BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

KOOTENAI ELECTRIC COOPERATIVE, INC., Complainant, vs. IDAHO POWER COMPANY, Defendant.	))))))))	Docket No. UM 1572 KOOTENAI ELECTRIC COOPERATIVE, INC.'S MOTION FOR SUMMARY JUDGMENT

I. INTRODUCTION

Kootenai Electric Cooperative, Inc. ("Kootenai") hereby moves the Public Utility Commission of Oregon (the "OPUC"), pursuant to Oregon Administrative Rule 860-001-0420 and Oregon Rule of Civil Procedure 47, to grant Kootenai summary judgment on the sole claim in the Complaint. Pursuant to the Public Utility Regulatory Policies Act of 1978 ("PURPA") Kootenai's Fighting Creek Landfill Gas to Energy qualifying facility ("QF") is entitled to the OPUC Schedule 85 power purchase agreement ("PPA") or another legally enforceable obligation consistent with the Schedule 85 terms and rates in effect at the time Kootenai obligated itself.

Kootenai's QF is located in Northern Idaho and will use the transmission system of Avista Corporation ("Avista") to deliver electrical output to a point where Idaho Power's and Avista's systems are interconnected near Imnaha, Oregon. That is the point of delivery between the two utilities on the 108-mile-long transmission line from Avista's Lolo Substation in Idaho, to Idaho Power's Oxbow Substation in Oregon. Idaho Power's sole defense thus far raised before the OPUC is that the point of delivery for this transaction is at Avista's Lolo Substation in the State of Idaho, and therefore the OPUC rules and rates do not apply. This argument is misleading, at best. The governing Interconnection Agreement between Idaho Power and Avista expressly states the point of delivery is the point in change in ownership of the line. The utilities' regulatory filings and Idaho Power's own admissions establish that the point at Imnaha, Oregon is the point that not only delineates the change in ownership of the transmission line, but also delineates the change in allocation of line losses, the change in the utility responsible for interconnection agreements with QFs, and the change in the utility responsible for operation and maintenance of the line. Further, under Avista's Open Access Transmission Tariff ("OATT"), Kootenai must pay transmission rates and line losses that include embedded within them the cost of using Avista's transmission facilities up to Imnaha, Oregon.

The Federal Energy Regulatory Commission's ("FERC") regulations implementing PURPA require state utility commissions to compel a utility to purchase QF output wheeled over a third party utility's transmission system as if the QF were directly interconnected to the purchasing utility. 18 C.F.R. § 292.303(d). The OPUC's rules implementing PURPA therefore apply just as if Kootenai's QF were directly interconnecting to Idaho Power at Imnaha, Oregon. To deny Kootenai's proposed transaction would violate the Dormant Commerce Clause of the United States Constitution by excluding an out-of-state QF from participating in the distinct PURPA and renewable energy credit ("REC") markets created by the State of Oregon. Kootenai respectfully requests that the OPUC require Idaho Power to purchase Kootenai's QF output pursuant to the terms and rates in the standard OPUC Schedule 85 PPA executed by Kootenai.

II. FACTUAL BACKGROUND

A. Background Regarding the Lolo-Oxbow Line Over Which Kootenai Will Deliver to Idaho Power's Electrical System at Imnaha, Oregon

The critical facts in this case regard the point of delivery from Avista's electrical system to Idaho Power's electrical system. *See Amended Answer* at ¶ 2. The two utilities' sole interconnection dates to a 1958 Interconnection Agreement, which is still in effect in relevant parts and on file with FERC.

In 1958, Idaho Power, Washington Water Power Company (now Avista), and Pacific Power and Light Company (now PacifiCorp) entered into an Interconnection Agreement. *See Affidavit of Peter J. Richardson* ("*Richardson Affidavit*") at Exhibit 1 at pp. 14-75 (containing the 1958 Interconnection Agreement and all subsequent amendments thereto). The utilities agreed to construct transmission facilities to allow for deliveries between each other. *See id.* at pp. 27-28. Idaho Power agreed to construct a 230 kilovolt ("kv") line from its Browlee and Oxbow substations in Oregon to a point located on the bank of the Snake River at a location known as Divide Creek in Idaho, and Avista agreed to construct a 230 kv line from Divide Creek to its Lolo Substation near Lewiston, Idaho. *Id*.

