTS POWER AT TIER 1 RATES

The portion of Surprise Valley's purchase obligation that is priced at Tier 1 Rates is established in section 8.1(1) of the body of this Agreement.

2. FIRM REQUIREMENTS POWER AT TIER 2 RATES

2.1 Notice to Purchase Zero Amounts at Tier 2 Rates

If Surprise Valley elects not to purchase Firm Requirements Power at Tier 2 Rates for a Purchase Period, then by March 31 immediately following the corresponding Notice Deadline, BPA shall update this exhibit to indicate such election by adding an "X" to the applicable cell in the following table. Such election means that for the Purchase Period specified below, Surprise Valley shall: (1) purchase zero amounts of Firm Requirements Power at Tier 2 Rates, and (2) serve all of its Above-RHWM Load that is greater than or equal to 8,760 megawatt-hours with power other than Firm Requirements Power. Surprise Valley may serve its Above-RHWM Load that is less than 8,760 megawatt-hours with power other than Firm Requirements Power.

Zero Tier 2	Purchase Period
	FY 2012 - FY 2014
	FY 2015 - FY 2019
	FY 2020 - FY 2024
	FY 2025 - FY 2028

2.2 Tier 2 Load Growth Rate

2.2.1 First Election Opportunity

If Surprise Valley elects by the first Notice Deadline (November 1, 2009) to purchase Firm Requirements Power at Tier 2 Load Growth Rates starting October 1, 2011, then in its election Surprise Valley shall elect one of the three Tier 2 Load Growth Rate options listed in section 2.2.3 of this exhibit. If Surprise Valley elects Option 3, then Surprise Valley shall state the amounts to be listed in the table in section 2.2.3.3 of this exhibit and Surprise Valley's Tier 2 Short-Term Rate election pursuant to section 2.4.1 of this exhibit. BPA shall amend this exhibit by March 31, 2010, to indicate Surprise Valley's election by adding an "X" to the "1st Notice Deadline" box next to the applicable option below. If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates by the first Notice Deadline, then Surprise Valley shall not have the right to

purchase Firm Requirements Power at Tier 2 Load Growth Rates during the first Purchase Period.

2.2.2 **Second Election Opportunity**

2.2.2.1 If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates starting the first Purchase Period, then Surprise Valley may purchase Firm Requirements Power at Tier 2 Load Growth Rates starting October 1, 2014, provided:

(1) any elections of Tier 2 Rate alternatives or additions of New Resources under this Agreement that extend beyond the initial Purchase Period shall continue to apply for their term, and

(2) the Tier 2 Load Growth Rate applicable under this election may be different than the Tier 2 Load Growth Rate that was available during the first Purchase Period.

2.2.2.2 If Surprise Valley elects by the second Notice Deadline (September 30, 2011) to purchase Firm Requirements Power at Tier 2 Load Growth Rates, then in its election Surprise Valley shall elect one of the three Tier 2 Load Growth Rate options listed in section 2.2.3 of this exhibit. In such case, Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates under such elected option starting October 1, 2014.

2.2.2.3 If Surprise Valley elects Option 3, described in section 2.2.3.3 of this exhibit, then Surprise Valley shall state the amounts to be listed in the table in section 2.2.3.3 of this exhibit and Surprise Valley's Tier 2 Short-Term Rate election pursuant to section 2.4.1 of this exhibit. If Surprise Valley has prior elections of rate alternatives or resource additions that extend beyond the first Purchase Period, then Surprise Valley shall not have the right to elect Options 1 or 2 below. In such case, the amounts listed in the table in section 2.2.3.3 of this exhibit shall not be less than the sum of Surprise Valley's prior elections for each year.

2.2.2.4 BPA shall amend this exhibit by March 31, 2012, to indicate Surprise Valley's election by adding an "X" to the "2nd Notice Deadline" box next to the applicable option below. If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates by the second Notice Deadline, then Surprise Valley shall not purchase Firm Requirements

Power at Tier 2 Load Growth Rates for the term of this Agreement.

2.2.3 **Tier 2 Load Growth Rate Options**

1st Notice Deadline ☐ 2.2.3.1 **Option 1 - Full Tier 2 Load Growth Rate**
2nd Notice Deadline ☐
If Surprise Valley elects this option, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load.

1st Notice Deadline ☐ 2.2.3.2 **Option 2 - Shared Rate Plan**
2nd Notice Deadline ☐

(1) **Obligation**
If Surprise Valley elects this option, provided that BPA determines Surprise Valley qualifies under the limit for the Shared Rate Plan as established in section 7 of the TRM, then Surprise Valley shall pay rates under the Shared Rate Plan for Firm Requirements Power purchased under this Agreement. If BPA determines Surprise Valley does not qualify under such limit, then Surprise Valley shall not have the right to elect this option and Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates under Option 1 as established in section 2.2.3.1 of this exhibit. For the second election opportunity stated in section 2.2.2 of this exhibit, availability under the limit for the Shared Rate Plan established in section 7 of the TRM shall equal such limit minus the amounts used by other customers who elected this Option 2 by the first Notice Deadline.

(2) **Terminating Participation**
Surprise Valley may terminate participation in the Shared Rate Plan by providing BPA notice in writing by March 31 of a Forecast Year. In such case, the change shall be effective the next Rate Period. If Surprise Valley stops participation in the Shared Rate Plan, then Surprise Valley shall not have the right to resume participation. Surprise Valley shall continue to purchase Firm Requirements Power priced at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load.

1st Notice Deadline ☐ 2.2.3.3 **Option 3 - Partial Tier 2 Load Growth Rate**
2nd Notice Deadline ☐
If Surprise Valley elects this option, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load minus the amounts stated in the table below that Surprise Valley elects are not subject to Tier 2 Load Growth Rates. Surprise Valley

shall establish such amounts at the time Surprise Valley elects this option and such amounts shall not change for the term of this Agreement. Surprise Valley may serve such amounts with Dedicated Resources or with Firm Requirements Power purchased at other Tier 2 Rates. BPA shall update the table below by March 31 immediately following Surprise Valley's election of this option.

Load Amounts Not Subject To Tier 2 Load Growth Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW									
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

2.2.4 **Modification to Tier 2 Load Growth Rate Election**

2.2.4.1 **Notice**
Surprise Valley shall have the right to stop purchasing Firm Requirements Power at Tier 2 Load Growth Rates effective the upcoming Rate Period, except for the amount established in section 2.2.4.2 of this exhibit. If Surprise Valley chooses to modify its purchases at Tier 2 Load Growth Rates in this manner, then Surprise Valley shall notify BPA in writing by October 31 of a Rate Case Year.

2.2.4.2 **Continued Purchase Amount**
For the remaining term of this Agreement, Surprise Valley shall continue to purchase at Tier 2 Load Growth Rates the amount of Firm Requirements Power that Surprise Valley purchased at Tier 2 Load Growth Rates the year before the modification described above is effective.

2.2.4.3 **Obligation to Apply Dedicated Resources**
If Surprise Valley provides notice to modify its purchases at Tier 2 Load Growth Rates under section 2.2.4.1 of this exhibit, then for the remainder of the effective Purchase Period and all of the next Purchase Period, Surprise Valley shall apply Dedicated Resources to serve all of its Above-RHWM Load that is in excess of the sum of all Tier 2 commitments.

2.2.4.4 **Charges to Modify Tier 2 Load Growth Rate Purchase**
Surprise Valley shall be liable for payment of any costs that apply as a result of Surprise Valley modifying its Tier 2 Load Growth Rate purchase obligation under this section 2.2.4. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley at Tier 2 Load Growth Rates as a result of the modification, and (2) is unable to recover through other transactions.

BPA shall determine such costs, if any, during the 7(i) Process that follows Surprise Valley's notice. If BPA determines that Surprise Valley owes payment for such costs, then Surprise Valley shall pay the entire amount to BPA in no more than 24 equal monthly amounts starting the first month of the upcoming Rate Period. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley modifying its Tier 2 Load Growth Rate purchase obligation under this section 2.2.4.

2.2.4.5 **Exhibit Update**
By March 31 following Surprise Valley's notice, BPA shall indicate Surprise Valley's election to modify its Tier 2 Load Growth Rate purchase by filling in the table below. As established in section 2.2.4.2 of this exhibit, Surprise Valley shall continue to purchase the following amounts of Firm Requirements Power at Tier 2 Load Growth Rates:

Continuing Tier 2 Load Growth Rates Purchase Obligation					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
aMW					
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
aMW					
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
aMW					
Fiscal Year	**2027**	**2028**			
aMW					
Note: Fill in the table above with annual Average Megawatts, rounded to three decimal places, for each year that follows Surprise Valley's modification beginning with the effective year of modification					

2.3 **Tier 2 Vintage Rates**
If Surprise Valley elects Option 1 or 2 in section 2.2.3 of this exhibit, then this section shall not apply. Otherwise:

2.3.1 **Election Process**

2.3.1.1 **Right to Convert**
Subject to the amounts of power BPA makes available at one or more Tier 2 Vintage Rates, Surprise Valley shall have the right to convert some or all of the amounts of Firm Requirements Power it has elected to purchase at Tier 2 Short-Term Rates, as stated in section 2.4 of this exhibit, to an equal purchase amount at Tier 2 Vintage Rates.

2.3.1.2 **Statement of Intent**
If Surprise Valley elects to purchase Firm Requirements Power from BPA at Tier 2 Vintage Rates, then Surprise Valley shall sign a Statement of Intent offered by BPA. "Statement of Intent" means a statement prepared by BPA

and signed by Surprise Valley that describes the approach and cost structure that will be used for a specific Tier 2 Cost Pool. If BPA establishes a Tier 2 Cost Pool for a Tier 2 Vintage Rate consistent with the Statement of Intent, then Surprise Valley agrees to have the portion of its Tier 2 Rate power purchase specified in the Statement of Intent priced at that rate. If BPA is unable to establish the Tier 2 Cost Pool for the specific Tier 2 Vintage Rate, then Surprise Valley agrees to purchase such amount of Firm Requirements Power at Tier 2 Short-Term Rates, except as stated in section 2.3.1.5 of this exhibit.

2.3.1.3 **Insufficient Availability**
The Statement of Intent shall include procedures to allocate between competing applications for a specific Tier 2 Cost Pool if requests exceed amounts available.

2.3.1.4 **Conversion Costs**
Upon establishment of a Tier 2 Vintage Rate for which Surprise Valley signed a Statement of Intent, Surprise Valley shall be liable for payment of any outstanding costs under Tier 2 Short-Term Rates that apply to Surprise Valley. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley under Tier 2 Short-Term Rates as a result of the conversion, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, in the first 7(i) Process that establishes the applicable Tier 2 Vintage Rate. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley's conversion of purchase amounts at Tier 2 Short-Term Rates to purchase amounts at Tier 2 Vintage Rates.

2.3.1.5 **Additional Offerings**
In addition to the right to convert to Tier 2 Vintage Rates established in section 2.3.1.1 of this exhibit, Surprise Valley may have the opportunity to purchase Firm Requirements Power at Tier 2 Vintage Rates regardless of whether Surprise Valley is purchasing at Tier 2 Short-Term Rates if:

(1) BPA determines, in its sole discretion, that all requests for service at Tier 2 Vintage Rates by purchasers of Firm Requirements Power at Tier 2 Short-Term Rates are able to be satisfied, and

(2) BPA determines, in its sole discretion, to offer Surprise Valley a Statement of Intent that would provide Surprise Valley the opportunity to purchase Firm Requirements at Tier 2 Vintage Rates.

If Surprise Valley signs a Statement of Intent offered by BPA pursuant to this section 2.3.1.5, and if BPA is unable to establish the Tier 2 Cost Pool for the applicable Tier 2 Vintage Rate, then Surprise Valley's current elections for service to its Above-RHWM Load shall continue to apply.

Except as provided in this section 2.3.1, any election by Surprise Valley to purchase Firm Requirements Power at Tier 2 Vintage Rates shall not relieve Surprise Valley of any obligation to purchase Firm Requirements Power at another Tier 2 Rate.

2.3.1.6 **Exhibit Updates**
By September 15 immediately following the establishment of a Tier 2 Vintage Rate for which Surprise Valley signed a Statement of Intent, BPA shall amend this exhibit to show Surprise Valley's Tier 2 Vintage Rate purchases and remove Surprise Valley's Tier 2 Short-Term Rate purchases by the amounts purchased at the Tier 2 Vintage Rate, if Surprise Valley is converting to the Tier 2 Vintage Rate from the Tier 2 Short-Term Rate. BPA shall insert applicable tables, terms, and conditions for each Tier 2 Vintage Rate in section 2.3.2 of this exhibit.

2.3.2 **Vintage Rate Elections**
Surprise Valley has no Tier 2 Vintage Rate elections at this time.

2.4 **Tier 2 Short-Term Rate**
If Surprise Valley elects Option 1 or 2 in section 2.2.3 of this exhibit, then this section shall not apply. Otherwise:

2.4.1 **Short-Term Rate Purchases**
Unless Surprise Valley elects, in section 2.1 of this exhibit, not to purchase Firm Requirements Power at Tier 2 Rates for a given Purchase Period, by each Notice Deadline Surprise Valley shall elect in writing either Alternative A or B below for the duration of the corresponding Purchase Period. If Surprise Valley elects Alternative A and elects to apply Dedicated Resources to serve its Above-RHWM Load, then Surprise Valley shall state the amounts to be listed in the table in section 2.4.1.1(2) of this exhibit. If Surprise Valley elects Alternative B, then Surprise Valley shall state the amounts to be listed in the table in section 2.4.1.3 of this exhibit. By March 31 immediately following each Notice Deadline, BPA shall update the tables in this section 2.4.1 to show Surprise Valley's Tier 2 Short-Term Rate election for the corresponding Purchase Period.

2.4.1.1 **Alternative A – Customer Planned Load Not Otherwise Served**
If Surprise Valley elects this alternative, then Surprise Valley shall purchase Firm Requirements Power priced at Tier 2 Short-Term Rates to serve all of Surprise Valley's Above-RHWM Load that Surprise Valley has not otherwise agreed to serve with:

(1) Firm Requirements Power purchased at other Tier 2 Rates, or

(2) the amounts of Dedicated Resources, stated in the table below, that Surprise Valley shall apply during the Purchase Period to serve its Above-RHWM Load. If Surprise Valley purchases power at Tier 2 Load Growth Rates, then these Dedicated Resource amounts shall not exceed the amounts stated in the table in section 2.2.3.3 of this exhibit.

Purchase Period Dedicated Resource Elections					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
Election	0.000	0.000	0.000	0.000	0.000
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
Election	0.000	0.000	0.000		
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
Election					
Fiscal Year	**2027**	**2028**			
Election					
Note: Insert amounts in Average Megawatts rounded to three decimal places for each year of the applicable Purchase Period.					

2.4.1.2 **Alternative B – Limited Amounts**
If Surprise Valley elects this alternative, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Short-Term Rates to serve Surprise Valley's Above-RHWM Load that Surprise Valley has not otherwise agreed to serve with Firm Requirements Power purchased at other Tier 2 Rates; provided however, that amounts purchased at Tier 2 Short-Term Rates shall not exceed the amounts (including zero amounts) stated in the table in section 2.4.1.3 of this exhibit. Surprise Valley agrees to serve any of its remaining Above-RHWM Load with power other than Firm Requirements Power.

2.4.1.3 **Tier 2 Short-Term Rate Elections**
If Surprise Valley elects Alternative A above, then BPA shall indicate that election by adding an "X" to the table below for each year of the applicable Purchase Period. If Surprise

Valley elects Alternative B above, then BPA shall indicate that election by adding amounts (in Average Megawatts rounded to three decimal places) to the table below for each year of the applicable Purchase Period.

Tier 2 Short-Term Rate Table					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
Election	X	X	X	X	X
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
Election	X	X	X		
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
Election					
Fiscal Year	**2027**	**2028**			
Election					

2.4.2 **Right to Reduce Tier 2 Short-Term Rate Purchase Amounts**

2.4.2.1 **Notice**
If Surprise Valley notifies BPA in writing by October 31 of a Rate Case Year, then Surprise Valley may reduce, in equal amounts for all hours of the year, some or all of the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates. The reduction may take effect in either year of the upcoming Rate Period and shall be effective for the remaining duration of the applicable Purchase Period(s). In its written notice, Surprise Valley shall state the amount of the reduction and the date the reduction shall take effect. Surprise Valley shall replace all reduced Tier 2 Short-Term Rate purchase amounts with amounts of Dedicated Resources applied pursuant to section 3.3 of the body of this Agreement.

2.4.2.2 **Charges to Reduce Purchase Amounts**
Surprise Valley shall be liable for payment of any costs that apply as a result of Surprise Valley reducing, under section 2.4.2.1 of this exhibit, the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley under Tier 2 Short-Term Rates as a result of the reduction, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, during the 7(i) Process that follows Surprise Valley's notice. If BPA determines that Surprise Valley owes payment for such costs, then Surprise Valley shall pay the entire amount to BPA in no more than 24 equal monthly amounts starting the first month of the upcoming Rate Period. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley reducing the amounts of Firm Requirements

Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates.

2.4.2.3 **Exhibit Updates**
By March 31 following Surprise Valley's notice, BPA shall revise this exhibit and Exhibit A to show Surprise Valley's reduced Tier 2 Short-Term Rate purchase amounts and Surprise Valley's Dedicated Resource additions.

2.5 **Amounts of Power to be Billed at Tier 2 Rates**

2.5.1 **Treatment for FY 2012 – FY 2013**
By March 31, 2010, BPA shall update the table in section 2.5.2 of this exhibit, consistent with Surprise Valley's elections, with amounts of Firm Requirements Power which Surprise Valley shall purchase at applicable Tier 2 Rates for the FY 2012 – FY 2013 Rate Period.

2.5.2 **Amounts of Power for Subsequent Rate Periods**
For each Rate Period after the FY 2012 – FY 2013 Rate Period, BPA shall establish for the upcoming Rate Period consistent with Surprise Valley's elections: (1) the planned annual average amounts of Firm Requirements Power which Surprise Valley shall purchase at applicable Tier 2 Rates, and (2) any remarketed Tier 2 Rate purchase amounts in accordance with section 10 of the body of this Agreement. By March 31, 2013, and by March 31 of each Rate Case Year thereafter, BPA shall update the table below with such amounts for each year of the upcoming Rate Period.

Annual Amounts Priced at Tier 2 Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Tier 2 Short-Term Rate	0.000	0.000							
Remarketed Amounts									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
No Tier 2 at this time									
Remarketed Amounts									

Notes:
1. List each applicable Tier 2 rate in the table above. For the first applicable Tier 2 rate replace **No Tier 2 at this time** with the name of the applicable Tier 2 rate. For each additional Tier 2 rate, add a new row above the **Remarketed Amounts** row. If Surprise Valley elects not to purchase at Tier 2 rates, then leave **No Tier 2 at this time** in the table and leave the remainder of the table blank.
2. Fill in the table above with annual Average Megawatts rounded to three decimal places.

3. MONTHLY PF RATES

Applicable monthly Tier 1 and Tier 2 Rates are specified in BPA Wholesale Power Rate Schedules and GRSPs.

4. REVISIONS

BPA shall revise this exhibit to reflect Surprise Valley's elections regarding service to its Above-RHWM Load and BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110 EXH C R2.DOC) 03/12/12

Revision No. 3, Exhibit C
PURCHASE OBLIGATIONS
Effective March 31, 2013

This revision updates section 2.5.2 to add Surprise Valley's Tier 2 purchase amounts for the FY 2014 – FY 2015 Rate Period.

1. FIRM REQUIREMENTS POWER AT TIER 1 RATES
The portion of Surprise Valley's purchase obligation that is priced at Tier 1 Rates is established in section 8.1(1) of the body of this Agreement.

2. FIRM REQUIREMENTS POWER AT TIER 2 RATES

2.1 **Notice to Purchase Zero Amounts at Tier 2 Rates**
If Surprise Valley elects not to purchase Firm Requirements Power at Tier 2 Rates for a Purchase Period, then by March 31 immediately following the corresponding Notice Deadline, BPA shall update this exhibit to indicate such election by adding an "X" to the applicable cell in the following table. Such election means that for the Purchase Period specified below, Surprise Valley shall: (1) purchase zero amounts of Firm Requirements Power at Tier 2 Rates, and (2) serve all of its Above-RHWM Load that is greater than or equal to 8,760 megawatt-hours with power other than Firm Requirements Power. Surprise Valley may serve its Above-RHWM Load that is less than 8,760 megawatt-hours with power other than Firm Requirements Power.

Zero Tier 2	Purchase Period
	FY 2012 - FY 2014
	FY 2015 - FY 2019
	FY 2020 - FY 2024
	FY 2025 - FY 2028

2.2 **Tier 2 Load Growth Rate**

2.2.1 **First Election Opportunity**
If Surprise Valley elects by the first Notice Deadline (November 1, 2009) to purchase Firm Requirements Power at Tier 2 Load Growth Rates starting October 1, 2011, then in its election Surprise Valley shall elect one of the three Tier 2 Load Growth Rate options listed in section 2.2.3 of this exhibit. If Surprise Valley elects Option 3, then Surprise Valley shall state the amounts to be listed in the table in section 2.2.3.3 of this exhibit and Surprise Valley's Tier 2 Short-Term Rate election pursuant to section 2.4.1 of this exhibit. BPA shall amend this exhibit by March 31, 2010, to indicate Surprise Valley's election by adding an "X" to the "1st Notice Deadline" box next to the applicable option below. If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates by the first Notice Deadline, then Surprise Valley shall not have the right to

purchase Firm Requirements Power at Tier 2 Load Growth Rates during the first Purchase Period.

2.2.2 **Second Election Opportunity**

2.2.2.1 If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates starting the first Purchase Period, then Surprise Valley may purchase Firm Requirements Power at Tier 2 Load Growth Rates starting October 1, 2014, provided:

(1) any elections of Tier 2 Rate alternatives or additions of New Resources under this Agreement that extend beyond the initial Purchase Period shall continue to apply for their term, and

(2) the Tier 2 Load Growth Rate applicable under this election may be different than the Tier 2 Load Growth Rate that was available during the first Purchase Period.

2.2.2.2 If Surprise Valley elects by the second Notice Deadline (September 30, 2011) to purchase Firm Requirements Power at Tier 2 Load Growth Rates, then in its election Surprise Valley shall elect one of the three Tier 2 Load Growth Rate options listed in section 2.2.3 of this exhibit. In such case, Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates under such elected option starting October 1, 2014.

2.2.2.3 If Surprise Valley elects Option 3, described in section 2.2.3.3 of this exhibit, then Surprise Valley shall state the amounts to be listed in the table in section 2.2.3.3 of this exhibit and Surprise Valley's Tier 2 Short-Term Rate election pursuant to section 2.4.1 of this exhibit. If Surprise Valley has prior elections of rate alternatives or resource additions that extend beyond the first Purchase Period, then Surprise Valley shall not have the right to elect Options 1 or 2 below. In such case, the amounts listed in the table in section 2.2.3.3 of this exhibit shall not be less than the sum of Surprise Valley's prior elections for each year.

2.2.2.4 BPA shall amend this exhibit by March 31, 2012, to indicate Surprise Valley's election by adding an "X" to the "2nd Notice Deadline" box next to the applicable option below. If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates by the second Notice Deadline, then Surprise Valley shall not purchase Firm Requirements

Power at Tier 2 Load Growth Rates for the term of this Agreement.

2.2.3 **Tier 2 Load Growth Rate Options**

1st Notice Deadline ☐
2nd Notice Deadline ☐

2.2.3.1 **Option 1 - Full Tier 2 Load Growth Rate**
If Surprise Valley elects this option, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load.

1st Notice Deadline ☐
2nd Notice Deadline ☐

2.2.3.2 **Option 2 - Shared Rate Plan**

(1) **Obligation**
If Surprise Valley elects this option, provided that BPA determines Surprise Valley qualifies under the limit for the Shared Rate Plan as established in section 7 of the TRM, then Surprise Valley shall pay rates under the Shared Rate Plan for Firm Requirements Power purchased under this Agreement. If BPA determines Surprise Valley does not qualify under such limit, then Surprise Valley shall not have the right to elect this option and Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates under Option 1 as established in section 2.2.3.1 of this exhibit. For the second election opportunity stated in section 2.2.2 of this exhibit, availability under the limit for the Shared Rate Plan established in section 7 of the TRM shall equal such limit minus the amounts used by other customers who elected this Option 2 by the first Notice Deadline.

(2) **Terminating Participation**
Surprise Valley may terminate participation in the Shared Rate Plan by providing BPA notice in writing by March 31 of a Forecast Year. In such case, the change shall be effective the next Rate Period. If Surprise Valley stops participation in the Shared Rate Plan, then Surprise Valley shall not have the right to resume participation. Surprise Valley shall continue to purchase Firm Requirements Power priced at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load.

1st Notice Deadline ☐
2nd Notice Deadline ☐

2.2.3.3 **Option 3 - Partial Tier 2 Load Growth Rate**
If Surprise Valley elects this option, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load minus the amounts stated in the table below that Surprise Valley elects are not subject to Tier 2 Load Growth Rates. Surprise Valley

shall establish such amounts at the time Surprise Valley elects this option and such amounts shall not change for the term of this Agreement. Surprise Valley may serve such amounts with Dedicated Resources or with Firm Requirements Power purchased at other Tier 2 Rates. BPA shall update the table below by March 31 immediately following Surprise Valley's election of this option.

Load Amounts Not Subject To Tier 2 Load Growth Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW									
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

2.2.4 **Modification to Tier 2 Load Growth Rate Election**

2.2.4.1 **Notice**
Surprise Valley shall have the right to stop purchasing Firm Requirements Power at Tier 2 Load Growth Rates effective the upcoming Rate Period, except for the amount established in section 2.2.4.2 of this exhibit. If Surprise Valley chooses to modify its purchases at Tier 2 Load Growth Rates in this manner, then Surprise Valley shall notify BPA in writing by October 31 of a Rate Case Year.

2.2.4.2 **Continued Purchase Amount**
For the remaining term of this Agreement, Surprise Valley shall continue to purchase at Tier 2 Load Growth Rates the amount of Firm Requirements Power that Surprise Valley purchased at Tier 2 Load Growth Rates the year before the modification described above is effective.

2.2.4.3 **Obligation to Apply Dedicated Resources**
If Surprise Valley provides notice to modify its purchases at Tier 2 Load Growth Rates under section 2.2.4.1 of this exhibit, then for the remainder of the effective Purchase Period and all of the next Purchase Period, Surprise Valley shall apply Dedicated Resources to serve all of its Above-RHWM Load that is in excess of the sum of all Tier 2 commitments.

2.2.4.4 **Charges to Modify Tier 2 Load Growth Rate Purchase**
Surprise Valley shall be liable for payment of any costs that apply as a result of Surprise Valley modifying its Tier 2 Load Growth Rate purchase obligation under this section 2.2.4. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley at Tier 2 Load Growth Rates as a result of the modification, and (2) is unable to recover through other transactions.

BPA shall determine such costs, if any, during the 7(i) Process that follows Surprise Valley's notice. If BPA determines that Surprise Valley owes payment for such costs, then Surprise Valley shall pay the entire amount to BPA in no more than 24 equal monthly amounts starting the first month of the upcoming Rate Period. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley modifying its Tier 2 Load Growth Rate purchase obligation under this section 2.2.4.

2.2.4.5 **Exhibit Update**
By March 31 following Surprise Valley's notice, BPA shall indicate Surprise Valley's election to modify its Tier 2 Load Growth Rate purchase by filling in the table below. As established in section 2.2.4.2 of this exhibit, Surprise Valley shall continue to purchase the following amounts of Firm Requirements Power at Tier 2 Load Growth Rates:

Continuing Tier 2 Load Growth Rates Purchase Obligation					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
aMW					
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
aMW					
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
aMW					
Fiscal Year	**2027**	**2028**			
aMW					
Note: Fill in the table above with annual Average Megawatts, rounded to three decimal places, for each year that follows Surprise Valley's modification beginning with the effective year of modification					

2.3 **Tier 2 Vintage Rates**
If Surprise Valley elects Option 1 or 2 in section 2.2.3 of this exhibit, then this section shall not apply. Otherwise:

2.3.1 **Election Process**

2.3.1.1 **Right to Convert**
Subject to the amounts of power BPA makes available at one or more Tier 2 Vintage Rates, Surprise Valley shall have the right to convert some or all of the amounts of Firm Requirements Power it has elected to purchase at Tier 2 Short-Term Rates, as stated in section 2.4 of this exhibit, to an equal purchase amount at Tier 2 Vintage Rates.

2.3.1.2 **Statement of Intent**
If Surprise Valley elects to purchase Firm Requirements Power from BPA at Tier 2 Vintage Rates, then Surprise Valley shall sign a Statement of Intent offered by BPA. "Statement of Intent" means a statement prepared by BPA

and signed by Surprise Valley that describes the approach and cost structure that will be used for a specific Tier 2 Cost Pool. If BPA establishes a Tier 2 Cost Pool for a Tier 2 Vintage Rate consistent with the Statement of Intent, then Surprise Valley agrees to have the portion of its Tier 2 Rate power purchase specified in the Statement of Intent priced at that rate. If BPA is unable to establish the Tier 2 Cost Pool for the specific Tier 2 Vintage Rate, then Surprise Valley agrees to purchase such amount of Firm Requirements Power at Tier 2 Short-Term Rates, except as stated in section 2.3.1.5 of this exhibit.

2.3.1.3 **Insufficient Availability**
The Statement of Intent shall include procedures to allocate between competing applications for a specific Tier 2 Cost Pool if requests exceed amounts available.

2.3.1.4 **Conversion Costs**
Upon establishment of a Tier 2 Vintage Rate for which Surprise Valley signed a Statement of Intent, Surprise Valley shall be liable for payment of any outstanding costs under Tier 2 Short-Term Rates that apply to Surprise Valley. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley under Tier 2 Short-Term Rates as a result of the conversion, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, in the first 7(i) Process that establishes the applicable Tier 2 Vintage Rate. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley's conversion of purchase amounts at Tier 2 Short-Term Rates to purchase amounts at Tier 2 Vintage Rates.

2.3.1.5 **Additional Offerings**
In addition to the right to convert to Tier 2 Vintage Rates established in section 2.3.1.1 of this exhibit, Surprise Valley may have the opportunity to purchase Firm Requirements Power at Tier 2 Vintage Rates regardless of whether Surprise Valley is purchasing at Tier 2 Short-Term Rates if:

(1) BPA determines, in its sole discretion, that all requests for service at Tier 2 Vintage Rates by purchasers of Firm Requirements Power at Tier 2 Short-Term Rates are able to be satisfied, and

(2) BPA determines, in its sole discretion, to offer Surprise Valley a Statement of Intent that would provide Surprise Valley the opportunity to purchase Firm Requirements at Tier 2 Vintage Rates.

If Surprise Valley signs a Statement of Intent offered by BPA pursuant to this section 2.3.1.5, and if BPA is unable to establish the Tier 2 Cost Pool for the applicable Tier 2 Vintage Rate, then Surprise Valley's current elections for service to its Above-RHWM Load shall continue to apply.

Except as provided in this section 2.3.1, any election by Surprise Valley to purchase Firm Requirements Power at Tier 2 Vintage Rates shall not relieve Surprise Valley of any obligation to purchase Firm Requirements Power at another Tier 2 Rate.

2.3.1.6 **Exhibit Updates**
By September 15 immediately following the establishment of a Tier 2 Vintage Rate for which Surprise Valley signed a Statement of Intent, BPA shall amend this exhibit to show Surprise Valley's Tier 2 Vintage Rate purchases and remove Surprise Valley's Tier 2 Short-Term Rate purchases by the amounts purchased at the Tier 2 Vintage Rate, if Surprise Valley is converting to the Tier 2 Vintage Rate from the Tier 2 Short-Term Rate. BPA shall insert applicable tables, terms, and conditions for each Tier 2 Vintage Rate in section 2.3.2 of this exhibit.

2.3.2 **Vintage Rate Elections**
Surprise Valley has no Tier 2 Vintage Rate elections at this time.

2.4 **Tier 2 Short-Term Rate**
If Surprise Valley elects Option 1 or 2 in section 2.2.3 of this exhibit, then this section shall not apply. Otherwise:

2.4.1 **Short-Term Rate Purchases**
Unless Surprise Valley elects, in section 2.1 of this exhibit, not to purchase Firm Requirements Power at Tier 2 Rates for a given Purchase Period, by each Notice Deadline Surprise Valley shall elect in writing either Alternative A or B below for the duration of the corresponding Purchase Period. If Surprise Valley elects Alternative A and elects to apply Dedicated Resources to serve its Above-RHWM Load, then Surprise Valley shall state the amounts to be listed in the table in section 2.4.1.1(2) of this exhibit. If Surprise Valley elects Alternative B, then Surprise Valley shall state the amounts to be listed in the table in section 2.4.1.3 of this exhibit. By March 31 immediately following each Notice Deadline, BPA shall update the tables in this section 2.4.1 to show Surprise Valley's Tier 2 Short-Term Rate election for the corresponding Purchase Period.

2.4.1.1 **Alternative A – Customer Planned Load Not Otherwise Served**
If Surprise Valley elects this alternative, then Surprise Valley shall purchase Firm Requirements Power priced at Tier 2 Short-Term Rates to serve all of Surprise Valley's Above-RHWM Load that Surprise Valley has not otherwise agreed to serve with:

(1) Firm Requirements Power purchased at other Tier 2 Rates, or

(2) the amounts of Dedicated Resources, stated in the table below, that Surprise Valley shall apply during the Purchase Period to serve its Above-RHWM Load. If Surprise Valley purchases power at Tier 2 Load Growth Rates, then these Dedicated Resource amounts shall not exceed the amounts stated in the table in section 2.2.3.3 of this exhibit.

Purchase Period Dedicated Resource Elections					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
Election	0.000	0.000	0.000	0.000	0.000
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
Election	0.000	0.000	0.000		
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
Election					
Fiscal Year	**2027**	**2028**			
Election					
Note: Insert amounts in Average Megawatts rounded to three decimal places for each year of the applicable Purchase Period.					

2.4.1.2 **Alternative B – Limited Amounts**
If Surprise Valley elects this alternative, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Short-Term Rates to serve Surprise Valley's Above-RHWM Load that Surprise Valley has not otherwise agreed to serve with Firm Requirements Power purchased at other Tier 2 Rates; provided however, that amounts purchased at Tier 2 Short-Term Rates shall not exceed the amounts (including zero amounts) stated in the table in section 2.4.1.3 of this exhibit. Surprise Valley agrees to serve any of its remaining Above-RHWM Load with power other than Firm Requirements Power.

2.4.1.3 **Tier 2 Short-Term Rate Elections**
If Surprise Valley elects Alternative A above, then BPA shall indicate that election by adding an "X" to the table below for each year of the applicable Purchase Period. If Surprise

Valley elects Alternative B above, then BPA shall indicate that election by adding amounts (in Average Megawatts rounded to three decimal places) to the table below for each year of the applicable Purchase Period.

Tier 2 Short-Term Rate Table					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
Election	X	X	X	X	X
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
Election	X	X	X		
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
Election					
Fiscal Year	**2027**	**2028**			
Election					

2.4.2 **Right to Reduce Tier 2 Short-Term Rate Purchase Amounts**

2.4.2.1 **Notice**
If Surprise Valley notifies BPA in writing by October 31 of a Rate Case Year, then Surprise Valley may reduce, in equal amounts for all hours of the year, some or all of the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates. The reduction may take effect in either year of the upcoming Rate Period and shall be effective for the remaining duration of the applicable Purchase Period(s). In its written notice, Surprise Valley shall state the amount of the reduction and the date the reduction shall take effect. Surprise Valley shall replace all reduced Tier 2 Short-Term Rate purchase amounts with amounts of Dedicated Resources applied pursuant to section 3.3 of the body of this Agreement.

2.4.2.2 **Charges to Reduce Purchase Amounts**
Surprise Valley shall be liable for payment of any costs that apply as a result of Surprise Valley reducing, under section 2.4.2.1 of this exhibit, the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley under Tier 2 Short-Term Rates as a result of the reduction, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, during the 7(i) Process that follows Surprise Valley's notice. If BPA determines that Surprise Valley owes payment for such costs, then Surprise Valley shall pay the entire amount to BPA in no more than 24 equal monthly amounts starting the first month of the upcoming Rate Period. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley reducing the amounts of Firm Requirements

Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates.

2.4.2.3 **Exhibit Updates**
By March 31 following Surprise Valley's notice, BPA shall revise this exhibit and Exhibit A to show Surprise Valley's reduced Tier 2 Short-Term Rate purchase amounts and Surprise Valley's Dedicated Resource additions.

2.5 **Amounts of Power to be Billed at Tier 2 Rates**

2.5.1 **Treatment for FY 2012 – FY 2013**
By March 31, 2010, BPA shall update the table in section 2.5.2 of this exhibit, consistent with Surprise Valley's elections, with amounts of Firm Requirements Power which Surprise Valley shall purchase at applicable Tier 2 Rates for the FY 2012 – FY 2013 Rate Period.

2.5.2 **Amounts of Power for Subsequent Rate Periods**
For each Rate Period after the FY 2012 – FY 2013 Rate Period, BPA shall establish for the upcoming Rate Period consistent with Surprise Valley's elections: (1) the planned annual average amounts of Firm Requirements Power which Surprise Valley shall purchase at applicable Tier 2 Rates, and (2) any remarketed Tier 2 Rate purchase amounts in accordance with section 10 of the body of this Agreement. By March 31, 2013, and by March 31 of each Rate Case Year thereafter, BPA shall update the table below with such amounts for each year of the upcoming Rate Period.

Annual Amounts Priced at Tier 2 Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Tier 2 Short-Term Rate	0.000	0.000	0.000	0.000					
Remarketed Amounts									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
No Tier 2 at this time									
Remarketed Amounts									
Notes: 1. List each applicable Tier 2 rate in the table above. For the first applicable Tier 2 rate replace **No Tier 2 at this time** with the name of the applicable Tier 2 rate. For each additional Tier 2 rate, add a new row above the **Remarketed Amounts** row. If Surprise Valley elects not to purchase at Tier 2 rates, then leave **No Tier 2 at this time** in the table and leave the remainder of the table blank. 2. Fill in the table above with annual Average Megawatts rounded to three decimal places.									

3. MONTHLY PF RATES
Applicable monthly Tier 1 and Tier 2 Rates are specified in BPA Wholesale Power Rate Schedules and GRSPs.

4. REVISIONS

BPA shall revise this exhibit to reflect Surprise Valley's elections regarding service to its Above-RHWM Load and BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110 EXH C R3.doc) 03/22/13

Revision No. 4, Exhibit C
PURCHASE OBLIGATIONS
Effective March 31, 2015

AUTHENTICATED

This revision updates section 2.5.2 to add Surprise Valley's Tier 2 purchase amounts for the FY 2016 – FY 2017 Rate Period.

1. FIRM REQUIREMENTS POWER AT TIER 1 RATES

The portion of Surprise Valley's purchase obligation that is priced at Tier 1 Rates is established in section 8.1(1) of the body of this Agreement.

2. FIRM REQUIREMENTS POWER AT TIER 2 RATES

2.1 Notice to Purchase Zero Amounts at Tier 2 Rates

If Surprise Valley elects not to purchase Firm Requirements Power at Tier 2 Rates for a Purchase Period, then by March 31 immediately following the corresponding Notice Deadline, BPA shall update this exhibit to indicate such election by adding an "X" to the applicable cell in the following table. Such election means that for the Purchase Period specified below, Surprise Valley shall: (1) purchase zero amounts of Firm Requirements Power at Tier 2 Rates, and (2) serve all of its Above-RHWM Load that is greater than or equal to 8,760 megawatt-hours with power other than Firm Requirements Power. Surprise Valley may serve its Above-RHWM Load that is less than 8,760 megawatt-hours with power other than Firm Requirements Power.

Zero Tier 2	Purchase Period
	FY 2012 - FY 2014
	FY 2015 - FY 2019
	FY 2020 - FY 2024
	FY 2025 - FY 2028

2.2 Tier 2 Load Growth Rate

2.2.1 First Election Opportunity

If Surprise Valley elects by the first Notice Deadline (November 1, 2009) to purchase Firm Requirements Power at Tier 2 Load Growth Rates starting October 1, 2011, then in its election Surprise Valley shall elect one of the three Tier 2 Load Growth Rate options listed in section 2.2.3 of this exhibit. If Surprise Valley elects Option 3, then Surprise Valley shall state the amounts to be listed in the table in section 2.2.3.3 of this exhibit and Surprise Valley's Tier 2 Short-Term Rate election pursuant to section 2.4.1 of this exhibit. BPA shall amend this exhibit by March 31, 2010, to indicate Surprise Valley's election by adding an "X" to the "1st Notice Deadline" box next to the applicable option below. If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates by the first Notice Deadline, then Surprise Valley shall not have the right to

purchase Firm Requirements Power at Tier 2 Load Growth Rates during the first Purchase Period.

2.2.2 **Second Election Opportunity**

2.2.2.1 If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates starting the first Purchase Period, then Surprise Valley may purchase Firm Requirements Power at Tier 2 Load Growth Rates starting October 1, 2014, provided:

(1) any elections of Tier 2 Rate alternatives or additions of New Resources under this Agreement that extend beyond the initial Purchase Period shall continue to apply for their term, and

(2) the Tier 2 Load Growth Rate applicable under this election may be different than the Tier 2 Load Growth Rate that was available during the first Purchase Period.

2.2.2.2 If Surprise Valley elects by the second Notice Deadline (September 30, 2011) to purchase Firm Requirements Power at Tier 2 Load Growth Rates, then in its election Surprise Valley shall elect one of the three Tier 2 Load Growth Rate options listed in section 2.2.3 of this exhibit. In such case, Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates under such elected option starting October 1, 2014.

2.2.2.3 If Surprise Valley elects Option 3, described in section 2.2.3.3 of this exhibit, then Surprise Valley shall state the amounts to be listed in the table in section 2.2.3.3 of this exhibit and Surprise Valley's Tier 2 Short-Term Rate election pursuant to section 2.4.1 of this exhibit. If Surprise Valley has prior elections of rate alternatives or resource additions that extend beyond the first Purchase Period, then Surprise Valley shall not have the right to elect Options 1 or 2 below. In such case, the amounts listed in the table in section 2.2.3.3 of this exhibit shall not be less than the sum of Surprise Valley's prior elections for each year.

2.2.2.4 BPA shall amend this exhibit by March 31, 2012, to indicate Surprise Valley's election by adding an "X" to the "2nd Notice Deadline" box next to the applicable option below. If Surprise Valley does not elect to purchase Firm Requirements Power at Tier 2 Load Growth Rates by the second Notice Deadline, then Surprise Valley shall not purchase Firm Requirements

Power at Tier 2 Load Growth Rates for the term of this Agreement.

2.2.3 **Tier 2 Load Growth Rate Options**

1st Notice Deadline ☐
2nd Notice Deadline ☐

2.2.3.1 **Option 1 - Full Tier 2 Load Growth Rate**
If Surprise Valley elects this option, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load.

1st Notice Deadline ☐
2nd Notice Deadline ☐

2.2.3.2 **Option 2 - Shared Rate Plan**

(1) **Obligation**
If Surprise Valley elects this option, provided that BPA determines Surprise Valley qualifies under the limit for the Shared Rate Plan as established in section 7 of the TRM, then Surprise Valley shall pay rates under the Shared Rate Plan for Firm Requirements Power purchased under this Agreement. If BPA determines Surprise Valley does not qualify under such limit, then Surprise Valley shall not have the right to elect this option and Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates under Option 1 as established in section 2.2.3.1 of this exhibit. For the second election opportunity stated in section 2.2.2 of this exhibit, availability under the limit for the Shared Rate Plan established in section 7 of the TRM shall equal such limit minus the amounts used by other customers who elected this Option 2 by the first Notice Deadline.

(2) **Terminating Participation**
Surprise Valley may terminate participation in the Shared Rate Plan by providing BPA notice in writing by March 31 of a Forecast Year. In such case, the change shall be effective the next Rate Period. If Surprise Valley stops participation in the Shared Rate Plan, then Surprise Valley shall not have the right to resume participation. Surprise Valley shall continue to purchase Firm Requirements Power priced at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load.

1st Notice Deadline ☐
2nd Notice Deadline ☐

2.2.3.3 **Option 3 - Partial Tier 2 Load Growth Rate**
If Surprise Valley elects this option, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Load Growth Rates for all of Surprise Valley's Above-RHWM Load minus the amounts stated in the table below that Surprise Valley elects are not subject to Tier 2 Load Growth Rates. Surprise Valley

shall establish such amounts at the time Surprise Valley elects this option and such amounts shall not change for the term of this Agreement. Surprise Valley may serve such amounts with Dedicated Resources or with Firm Requirements Power purchased at other Tier 2 Rates. BPA shall update the table below by March 31 immediately following Surprise Valley's election of this option.

Load Amounts Not Subject To Tier 2 Load Growth Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW									
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

2.2.4 **Modification to Tier 2 Load Growth Rate Election**

2.2.4.1 **Notice**
Surprise Valley shall have the right to stop purchasing Firm Requirements Power at Tier 2 Load Growth Rates effective the upcoming Rate Period, except for the amount established in section 2.2.4.2 of this exhibit. If Surprise Valley chooses to modify its purchases at Tier 2 Load Growth Rates in this manner, then Surprise Valley shall notify BPA in writing by October 31 of a Rate Case Year.

2.2.4.2 **Continued Purchase Amount**
For the remaining term of this Agreement, Surprise Valley shall continue to purchase at Tier 2 Load Growth Rates the amount of Firm Requirements Power that Surprise Valley purchased at Tier 2 Load Growth Rates the year before the modification described above is effective.

2.2.4.3 **Obligation to Apply Dedicated Resources**
If Surprise Valley provides notice to modify its purchases at Tier 2 Load Growth Rates under section 2.2.4.1 of this exhibit, then for the remainder of the effective Purchase Period and all of the next Purchase Period, Surprise Valley shall apply Dedicated Resources to serve all of its Above-RHWM Load that is in excess of the sum of all Tier 2 commitments.

2.2.4.4 **Charges to Modify Tier 2 Load Growth Rate Purchase**
Surprise Valley shall be liable for payment of any costs that apply as a result of Surprise Valley modifying its Tier 2 Load Growth Rate purchase obligation under this section 2.2.4. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley at Tier 2 Load Growth Rates as a result of the modification, and (2) is unable to recover through other transactions.

BPA shall determine such costs, if any, during the 7(i) Process that follows Surprise Valley's notice. If BPA determines that Surprise Valley owes payment for such costs, then Surprise Valley shall pay the entire amount to BPA in no more than 24 equal monthly amounts starting the first month of the upcoming Rate Period. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley modifying its Tier 2 Load Growth Rate purchase obligation under this section 2.2.4.

2.2.4.5 **Exhibit Update**
By March 31 following Surprise Valley's notice, BPA shall indicate Surprise Valley's election to modify its Tier 2 Load Growth Rate purchase by filling in the table below. As established in section 2.2.4.2 of this exhibit, Surprise Valley shall continue to purchase the following amounts of Firm Requirements Power at Tier 2 Load Growth Rates:

Continuing Tier 2 Load Growth Rates Purchase Obligation					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
aMW					
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
aMW					
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
aMW					
Fiscal Year	**2027**	**2028**			
aMW					
Note: Fill in the table above with annual Average Megawatts, rounded to three decimal places, for each year that follows Surprise Valley's modification beginning with the effective year of modification					

2.3 **Tier 2 Vintage Rates**
If Surprise Valley elects Option 1 or 2 in section 2.2.3 of this exhibit, then this section shall not apply. Otherwise:

2.3.1 **Election Process**

2.3.1.1 **Right to Convert**
Subject to the amounts of power BPA makes available at one or more Tier 2 Vintage Rates, Surprise Valley shall have the right to convert some or all of the amounts of Firm Requirements Power it has elected to purchase at Tier 2 Short-Term Rates, as stated in section 2.4 of this exhibit, to an equal purchase amount at Tier 2 Vintage Rates.

2.3.1.2 **Statement of Intent**
If Surprise Valley elects to purchase Firm Requirements Power from BPA at Tier 2 Vintage Rates, then Surprise Valley shall sign a Statement of Intent offered by BPA. "Statement of Intent" means a statement prepared by BPA

and signed by Surprise Valley that describes the approach and cost structure that will be used for a specific Tier 2 Cost Pool. If BPA establishes a Tier 2 Cost Pool for a Tier 2 Vintage Rate consistent with the Statement of Intent, then Surprise Valley agrees to have the portion of its Tier 2 Rate power purchase specified in the Statement of Intent priced at that rate. If BPA is unable to establish the Tier 2 Cost Pool for the specific Tier 2 Vintage Rate, then Surprise Valley agrees to purchase such amount of Firm Requirements Power at Tier 2 Short-Term Rates, except as stated in section 2.3.1.5 of this exhibit.

2.3.1.3 **Insufficient Availability**
The Statement of Intent shall include procedures to allocate between competing applications for a specific Tier 2 Cost Pool if requests exceed amounts available.

2.3.1.4 **Conversion Costs**
Upon establishment of a Tier 2 Vintage Rate for which Surprise Valley signed a Statement of Intent, Surprise Valley shall be liable for payment of any outstanding costs under Tier 2 Short-Term Rates that apply to Surprise Valley. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley under Tier 2 Short-Term Rates as a result of the conversion, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, in the first 7(i) Process that establishes the applicable Tier 2 Vintage Rate. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley's conversion of purchase amounts at Tier 2 Short-Term Rates to purchase amounts at Tier 2 Vintage Rates.

2.3.1.5 **Additional Offerings**
In addition to the right to convert to Tier 2 Vintage Rates established in section 2.3.1.1 of this exhibit, Surprise Valley may have the opportunity to purchase Firm Requirements Power at Tier 2 Vintage Rates regardless of whether Surprise Valley is purchasing at Tier 2 Short-Term Rates if:

(1) BPA determines, in its sole discretion, that all requests for service at Tier 2 Vintage Rates by purchasers of Firm Requirements Power at Tier 2 Short-Term Rates are able to be satisfied, and

(2) BPA determines, in its sole discretion, to offer Surprise Valley a Statement of Intent that would provide Surprise Valley the opportunity to purchase Firm Requirements at Tier 2 Vintage Rates.

If Surprise Valley signs a Statement of Intent offered by BPA pursuant to this section 2.3.1.5, and if BPA is unable to establish the Tier 2 Cost Pool for the applicable Tier 2 Vintage Rate, then Surprise Valley's current elections for service to its Above-RHWM Load shall continue to apply.

Except as provided in this section 2.3.1, any election by Surprise Valley to purchase Firm Requirements Power at Tier 2 Vintage Rates shall not relieve Surprise Valley of any obligation to purchase Firm Requirements Power at another Tier 2 Rate.

2.3.1.6 **Exhibit Updates**
By September 15 immediately following the establishment of a Tier 2 Vintage Rate for which Surprise Valley signed a Statement of Intent, BPA shall amend this exhibit to show Surprise Valley's Tier 2 Vintage Rate purchases and remove Surprise Valley's Tier 2 Short-Term Rate purchases by the amounts purchased at the Tier 2 Vintage Rate, if Surprise Valley is converting to the Tier 2 Vintage Rate from the Tier 2 Short-Term Rate. BPA shall insert applicable tables, terms, and conditions for each Tier 2 Vintage Rate in section 2.3.2 of this exhibit.

2.3.2 **Vintage Rate Elections**
Surprise Valley has no Tier 2 Vintage Rate elections at this time.

2.4 **Tier 2 Short-Term Rate**
If Surprise Valley elects Option 1 or 2 in section 2.2.3 of this exhibit, then this section shall not apply. Otherwise:

2.4.1 **Short-Term Rate Purchases**
Unless Surprise Valley elects, in section 2.1 of this exhibit, not to purchase Firm Requirements Power at Tier 2 Rates for a given Purchase Period, by each Notice Deadline Surprise Valley shall elect in writing either Alternative A or B below for the duration of the corresponding Purchase Period. If Surprise Valley elects Alternative A and elects to apply Dedicated Resources to serve its Above-RHWM Load, then Surprise Valley shall state the amounts to be listed in the table in section 2.4.1.1(2) of this exhibit. If Surprise Valley elects Alternative B, then Surprise Valley shall state the amounts to be listed in the table in section 2.4.1.3 of this exhibit. By March 31 immediately following each Notice Deadline, BPA shall update the tables in this section 2.4.1 to show Surprise Valley's Tier 2 Short-Term Rate election for the corresponding Purchase Period.

2.4.1.1 **Alternative A – Customer Planned Load Not Otherwise Served**

If Surprise Valley elects this alternative, then Surprise Valley shall purchase Firm Requirements Power priced at Tier 2 Short-Term Rates to serve all of Surprise Valley's Above-RHWM Load that Surprise Valley has not otherwise agreed to serve with:

(1) Firm Requirements Power purchased at other Tier 2 Rates, or

(2) the amounts of Dedicated Resources, stated in the table below, that Surprise Valley shall apply during the Purchase Period to serve its Above-RHWM Load. If Surprise Valley purchases power at Tier 2 Load Growth Rates, then these Dedicated Resource amounts shall not exceed the amounts stated in the table in section 2.2.3.3 of this exhibit.

Purchase Period Dedicated Resource Elections					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
Election	0.000	0.000	0.000	0.000	0.000
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
Election	0.000	0.000	0.000		
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
Election					
Fiscal Year	**2027**	**2028**			
Election					
Note: Insert amounts in Average Megawatts rounded to three decimal places for each year of the applicable Purchase Period.					

2.4.1.2 **Alternative B – Limited Amounts**

If Surprise Valley elects this alternative, then Surprise Valley shall purchase Firm Requirements Power at Tier 2 Short-Term Rates to serve Surprise Valley's Above-RHWM Load that Surprise Valley has not otherwise agreed to serve with Firm Requirements Power purchased at other Tier 2 Rates; provided however, that amounts purchased at Tier 2 Short-Term Rates shall not exceed the amounts (including zero amounts) stated in the table in section 2.4.1.3 of this exhibit. Surprise Valley agrees to serve any of its remaining Above-RHWM Load with power other than Firm Requirements Power.

2.4.1.3 **Tier 2 Short-Term Rate Elections**

If Surprise Valley elects Alternative A above, then BPA shall indicate that election by adding an "X" to the table below for each year of the applicable Purchase Period. If Surprise

Valley elects Alternative B above, then BPA shall indicate that election by adding amounts (in Average Megawatts rounded to three decimal places) to the table below for each year of the applicable Purchase Period.

Tier 2 Short-Term Rate Table					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
Election	X	X	X	X	X
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
Election	X	X	X		
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
Election					
Fiscal Year	**2027**	**2028**			
Election					

2.4.2 **Right to Reduce Tier 2 Short-Term Rate Purchase Amounts**

2.4.2.1 **Notice**
If Surprise Valley notifies BPA in writing by October 31 of a Rate Case Year, then Surprise Valley may reduce, in equal amounts for all hours of the year, some or all of the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates. The reduction may take effect in either year of the upcoming Rate Period and shall be effective for the remaining duration of the applicable Purchase Period(s). In its written notice, Surprise Valley shall state the amount of the reduction and the date the reduction shall take effect. Surprise Valley shall replace all reduced Tier 2 Short-Term Rate purchase amounts with amounts of Dedicated Resources applied pursuant to section 3.3 of the body of this Agreement.

2.4.2.2 **Charges to Reduce Purchase Amounts**
Surprise Valley shall be liable for payment of any costs that apply as a result of Surprise Valley reducing, under section 2.4.2.1 of this exhibit, the amounts of Firm Requirements Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from Surprise Valley under Tier 2 Short-Term Rates as a result of the reduction, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, during the 7(i) Process that follows Surprise Valley's notice. If BPA determines that Surprise Valley owes payment for such costs, then Surprise Valley shall pay the entire amount to BPA in no more than 24 equal monthly amounts starting the first month of the upcoming Rate Period. In no event shall BPA make payment to Surprise Valley as a result of Surprise Valley reducing the amounts of Firm Requirements

Power that Surprise Valley is obligated to purchase at Tier 2 Short-Term Rates.

2.4.2.3 **Exhibit Updates**
By March 31 following Surprise Valley's notice, BPA shall revise this exhibit and Exhibit A to show Surprise Valley's reduced Tier 2 Short-Term Rate purchase amounts and Surprise Valley's Dedicated Resource additions.

2.5 **Amounts of Power to be Billed at Tier 2 Rates**

2.5.1 **Treatment for FY 2012 – FY 2013**
By March 31, 2010, BPA shall update the table in section 2.5.2 of this exhibit, consistent with Surprise Valley's elections, with amounts of Firm Requirements Power which Surprise Valley shall purchase at applicable Tier 2 Rates for the FY 2012 – FY 2013 Rate Period.

2.5.2 **Amounts of Power for Subsequent Rate Periods**
For each Rate Period after the FY 2012 – FY 2013 Rate Period, BPA shall establish for the upcoming Rate Period consistent with Surprise Valley's elections: (1) the planned annual average amounts of Firm Requirements Power which Surprise Valley shall purchase at applicable Tier 2 Rates, and (2) any remarketed Tier 2 Rate purchase amounts in accordance with section 10 of the body of this Agreement. By March 31, 2013, and by March 31 of each Rate Case Year thereafter, BPA shall update the table below with such amounts for each year of the upcoming Rate Period.

Annual Amounts Priced at Tier 2 Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Tier 2 Short-Term Rate	0.000	0.000	0.000	0.000	0.000	0.000			
Remarketed Amounts									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
No Tier 2 at this time									
Remarketed Amounts									

Notes:
1. List each applicable Tier 2 rate in the table above. For the first applicable Tier 2 rate replace **No Tier 2 at this time** with the name of the applicable Tier 2 rate. For each additional Tier 2 rate, add a new row above the **Remarketed Amounts** row. If Surprise Valley elects not to purchase at Tier 2 rates, then leave **No Tier 2 at this time** in the table and leave the remainder of the table blank.
2. Fill in the table above with annual Average Megawatts rounded to three decimal places.

3. MONTHLY PF RATES
Applicable monthly Tier 1 and Tier 2 Rates are specified in BPA Wholesale Power Rate Schedules and GRSPs.

4. REVISIONS

BPA shall revise this exhibit to reflect Surprise Valley's elections regarding service to its Above-RHWM Load and BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110 EXH C R4.docx) 03/04/15

Revision No. 2, Exhibit D
ADDITIONAL PRODUCTS AND SPECIAL PROVISIONS
Effective January 1, 2013

This revision adds section 6, "Transfer of Carbon Allowances" to BPA to allow for Surprise Valley's annual transfer of carbon allowances to BPA to meet the California Air Resource Board's carbon compliance obligations and renumbers the Revisions section.

1. CF/CT AND NEW LARGE SINGLE LOADS

1.1 CF/CT Loads

Surprise Valley has no loads identified that were contracted for, or committed to (CF/CT), as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act.

1.2 Potential NLSLs

Surprise Valley has no identified potential NLSLs.

1.3 Existing NLSLs

Surprise Valley has no existing NLSLs.

2. RESOURCE SUPPORT SERVICES

2.1 BPA shall develop the RSS products to support applicable Specified Resources listed in section 2 of Exhibit A for the FY 2012 through 2014 Purchase Period and offer such as a revision to this exhibit by August 1, 2009 and by August 1 prior to each Notice Deadline thereafter. Prior to that date, BPA shall provide Surprise Valley a reasonable opportunity to provide input into the development of the products and the related contract provisions. By the November 1, 2009 Notice Deadline and each Notice Deadline thereafter, Surprise Valley shall notify BPA in writing of any RSS products it elects to buy from BPA under the terms of this Agreement and shall identify the applicable resource(s), for which it shall purchase the RSS product(s) for the upcoming Purchase Period. Such election shall be a binding commitment of both Parties. If Surprise Valley makes such election, the Parties shall revise this exhibit so that it incorporates the agreed changes to applicable provisions, including the applicable resource amounts, if known, by March 31, 2010 or by March 31 of the year following the Notice Deadline for future years. By September 30 of the last Rate Case Year prior to the first Rate Period when service begins, and by each applicable September 30 thereafter in accordance with the applicable incorporated contract language, BPA shall update the relevant tables included in the incorporated contract language with the applicable charges and any necessary updates to resource amounts.

2.2 If Surprise Valley adds a new Specified Resource within a Purchase Period to meet its obligations to serve Above-RHWM Load with Dedicated Resources, consistent with section 3.5.1 of the body of this Agreement, Surprise Valley may purchase DFS or FORS to support such resource. Surprise Valley shall

FEB 2 8 2013

request a copy of the then-current DFS or FORS standard contract provisions from BPA and shall notify BPA in writing by October 31 of a Rate Case Year that it elects to purchase DFS or FORS for the new Specified Resource under the terms stated in the then-current contract provisions and the terms of this section 2.2. Such election shall be a binding commitment of both Parties. The elected DFS or FORS will be effective at the start of the upcoming Rate Period. The duration of such purchase shall be for the remainder of the Purchase Period and for the following Purchase Period. If Surprise Valley makes such election, the Parties shall revise this exhibit by March 31 of the calendar year after Surprise Valley has given notice of its election. Such revision shall incorporate the agreed changes to applicable provisions, including the applicable resource amounts, if known. By September 30 of the last Rate Case Year prior to the first Rate Period when service begins, and by each applicable September 30 thereafter, in accordance with the applicable incorporated contract language, BPA shall update the relevant tables included in the incorporated contract language with the applicable charges and any necessary updates to resource amounts.

3. IRRIGATION RATE MITIGATION

Subject to the terms specified in BPA's applicable Wholesale Power Rate Schedules and GRSPs:

3.1 for billing purposes, in the months listed below for each year during the term of this Agreement, BPA shall apply Irrigation Rate Mitigation to the lesser of the corresponding amount purchased at the Tier 1 Rate in the month or the energy amount in the table below:

Irrigation Amounts (kWh)

May	Jun	Jul	Aug	Sept	Annual Total
6,464,252	9,066,424	11,421,596	11,671,642	7,586,987	46,210,901

3.2 after the end of each irrigation season, the Parties shall administer a true-up process to ensure Surprise Valley's irrigation load meets or exceeds the total eligible irrigation amount (in kilowatt-hours) listed above; and

3.3 Surprise Valley shall be responsible for implementing cost-effective conservation measures on irrigation systems in their service territories. Surprise Valley shall verify and report all conservation measures and project savings consistent with section 18.1.2 of the body of this Agreement.

4. LIMITATIONS ON EXCHANGE OF EXISTING RESOURCES

4.1 Option on Full ASC Participation and Alternative Contract

BPA's 2008 Average System Cost (ASC) Methodology limits the loads and resource costs included in ASCs for consumer-owned utilities that sign a CHWM Contract. The TRM establishes a Tier 1 PF Exchange Rate for such consumer-owned utilities. Pursuant to section 12.2 of the body of this

Agreement and section 20 of the Residential Purchase and Sale Agreement (RPSA), Surprise Valley is contractually precluded from seeking or receiving Residential Exchange Program (REP) benefits based on an ASC other than as provided for in Section IV(G) of the 2008 ASC Methodology or its successor.

BPA and Surprise Valley understand and acknowledge that this is the first time BPA has attempted to implement an REP with two different ASC cost structures and two differing levels of benefits, and that as a consequence, the implementation of the REP may be revised over time. Because of the contractual preclusions in the paragraph above and because a limited number of consumer-owned utilities with CHWM Contracts may participate in the REP, the intent of this section 4 is to provide limited protection to such consumer-owned utilities from future changes in the REP.

Any impact to Surprise Valley's access to REP benefits, pursuant to section 5(c) of the Northwest Power Act, as a result of an action taken by BPA as required by a statutory change or final judicial action shall not be considered an Action as provided in section 4.2 below, shall not be subject to the criteria provided in section 4.3 below, and shall not make available the option provided in section 4.4 below.

Absent the exercise by Surprise Valley of the option set forth in section 4.4 below, nothing in this section 4 is intended to alter the application of any provision of the ASC Methodology.

4.2 **Actions**

If BPA takes any of the following Actions and such Actions meet the criteria specified in section 4.3, then Surprise Valley may elect the option set forth in section 4.4 below.

Action 1. BPA adopts, in a final record of decision issued in a section 7(i) proceeding for a Rate Period, a Base Tier 1 PF Exchange Rate for customers with CHWM Contracts which is calculated in a manner that differs from the following:

Base **T1** PF Exchange Rate =

$$\frac{(PFCosts - PFCredits) - (T2Costs - T2Credits)}{PFLoad - T2Load} + TmnAddr$$

Where:

Base T1 PF Exchange Rate is the Base Tier 1 PF Exchange rate prior to the final allocation of any rate protection costs arising from the section 7(b)(2) rate test, as determined in each 7(i) Process.

PFCosts are all costs allocated in a 7(i) Process to the Priority Firm rates when the Base PF Exchange rate is calculated (also known as the unbifurcated PF rate) and prior to any reflection of the tiering of the PF Preference rate.

PFCredits are all credits allocated in a 7(i) Process to the Priority Firm rates when the Base PF Exchange rate is calculated (also known as the unbifurcated PF rate) and prior to any reflection of the tiering of the PF Preference rate.

T2Costs are all costs allocated in a 7(i) Process to Tier 2 Cost Pools.

T2Credits are all credits allocated in a 7(i) Process to Tier 2 Cost Pools.

PFLoad is the BPA forecast of load used to determine the unbifurcated PF rate in a 7(i) Process.

T2Load is the BPA forecast of load used to determine Tier 2 Rates in a 7(i) Process.

TmnAddr is the same unit charge for transmission added to the Base PF Exchange rate.

The Tier 1 PF Exchange rate used to calculate Surprise Valley's REP benefits is the Base Tier 1 PF Exchange rate as modified by any Supplemental 7(b)(3) Rate Charge, as determined in each 7(i) Process and may be adjusted pursuant to the Supplemental 7(b)(3) Rate Charge Adjustment, any cost recovery adjustment clause, and any dividend distribution clause, as determined to be applicable to the Tier 1 PF Exchange rate in a 7(i) Process.

Action 2. BPA adopts, in a final record of decision, policy or interpretation, a method of calculating Surprise Valley's ASC for a Fiscal Year(s) of an Exchange Period pursuant to BPA's 2008 ASC Methodology or its successor that differs from the following formula:

$$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$

Where:

RHWM ASC is the ASC for Surprise Valley for an Exchange Period, as defined by BPA's 2008 ASC Methodology.

Contract System Cost is as defined in BPA's 2008 ASC Methodology.

NewRes$ is the forecast cost of resources (including purchased power contracts) used under this Agreement to serve Surprise Valley's Above-RHWM Load. Such resources are exclusive of Surprise Valley's Existing Resources for CHWMs as specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA. The costs included in NewRes$ will be determined using a methodology similar to Appendix 1 Endnote d of BPA's 2008 ASC Methodology.

Contract System Load is as defined in BPA's 2008 ASC Methodology.

NewResMWh is the forecast generation from resources (including purchased power contracts) used under this agreement to serve Surprise Valley's Above-RHWM Load. Such resources are exclusive of Surprise Valley's Existing Resources for CHWMs specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA.

Action 3. BPA offers Surprise Valley an RPSA with an Exchange Load used to calculate Surprise Valley's REP benefits payments that differs from the following formula, or interprets such RPSA in a manner that differs from the following formula:

$$\text{Actual RHWM Exchange Load} = \text{RRL} \times \text{T1Pctg}$$

Where:

Actual RHWM Exchange Load is the monthly residential and small farm load of Surprise Valley used to calculate the actual monthly REP payments to Surprise Valley as specified in the RPSA.

RRL is Surprise Valley's actual total qualifying residential and small farm retail load for a month as specified in the RPSA.

$$\text{T1Pctg} = \frac{\text{T1MWh} + \text{ExistResMWh}}{\text{TRL} - \text{NLSL}}$$

Where:

T1Pctg is BPA's forecast percentage of Surprise Valley's load that is expected to be served by purchases of power at Tier 1 Rates from BPA and from Surprise Valley's Existing Resources for CHWM, and will be computed for each Fiscal Year of the applicable Rate Period. Such computation will be performed in the applicable RHWM Process for the Rate Period.

T1MWh is the amount of power at Tier 1 Rates BPA forecasts to be purchased by Surprise Valley from BPA in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

ExistResMWh is the specified output of Surprise Valley's Existing Resources for CHWM, as specified in Attachment C, Column D, of the TRM.

TRL is BPA's forecast of Surprise Valley's Total Retail Load in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

NLSL is BPA's forecast of Surprise Valley's New Large Single Loads in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

Action 4. BPA adopts a final record of decision, policy or interpretation that changes the terms of the TRM or the 2008 ASC Methodology applicable to REP participants with CHWM Contracts and such change is not encompassed in Actions 1-3, and such change meets the criteria in section 4.3 for application of the option in section 4.4.

4.3 **Criteria**
The option set forth in section 4.4 below is available to Surprise Valley if BPA has taken any of the Actions 1-4 set forth in section 4.2 and the Actions taken, when considered in combination with all BPA actions being undertaken at that time, result in a material reduction in the REP benefits of the class of REP participants with CHWM Contracts. A reduction shall not be "material" for purposes of this section 4.3 if such Action(s), when considered in combination with all BPA actions being undertaken at that time, are applied to the provisions applicable to all REP participants and produce the same or comparable effects on all REP participants, even if such Action(s) results in an otherwise material reduction in the REP benefits of the class of REP participants with CHWM Contracts.

4.4 **Option**
If Surprise Valley believes that BPA has taken any of the Actions 1 through 4 set forth in section 4.2 that satisfies the criteria for this option as set forth in section 4.3, and if BPA has provided a public comment process as part of BPA's decision process (for the relevant Action of Actions 1 through 4 set forth in section 4.2) in which Surprise Valley has commented that BPA was proposing or about to take such Action, then Surprise Valley, within 30 calendar days of BPA taking such alleged Action(s), may provide written notice to BPA in accordance with section 20 of this Agreement requesting an alternative power sales contract without a CHWM. Upon receipt of such written notice, BPA shall review the request and, within 60 calendar days, issue a written statement regarding whether the criteria of section 4.3 have been satisfied.

4.4.1 If BPA believes the criteria of section 4.3 have not been satisfied, the dispute shall be resolved through the dispute resolution provisions in section 22 of this Agreement, provided, however, that the sole function of arbitration shall be to determine whether the criteria of section 4.3 have been satisfied, not the exclusive remedy of money damages set forth in section 22.4 of this Agreement. If the dispute resolution results in a final determination that the criteria of section 4.3 have been satisfied, BPA shall have 90 calendar days from the date of such final determination to take curative action to restore the REP benefits of the class of REP participants with CHWM Contracts to the level that would have existed had BPA not taken the Action(s) that resulted in the criteria of section 4.3 being satisfied; provided, however, that if

BPA elects not to take such curative action within such 90 day period, BPA shall have 180 calendar days after the date of such determination to offer to Surprise Valley an alternative power sales contract without a CHWM.

4.4.2 If BPA determines that the criteria of section 4.3 have been satisfied, BPA shall have 90 calendar days from the date of such determination to take curative action to restore the REP benefits of the class of REP participants with CHWM Contracts to the level that would have existed had BPA not taken the Action(s) that resulted in the criteria of section 4.3 being satisfied; provided, however, that if BPA elects not to take such curative action, it shall have 180 calendar days after the date of such determination to offer to Surprise Valley an alternative power sales contract without a CHWM.

4.4.3 Such alternative power sales contract shall be for the same purchase obligation in section 3 of this Agreement that is in effect at the time the notice under this section 4.4 is provided to BPA. Surprise Valley acknowledges that the terms and conditions of such alternative power sales contract may vary from those contained in the CHWM Contract.

4.4.4 Surprise Valley shall notify BPA in accordance with section 20 no later than 60 calendar days after the date of its receipt of such alternative power sales contract whether it will terminate its CHWM Contract and execute such alternative power sales contract, or retain its CHWM Contract. If Surprise Valley fails to notify BPA within the 60-day period of its decision regarding its CHWM Contract, BPA's offer of the alternative power sales contract without a CHWM shall be withdrawn as of the 61st day and Surprise Valley will be conclusively presumed to have elected to retain its CHWM Contract.

4.4.5 If Surprise Valley provides BPA timely notice of its election to terminate its CHWM Contract and executes the alternative power sales contract, service under such alternative power sales contract shall not commence until the beginning of the Rate Period immediately following the Rate Period in which the alternative power sales contract is executed. Termination of Surprise Valley's CHWM Contract shall be effective at commencement of service under the alternative power sales contract.

5. TERMS AND CONDITIONS OF SURPRISE VALLEY'S WREGIS SUBACCOUNT

Although section 5(2) of Exhibit H, Renewable Energy Certificates and Carbon Attributes states that the terms and conditions of Surprise Valley's BPA-managed WREGIS subaccount (WREGIS subaccount) will be established in a separate agreement, this provision establishes the terms and conditions of Surprise Valley's WREGIS subaccount into this Exhibit D in lieu of a separate agreement.

5.1 **Definitions**
In addition to the defined terms included in Exhibit H, Renewable Energy Certificates and Carbon Attributes, this section 5 also includes the following defined term: "Retire" or "Retirement" which means an action taken to remove a REC from circulation within Western Renewable Energy Generation Information System (WREGIS) or its successor.

5.2 **Establishment of WREGIS Subaccount**
In accordance with Surprise Valley's election under section 5(2) of Exhibit H to have Surprise Valley's RECs transferred to a WREGIS subaccount, BPA shall establish a subaccount in Surprise Valley's name within BPA's WREGIS account. BPA shall provide Surprise Valley read-only access to its subaccount.

BPA shall use such subaccount solely for the purposes of transferring and Retiring RECs that Surprise Valley receives from BPA.

Surprise Valley gives its consent to be bound by the terms stated in the WREGIS Account Holder Registration Agreement, also referred to as the WREGIS Terms of Use (WREGIS TOU) Agreement, Contract No. 08PB-11957, executed by BPA and including any revisions. BPA shall make the executed WREGIS TOU Agreement available at a publicly accessible website.

5.3 **Transfer of RECs to Surprise Valley's WREGIS Subaccount**
BPA shall transfer Surprise Valley's share of Tier 1 RECs, and Tier 2 RECs if applicable, to Surprise Valley's WREGIS subaccount pursuant to the timeline established in section 5 of Exhibit H.

Any RECs BPA transfers to Surprise Valley shall be limited to those available to BPA through WREGIS and shall be a blend of RECs pursuant to Exhibit H. If BPA adds, replaces, or removes a resource from the list in section 2 of Exhibit H, then BPA may adjust the blend of RECs accordingly. BPA shall notify Surprise Valley of any such changes in the letter BPA provides to Surprise Valley by April 15 pursuant to section 3(2) of Exhibit H.

5.4 **Resale, Purchase, and Retirement of RECs**
If Surprise Valley wants to sell RECs received from BPA outside of its service territory or purchase RECs other than those RECs it receives from BPA, then Surprise Valley shall terminate its WREGIS subaccount pursuant to section 5.6 below and establish its own WREGIS account.

Upon receipt of written notice for Retirement from Surprise Valley, BPA shall Retire Surprise Valley's RECs on its behalf. In such notice, for the RECs Surprise Valley wants BPA to Retire Surprise Valley shall identify REC quantity, the name of the renewable project(s) which generated the RECs, and the month and year the RECs were generated by the project(s).

5.5 WREGIS Subaccount Fees

Consistent with section 6 of Exhibit H, BPA shall pay any fees associated with establishing Surprise Valley's WREGIS subaccount and any fees associated with the transfer of RECs into Surprise Valley's WREGIS subaccount. Surprise Valley shall reimburse BPA for all other fees associated with Surprise Valley's WREGIS subaccount including but not limited to any REC Retirement fees. Such reimbursement shall be effectuated through a charge on Surprise Valley's bill pursuant to section 16 of this Agreement. Surprise Valley shall be responsible for all WREGIS fees incurred from the termination of its WREGIS subaccount and Surprise Valley shall pay all fees associated with establishment of its own WREGIS account.

5.6 Termination of Surprise Valley's WREGIS Subaccount

Either Party may terminate Surprise Valley's WREGIS subaccount after providing 30 days' advance written notice to the other Party.

However, BPA shall not terminate Surprise Valley's WREGIS subaccount until: (1) Surprise Valley has established its own WREGIS account and BPA has received written notice from Surprise Valley to transfer 100 percent of Surprise Valley's RECs into Surprise Valley's own WREGIS account; or (2) BPA has provided all RECs due to Surprise Valley for the previous calendar year under section 5.3 above and BPA has received written notification from Surprise Valley to Retire 100 percent of Surprise Valley's RECs contained in Surprise Valley's WREGIS subaccount. Surprise Valley may not have both a WREGIS account and a WREGIS subaccount open at the same time.

Unless otherwise agreed by the Parties, if Surprise Valley terminates its WREGIS subaccount, then BPA shall not establish another WREGIS subaccount for Surprise Valley for the remaining term of this Agreement.

6. TRANSFER OF CARBON ALLOWANCES TO BPA

Starting in calendar year 2013, the California Air Resource Board (CARB) will institute a carbon compliance obligation on electricity importers that provide power into California. The U S. Department of Energy has directed BPA to voluntarily comply with the requirement of this state obligation by obtaining without charge from Surprise Valley sufficient carbon allowances to cover BPA's firm requirements power delivery to Surprise Valley.

Over the term of this Agreement, Surprise Valley shall annually transfer carbon allowances to BPA in the amount requested by BPA that is sufficient to satisfy the BPA voluntary compliance obligations that arise in order to serve Surprise Valley's load in California. Starting January 2014 and each January thereafter, BPA shall calculate and inform Surprise Valley of the amount of carbon allowances required to be transferred based on the amount of power BPA imported into California to serve Surprise Valley during the prior calendar year. The calculation to determine the amount of carbon allowances Surprise Valley shall transfer to BPA shall have two variables that when multiplied together result in a carbon compliance amount in metric tons of carbon dioxide equivalent (CO_2e):

(a) the amount of power deliveries (in megawatt hours) that BPA made to Surprise Valley in California during the prior calendar year and

(b) the BPA system emission factor for the prior calendar year as reported and confirmed with CARB in metric tons of CO2e per megawatt hour.

Surprise Valley shall complete the transfer of carbon allowances to BPA using CARB's Compliance Instrument Tracking System Service (CITSS), or its successor tracking system, no later than September 1 of each year.

BPA shall provide Surprise Valley with BPA's system emission factor for the applicable calendar year no later than March 31 of such applicable year to aid Surprise Valley in estimating the amount of carbon allowances to be transferred to BPA.

Surprise Valley agrees that fees charged to BPA by CARB, if any, on power deliveries to Surprise Valley shall be charged to Surprise Valley by BPA, on an annual basis and stated in Surprise Valley's December power bill.

7. REVISIONS
This exhibit shall be revised by mutual agreement of the Parties to reflect additional products Surprise Valley purchases during the term of this Agreement.

8. SIGNATURES
The Parties have executed this revision as of the last date indicated below.

SURPRISE VALLEY ELECTRIFICATION CORPORATION	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By C. James Hays	By Daniel E. Bloyer
Name C. James Hays (Print/Type)	Name Daniel E. Bloyer (Print/Type)
Title General Manager	Title Account Executive
Date February, 12, 2013	Date February 15, 2013

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\Exh D\ 13110 Exh D R2.DOC) 01/16/13

Revision No. 3, Exhibit D
ADDITIONAL PRODUCTS AND SPECIAL PROVISIONS
Effective July 1, 2015

This revision updates section 6 "Transfer of Carbon Allowances to BPA", adds section 7 "Temporary Application of Surprise Valley's Paisley Geothermal Resource Amounts to Serve Total Retail Load", and renumbers the "Revisions" and "Signatures" sections.

1. CF/CT AND NEW LARGE SINGLE LOADS

1.1 CF/CT Loads
Surprise Valley has no loads identified that were contracted for, or committed to (CF/CT), as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act.

1.2 Potential NLSLs
Surprise Valley has no identified potential NLSLs.

1.3 Existing NLSLs
Surprise Valley has no existing NLSLs.

2. RESOURCE SUPPORT SERVICES

2.1 BPA shall develop the RSS products to support applicable Specified Resources listed in section 2 of Exhibit A for the FY 2012 through 2014 Purchase Period and offer such as a revision to this exhibit by August 1, 2009 and by August 1 prior to each Notice Deadline thereafter. Prior to that date, BPA shall provide Surprise Valley a reasonable opportunity to provide input into the development of the products and the related contract provisions. By the November 1, 2009 Notice Deadline and each Notice Deadline thereafter, Surprise Valley shall notify BPA in writing of any RSS products it elects to buy from BPA under the terms of this Agreement and shall identify the applicable resource(s), for which it shall purchase the RSS product(s) for the upcoming Purchase Period. Such election shall be a binding commitment of both Parties. If Surprise Valley makes such election, the Parties shall revise this exhibit so that it incorporates the agreed changes to applicable provisions, including the applicable resource amounts, if known, by March 31, 2010 or by March 31 of the year following the Notice Deadline for future years. By September 30 of the last Rate Case Year prior to the first Rate Period when service begins, and by each applicable September 30 thereafter in accordance with the applicable incorporated contract language, BPA shall update the relevant tables included in the incorporated contract language with the applicable charges and any necessary updates to resource amounts.

2.2 If Surprise Valley adds a new Specified Resource within a Purchase Period to meet its obligations to serve Above-RHWM Load with Dedicated Resources, consistent with section 3.5.1 of the body of this Agreement, Surprise Valley may purchase DFS or FORS to support such resource. Surprise Valley shall request a copy of the then-current DFS or FORS standard contract provisions from BPA and shall notify BPA in writing by October 31 of a Rate Case Year that it elects to purchase DFS or FORS for the new Specified Resource under the terms stated in the then-current contract provisions and the terms of this section 2.2. Such election shall be a binding commitment of both Parties. The elected DFS or FORS will be effective at the start of the upcoming Rate Period. The duration of such purchase shall be for the remainder of the Purchase Period and for the following Purchase Period. If Surprise Valley makes such election, the Parties shall revise this exhibit by March 31 of the calendar year after Surprise Valley has given notice of its election. Such revision shall incorporate the agreed changes to applicable provisions, including the applicable resource amounts, if known. By September 30 of the last Rate Case Year prior to the first Rate Period when service begins, and by each applicable September 30 thereafter, in accordance with the applicable incorporated contract language, BPA shall update the relevant tables included in the incorporated contract language with the applicable charges and any necessary updates to resource amounts.

3. IRRIGATION RATE MITIGATION

Subject to the terms specified in BPA's applicable Wholesale Power Rate Schedules and GRSPs:

3.1 for billing purposes, in the months listed below for each year during the term of this Agreement, BPA shall apply Irrigation Rate Mitigation to the lesser of the corresponding amount purchased at the Tier 1 Rate in the month or the energy amount in the table below:

Irrigation Amounts (kWh)

May	Jun	Jul	Aug	Sept	Annual Total
6,464,252	9,066,424	11,421,596	11,671,642	7,586,987	46,210,901

3.2 after the end of each irrigation season, the Parties shall administer a true-up process to ensure Surprise Valley's irrigation load meets or exceeds the total eligible irrigation amount (in kilowatt-hours) listed above; and

3.3 Surprise Valley shall be responsible for implementing cost-effective conservation measures on irrigation systems in their service territories. Surprise Valley shall verify and report all conservation measures and project savings consistent with section 18.1.2 of the body of this Agreement.

4. LIMITATIONS ON EXCHANGE OF EXISTING RESOURCES

4.1 **Option on Full ASC Participation and Alternative Contract**
BPA's 2008 Average System Cost (ASC) Methodology limits the loads and resource costs included in ASCs for consumer-owned utilities that sign a CHWM Contract. The TRM establishes a Tier 1 PF Exchange Rate for such consumer-owned utilities. Pursuant to section 12.2 of the body of this

Agreement and section 20 of the Residential Purchase and Sale Agreement (RPSA), Surprise Valley is contractually precluded from seeking or receiving Residential Exchange Program (REP) benefits based on an ASC other than as provided for in Section IV(G) of the 2008 ASC Methodology or its successor.

BPA and Surprise Valley understand and acknowledge that this is the first time BPA has attempted to implement an REP with two different ASC cost structures and two differing levels of benefits, and that as a consequence, the implementation of the REP may be revised over time. Because of the contractual preclusions in the paragraph above and because a limited number of consumer-owned utilities with CHWM Contracts may participate in the REP, the intent of this section 4 is to provide limited protection to such consumer-owned utilities from future changes in the REP.

Any impact to Surprise Valley's access to REP benefits, pursuant to section 5(c) of the Northwest Power Act, as a result of an action taken by BPA as required by a statutory change or final judicial action shall not be considered an Action as provided in section 4.2 below, shall not be subject to the criteria provided in section 4.3 below, and shall not make available the option provided in section 4.4 below.

Absent the exercise by Surprise Valley of the option set forth in section 4.4 below, nothing in this section 4 is intended to alter the application of any provision of the ASC Methodology.

4.2 **Actions**

If BPA takes any of the following Actions and such Actions meet the criteria specified in section 4.3, then Surprise Valley may elect the option set forth in section 4.4 below.

<u>**Action 1.**</u> BPA adopts, in a final record of decision issued in a section 7(i) proceeding for a Rate Period, a Base Tier 1 PF Exchange Rate for customers with CHWM Contracts which is calculated in a manner that differs from the following:

$$\text{Base T1 PF Exchange Rate} = \frac{(\text{PFCosts} - \text{PFCredits}) - (\text{T2Costs} - \text{T2Credits})}{\text{PFLoad} - \text{T2Load}} + \text{TmnAddr}$$

Where:

Base T1 PF Exchange Rate is the Base Tier 1 PF Exchange rate prior to the final allocation of any rate protection costs arising from the section 7(b)(2) rate test, as determined in each 7(i) Process.

PFCosts are all costs allocated in a 7(i) Process to the Priority Firm rates when the Base PF Exchange rate is calculated (also known as the unbifurcated PF rate) and prior to any reflection of the tiering of the PF Preference rate.

PFCredits are all credits allocated in a 7(i) Process to the Priority Firm rates when the Base PF Exchange rate is calculated (also known as the unbifurcated PF rate) and prior to any reflection of the tiering of the PF Preference rate.

T2Costs are all costs allocated in a 7(i) Process to Tier 2 Cost Pools.

T2Credits are all credits allocated in a 7(i) Process to Tier 2 Cost Pools.

PFLoad is the BPA forecast of load used to determine the unbifurcated PF rate in a 7(i) Process.

T2Load is the BPA forecast of load used to determine Tier 2 Rates in a 7(i) Process.

TmnAddr is the same unit charge for transmission added to the Base PF Exchange rate.

The Tier 1 PF Exchange rate used to calculate Surprise Valley's REP benefits is the Base Tier 1 PF Exchange rate as modified by any Supplemental 7(b)(3) Rate Charge, as determined in each 7(i) Process and may be adjusted pursuant to the Supplemental 7(b)(3) Rate Charge Adjustment, any cost recovery adjustment clause, and any dividend distribution clause, as determined to be applicable to the Tier 1 PF Exchange rate in a 7(i) Process.

Action 2. BPA adopts, in a final record of decision, policy or interpretation, a method of calculating Surprise Valley's ASC for a Fiscal Year(s) of an Exchange Period pursuant to BPA's 2008 ASC Methodology or its successor that differs from the following formula:

$$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$

Where:

RHWM ASC is the ASC for Surprise Valley for an Exchange Period, as defined by BPA's 2008 ASC Methodology.