The 1958 Interconnection Agreement states: "The *Points of Delivery* for energy supplied between the parties hereto, unless otherwise specified, shall be at the place and in the interconnecting circuit between the parties *where ownership and control of the facilities changes*." *Id.* at p. 28 (emphasis added). The 1958 Interconnection Agreement's provision regarding metering requires "making adjustments for line losses." *Id*. The 1958 Interconnection Agreement also requires each utility to indemnify the others for occurrences on its side of the Points of Delivery. *Id.* at p. 30.

In 1958, Idaho Power and Avista also executed a Transmission Line Agreement regarding the 20.23 mile section of the Lolo-Oxbow line which spanned from Divide Creek, at the Idaho-Oregon State border, to a location defined as Idaho Power's engineer station at Imnaha, Oregon. *See id.* at pp. 63-65. Avista agreed to pay Idaho Power to construct, operate, and maintain this section of the line, and Idaho Power agreed to transfer all power scheduled by Avista over the section. *Id.* With the advent of FERC-mandated open access to transmission, the utilities construed the 1958 Interconnection Agreement and Line Agreement in a manner such that "capacity over the [Divide Creek to Imnaha section of the] line is posted on Avista's [Open Access Same Time Information System ("OASIS")] as available transmission capacity on the Avista transmission system." *Complaint* at Exhibit 102 at pp. 12, 14. The 1958 Line Agreement also gave Avista the option to purchase the line from Divide Creek to Imnaha. *Richardson Affidavit* at Exhibit 1 at pp. 64-65. Avista exercised its option to purchase that section in 2000. *Complaint* at Exhibit 102 at pp. 4-5, 8, 30-31. The utilities represented to FERC that, "After the transfer of the facilities, the line will continue to be used in the same way, and Avista will continue to post the available transmission capacity on its OASIS." *Id.* at 12, 14. FERC approved the sale. *Id.* at pp. 38-39. Idaho Power even admits in its Answer in this case "that transmission capacity over the Divide Creek to Imnaha portion of the 230 kV Lolo-Oxbow Line is posted on Avista's OASIS site." *Amended Answer* at ¶ 40.