Contract System Cost is as defined in BPA's 2008 ASC Methodology.

NewRes$ is the forecast cost of resources (including purchased power contracts) used under this Agreement to serve Surprise Valley's Above-RHWM Load. Such resources are exclusive of Surprise Valley's Existing Resources for CHWMs as specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA. The costs included in NewRes$ will be determined using a methodology similar to Appendix 1 Endnote d of BPA's 2008 ASC Methodology.

Contract System Load is as defined in BPA's 2008 ASC Methodology.

NewResMWh is the forecast generation from resources (including purchased power contracts) used under this agreement to serve Surprise Valley's Above-RHWM Load. Such resources are exclusive of Surprise Valley's Existing Resources for CHWMs specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA.

Action 3. BPA offers Surprise Valley an RPSA with an Exchange Load used to calculate Surprise Valley's REP benefits payments that differs from the following formula, or interprets such RPSA in a manner that differs from the following formula:

$$\text{Actual RHWM Exchange Load} = \text{RRL} \times \text{T1Pctg}$$

Where:

Actual RHWM Exchange Load is the monthly residential and small farm load of Surprise Valley used to calculate the actual monthly REP payments to Surprise Valley as specified in the RPSA.

RRL is Surprise Valley's actual total qualifying residential and small farm retail load for a month as specified in the RPSA.

$$\text{T1Pctg} = \frac{\text{T1MWh} + \text{ExistResMWh}}{\text{TRL} - \text{NLSL}}$$

Where:

T1Pctg is BPA's forecast percentage of Surprise Valley's load that is expected to be served by purchases of power at Tier 1 Rates from BPA and from Surprise Valley's Existing Resources for CHWM, and will be computed for each Fiscal Year of the applicable Rate Period. Such computation will be performed in the applicable RHWM Process for the Rate Period.

T1MWh is the amount of power at Tier 1 Rates BPA forecasts to be purchased by Surprise Valley from BPA in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

ExistResMWh is the specified output of Surprise Valley's Existing Resources for CHWM, as specified in Attachment C, Column D, of the TRM.

TRL is BPA's forecast of Surprise Valley's Total Retail Load in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

NLSL is BPA's forecast of Surprise Valley's New Large Single Loads in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

Action 4. BPA adopts a final record of decision, policy or interpretation that changes the terms of the TRM or the 2008 ASC Methodology applicable to REP participants with CHWM Contracts and such change is not encompassed in Actions 1-3, and such change meets the criteria in section 4.3 for application of the option in section 4.4.

4.3 **Criteria**
The option set forth in section 4.4 below is available to Surprise Valley if BPA has taken any of the Actions 1-4 set forth in section 4.2 and the Actions taken, when considered in combination with all BPA actions being undertaken at that time, result in a material reduction in the REP benefits of the class of REP participants with CHWM Contracts. A reduction shall not be "material" for purposes of this section 4.3 if such Action(s), when considered in combination with all BPA actions being undertaken at that time, are applied to the provisions applicable to all REP participants and produce the same or comparable effects on all REP participants, even if such Action(s) results in an otherwise material reduction in the REP benefits of the class of REP participants with CHWM Contracts.

4.4 **Option**
If Surprise Valley believes that BPA has taken any of the Actions 1 through 4 set forth in section 4.2 that satisfies the criteria for this option as set forth in section 4.3, and if BPA has provided a public comment process as part of BPA's decision process (for the relevant Action of Actions 1 through 4 set forth in section 4.2) in which Surprise Valley has commented that BPA was proposing or about to take such Action, then Surprise Valley, within 30 calendar days of BPA taking such alleged Action(s), may provide written notice to BPA in accordance with section 20 of this Agreement requesting an alternative power sales contract without a CHWM. Upon receipt of such written notice, BPA shall review the request and, within 60 calendar days, issue a written statement regarding whether the criteria of section 4.3 have been satisfied.

4.4.1 If BPA believes the criteria of section 4.3 have not been satisfied, the dispute shall be resolved through the dispute resolution provisions in section 22 of this Agreement, provided, however, that the sole function of arbitration shall be to determine whether the criteria of section 4.3 have been satisfied, not the exclusive remedy of money damages set forth in section 22.4 of this Agreement. If the dispute resolution results in a final determination that the criteria of section 4.3 have been satisfied, BPA shall have 90 calendar days from the date of such final determination to take curative action to restore the REP benefits of the class of REP participants with CHWM Contracts to the level that would have existed had BPA not taken the Action(s) that resulted in the criteria of section 4.3 being satisfied; provided, however, that if

BPA elects not to take such curative action within such 90 day period, BPA shall have 180 calendar days after the date of such determination to offer to Surprise Valley an alternative power sales contract without a CHWM.

4.4.2 If BPA determines that the criteria of section 4.3 have been satisfied, BPA shall have 90 calendar days from the date of such determination to take curative action to restore the REP benefits of the class of REP participants with CHWM Contracts to the level that would have existed had BPA not taken the Action(s) that resulted in the criteria of section 4.3 being satisfied; provided, however, that if BPA elects not to take such curative action, it shall have 180 calendar days after the date of such determination to offer to Surprise Valley an alternative power sales contract without a CHWM.

4.4.3 Such alternative power sales contract shall be for the same purchase obligation in section 3 of this Agreement that is in effect at the time the notice under this section 4.4 is provided to BPA. Surprise Valley acknowledges that the terms and conditions of such alternative power sales contract may vary from those contained in the CHWM Contract.

4.4.4 Surprise Valley shall notify BPA in accordance with section 20 no later than 60 calendar days after the date of its receipt of such alternative power sales contract whether it will terminate its CHWM Contract and execute such alternative power sales contract, or retain its CHWM Contract. If Surprise Valley fails to notify BPA within the 60-day period of its decision regarding its CHWM Contract, BPA's offer of the alternative power sales contract without a CHWM shall be withdrawn as of the 61st day and Surprise Valley will be conclusively presumed to have elected to retain its CHWM Contract.

4.4.5 If Surprise Valley provides BPA timely notice of its election to terminate its CHWM Contract and executes the alternative power sales contract, service under such alternative power sales contract shall not commence until the beginning of the Rate Period immediately following the Rate Period in which the alternative power sales contract is executed. Termination of Surprise Valley's CHWM Contract shall be effective at commencement of service under the alternative power sales contract.

5. TERMS AND CONDITIONS OF SURPRISE VALLEY'S WREGIS SUBACCOUNT

Although section 5(2) of Exhibit H, Renewable Energy Certificates and Carbon Attributes states that the terms and conditions of Surprise Valley's BPA-managed WREGIS subaccount (WREGIS subaccount) will be established in a separate agreement, this provision establishes the terms and conditions of Surprise Valley's WREGIS subaccount into this Exhibit D in lieu of a separate agreement.

5.1 **Definitions**
In addition to the defined terms included in Exhibit H, Renewable Energy Certificates and Carbon Attributes, this section 5 also includes the following defined term: "Retire" or "Retirement" which means an action taken to remove a REC from circulation within Western Renewable Energy Generation Information System (WREGIS) or its successor.

5.2 **Establishment of WREGIS Subaccount**
In accordance with Surprise Valley's election under section 5(2) of Exhibit H to have Surprise Valley's RECs transferred to a WREGIS subaccount, BPA shall establish a subaccount in Surprise Valley's name within BPA's WREGIS account. BPA shall provide Surprise Valley read-only access to its subaccount.

BPA shall use such subaccount solely for the purposes of transferring and Retiring RECs that Surprise Valley receives from BPA.

Surprise Valley gives its consent to be bound by the terms stated in the WREGIS Account Holder Registration Agreement, also referred to as the WREGIS Terms of Use (WREGIS TOU) Agreement, Contract No. 08PB-11957, executed by BPA and including any revisions. BPA shall make the executed WREGIS TOU Agreement available at a publicly accessible website.

5.3 **Transfer of RECs to Surprise Valley's WREGIS Subaccount**
BPA shall transfer Surprise Valley's share of Tier 1 RECs, and Tier 2 RECs if applicable, to Surprise Valley's WREGIS subaccount pursuant to the timeline established in section 5 of Exhibit H.

Any RECs BPA transfers to Surprise Valley shall be limited to those available to BPA through WREGIS and shall be a blend of RECs pursuant to Exhibit H. If BPA adds, replaces, or removes a resource from the list in section 2 of Exhibit H, then BPA may adjust the blend of RECs accordingly. BPA shall notify Surprise Valley of any such changes in the letter BPA provides to Surprise Valley by April 15 pursuant to section 3(2) of Exhibit H.

5.4 **Resale, Purchase, and Retirement of RECs**
If Surprise Valley wants to sell RECs received from BPA outside of its service territory or purchase RECs other than those RECs it receives from BPA, then Surprise Valley shall terminate its WREGIS subaccount pursuant to section 5.6 below and establish its own WREGIS account.

Upon receipt of written notice for Retirement from Surprise Valley, BPA shall Retire Surprise Valley's RECs on its behalf. In such notice, for the RECs Surprise Valley wants BPA to Retire Surprise Valley shall identify REC quantity, the name of the renewable project(s) which generated the RECs, and the month and year the RECs were generated by the project(s).

5.5 **WREGIS Subaccount Fees**
Consistent with section 6 of Exhibit H, BPA shall pay any fees associated with establishing Surprise Valley's WREGIS subaccount and any fees associated with the transfer of RECs into Surprise Valley's WREGIS subaccount. Surprise Valley shall reimburse BPA for all other fees associated with Surprise Valley's WREGIS subaccount including but not limited to any REC Retirement fees. Such reimbursement shall be effectuated through a charge on Surprise Valley's bill pursuant to section 16 of this Agreement. Surprise Valley shall be responsible for all WREGIS fees incurred from the termination of its WREGIS subaccount and Surprise Valley shall pay all fees associated with establishment of its own WREGIS account.

5.6 **Termination of Surprise Valley's WREGIS Subaccount**
Either Party may terminate Surprise Valley's WREGIS subaccount after providing 30 days' advance written notice to the other Party.

However, BPA shall not terminate Surprise Valley's WREGIS subaccount until: (1) Surprise Valley has established its own WREGIS account and BPA has received written notice from Surprise Valley to transfer 100 percent of Surprise Valley's RECs into Surprise Valley's own WREGIS account; or (2) BPA has provided all RECs due to Surprise Valley for the previous calendar year under section 5.3 above and BPA has received written notification from Surprise Valley to Retire 100 percent of Surprise Valley's RECs contained in Surprise Valley's WREGIS subaccount. Surprise Valley may not have both a WREGIS account and a WREGIS subaccount open at the same time.

Unless otherwise agreed by the Parties, if Surprise Valley terminates its WREGIS subaccount, then BPA shall not establish another WREGIS subaccount for Surprise Valley for the remaining term of this Agreement.

6. TRANSFER OF CARBON ALLOWANCES TO BPA
Starting in calendar year 2013, the California Air Resource Board (CARB) will institute a carbon compliance obligation on electricity importers that provide power into California. The U S. Department of Energy has directed BPA to voluntarily comply with the requirement of this state obligation by obtaining, without charge from Surprise Valley, sufficient carbon allowances to cover BPA's firm requirements power delivery to Surprise Valley.

Over the term of this Agreement, Surprise Valley shall annually transfer carbon allowances to BPA in the amount requested by BPA that is sufficient to satisfy BPA's voluntary compliance obligations that arise in order to serve Surprise Valley's load in California. Starting January 2014 and by each September 30 thereafter, BPA shall calculate and inform Surprise Valley of the amount of carbon allowances required to be transferred based on the amount of power BPA imported into California to serve Surprise Valley during the prior calendar year. The calculation to determine the amount of carbon allowances Surprise Valley shall transfer to BPA shall have three variables that when multiplied together result in a carbon compliance amount in metric tons of carbon dioxide equivalent (CO_2e):

(a) the amount of power deliveries (in megawatt hours) that BPA made to Surprise Valley in California during the prior calendar year, and

(b) the BPA system emission factor for the prior calendar year as reported and confirmed with CARB in metric tons of CO_2e per megawatt hour, and

(c) 2 percent transmission loss factor.

Surprise Valley shall complete the transfer of carbon allowances to BPA using CARB's Compliance Instrument Tracking System Service (CITSS), or its successor tracking system, no later than September 30 of each year.

BPA shall provide Surprise Valley with BPA's preliminary system emission factor for the applicable calendar year no later than March 31 of such applicable year to aid Surprise Valley in estimating the amount of carbon allowances to be transferred to BPA.

Surprise Valley agrees that fees charged to BPA by CARB, if any, on power deliveries to Surprise Valley shall be charged to Surprise Valley by BPA, on an annual basis and stated in Surprise Valley's December power bill.

7. TEMPORARY APPLICATION OF SURPRISE VALLEY'S PAISLEY GEOTHERMAL RESOURCE AMOUNTS TO SERVE TOTAL RETAIL LOAD

Surprise Valley has constructed, and owns, the Paisley Geothermal resource, which is expected to have completed testing and commissioning by June 2015. Paisley Geothermal is nameplate rated at 3.65 MW and will produce approximately 2.1 aMWs in output. Surprise Valley anticipates finalizing a power purchase agreement, for the entire Paisley Geothermal output, with PacifiCorp.

Surprise Valley requested (via letter to BPA dated November 4, 2014) to use the generation from Paisley Geothermal to serve Surprise Valley's Total Retail load on a temporary basis from January 1, 2015 through September 30, 2015.

In response to Surprise Valley's request, BPA agrees: (1) to allow Surprise Valley to temporarily apply the output of Paisley Geothermal, as listed in section 6 of Exhibit A, to serve its Total Retail Load; and (2) that the temporary application of Paisley Geothermal to Surprise Valley's Total Retail Load shall not exceed September 30, 2015; and (3) during such time frame, to not apply section 3.2, "Take or Pay" and section 3.5.1, "Specified Resource Additions to Meet Above-RHWM Load".

Surprise Valley shall notify BPA of the date that Paisley Geothermal has completed testing and commissioning and the date Paisley Geothermal will commence commercial operation, and thus begin temporary application to Surprise Valley load. Provided, however, that such notice to BPA shall be prior to the month that Paisley Geothermal commences commercial operation.

When Surprise Valley commences its temporary application of Paisley Geothermal to its load, then the Parties shall revise Exhibit E to exclude the generation at meter point 4122 and shall not apply such generation to Surprise Valley's power bills.

By September 1, 2015, or sooner, Surprise Valley shall notify BPA if Surprise Valley has agreed to sell the output of Paisley Geothermal to PacifiCorp or another party effective October 1, 2015. If Surprise Valley has not agreed to sell the output to PacifiCorp or another party by October 1, 2015, then Surprise Valley may request that BPA add Paisley Geothermal as a Specified Resource to section 2 of Exhibit A of this Agreement with amounts effective October 1, 2015. If Surprise Valley does not have a power sale to PacifiCorp or another party and does not request that BPA add Paisley Geothermal as a Specified Resource effective October 1, 2015, then Surprise Valley agrees to end temporary service to load and BPA will revise Exhibit E to include generation metered at meter point 4122 in Surprise Valley's power bills effective October 1, 2015.

If the Parties agree that Surprise Valley can shut off generation at the Paisley Geothermal resource during an Oversupply Management Protocol event, then BPA shall have the right to replace Surprise Valley's Paisley Geothermal resource with BPA power at no cost to Surprise Valley if such an event occurs.

8. REVISIONS

This exhibit shall be revised by mutual agreement of the Parties to reflect additional products Surprise Valley purchases during the term of this Agreement.

9. SIGNATURES

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

SURPRISE VALLEY ELECTRIFICATION CORPORATION	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By Bradley A Kresge	By Daniel E Bloyer
Name Bradley A. Kresge (Print/Type)	Name Daniel E. Bloyer (Print/Type)
Title General Manager	Title Account Executive
Date 7/23/15	Date 8/3/2015

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\Exh D\ 13110 Exh D R3.DOC) 06/22/15

Revision No. 4, Exhibit D
ADDITIONAL PRODUCTS AND SPECIAL PROVISIONS
Effective October 1, 2015

This revision updates section 7 "Temporary Application of Surprise Valley's Paisley Geothermal Resource Amounts to Serve Total Retail Load".

1. CF/CT AND NEW LARGE SINGLE LOADS

1.1 CF/CT Loads

Surprise Valley has no loads identified that were contracted for, or committed to (CF/CT), as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act.

1.2 Potential NLSLs

Surprise Valley has no identified potential NLSLs.

1.3 Existing NLSLs

Surprise Valley has no existing NLSLs.

2. RESOURCE SUPPORT SERVICES

2.1 BPA shall develop the RSS products to support applicable Specified Resources listed in section 2 of Exhibit A for the FY 2012 through 2014 Purchase Period and offer such as a revision to this exhibit by August 1, 2009 and by August 1 prior to each Notice Deadline thereafter. Prior to that date, BPA shall provide Surprise Valley a reasonable opportunity to provide input into the development of the products and the related contract provisions. By the November 1, 2009 Notice Deadline and each Notice Deadline thereafter, Surprise Valley shall notify BPA in writing of any RSS products it elects to buy from BPA under the terms of this Agreement and shall identify the applicable resource(s), for which it shall purchase the RSS product(s) for the upcoming Purchase Period. Such election shall be a binding commitment of both Parties. If Surprise Valley makes such election, the Parties shall revise this exhibit so that it incorporates the agreed changes to applicable provisions, including the applicable resource amounts, if known, by March 31, 2010 or by March 31 of the year following the Notice Deadline for future years. By September 30 of the last Rate Case Year prior to the first Rate Period when service begins, and by each applicable September 30 thereafter in accordance with the applicable incorporated contract language, BPA shall update the relevant tables included in the incorporated contract language with the applicable charges and any necessary updates to resource amounts.

2.2 If Surprise Valley adds a new Specified Resource within a Purchase Period to meet its obligations to serve Above-RHWM Load with Dedicated Resources, consistent with section 3.5.1 of the body of this Agreement, Surprise Valley may purchase DFS or FORS to support such resource. Surprise Valley shall request a copy of the then-current DFS or FORS standard contract provisions

OCT 1 5 2015

from BPA and shall notify BPA in writing by October 31 of a Rate Case Year that it elects to purchase DFS or FORS for the new Specified Resource under the terms stated in the then-current contract provisions and the terms of this section 2.2. Such election shall be a binding commitment of both Parties. The elected DFS or FORS will be effective at the start of the upcoming Rate Period. The duration of such purchase shall be for the remainder of the Purchase Period and for the following Purchase Period. If Surprise Valley makes such election, the Parties shall revise this exhibit by March 31 of the calendar year after Surprise Valley has given notice of its election. Such revision shall incorporate the agreed changes to applicable provisions, including the applicable resource amounts, if known. By September 30 of the last Rate Case Year prior to the first Rate Period when service begins, and by each applicable September 30 thereafter, in accordance with the applicable incorporated contract language, BPA shall update the relevant tables included in the incorporated contract language with the applicable charges and any necessary updates to resource amounts.

3. IRRIGATION RATE MITIGATION

Subject to the terms specified in BPA's applicable Wholesale Power Rate Schedules and GRSPs:

3.1 for billing purposes, in the months listed below for each year during the term of this Agreement, BPA shall apply Irrigation Rate Mitigation to the lesser of the corresponding amount purchased at the Tier 1 Rate in the month or the energy amount in the table below:

Irrigation Amounts (kWh)

May	Jun	Jul	Aug	Sept	Annual Total
6,464,252	9,066,424	11,421,596	11,671,642	7,586,987	46,210,901

3.2 after the end of each irrigation season, the Parties shall administer a true-up process to ensure Surprise Valley's irrigation load meets or exceeds the total eligible irrigation amount (in kilowatt-hours) listed above; and

3.3 Surprise Valley shall be responsible for implementing cost-effective conservation measures on irrigation systems in their service territories. Surprise Valley shall verify and report all conservation measures and project savings consistent with section 18.1.2 of the body of this Agreement.

4. LIMITATIONS ON EXCHANGE OF EXISTING RESOURCES

4.1 **Option on Full ASC Participation and Alternative Contract**
BPA's 2008 Average System Cost (ASC) Methodology limits the loads and resource costs included in ASCs for consumer-owned utilities that sign a CHWM Contract. The TRM establishes a Tier 1 PF Exchange Rate for such consumer-owned utilities. Pursuant to section 12.2 of the body of this Agreement and section 20 of the Residential Purchase and Sale Agreement

(RPSA), Surprise Valley is contractually precluded from seeking or receiving Residential Exchange Program (REP) benefits based on an ASC other than as provided for in Section IV(G) of the 2008 ASC Methodology or its successor.

BPA and Surprise Valley understand and acknowledge that this is the first time BPA has attempted to implement an REP with two different ASC cost structures and two differing levels of benefits, and that as a consequence, the implementation of the REP may be revised over time. Because of the contractual preclusions in the paragraph above and because a limited number of consumer-owned utilities with CHWM Contracts may participate in the REP, the intent of this section 4 is to provide limited protection to such consumer-owned utilities from future changes in the REP.

Any impact to Surprise Valley's access to REP benefits, pursuant to section 5(c) of the Northwest Power Act, as a result of an action taken by BPA as required by a statutory change or final judicial action shall not be considered an Action as provided in section 4.2 below, shall not be subject to the criteria provided in section 4.3 below, and shall not make available the option provided in section 4.4 below.

Absent the exercise by Surprise Valley of the option set forth in section 4.4 below, nothing in this section 4 is intended to alter the application of any provision of the ASC Methodology.

4.2 **Actions**

If BPA takes any of the following Actions and such Actions meet the criteria specified in section 4.3, then Surprise Valley may elect the option set forth in section 4.4 below.

<u>**Action 1.**</u> BPA adopts, in a final record of decision issued in a section 7(i) proceeding for a Rate Period, a Base Tier 1 PF Exchange Rate for customers with CHWM Contracts which is calculated in a manner that differs from the following:

$$\text{Base T1 PF Exchange Rate} = \frac{(\text{PFCosts} - \text{PFCredits}) - (\text{T2Costs} - \text{T2Credits})}{\text{PFLoad} - \text{T2Load}} + \text{TmnAddr}$$

Where:

Base T1 PF Exchange Rate is the Base Tier 1 PF Exchange rate prior to the final allocation of any rate protection costs arising from the section 7(b)(2) rate test, as determined in each 7(i) Process.

PFCosts are all costs allocated in a 7(i) Process to the Priority Firm rates when the Base PF Exchange rate is calculated (also known as the unbifurcated PF rate) and prior to any reflection of the tiering of the PF Preference rate.

PFCredits are all credits allocated in a 7(i) Process to the Priority Firm rates when the Base PF Exchange rate is calculated (also known as the unbifurcated PF rate) and prior to any reflection of the tiering of the PF Preference rate.

T2Costs are all costs allocated in a 7(i) Process to Tier 2 Cost Pools.

T2Credits are all credits allocated in a 7(i) Process to Tier 2 Cost Pools.

PFLoad is the BPA forecast of load used to determine the unbifurcated PF rate in a 7(i) Process.

T2Load is the BPA forecast of load used to determine Tier 2 Rates in a 7(i) Process.

TmnAddr is the same unit charge for transmission added to the Base PF Exchange rate.

The Tier 1 PF Exchange rate used to calculate Surprise Valley's REP benefits is the Base Tier 1 PF Exchange rate as modified by any Supplemental 7(b)(3) Rate Charge, as determined in each 7(i) Process and may be adjusted pursuant to the Supplemental 7(b)(3) Rate Charge Adjustment, any cost recovery adjustment clause, and any dividend distribution clause, as determined to be applicable to the Tier 1 PF Exchange rate in a 7(i) Process.

Action 2. BPA adopts, in a final record of decision, policy or interpretation, a method of calculating Surprise Valley's ASC for a Fiscal Year(s) of an Exchange Period pursuant to BPA's 2008 ASC Methodology or its successor that differs from the following formula:

$$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$

Where:

RHWM ASC is the ASC for Surprise Valley for an Exchange Period, as defined by BPA's 2008 ASC Methodology.

Contract System Cost is as defined in BPA's 2008 ASC Methodology.

NewRes$ is the forecast cost of resources (including purchased power contracts) used under this Agreement to serve Surprise Valley's Above-RHWM Load. Such resources are exclusive of Surprise Valley's Existing Resources for CHWMs as specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA. The costs included in NewRes$ will be determined using a methodology similar to Appendix 1 Endnote d of BPA's 2008 ASC Methodology.

Contract System Load is as defined in BPA's 2008 ASC Methodology.

NewResMWh is the forecast generation from resources (including purchased power contracts) used under this agreement to serve Surprise Valley's Above-RHWM Load. Such resources are exclusive of Surprise Valley's Existing Resources for CHWMs specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA.

Action 3. BPA offers Surprise Valley an RPSA with an Exchange Load used to calculate Surprise Valley's REP benefits payments that differs from the following formula, or interprets such RPSA in a manner that differs from the following formula:

$$\text{Actual RHWM Exchange Load} = \text{RRL} \times \text{T1Pctg}$$

Where:

Actual RHWM Exchange Load is the monthly residential and small farm load of Surprise Valley used to calculate the actual monthly REP payments to Surprise Valley as specified in the RPSA.

RRL is Surprise Valley's actual total qualifying residential and small farm retail load for a month as specified in the RPSA.

$$\text{T1Pctg} = \frac{\text{T1MWh} + \text{ExistResMWh}}{\text{TRL} - \text{NLSL}}$$

Where:

T1Pctg is BPA's forecast percentage of Surprise Valley's load that is expected to be served by purchases of power at Tier 1 Rates from BPA and from Surprise Valley's Existing Resources for CHWM, and will be computed for each Fiscal Year of the applicable Rate Period. Such computation will be performed in the applicable RHWM Process for the Rate Period.

T1MWh is the amount of power at Tier 1 Rates BPA forecasts to be purchased by Surprise Valley from BPA in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

ExistResMWh is the specified output of Surprise Valley's Existing Resources for CHWM, as specified in Attachment C, Column D, of the TRM.

TRL is BPA's forecast of Surprise Valley's Total Retail Load in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

NLSL is BPA's forecast of Surprise Valley's New Large Single Loads in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

<u>Action 4.</u> BPA adopts a final record of decision, policy or interpretation that changes the terms of the TRM or the 2008 ASC Methodology applicable to REP participants with CHWM Contracts and such change is not encompassed in Actions 1-3, and such change meets the criteria in section 4.3 for application of the option in section 4.4.

4.3 **Criteria**
The option set forth in section 4.4 below is available to Surprise Valley if BPA has taken any of the Actions 1-4 set forth in section 4.2 and the Actions taken, when considered in combination with all BPA actions being undertaken at that time, result in a material reduction in the REP benefits of the class of REP participants with CHWM Contracts. A reduction shall not be "material" for purposes of this section 4.3 if such Action(s), when considered in combination with all BPA actions being undertaken at that time, are applied to the provisions applicable to all REP participants and produce the same or comparable effects on all REP participants, even if such Action(s) results in an otherwise material reduction in the REP benefits of the class of REP participants with CHWM Contracts.

4.4 **Option**
If Surprise Valley believes that BPA has taken any of the Actions 1 through 4 set forth in section 4.2 that satisfies the criteria for this option as set forth in section 4.3, and if BPA has provided a public comment process as part of BPA's decision process (for the relevant Action of Actions 1 through 4 set forth in section 4.2) in which Surprise Valley has commented that BPA was proposing or about to take such Action, then Surprise Valley, within 30 calendar days of BPA taking such alleged Action(s), may provide written notice to BPA in accordance with section 20 of this Agreement requesting an alternative power sales contract without a CHWM. Upon receipt of such written notice, BPA shall review the request and, within 60 calendar days, issue a written statement regarding whether the criteria of section 4.3 have been satisfied.

4.4.1 If BPA believes the criteria of section 4.3 have not been satisfied, the dispute shall be resolved through the dispute resolution provisions in section 22 of this Agreement, provided, however, that the sole function of arbitration shall be to determine whether the criteria of section 4.3 have been satisfied, not the exclusive remedy of money damages set forth in section 22.4 of this Agreement. If the dispute resolution results in a final determination that the criteria of section 4.3 have been satisfied, BPA shall have 90 calendar days from the date of such final determination to take curative action to restore the REP benefits of the class of REP participants with CHWM Contracts to the level that would have existed had BPA not taken the Action(s) that resulted in the criteria of section 4.3 being satisfied; provided, however, that if

BPA elects not to take such curative action within such 90 day period, BPA shall have 180 calendar days after the date of such determination to offer to Surprise Valley an alternative power sales contract without a CHWM.

4.4.2 If BPA determines that the criteria of section 4.3 have been satisfied, BPA shall have 90 calendar days from the date of such determination to take curative action to restore the REP benefits of the class of REP participants with CHWM Contracts to the level that would have existed had BPA not taken the Action(s) that resulted in the criteria of section 4.3 being satisfied; provided, however, that if BPA elects not to take such curative action, it shall have 180 calendar days after the date of such determination to offer to Surprise Valley an alternative power sales contract without a CHWM.

4.4.3 Such alternative power sales contract shall be for the same purchase obligation in section 3 of this Agreement that is in effect at the time the notice under this section 4.4 is provided to BPA. Surprise Valley acknowledges that the terms and conditions of such alternative power sales contract may vary from those contained in the CHWM Contract.

4.4.4 Surprise Valley shall notify BPA in accordance with section 20 no later than 60 calendar days after the date of its receipt of such alternative power sales contract whether it will terminate its CHWM Contract and execute such alternative power sales contract, or retain its CHWM Contract. If Surprise Valley fails to notify BPA within the 60-day period of its decision regarding its CHWM Contract, BPA's offer of the alternative power sales contract without a CHWM shall be withdrawn as of the 61st day and Surprise Valley will be conclusively presumed to have elected to retain its CHWM Contract.

4.4.5 If Surprise Valley provides BPA timely notice of its election to terminate its CHWM Contract and executes the alternative power sales contract, service under such alternative power sales contract shall not commence until the beginning of the Rate Period immediately following the Rate Period in which the alternative power sales contract is executed. Termination of Surprise Valley's CHWM Contract shall be effective at commencement of service under the alternative power sales contract.

5. TERMS AND CONDITIONS OF SURPRISE VALLEY'S WREGIS SUBACCOUNT

Although section 5(2) of Exhibit H, Renewable Energy Certificates and Carbon Attributes states that the terms and conditions of Surprise Valley's BPA-managed WREGIS subaccount (WREGIS subaccount) will be established in a separate agreement, this provision establishes the terms and conditions of Surprise Valley's WREGIS subaccount into this Exhibit D in lieu of a separate agreement.

5.1 **Definitions**

In addition to the defined terms included in Exhibit H, Renewable Energy Certificates and Carbon Attributes, this section 5 also includes the following defined term: "Retire" or "Retirement" which means an action taken to remove a REC from circulation within Western Renewable Energy Generation Information System (WREGIS) or its successor.

5.2 **Establishment of WREGIS Subaccount**

In accordance with Surprise Valley's election under section 5(2) of Exhibit H to have Surprise Valley's RECs transferred to a WREGIS subaccount, BPA shall establish a subaccount in Surprise Valley's name within BPA's WREGIS account. BPA shall provide Surprise Valley read-only access to its subaccount.

BPA shall use such subaccount solely for the purposes of transferring and Retiring RECs that Surprise Valley receives from BPA.

Surprise Valley gives its consent to be bound by the terms stated in the WREGIS Account Holder Registration Agreement, also referred to as the WREGIS Terms of Use (WREGIS TOU) Agreement, Contract No. 08PB-11957, executed by BPA and including any revisions. BPA shall make the executed WREGIS TOU Agreement available at a publicly accessible website.

5.3 **Transfer of RECs to Surprise Valley's WREGIS Subaccount**

BPA shall transfer Surprise Valley's share of Tier 1 RECs, and Tier 2 RECs if applicable, to Surprise Valley's WREGIS subaccount pursuant to the timeline established in section 5 of Exhibit H.

Any RECs BPA transfers to Surprise Valley shall be limited to those available to BPA through WREGIS and shall be a blend of RECs pursuant to Exhibit H. If BPA adds, replaces, or removes a resource from the list in section 2 of Exhibit H, then BPA may adjust the blend of RECs accordingly. BPA shall notify Surprise Valley of any such changes in the letter BPA provides to Surprise Valley by April 15 pursuant to section 3(2) of Exhibit H.

5.4 **Resale, Purchase, and Retirement of RECs**

If Surprise Valley wants to sell RECs received from BPA outside of its service territory or purchase RECs other than those RECs it receives from BPA, then Surprise Valley shall terminate its WREGIS subaccount pursuant to section 5.6 below and establish its own WREGIS account.

Upon receipt of written notice for Retirement from Surprise Valley, BPA shall Retire Surprise Valley's RECs on its behalf. In such notice, for the RECs Surprise Valley wants BPA to Retire Surprise Valley shall identify REC quantity, the name of the renewable project(s) which generated the RECs, and the month and year the RECs were generated by the project(s).

5.5 **WREGIS Subaccount Fees**
Consistent with section 6 of Exhibit H, BPA shall pay any fees associated with establishing Surprise Valley's WREGIS subaccount and any fees associated with the transfer of RECs into Surprise Valley's WREGIS subaccount. Surprise Valley shall reimburse BPA for all other fees associated with Surprise Valley's WREGIS subaccount including but not limited to any REC Retirement fees. Such reimbursement shall be effectuated through a charge on Surprise Valley's bill pursuant to section 16 of this Agreement. Surprise Valley shall be responsible for all WREGIS fees incurred from the termination of its WREGIS subaccount and Surprise Valley shall pay all fees associated with establishment of its own WREGIS account.

5.6 **Termination of Surprise Valley's WREGIS Subaccount**
Either Party may terminate Surprise Valley's WREGIS subaccount after providing 30 days' advance written notice to the other Party.

However, BPA shall not terminate Surprise Valley's WREGIS subaccount until: (1) Surprise Valley has established its own WREGIS account and BPA has received written notice from Surprise Valley to transfer 100 percent of Surprise Valley's RECs into Surprise Valley's own WREGIS account; or (2) BPA has provided all RECs due to Surprise Valley for the previous calendar year under section 5.3 above and BPA has received written notification from Surprise Valley to Retire 100 percent of Surprise Valley's RECs contained in Surprise Valley's WREGIS subaccount. Surprise Valley may not have both a WREGIS account and a WREGIS subaccount open at the same time.

Unless otherwise agreed by the Parties, if Surprise Valley terminates its WREGIS subaccount, then BPA shall not establish another WREGIS subaccount for Surprise Valley for the remaining term of this Agreement.

6. TRANSFER OF CARBON ALLOWANCES TO BPA
Starting in calendar year 2013, the California Air Resource Board (CARB) will institute a carbon compliance obligation on electricity importers that provide power into California. The U S. Department of Energy has directed BPA to voluntarily comply with the requirement of this state obligation by obtaining, without charge from Surprise Valley, sufficient carbon allowances to cover BPA's firm requirements power delivery to Surprise Valley.

Over the term of this Agreement, Surprise Valley shall annually transfer carbon allowances to BPA in the amount requested by BPA that is sufficient to satisfy BPA's voluntary compliance obligations that arise in order to serve Surprise Valley's load in California. Starting January 2014 and by each September 30 thereafter, BPA shall calculate and inform Surprise Valley of the amount of carbon allowances required to be transferred based on the amount of power BPA imported into California to serve Surprise Valley during the prior calendar year. The calculation to determine the amount of carbon allowances Surprise Valley shall transfer to BPA shall have three variables that when multiplied together result in a carbon compliance amount in metric tons of carbon dioxide equivalent (CO_2e):

(a) the amount of power deliveries (in megawatt hours) that BPA made to Surprise Valley in California during the prior calendar year, and

(b) the BPA system emission factor for the prior calendar year as reported and confirmed with CARB in metric tons of CO2e per megawatt hour, and

(c) 2 percent transmission loss factor.

Surprise Valley shall complete the transfer of carbon allowances to BPA using CARB's Compliance Instrument Tracking System Service (CITSS), or its successor tracking system, no later than September 30 of each year.

BPA shall provide Surprise Valley with BPA's preliminary system emission factor for the applicable calendar year no later than March 31 of such applicable year to aid Surprise Valley in estimating the amount of carbon allowances to be transferred to BPA.

Surprise Valley agrees that fees charged to BPA by CARB, if any, on power deliveries to Surprise Valley shall be charged to Surprise Valley by BPA, on an annual basis and stated in Surprise Valley's December power bill.

7. TEMPORARY APPLICATION OF SURPRISE VALLEY'S PAISLEY GEOTHERMAL RESOURCE AMOUNTS TO SERVE TOTAL RETAIL LOAD

Surprise Valley has constructed, and owns, the Paisley Geothermal resource, which is expected to have completed testing and commissioning by September 2015. Paisley Geothermal is nameplate rated at 3.65 MW and will produce approximately 2.1 aMWs in output. Surprise Valley anticipates finalizing a power purchase agreement with a third party, for the entire Paisley Geothermal output prior to October 2016.

Surprise Valley requested (via letter to BPA dated August 7, 2015) to use the generation from Paisley Geothermal to serve Surprise Valley's Total Retail load on a temporary basis through September 30, 2016.

In response to Surprise Valley's request, BPA agrees: (1) to allow Surprise Valley to temporarily apply the output of Paisley Geothermal, as listed in section 6 of Exhibit A, to serve its Total Retail Load; and (2) that the temporary application of Paisley Geothermal to Surprise Valley's Total Retail Load shall not exceed September 30, 2016; and (3) during such time frame, to not apply section 3.2, "Take or Pay" and section 3.5.1, "Specified Resource Additions to Meet Above-RHWM Load".

Surprise Valley shall notify BPA of the date that Paisley Geothermal has completed testing and commissioning and the date Paisley Geothermal will commence commercial operation, and thus begin temporary application to Surprise Valley load. Provided, however, that such notice to BPA shall be prior to the month that Paisley Geothermal commences commercial operation.

When Surprise Valley commences its temporary application of Paisley Geothermal to its load, then the Parties shall revise Exhibit E to exclude the generation at meter point 4122 and shall not apply such generation to Surprise Valley's power bills.

By September 1, 2016, or sooner, Surprise Valley shall notify BPA if Surprise Valley has agreed to sell the output of Paisley Geothermal to another party effective October 1, 2016. If Surprise Valley has not agreed to sell the output to another party by October 1, 2016, then Surprise Valley may request that BPA add Paisley Geothermal as a Specified Resource to section 2 of Exhibit A of this Agreement with amounts effective October 1, 2016. If Surprise Valley does not have a power sale to another party and does not request that BPA add Paisley Geothermal as a Specified Resource effective October 1, 2016, then Surprise Valley agrees to end temporary service to load and BPA will revise Exhibit E to include generation metered at meter point 4122 in Surprise Valley's power bills effective October 1, 2016.

If the Parties agree that Surprise Valley can shut off generation at the Paisley Geothermal resource during an Oversupply Management Protocol event, then BPA shall have the right to replace Surprise Valley's Paisley Geothermal resource with BPA power at no cost to Surprise Valley if such an event occurs.

8. REVISIONS

This exhibit shall be revised by mutual agreement of the Parties to reflect additional products Surprise Valley purchases during the term of this Agreement.

9. SIGNATURES

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

SURPRISE VALLEY ELECTRIFICATION CORPORATION		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By	Bradley A Kresge	By	Daniel E Bloyer
Name	Bradley A. Kresge (Print/Type)	Name	Daniel E. Bloyer (Print/Type)
Title	General Manager	Title	Account Executive
Date	9/28/15	Date	9/30/15

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\Exh D\ 13110 Exh D R4.docx) 09/01/15

Revision No. 2, Exhibit E
METERING
Effective July 1, 2014

This revision No. 2: (1) corrects POD name in section 1.2(4); (2) adds the Lakeview In POM in section 1.2(6) and (3) adds the Paisley Geothermal Generation POMs in section 1.3(1).

1. **METERING**

1.1 **Directly Connected Points of Delivery and Load Metering**
None.

1.2 **Transfer Points of Delivery and Load Metering**

(1) **BPA POD Name:** Alturas 12.5 kV;
BPA POD Number: 817;
WECC Balancing Authority: PACW;

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

Voltage: 12.5 kV;

Metering: adjacent to PacifiCorp's Alturas Substation in the Surprise Valley's equipment yard 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Alturas Out;
BPA Meter Point Number: 244;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) This POD is subject to charges for Low Voltage Delivery established in section 14.6.2 of the body of this Agreement;

(B) The potential and current transformers are owned by Surprise Valley.

(2) **BPA POD Name:** Austin 69 kV;
BPA POD Number: 41;
WECC Balancing Authority: PACW;

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 flows;

BPA Meter Point Name: Austin Out;
BPA Meter Point Number: 132;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley

Metering Loss Adjustment: None;

Exception: The potential and current transformers are owned by BPA.

(3) **BPA POD Name:** Canby 69 kV;
BPA POD Number: 104;
WECC Balancing Authority: BPAT;

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

Voltage: 69 kV;

Metering: in Surprise Valley's Canby Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Canby Out (SVEC);
BPA Meter Point Number: 44;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: None.

(4) **BPA POD Name:** Cedarville Junction 69 kV - SURP;
BPA POD Number: 117;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Cedarville Junction Switching Station where the 69 kV facilities of Surprise Valley and BPA are connected;

Voltage: 69 kV;

Metering:

(A) in BPA's Cedarville Junction Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville Out;
BPA Meter Point Number: 65;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

(B) in Surprise Valley's Cedarville Substation in the 12.47 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville (PP&L) Out;
BPA Meter Point Number: 861;
Direction for PF Billing Purposes: Negative;
Manner of Service: Transfer, BPA to Surprise Valley to PacifiCorp;

Metering Loss Adjustment: BPA shall adjust for losses between the POD and the Cedarville (PP&L) Out POM. Such adjustments shall be specified in writing between BPA and Surprise Valley;

Exception: None.

(5) **BPA POD Name:** Davis Creek 12.5 kV;
BPA POD Number: 169;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Davis Creek Substation where the 12.5 kV facilities of Surprise Valley and BPA are connected;

Voltage: 12.5 kV;

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

BPA Meter Point Name: Davis Creek Out;
BPA Meter Point Number: 259;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) The potential transformers in the 12.5 kV meter installation are owned by Surprise Valley;

(B) BPA shall have unrestricted use, at no charge, of Surprise Valley's Davis Creek 115 kV Substation and tapline facilities.

(6) **BPA POD Name:** Lakeview 69 kV;
BPA POD Number: 383;
WECC Balancing Authority: PACW;

Location: the point in 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 flows;

BPA Meter Point Name: Lakeview Out;
BPA Meter Point Number: 41;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

BPA Meter Point Name: Lakeview In;
BPA Meter Point Number: 4123;
Direction for PF Billing Purposes: Negative;
Manner of Service: Transfer, Surprise Valley to PacifiCorp to BPA;

Metering Loss Adjustment: None;

Exception: The potential transformers in the 69 kV meter installation are owned by Surprise Valley.

1.3 **Resource Locations and Metering**

(1) **Resource Name:** Paisley Geothermal

Metering: in Surprise Valley's Paisley Geothermal Generation project in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Paisley GENR In;
BPA Meter Point Number: 4122;
Direction for PF Billing Purposes: Positive;
Manner of Service: Surprise Valley to PacifiCorp to BPA;

BPA Meter Point Name: Paisley STN SVC Out;
BPA Meter Point Number: 4121;
Direction for PF Billing Purposes: Not counted;
Manner of Service: BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: POM # 4122 and 4121 are located downstream from Surprise Valley's Lakeview Switching station. The Paisley Geothermal Generation offsets the load at Lakeview that would otherwise be captured at POM # 41. Therefore POM # 4121 is not used for PBL billed load.

2. REVISIONS

Each Party shall notify the other in writing if updates to this exhibit are necessary to accurately reflect the actual characteristics of POD and meter information described in this exhibit. The Parties shall revise this exhibit to reflect such changes. The Parties shall mutually agree on any such exhibit revisions and agreement shall not be unreasonably withheld or delayed. The effective date of any exhibit revision shall be the date the actual circumstances described by the revision occur.

3. SIGNATURES

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

SURPRISE VALLEY ELECTRIFICATION CORPORATION.

By Bradley A. Kresge

Name Brad Kresge
(Print/Type)

Title General Manager

Date 7/28/14

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Daniel E. Bloyer

Name Daniel E. Bloyer
(Print/Type)

Title Account Executive

Date 7-21-2014

(Surprise Valley_09PB-13110_ExE_Rev2_061014.doc)

Revision No. 3, Exhibit E
METERING
Effective October 1, 2015

This revision changes direction to meter #4122 for billing purposes and adds Exception language to the Paisley Geothermal Resource in section 1.3.

1. METERING

1.1 Directly Connected Points of Delivery and Load Metering

None.

1.2 Transfer Points of Delivery and Load Metering

(1) **BPA POD Name:** Alturas 12.5 kV;
BPA POD Number: 817;
WECC Balancing Authority: PACW;

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

Voltage: 12.5 kV;

Metering: adjacent to PacifiCorp's Alturas Substation in the Surprise Valley's equipment yard 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Alturas Out;
BPA Meter Point Number: 244;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) This POD is subject to charges for Low Voltage Delivery established in section 14.6.2 of the body of this Agreement;

(B) The potential and current transformers are owned by Surprise Valley.

(2) **BPA POD Name:** Austin 69 kV;
BPA POD Number: 41;
WECC Balancing Authority: PACW;

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 flows;

> **BPA Meter Point Name:** Austin Out;
> **BPA Meter Point Number:** 132;
> **Direction for PF Billing Purposes:** Positive;
> **Manner of Service:** Transfer, BPA to PacifiCorp to Surprise Valley

Metering Loss Adjustment: None;

Exception: The potential and current transformers are owned by BPA.

(3) **BPA POD Name:** Canby 69 kV;
BPA POD Number: 104;
WECC Balancing Authority: BPAT;

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

Voltage: 69 kV;

Metering: in Surprise Valley's Canby Substation in the 69 kV circuit over which such electric power flows;

> **BPA Meter Point Name:** Canby Out (SVEC);
> **BPA Meter Point Number:** 44;
> **Direction for PF Billing Purposes:** Positive;
> **Manner of Service:** Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: None.

(4) **BPA POD Name:** Cedarville Junction 69 kV-SURP;
BPA POD Number: 117;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Cedarville Junction Switching Station where the 69 kV facilities of Surprise Valley and BPA are connected;

Voltage: 69 kV;

Metering:

(A) in BPA's Cedarville Junction Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville Out;
BPA Meter Point Number: 65;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

(B) in Surprise Valley's Cedarville Substation in the 12.47 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville (PP&L) Out;
BPA Meter Point Number: 861;
Direction for PF Billing Purposes: Negative;
Manner of Service: Transfer, BPA to Surprise Valley to PacifiCorp;

Metering Loss Adjustment: BPA shall adjust for losses between the POD and the Cedarville (PP&L) Out POM. Such adjustments shall be specified in writing between BPA and Surprise Valley;

Exception: None.

(5) **BPA POD Name:** Davis Creek 12.5 kV;
BPA POD Number: 169;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Davis Creek Substation where the 12.5 kV facilities of Surprise Valley and BPA are connected;

Voltage: 12.5 kV;

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

BPA Meter Point Name: Davis Creek Out;
BPA Meter Point Number: 259;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) The potential transformers in the 12.5 kV meter installation are owned by Surprise Valley;

(B) BPA shall have unrestricted use, at no charge, of Surprise Valley's Davis Creek 115 kV Substation and tapline facilities.

(6) **BPA POD Name:** Lakeview 69 kV;
BPA POD Number: 383;
WECC Balancing Authority: PACW;

Location: the point in 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 flows;

BPA Meter Point Name: Lakeview Out;
BPA Meter Point Number: 41;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

BPA Meter Point Name: Lakeview In;
BPA Meter Point Number: 4123;
Direction for PF Billing Purposes: Negative;
Manner of Service: Transfer, Surprise Valley to PacifiCorp to BPA;

Metering Loss Adjustment: None;

Exception: The potential transformers in the 69 kV meter installation are owned by Surprise Valley.

1.3 **Resource Locations and Metering**

(1) Resource Name: Paisley Geothermal

Metering: in Surprise Valley's Paisley Geothermal Generation project in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Paisley GENR In;
BPA Meter Point Number: 4122;
Direction for PF Billing Purposes: Not counted;
Manner of Service: Surprise Valley to PacifiCorp to BPA;

BPA Meter Point Name: Paisley STN SVC Out;
BPA Meter Point Number: 4121;
Direction for PF Billing Purposes: Not counted;
Manner of Service: BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) POM # 4122 and 4121 are located downstream from Surprise Valley's Lakeview Switching station. The Paisley Geothermal Generation offsets the load at Lakeview that would otherwise be captured at POM # 41. POM # 4121 is not used for PBL billed load.

(B) For the period October 1, 2015 through September 30, 2016, Paisley Geothermal will be treated temporarily as if it were a small nondispatchable resource, and will be allowed contractually to serve Surprise Valley load. Therefore, for this period, subject to start and end dates established in accordance with Exhibit D, amounts measured by MP #4122 will not be counted in the Customer Load Report on Surprise Valley's Power Bill.

2. REVISIONS

Each Party shall notify the other in writing if updates to this exhibit are necessary to accurately reflect the actual characteristics of POD and meter information described in this exhibit. The Parties shall revise this exhibit to reflect such changes. The Parties shall mutually agree on any such exhibit revisions and agreement shall not be unreasonably withheld or delayed. The effective date of any exhibit revision shall be the date the actual circumstances described by the revision occur.

3. SIGNATURES

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

SURPRISE VALLEY ELECTRIFICATION CORPORATION.

By Bradley A Kresge

Name Bradley A Kresge
(Print/Type)

Title General Manager

Date 10/20/15

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

By Daniel E Bloyer

Name Daniel E. Bloyer
(Print/Type)

Title Account Executive

Date 10/30/15

(Surprise Valley_09PB-13110_ExE_Rev3_092315.doc)

Revision No. 1, Exhibit E
METERING
Effective October 1, 2011

This revision No. 1 adds exception language in section 1.2(1) and updates the POD location description in section 1.2(4).

1. METERING

1.1 Directly Connected Points of Delivery and Load Metering
None.

1.2 Transfer Points of Delivery and Load Metering

(1) **BPA POD Name:** Alturas 12.5 kV;
BPA POD Number: 817;
WECC Balancing Authority: PACW;

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

Voltage: 12.5 kV;

Metering: adjacent to PacifiCorp's Alturas Substation in the Surprise Valley's equipment yard 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Alturas Out;
BPA Meter Point Number: 244;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) This POD is subject to charges for Low Voltage Delivery established in section 14.6.2 of the body of this Agreement;

(B) The potential and current transformers are owned by Surprise Valley.

(2) **BPA POD Name:** Austin 69 kV;
BPA POD Number: 41;
WECC Balancing Authority: PACW;

AUG - 8 2011

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 flows;

> **BPA Meter Point Name:** Austin Out;
> **BPA Meter Point Number:** 132;
> **Direction for PF Billing Purposes:** Positive;
> **Manner of Service:** Transfer, BPA to PacifiCorp to Surprise Valley

Metering Loss Adjustment: None;

Exception: The potential and current transformers are owned by BPA.

(3) **BPA POD Name:** Canby 69 kV;
BPA POD Number: 104;
WECC Balancing Authority: BPAT;

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

Voltage: 69 kV;

Metering: in Surprise Valley's Canby Substation in the 69 kV circuit over which such electric power flows;

> **BPA Meter Point Name:** Canby Out (SVEC);
> **BPA Meter Point Number:** 44;
> **Direction for PF Billing Purposes:** Positive;
> **Manner of Service:** Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: None.

(4) **BPA POD Name:** Cedarville Junction 69-SURP;
BPA POD Number: 117;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Cedarville Junction Switching Station where the 69 kV facilities of Surprise Valley and BPA are connected;

Voltage: 69 kV;

Metering:

(A) in BPA's Cedarville Junction Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville Out;
BPA Meter Point Number: 65;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

(B) in Surprise Valley's Cedarville Substation in the 12.47 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville (PP&L) Out;
BPA Meter Point Number: 861;
Direction for PF Billing Purposes: Negative;
Manner of Service: Transfer, BPA to Surprise Valley to PacifiCorp;

Metering Loss Adjustment: BPA shall adjust for losses between the POD and the Cedarville (PP&L) Out POM. Such adjustments shall be specified in writing between BPA and Surprise Valley;

Exception: None.

(5) **BPA POD Name:** Davis Creek 12.5 kV;
BPA POD Number: 169;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Davis Creek Substation where the 12.5 kV facilities of Surprise Valley and BPA are connected;

Voltage: 12.5 kV;

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

BPA Meter Point Name: Davis Creek Out;
BPA Meter Point Number: 259;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) The potential transformers in the 12.5 kV meter installation are owned by Surprise Valley;

(B) BPA shall have unrestricted use, at no charge, of Surprise Valley's Davis Creek 115 kV Substation and tapline facilities.

(6) **BPA POD Name:** Lakeview 69 kV;
BPA POD Number: 383;
WECC Balancing Authority: PACW;

Location: the point in 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 flows;

BPA Meter Point Name: Lakeview Out;
BPA Meter Point Number: 41;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacificCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: The potential transformers in the 69 kV meter installation are owned by Surprise Valley.

1.3 **Resource Locations and Metering**
None.

2. REVISIONS

Each Party shall notify the other in writing if updates to this exhibit are necessary to accurately reflect the actual characteristics of POD and meter information described in this exhibit. The Parties shall revise this exhibit to reflect such changes. The

Parties shall mutually agree on any such exhibit revisions and agreement shall not be unreasonably withheld or delayed. The effective date of any exhibit revision shall be the date the actual circumstances described by the revision occur.

3. **SIGNATURES**
The Parties have caused this revision to be executed as of the date both Parties have signed this revision.

SURPRISE VALLEY ELECTRIFICATION CORPORATION.		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By	[signature]	By	[signature]
Name	Daniel W. Silveria (Print/Type)	Name	Daniel E. Blover (Print/Type)
Title	General Manager	Title	Account Executive
Date	July, 19, 2011	Date	7/26/11

(Surprise Valley 09PB-13110_Exh E_Rev1_052611.doc)

Revision No. 1, Exhibit F
TRANSMISSION SCHEDULING SERVICE
Effective on the Date Executed by Both Parties

This revision incorporates the provisions for the Transmission Curtailment Management Service (TCMS) as a feature of Transmission Scheduling Service.

1. DEFINITIONS, PURPOSE AND PARAMETERS

1.1 Definitions

1.1.1 "Planned Transmission Outage" means an event that reduces the transmission capacity on a segment of the transmission path used to deliver Surprise Valley's Dedicated Resource prior to the initial approval of the E-Tag.

1.1.2 "Transmission Curtailment" means an event that is initiated by a transmission provider through a curtailment to the E-Tag as a result of transmission congestion or an outage on the path used to deliver Surprise Valley's Dedicated Resource.

1.1.3 "Transmission Event" means a Planned Transmission Outage or a Transmission Curtailment.

1.2 Purpose

Transmission Scheduling Service is provided by Power Services to help Surprise Valley manage certain aspects of its BPA Network Integration Transmission Service Agreement (BPA NT Agreement), to allow BPA to use the inherent flexibilities of Surprise Valley's network rights in combination with other network customers' rights to manage BPA's power resources efficiently, and to provide seamless scheduling for Transfer Service customers.

1.3 Parameters of Transmission Scheduling Service

Beginning October 1, 2011, and through the term of this Agreement, Power Services shall provide and Surprise Valley shall purchase Transmission Scheduling Service. Power Services shall schedule Surprise Valley's federal power and Dedicated Resources to Surprise Valley's Total Retail Load under Surprise Valley's BPA NT Agreement and/or other transmission agreement(s). Power Services shall not provide Transmission Scheduling Service for anything other than delivery to Surprise Valley's Total Retail Load.

Power Services shall perform all necessary prescheduling and real-time scheduling functions, and make other arrangements and adjustments, consistent with any RSS products and any other products and services Surprise Valley is purchasing from Power Services. Surprise Valley shall continue to be responsible for all non-scheduling provisions of its transmission agreement(s) used to serve Surprise Valley's Total Retail Load,

OCT 25 2010

in accordance with the applicable OATT, including, but not limited to, the designation and undesignation of Network Resources, as defined by the applicable OATT.

Surprise Valley shall be subject to the rates, terms and conditions for Transmission Scheduling Service specified in BPA's applicable Wholesale Power Rate Schedules and GRSPs.

2. ASSIGNMENT OF SCHEDULING RIGHTS

Prior to Power Services providing Transmission Scheduling Service, Surprise Valley shall:

(1) notify Transmission Services that Power Services is the scheduling entity for service taken under Surprise Valley's BPA NT Agreement;

(2) assign Power Services the right to acquire and manage secondary service pursuant to section 28.4 of the BPA OATT as necessary to fulfill BPA's obligations under this Agreement; and

(3) provide copies of Surprise Valley's transmission agreement(s) used to serve Surprise Valley's Total Retail Load.

Additionally, over the term of this Agreement, Surprise Valley shall provide Power Services with any additional transmission agreements Surprise Valley enters into which are used for service to its Total Retail Load and all amendments and modifications to current copies of Surprise Valley's transmission agreement(s).

3. LOAD FORECAST

If a daily load forecast is required by Surprise Valley's transmission agreement(s), then BPA shall develop the daily and hourly load forecasts for Surprise Valley's Total Retail Load. Surprise Valley shall cooperate with BPA in all load forecasting. If any load specific information is needed for developing a daily or hourly load forecast, then Surprise Valley shall provide such information in a timely manner.

4. SCHEDULING OF SURPRISE VALLEY'S DEDICATED RESOURCES

4.1 **Prescheduling**

Surprise Valley shall submit a delivery schedule to Power Services for its Dedicated Resources for delivery to its Total Retail Load which shall include information such as the source, any points of receipt, any Open Access Same-time Information System (OASIS) reservation reference numbers needed for the delivery of non-federal power, the daily megawatt profile, and all purchasing selling entities in the path. This delivery schedule shall be submitted to Power Services by the earlier of one hour prior to the close of the firm transmission prescheduling deadline associated with the transmission agreement(s) used to deliver power to Surprise Valley's Total Retail Load, or 1100 hours Pacific Prevailing Time (PPT) on the preschedule day.

Surprise Valley shall submit all required prescheduled information in a format specified by Power Services.

At Power Services' request, Surprise Valley shall provide Power Services information on real power losses associated with Surprise Valley's transmission agreement(s).

4.2 **Real-Time Scheduling**

Power Services shall accept megawatt adjustments to Surprise Valley's Dedicated Resource schedule(s) up to the earlier of 45 minutes prior to the hour of delivery or 25 minutes prior to the earliest of the transmission real-time scheduling deadlines associated with delivery of power to Surprise Valley's Total Retail Load.

Surprise Valley shall submit all required real-time scheduling information in a format specified by Power Services.

4.3 **Transmission Curtailments**

4.3.1 **Notification Preference**

Prior to the delivery of Surprise Valley's Dedicated Resources to Surprise Valley's load, Surprise Valley shall notify BPA whether it wants to receive either an electronic copy of the E-Tag or an e-mail of a Transmission Curtailment that impacts any of Surprise Valley's Dedicated Resources. If Surprise Valley chooses notification of Transmission Curtailments by e-mail, then Surprise Valley shall provide BPA a single e-mail address for BPA to send such notifications to, and the Parties shall revise the table in section 4.3.6 below to include the e-mail address. BPA shall notify Surprise Valley no later than ten minutes after a Transmission Curtailment.

4.3.2 **Transmission Curtailment Management Service (TCMS)**

As a feature of Transmission Scheduling Service, BPA shall provide Transmission Curtailment Management Service (TCMS) for certain Surprise Valley Dedicated Resources that require an E-Tag for delivery. TCMS coverage shall apply when Transmission Events impact eligible resources, with certain limitations as described throughout this section 4.3.

In accordance with the BPA OATT, TCMS coverage shall not apply while Transmission Services is redispatching Surprise Valley's Dedicated Resource(s) to serve Surprise Valley's load during a Transmission Event.

4.3.3 **Curtailment and Outage Terms and Conditions for Resources without TCMS**

This section 4.3.3 shall apply to Surprise Valley's Dedicated Resources for which Power Services is not providing TCMS coverage.

4.3.3.1 If a Transmission Curtailment occurs prior to 45 minutes before the hour of delivery, then Surprise Valley shall be responsible for securing replacement energy or alternate transmission, arranging delivery to the Balancing Authority Area in which Surprise Valley is located, and notifying Power Services of the revised delivery schedule prior to 45 minutes before the hour of delivery.

If Power Services is unable to secure secondary network transmission for the replacement resource because Surprise Valley did not notify Power Services of the revised delivery schedule prior to 45 minutes prior to the hour of delivery or secondary network transmission is unavailable, then Surprise Valley shall be subject to charges consistent with the provisions of this Agreement and all related products and BPA's power rate schedules, including UAI charges.

4.3.3.2 Power Services shall not accept replacement delivery schedules for Transmission Curtailments that occur less than 45 minutes before the delivery hour. Surprise Valley shall be subject to charges consistent with the provisions of this Agreement and all related products and BPA's power rate schedules, including UAI charges.

4.3.3.3 If a Planned Transmission Outage is announced prior to Surprise Valley's submission of a delivery schedule in pre-schedule, then Surprise Valley shall be responsible for securing replacement energy or alternate transmission, arranging delivery to the Balancing Authority Area in which Surprise Valley is located, and notifying Power Services of the revised delivery schedule prior to the preschedule deadline described in section 4.1 of this exhibit.

4.3.4 **TCMS Coverage Eligibility, Determination and Termination**

4.3.4.1 **Eligibility of Resources for TCMS Coverage**
Power Services shall provide TCMS coverage for Surprise Valley's Dedicated Resource if such resource has been granted firm transmission by all applicable transmission providers.

Power Services may, on a case-by-case basis and with certain limitations on the service, provide TCMS coverage for Surprise Valley's Dedicated Resource that has not yet been granted firm network transmission by all applicable transmission providers if Power Services and Surprise Valley are actively engaged in the process of obtaining firm network transmission. Power Services and Surprise Valley shall work cooperatively to obtain firm network transmission for the

Dedicated Resource pursuant to the principles in Exhibit G of this Agreement and the Parties' executed Transfer Service Support for Non-Federal Resources Agreement. Power Services shall have sole discretion in determining whether or not Power Services and Surprise Valley are actively engaged in the process of obtaining firm network transmission. However, when making this determination Power Services shall use criteria including but not limited to: (1) the date Surprise Valley requests that Power Services pursue firm network transmission; (2) the planned start date for service from the Dedicated Resource; (3) the location of the resource; (4) the potential for Transmission Curtailments associated with delivering the resource on non-firm transmission; (5) the status of any ongoing OASIS requests and studies related to the resource; and (6) the length of time Power Services and Surprise Valley have been in the process of obtaining firm network transmission.

In addition, Power Services shall also provide TCMS coverage for Surprise Valley's Dedicated Resource as provided for in section 4.3.5 of this exhibit.

4.3.4.2 **BPA's Determination for TCMS Coverage**
If Surprise Valley notifies Power Services that it is pursuing firm network transmission with all applicable transmission providers, then Power Services shall provide Surprise Valley with a determination of whether or not it may purchase such TCMS within 30 days following Power Services' receipt of Surprise Valley's notice.

4.3.4.3 **Termination of TCMS Coverage**
If BPA is providing TCMS coverage to Surprise Valley for a Dedicated Resource that has not been granted firm network transmission by Transmission Services and a request for firm network transmission for such Dedicated Resource is withdrawn, or if such request is declined or invalidated without a timely resubmission of a similar request, then Surprise Valley shall notify BPA immediately and BPA shall terminate the provision of TCMS for Surprise Valley's Dedicated Resource ten Business Days after such notification.

If BPA is providing TCMS coverage to Surprise Valley for a Dedicated Resource that has not been granted firm network transmission and BPA offers Surprise Valley a Network Resource Exhibit to the Transfer Service Support for Non-Federal Resources Agreement for such Dedicated Resource, and such Network Resource Exhibit is not executed by Surprise Valley within 30 days of the offer, then BPA shall terminate the provision of TCMS for Surprise Valley's Dedicated Resource ten Business Days following the aforementioned 30 day period.

4.3.5 **Initial Resource Exception to Certain TCMS Limitations**
In order to facilitate customer acquisition of non-federal resources in the Transition Period described in sections 4.3.5(1) and 4.3.5(2) below, and in recognition that there may be delays in obtaining firm network transmission, BPA shall make the exception described in this section 4.3.5.

For certain Dedicated Resources that have not yet been granted firm network transmission by all applicable transmission providers, BPA shall provide TCMS without the case-by-case determination described in section 4.3.4.1 and without the limitations described in section 4.3.7.1. A Dedicated Resource shall be eligible for these exceptions only if it meets each of the following criteria:

(1) the Dedicated Resource is first used to serve Surprise Valley's Above-RHWM Load in FY 2012 or FY 2013 for a period of up to five Fiscal Years; and

(2) the Dedicated Resource is delivered in both a Flat Annual Shape and Flat Within-Month Shape and used to serve Surprise Valley's Above-RHWM Load for at least one Fiscal Year in duration; and

(3) the Dedicated Resource is a market purchase consistent with the terms of the Western Systems Power Pool Service Schedule C; and

(4) the Dedicated Resource is delivered at a point of receipt between the BPA Balancing Authority Area and the source Balancing Authority Area, delivered to the Northwest Market Hub on firm transmission, or delivered to the Mid-C hub as defined in Transmission Services Business Practices with a contractual arrangement that allows a new schedule to originate from the Mid-C hub; and

(5) the Dedicated Resource is recognized by Transmission Services as a firm resource for purposes of designation as a Network Resource and a request for firm network transmission for the Dedicated Resource has been submitted to all applicable Transmission Providers, and Surprise Valley is actively in the process of obtaining firm network transmission for the Dedicated Resource.

If a Dedicated Resource ceases to meet any of the conditions described in this section 4.3.5, BPA shall only provide TCMS as described in all other sections of this exhibit.

4.3.6 **TCMS Coverage by Resource**

The Parties shall list Surprise Valley's Dedicated Resources that require an E-Tag in the table(s) below, and indicate whether Surprise Valley shall purchase TCMS for each resource. BPA shall update the table(s) below as needed.

Name of Dedicated Resource	Location of Resource (Balancing Authority Area)	Name and E-mail address of Surprise Valley scheduling contact	Name and E-mail address of contact at resource
None at this time			

Firm Network Transmission			TCMS Coverage		All Applicable OASIS Assignment Reference Numbers (AREF)	Contract path for delivering resource (Source-POR-POD-Sink)
Yes	No	In Process	Yes	No		

4.3.7 **Curtailment and Outage Terms and Conditions for Resources with TCMS Coverage**

For Dedicated Resources with TCMS coverage identified in section 4.3.6 above, BPA shall deliver replacement power to Surprise Valley during any Transmission Event that is announced for the hour(s) of delivery that affects Surprise Valley's Dedicated Resource, through the duration of the Transmission Event, if any of the following occur:

(1) the Transmission Event affects any firm Point-to-Point Transmission used to deliver the resource to Surprise Valley's load, as identified in section 4.3.6 of this exhibit; or,

(2) the Transmission Event affects the Secondary Network Transmission used to deliver the resource to Surprise Valley's load, as identified in section 4.3.6 of this exhibit; or,

(3) Transmission Services has curtailed firm network transmission pursuant to section 33.6 or 33.7 of the BPA OATT; or,

(4) the Transmission Event affects the firm network transmission obtained by Power Services from a Third Party Transmission Provider and used to deliver the resource to Surprise Valley's load, as identified in section 4.3.6 of this exhibit.

If the Transmission Event is multiple hours in duration, BPA shall provide TCMS coverage for the entire Transmission Event. During any Planned Transmission Outage that impacts Surprise Valley's Dedicated Resource with TCMS coverage, BPA may, at BPA's sole discretion, obtain alternate transmission from such resource to Surprise Valley's load instead of delivering replacement power to Surprise Valley's load. If a Planned Transmission Outage affects a Dedicated Resource with TCMS coverage, then Power Services shall notify Surprise Valley of such Planned Transmission Outage.

If a Planned Transmission Outage is cancelled or adjusted such that Surprise Valley is able to deliver any portion of the resource to load normally during any portion of the previously announced Planned Transmission Outage, then Surprise Valley shall do so.

4.3.7.1 **Limitations on the Frequency of TCMS Coverage**
If Surprise Valley is purchasing TCMS for a Dedicated Resource with firm transmission from all applicable providers, or if Surprise Valley is purchasing TCMS for a Dedicated Resource as provided for in section 4.3.5, then BPA shall provide TCMS without the following limits identified in this section 4.3.7.1.

If, pursuant to section 4.3.4 above, BPA has allowed Surprise Valley to purchase TCMS for a resource that has not yet been granted firm network transmission, then throughout each Fiscal Year for each such resource, BPA shall periodically assess how frequently TCMS has been needed during that Fiscal Year. If BPA determines that in such Fiscal Year TCMS has been used to replace such Dedicated Resource in ten separate occurrences, where each occurrence TCMS was used was due to a separate Transmission Event on a different day, and for a cumulative total of at least 168 hours, BPA may terminate Surprise Valley's TCMS coverage for such resource 30 days after providing notice to Surprise Valley.

4.3.7.2 **TCMS Payment Obligations**
Surprise Valley shall be subject to charges for Transmission Scheduling Service, including applicable costs for TCMS, consistent with the provisions of this Agreement and BPA's Wholesale Power Rate Schedules and GRSPs, including any applicable UAI charges. Additionally, during a Transmission Event, BPA shall not assess a UAI charge on a Dedicated Resource with TCMS coverage.

4.3.8 **TCMS Coverage after Termination**
If TCMS coverage is terminated, pursuant to section 4.3.4 or 4.3.7.1 of this exhibit, Surprise Valley shall be responsible for obtaining replacement power during any Transmission Event that impacts such Dedicated Resource and for any applicable UAI charges that may apply pursuant to section 4.3.3 above.

In addition, for any resource for which BPA has terminated TCMS coverage due to frequency of use, as described in section 4.3.4 or 4.3.7.1 of this exhibit, BPA shall allow Surprise Valley to resume purchasing TCMS for the resource only after Surprise Valley notifies BPA that such resource has obtained firm network transmission.

5. E-TAGS

To the extent E-Tags are required by transmission provider(s), Power Services shall create all E-Tags necessary for delivery of energy to Surprise Valley's Total Retail Load.

6. GENERATION IMBALANCE

Surprise Valley shall be responsible for costs associated with deviations between the scheduled Dedicated Resources for an hour and the actual generation produced across such hour; provided, however, if Surprise Valley submits a delivery schedule consistent with all provisions of this exhibit and BPA receives that delivery schedule, and a generation imbalance results from a BPA scheduling error, then BPA shall accept responsibility for the generation imbalance associated with the BPA scheduling error.

7. PENALTIES

If Surprise Valley fails to submit prescheduling or real-time scheduling information to BPA as required and by the deadlines in section 4 of this exhibit, then Surprise Valley may be subject to applicable UAI charges, consistent with BPA's applicable Wholesale Power Rate Schedules and GRSPs.

8. AFTER THE FACT

BPA and Surprise Valley agree to reconcile all transactions, schedules and accounts at the end of each month (as early as possible within the first ten calendar days of the next month). BPA and Surprise Valley shall verify all transactions pursuant to this Agreement as to product or type of service, hourly amounts, daily and monthly totals, and related charges.

9. REVISIONS

BPA may unilaterally revise this exhibit:

(1) to implement changes that BPA determines are necessary to allow it to meet its power and scheduling obligations under this Agreement, or

(2) to comply with requirements of WECC, NAESB, or NERC, or their successors or assigns, or

(3) to update the table in section 4.3.6 to reflect which resources BPA provides TCMS for.

BPA shall provide a draft of any material revisions of this exhibit to Surprise Valley, with a reasonable time for comment, prior to BPA providing written notice of the revision. Revisions are effective 45 days after BPA provides written notice of the revisions to Surprise Valley unless, in BPA's sole judgment, less notice is necessary to comply with an emergency change to the requirements of WECC, NAESB, NERC, or their successors or assigns. In this case, BPA shall specify the effective date of such revisions.

10. SIGNATURES

The Parties have caused this revision to be executed as of the date both Parties have signed this revision.

SURPRISE VALLEY ELECTRIFICATION CORPORATION		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By	Daniel Silveria	By	Daniel E. Bloyer
Name	Daniel Silveria (Print/Type)	Name	Daniel E. Bloyer (Print/Type)
Title	General Manager	Title	Account Executive
Date	September 28, 2010	Date	10/4/2010

(PSW:\power\CONTRACT\CUSTOMER\SURPRISE\13110\Exh F\13110 Exh F R1.doc) 07/27/10

Revision No. 1, Exhibit G
PRINCIPLES OF NON-FEDERAL TRANSFER SERVICE
Effective July 31, 2014

This revision updates section 3.2 to allow for, on a case-by-case basis, less than one-year notice prior to Surprise Valley acquiring or purchasing a non-federal resource.

As provided by section 14.6.7 of the body of this Agreement and BPA's Long-Term Regional Dialogue Final Policy, July 2007, or any other later revision of that policy, if Surprise Valley acquires non-federal resources to serve its retail load above its established RHWM, then BPA's support and assistance to Surprise Valley regarding transfer service for its non-federal resources shall be consistent with the following principles:

1. **ESTABLISHED CAPS AND LIMITATIONS**
BPA shall provide financial support for the transmission capacity associated with non-federal resource purchases to all Transfer Service customers up to a maximum of 41 megawatts per fiscal year, cumulative over the duration of this Agreement. This cumulative megawatt limit is shown in the table below.

Fiscal Year	Per Year MW Limit	Cumulative MW Limit
FY 2012	41	41
FY 2013	41	82
FY 2014	41	123
FY 2015	41	164
FY 2016	41	205
FY 2017	41	246
FY 2018	41	287
FY 2019	41	328
FY 2020	41	369
FY 2021	41	410
FY 2022	41	451
FY 2023	41	492
FY 2024	41	533
FY 2025	41	574
FY 2026	41	615
FY 2027	41	656
FY 2028	41	697

2. Application of section 14.6.7 of the body of this Agreement shall be on a first come, first served basis in each year based on the date each request is received by BPA. Requests not met, in whole or in part, in any Fiscal Year will have priority over subsequent requests the following year. Once granted, BPA shall honor such request for the duration of the resource acquisition period, not to exceed the term of this Agreement.

3. PROCESS AND PARAMETERS FOR INITIALLY CHOOSING A NON-FEDERAL RESOURCE

3.1 BPA obtains Transfer Service from Third Party Transmission Providers pursuant to OATT Network Integration Transmission Service. Additionally, BPA acquires firm transmission for all load service obligations incurred. Therefore, BPA shall, on behalf of Surprise Valley, pursue Network Resource designation, as defined in the FERC OATT for Surprise Valley's non-federal resource. BPA shall provide all information the Third Party Transmission Provider requires to evaluate the Network Resource designation request. Surprise Valley shall provide all relevant information BPA determines is required to submit an application for designation of the resource as a Network Resource per section 29 of the OATT, or its successor.

3.2 Surprise Valley shall notify BPA of its intent and/or actions to acquire or purchase a non-federal resource at least one year prior to delivery. Such acquisition or purchase shall be for a period of no less than one year in duration. On a case by case basis, BPA may, but is not obligated to, consider notifications made less than one year prior to delivery.

3.3 If BPA's existing Transfer Service to Surprise Valley is pursuant to a non-OATT contractual arrangement, then BPA shall pursue all reasonable arrangements, including but not limited to OATT service, sufficient to enable Surprise Valley to utilize the non-federal resource to serve its load.

3.4 BPA shall not be liable to Surprise Valley in the event that Network Resource designation cannot be obtained.

3.5 BPA shall only obtain or pay for Transfer Service for Surprise Valley's non-federal resource if it is designated as a Network Resource under the Third Party Transmission Provider's OATT with a commitment of at least one year. The limitations in this principle 3 do not pertain to market purchases and the use of secondary network transmission, which are addressed below in principle 15.

4. Surprise Valley shall provide BPA all information BPA determines is reasonably necessary to administer firm network transmission service over the Third Party Transmission Provider's system.

5. BPA shall pay only the capacity costs associated with transmission service to Surprise Valley over transmission facilities of the Third Party Transmission Provider that either: (1) interconnect directly to Surprise Valley's facilities or (2) interconnect to BPA transmission facilities which subsequently interconnect with Surprise Valley's facilities. Surprise Valley shall arrange for, and pay any costs associated with, the delivery of non-federal power to an interconnection point with the Third Party Transmission Provider, including obtaining and paying for firm transmission across all intervening transmission systems.

6. Surprise Valley shall pay a portion of the costs of all Ancillary Services necessary to deliver any non-federal resource to serve its load. The Ancillary Service costs imposed by the Third Party Transmission Provider shall be apportioned between BPA and Surprise Valley based on either:

(1) metered/scheduled quantities of the non-federal resource, expressed as a percentage of total load, multiplied by the total costs assessed BPA by the Third Party Transmission Provider; or

(2) actual charges assessed by the Third Party Transmission Provider.

However, BPA shall treat the cost of load regulation service consistent with the load regulation service cost as described in section 14.6.1(1) of the body of this Agreement. BPA shall be responsible for the cost of generation supplied reactive power, and Surprise Valley shall be responsible for any generation imbalance costs, if any, related to Surprise Valley's non-federal resource.

7. Surprise Valley shall be responsible for the costs of all other transmission services for non-federal deliveries not included in principles 5 and 6 above, including, but not limited to: redispatch, congestion management costs, system and facility study costs associated with adding the non-federal generation as a Network Resource, direct assigned system upgrades, distribution and low-voltage charges, if applicable and real power losses.

8. Surprise Valley shall be responsible for all costs of interconnecting generation to a transmission system.

9. Surprise Valley shall be responsible for acquiring transmission services from BPA, including wheeling for non-federal resources. If Surprise Valley does not require transmission services from BPA for wheeling non-federal resources, then Surprise Valley shall be responsible for a pro rata share of the Third Party Transmission Provider transmission costs that BPA incurs to serve Surprise Valley.

10. Surprise Valley shall be responsible for all integration services to support its non-federal resources:

(1) in accordance with all requirements of the host Balancing Authority and/or Third Party Transmission Provider, and

(2) which are necessary for designation of the non-federal resource as a Network Resource.

11. As necessary, Surprise Valley shall meet all resource metering requirements including compliance with BPA standards and any requirements of the generation host Balancing Authority and/or Third Party Transmission Provider.

12. The Parties shall cooperate to establish the protocols, procedures, data exchanges or other arrangements the Parties deem reasonably necessary to support the transmission of Surprise Valley's non-federal resource.

13. Unless otherwise agreed, Surprise Valley shall be responsible for managing any non-federal resource consistent with Exhibit F.

14. BPA shall have no obligation to pay for Transfer Service for non-federal power to serve any portion of Surprise Valley's retail load that Surprise Valley is obligated to serve with federal power pursuant to this Agreement.

15. Once Surprise Valley's non-federal resource has been designated as a Network Resource, BPA will not undesignate Surprise Valley's Network Resource for marketing purposes. Also, once such Network Resource designation has been made, Surprise Valley may make market purchases to displace the Network Resource, which BPA shall schedule on secondary network service, provided that:

(1) such market purchases are at least one day in duration;

(2) the megawatt amount of the market purchase does not exceed the amount of the designated Network Resource that Surprise Valley would have scheduled to its load;

(3) such market purchases are only scheduled in preschedule consistent with section 4.1 of Exhibit F;

(4) Surprise Valley does not, under any circumstances, remarket its designated Network Resource or perform any other operation that would cause BPA to be in violation of its obligations under the Third Party Transmission Provider's OATT;

(5) Surprise Valley is responsible for any additional energy imbalance, redispatch, and/or UAI charges that result from a transmission curtailment that impacts the resulting secondary network schedule; and

(6) any RSS products that Surprise Valley has purchased from BPA are not applied to the market purchase(s).

16. These principles will be the basis for a separate agreement BPA shall offer to Surprise Valley to support the Transfer Service of Surprise Valley's non-federal resource. BPA shall include terms specific to a particular non-federal resource in exhibits to the separate agreement, with a separate exhibit for each non-federal resource. Surprise Valley is under no obligation to accept this separate agreement or the exhibit for the particular non-federal resource and BPA is not bound to acquire or pay for Transfer Service for non-federal resources if Surprise Valley does not accept the separate agreement or the exhibit for the particular non-federal resource.

17. BPA shall recover the costs associated with any agreements with Surprise Valley reached under these principles pursuant to BPA's Wholesale Power Rate Schedules and GRSPs.

(PSE:\power\CONTRACT\CUSTOMER\SURPRISE\13110\Exh G\13110 Exh G R1.doc) 07/21/14

Revision No. 1, Exhibit H
RENEWABLE ENERGY CERTIFICATES AND CARBON ATTRIBUTES
Effective July 26, 2011

This revision replaces Exhibit H pursuant to the REP Settlement Agreement, Contract No. 11PB-12322, and is effective as of the "Effective Date" of such REP Settlement Agreement.

1. DEFINITIONS

1.1 "Available Carbon Credits" means (i) eighty-six percent (86%) of the Carbon Credits that BPA determines are attributable to resources whose output is used to establish Tier 1 System Capability, as Tier 1 System Capability is defined in the TRM, excluding the Initial Tier 1 Renewable Projects; and (ii) one-hundred percent (100%) of the Carbon Credits attributable to electrical generation from Initial Tier 1 Renewable Projects, excluding Carbon Credits associated with EPP RECs.

1.2 "Available Tier 1 RECs" means the sum of: (i) eighty-six percent (86%) of the Future Tier 1 RECs; and (ii) one-hundred percent (100%) of the Current Tier 1 RECs.

1.3 "Carbon Credits" means Environmental Attributes consisting of greenhouse gas emission credits, certificates, or similar instruments.

1.4 "Current Tier 1 RECs" means Tier 1 RECs that BPA determines are attributable to electrical generation from Initial Tier 1 Renewable Projects, excluding EPP RECs.

1.5 "Environmental Attributes" means the current or future credits, benefits, emission reductions, offsets and allowances attributable to the generation of energy from a resource. Environmental Attributes do not include the tax credits associated with such resource. One megawatt-hour of energy generation from a resource is associated with one megawatt-hour of Environmental Attributes.

1.6 "Environmentally Preferred Power RECS" or "EPP RECs" means the portion of the Current Tier 1 RECs that is equal to an amount of up to 130 percent of the annual average of equivalent environmentally preferred power (EPP) contracted for as of October 1, 2009, for FYs 2010 and 2011 under Subscription power sales contracts containing rights to Environmental Attributes through FY 2016, as determined by BPA to be necessary to administer such rights.

1.7 "Future Tier 1 RECs" means Tier 1 RECs that BPA determines are attributable to resources whose output is used to establish Tier 1 System Capability, as Tier 1 System Capability is defined in the TRM, excluding the Initial Tier 1 Renewable Projects.

1.8 "Initial Tier 1 Renewable Projects" means the following projects existing as of the Effective Date of Surprise Valley's CHWM Contract:

OCT 6 2011

Project	Capacity (MW)
Foote Creek I	15.32
Foote Creek II	1.8
Stateline	89.76
Condon	49.8
Klondike I	24
Klondike III	50
Ashland Solar	0.015

1.9 "Renewable Energy Certificates" or "RECs" means the certificates, documentation, or other evidence that demonstrates, in the tracking system selected under section 5 of this exhibit, the ownership of Environmental Attributes.

1.10 "Tier 1 RECs" means the sum of the Current Tier 1 RECs and Future Tier 1 RECs.

1.11 "Tier 2 RECs" means the RECs attributable to generation of the resources whose costs are allocated to a given Tier 2 Cost Pool in accordance with the TRM.

2. BPA'S TIER 1 REC INVENTORY

BPA shall maintain a list on a publicly accessible BPA website and shall periodically update it. This list will include any then-current resources that BPA has determined have Tier 1 RECs attributable to them. BPA shall also include on this list its inventory of then-current resources that BPA has determined have Available Tier 1 RECs (and Available Carbon Credits). BPA shall calculate its Available Tier 1 RECs and Available Carbon Credits annually and after-the-fact based on energy generated by listed applicable resources during the previous calendar year.

3. SURPRISE VALLEY'S SHARE OF TIER 1 RECS

Beginning April 15, 2012, and by April 15 every year thereafter over the term of this Agreement, BPA shall transfer to Surprise Valley, or manage in accordance with section 5 of this exhibit, at no additional charge or premium beyond Surprise Valley's payment of the otherwise applicable Tier 1 Rate, a pro rata share of Available Tier 1 RECs based on Surprise Valley's RHWM divided by the total RHWMs of all holders of CHWM Contracts.

The amount of Available Tier 1 RECs available to BPA to transfer or manage shall be subject to available Available Tier 1 REC inventory.

4. TIER 2 RECS

If Surprise Valley chooses to purchase Firm Requirements Power at a Tier 2 Rate, and there are RECs which BPA has determined are attributable to the resources whose costs are allocated to the Tier 2 Cost Pool for such rate, then beginning April 15 of the year immediately following the first Fiscal Year in which Surprise Valley's Tier 2 purchase obligation commences, and by April 15 every year thereafter for the duration of Surprise Valley's Tier 2 purchase obligation, BPA shall, based on Surprise Valley's election pursuant to section 5 of this exhibit, transfer to or manage for Surprise Valley a pro rata share of applicable Tier 2 RECs generated during the previous calendar year. BPA shall, for transferred RECs, provide Surprise Valley with a letter assigning title of such Tier 2 RECs to Surprise Valley. The pro rata share of Tier 2 RECs BPA transfers to Surprise Valley shall be the ratio of Surprise Valley's amount of power purchased at the applicable Tier 2 Rate to the total amount of purchases under that Tier 2 Rate.

5. TRANSFER, TRACKING, AND MANAGEMENT OF RECS

Subject to BPA's determination that the commercial renewable energy tracking system WREGIS is adequate as a tracking system, BPA shall transfer Surprise Valley's share of Available Tier 1 RECs, and Tier 2 RECs if applicable, to Surprise Valley via WREGIS or its successor. If, during the term of this Agreement, BPA determines in consultation with customers that WREGIS is not adequate as a tracking system, then BPA may change commercial tracking systems with one year advance notice to Surprise Valley. In such case, the Parties shall establish a comparable process for BPA to provide Surprise Valley its Available Tier 1 and Tier 2 RECs.

Starting on July 15, 2011, and by July 15 prior to each Rate Period through the term of this Agreement, Surprise Valley shall notify BPA which one of the following three options it chooses for the transfer and management of Surprise Valley's share of Available Tier 1 RECs, and Tier 2 RECs if applicable, for each upcoming Rate Period:

(1) BPA shall transfer Surprise Valley's Available Tier 1 and Tier 2 RECs into Surprise Valley's own WREGIS account, which shall be established by Surprise Valley; or

(2) BPA shall transfer Surprise Valley's Available Tier 1 and Tier 2 RECs into a BPA-managed WREGIS subaccount. Such subaccount shall be established by BPA on Surprise Valley's behalf and the terms and conditions of which shall be determined by the Parties in a separate agreement; or

(3) Surprise Valley shall give BPA the authority to market Surprise Valley's Available Tier 1 and Tier 2 RECs on Surprise Valley's behalf. BPA shall annually credit Surprise Valley for Surprise Valley's pro rata share of all revenues generated by sales of Available Tier 1 and Tier 2 RECs from the same rate pool on its April bill, issued in May.