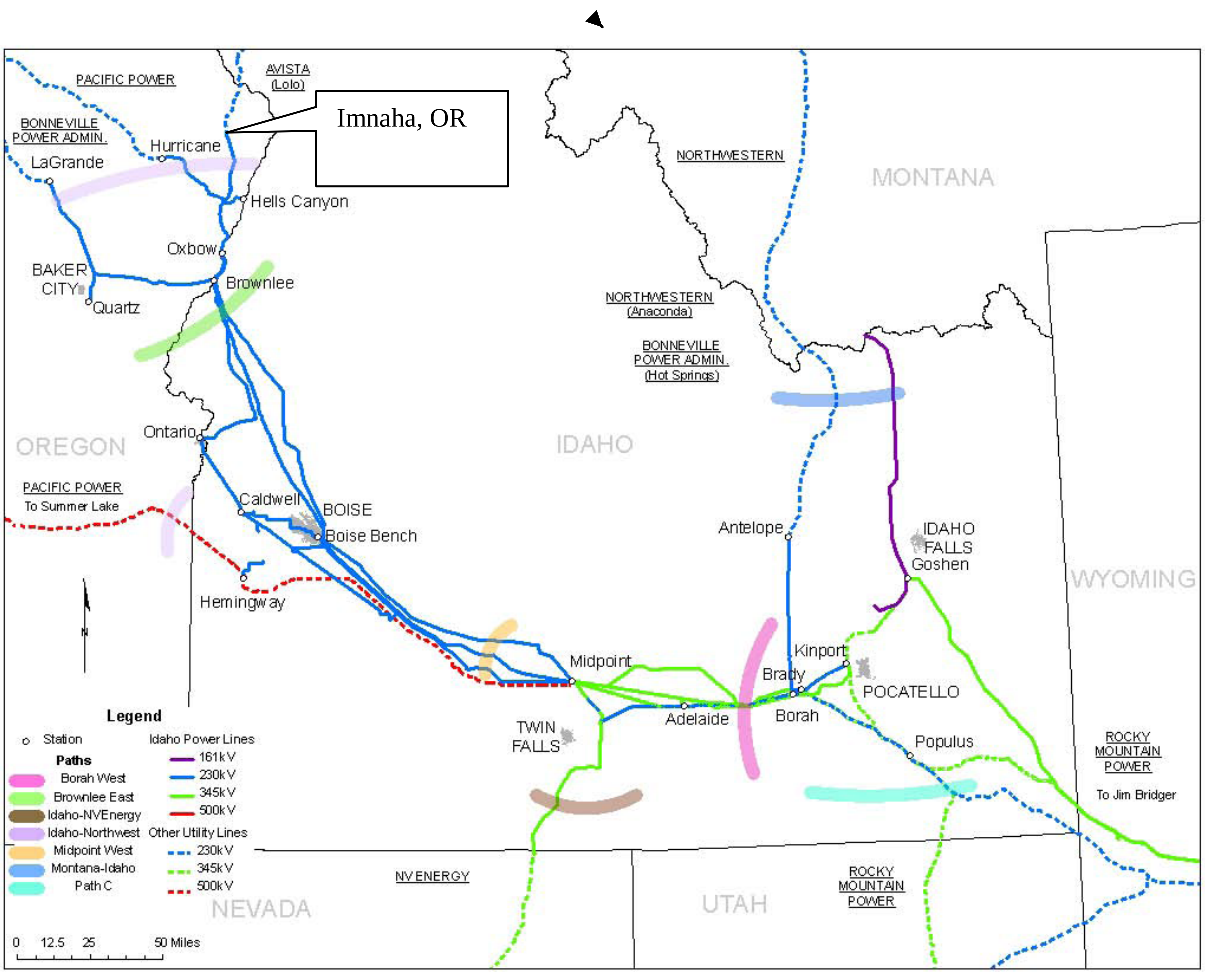
In 2003, Idaho Power filed an amended version of the 1958 Interconnection Agreement with FERC, which still defines the point of delivery as the point in change in ownership, and Idaho Power admits that the 1958 Interconnection Agreement is still in effect. *See Richardson Affidavit* at Exhibit 1 at pp. 1-84, 127-128.[1] Idaho Power also has confirmed that to this date "Avista's share of line losses are imputed to Imnaha through metering compensation." *Id*. at pp. 118-119. Also, "Idaho Power admits that Avista has responsibility for operation and maintenance of the line from Lolo Substation to a location near Imnaha, Oregon . . . ." *Amended Answer* at ¶ 37. Idaho Power even admits that a "request for interconnection between Lolo substation and Imnaha would be made to Avista." *Richardson Affidavit* at Exhibit 1 at p. 117. Idaho Power cannot identify any agreements filed with FERC to change the point of delivery, let

[1] The amendment removed a service schedule that provided each utility with the right to transmission services across each of the other utilities' entire system without additional charge, but its termination did not amend or alter the definition of points of delivery for the Lolo-Oxbow line or other terms set forth in the 1958 Interconnection Agreement. *Id.* at pp. 54-56, 71-75.

alone allocation of line losses, operation and maintenance, or liability, for electricity delivered over the Lolo-Oxbow interconnection. *See id.* at pp. 1, 86, 118-121, 127- 129, 133.