If Surprise Valley fails to notify BPA of its election by July 15 before the start of each Rate Period, then Surprise Valley shall be deemed to have elected the option in section 5(3) of this exhibit.

Any Available Tier 1 and Tier 2 RECs BPA transfers to Surprise Valley on April 15 of each year shall be limited to those generated January 1 through December 31 of the prior year, except that any Available Tier 1 and Tier 2 RECs BPA transfers to

Surprise Valley by April 15, 2012, shall be limited to those generated October 1, 2011, through December 31, 2011.

6. FEES

BPA shall pay any reasonable fees associated with: (1) the provision of Surprise Valley's Available Tier 1 and Tier 2 RECs and (2) the establishment of any subaccounts in Surprise Valley's name pursuant to sections 5(1) and 5(2) of this exhibit. Surprise Valley shall pay all other fees associated with any WREGIS or successor commercial tracking system, including WREGIS retirement, reserve, and export fees.

7. CARBON CREDITS

In the absence of regulations or legislation concerning carbon credits and directly affecting BPA, BPA intends to convey the value of any future Available Carbon Credits to Surprise Valley on a pro rata basis in the same manner as described for Available Tier 1 RECs and Tier 2 RECs in sections 3 and 4 of this exhibit. This value may be conveyed as: (1) the Available Carbon Credits themselves; (2) a revenue credit after BPA markets such Available Carbon Credits; or (3) the ability to claim that power purchases at the applicable PF rate are derived from certain federal resources.

8. BPA'S RIGHT TO TERMINATE SURPRISE VALLEY'S RECS AND/OR CARBON CREDITS

To the extent necessary to comply with any federal regulation or legislation which addresses Carbon Credits or any other form of Environmental Attribute(s) and includes compliance costs applicable to BPA, BPA may, upon reasonable notice to Surprise Valley, terminate Surprise Valley's contract rights to Available Tier 1 RECs under section 3 of this exhibit and/or Surprise Valley's pro rata share of Available Carbon Credits under section 7 of this exhibit.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\Exh H\13110 Exh H R 1.DOC) 09/09/11

Amendment No. 1
Contract No. 09PB-13110

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

SURPRISE VALLEY ELECTRIFICATION CORPORATION

This Amendment to the Power Sales Agreement Contract No. 09PB-13110 (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and SURPRISE VALLEY ELECTRIFICATION CORPORATION (Surprise Valley).

This Amendment No. 1 (Amendment) modifies the Agreement to revise definitions to be consistent with the final Tiered Rate Methodology, and make other changes agreed upon by the Parties.

BPA and Surprise Valley agree:

1. **EFFECTIVE DATE**
This Amendment shall take effect on the date executed by the Parties (Effective Date).

2. **AMENDMENTS TO BODY OF AGREEMENT**

(a) **Section 2, Definitions**

(1) Section 2.2 shall be deleted and replaced by the following:

"2.2 **"7(i) Process"** means a public process conducted, pursuant to section 7(i) of the Northwest Power Act or its successor, by BPA to establish rates for the sale of power and other products."

(2) Section 2.3 shall be deleted and replaced by the following:

"2.3 **"Above-RHWM Load"** means the forecast annual Total Retail Load, less Existing Resources, NLSLs, and the customer's RHWM, as determined in the RHWM Process. For the Transition Period (as defined in the TRM), Above-RHWM Load will be established as described in section 4.3.2.2 of the TRM."

OCT 2 6 2009

(3) Section 2.8 shall be deleted and replaced by the following:

"2.8 **"Business Day(s)"** means every Monday through Friday except Federal holidays."

(4) Section 2.17 shall be deleted and replaced by the following:

"2.17 **"Diurnal Flattening Service"** or "DFS" means a service that makes a resource that is variable or intermittent, or that portion of such resource that is variable or intermittent, equivalent to a resource that is flat within each Monthly/Diurnal period, as defined in the TRM."

(5) Section 2.29 shall be deleted and replaced by the following:

"2.29 **"Forced Outage Reserve Service"** or "FORS" means a service that provides an agreed-to amount of capacity and energy to load during the forced outages of a qualifying resource."

(6) Section 2.82 shall be deleted and replaced by the following:

"2.82 **"Transmission Curtailment Management Service"** or "TCMS" means the service BPA will provide to customers with a qualifying resource when a transmission curtailment occurs between such resource and the customer load."

(b) **Section 3.5.8, PURPA Resources**
Section 3.5.8 shall be deleted and replaced with the following:

"If Surprise Valley is required by the Public Utility Regulatory Policies Act (PURPA) to acquire output from a Generating Resource and plans to use that output to serve its Total Retail Load, then such output shall be added as a Specified Resource pursuant to Exhibit A. Surprise Valley shall purchase DFS from BPA (or equivalent service if DFS is unavailable) to support such resources for the term of this Agreement."

(c) **Section 3.6, Consumer-Owned Resources**
Section 3.6 shall be deleted and replaced with the following:

"Except for any Consumer-Owned Resources serving an NLSL, which Surprise Valley has applied to load consistent with section 23.3.7, Surprise Valley shall apply the output of the Consumer-Owned Resources as follows:"

(d) **Section 3.6.3, Application of Consumer-Owned Resources Serving Onsite Consumer Load**
Section 3.6.3 shall be deleted and replaced with the following:

"Power generated from Consumer-Owned Resources listed in section 7.1 of Exhibit A shall serve the Onsite Consumer Load. Surprise Valley shall receive no compensation from BPA for excess power generated on any hour from such resources."

(e) **Section 6.6.2, Rate Period High Water Mark Calculation**
The definition of the sum of CHWM (*ΣCHWM)* in section 6.6.2 shall be deleted and replaced with the following:

"*ΣCHWM* = sum of all Publics' (as defined in the TRM) Contract High Water Marks, including those for Publics without a CHWM Contract"

(f) **Section 7.1, Contract High Water Mark (CHWM)**
Section 7.1 shall be deleted and replaced with the following:

"BPA shall establish Surprise Valley's CHWM in the manner defined in section 4.1 of the TRM. Surprise Valley's CHWM and the circumstances under which it can change are stated in Exhibit B."

(g) **Section 9.1, Determination and Notice to Serve Above-RHWM Load**
Section 9.1 shall be deleted and replaced with the following:

"Surprise Valley shall determine and provide notice, as described below, to BPA whether Surprise Valley shall serve its Above-RHWM Load that is greater than or equal to 8,760 megawatt-hours with either: (1) Firm Requirements Power purchased from BPA at a Tier 2 Rate or rates, (2) Dedicated Resources, or (3) a specific combination of both (1) and (2). Surprise Valley may also provide notice to BPA that it shall use a Dedicated Resource to serve Above-RHWM Load that is less than 8,760 MWh. Surprise Valley shall make such determination and provide such notice as follows:"

(h) **Section 10, Tier 2 Remarketing and Resource Removal**
The following paragraph shall be added to the beginning of section 10:

"For the purpose of this section 10, any Dedicated Resources added to Exhibit A pursuant to section 3.5.3 or 3.5.7 do not have temporary resource removal or remarketing rights under this section. In addition, any Dedicated Resource amounts or amounts purchased at a Tier 2 Rate that would otherwise be made eligible for removal or remarketing due to the addition of resources under section 3.5.3 do not have temporary resource removal or remarketing rights under this section."

(i) **Section 10.4, Remarketing of Power Priced at Tier 2 Rates**
Section 10.4 and its heading shall be deleted and replaced with the following:

"10.4 **Remarketing of Power**
Consistent with rates established under the TRM, Surprise Valley shall be subject to applicable charges or credits associated with BPA's

remarketing of purchase amounts of Firm Requirements Power at Tier 2 Rates. Except as specified in section 10.5, Surprise Valley shall be responsible for remarketing of any amounts of its Dedicated Resources, Specified or Unspecified, that are removed or reduced pursuant to this Agreement."

(j) **Section 14.6.1, Ancillary Services**
Section 14.6.1(2) shall be deleted and replaced by the following:

"(2) BPA shall pay for the Ancillary Service(s) charged by a Third-Party Transmission Provider to deliver Firm Requirements Power to the PODs listed in Exhibit E, only if Surprise Valley is also purchasing such Ancillary Service(s) from Transmission Services to deliver Firm Requirements Power to the PODs in Exhibit E. If at any time Surprise Valley is not purchasing Ancillary Service(s) from Transmission Services to deliver Firm Requirements Power to one or more of the PODs listed in Exhibit E, then Surprise Valley shall pay Power Services for the Ancillary Service(s) charges to deliver power to such POD(s), at the applicable or equivalent Transmission Services Ancillary Services rate, in accordance with any applicable BPA Wholesale Power Rate Schedules or GRSPs."

(k) **Section 18.2.2, Reporting Requirements**
The first paragraph of section 18.2.2 shall be deleted and replaced by the following:

"This section 18.2.2 does not apply if Surprise Valley's Total Retail Load from the most recent prior Fiscal Year is 25 annual Average Megawatts or less or if Surprise Valley purchases all of its power from BPA to serve its Total Retail Load. If Surprise Valley's Total Retail Load from the most recent prior Fiscal Year is above 25 annual Average Megawatts, the following requirements may be satisfied by submitting plans and reports Surprise Valley prepares in the normal course of business as long as such plans and reports include the information required below."

(l) **Section 22.1, Judicial Resolution**
The last sentence of section 22.1 shall be deleted and replaced by the following:

"If BPA determines that a dispute is excluded from nonbinding arbitration under this section 22, then Surprise Valley may apply to the federal court having jurisdiction for an order determining whether such dispute is subject to nonbinding arbitration under this section 22."

(m) **Section 23.3.1, Determination of an NLSL**
Section 23.3.1.3 shall be deleted and replaced by the following:

"23.3.1.3 The Parties may agree that the applicable increase in load of installed production equipment at a facility will equal or exceed ten Average Megawatts consumption over any 12 consecutive months and that such production load shall constitute an NLSL. Any such agreement shall constitute a binding NLSL determination."

(n) **Section 23.3.5, Undetermined NLSLs**
The second paragraph of section 23.3.5 shall be deleted and replaced by the following:

"If BPA concludes in its sole judgment that Surprise Valley has not fulfilled its obligations, or has not been able to obtain access or information from the end-use consumer under sections 23.3.3 and 23.3.4, BPA may determine any load subject to NLSL monitoring to be an NLSL, in which case Surprise Valley shall be billed and pay in accordance with the last two sentences of the preceding paragraph. Such NLSL determination shall be final unless Surprise Valley proves to BPA's satisfaction that the applicable increase in load did not equal or exceed ten Average Megawatts in any 12-month monitoring period."

(o) **Section 23.3.6, Service Election for an NLSL**
Section 23.3.6 shall be deleted and replaced by the following:

"Before the Parties add an NLSL to Exhibit D, Surprise Valley shall elect, in writing, to:

(1) have BPA serve the NLSL at the NR rate; or

(2) serve the NLSL by adding a Dedicated Resource to Exhibit A that is not already being used to serve Surprise Valley's firm consumer load in the region.

This election shall be binding on Surprise Valley for the remaining term of this Agreement."

3. EXHIBIT REVISIONS

(a) **Exhibit C, Section 2.2.4.3, Obligation to Apply Dedicated Resources**
Section 2.2.4.3 of Exhibit C shall be deleted and replaced by the following:

"If Surprise Valley provides notice to modify its purchases at Tier 2 Load Growth Rates under section 2.2.4.1 of this exhibit, then for the remainder of the effective Purchase Period and all of the next Purchase Period, Surprise Valley shall apply Dedicated Resources to serve all of its Above-RHWM Load that is in excess of the sum of all Tier 2 commitments."

(b) **Exhibit C, Section 2.4.1.1, Alternative A – Customer Planned Load Not Otherwise Served**
The title of the table in section 2.4.1.1(2) of Exhibit C shall be deleted and replaced by the following:

"Purchase Period Dedicated Resource Elections"

(c) **Exhibit D, Section 2, Resource Support Services**
Section 2 of Exhibit D shall be deleted and replaced with the following:

"**2. RESOURCE SUPPORT SERVICES**

2.1 BPA shall develop the RSS products to support applicable Specified Resources listed in section 2 of Exhibit A for the FY 2012 through 2014 Purchase Period and offer such as a revision to this exhibit by August 1, 2009 and by August 1 prior to each Notice Deadline thereafter. Prior to that date, BPA shall provide Surprise Valley a reasonable opportunity to provide input into the development of the products and the related contract provisions. By the November 1, 2009 Notice Deadline and each Notice Deadline thereafter, Surprise Valley shall notify BPA in writing of any RSS products it elects to buy from BPA under the terms of this Agreement and shall identify the applicable resource(s), for which it shall purchase the RSS product(s) for the upcoming Purchase Period. Such election shall be a binding commitment of both Parties. If Surprise Valley makes such election, the Parties shall revise this exhibit so that it incorporates the agreed changes to applicable provisions, including the applicable resource amounts, if known, by March 31, 2010 or by March 31 of the year following the Notice Deadline for future years. By September 30 of the last Rate Case Year prior to the first Rate Period when service begins, and by each applicable September 30 thereafter in accordance with the applicable incorporated contract language, BPA shall update the relevant tables included in the incorporated contract language with the applicable charges and any necessary updates to resource amounts.

2.2 If Surprise Valley adds a new Specified Resource within a Purchase Period to meet its obligations to serve Above-RHWM Load with Dedicated Resources, consistent with section 3.5.1 of the body of this Agreement, Surprise Valley may purchase DFS or FORS to support such resource. Surprise Valley shall request a copy of the then-current DFS or FORS standard contract provisions from BPA and shall notify BPA in writing by October 31 of a Rate Case Year that it elects to purchase DFS or FORS for the new Specified Resource under the terms stated in the then-current contract provisions and the terms of this section 2.2. Such election shall be a binding commitment of both Parties. The elected DFS or FORS will be effective at the start of the upcoming Rate Period. The duration of such purchase shall be for the remainder of the Purchase Period and for the following Purchase Period. If Surprise Valley makes such election, the Parties shall revise this exhibit by March 31 of the calendar year after Surprise Valley has given notice of its election. Such revision shall incorporate the agreed changes to applicable provisions, including the applicable resource amounts, if known. By September 30 of the last Rate Case Year prior to the first Rate Period when service begins, and by each applicable September 30 thereafter, in accordance with the applicable incorporated contract language, BPA shall update the relevant tables included in the incorporated contract language with the applicable charges and any necessary updates to resource amounts."

(d) **Exhibit D, Section 4, Limitations on Exchange of Existing Resources** The following section 4 shall be added in Surprise Valley's Exhibit D and the Revisions section shall be renumbered to section 5:

"**4. LIMITATIONS ON EXCHANGE OF EXISTING RESOURCES**

4.1 **Option on Full ASC Participation and Alternative Contract**
BPA's 2008 Average System Cost (ASC) Methodology limits the loads and resource costs included in ASCs for consumer-owned utilities that sign a CHWM Contract. The TRM establishes a Tier 1 PF Exchange Rate for such consumer-owned utilities. Pursuant to section 12.2 of the body of this Agreement and section 20 of the Residential Purchase and Sale Agreement (RPSA), Surprise Valley is contractually precluded from seeking or receiving Residential Exchange Program (REP) benefits based on an ASC other than as provided for in Section IV(G) of the 2008 ASC Methodology or its successor.

BPA and Surprise Valley understand and acknowledge that this is the first time BPA has attempted to implement an REP with two different ASC cost structures and two differing levels of benefits, and that as a consequence, the implementation of the REP may be revised over time. Because of the contractual preclusions in the paragraph above and because a limited number of consumer-owned utilities with CHWM Contracts may participate in the REP, the intent of this section 4 is to provide limited protection to such consumer-owned utilities from future changes in the REP.

Any impact to Surprise Valley's access to REP benefits, pursuant to section 5(c) of the Northwest Power Act, as a result of an action taken by BPA as required by a statutory change or final judicial action shall not be considered an Action as provided in section 4.2 below, shall not be subject to the criteria provided in section 4.3 below, and shall not make available the option provided in section 4.4 below.

Absent the exercise by Surprise Valley of the option set forth in section 4.4 below, nothing in this section 4 is intended to alter the application of any provision of the ASC Methodology.

4.2 **Actions**

If BPA takes any of the following Actions and such Actions meet the criteria specified in section 4.3, then Surprise Valley may elect the option set forth in section 4.4 below.

Action 1. BPA adopts, in a final record of decision issued in a section 7(i) proceeding for a Rate Period, a Base Tier 1 PF Exchange Rate for customers with CHWM Contracts which is calculated in a manner that differs from the following:

$$\text{Base T1 PF Exchange Rate} = \frac{(\text{PFCosts} - \text{PFCredits}) - (\text{T2Costs} - \text{T2Credits})}{\text{PFLoad} - \text{T2Load}} + \text{TmnAddr}$$

Where:

Base T1 PF Exchange Rate is the Base Tier 1 PF Exchange rate prior to the final allocation of any rate protection costs arising from the section 7(b)(2) rate test, as determined in each 7(i) Process.

PFCosts are all costs allocated in a 7(i) Process to the Priority Firm rates when the Base PF Exchange rate is calculated (also known as the unbifurcated PF rate) and prior to any reflection of the tiering of the PF Preference rate.

PFCredits are all credits allocated in a 7(i) Process to the Priority Firm rates when the Base PF Exchange rate is calculated (also known as the unbifurcated PF rate) and prior to any reflection of the tiering of the PF Preference rate.

T2Costs are all costs allocated in a 7(i) Process to Tier 2 Cost Pools.

T2Credits are all credits allocated in a 7(i) Process to Tier 2 Cost Pools.

PFLoad is the BPA forecast of load used to determine the unbifurcated PF rate in a 7(i) Process.

T2Load is the BPA forecast of load used to determine Tier 2 Rates in a 7(i) Process.

TmnAddr is the same unit charge for transmission added to the Base PF Exchange rate.

The Tier 1 PF Exchange rate used to calculate Surprise Valley's REP benefits is the Base Tier 1 PF Exchange rate as modified by any Supplemental 7(b)(3) Rate Charge, as determined in each 7(i) Process and may be adjusted pursuant to the Supplemental 7(b)(3) Rate Charge Adjustment, any cost recovery adjustment clause, and any dividend distribution clause, as determined to be applicable to the Tier 1 PF Exchange rate in a 7(i) Process.

Action 2. BPA adopts, in a final record of decision, policy or interpretation, a method of calculating Surprise Valley's ASC for a Fiscal Year(s) of an Exchange Period pursuant to BPA's 2008 ASC Methodology or its successor that differs from the following formula:

$$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$

Where:

RHWM ASC is the ASC for Surprise Valley for an Exchange Period, as defined by BPA's 2008 ASC Methodology.

Contract System Cost is as defined in BPA's 2008 ASC Methodology.

NewRes$ is the forecast cost of resources (including purchased power contracts) used under this Agreement to serve Surprise Valley's Above-RHWM Load. Such resources are exclusive of Surprise Valley's Existing Resources for CHWMs as specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA. The costs included in NewRes$ will be determined using a methodology similar to Appendix 1 Endnote d of BPA's 2008 ASC Methodology.

Contract System Load is as defined in BPA's 2008 ASC Methodology.

NewResMWh is the forecast generation from resources (including purchased power contracts) used under this agreement to serve Surprise Valley's Above-RHWM Load. Such resources are exclusive of Surprise Valley's Existing Resources for CHWMs specified in Attachment C, Column D, of the TRM, and exclusive of purchases of power at Tier 1 Rates from BPA.

Action 3. BPA offers Surprise Valley an RPSA with an Exchange Load used to calculate Surprise Valley's REP benefits payments that differs from the following formula, or interprets such RPSA in a manner that differs from the following formula:

$$\text{Actual RHWM Exchange Load} = \text{RRL} \times \text{T1Pctg}$$

Where:

Actual RHWM Exchange Load is the monthly residential and small farm load of Surprise Valley used to calculate the actual monthly REP payments to Surprise Valley as specified in the RPSA.

RRL is Surprise Valley's actual total qualifying residential and small farm retail load for a month as specified in the RPSA.

$$\text{T1Pctg} = \frac{\text{T1MWh} + \text{ExistResMWh}}{\text{TRL} - \text{NLSL}}$$

Where:

T1Pctg is BPA's forecast percentage of Surprise Valley's load that is expected to be served by purchases of power at Tier 1 Rates from BPA and from Surprise Valley's Existing Resources for CHWM, and will be computed for each Fiscal Year of the applicable Rate Period. Such computation will be performed in the applicable RHWM Process for the Rate Period.

T1MWh is the amount of power at Tier 1 Rates BPA forecasts to be purchased by Surprise Valley from BPA in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

ExistResMWh is the specified output of Surprise Valley's Existing Resources for CHWM, as specified in Attachment C, Column D, of the TRM.

TRL is BPA's forecast of Surprise Valley's Total Retail Load in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

NLSL is BPA's forecast of Surprise Valley's New Large Single Loads in each Fiscal Year of a Rate Period as forecast in each RHWM Process for a Rate Period.

Action 4. BPA adopts a final record of decision, policy or interpretation that changes the terms of the TRM or the 2008 ASC Methodology applicable to REP participants with CHWM Contracts and such change is not encompassed in Actions 1-3, and such change meets the criteria in section 4.3 for application of the option in section 4.4.

4.3 **Criteria**
The option set forth in section 4.4 below is available to Surprise Valley if BPA has taken any of the Actions 1-4 set forth in section 4.2 and the Actions taken, when considered in combination with all BPA actions being undertaken at that time, result in a material reduction in the REP benefits of the class of REP participants with CHWM Contracts. A reduction shall not be "material" for purposes of this section 4.3 if such Action(s), when considered in combination with all BPA actions being undertaken at that time, are applied to the provisions applicable to all REP participants and produce the same or comparable effects on all REP participants, even if such Action(s) results in an otherwise material reduction in the REP benefits of the class of REP participants with CHWM Contracts.

4.4 **Option**
If Surprise Valley believes that BPA has taken any of the Actions 1 through 4 set forth in section 4.2 that satisfies the criteria for this option as set forth in section 4.3, and if BPA has provided a public comment process as part of BPA's decision process (for the relevant Action of Actions 1 through 4 set forth in section 4.2) in which Surprise Valley has commented that BPA was proposing or about to take such Action, then Surprise Valley, within 30 calendar days of BPA taking such alleged Action(s), may provide written notice to BPA in accordance with section 20 of this Agreement requesting an alternative power sales contract without a CHWM. Upon receipt of such written notice, BPA shall review the request and, within 60 calendar days, issue a written statement regarding whether the criteria of section 4.3 have been satisfied.

4.4.1 If BPA believes the criteria of section 4.3 have not been satisfied, the dispute shall be resolved through the dispute resolution provisions in section 22 of this Agreement, provided, however, that the sole function of arbitration shall be to determine whether the criteria of section 4.3 have been satisfied, not the exclusive remedy of money damages set forth in section 22.4 of this Agreement. If the dispute resolution results in a final determination that the criteria of section 4.3 have been satisfied, BPA shall have 90 calendar days from the date of such final determination to take curative action to restore the REP benefits of the class of REP participants with CHWM Contracts to the level that would have existed had BPA not taken the Action(s) that resulted in the criteria of section 4.3 being satisfied; provided, however, that if BPA elects not to take such curative action within such 90 day period, BPA shall have 180 calendar days after the date of such determination to offer to Surprise Valley an alternative power sales contract without a CHWM.

4.4.2 If BPA determines that the criteria of section 4.3 have been satisfied, BPA shall have 90 calendar days from the date of such determination to take curative action to restore the REP benefits of the class of REP participants with CHWM Contracts to the level that would have existed had BPA not taken the Action(s) that resulted in the criteria of section 4.3 being satisfied; provided, however, that if BPA elects not to take such curative action, it shall have 180 calendar days after the date of such determination to offer to Surprise Valley an alternative power sales contract without a CHWM.

4.4.3 Such alternative power sales contract shall be for the same purchase obligation in section 3 of this Agreement that is in effect at the time the notice under this section 4.4 is provided to BPA. Surprise Valley acknowledges that the terms and conditions of such alternative power sales contract may vary from those contained in the CHWM Contract.

4.4.4 Surprise Valley shall notify BPA in accordance with section 20 no later than 60 calendar days after the date of its receipt of such alternative power sales contract whether it will terminate its CHWM Contract and execute such alternative power sales contract, or retain its CHWM Contract. If Surprise Valley fails to notify BPA within the 60-day period of its decision regarding its CHWM Contract, BPA's offer of the alternative power sales contract without a CHWM shall be withdrawn as of the 61st day and Surprise Valley will be conclusively presumed to have elected to retain its CHWM Contract.

4.4.5 If Surprise Valley provides BPA timely notice of its election to terminate its CHWM Contract and executes the alternative power sales contract, service under such alternative power sales contract shall not commence until the beginning of the Rate Period immediately following the Rate Period in which the alternative power sales contract is executed. Termination of Surprise Valley's CHWM Contract shall be effective at commencement of service under the alternative power sales contract."

(e) **Exhibit H, Section 4, Tier 2 RECS**
Section 4 of Exhibit H shall be deleted and replaced by the following:

"**4. TIER 2 RECS**
If Surprise Valley chooses to purchase Firm Requirements Power at a Tier 2 Rate, and there are RECs which BPA has determined are associated with the resources whose costs are allocated to the Tier 2 Cost Pool for such rate, then beginning April 15 of the year immediately following the first Fiscal Year in which Surprise Valley's Tier 2 purchase obligation commences, and by April 15 every year thereafter for the duration of Surprise Valley's Tier 2 purchase obligation, BPA shall, based on Surprise Valley's election pursuant to section 5 of this exhibit, transfer to or manage for Surprise Valley a pro rata share of applicable Tier 2 RECs generated during the previous calendar year. BPA shall, for transferred RECs, provide Surprise Valley with a letter assigning title of such Tier 2 RECs to Surprise Valley. The pro rata share of Tier 2 RECs BPA transfers to Surprise Valley shall be the ratio of Surprise Valley's amount of power purchased at the applicable Tier 2 Rate to the total amount of purchases under that Tier 2 Rate."

4. SIGNATURES

The signatories represent that they are authorized to enter into this Amendment on behalf of the Party for which they sign.

SURPRISE VALLEY ELECTRIFICATION CORPORATION		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By	Daniel Silveria	By	Daniel E. Bloyer
Name	Daniel Silveria *(Print/Type)*	Name	Daniel E. Bloyer *(Print/Type)*
Title	General Manager	Title	Account Executive
Date	October 2, 2009	Date	10/6/09

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\AA1\13110 AA1.DOC) 08/05/09

Amendment No. 2
Contract No. 09PB-13110

AMENDMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

SURPRISE VALLEY ELECTRIFICATION CORPORATION

This AMENDMENT to Power Sales Agreement Contract No. 09PB-13110 (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA) and SURPRISE VALLEY ELECTRIFICATION CORPORATION (Surprise Valley), hereinafter collectively referred to as the "Parties".

This Amendment No. 2 (Amendment) between BPA and Surprise Valley amends the body of the Agreement to remove the provisions related to the delivery of New Resources over multiple transmission systems.

BPA and Surprise Valley agree:

1. **EFFECTIVE DATE**
This Amendment shall take effect on July 31, 2014.

2. **AMENDMENT OF AGREEMENT**
BPA and Surprise Valley shall amend the Agreement to delete section 14.7 "Delivery of New Resources Over Multiple Transmission Systems" in its entirety.

3. **EXHIBIT REVISION**
Exhibit G shall be deleted and replaced with the attached Revision No. 1 to Exhibit G.

4. **SIGNATURES**

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

SURPRISE VALLEY ELECTRIFICATION CORPORATION		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By	Bradley A Kresge	By	Daniel E Bloyer
Name	Bradley A. Kresge (Print/Type)	Name	Daniel E. Bloyer (Print/Type)
Title	General Manager	Title	Account Executive
Date	August 15, 2014	Date	8-21-2014

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\AA2\13110 AA2.DOC) 07/21/14

Revision No. 1, Exhibit G
PRINCIPLES OF NON-FEDERAL TRANSFER SERVICE
Effective July 31, 2014

This revision updates section 3.2 to allow for, on a case-by-case basis, less than one-year notice prior to Surprise Valley acquiring or purchasing a non-federal resource.

As provided by section 14.6.7 of the body of this Agreement and BPA's Long-Term Regional Dialogue Final Policy, July 2007, or any other later revision of that policy, if Surprise Valley acquires non-federal resources to serve its retail load above its established RHWM, then BPA's support and assistance to Surprise Valley regarding transfer service for its non-federal resources shall be consistent with the following principles:

1. **ESTABLISHED CAPS AND LIMITATIONS**
BPA shall provide financial support for the transmission capacity associated with non-federal resource purchases to all Transfer Service customers up to a maximum of 41 megawatts per fiscal year, cumulative over the duration of this Agreement. This cumulative megawatt limit is shown in the table below.

Fiscal Year	Per Year MW Limit	Cumulative MW Limit
FY 2012	41	41
FY 2013	41	82
FY 2014	41	123
FY 2015	41	164
FY 2016	41	205
FY 2017	41	246
FY 2018	41	287
FY 2019	41	328
FY 2020	41	369
FY 2021	41	410
FY 2022	41	451
FY 2023	41	492
FY 2024	41	533
FY 2025	41	574
FY 2026	41	615
FY 2027	41	656
FY 2028	41	697

2. Application of section 14.6.7 of the body of this Agreement shall be on a first come, first served basis in each year based on the date each request is received by BPA. Requests not met, in whole or in part, in any Fiscal Year will have priority over subsequent requests the following year. Once granted, BPA shall honor such request for the duration of the resource acquisition period, not to exceed the term of this Agreement.

3. PROCESS AND PARAMETERS FOR INITIALLY CHOOSING A NON-FEDERAL RESOURCE

3.1 BPA obtains Transfer Service from Third Party Transmission Providers pursuant to OATT Network Integration Transmission Service. Additionally, BPA acquires firm transmission for all load service obligations incurred. Therefore, BPA shall, on behalf of Surprise Valley, pursue Network Resource designation, as defined in the FERC OATT for Surprise Valley's non-federal resource. BPA shall provide all information the Third Party Transmission Provider requires to evaluate the Network Resource designation request. Surprise Valley shall provide all relevant information BPA determines is required to submit an application for designation of the resource as a Network Resource per section 29 of the OATT, or its successor.

3.2 Surprise Valley shall notify BPA of its intent and/or actions to acquire or purchase a non-federal resource at least one year prior to delivery. Such acquisition or purchase shall be for a period of no less than one year in duration. On a case by case basis, BPA may, but is not obligated to, consider notifications made less than one year prior to delivery.

3.3 If BPA's existing Transfer Service to Surprise Valley is pursuant to a non-OATT contractual arrangement, then BPA shall pursue all reasonable arrangements, including but not limited to OATT service, sufficient to enable Surprise Valley to utilize the non-federal resource to serve its load.

3.4 BPA shall not be liable to Surprise Valley in the event that Network Resource designation cannot be obtained.

3.5 BPA shall only obtain or pay for Transfer Service for Surprise Valley's non-federal resource if it is designated as a Network Resource under the Third Party Transmission Provider's OATT with a commitment of at least one year. The limitations in this principle 3 do not pertain to market purchases and the use of secondary network transmission, which are addressed below in principle 15.

4. Surprise Valley shall provide BPA all information BPA determines is reasonably necessary to administer firm network transmission service over the Third Party Transmission Provider's system.

5. BPA shall pay only the capacity costs associated with transmission service to Surprise Valley over transmission facilities of the Third Party Transmission Provider that either: (1) interconnect directly to Surprise Valley's facilities or (2) interconnect to BPA transmission facilities which subsequently interconnect with Surprise Valley's facilities. Surprise Valley shall arrange for, and pay any costs associated with, the delivery of non-federal power to an interconnection point with the Third Party Transmission Provider, including obtaining and paying for firm transmission across all intervening transmission systems.

6. Surprise Valley shall pay a portion of the costs of all Ancillary Services necessary to deliver any non-federal resource to serve its load. The Ancillary Service costs imposed by the Third Party Transmission Provider shall be apportioned between BPA and Surprise Valley based on either:

(1) metered/scheduled quantities of the non-federal resource, expressed as a percentage of total load, multiplied by the total costs assessed BPA by the Third Party Transmission Provider; or

(2) actual charges assessed by the Third Party Transmission Provider.

However, BPA shall treat the cost of load regulation service consistent with the load regulation service cost as described in section 14.6.1(1) of the body of this Agreement. BPA shall be responsible for the cost of generation supplied reactive power, and Surprise Valley shall be responsible for any generation imbalance costs, if any, related to Surprise Valley's non-federal resource.

7. Surprise Valley shall be responsible for the costs of all other transmission services for non-federal deliveries not included in principles 5 and 6 above, including, but not limited to: redispatch, congestion management costs, system and facility study costs associated with adding the non-federal generation as a Network Resource, direct assigned system upgrades, distribution and low-voltage charges, if applicable and real power losses.

8. Surprise Valley shall be responsible for all costs of interconnecting generation to a transmission system.

9. Surprise Valley shall be responsible for acquiring transmission services from BPA, including wheeling for non-federal resources. If Surprise Valley does not require transmission services from BPA for wheeling non-federal resources, then Surprise Valley shall be responsible for a pro rata share of the Third Party Transmission Provider transmission costs that BPA incurs to serve Surprise Valley.

10. Surprise Valley shall be responsible for all integration services to support its non-federal resources:

(1) in accordance with all requirements of the host Balancing Authority and/or Third Party Transmission Provider, and

(2) which are necessary for designation of the non-federal resource as a Network Resource.

11. As necessary, Surprise Valley shall meet all resource metering requirements including compliance with BPA standards and any requirements of the generation host Balancing Authority and/or Third Party Transmission Provider.

12. The Parties shall cooperate to establish the protocols, procedures, data exchanges or other arrangements the Parties deem reasonably necessary to support the transmission of Surprise Valley's non-federal resource.

13. Unless otherwise agreed, Surprise Valley shall be responsible for managing any non-federal resource consistent with Exhibit F.

14. BPA shall have no obligation to pay for Transfer Service for non-federal power to serve any portion of Surprise Valley's retail load that Surprise Valley is obligated to serve with federal power pursuant to this Agreement.

15. Once Surprise Valley's non-federal resource has been designated as a Network Resource, BPA will not undesignate Surprise Valley's Network Resource for marketing purposes. Also, once such Network Resource designation has been made, Surprise Valley may make market purchases to displace the Network Resource, which BPA shall schedule on secondary network service, provided that:

(1) such market purchases are at least one day in duration;

(2) the megawatt amount of the market purchase does not exceed the amount of the designated Network Resource that Surprise Valley would have scheduled to its load;

(3) such market purchases are only scheduled in preschedule consistent with section 4.1 of Exhibit F;

(4) Surprise Valley does not, under any circumstances, remarket its designated Network Resource or perform any other operation that would cause BPA to be in violation of its obligations under the Third Party Transmission Provider's OATT;

(5) Surprise Valley is responsible for any additional energy imbalance, redispatch, and/or UAI charges that result from a transmission curtailment that impacts the resulting secondary network schedule; and

(6) any RSS products that Surprise Valley has purchased from BPA are not applied to the market purchase(s).

16. These principles will be the basis for a separate agreement BPA shall offer to Surprise Valley to support the Transfer Service of Surprise Valley's non-federal resource. BPA shall include terms specific to a particular non-federal resource in exhibits to the separate agreement, with a separate exhibit for each non-federal resource. Surprise Valley is under no obligation to accept this separate agreement or the exhibit for the particular non-federal resource and BPA is not bound to acquire or pay for Transfer Service for non-federal resources if Surprise Valley does not accept the separate agreement or the exhibit for the particular non-federal resource.

17. BPA shall recover the costs associated with any agreements with Surprise Valley reached under these principles pursuant to BPA's Wholesale Power Rate Schedules and GRSPs.

(PSE:\power\CONTRACT\CUSTOMER\SURPRISE\13110\Exh G\13110 Exh G R1.doc) 07/21/14

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/117

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.10**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.10

PacifiCorp Data Request 3.10

Refer to SVEC/400, Anderson 4, lines 3-4. What legal authority would PacifiCorp ESM have for taking title to "increased amount of power flowing on PacifiCorp's electrical system."?

Response to PacifiCorp Data Request 3.10

Surprise Valley objects to this data request on the grounds that Mr. Anderson is not testifying regarding the contractual details between BPA, PacifiCorp and/or Surprise Valley. Mr. Anderson is testifying regarding the electrical engineering issues.

Surprise Valley objects to this data request on the grounds that it calls for a legal conclusion.

Notwithstanding this objection, Surprise Valley responds as follows:

This question appears to confuse contract and physical flow of power. As explained in the direct testimony of Gary Saleba and Gail Tabone, contract and physical power flows are different, and this type of question is irrelevant to the issues in this proceeding.

Surprise Valley and PacifiCorp's power purchase agreement or other legally enforceable obligation make the entire net output of the QF available to PacifiCorp and provide PacifiCorp with legal title to that full net output.

Please also refer to Surprise Valley's response to PacifiCorp data request 3.2.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/118

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.14,
INCLUDING ATTACHMENT 3.14**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.14

PacifiCorp Data Request 3.14

At SVEC/400, Anderson/12, lines 7-10, Mr. Anderson explains that "from a contractual perspective," Surprise Valley will continue to purchase BPA power for its full retail load, even as it sells power to PacifiCorp.

Please provide all documents supporting this assertion, including, but not limited to, all agreements supporting this assertion and all communications with BPA.

Response to PacifiCorp Data Request 3.14

Surprise Valley objects to this data request on the grounds of relevancy and that Mr. Anderson is not testifying regarding the contractual details between BPA, PacifiCorp and/or Surprise Valley. Mr. Anderson is testifying regarding the electrical engineering issues.

Notwithstanding this objection, Surprise Valley responds as follows:

This question appears to confuse contract and physical flow of power. As explained in the direct testimony of Gary Saleba and Gail Tabone, contract and physical power flows are different, and this type of question is irrelevant to the issues in this proceeding.

PacifiCorp has copies of Surprise Valley and BPA's power sale and transmission agreements, which support this statement.

Please refer to UM 1742 Attachment 3.14.

From: Bloyer,Dan (BPA) - PSE-BEND <debloyer@bpa.gov>
Sent: Monday, April 07, 2014 3:40 PM
To: 'lynnsvec@frontier.com' (lynnsvec@frontier.com)
Cc: 'Brad Kresge' (bradsvec@frontier.com)
Subject: Draft Exhibits for discussion
Attachments: Exh A Rev 1.doc; Surprise Valley_09PB-13110_EXE_X_R2_Redline.doc

Hi Lynn – Based on the current thinking that has the output of Paisley Geothermal being sold to PAC, the attached draft amendments are necessary. There are some blanks to fill in toward the end of section 6 on Exhibit A (Nameplate MW and annual Expected output aMW).

We can talk about these when you have time.

If you find that a sale to PAC is unachievable we can discuss the possibility of dedicating the resource to serve SVEC load and using a new resource remarketing service from BPA for a number of years. The credit for this service is currently $28.84/MWh. There would also be a small Resource Support Service charge.

Thanks, Dan.

Formatted: Font color: Auto

Formatted: Centered

Revision No. 1, Exhibit A
NET REQUIREMENTS AND RESOURCES
Effective (DATE)

This revision updates section 6 to add the Paisley Geothermal resource.

1. NET REQUIREMENTS

Surprise Valley's Net Requirement equals its Total Retail Load minus Surprise Valley's Dedicated Resources determined pursuant to section 3.3 of the body of this Agreement and listed in sections 2, 3, and 4 of this exhibit. The Parties shall not add or remove resource amounts to change Surprise Valley's purchase obligations from BPA under section 3.1 of the body of this Agreement except in accordance with sections 3.5 and 10 of the body of this Agreement.

2. LIST OF SPECIFIED RESOURCES

2.1 **Generating Resources**
Surprise Valley does not have any Generating Resources that are Specified Resources at this time.

2.2 **Contract Resources**
Surprise Valley does not have any Contract Resources that are Specified Resources at this time.

2.3 **Small Non-Dispatchable Resources**
Surprise Valley does not have any Small Non-Dispatchable Resources at this time. If Surprise Valley adds Small Non-Dispatchable Resources to this section and if the aggregate nameplate capability of such Small Non-Dispatchable Resources that are also New Resources exceeds one megawatt, then BPA shall consider the impacts of the aggregate shape of such New Resources and may require the application of DFS to account for the impact of the aggregate shape on Surprise Valley's load.

3. UNSPECIFIED RESOURCE AMOUNTS

3.1 **Unspecified Resource Amounts Used to Serve Total Retail Load**

3.1.1 **Shape of Unspecified Resource Amounts**
Surprise Valley's Unspecified Resource Amounts shall be calculated using the selected monthly and Diurnal shapes listed below. BPA shall update the table below consistent with section 3.4.2 of the body of this Agreement.

Shape of Unspecified Resource Amounts				
	Monthly Shape Choice		Diurnal Shape Choice	
Purchase Period	**Total Retail Load Monthly Shape**	**Flat Annual Shape**	**HLH Diurnal Shape**	**Flat Within-Month Shape**
FY 2012 – FY 2014		X		X
FY 2015 – FY 2019		X		X
FY 2020 – FY 2024		X		X
FY 2025 – FY 2028		X		X

3.1.2 **Unspecified Resource Amounts**
Surprise Valley does not have any Unspecified Resource Amounts at this time.

3.2 **Unspecified Resource Amounts for 9(c) Export Decrements**
BPA shall insert a table below pursuant to section 3.5.3 of the body of this Agreement.

4. DEDICATED RESOURCE AMOUNTS FOR AN NLSL
Surprise Valley does not have any Dedicated Resource amounts serving an NLSL at this time, in accordance with section 3.5.7 of the body of this Agreement.

5. TOTAL DEDICATED RESOURCE AMOUNTS
Surprise Valley does not have any Dedicated Resource amounts at this time.

6. LIST OF RESOURCES NOT USED TO SERVE TOTAL RETAIL LOAD
Pursuant to section 17 of the body of this Agreement, all Generating Resources and Contract Resources Surprise Valley ~~does not~~ owns that are ~~any Generating Resources or Contract Resources that are~~ (1) not Specified Resources listed in section 2 of Exhibit A, and (2) greater than 200 kilowatts of nameplate capability, are listed below.

(1) **Paisley Geothermal**

(A) Special Provisions
The Paisley Geothermal resource is a generating facility developed and owned by Surprise Valley. PacifiCorp will purchase the net output generated by the Paisley Geothermal resource subject to the terms of the power purchase agreement between Surprise Valley and PacifiCorp. The term of the power purchase agreement is (DATE) through (DATE), unless terminated earlier pursuant to the terms of the purchase agreement. Surprise Valley shall inform BPA of any sale or disposition of the Paisley Geothermal resource for any subsequent years.

Formatted: Font: Bold
Formatted: Font: Bold
Formatted: Indent: Left: 1.5"

(B) **Resource Profile**

Fuel Type	Type of Resource: Generating Resource	Type of Resource: Contract Resource	Percent of Resource Not Used to Serve Load	Nameplate Capability (MW)
Geothermal	X		100%	

(C) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW									
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

7. LIST OF CONSUMER-OWNED RESOURCES

7.1 **Consumer-Owned Resources Serving Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving Onsite Consumer Load at this time.

7.2 **Consumer-Owned Resources Serving Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving load other than Onsite Consumer Load at this time.

7.3 **Consumer-Owned Resources Serving Both Onsite Consumer Load and Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving both Onsite Consumer Load and load other than Onsite Consumer Load at this time.

7.4 **Consumer-Owned Resources Serving an NLSL**
Pursuant to section 23.3.7 of the body of this Agreement, Surprise Valley does not have any Consumer-Owned Resources serving an NLSL at this time.

8. TABLES FOR ALLOWABLE DEDICATED RESOURCE SHAPES

8.1 **Total Retail Load Monthly Shape**
By March 31 immediately following each of the Fiscal Years 2010, 2015, and 2020, BPA shall fill in the table below with Surprise Valley's Total Retail Load Monthly Shape, in accordance with section 3.4.2 of the body of this Agreement. Surprise Valley's Total Retail Load Monthly Shape shall be calculated by dividing Surprise Valley's Total Retail Load (in

megawatt-hours) in each month of Fiscal Years 2010, 2015, and 2020 by the Fiscal Year total of Surprise Valley's Total Retail Load (in megawatt-hours). BPA shall weather-normalize Surprise Valley's Total Retail Load data, prior to calculating the Total Retail Load Monthly Shape, using the same weather-normalization procedures set forth in section 4.1.1 of the TRM.

Total Retail Load Monthly Shape (%)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
FY 2010													100.0
FY 2015													100.0
FY 2020													100.0
Note: Fill in the table above with percents rounded to the nearest one decimal place													

8.2 **HLH Diurnal Shape**

8.2.1 **Specified Resources**
If Surprise Valley elects the HLH Diurnal Shape for its Specified Resources, Surprise Valley shall fill in a table with monthly LLH and HLH amounts for each year of the upcoming Purchase Period for each Specified Resource. The monthly LLH and HLH distributions shall be the same across all years of a Purchase Period. Surprise Valley shall submit the tables to BPA when Surprise Valley makes its reshaping elections. BPA shall update the appropriate Dedicated Resource amounts pursuant to Surprise Valley's submitted elections and consistent with section 3.4.2 of the body of this Agreement.

8.2.2 **Unspecified Resource Amounts**
If Surprise Valley elects the HLH Diurnal Shape for its Unspecified Resource Amounts, then Surprise Valley shall submit to BPA in writing its elected ratios of megawatt-hours per hour in HLH to megawatt-hours per hour in LLH by the Notice Deadline. Surprise Valley shall submit to BPA twelve monthly ratios and such monthly ratios shall apply for all years of the corresponding Purchase Period. BPA shall update the table below pursuant to Surprise Valley's submitted elections and consistent with section 3.4.2 of the body of this Agreement. BPA shall calculate Surprise Valley's Unspecified Resource Amounts using the ratios in the table below.

HLH Diurnal Shape for Unspecified Resource Amounts												
	HLH to LLH Ratios (HLH:LLH)											
Purchase Period	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 2012 – FY 2014												
FY 2015 – FY 2019												
FY 2020 – FY 2024												
FY 2025 – FY 2028												

9. SUPER PEAK AMOUNTS
Surprise Valley may reshape some or all of its HLH Dedicated Resource amounts for its (1) Specified Resources listed in section 2 of this exhibit, except for any Small

Non-Dispatchable Resources and any Specified Resources Surprise Valley is supporting with DFS or SCS from BPA; and (2) Unspecified Resource Amounts listed in section 3.1.2 of this exhibit; into the Super Peak Period to receive a Super Peak Credit. BPA shall update the table below consistent with section 3.4.4 of the body of this Agreement.

Super Peak Amounts (MW)												
Fiscal Year	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												
Note: Fill in the table above with megawatts rounded to the nearest three decimal places.												

10. REVISIONS

BPA shall revise this exhibit to reflect (1) Surprise Valley's elections regarding the application and use of all resources owned by Surprise Valley and Surprise Valley's retail consumers and (2) BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSE-W:\POWER\CONTRACT\CUSTOMER\SURPRISE\13110\13110 Exh A R1 draft.DOC)
~~09~~04/~~09~~07/~~08~~14

Revision No. 2~~1~~, Exhibit E
METERING
Effective April~~October~~ 1, 2014~~1~~

~~**AUTHENTICATED**~~

This revision No. 2: (1)~~1~~ adds the Lakeview In POM~~exception language~~ in section 1.2(6~~1~~) and (2) ~~updates the POD location description~~ adds the Paisley Geothermal Generation POMs in section 1.3~~2~~(14).

1. METERING

1.1 **Directly Connected Points of Delivery and Load Metering**
None.

1.2 **Transfer Points of Delivery and Load Metering**

(1) **BPA POD Name:** Alturas 12.5 kV;
BPA POD Number: 817;
WECC Balancing Authority: PACW;

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

Voltage: 12.5 kV;

Metering: adjacent to PacifiCorp's Alturas Substation in the Surprise Valley's equipment yard 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Alturas Out;
BPA Meter Point Number: 244;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) This POD is subject to charges for Low Voltage Delivery established in section 14.6.2 of the body of this Agreement;

(B) The potential and current transformers are owned by Surprise Valley.

(2) **BPA POD Name:** Austin 69 kV;
BPA POD Number: 41;
WECC Balancing Authority: PACW;

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 flows;

BPA Meter Point Name: Austin Out;
BPA Meter Point Number: 132;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley

Metering Loss Adjustment: None;

Exception: The potential and current transformers are owned by BPA.

(3) **BPA POD Name:** Canby 69 kV;
BPA POD Number: 104;
WECC Balancing Authority: BPAT;

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

Voltage: 69 kV;

Metering: in Surprise Valley's Canby Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Canby Out (SVEC);
BPA Meter Point Number: 44;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to Surprise Valley;

Metering Loss Adjustment: None;

Exception: None.

(4) **BPA POD Name:** Cedarville Junction 69-SURP;
BPA POD Number: 117;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Cedarville Junction Switching Station where the 69 kV facilities of Surprise Valley and BPA are connected;

Voltage: 69 kV;

Metering:

(A) in BPA's Cedarville Junction Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville Out;
BPA Meter Point Number: 65;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

(B) in Surprise Valley's Cedarville Substation in the 12.47 kV circuit over which such electric power flows;

BPA Meter Point Name: Cedarville (PP&L) Out;
BPA Meter Point Number: 861;
Direction for PF Billing Purposes: Negative;
Manner of Service: Transfer, BPA to Surprise Valley to PacifiCorp;

Metering Loss Adjustment: BPA shall adjust for losses between the POD and the Cedarville (PP&L) Out POM. Such adjustments shall be specified in writing between BPA and Surprise Valley;

Exception: None.

(5) **BPA POD Name:** Davis Creek 12.5 kV;
BPA POD Number: 169;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Davis Creek Substation where the 12.5 kV facilities of Surprise Valley and BPA are connected;

Voltage: 12.5 kV;

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

BPA Meter Point Name: Davis Creek Out;
BPA Meter Point Number: 259;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacifiCorp to BPA to Surprise Valley;

Metering Loss Adjustment: None;

Exception:

(A) The potential transformers in the 12.5 kV meter installation are owned by Surprise Valley;

(B) BPA shall have unrestricted use, at no charge, of Surprise Valley's Davis Creek 115 kV Substation and tapline facilities.

(6) **BPA POD Name:** Lakeview 69 kV;
BPA POD Number: 383;
WECC Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley's Lakeview Switching Station where the 69 kV facilities of PacificCorp 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 flows;

BPA Meter Point Name: Lakeview Out;
BPA Meter Point Number: 41;
Direction for PF Billing Purposes: Positive;
Manner of Service: Transfer, BPA to PacificCorp to Surprise Valley;

BPA Meter Point Name: Lakeview In;
BPA Meter Point Number: 4123;
Direction for PF Billing Purposes: Negative;
Manner of Service: Transfer, Surprise Valley to PacificCorp to BPA;

Metering Loss Adjustment: None;

Exception: The potential transformers in the 69 kV meter installation are owned by Surprise Valley.

1.3 **Resource Locations and Metering**
~~None.~~

(1) Resource Name: Paisley Geothermal Generation

Metering: in Surprise Valley Electrification Corporation's Paisley Geothermal Generation project in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Paisley Genr In;
BPA Meter Point Number: 4122;
Direction for PF Billing Purposes: See Exceptions;
Manner of Service: Directly Connected to Surprise Valley;

BPA Meter Point Name: Paisley STN SVC Out;
BPA Meter Point Number: 4121;
Direction for PF Billing Purposes: Not counted;
Manner of Service: Directly Connected to Surprise Valley;

Metering Loss Adjustment: None;

Exception: POM # 4122 and 4121 are located downstream from Surprise Valley's Lakeview Switching station. The Paisley Geothermal Generation offsets the load at Lakeview that would otherwise be captured at POM # 41. Therefore POM # 4121 is not used for PBL billed load.

2. REVISIONS
Each Party shall notify the other in writing if updates to this exhibit are necessary to accurately reflect the actual characteristics of POD and meter information described in this exhibit. The Parties shall revise this exhibit to reflect such changes. The Parties shall mutually agree on any such exhibit revisions and agreement shall not be unreasonably withheld or delayed. The effective date of any exhibit revision shall be the date the actual circumstances described by the revision occur.

3. SIGNATURES
The Parties have executed this revision as of the last date indicated below.
~~The Parties have caused this revision to be executed as of the date both Parties have signed this revision.~~

Formatted: Indent: First line: 0.5"

SURPRISE VALLEY ELECTRIFICATION CORPORATION.	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By ~~/S/ DANIEL W. SILVERIA~~	By ~~/S/ DANIEL BLOYER~~
Name ~~Daniel W. Silveria~~ Brad Kresge *(Print/Type)*	Name Daniel E. Bloyer *(Print/Type)*
Title **General Manager**	Title Account Executive
Date ~~7/19/11~~	Date ~~7/26/2011~~

(Surprise Valley_~~-~~09PB-13110_Ex~~h-~~E_Rev2~~1~~_01081352611.doc)

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/119

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.15

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.15

PacifiCorp Data Request 3.15

At SVEC/400, Anderson/4, lines 9-14, Mr. Anderson states that the generation from the Paisley Project will generally be consumed by Surprise Valley's load. Confirm or deny that this will decrease the amount of Surprise Valley's load metered at the Lakeview substation on BPA meter 41.

Response to PacifiCorp Data Request 3.15

The Paisley Project's generation will normally be consumed by Surprise Valley's load. This generation will decrease the amount of power delivered to meet Surprise Valley's load metered at the Lakeview substation on BPA meter 41. The Surprise Valley loads at the BPA Meter Point 41 include the power flowing to its substations, including Valley Falls, Adel, Westside and Lakeview. The monthly average load totals between 3.0 and 6.6 megawatts, more than is expected to be generated at the Paisley Project. The annual average is 4.6 megawatts. The bi-directional meter #4123 installed at the Meter Point 41 to measure any power flowing back into the PacifiCorp system in July 2014 has not measured any flow into the PacifiCorp system in any month.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/120

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.24**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.24

PacifiCorp Data Request 3.24

Does Surprise Valley believe that PURPA requires a utility to sign a PPA to purchase the full net output of a QF, even if the utility cannot verify that it receives the benefit of the full net output of the QF?

Response to PacifiCorp Data Request 3.24

Surprise Valley objects to this data request on the grounds that the terms "the utility cannot verify that it receives the benefit of the full net output of the QF" are unclear.

Notwithstanding this objection, Surprise Valley responds as follows:

Yes. A contract or legally enforceable obligation can be entered into before the utility can verify that it receives the benefit of the full net output of the QF. For example, QF power purchase agreements are typically signed before interconnection and transmission related issues are fully resolved.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/121

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.30

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.30

PacifiCorp Data Request 3.30

Has Surprise Valley provided PacifiCorp with a draft PPA proposing the delivery arrangements discussed in Mr. Anderson's testimony? If so, please identify the draft PPA and when it was provided to PacifiCorp.

Response to PacifiCorp Data Request 3.30

Surprise Valley objects to this data request on the grounds that Mr. Anderson is not testifying regarding the contractual details between BPA, PacifiCorp and/or Surprise Valley. Mr. Anderson is testifying regarding the electrical engineering issues.

Notwithstanding this objection, Surprise Valley responds as follows:

Surprise Valley has provided PacifiCorp with its proposed delivery arrangements on multiple occasions.

On April 14, 2014, Surprise Valley provided PacifiCorp with a "Concept Paper."

On May 20, 2014, and July 22, 2014, Surprise Valley provided draft PPAs consistent with the delivery arrangements discussed in Mr. Anderson's testimony.

On June 22, 2015, Surprise Valley executed a PPA consistent with the delivery arrangements discussed in Mr. Anderson's testimony.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP.,
Complainant
v.
PACIFICORP, d/b/a PACIFIC POWER,
Respondent.

EXHIBIT PAC/122

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.33

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.33

PacifiCorp Data Request 3.33

Has Surprise Valley provided PacifiCorp with a draft PPA that Surprise Valley believes has both of these qualities: (1) PURPA requires PacifiCorp to sign it, and (2) Surprise Valley is willing to sign it? If so, please identify the draft PPA and when it was provided to PacifiCorp.

Response to PacifiCorp Data Request 3.33

Surprise Valley objects to this data request on the grounds that it calls for a legal conclusion.

Notwithstanding this objection, Surprise Valley responds as follows:

Yes.

On May 20, 2014, and July 22, 2014, Surprise Valley provided draft PPAs Surprise Valley was willing to sign.

On June 22, 2015, Surprise Valley executed a PPA.

Surprise Valley has been willing to sign a PPA with other terms and conditions; however, PacifiCorp has not been willing to sign a PPA with rates in effect prior to August 20, 2014 or identify what combination of metering and transmission arrangements are necessary to sell the net output.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/123

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.34

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.34

PacifiCorp Data Request 3.34

Has Surprise Valley considered using Order 69 displacement to sell the Paisley Project's net output to BPA, Surprise Valley's full-requirements provider? If not, why not?

Response to PacifiCorp Data Request 3.34

Surprise Valley objects to this data request on the grounds of relevance and because PacifiCorp appears to have a different legal interpretation of the Order 69 and a far narrower factual understanding of displacement than Surprise Valley.

Notwithstanding this objection, Surprise Valley responds as follows:

Surprise Valley has the legal right to sell its net output to any utility that it is directly or indirectly connected to and is not limited to selling the output to BPA. Surprise Valley is both indirectly and directly connected to PacifiCorp.

Surprise Valley has considered selling the net output of the Paisley Project to BPA, but BPA is not interested in purchasing the net output.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/124

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.39

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.39

PacifiCorp Data Request 3.39

To the best of Surprise Valley's knowledge, does BPA schedule hourly energy deliveries for each of BPA's wholesale customers served by the General Transfer Agreement separately?

Response to PacifiCorp Data Request 3.39

Surprise Valley objects to this data request on the grounds that BPA's scheduling practices and the General Transfer Agreement between BPA and PacifiCorp are not relevant to the issues in this proceeding, and are subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission.

Surprise Valley objects to this data request on the grounds that Surprise Valley is not a party to any transmission contracts that detail BPA's scheduling practices to serve Surprise Valley's entire load. PacifiCorp is a party to these contracts and can provide Surprise Valley with information regarding these scheduling practices.

Notwithstanding this objection, Surprise Valley responds as follows:

PacifiCorp did not identify issues related to scheduling BPA power under its transmission agreements until after Surprise Valley sent a demand letter to PacifiCorp on April 16, 2015. This issue was discussed in confidential settlement discussions. In order to participate in settlement negotiations, Surprise Valley investigated how BPA schedules power for its wholesale customers under the General Transfer Agreement. This response does not reveal confidential material PacifiCorp provided to Surprise Valley in those discussions.

Surprise Valley's response is based on the best of its knowledge that relies upon discussions with BPA and PacifiCorp, and may not accurately capture the exact hourly scheduling that occurs under the General Transfer Agreement. PacifiCorp and BPA are the parties to the transmission agreement in which BPA schedules for delivery of power to Surprise Valley's system, and PacifiCorp is better suited to answer this question.

BPA's load forecast model does not generate a stand-alone load forecast of Surprise Valley's loads.

BPA uses Itron software to forecast load for its electric utility customers, which includes the loads for the Surprise Valley. Itron generates day-ahead load forecasts using the most recent three years of historic hourly load data as inputs. Forecast loads are adjusted based on a weekend variable, a day of the week variable, a holiday variable, and projected temperatures. BPA uses temperature data from the Lakeview, Oregon weather station to forecast the hourly loads for Surprise Valley. The model runs regressions against dry bulb temperatures.

BPA does not create an hourly load forecast for Surprise Valley on a pre-schedule basis. BPA's load forecast model embeds Surprise Valley's hourly loads in an aggregated load forecast for all of BPA's customer utilities that are located in the PacifiCorp West balancing authority. BPA's customers that are in PacifiCorp West's balancing authority are served over PacifiCorp's transmission system via general transfer agreements. BPA submits the aggregated PacifiCorp West GTA hourly load forecasts on a pre-schedule basis to PacifiCorp as one load. The load forecasts are not revised after they are submitted. There are no adjustments made on an hour-ahead or real-time basis. Deviations between forecast and actual loads are tracked. Hourly deviations accumulate in an energy storage account under the GTAs. The balance of the energy in the GTA storage account is settled pursuant to the terms of the GTAs.

Surprise Valley generally understands that PacifiCorp provides an imbalance-type service to BPA to make up for the differential between BPA's schedules/deliveries to PacifiCorp and Surprise Valley's actual load in any given hour under the General Transfer Agreement. PacifiCorp's act of supplying this imbalance-type energy to BPA could be considered to be a "sale" of energy by PacifiCorp to BPA for delivery to Surprise Valley's load, albeit pursuant to the General Transfer Agreement. To the extent that PacifiCorp believes that BPA is not accurately scheduling and delivering energy necessary to serve Surprise Valley's loads, and is also not adequately compensating PacifiCorp for the imbalance-type service provided to BPA under the General Transfer Agreement, that is an issue that PacifiCorp must raise with BPA and/or FERC under that transmission agreement or the Federal Power Act; the dispute over the FERC-jurisdictional transmission agreement between PacifiCorp and BPA is not relevant to PacifiCorp's separate obligation to purchase the entire net output of Surprise Valley's QF made available to PacifiCorp. Surprise Valley objects to inclusion of that transmission issue in this proceeding on grounds of federal preemption.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/125

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.48

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.48

PacifiCorp Data Request 3.48

Admit or deny that Surprise Valley is willing to execute PacifiCorp's standard, Oregon on-system qualifying facility power purchase agreement without revision.

Response to PacifiCorp Data Request 3.48

Admit. Surprise Valley believes that the standard, on-system qualifying facility power purchase agreement allows Surprise Valley to sell the entire net output to PacifiCorp. Surprise Valley understands that PacifiCorp disagrees, and believes that standard, the on-system qualifying facility power purchase agreement only allows Surprise Valley to sell the net output that directly flows on to PacifiCorp's system.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/126

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.49

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.49

PacifiCorp Data Request 3.49

Admit or deny that Surprise Valley is willing to execute PacifiCorp's standard, Oregon off-system qualifying facility power purchase agreement, without revision.

Response to PacifiCorp Data Request 3.49

Surprise Valley was willing to execute PacifiCorp's standard, Oregon off-system qualifying facility power purchase agreement, without revision, using rates in effect prior to August 20, 2014.

Surprise Valley is not currently willing to execute PacifiCorp's standard, Oregon off-system qualifying facility power purchase agreement, without revision because: 1) PacifiCorp is not willing to use the rates in effect prior to August 20, 2014, and 2) it includes terms and conditions that are factually incorrect (e.g., Surprise Valley is located in PacifiCorp's balancing authority and the standard, Oregon off-system qualifying facility power purchase agreement explicitly states that the QF is located outside of PacifiCorp's balancing authority, and it states that the owner and operator of the system between the QF and PacifiCorp requires the QF to purchase ancillary services as a condition of making uninterruptible transfers of the entire net output to PacifiCorp – neither of those statements is correct).

Surprise Valley, however, is likely willing to sign PacifiCorp's standard, off-system qualifying facility power purchase agreement with rates in effect prior to August 20, 2014 once PacifiCorp identifies what transmission arrangements PacifiCorp requires or is willing to accept. Surprise Valley will sign the standard, off-system qualifying facility power purchase agreement with inaccurate provisions (e.g., stating that Surprise Valley is located outside of PacifiCorp's balancing authority) if Surprise Valley is paid rates in effect prior to August 20, 2014 and Surprise Valley does not need to purchase unreasonably expensive "transmission arrangements."

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/127

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.50**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.50

PacifiCorp Data Request 3.50

Admit or deny that Surprise Valley is willing to execute PacifiCorp's standard, Oregon off-system qualifying facility power purchase agreement, revised to remove: (1) the language "located in non-PacifiCorp Control Area" from the description under the title on the cover page of the template agreement; and (2) the first recital in Addendum W ("WHEREAS, Seller's Facility is not located within the control area of PacifiCorp").

Response to PacifiCorp Data Request 3.50

Surprise Valley was willing to execute PacifiCorp's standard, Oregon off-system qualifying facility power purchase agreement, without revision, using rates in effect prior to August 20, 2014.

Surprise Valley is not currently willing to execute PacifiCorp's standard, Oregon off-system qualifying facility power purchase agreement, without revision because: 1) PacifiCorp is not willing to use the rates in effect prior to August 20, 2014, and 2) even with PacifiCorp's proposed revision in this data request, it includes terms and conditions that are factually incorrect (e.g., it states that the owner and operator of the system between the QF and PacifiCorp requires the QF to purchase ancillary services as a condition of making uninterruptible transfers of the entire net output to PacifiCorp – that statement is incorrect).

Surprise Valley, however, is likely willing to sign PacifiCorp's standard, off-system qualifying facility power purchase agreement with rates in effect prior to August 20, 2014 once PacifiCorp identifies what transmission arrangements PacifiCorp requires or is willing to accept. Surprise Valley will sign the standard, off-system qualifying facility power purchase agreement with inaccurate provisions (e.g., stating that Surprise Valley is located outside of PacifiCorp's balancing authority) if Surprise Valley is paid rates in effect prior to August 20, 2014 and Surprise Valley does not need to purchase unreasonably expensive "transmission arrangements."

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP., Complainant v. PACIFICORP, d/b/a PACIFIC POWER, Respondent.

EXHIBIT PAC/128

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.54

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.54

PacifiCorp Data Request 3.54

Confirm or deny that Power Engineers, Inc. was retained by Surprise Valley to assist with the Paisley Project. If confirmed, explain in detail Power Engineers, Inc.'s specific role.

Response to PacifiCorp Data Request 3.54

Confirmed. Surprise Valley retained POWER Engineers, Inc. ("PEI") as project engineers for the project gathering system and instrument controls for same, electrical substation and transmission power line. PEI consulted Surprise Valley on a number of issues dealing with the geothermal plant design and construction. PEI assisted Surprise Valley in communicating with PacifiCorp Transmission and PacifiCorp ESM regarding numerous of the Paisley Project issues, including but not limited to interconnection. Schedule 37 questions, reviewing and addressing issues in the various PPA drafts, and participating in discussions with Surprise Valley, PacifiCorp, and BPA on issues concerning the PPA and metering.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/129

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.55

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.55

PacifiCorp Data Request 3.55

Has Surprise Valley retained any other experts or consulting firms to assist with the development of the Paisley Project, and/or the negotiation of a power purchase agreement, generator interconnection, or transmission service for the Paisley Project?

Response to PacifiCorp Data Request 3.55

Surprise Valley objects to this data request on the grounds of attorney client privilege. Notwithstanding this objection, Surprise Valley responds as follows:

Geologists Leland L. Mink and Silvio Pezzopane; Geologica; Anna Carter (Permits and Land Use issues); Bonneville Environmental Foundation; Evergreen Engineering; Anderson Engineering; Daedalus Engineering; Brian Brown Engineering; Sustainable Engineering; Klamath Pump Company; Capuano Engineering; GSI Water Solutions; TAS Energy; David Workman (Financial Forecasts); POWER Engineers, Inc.; and EES Consulting.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP., Complainant v. PACIFICORP, d/b/a PACIFIC POWER, Respondent.

EXHIBIT PAC/130

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.56

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.56

PacifiCorp Data Request 3.56

When did Surprise Valley retain EES Consulting and Evergreen Energy? Were they retained solely for the purposes of the complaint before the Public Utility Commission of Oregon?

Response to PacifiCorp Data Request 3.56

Surprise Valley retained Evergreen Energy in August 2015. Evergreen Energy was not originally hired for the purpose of the complaint before the Public Utility Commission of Oregon.

Surprise Valley retained EES Consulting in August 2015. EES Consulting was originally retained to assist in the settlement negotiations regarding the complaint before the Public Utility Commission of Oregon.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP., Complainant v. PACIFICORP, d/b/a PACIFIC POWER, Respondent.

EXHIBIT PAC/131

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.64

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.64

PacifiCorp Data Request 3.64

Refer to SVEC/100, Kresge/18, lines 22-23, where Mr. Kresge states that "Surprise Valley sent PacifiCorp ESM a complete draft PPA with all project specific information included on May 20, 2014." Confirm or deny that that draft PPA included a number of remaining questions from Surprise Valley regarding Addendum W and included Surprise Valley's proposal that PacifiCorp agree to accept power from BPA.

Response to PacifiCorp Data Request 3.64

Confirmed. That draft PPA included a number of remaining questions from Surprise Valley regarding Addendum W.

Denied that Surprise Valley's proposal that PacifiCorp agree to accept power from BPA on a contractual basis.

Please also refer to Surprise Valley's responses to PacifiCorp data request 3.2 through 3.8 regarding whether Surprise Valley's proposal was that PacifiCorp would agree to accept power from BPA.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/132

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.65,
INCLUDING ATTACHMENT 3.65

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.65

PacifiCorp Data Request 3.65

Refer to SVEC/100, Kresge/19, lines 13-15, where Mr. Kresge states that "Our metering proposal and draft PPA provided on May 20, 2014 was based on what we believed PacifiCorp had previously communicated would be acceptable to the company." Provide all communications that support this statement. If Surprise Valley believes it has previously provided these communications, please point to the specific communications it believes supports this statement.

Response to PacifiCorp Data Request 3.65

Please refer to UM 1742 Attachment 3.65.

From: Jeff Mann <jmann@powereng.com>
Sent: Monday, May 19, 2014 6:58 AM
To: Lynn Culp
Subject: RE: PPA Exhibit B
Attachments: SVEC System One-Line Including Paisley Geo.pdf

Lynn,

Please call me if you would like to discuss the below. I could revamp the attached one line if you would like.

Jeff

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Friday, May 16, 2014 11:48 PM
To: Jeff Mann 3356; Mike Long 3344; Eric Taylor; Gregory L (BPA) - TPCV-ALVEY Vassallo; Dennis Reed; Chun Chin 3527
Cc: Kirk Gibson; Brad Kresge
Subject: PPA Exhibit B

Hello All, Please review exhibit B. See below.
We are trying to show that there are two points of delivery. First at the Lakeview 940 switch SVEC with PAC; and at the point near Chiloquin where BPA and PAC interconnect. Erik, What is the name of this point?
In our meeting with PAC transmission last week, it cam across that we need to prove to PAC that they are getting the energy. We all seem to agree that the Paisley energy being put on the grid will displace energy in the PAC system. BPA will continue to supply SVE full requirement and the access displaced by Paisley will serve PAC Lakeview load.

How can we prove this to PAC. Wondering, during test generation, can we show PAC how this will work? Using metering at Chiloquin?, Lakeview and Paisley are we able to prove that PAC is getting this energy?

Please provide you comments and thoughts on how we can prove this to them.

Thank you all for your continued support of SVE on this project. Your assistance has been invaluable to us.
Lynn

EXHIBIT B

SELLER'S INTERCONNECTION FACILITIES

[Seller to provide its own diagram and description]

<u>POINT OF DELIVERY / SELLER'S INTERCONNECTION FACILITIES</u>

Instructions to Seller:

Describe the point(s) of metering, including the type of meter(s), and the owner of the meter(s). The Paisley Plant is located near Paisley Oregon within the service territory of SVEC and within the PacifiCorp Balancing Area. The net output of the Paisley Plant will be metered at the plant with a PacifiCorp revenue meter. SVEC also has a meter at the plant. The electricity produced by the plant will be interconnected to the grid at the SVEC 69 Kv transmission line at the Paisley substation. This substation is located approximately one mile from the Paisley Plant.

The **points of delivery for this transaction are at the Lakeview Switch 940** where BPA has a revenue meter and SVEC interconnects with PacifiCorp Transmission) and at Chiloquin ______Switch? where BPA has a revenue meter and interconnects with PacifiCorp Transmission SVEC has a 44 mile 69 Kv transmission line from the point of interconnect to the Lakeview 940 switch Point of Delivery to PacifiCorp Transmission at Lakeview. SVEC's service territory is served from this transmission line. BPA serves the Chiloquin___Switch with a 500 Kv transmission line to this Point of Delivery with PacifiCorp Transmission

PacifiCorp transmission delivers and SVEC receives its BPA power at Lakeview Switch 940. PacifiCorp transmission also delivers all of the power needs for PacifiCorp retail customers in the area surrounding SVEC's service territory. BPA will continue to supply SVEC with its full load requirements. Consequently, there will be additional power in the PacifiCorp transmission system because the Paisley Plant is generating. This excess amount will be equal to the amount of power generated by the Paisley Plant less the predetermined amount allowing for transmission line losses as determined by the meter readings at the Chiloquin Delivery Point less the deliveries to SVEC by PacifiCorp Transmission (on behalf of BPA). This power will be delivered into PacifiCorp Transmision's system and be available for use by PacifiCorp retail customers. In other words, the amount of power generated by the Paisley Plant will effectively be serving PacifiCorp retail customer loads in this remote part of the PacifiCorp Balancing Area. The PacifiCorp resources serving the PAC Mile High substation will be correspondingly reduced by the net output (minus transmission line loss) at the Paisley Plant.

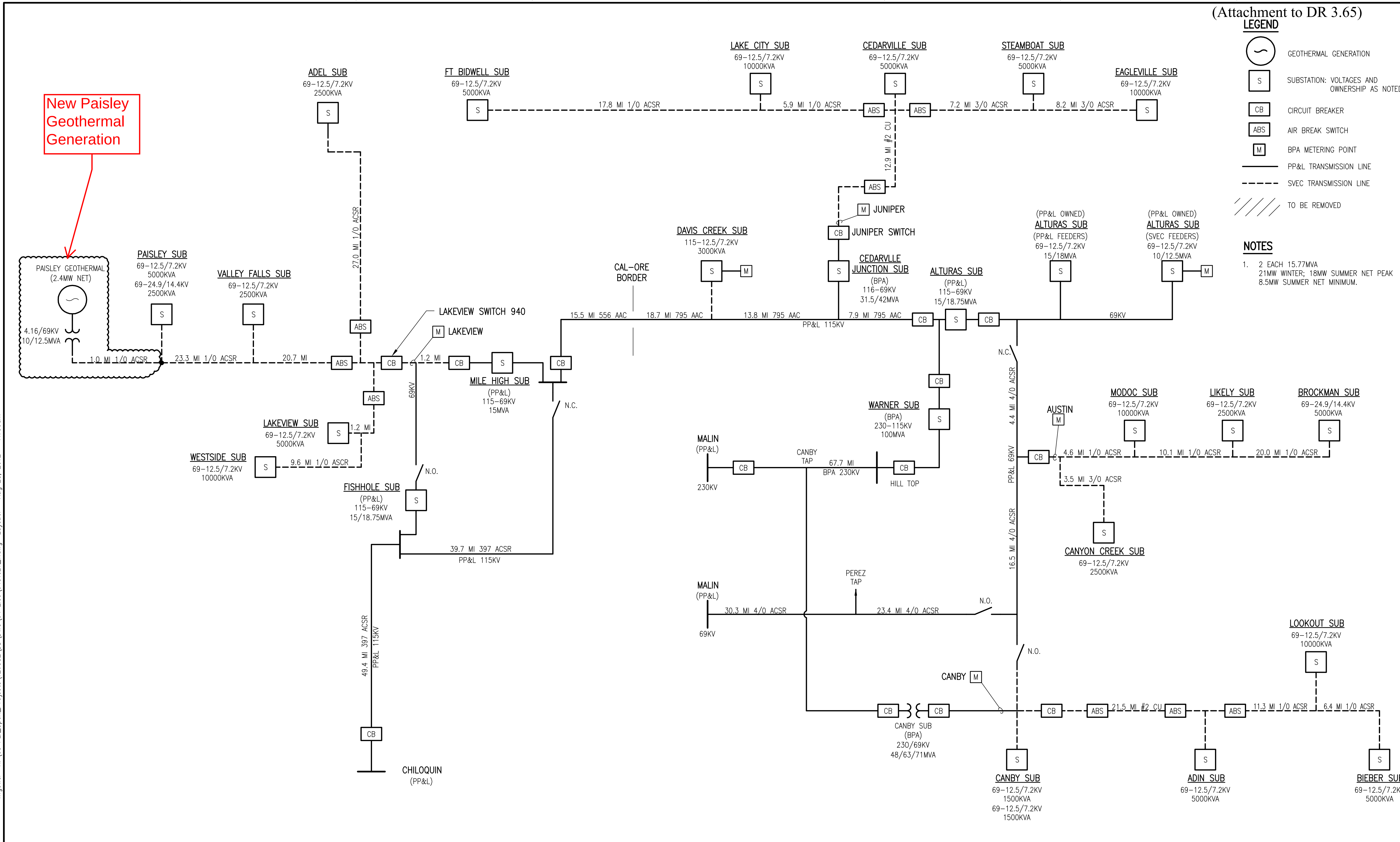
Under this conceptual understanding, PacifiCorp will pay SVEC for the amount of power generated at the Paisley Plant, less the predetermined amount for transmission line losses, at the rates set forth in this contract entered into between SVEC and PacifiCorp.

2. Provide single line diagram of Facility including station use meter, Facility output meter(s), Interconnection Facilities, Point of Interconnection,

3. Specify the Point of Delivery, and any transmission facilities on Seller's side of the Point of Delivery used to deliver Net Output.

The **points of delivery for this transaction are at the Lakeview Switch 940** where BPA has a revenue meter and SVEC interconnects with PacifiCorp Transmission and at Chiloquin ______Switch? where BPA has a revenue meter and interconnects with PacifiCorp. SVEC has a 44 mile 69 Kv transmission line from the point of interconnect to the **Lakeview Switch 940** Point of Delivery to PacifiCorp Transmission at Lakeview. SVEC's service territory is served from this transmission line. BPA serves the Chiloquin____Switch with a 500 Kv transmission line to the Point of Delivery with PacifiCorp Transmission

PAC/132
Griswold/4
(Attachment to DR 3.65)



mgower R:\05 PEI_Open_Projects\126382\DD\DWG\04 Elec\94sveE1_1.dwg Layout1 Aug 28, 2012 – 11:06am

94sveE1_1.dwg

THIS DRAWING WAS PREPARED BY POWER ENGINEERS, INC. FOR A SPECIFIC PROJECT, TAKING INTO CONSIDERATION THE SPECIFIC AND UNIQUE REQUIREMENTS OF THE PROJECT. REUSE OF THIS DRAWING OR ANY INFORMATION CONTAINED IN THIS DRAWING FOR ANY PURPOSE IS PROHIBITED UNLESS WRITTEN PERMISSION FROM BOTH POWER AND POWER'S CLIENT IS GRANTED.

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
A	ISSUED FOR FEASIBILITY STUDY	8/28/12	MAG	JJM	JJM	

REFERENCE DRAWINGS

DSGN	JJM	8/27/12
DRN	MAG	8/27/12
CKD	JJM	8/27/12
SCALE:	NONE	

FOR 22x34 DWG ONLY

POWER ENGINEERS www.powereng.com

SURPRISE VALLEY ELECT CORP
TRANSMISSION SYSTEM
ONE LINE DIAGRAM – PAISLEY GEOTHERMAL PROJECT

JOB NUMBER 126382
REV A
DRAWING NUMBER E1-1

From: Vassallo,Gregory L (BPA) - TPCV-ALVEY <glvassallo@bpa.gov>
Sent: Monday, May 19, 2014 8:19 AM
To: Lynn Culp; Kirk Gibson; Mike Long; Jeff Mann; Chun Chin; Taylor,Eric K (BPA) - TSE-TPP-2; Brad Kresge; Dennis Reed; John Minto
Cc: Ted Case
Subject: RE: SVEC Model
Attachments: 308653-01[1].pdf; PACW Oneiline 103551.045 excerpt.pdf

Lynn,

I am attaching our Project Requirements Diagram (PRD 308653) and an excerpt from PACW One-line for the Lakeview area. You could use them in conjunction with your write-up.

Greg

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Sunday, May 18, 2014 11:52 PM
To: Kirk Gibson; Mike Long; Jeff Mann; Chun Chin; Taylor,Eric K (BPA) - TSE-TPP-2; Vassallo,Gregory L (BPA) - TPCV-ALVEY; Brad Kresge; Dennis Reed; John Minto
Cc: Ted Case
Subject: SVEC Model

Hi All, See attached simple model of what we plan to do with our generation in the PAC system.For whatever reason PAC is having a difficult time seeing that the Paisley generation will displace load in their service area. We need to show them how this will work.

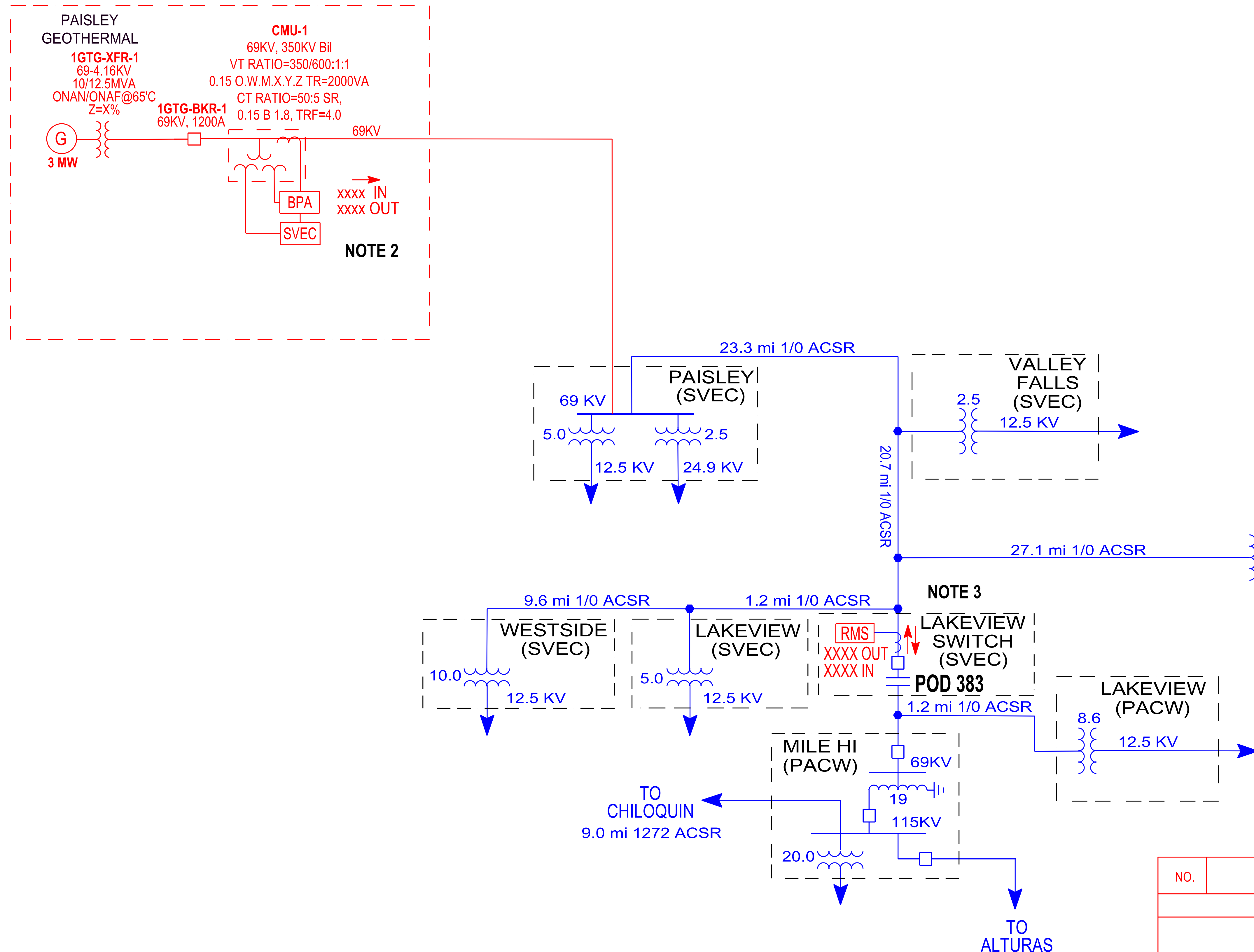
Erik/Greg, Do I have it correct that PAC and BPA come together at Chiloquin? Is this a PAC or BPA substation or switch? What is the correct name/terminology? Is my description correct? What would you change or add? Also, can we get real numbers mW for this time of year. Does BPA deliver a portion of our CA load through PAC and Mile high to Davis Creek? Should that be included here?

How can we prove to PAC that they are getting the generation from Paisley in their system? We have an opportunity during the test period. Thank you for your thoughts on this. Lynn

DISTRICT: REDMOND

LEGEND

BPA BONNEVILLE POWER ADMINISTRATION
SVEC SURPRISE VALLEY ELECTRIFICATION CORPORATION
PACW PACIFICORP (WEST)



NOTES:

1. THIS PROJECT IS TO INSTALL A NEW PRE-STOCKED, JEMSTAR RMS METERING PACKAGE AT SVEC'S PAISLEY GEOTHERMAL PROJECT. THIS PROJECT WILL ALSO REQUIRE REPLACEMENT OF THE RMS METER (JEM-313) WITH BI-DIRECTIONAL METERING (JEMSTAR) IN THE EXISTING METERING RACK AT SVEC'S LAKEVIEW SWITCHING STATION.

2. BPA WILL INSTALL A NEW METER PACKAGE AT SVEC PAISLEY. THE NEW BI-DIRECTIONAL METER WILL BE USING THE BPA WIRELESS STANDARD WITH THE TRANSDATA RECORDER AND/OR THE JEMSTAR.

3. BPA METER REPLACEMENT AT LAKEVIEW WILL INCLUDE REMOVING THE EXISTING RMS UNIT AND WIRED COMMUNICATION. THE NEW BI-DIRECTIONAL METER WILL BE USING THE BPA WIRELESS STANDARD WITH THE TRANSDATA RECORDER AND/OR THE JEMSTAR.

4. THIS PROJECT IS IN PACW BALANCING AUTHORITY AREA. THESE METERS ARE FOR BILLING PURPOSES ONLY.

COORDINATING ENGINEER:
GREG VASSALLO - TPC/ALVEY
PH: (541) 988-7422
EMAIL: glvassallo@bpa.gov

NOTE: SCROLL DOWN TO SEE CUSTOMER ONE-LINE

PACW BALANCING AUTHORITY AREA

LEGEND:

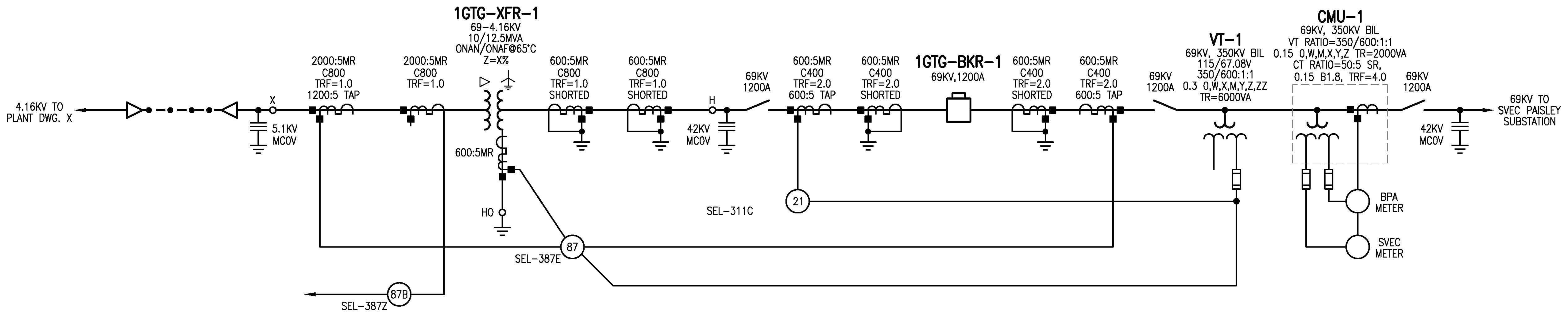
THIS PROJECT
EXISTING OR OTHER PROJECTS
REMOVE
FUTURE
BOUNDARY LINE

NO.	COMPUTER REVISION ONLY	COORDINATING ENGINEER	APPROVED

PROJECT REQUIREMENTS DIAGRAM
UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
PORTLAND, OREGON

ENERGIZATION DATE(S): OCTOBER 31, 2013	OPERATIONS & PLANNING
PRELIMINARY APPROVED: CHERILYN C. RANDALL, DATE: 2/21/2013	SVEC PAISLEY GEOTHERMAL METERING PROJECT
COORDINATING ENGINEER: GREG VASSALLO	
FINAL APPROVED: CHERILYN C. RANDALL, DATE: 3/25/2013	SERIAL: 308653; SOURCE: TP; SIZE: A3; SHEET: 1 OF 1; REV.: 0

RS1F01\TOC\PRDS\PRDS\300-000 THRU 309-999\308653_Paisley Geothermal.dgn



LEGEND

- POWER CIRCUIT BREAKER
- POWER TRANSFORMER
- BUSHING CURRENT TRANSFORMER
- CURRENT TRANSFORMER
- POTENTIAL TRANSFORMER
- FUSE
- DISCONNECT SWITCH
- RELAY OR METER
- CABLE TERMINATOR
- UNDERGROUND CABLE
- SURGE ARRESTER
- AC POWER/CONTROL CIRCUIT
- DC CONTROL CIRCUIT
- DELTA CONNECTION
- WYE CONNECTION
- KV KILOVOLTS
- MCOV MAXIMUM CONTINUOUS OVER VOLTAGE
- 21 IMPEDANCE RELAY
- 87 DIFFERENTIAL RELAY ELEMENT
- 87B BUS DIFFERENTIAL RELAY ELEMENT

23SVE8-1.DWG

REV	REVISIONS	DATE	DRN	DSGN	CKD	APPD
A	ISSUED FOR REVIEW	X/XX/XX	EJH	JDR	–	–

REFERENCE DRAWINGS

DSGN	JDR	9/12/12
DRN	EJH	9/17/12
CKD		
SCALE:	NONE	

FOR 22x34 DWG ONLY

POWER ENGINEERS

SUPRISE VALLEY ELECTRIFICATION CORP.

PAISLEY GEOTHERMAL

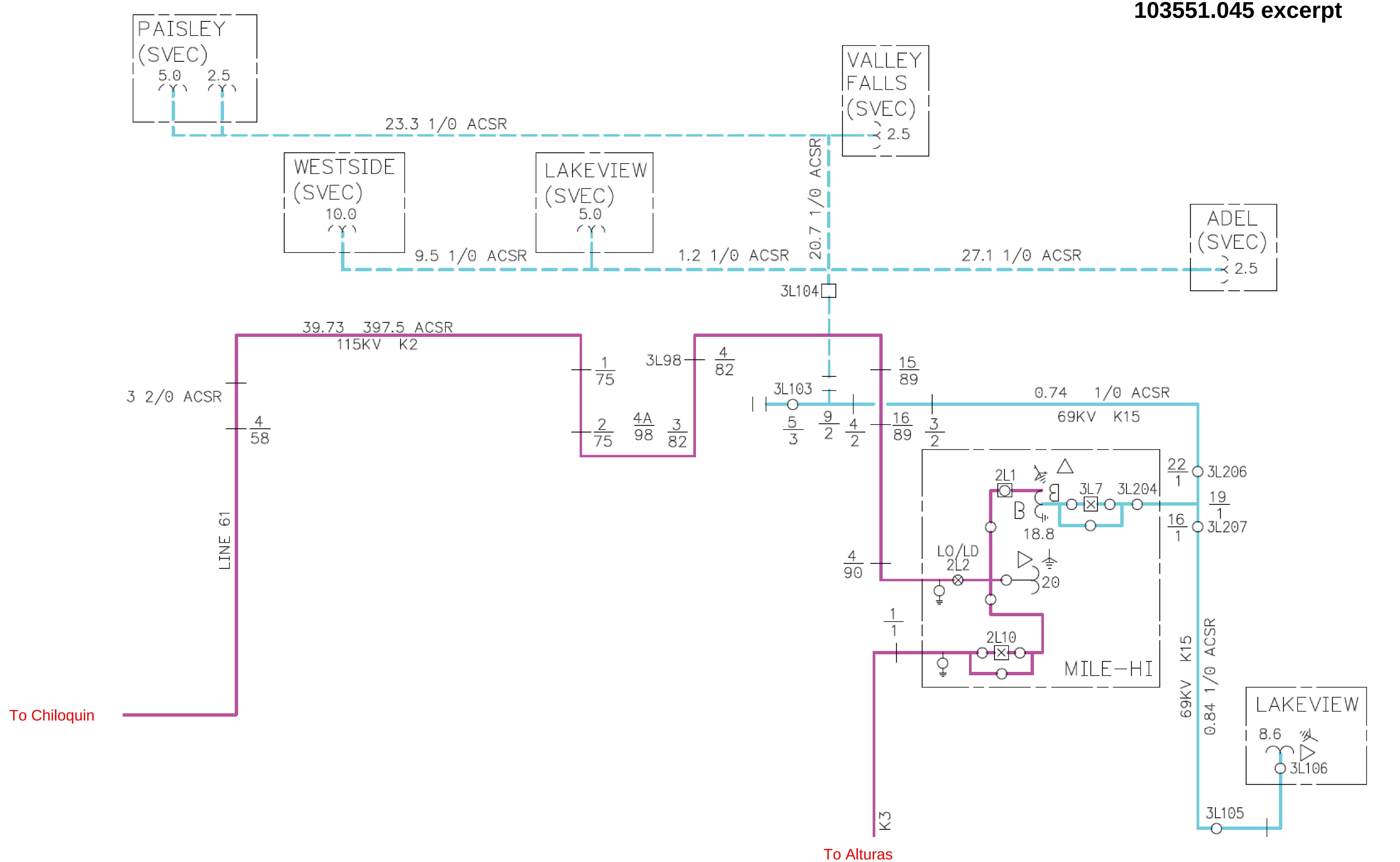
ONE LINE DIAGRAM

JOB NUMBER: 126382

REV: A

DRAWING NUMBER: E8-1

PACW One-line
103551.045 excerpt



From: Vassallo,Gregory L (BPA) - TPCV-ALVEY <glvassallo@bpa.gov>
Sent: Monday, May 19, 2014 3:27 PM
To: Lynn Culp; Kirk Gibson; Mike Long; Jeff Mann; Chun Chin; Taylor,Eric K (BPA) - TSE-TPP-2; Brad Kresge; Dennis Reed; John Minto
Cc: Ted Case
Subject: RE: SVEC Model

Lynn,

Eric & I looked it over. Here are our edits for the PPA wording as you requested:

1.

The **points of delivery for this transaction are at the Lakeview Switch 940** where BPA has a revenue meter and SVEC interconnects with PacifiCorp Transmission) and at the point near structure 47/5 in the BPA's La Pine- Chiloquin 230 kV transmission line, where 230 kV facilities of BPA and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012). SVEC has a 44 mile 69 kV transmission line from the point of interconnect to the Lakeview 940 switch Point of Delivery to PacifiCorp Transmission at Lakeview. SVEC's service territory is served from this transmission line. BPA serves the Yamsay 230 kV with a 230 kV transmission line to this Point of Delivery with PacifiCorp Transmission

PacifiCorp transmission delivers and SVEC receives its BPA power at Lakeview Switch 940. PacifiCorp transmission also delivers all of the power needs for PacifiCorp retail customers in the area surrounding SVEC's service territory. BPA will continue to supply SVEC with its full load requirements. Consequently, there will be additional power in the PacifiCorp transmission system because the Paisley Plant is generating. This excess amount will be equal to the amount of power generated by the Paisley Plant less the predetermined amount allowing for transmission line losses as determined by the meter readings at the Yamsay 230 kV Delivery Point less the deliveries to SVEC by PacifiCorp Transmission (on behalf of BPA). This power will be delivered into PacifiCorp Transmission's system and be available for use by PacifiCorp retail customers. In other words, the amount of power generated by the Paisley Plant will effectively be serving PacifiCorp retail customer loads in this remote part of the PacifiCorp Balancing Area. The PacifiCorp resources serving the PAC Mile High substation will be correspondingly reduced by the net output (minus transmission line loss) at the Paisley Plant.

Under this conceptual understanding, PacifiCorp will pay SVEC for the amount of power generated at the Paisley Plant, less the predetermined amount for transmission line losses, at the rates set forth in this contract entered into between SVEC and PacifiCorp.

3.

The **points of delivery for this transaction are at the Lakeview Switch 940** where BPA has a revenue meter and SVEC interconnects with PacifiCorp Transmission and at the point near structure 47/5 in BPA's La Pine- Chiloquin 230 kV transmission line, where 230 kV facilities of BPA and PacifiCorp are connected (Point of Receipt: Yamsay 230 kV; POR Number: 4012).. SVEC has a 44 mile 69 kV transmission line from the point of interconnect to the **Lakeview Switch 940** Point of Delivery to PacifiCorp Transmission at Lakeview. SVEC's service territory is served from this transmission line. BPA serves the Yamsay 230 kV with a 230 kV transmission line to the Point of Delivery with PacifiCorp Transmission

Greg

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Monday, May 19, 2014 8:34 AM
To: Vassallo,Gregory L (BPA) - TPCV-ALVEY; Kirk Gibson; Mike Long; Jeff Mann; Chun Chin; Taylor,Eric K (BPA) - TSE-TPP-2; Brad Kresge; Dennis Reed; John Minto
Cc: Ted Case
Subject: Re: SVEC Model

Thanks Greg, Is the write up correct? And how would BPA & PAC refer to the connection at Chiloquin?

From: Vassallo,Gregory L (BPA) - TPCV-ALVEY
Sent: Monday, May 19, 2014 8:19 AM
To: Lynn Culp ; Kirk Gibson ; Mike Long ; Jeff Mann ; Chun Chin ; Taylor,Eric K (BPA) - TSE-TPP-2 ; Brad Kresge ; Dennis Reed ; John Minto
Cc: Ted Case
Subject: RE: SVEC Model

Lynn,

I am attaching our Project Requirements Diagram (PRD 308653) and an excerpt from PACW One-line for the Lakeview area. You could use them in conjunction with your write-up.

Greg

From: Lynn Culp [mailto:lynnsvec@frontier.com]
Sent: Sunday, May 18, 2014 11:52 PM
To: Kirk Gibson; Mike Long; Jeff Mann; Chun Chin; Taylor,Eric K (BPA) - TSE-TPP-2; Vassallo,Gregory L (BPA) - TPCV-ALVEY; Brad Kresge; Dennis Reed; John Minto
Cc: Ted Case
Subject: SVEC Model

Hi All, See attached simple model of what we plan to do with our generation in the PAC system.For whatever reason PAC is having a difficult time seeing that the Paisley generation will displace load in their service area. We need to show them how this will work.

Erik/Greg, Do I have it correct that PAC and BPA come together at Chiloquin? Is this a PAC or BPA substation or switch? What is the correct name/terminology? Is my description correct? What would you change or add? Also, can we get real numbers mW for this time of year. Does BPA deliver a portion of our CA load through PAC and Mile high to Davis Creek? Should that be included here?

How can we prove to PAC that they are getting the generation from Paisley in their system? We have an opportunity during the test period. Thank you for your thoughts on this. Lynn

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/133

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.75**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.75

PacifiCorp Data Request 3.75

Refer to SVEC/200, Culp/11, lines 8-10. Provide all documents and communications where PacifiCorp stated the approach in the concept paper was acceptable.

Response to PacifiCorp Data Request 3.75

This was orally communicated to Surprise Valley on a number of occasions.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/134

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.77**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.77

PacifiCorp Data Request 3.77

Refer to SVEC/200, Culp/16, lines 16-18. Provide all documents and communications supporting the statement that Surprise Valley had agreed to all of PacifiCorp's conditions and terms, except for the metering language.

Response to PacifiCorp Data Request 3.77

Surprise Valley understood that, based on discussions at the July 11, 2014 meeting, PacifiCorp had agreed to all the conditions and terms, except for the metering language that PacifiCorp had not provided to Surprise Valley. On July 22, 2014, Surprise Valley sent a revised draft PPA incorporating the non- substantive changes and recommendations made by PacifiCorp at and after the July 11, 2014 meeting. The July 22, 2014 draft also included non-substantive edits to reflect that two months had passed since Surprise Valley sent the May 20, 2014 draft PPA.

Surprise Valley repeatedly requested that PacifiCorp state whether it disagreed with the July 22, 2014 draft PPA, and requested a meeting to finalize and "wrap up the Agreement." Surprise Valley also asked whether Surprise Valley needed to provide any information in order to complete the PPA process. PacifiCorp did not provide any information to contradict Surprise Valley's understanding until August 26, 2014.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/135

SURPRISE VALLEY'S RESPONSE TO PACIFICORP'S DATA REQUEST 3.79

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.79

PacifiCorp Data Request 3.79

Refer to SVEC/207. Confirm or deny that Surprise Valley intended to schedule firm deliveries under the proposed power purchase agreement sent to PacifiCorp on July 22, 2014. If confirmed, provide the date Surprise Valley notified PacifiCorp it has arrangements in place to schedule firm deliveries, and provide all supporting documents and communications. If denied, explain the basis for the statement in Recital G.

Response to PacifiCorp Data Request 3.79

Surprise Valley objects to this data request based on the fact that it is unclear what PacifiCorp means by "schedule firm deliveries." If PacifiCorp is asking when Surprise Valley made "transmission arrangements," then Surprise Valley objects to this request because PacifiCorp did not identify that Surprise Valley needed to make "transmission arrangements" until PacifiCorp filed its complaint on July 29, 2015, and PacifiCorp has refused to explain what metering and "transmission arrangements" it believes are required or what that term means.

Notwithstanding this objection, Surprise Valley responds as follows:

As early as September 12, 2013, PacifiCorp informed Surprise Valley that the status of interconnection or transmission arrangements were "complete." PacifiCorp ESM and Transmission also informed Surprise Valley that it would not need to make any additional arrangements for "firm deliveries" other than the PacifiCorp ESM network transmission request from PacifiCorp Transmission.

Surprise Valley's testimony and exhibits provide explanation and documentation of the issue of delivery and transmission arrangements. Surprise Valley was willing to execute the agreement submitted on July 22, 2014 because it understood that PacifiCorp communicated that form of written agreement to be its preference. Surprise Valley intended to perform under the agreement, which contained the rates in effect at that time. Surprise Valley does not concede that the scheduling provisions contained in the July 22, 2014 agreement may be lawfully imposed upon Surprise Valley's QF, located within PacifiCorp's balancing authority, by PacifiCorp absent Surprise Valley's agreement. Surprise Valley's attempt to execute such an agreement in July 2014 in order to obtain PacifiCorp's signature on a contract is not a concession that PacifiCorp may lawfully limit its purchase of QF energy to scheduled QF energy or otherwise relieve PacifiCorp's obligation to purchase unscheduled QF net output made available to PacifiCorp within its balancing authority.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/136

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.85**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.85

PacifiCorp Data Request 3.85

Refer to SVEC/207. Confirm or deny that Surprise Valley agreed to provide all generation reserves and schedule energy into PacifiCorp's system in the July 22, 2014 proposed power purchase agreement. Provide the date Surprise Valley arranged for generation reserves and scheduling, along with all supporting documents and communications.

Response to PacifiCorp Data Request 3.85

Surprise Valley objects to this data request on the ground that it seeks a legal conclusion and is vague; it is unclear what PacifiCorp means by "schedule firm deliveries." If PacifiCorp is asking when Surprise Valley made "transmission arrangements," then Surprise Valley objects to this request because PacifiCorp did not identify that Surprise Valley needed to make "transmission arrangements" until PacifiCorp filed its complaint on July 29, 2015, and PacifiCorp has refused to explain what metering and "transmission arrangements" it believes are required or what that term means.

Without waiving these objections, Surprise Valley was willing to execute the agreement submitted on July 22, 2014 because it understood PacifiCorp to communicate that form of written agreement to be its preference. Surprise Valley intended to perform under the agreement, which contained the rates in effect at that time. Surprise Valley does not concede that the scheduling provisions or references to ancillary services contained in the July 22, 2014 agreement may be lawfully imposed upon Surprise Valley's QF, located within PacifiCorp's balancing authority, by PacifiCorp absent Surprise Valley's agreement. Surprise Valley's attempt to execute such an agreement in July 2014 in order to obtain PacifiCorp's signature on a contract is not a concession that PacifiCorp may lawfully limit its purchase of QF energy to scheduled QF energy or otherwise relieve PacifiCorp's obligation to purchase unscheduled QF net output made available to PacifiCorp within its balancing authority.

Surprise Valley has requested repeatedly in discovery and outside of this contested docket whether PacifiCorp Transmission would agree to sell such ancillary services to Surprise Valley and whether PacifiCorp ESM will require those services, but to date PacifiCorp Transmission has offered no "ancillary services agreement" that would satisfy the desires of PacifiCorp ESM. Thus, to date, no such agreement exists.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/137

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.92

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.92

PacifiCorp Data Request 3.92

Refer to SVEC/502. Confirm or deny that the PPA executed between Kootenai Electric Cooperative, Inc. and Avista Corporation was priced at the lower of: (1) 85% the Dow Jones Mid-Columbia Non-Firm Index; or (2) Avista's avoided cost rates identified in the PPA.

Response to PacifiCorp Data Request 3.92

Confirmed. However, as explained in Mr. Dolan's testimony, Kootenai Electric Cooperative, Inc. and Avista negotiated an agreement that the parties were prepared to sign, but for a dispute over ownership of environmental attributes, that would have been a sale of firm energy deliveries with firm transmission service at the full, long-term avoided cost rates. The final executable agreement offered by Avista to Kootenai is contained in SVEC/503. The transmission arrangements in that PPA for "firm" energy deliveries were materially indistinguishable from the as-available or "non-firm" PPA, other than Kootenai's agreement in the firm PPA to preserve the transmission capacity necessary for the QF output and not allocate it to some other use. Notably, that PPA for firm deliveries expressly stated that the seller must purchase ancillary services only if its facility was located outside of Avista's balancing authority. SVEC/503, Dolan/11. The relevant provisions of that agreement appear in Section 11, SVEC/503, Dolan/21:

> **11.1** Seller shall make all necessary arrangements and pay all costs to interconnect its
> Facility with the electrical system of the Transmitting Entity [defined in Section 1.54 as Seller]. The Parties shall, prior to Commercial Operation, execute an amendment to the Interconnection and Operating Agreement which incorporates all necessary provisions for the interconnection and operation of the Facility within Avista's Balancing Authority Area. At such time, the Parties will update Exhibit F by attaching the amended Interconnection and Operating Agreement.
>
> **11.2** Seller, as the Transmitting Entity, shall provide sufficient capacity on its distribution and transmission systems between the point of interconnection on Seller's system and the Point of Delivery to ensure deliveries of Net Output to the Point of Delivery on a firm basis for the Term of this Agreement.
>
> **11.3** In the event that Seller or Avista is required to curtail, interrupt or reduce delivery
> of Net Output to the Point of Delivery, Seller may use reasonable commercial efforts to arrange, at Seller's sole expense, for delivery of Net Output at a secondary point of delivery ("Alternate Point of Delivery"). Avista will use

> reasonable commercial efforts to accept Net Output at such Alternate Point of Delivery; *provided, however,* that the Parties have enabled and established the use of such Alternate Point of Delivery pursuant to Section 11.5.

Had PacifiCorp negotiated in good faith with Surprise Valley in this case, the parties could have easily agreed to very similar provisions to include in a modification to either the on-system or off-system standard contract of PacifiCorp. Surprise Valley understands that resolving this issue for Kootenai and Avista was a simple matter of engineering, in contrast to the protracted legal wrangling caused by PacifiCorp in this case.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY ELECTRIFICATION CORP., Complainant v. PACIFICORP, d/b/a PACIFIC POWER, Respondent.

EXHIBIT PAC/138

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 3.93

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 4, 2016
SVEC Response to PacifiCorp Data Request 3.93

PacifiCorp Data Request 3.93

Refer to SVEC/502. Confirm or deny that the Kootenai Electric Cooperative, Inc. sold power to Avista under the PPA on a non-firm, as available basis.

Response to PacifiCorp Data Request 3.93

Confirmed. However, as explained in Mr. Dolan's testimony, Kootenai Electric Cooperative, Inc. and Avista negotiated an agreement that the parties were prepared to sign, but for a dispute over ownership of environmental attributes, that would have been a sale of firm energy deliveries with firm transmission service at the full, long-term avoided cost rates. The final executable agreement offered by Avista to Kootenai is contained in SVEC/503. The transmission arrangements in that PPA for "firm" energy deliveries were materially indistinguishable from the as-available or "non-firm" PPA, other than Kootenai's agreement in the firm PPA to preserve the transmission capacity necessary for the QF output and not allocate it to some other use. Notably, that PPA for firm deliveries expressly stated that the seller must purchase ancillary services only if its facility was located outside of Avista's balancing authority. SVEC/503, Dolan/11. The relevant provisions of that agreement appear in Section 11, SVEC/503, Dolan/21:

> **11.1** Seller shall make all necessary arrangements and pay all costs to interconnect its
> Facility with the electrical system of the Transmitting Entity [defined in Section 1.54 as Seller]. The Parties shall, prior to Commercial Operation, execute an amendment to the Interconnection and Operating Agreement which incorporates all necessary provisions for the interconnection and operation of the Facility within Avista's Balancing Authority Area. At such time, the Parties will update Exhibit F by attaching the amended Interconnection and Operating Agreement.
>
> **11.2** Seller, as the Transmitting Entity, shall provide sufficient capacity on its distribution and transmission systems between the point of interconnection on Seller's system and the Point of Delivery to ensure deliveries of Net Output to the Point of Delivery on a firm basis for the Term of this Agreement.
>
> **11.3** In the event that Seller or Avista is required to curtail, interrupt or reduce delivery
> of Net Output to the Point of Delivery, Seller may use reasonable commercial efforts to arrange, at Seller's sole expense, for delivery of Net Output at a secondary point of delivery ("Alternate Point of Delivery"). Avista will use reasonable commercial efforts to accept Net Output at such Alternate Point of Delivery; *provided, however,* that the Parties have enabled and established the use of such Alternate Point of Delivery pursuant to Section 11.5.

Had PacifiCorp negotiated in good faith with Surprise Valley in this case, the parties could have easily agreed to very similar provisions to include in a modification to either the on-system or off-system standard contract of PacifiCorp. Surprise Valley understands that resolving this issue for Kootenai and Avista was a simple matter of engineering, in contrast to the protracted legal wrangling caused by PacifiCorp in this case.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/139

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.1

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.1

PacifiCorp Data Request 4.1

Has Mr. Saleba previously assisted with the negotiation of a power purchase agreement between a QF and a utility purchasing the QF's power under PURPA?

Response to PacifiCorp Data Request 4.1

No.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/140

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.3

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.3

PacifiCorp Data Request 4.3

Has Ms. Tabone previously assisted with the negotiation of a power purchase agreement between a QF and a utility purchasing the QF's power under PURPA?

Response to PacifiCorp Data Request 4.3

No.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/141

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.5**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.5

PacifiCorp Data Request 4.5

At SVEC/300, Saleba-Tabone/4, lines 3-4, the witnesses state that "…the circumstances of this purchase of QF power are unusual, although they are not unprecedented." Please explain how the circumstances of this purchase of QF power are unusual.

Response to PacifiCorp Data Request 4.5

The circumstances are unusual due to the fact that the sale is from a utility that is within the balancing authority of one utility while obtaining its power supply from a second utility through a general transfer agreement with the first utility.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/142

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.14

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.14

PacifiCorp Data Request 4.14

At SVEC/300, Saleba-Tabone/6, lines 3-6, the witnesses state that "As Surprise Valley does not plan to use the Paisley Project to serve its own loads, it has no impact on the contract to purchase power supply, transmission and ancillary services from BPA." If the Paisley Project has no impact on the power supply contract between BPA and Surprise Valley, please explain why BPA and Surprise Valley amended that power supply contract to reflect the Paisley Project's generation.

Response to PacifiCorp Data Request 4.14

BPA and Surprise Valley amended the power supply contract to ensure proper metering and accounting for power deliveries, and to ensure that the Paisley Project has no impact on the amount of power or obligations under Surprise Valley's power and transmission contracts with BPA. If the BPA and Surprise Valley power sale agreement had not been modified to reflect the existence of the Paisley Project, then it would appear that the Paisley Project served Surprise Valley's retail load. This would result in Surprise Valley's retail load appearing smaller. To ensure that the net output of the Paisley Project did not appear to serve Surprise Valley's retail load, the net output of the Paisley Project needed to be measured.

All BPA customers are required to list generating and contract resources in their service area that are over 200 kW in Exhibit A of their power supply contract. The listing of these resources allows for the proper tracking of BPA's obligation to serve their customers. In all cases these resources need to be accounted for in a manner to allow BPA to measure the load for which BPA is obligated to provide power supply. This is true in cases where the resources listed are used to serve load as well as for those cases where the listed resources are sold to a third party. Metering needs to be configured and identified such that BPA can account for the load it is obligated to serve.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/143

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.17

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.17

PacifiCorp Data Request 4.17

SVEC/300, Saleba-Tabone/7, lines 13-17, states that "Paisley Project power should be considered a delivered product since, on a contractual basis, Surprise Valley's system would be used to deliver the power to the point of interconnection between Surprise Valley and PacifiCorp."

If BPA fails to schedule enough power to serve Surprise Valley's full retail load under the power sales contract between BPA and Surprise Valley, should the Paisley Project's power still be considered "a delivered product" on a contractual basis? If yes, please explain which party would be responsible for the shortfall of power in this set of contractual obligations.

Response to PacifiCorp Data Request 4.17

Surprise Valley objects to this data request on the grounds that BPA's scheduling practices and the General Transfer Agreement between BPA and PacifiCorp are not relevant to the issues in this proceeding, and are subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission.

Surprise Valley objects to this data request on the grounds that Surprise Valley is not a party to any transmission contracts that detail BPA's scheduling practices to serve Surprise Valley's entire load. PacifiCorp is a party to these contracts and can provide Surprise Valley with information regarding these scheduling practices.

Notwithstanding these objections, Surprise Valley provides the following:

Yes. On a contractual basis, the sale of power from the Paisley Project is entirely separate from the power sales contract between BPA and Surprise Valley. A failure of BPA to schedule enough power to serve Surprise Valley's full retail load is no different with or without the existence of the Paisley Project and is a matter between BPA and PacifiCorp.

This question appears to confuse contract and physical flow of power. As explained in the direct testimony of Gary Saleba and Gail Tabone, contract and physical power flows are different, and this type of question is irrelevant to the issues in this proceeding.

Surprise Valley purchases power to serve its total retail loads from BPA, which are transmitted by PacifiCorp. The rights and obligations related to these transactions are contained in Surprise Valley and BPA's contracts, and PacifiCorp and BPA's contracts. If PacifiCorp, Surprise Valley or BPA violate or otherwise do not abide by these terms and conditions, then those agreements detail the legal remedies available to the parties.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/144

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.26**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.26

PacifiCorp Data Request 4.26

Refer to SVEC/300, Saleba-Tabone/7, lines 7-10. Assume BPA fails to provide enough power to Surprise Valley to meet Surprise Valley's full retail load needs. What ancillary services will be provided to ensure the Paisley Project's power is delivered to PacifiCorp's system on a firm basis, who will provide them, and what agreements will govern such services?

Response to PacifiCorp Data Request 4.26

Surprise Valley objects to this data request on the grounds that BPA's scheduling practices and the General Transfer Agreement between BPA and PacifiCorp are not relevant to the issues in this proceeding, and are subject to the exclusive jurisdiction of the Federal Energy Regulatory Commission.

Surprise Valley objects to this data request on the grounds that Surprise Valley is not a party to any transmission contracts that detail BPA's scheduling practices to serve Surprise Valley's entire load. PacifiCorp is a party to these contracts and can provide Surprise Valley with information regarding these scheduling practices.

Notwithstanding these objections, Surprise Valley provides the following:

This question appears to confuse contract and physical flow of power. As explained in the direct testimony of Gary Saleba and Gail Tabone, contract and physical power flows are different, and this type of question is irrelevant to the issues in this proceeding.

Surprise Valley purchases power to serve its total retail loads from BPA, which are transmitted by PacifiCorp. The rights and obligations related to these transactions are contained in Surprise Valley and BPA's contracts, and PacifiCorp and BPA's contracts. If PacifiCorp, Surprise Valley or BPA violate or otherwise do not abide by these terms and conditions, then those agreements detail the legal remedies available to the parties. Under and over schedules, and under and over deliveries are addressed under the terms of those agreements, and can occur regardless of whether or not Surprise Valley sells the net output of the Paisley Project to PacifiCorp. Therefore, if BPA fails to schedule sufficient power to meet Surprise Valley's full retail load, then PacifiCorp's rights and obligations would be included in the BPA and PacifiCorp transmission agreement(s) under which BPA is scheduling power.

No ancillary services are required to ensure that the Paisley Project's power is delivered to PacifiCorp's system on a firm basis. Surprise Valley has firm transfer capacity available to deliver the entire net output of the Paisley Project to PacifiCorp.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/145

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.40**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.40

PacifiCorp Data Request 4.40

At SVEC/300, Saleba-Tabone/10, lines 10-12, the witnesses state that "The only thing that may need to change are the metering points identified in the contract between Surprise Valley and BPA and between PacifiCorp and BPA." Is it Surprise Valley's position that PURPA requires a purchasing utility to amend existing third party contracts in order to accommodate the purchase of QF power?

Response to PacifiCorp Data Request 4.40

Surprise Valley objects to this data request on the grounds that it calls for a legal opinion.

Notwithstanding this objection, Surprise Valley responds as follows:

Surprise Valley's position is that the purchasing utility must make reasonable efforts to accommodate the purchase of QF power, and a purchasing utility cannot rely upon a transmission agreement that is subject to the regulation of the Federal Energy Regulatory Commission to refuse to enter into a power purchase agreement with a qualifying facility. If any metering points need to be changed in the PacifiCorp and BPA transmission agreement(s), then PacifiCorp Transmission is illegally refusing to make changes necessary to effectuate PacifiCorp ESM's purchase of the full net output of the Paisley Project.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/146

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.45

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.45

PacifiCorp Data Request 4.45

Refer to SVEC/300, Saleba-Tabone/14, line 17-Saleba-Tabone/15, line 6. Confirm or deny that the delivery arrangements made by the other “BPA customer utilities” identified in this response are not PURPA delivery arrangements.

Response to PacifiCorp Data Request 4.45

Confirmed.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/147

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.50

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.50

PacifiCorp Data Request 4.50

When does Surprise Valley assert that PacifiCorp was notified of the contractual arrangements between BPA and Surprise Valley that would ensure that the "physical flow of power" matched the "contractual sale of power" for purposes of Surprise Valley's sale to PacifiCorp? (see SVEC/300, Saleba-Tabone/7, lines 7-10.) Please provide or identify all communications supporting your response.

Response to PacifiCorp Data Request 4.50

On April 14, 2014, Surprise Valley provided PacifiCorp with a "Concept Paper."

On May 20, 2014, and July 22, 2014, Surprise Valley provided draft PPAs that included contract provisions that would ensure that the "physical flow of power" matched the "contractual sale of power" for purposes of Surprise Valley's sale to PacifiCorp.

On June 22, 2015, Surprise Valley executed a PPA that included contract provisions that would ensure that the "physical flow of power" matched the "contractual sale of power" for purposes of Surprise Valley's sale to PacifiCorp.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/148

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.64**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.64

PacifiCorp Data Request 4.64

On March 21, 2016, Surprise Valley sent PacifiCorp Attachment 2.3(c), the power sales agreement between BPA and Surprise Valley. Please explain the effect of Revision No. 1, Exhibit A, effective July 1, 2015, on that power sales agreement.

Response to PacifiCorp Data Request 4.64

To ensure that the Paisley Project is not used to serve Surprise Valley's retail load under the BPA contract.

Please also refer to Surprise Valley's response to PacifiCorp data request 4.14.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/149

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.67**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.67

PacifiCorp Data Request 4.67

Does Surprise Valley contend that Revision No. 1, Exhibit A to Attachment 2.3(c) is necessary to ensure that the "physical flow of power" matches the "contractual sale of power" for purposes of Surprise Valley's sale of the Paisley Project's power to PacifiCorp (see SVEC/300, Saleba-Tabone/7, lines 7-10.) Please explain.

Response to PacifiCorp Data Request 4.67

Yes. The change was made to ensure that the Paisley Project is not used to serve Surprise Valley's retail load under the BPA contract. If the Paisley Project is contractually used to serve Surprise Valley's retail load, then Surprise Valley cannot sell the net output to a third party like PacifiCorp.

Please also refer to Surprise Valley's response to PacifiCorp data request 4.14.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/150

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 4.71**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.71

PacifiCorp Data Request 4.71

Confirm or deny that Revision No. 2, Exhibit A to Attachment 2.3(c) is necessary to ensure that the “physical flow of power” matches the “contractual sale of power” for purposes of Surprise Valley’s sale of the Paisley Project’s power to to [sic] PacifiCorp (see SVEC/300, Saleba-Tabone/7, lines 7-10.) Please explain.

Response to PacifiCorp Data Request 4.71

Confirmed. Without the contract amendment, the Paisley Project would contractually serve Surprise Valley’s load.

Please also refer to Surprise Valley’s response to PacifiCorp data request 4.14.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/151

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 5.3

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 8, 2016
SVEC Response to PacifiCorp Data Request 5.3

PacifiCorp Data Request 5.3

Does Surprise Valley assert that PacifiCorp has benefited from reduced deliveries under the GTA while the Paisley Project was running between July 12, 2015 and September 30, 2015? If so, please explain.

Response to PacifiCorp Data Request 5.3

Surprise Valley objects to this data request on the grounds of relevance and preemption. The GTA is a FERC-jurisdictional transmission agreement, and any disputes regarding that agreement or performance thereunder are within FERC's exclusive jurisdiction.

Notwithstanding these objections, Surprise Valley provides the following:

Surprise Valley lacks information at this time to know whether PacifiCorp has benefited from reduced deliveries under the GTA while the Paisley Project was running between July 12, 2015 and September 30, 2015.

PacifiCorp is required to compensate Surprise Valley for the net output of the Paisley Project between July 12, 2015 and September 30, 2015.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/152

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 5.13**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 8, 2016
SVEC Response to PacifiCorp Data Request 5.13

PacifiCorp Data Request 5.13

At SVEC/500, Dolan/2, lines 10-11, Mr. Dolan states, "My testimony will not address the specific dispute between Surprise Valley and PacifiCorp." Does Mr. Dolan assert that PacifiCorp is required by PURPA to accept the delivery arrangements proposed by Surprise Valley (described in SVEC/300 and SVEC/400)?

Response to PacifiCorp Data Request 5.13

Surprise Valley objects to this request on the ground that it seeks a legal conclusion. Mr. Dolan is not an attorney and will not respond to the legal requirements of PURPA or PacifiCorp's obligations to Surprise Valley thereunder.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/153

SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 5.14

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 8, 2016
SVEC Response to PacifiCorp Data Request 5.14

PacifiCorp Data Request 5.14

Does Mr. Dolan assert that the power purchase agreement and delivery arrangements between Kootenai and Avista described in his testimony (supporting SVEC/502) are evidence that PacifiCorp is required, as a legal matter, to accept Surprise Valley's proposed delivery arrangements?

Response to PacifiCorp Data Request 5.14

Surprise Valley objects to this request on the ground that it seeks a legal conclusion. Mr. Dolan is not an attorney and will not respond to the legal requirements of PURPA or PacifiCorp's obligations to Surprise Valley thereunder.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/154

SURPRISE VALLEY'S RESPONSE TO PACIFICORP'S DATA REQUEST 5.15

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 8, 2016
SVEC Response to PacifiCorp Data Request 5.15

PacifiCorp Data Request 5.15

Does Mr. Dolan agree that a utility can agree to purchase power from another entity, even when that purchase is not required by law? If not, please explain.

Response to PacifiCorp Data Request 5.15

Surprise Valley objects to this request on the ground that it seeks a legal conclusion. Mr. Dolan is not an attorney and will not respond to the legal requirements of PURPA or PacifiCorp's obligations to Surprise Valley thereunder.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/155

**SURPRISE VALLEY'S RESPONSE
TO PACIFICORP'S DATA REQUEST 5.16**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 8, 2016
SVEC Response to PacifiCorp Data Request 5.16

PacifiCorp Data Request 5.16

Does Mr. Dolan have personal knowledge of all of the agreements underlying Surprise Valley's proposed sale and delivery of QF power to PacifiCorp's system?

Response to PacifiCorp Data Request 5.16

No.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/200

REBUTTAL TESTIMONY OF RICHARD A. VAIL

May 17, 2016

TABLE OF CONTENTS

ATTACHED EXHIBITS

Exhibit PAC/201—Surprise Valley's Response to PacifiCorp's Data Request 5.1

Exhibit PAC/202—Surprise Valley's Response to PacifiCorp's Data Request 4.66 and Excerpt from Attachment 4.66

I. INTRODUCTION

Q. Please state your name, business address and position with PacifiCorp.

A. My name is Richard A. Vail. My business address is 825 N.E. Multnomah, Suite 1600, Portland, Oregon 97232. I am the Vice President of Transmission for PacifiCorp Transmission, a division of PacifiCorp. In that role, I am responsible for transmission system planning, customer generator interconnection requests and transmission service requests, regional transmission initiatives, capital budgeting for transmission, and administration of the Open Access Transmission Tariff (OATT). I am testifying in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

Q. Please describe your education qualifications.

A. I have B.S. degree with Honors in Electrical Engineering, with a focus in electric power systems from Portland State University. I have been Vice President of Transmission for PacifiCorp since December 2012. I was Director of Asset Management at PacifiCorp from 2007 to 2012. Before that, I had management responsibility for a number of organizations in PacifiCorp's asset management group, including capital planning, maintenance policy, maintenance planning, and investment planning since joining PacifiCorp in 2001.

Q. Have you testified in other Oregon Public Utility Commission (Commission) proceedings?

A. Yes. I have testified in multiple Commission proceedings over the years.

II. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. My testimony describes PacifiCorp Transmission's role in transactions with qualifying facilities (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA), with an emphasis on the basic components of QF power delivery arrangements. I then address PacifiCorp Transmission's role in Surprise Valley Electrification Corporation's (Surprise Valley) arrangements to deliver power from Surprise Valley's Paisley Project (Paisley or Paisley Project) to Surprise Valley's point of delivery on PacifiCorp's transmission system, and from that point of delivery to PacifiCorp's load. I also attempt to provide clarification on several Surprise Valley delivery issues, including the provision of ancillary services, the role of a Balancing Authority (BA), the studies PacifiCorp Transmission has performed related to different components of Surprise Valley's QF power delivery arrangements, and the General Transfer Agreement (GTA) between PacifiCorp and the Bonneville Power Administration (BPA).

III. BACKGROUND

Q. Please describe PacifiCorp Transmission.

A. PacifiCorp Transmission manages PacifiCorp's transmission services, transmission planning, and system operations for six states, as well as PacifiCorp's transmission expansion projects. PacifiCorp operates an integrated transmission system spanning two balancing authority areas—PacifiCorp East, which covers Utah, Wyoming and Southeast Idaho, and PacifiCorp West, which covers Oregon, Washington and California.

A. Separation of Functions

Q. How does PacifiCorp Transmission differ from PacifiCorp's merchant function (i.e., PacifiCorp ESM)?

PacifiCorp Transmission is a different business unit than PacifiCorp ESM. Under the Federal Energy Regulatory Commission's (FERC) Standard of Conduct rules,[1] public

[1] *See generally*, 18 C.F.R. Part 358 (2016).

utilities are required to “functionally separate” their transmission operations from their marketing operations. To that end, PacifiCorp split into separate power marketing and transmission operation divisions and eventually became what is now PacifiCorp ESM and PacifiCorp Transmission.

Q. Does PacifiCorp ESM have the ability to provide transmission service for itself?

A. No. Under the functional unbundling requirements, marketing affiliates, such as PacifiCorp ESM, must separately arrange for transmission services from the transmission side, in this case PacifiCorp Transmission, in the same way as any third-party transmission customer. PacifiCorp Transmission in turn provides transmission service to PacifiCorp ESM at the same rates, terms and conditions as it provides service to its other transmission customers.

Q. Does PacifiCorp ESM have the ability to secure transmission service on behalf of others?

A. No. PacifiCorp ESM, as the marketing function, is prohibited from engaging in the provision of transmission service under FERC’s Standards of Conduct rules.

Q. Does PacifiCorp Transmission participate in the negotiation of potential power purchase agreement (PPA) transactions between PacifiCorp ESM and third parties?

A. No.

Q. Is PacifiCorp Transmission a party to PPAs between PacifiCorp ESM and third parties?

A. No. PacifiCorp Transmission is not a party to PPAs. Because of functional separation requirements mandated by FERC, interconnection and PPAs are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (including, but not limited to, PacifiCorp Transmission), while PPAs are handled by the Company's merchant function (including, but not limited to, PacifiCorp ESM).

B. PacifiCorp Transmission's Role in PURPA Transactions

Q. Please describe the basic components of a QF's power delivery arrangement.

A. There are essentially two parts to a QF power delivery arrangement: (1) a QF's obligation to deliver its power to the purchasing utility's system; and (2) the purchasing utility's obligation to deliver the QF's power from the QF's point of delivery on the utility's system to the utility's load. These two basic segments are illustrated in the simple diagram below.

Q. Please describe the first segment of a QF power delivery arrangement.

A. The first delivery segment involves the QF's obligation to arrange to deliver its power to PacifiCorp's system. To accomplish this, a generator either interconnects directly with PacifiCorp's transmission/distribution system, or it interconnects to a third party's transmission/distribution system, which in turn interconnects to PacifiCorp's system.

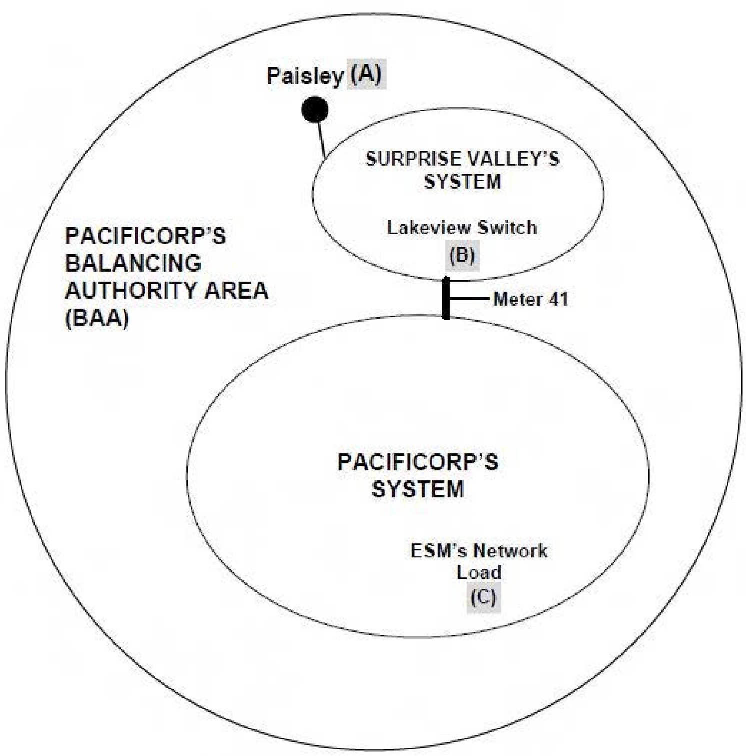
If the QF generator is interconnected directly to PacifiCorp's system, the generator is required to request and enter into a generation interconnection agreement with PacifiCorp Transmission. Surprise Valley did not construct a radial line to directly interconnect with PacifiCorp's system, so there is no generator interconnection agreement between Surprise Valley and PacifiCorp Transmission.

If, on the other hand, the QF generator is interconnected to a third party system (as is the case for Surprise Valley's Paisley Project QF, which is interconnected with

Surprise Valley's system), then the generator is required to acquire service on the intervening system for QF power delivery from: (1) the QF (shown as A below); to (2) PacifiCorp's system (shown as B below). PacifiCorp is not a party to that delivery arrangement between the QF and the intervening third party system.

Q. Please describe the second segment of a QF power delivery arrangement.

A. The second delivery segment involves PacifiCorp ESM's obligation to deliver the QF's power from the QF's point of delivery on PacifiCorp's system to load. In particular, once the QF enters into a PPA with PacifiCorp ESM, then PacifiCorp ESM requests transmission service from PacifiCorp Transmission to deliver the QF power from: (1) the QF's point of delivery on PacifiCorp's system (again, shown as B below); to (2) PacifiCorp's load (shown as C below).



Q. Would it be accurate to state that PacifiCorp Transmission's role is rather limited with respect to QFs in a PURPA transaction?

A. Yes. As noted above, it generally differs depending on whether the QF is an on-system or off-system QF; that is, whether the QF wishes to sell power through a direct or an indirect interconnection. If the QF wishes to interconnect directly with PacifiCorp's system, the QF negotiates an interconnection agreement with PacifiCorp Transmission. Otherwise, PacifiCorp Transmission's role is very limited until PacifiCorp ESM requests transmission service to deliver the QF power to load (or B to C in the diagram above).

Q. Does the Company's Schedule 37 reflect these different roles?

A. Yes. Schedule 37 states:

> Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading) [now PacifiCorp ESM].

1. PacifiCorp Transmission's Role—On-System/Directly Interconnected QFs

Q. Please describe PacifiCorp Transmission's role if there is a directly interconnected or on-system QF.

A. PacifiCorp Transmission is required by PURPA to accept QF requests to interconnect to PacifiCorp's system, perform agreed to studies that determine the scope of work required for interconnecting the generator, and, if the customer moves forward, to negotiate a generator interconnection agreement.

Q. Is the Paisley Project directly interconnected with PacifiCorp's system?

A. No. The Paisley Project is directly interconnected with Surprise Valley's system.

Q. How would the Paisley Project become directly interconnected with PacifiCorp's system?

A. To directly interconnect with PacifiCorp's system, Surprise Valley would need to construct a radial line from the generator to PacifiCorp's system and complete any associated upgrades identified in the interconnection studies.

Q. Has the Paisley Project requested a direct interconnection between the QF and PacifiCorp's system?

A. Surprise Valley asked if an interconnection was required to allow their generator to sell to PacifiCorp. PacifiCorp Transmission informed them that, since the plan was to interconnect to the Surprise Valley system, not PacifiCorp's system, there was no interconnection with PacifiCorp and no need to request an interconnection.

Q. Could the Paisley Project request a direct interconnection between the QF and PacifiCorp's system?

A. Yes. But my understanding is that, due to the location of the Paisley Project, it would require a fairly long and expensive radial line to connect the project directly with PacifiCorp's system.

Q. If Surprise Valley requested a direct interconnection between the Paisley Project and PacifiCorp's system, would PacifiCorp Transmission enter into an agreement with Surprise Valley to effectuate a direct interconnection?

A. Yes.

2. PacifiCorp Transmission's Role—Off-System/Indirectly Interconnected QFs

Q. Please describe PacifiCorp Transmission's role with off-system or indirectly interconnected QFs.

A. PacifiCorp Transmission's role with off-system QFs is fairly limited and is not mentioned in Schedule 37. If a QF is not directly interconnected with PacifiCorp's transmission or distribution system, the QF must wheel its power to PacifiCorp's system. It does so by making delivery arrangements with its local utility or interconnected utilities—not with PacifiCorp Transmission. PacifiCorp Transmission is not a party to a QF's wheeling arrangements.

Q. Does PacifiCorp Transmission make wheeling arrangements for indirectly interconnected QFs?

A. No. PacifiCorp Transmission does not make those arrangements nor is it privy to those arrangements. A QF is responsible for making wheeling arrangements with its local utility for delivery of its power to PacifiCorp's system.

Q. Why doesn't PacifiCorp Transmission make wheeling arrangements for an indirectly interconnected QF?

A. PacifiCorp Transmission does not own or operate the intervening transmission system needed to deliver an off-system QF's power to PacifiCorp's system. Consider the following hypothetical example: a QF interconnected with Idaho Power's system wants to deliver its power to PacifiCorp's system to enable a PURPA sale. PacifiCorp Transmission cannot transmit that QF power because PacifiCorp Transmission does not own or operate Idaho Power's transmission system that sits between the QF and PacifiCorp's system. PacifiCorp Transmission has no right to operate Idaho Power's transmission system, no access to information on Idaho Power's system, and no way to make those arrangements. The delivery arrangements would be made by the QF, and they would be strictly between the QF and Idaho Power.

Q. Does PacifiCorp's Schedule 37 make this clear?

A. Yes. Schedule 37 states as follows:

> NOTE: Section II [Interconnection] applies only to QFs connecting directly to PacifiCorp's electrical system. *An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.*

Q. In this case, who is the Paisley Project's "local utility or transmission provider"?

A. Surprise Valley.

Q. Does PacifiCorp's FERC-regulated OATT govern an indirectly interconnected QF's transmission arrangements with its wheeling utility?

A. No. The wheeling utility's governing regulations (whether state or federal) would govern the QF's transmission arrangements with its wheeling utility (Surprise Valley). PacifiCorp Transmission's OATT only governs the provision of transmission service on PacifiCorp's system.

Q. Is an indirectly interconnected QF a PacifiCorp Transmission customer?

A. Generally no, not for transmission service.

Q. Under the QF power delivery arrangements proposed by Surprise Valley witnesses Anderson, Saleba, and Tabone, would Surprise Valley purchase transmission service from PacifiCorp Transmission?

A. No.

Q. Does PacifiCorp Transmission direct an indirectly interconnected QF to make any specific types of transmission arrangements as part of negotiating a QF PPA?

A. No. PacifiCorp Transmission does not tell the QF what its transmission arrangements must look like for the QF to be eligible for a PPA with PacifiCorp ESM. PacifiCorp

ESM—not PacifiCorp Transmission—ensures that a QF is willing to agree to PPA terms and conditions, including delivery terms.

Q. Might PacifiCorp Transmission provide ancillary services in support of an indirectly interconnected QF's wheeling arrangement?

A. Yes. An indirectly interconnected QF can seek an ancillary services agreement if the QF or its wheeling utility are within PacifiCorp's Balancing Authority Area (BAA) and the QF cannot self-supply those services, the QF's wheeling utility cannot supply them, and the QF does not receive services from a third party.

Q. What are ancillary services?

A. Ancillary services are services that support the reliable transmission of electricity from one point to another. They may include services such as load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.

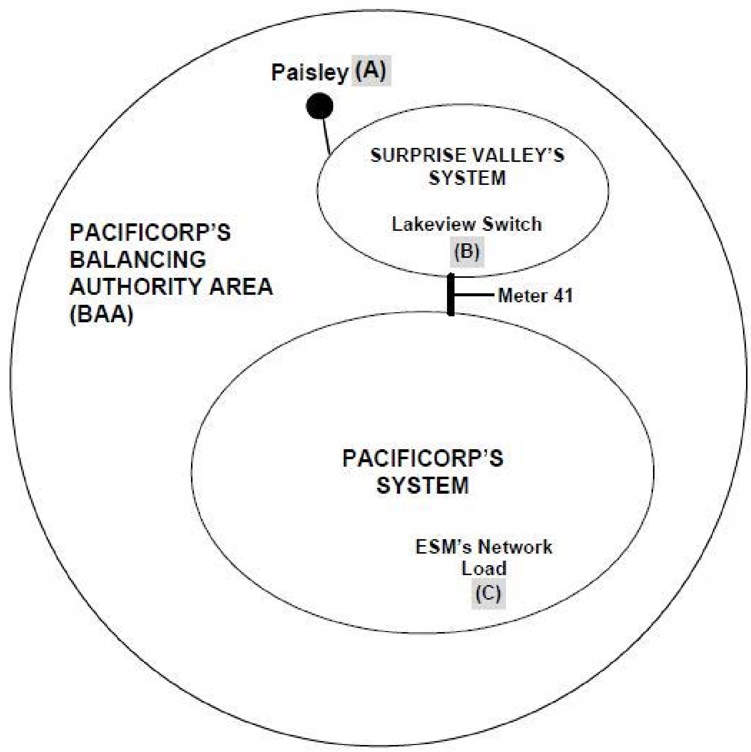
Q. If PacifiCorp Transmission provides ancillary services to support a QF wheeling arrangement, is that the same thing as providing the QF with a wheeling arrangement?

A. No. Ancillary services support the QF's separate wheeling arrangement. An agreement for ancillary services is not itself a wheeling arrangement. As I explained previously, PacifiCorp Transmission does not (and cannot) wheel power from an indirectly interconnected QF to PacifiCorp's system because that intervening system is operated by another utility.

3. PacifiCorp Transmission's Role—QF Power Delivery for PacifiCorp ESM

Q. What is PacifiCorp Transmission's role in QF power delivery for PacifiCorp ESM?

A. Once a QF has made arrangements to deliver its power to a specific point of delivery on PacifiCorp's system (shown as B on the diagram below), and PacifiCorp ESM signs a PPA, then PacifiCorp ESM requests transmission service from PacifiCorp Transmission. PacifiCorp Transmission performs the required studies to identify any upgrades necessary to ensure PacifiCorp ESM can deliver the QF power from the QF's point of delivery on PacifiCorp's system (again, shown as B below) to PacifiCorp's load (shown as C below).



Q. Does Surprise Valley appear to be confused about this role?

A. Yes. The testimony of Brad Kresge and Lynn Culp suggests that Mr. Kresge and Mr. Culp believe that the studies and delivery arrangements between PacifiCorp ESM and PacifiCorp Transmission address the ability of a QF to deliver power to PacifiCorp.[2]

Q. Is this the case?

A. No. When PacifiCorp Transmission receives a transmission service request from PacifiCorp ESM related to a QF PPA, PacifiCorp Transmission performs the studies required under the OATT, which identify system upgrades needed to deliver QF power from: (1) the point where the QF delivers the power to PacifiCorp's system (shown as B above); to (2) PacifiCorp's load (shown as C above). The studies do not examine delivery from the QF generator (shown as A above) to PacifiCorp's system (shown as B above).

Q. How does PacifiCorp ESM arrange for delivery of QF power from the point of delivery on the Company's system to PacifiCorp's load?

A. PacifiCorp ESM ordinarily relies on its transmission agreements with PacifiCorp Transmission to transmit purchased QF power to PacifiCorp's load.

Q. Under what transmission agreement is this accomplished?

A. PacifiCorp ESM and PacifiCorp Transmission have a transmission delivery agreement referred to as the Network Integration Transmission Service Agreement (NITSA). Once PacifiCorp ESM signs a PPA with a QF, PacifiCorp ESM requests designation of that QF

[2] *See, e.g.,* SVEC/100, Kresge/17-18, 25, 28 ("PacifiCorp used the network transmission study process to identify the additional metering necessary to *purchase* the Paisley Project's net output.") (emphasis added); *see also* SVEC/200, Culp/3 ("Second, I describe the interconnection, affected impact study, and transmission study process. This is important because: 1) PacifiCorp ESM stated that obtaining approval from PacifiCorp Transmission to designate the generator as a network resource with network transmission to PacifiCorp loads would resolve the metering and power verification issues. . ."); *id.* at Culp/11 ("Our understanding was that PacifiCorp could purchase the additional power on its system that resulted from the Paisley Project generating power and displacing or offsetting BPA power wheeled by PacifiCorp. Our understanding was that the metering details would need to be worked out, *which could be resolved through the network transmission study request.*") (emphasis added).

PPA as a network resource (also referred to as a DNR) under the NITSA. This is a transmission service request.

Q. What is network integration transmission service?

A. Network integration transmission service is a type of transmission service used by a transmission customer to serve its load. Under a NITSA, a transmission customer designates certain loads as designated network loads and certain resources as designated network resources.

Q. What it a network resource?

A. A network resource is a generating resource that is owned, purchased, or leased by a network customer, and designated as a network resource under the NITSA. Network resources are used to serve load rather than for sales to third parties.

Q. Does a QF resource have DNR status before PacifiCorp ESM signs a PPA with the QF?

A. No. Under PacifiCorp's OATT, a DNR resource must be owned, purchased, or leased by PacifiCorp ESM (which is the network customer in that scenario). Generally speaking, PacifiCorp ESM must sign a PPA before PacifiCorp ESM submits a request to designate that PPA as a network resource under the NITSA between PacifiCorp Transmission and PacifiCorp ESM. This is required by FERC and the Company's FERC-regulated OATT, which states at Section 30.2 that a DNR request must contain the following statements:

> (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a noninterruptible basis,

> except for purposes of fulfilling obligations under a reserve sharing program.

Q. What happens when PacifiCorp ESM seeks designation of a QF PPA as a DNR?

A. Under Section 30 of the OATT, PacifiCorp Transmission will conduct studies to determine whether system upgrades are needed to deliver PacifiCorp ESM's new resource to load. These may include a system impact study and a facilities study.

Q. Would these studies include a study of Surprise Valley's system, the system over which Surprise Valley intends to wheel its power to reach PacifiCorp's system?

A. No. The studies described are studies of PacifiCorp Transmission's own system. They look at upgrades needed to deliver PacifiCorp ESM's resource from: (1) the point on the system where the generator's transmission provider (Surprise Valley) delivers the resource to PacifiCorp's system (shown as B on the diagram above); to (2) PacifiCorp ESM's own load (shown as C on the diagram above).

Q. Who studies and identifies any upgrades necessary to wheel the Paisley Project's generation across Surprise Valley's system to PacifiCorp's system?

Surprise Valley. In particular, I understand that Surprise Valley intends to wheel the Paisley Project's generation across Surprise Valley's distribution system to PacifiCorp's system at the Lakeview switch.[3] Any studies or upgrades needed to accommodate that wheel from the Paisley Project (shown as A on the diagram above) to the Lakeview point of delivery (shown as B on the diagram above) would need to be undertaken by Surprise Valley.

Q. So any system impact study or facilities study conducted by PacifiCorp Transmission is a study of PacifiCorp's own system?

[3] Surprise Valley's Response to PacifiCorp's Data Request 5.1, attached as PAC/201.

A. Yes.

Q. Who is the counterparty to any agreements for these studies?

A. In the case of the Paisley generator, PacifiCorp ESM would be PacifiCorp Transmission's counterparty. In other words, PacifiCorp Transmission is the transmission provider providing transmission service to its network transmission customer, PacifiCorp ESM.

Q. Surprise Valley's testimony contains a number of references to PacifiCorp transmission studies. If Surprise Valley is not the intended customer for these studies, why does Surprise Valley have information about these studies?

A. Ordinarily Surprise Valley would not have this information. My understanding is that PacifiCorp ESM requested specific studies from PacifiCorp Transmission that were somewhat unusual, but were requested and performed in an effort to explore and accommodate options for receiving QF power under Surprise Valley's unusual configuration. PacifiCorp ESM then signed a waiver to allow Surprise Valley to see the studies.

Q. Just to be clear, these studies were not conducted to determine anything about Surprise Valley's own transmission arrangements?

A. No. The studies had nothing to do with Surprise Valley's own transmission arrangements or transmission obligations.

Q. What obligations does PacifiCorp Transmission have to the QF with respect to the QF's requirements to deliver power to PacifiCorp's system?

A. None, other than to ensure that PacifiCorp's system can safely and reliably accept power delivered to the point of receipt on PacifiCorp's system under the delivery arrangements between the QF and its local utility. PacifiCorp Transmission's determination that PacifiCorp could safely and reliably "receive" the Paisley Project's power is not the same thing as a determination that the Paisley Project has, in fact, made appropriate arrangements to deliver its power to PacifiCorp.

IV. PACIFICORP TRANSMISSION'S ROLE AS BA AND TRANSMISSION PROVIDER

Q. Please explain the purpose of this section.

A. In this section I address various issues that arose out of discussions between the parties about PacifiCorp's role as the BA in an effort to clear up some possible misunderstandings.

A. PacifiCorp Transmission's Role as BA

Q. What is a BA?

A. A BA is the entity responsible for ensuring reliability in a BAA. A BA is responsible for integrating resource plans ahead of time, maintaining demand and resource balance within a BAA, and ensuring reliability within the BAA. Put most simply, as BA, PacifiCorp Transmission maintains reliability and load-resource balances within this area.

Q. What is a BAA?

A. A BAA, previously called a "Control Area," is the collection of generation, loads and transmission within the metered boundaries of the BA. In a BAA, the BA is responsible to maintain the load-resource balance within the area—the total of all generation must equal the total of all loads.

Q. Is Surprise Valley located within PacifiCorp's BAA?

A. Yes.

Q. Does this mean that the Paisley Project is automatically a PacifiCorp ESM DNR?

A. No. The fact that a generator is located in PacifiCorp's BAA does not make it a PacifiCorp ESM DNR, or any kind of DNR for that matter. For example, the Paisley Project is currently designated as a DNR under Surprise Valley's NITSA with BPA, meaning it is a resource used under BPA's agreement with Surprise Valley to serve Surprise Valley's load.[4] As stated earlier in my testimony, for a generator to become a DNR for PacifiCorp ESM, the generator must enter into a PPA with PacifiCorp ESM, and PacifiCorp ESM must request DNR status for that PPA under its NITSA with PacifiCorp Transmission.

Q. What is PacifiCorp Transmission's relationship to generators in its BAA?

A. As the BA of the BAA, PacifiCorp Transmission must ensure it is aware of generation in its BAA. It must ensure the BAA is operated appropriately and in accordance with NERC and WECC standards.

Q. What other obligations might a BA have to a QF located in its BAA?

A. This is not a PURPA-specific obligation, but a BA is considered the default provider for certain ancillary services for parties with transmission agreements in the BAA.

Q. Is PacifiCorp Transmission willing to provide those services to Surprise Valley?

A. PacifiCorp is willing to provide these ancillary services upon request. In fact, Surprise Valley asked for an ancillary services agreement on March 17, 2016, to support its planned delivery of the Paisley Project's power from the QF to PacifiCorp's system. Surprise Valley and PacifiCorp Transmission met on April 22, 2016, to discuss the

[4] Surprise Valley's Response to PacifiCorp's Data Request 4.66 and Excerpt from Attachment 4.66, attached as PAC/202.

agreement, and the parties are in the process of negotiating that ancillary services agreement.[5]

Q. Is PacifiCorp Transmission's willingness to provide an ancillary services agreement dependent on Surprise Valley's attempt to secure a PPA with PacifiCorp ESM?

A. No. PacifiCorp Transmission is willing to provide an ancillary services agreement at Surprise Valley's request, regardless of whether Surprise Valley's intends to use the underlying delivery arrangement to obtain a PURPA PPA, or if it intends to use that delivery arrangement for some other purpose.

Q. Can a generation resource within PacifiCorp's BAA deliver power to PacifiCorp through a pseudo-tie?

A. No. A generation resource within PacifiCorp's BAA cannot be pseudo-tied to PacifiCorp's system. Pseudo-ties are only possible for generators located in a different BAA.

B. PacifiCorp's GTA with BPA

Q. What is PacifiCorp's GTA with BPA?

A. The GTA is a reciprocal transfer agreement between PacifiCorp and BPA. The GTA provides for the transfer of energy across PacifiCorp's transmission and distribution system to certain of BPA's wholesale power customers, including Surprise Valley. BPA schedules power to PacifiCorp's system, and PacifiCorp delivers that power to certain of BPA's customer on BPA's behalf. BPA does the same for PacifiCorp in return. The parties' scheduled deliveries are trued up with actual deliveries on a monthly basis and netted out.

[5] Because the Paisley Project is in PacifiCorp's BAA, PacifiCorp would expect the Paisley Project to sign a BA services agreement including a number of these services.

Q. Is there a power purchase or sale component to the GTA?

A. No. PacifiCorp does not take title to BPA's power when PacifiCorp delivers BPA's power to BPA's customers. Likewise, BPA does not take title to PacifiCorp's power when it delivers PacifiCorp's power to PacifiCorp's customers.

Q. Why is the GTA relevant to this dispute?

A. Surprise Valley makes the GTA an explicit and integral part of Surprise Valley's own power delivery proposal. For example, at SVEC/300, Saleba-Tabone/3-4, witnesses Saleba and Tabone summarize Surprise Valley's power delivery proposal in several bullet points. One of those bullet points states, on lines 16-19, "a portion of the BPA power delivered to PacifiCorp on behalf of Surprise Valley will be retained by PacifiCorp for its own use."

Q. Is this passage referring to PacifiCorp's delivery of power under the GTA?

A. Yes.

Q. Does BPA schedule power for delivery to its customers under the GTA?

A BPA schedules power for delivery to its customers under the GTA on an aggregated basis.

Q. Does BPA schedule power for delivery specifically to Surprise Valley's system?

A. No. Under the GTA, BPA only schedules power in the aggregate to its wholesale power customers covered under the GTA.

Q. Is it possible for PacifiCorp Transmission to know how much of that aggregated power schedule is attributable to BPA's scheduled power delivery to Surprise Valley?

A. No.

Q. What is the significance of BPA's aggregated scheduling?

A. BPA's aggregated scheduling makes it impossible for PacifiCorp ESM to verify that it would actually obtain power from Surprise Valley under Surprise Valley's delivery proposal. Mr. Bruce W. Griswold addresses this issue in his testimony.

Q. Is BPA willing to provide schedules specifically for Surprise Valley?

A. No. My understanding is that Surprise Valley asked BPA for hourly delivery schedules to Surprise Valley's system some time ago, but BPA refused to provide these schedules. More recently, PacifiCorp Transmission contacted BPA directly to see whether BPA would provide these schedules, but BPA confirmed its unwillingness to do so.

Q. Why did PacifiCorp Transmission contact BPA?

A. PacifiCorp Transmission contacted BPA at PacifiCorp ESM's request, in an effort to find a creative solution to Surprise Valley's delivery problem. PacifiCorp Transmission's hope was that BPA would be willing to provide this information in order to assist Surprise Valley with their delivery issues.

C. Studies Conducted by PacifiCorp Transmission

Q. During the course of PacifiCorp ESM's negotiations with Surprise Valley, PacifiCorp Transmission conducted a number of system studies. Can you explain the significance of these studies?

A. Yes. PacifiCorp Transmission conducted an affected system study in 2013 at Surprise Valley's request. In June 2014 and September 2014, PacifiCorp Transmission completed a system impact study and facilities study, respectively, at PacifiCorp ESM's request.

1. Affected System Study

Q. Why was the affected system study needed?

A. An affected system study is needed when the addition of a new generator can have impacts on a neighboring or interconnected system's transmission grid. The study evaluated the impact that the Paisley generator, which is directly interconnected to Surprise Valley's system, might have on the reliability of PacifiCorp's neighboring system. In this case, the study was needed before the Paisley generator could begin generating.

Q. Who requested the affected system study?

A. Surprise Valley requested the study on February 6, 2013. PacifiCorp Transmission and Surprise Valley executed an affected system study agreement on August 1, 2013.

Q. What did the affected system study agreement obligate PacifiCorp Transmission to do?

A. PacifiCorp Transmission agreed to study the impact to PacifiCorp's Transmission system of the Paisley Project's interconnection with Surprise Valley's system.

Q. Did PacifiCorp Transmission perform that evaluation?

A. Yes. PacifiCorp Transmission performed two studies, and then delivered the results of the studies to Surprise Valley on October 30, 2013.

Q. What did the results of the Affected System studies show?

A. The studies showed the need for some relay upgrades, which were completed.

Q. Did the Affected System studies address how Surprise Valley could deliver its power to PacifiCorp's system in order to obtain a PPA with PacifiCorp ESM?

A. No. Consistent with its purpose, the Affected System studies simply evaluated whether the interconnection of the Paisley Project's generation to Surprise Valley's system, which is in turn connected to PacifiCorp's neighboring system, might have impacts on PacifiCorp's system.

Q. Surprise Valley contends the Affected System studies took too long to complete. What is your response?

A. Although there are no state or federal rules dictating study timelines for an affected system study, we could compare the time used to produce the combined system impact/facilities study to interconnection studies under the state or federal rules. Under state and federal rules, a system impact study is due back to the customer in 45 business days and the facilities study in another 45 business days. Not accounting for customer review and study agreement processing time, the impacted system studies were completed in a timeline shorter than state or federal rules for interconnection.

2. System Impact Study and Facilities Study

Q. Why were the system impact study and facilities study conducted?

A. PacifiCorp ESM submitted a transmission service request to PacifiCorp Transmission on March 25, 2014, requesting DNR status for the Paisley generator. In accordance with that request, and consistent with its OATT, PacifiCorp Transmission conducted a system impact study and a facilities study. PacifiCorp Transmission issued the system impact study report in June 2014, and the facilities study report in September 2014.

Q. Who were the system impact study and facilities study reports issued to?

A. PacifiCorp ESM, the network transmission customer requesting the studies.

Q. What was the purpose of the studies?

A. Under the transmission service request study process, PacifiCorp Transmission completes the planning and engineering studies to determine impacts, if any, to the transmission system and what infrastructure additions would be required to designate a PPA for the Paisley Project as a network resource to serve PacifiCorp's retail load.

Q. What did the studies show?

A. The studies showed the need for additional metering and communications equipment to allow PacifiCorp Transmission to receive the Paisley Project's net output at Surprise Valley's point of delivery (shown as B on the diagram above) and deliver it to PacifiCorp's load (shown as C on the diagram above).[6]

Q. Did the system impact study or facilities study reports address how Surprise Valley might deliver its power to PacifiCorp's system to obtain a PPA with PacifiCorp ESM?

A. No. Consistent with their purpose, the system impact study and facilities study reports simply studied the impacts and what upgrades would be needed on PacifiCorp's system for PacifiCorp Transmission to deliver the Paisley Project's power from Surprise Valley's point of delivery on PacifiCorp's system (shown as B on the diagram above) to PacifiCorp's load (shown as C on the diagram above).

Q. So the studies assumed that Surprise Valley would deliver its power to PacifiCorp's system?

A. Yes.

Q. Did PacifiCorp Transmission know whether Surprise Valley had, in fact, arranged for delivery of its power to PacifiCorp's system?

A. No. PacifiCorp Transmission simply conducted the studies as requested.

[6] *See* SVEC/209, Culp/8-23.

Q. Surprise Valley contends the studies took too long to complete. What is your response?

A. The studies were performed at the request of and for PacifiCorp Transmission's customer, PacifiCorp ESM. The studies were not performed for Surprise Valley. That being said, the system impact study was completed in 50 days, which is well within the OATT-prescribed timeline of 60 days. The facilities study was completed in 59 days, which is also within the OATT prescribed timeline of 60 days.

3. Construction Agreement

Q. Surprise Valley also refers to a construction agreement.[7] Can you explain what the construction agreement is?

A. Yes. In connection with the transmission service request studies noted above, PacifiCorp Transmission tendered a construction agreement to PacifiCorp ESM. This agreement was signed by the parties and pertained to the work that had been identified in the transmission service request studies as necessary to deliver Paisley Project power from the Surprise Valley point of delivery on PacifiCorp's system to PacifiCorp's load.

Q. Who were the parties to the construction agreement?

A. PacifiCorp Transmission and PacifiCorp ESM.

Q. Surprise Valley contends that PacifiCorp Transmission and PacifiCorp ESM took too long to complete the construction agreement. What is your response?

A. The agreement was between PacifiCorp Transmission and its customer PacifiCorp ESM. Surprise Valley was not a party to the agreement. That being said, there are no state or federal set timelines for parties to follow when negotiating a construction agreement.

[7] SVEC/200, Culp/36.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/201

**SURPRISE VALLEY'S RESPONSE TO
PACIFICORP DATA REQUEST 5.1**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 8, 2016
SVEC Response to PacifiCorp Data Request 5.1

PacifiCorp Data Request 5.1

Please identify which of the following arrangements describes Surprise Valley's proposal for delivering the net output of the Paisley Project to PacifiCorp's system, and identify and provide all supporting transmission or other contracts or arrangements:

a. The Paisley Project's net output will be delivered over Surprise Valley's distribution system to the PacifiCorp' system, with the point of interconnection between the PacifiCorp and Surprise Valley systems as the point of delivery under the power purchase agreement.

b. PacifiCorp will accept the Bonneville Power Administration (BPA) power, in an amount equal to the net output of the Paisley Project, delivered to Surprise Valley's Lakeview substation over PacifiCorp's system via PacifiCorp's General Transfer Agreement (GTA) with BPA.

c. PacifiCorp will accept BPA power, in an amount equal to the net output of the Paisley Project, delivered over BPA's system to a point near structure 47/5 in BPA's La Pine-Chiloquin 230 kV transmission line where the 230 kV facilities of BPA and PacifiCorp are connected, under some transmission arrangement.

d. PacifiCorp will accept BPA power, in an amount equal to the net output of the Paisley Project, delivered over BPA's system to an unspecified point (or points) on PacifiCorp's system under some transmission arrangement.

e. A combination of the delivery arrangements above (please describe in detail).

f. A delivery arrangement not described above (please describe the arrangement with specificity and provide supporting documents and agreements, or identify the specific documents already provided).

g. No specific arrangement for the delivery of the Paisley Project's net output (simple "displacement," or movement of electrons)

Response to PacifiCorp Data Request 5.1

Surprise Valley objects this data request on the ground that PacifiCorp did not request that Surprise Valley provide any specific transmission contracts or arrangements until it filed its answer to the complaint in this matter. Surprise Valley also objects to the extent that this request is vague in its descriptions, and appears to operate under erroneous assumption that electric energy can be color coded from generator to load such that

PacifiCorp could accurately determine whether energy on its system was derived from BPA resources or other resources on the interconnected grid.

Notwithstanding these objections, Surprise Valley provides the following:

Surprise Valley is able to provide transfers of the QF's net output consistent with subpart a. For a description of the arrangements and supporting documentation that Surprise Valley possesses the transmission capacity necessary to make deliveries consistent with subpart a., please see SVEC/400, Anderson/10-11. If this request is asking if Surprise Valley has entered into a transmission contract with itself, the response is "no," aside from its ownership and control of the interconnected system from the generator to the Lakeview Substation point of delivery, Surprise Valley has not executed a transmission agreement with itself because it is not necessary for Surprise Valley to do so in order to possess a right to deliver the QF's net output to PacifiCorp. See SVEC/300, Saleba-Tabone/11-13.

If PacifiCorp would be willing to agree, Surprise Valley could likely also enter into several alternative forms of delivery described in this request. For example, for subpart c., please refer to Surprise Valley's response to PacifiCorp data request 2.15.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1742

SURPRISE VALLEY
ELECTRIFICATION CORP.,

Complainant

v.

PACIFICORP, d/b/a PACIFIC POWER,

Respondent.

EXHIBIT PAC/202

**SURPRISE VALLEY'S RESPONSE TO
PACIFICORP DATA REQUEST 4.66 AND EXCERPT
FROM ATTACHMENT 4.66**

May 17, 2016

Oregon Public Utility Commission
OPUC Docket UM 1742
April 5, 2016
SVEC Response to PacifiCorp Data Request 4.66

PacifiCorp Data Request 4.66

Please provide all documents discussing or addressing Revision No. 1, Exhibit A to Attachment 2.3(c). These should include, but not be limited to, all internal and external communications, internal memoranda, and any other documents addressing or referencing the need for this amendment, the plans for this amendment, and any other reference to amendment.

Response to PacifiCorp Data Request 4.66

Please refer to UM 1742 Attachment 4.66

EXHIBIT A
SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE

TABLE 1, REVISION NO. 3
TRANSMISSION SERVICE REQUEST
Assign Ref is: 375847 & 78969781

Exhibit A, Table 1, Revision No. 3 replaces Exhibit A, Table 1, Revision No. 2 in its entirety and reflects the following: 1) adds Paisley Geothermal Generating Plant as a Designated Network Resource in Section 2(c); 2) adds the Point of Delivery (POD) and meters associated with Surprise Valley Electrification Corporation's (Surprise Valley) Lakeview POD that were inadvertently deleted in the previous revision; 3) corrects Section 4 to add the Cedarville In Meter Point Number 4300; and 4) corrects the location description of Meter Point Number 861 to be in Surprise Valley's Cedarville Substation rather than in the Bonneville Power Administration's Cedarville Junction Substation.

1. **TERM OF TRANSACTION**
For Assign Ref(s): 375847 & 78969781
Service Agreement Commencement Date: at 0000 hours on October 1, 2001.
Service Agreement Termination Date: at 0000 hours on October 1, 2031.

2. **NETWORK RESOURCES**
Pursuant to section 29.2 and 30.2 of Transmission Provider's Tariff, Transmission Customer has designated the following Network Resources:

(a) **Generation Owned by the Transmission Customer**

Resource Name	Start Date	Stop Date	Designated Capacity (MW)	Point of Receipt & Source	Balancing Authority	Associated Assign Ref
N/A						

(b) **Generation Purchased by the Transmission Customer**

Source (Contract No.) or Resource Name	Start Date	Stop Date	Designated Capacity (MW)	Point of Receipt & Source	Balancing Authority	Associated Assign Ref
Power Contract No. 09PB-13110	10/1/2011	9/3/2028	Net Requirements	FCRPS	BPAT	NA[1]

[1] There is no Assign Ref for this Network Resource.

(c) **Local Resource Behind the Meter (owned or purchased)**

Resource Name	Start Date	Stop Date	Designated Capacity (MW)	Balancing Authority	Associated Assign Ref
Paisley Geothermal Generating Plant	10/1/2015	9/30/2016	3.65	PACW	N/A[1]

3. POINT(S) OF RECEIPT

(a) **Federal Generation Point(s) of Receipt**

Transmission Customer Point of Receipt: Federal Columbia River Power System (FCRPS);

POR Number: 3453;

Balancing Authority: BPAT;

Location: FCRPS;

Voltage: 500 kV;

Metering: scheduled quantity;

Exceptions: not applicable.

(b) **Non-Federal Generation Point(s) of Receipt**
Not applicable.

4. POINT(S) OF DELIVERY

(a) **Description of Network Point(s) of Delivery:**
Surprise Valley BPA NT DP.

Transmission Customer Point of Delivery: Canby 69 kV;

BPA POD Name: SURPRISVLY;

BPA POD Number: 104;

Balancing Authority: BPAT;

Location: the point in the vicinity of Surprise Valley Electric Corporation's Canby Switching Station, where the 69 kV facilities of the Transmission Provider and Surprise Valley Electric Corporation are connected;

Voltage: 69 kV;

Metering: in Surprise Valley Electrification Corporation's Canby Substation in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Canby Out (SVEC);

BPA Meter Point Number: 44;

Direction for Billing Purposes: positive;

Manner of Service: direct;

Metering Loss Adjustment: not applicable;

Exceptions: not applicable.

(b) **Description of Transfer Point(s) of Delivery:**
For purposes of this section the following definitions shall apply:

"Transfer Point of Delivery" means the point where the Transmission Provider delivers power to the Intervening System.

"Point of Receipt from Intervening System" means the point where the Transmission Provider or a Third Party receives power from the Intervening System prior to delivery of power to the Point of Delivery.

Transfer Point of Delivery: Buckley – Summer Lake 500 kV;

(1) **Transmission Customer Point of Delivery:** Alturas 12.5 kV;

BPA POD Name: BPAT.PACW;

BPA POD Number: 817;

Balancing Authority: PACW;

Location: the point in PacifiCorp's Alturas Substation, in Surprise Valley Electrification Corporation's equipment yard, where the 12.5 kV facilities of PacifiCorp and Surprise Valley Electric Corporation are connected;

Voltage: 12.5 kV;

Metering: in the Surprise Valley Electrification Corporation's Alturas equipment yard 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Alturas Out;

BPA Meter Point Number: 244;

Direction for Billing Purposes: positive;

Manner of Service: transfer, Transmission Provider to PacifiCorp to Surprise Valley Electrification Corporation;

Metering Loss Adjustment: not applicable;

Exceptions: the potential and current transformers are owned by Surprise Valley Electrification Corporation.

(2) **Transmission Customer Point of Delivery:** Austin 69 kV;

BPA POD Name: BPAT.PACW;

BPA POD Number: 41;

Balancing Authority: PACW;

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

Voltage: 69 kV;

Metering: in Surprise Valley Electrification Corporation's Austin switching station in the 69 kV circuit over which such electric power flows;

BPA Meter Point Name: Austin Out;

BPA Meter Point Number: 132;

Direction for Billing Purposes: positive;

Manner of Service: transfer, Transmission Provider to PacifiCorp to Surprise Valley Electrification Corporation;

Metering Loss Adjustment: not applicable;

Exceptions: not applicable.

(3) **Point of Receipt from Intervening System:** Cedarville Junction (BPA) 115 kV where the facilities of PacifiCorp and BPA are connected;

Transmission Customer Point of Delivery: Cedarville Junction 69 kV – SURP;

BPA POD Name: BPAT.PACW;

BPA POD Number: 117;

Balancing Authority: PACW;

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 are connected;

Voltage: 69 kV;

Metering: in the Transmission Provider's Cedarville Junction Substation in the 69 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Cedarville Out;

BPA Meter Point Number: 65;

Direction for Billing Purposes: positive;

Manner of Service: transfer, Transmission Provider to PacifiCorp to Transmission Provider to Surprise Valley Electrification Corporation;

(B) **BPA Meter Point Name:** Cedarville In;

BPA Meter Point Number: 4300;

Direction for Billing Purposes: negative;

Manner of Service: transfer, Surprise Valley Electrification Corporation to Transmission Provider to PacifiCorp to Transmission Provider;

Location: the point in the vicinity of Surprise Valley Electrification Corporation's Cedarville Substation, where the 12.5 kV facilities of Surprise Valley Electrification Corporation and PacifiCorp are connected;

Voltage: 12.5 kV;

Metering: in Surprise Valley Electrification Corporation's Cedarville Substation in the 12.47 kV circuit over which such electric power flows;

(C) **BPA Meter Point Name:** Cedarville (PP&L) Out;

BPA Meter Point Number: 861;

Direction for Billing Purposes: negative;

Manner of Service: transfer, Surprise Valley Electrification Corporation to PacifiCorp;

Metering Loss Adjustment: BPA shall adjust for losses between the Cedarville Junction POD and the Cedarville (PP&L) Out POM. Such adjustments shall be specified in writing between BPA and SVEC. This meter is used to subtract the PacifiCorp Cedarville load from the total Surprise Valley Electrification Corporation load measured at Cedarville Junction (i.e.: MP 65 – (MP 861 x LF) = SVEC load);

Exceptions: the potential and current transformers are owned by PP&L.

(4) **Point of Receipt from Intervening System:** Davis Creek (BPA) 115 kV where the facilities of PacifiCorp and BPA are connected;

Transmission Customer Point of Delivery: Davis Creek 12.5 kV;

BPA POD Name: BPAT.PACW;

BPA POD Number: 169;

Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley Electrification Corporation's Davis Creek Substation, where the 12.5 kV facilities of the Transmission Provider and Surprise Valley Electrification Corporation are connected;

Voltage: 12.5 kV;

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

> **BPA Meter Point Name:** Davis Creek Out;
>
> **BPA Meter Point Number:** 259;
>
> **Direction for Billing Purposes:** positive;
>
> **Manner of Service:** transfer, Transmission Provider to PacifiCorp to Transmission Provider to Surprise Valley Electrification Corporation;

Metering Loss Adjustment: not applicable;

Exceptions: the 115 kV tap line, 115/12.5 kV transformer, potential and current transformers (used for revenue meter installation) are owned by BPA. BPA shall have unrestricted use, at no charge, of Surprise Valley's Davis Creek 115 kV Substation facilities.

(5) **Transmission Customer Point of Delivery:** Lakeview 69 kV;

BPA POD Name: BPAT.PACW;

BPA POD Number: 383;

Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley Electrification Corporation's Lakeview Switching Station, where the 69 kV facilities of PacifiCorp and Surprise Valley Electrification Corporation are connected;

Voltage: 69 kV;

Metering: in Surprise Valley Electrification Corporation's Lakeview Switching station, in the 69 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Lakeview Out;

BPA Meter Point Number: 41;

Direction for Billing Purposes: positive;

Manner of Service: Transmission Provider to PacifiCorp to Surprise Valley Electrification Corporation;

(B) **BPA Meter Point Name:** Lakeview In;

BPA Meter Point Number: 4123;

Direction for Billing Purposes: negative;

Manner of Service: transfer, Surprise Valley Electrification Corporation to PacifiCorp to Transmission Provider;

Metering Loss Adjustment: not applicable;

Exceptions: not applicable.

(6) **Transmission Customer Point of Delivery:** Paisley Geothermal 69 kV;

BPA POD Name: BPAT.PACW;

BPA POD Number: 4434;

Balancing Authority: PACW;

Location: the point in the vicinity of Surprise Valley Electrification Corporation's Paisley Geothermal Generation project in the 69 kV circuit where the generation facilities and the transmission facilities are connected;

Voltage: 69 kV;

Metering: in Surprise Valley Electrification Corporation's Paisley Geothermal Generation project in the 69 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Paisley GENR In;

BPA Meter Point Number: 4122;

Direction for Billing Purposes: positive;

Manner of Service: Surprise Valley Electrification Corporation to PacifiCorp to Transmission Provider;

(B) **BPA Meter Point Name:** Paisley STN SVC Out;

BPA Meter Point Number: 4121;

Direction for Billing Purposes: not counted;

Manner of Service: transfer, Transmission Provider to PacifiCorp to Surprise Valley Electrification Corporation;

Metering Loss Adjustment: not applicable;

Exceptions: not applicable.

5. NETWORK LOAD

The Application provides the Transmission Customer's initial annual load and resource information. Annual load and resource information updates shall be submitted to the Transmission Provider at the address specified in Exhibit B (Notices), by September 30th of each year, unless otherwise agreed to by the Transmission Provider and the Transmission Customer.

6. DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliates (if they own or control transmission facilities).

7. NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

PacifiCorp Contract No. DE-MS79-82BP90049.

8. SERVICE AGREEMENT CHARGES

Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 **Transmission Charge**
Network Integration Rate Schedule, or its successor, in effect at the time of service.

Short Distance Discount

The following Designated Network Resource(s) are eligible for the Short Distance Discount (DNR SD) subject to the Transmission and Ancillary Service Rate Schedules, or their successors, in effect at the time of service.

(1) **Resource Name:** Paisley Geothermal;

Transmission Distance: 0 Circuit Miles[2];

8.2 **System Impact and/or Facilities Study Charges**
System Impact and/or Facilities Study Charges are not required for service under this Agreement.

8.3 **Direct Assignment Facilities Charges**
Facilities Charges are not required at this time for the service under this Agreement.

8.4 **Ancillary Service Charges**
Described in Exhibit A, Table 2 (Ancillary Service Charges) of this Agreement.

9. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT

Not applicable.

10. SIGNATURES

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

SURPRISE VALLEY ELECTRIFICATION CORPORATION		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:	Bradley A Kresge	By:	Eric K. Taylor
Name:	Bradley A Kresge (Print/Type)	Name:	Eric K. Taylor (Print/Type)
Title:	General Manager	Title:	Transmission Account Executive
Date:	11/9/15	Date:	11/16/15

[2] For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Transmission Distance shall be zero.