The separation is perhaps best depicted by the map below from one of Idaho Power's own public presentations[2]:

Transmission System Map



Idaho Power's transmission system ends at Imnaha, Oregon, where the solid line becomes a dashed line representing "Other Utility Lines." Idaho Power's transmission system (depicted by

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2 The inserted map is subject to official notice pursuant to O.A.R. 860-001-0460(1)(a) and O.R.S. § 40.065(2). The map is publicly available on Idaho Power's wind integration website at http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/wind/windWorkshop031611.pdf, slide 8, last accessed April 27, 2012. The map has been altered only to insert the arrow to Imnaha, Oregon.

a solid line) does not reach north into Idaho towards the Lolo Substation. Indeed, Lolo Substation is so far removed from Idaho Power's electrical system (over 60 miles) that it is not even included on Idaho Power's own map of its transmission system.

B. Kootenai's QF Project And Its Attempts To Secure A QF PPA

Kootenai's Fighting Creek Landfill Gas Station is located at the Kootenai County Solid Waste Facility, near Bellgrove, Idaho. *Affidavit of Doug Elliott* ("*Elliott Affidavit*") at ¶ 4. The County produces methane gas from decomposition of waste interned at the landfill, and sells that gas to Kootenai to generate renewable electricity through two 1.6 megawatt ("MW") generators, for a maximum electrical capacity of 3.2 MW. *Id.* at ¶5. Kootenai self-certified the project as a QF in FERC Docket No. QF11- 178. *See Amended Answer* at ¶ 20.

Kootenai's QF is directly interconnected to Kootenai's own electric distribution system. *Elliott Affidavit* at ¶ 7. Kootenai's electrical distribution system is interconnected with Avista's system at several locations in the State of Idaho. *Id.* at ¶ 8. Kootenai has executed an Interconnection Agreement with Avista, which governs deliveries of the QF's output to Avista's system. *Id.* at ¶¶ 10-15; *see also Complaint* at Exhibit 101.

Kootenai attempted for several months to enter into a long-term PPA with Avista for sale of the electrical output at a point of delivery in the State of Idaho using the Idaho Public Utilities Commission's ("Idaho PUC") implementation of PURPA. *Elliott Affidavit* at ¶¶ 9-10 and Attached CD.[3] Kootenai and Avista agreed on all terms other than terms addressing ownership of non-energy environmental attributes of the generation, such as RECs. *Id.* at ¶¶16-21.

[3] Mr. Elliott's Affidavit includes a CD with correspondence between Kootenai and Avista. Due to the volume of the materials, Kootenai has included it on CD rather than as a paper filing. The same documents were provided to Idaho Power in discovery and the CD contains the same labeling and page numbering as in the discovery response. The documents regard amendment of the pre-existing Interconnection Agreement to accommodate QF deliveries and negotiations for a long-term PPA with Avista (Kootenai Response No. 1 Attachments 1 and 2), as well as correspondence between Kootenai and Avista Transmission (Kootenai Response No. 3 Attachment).

Investor-owned utilities in Idaho have in the last year begun requiring clauses in QF PPAs that cloud the title to the QF's ownership to the environmental attributes, and the Idaho PUC has not resolved the issue of whether the utilities' insistence on these clauses is permissible. *Id.*[4] Avista insisted on a clause that clouded the QF's title to the RECs throughout the term of the PPA. *Id.* at ¶ 19. Kootenai will not own all of the environmental attributes of the Fighting Creek QF generation under its fuel purchase agreement with Kootenai County. *Id.* at 20. Therefore, Kootenai could not agree to Avista's RECs clause. *Id.* at ¶¶ 21-22.

The OPUC has ruled that QFs retain the RECs pursuant to PPAs with standard rates. *See In Re Rulemaking*, OPUC Order No. 05-1229, pp. 8-9, Docket No. AR 495 (2005); O.A.R. 860-022-0075. Accordingly, Idaho Power's OPUC Schedule 85 PPA contains an express waiver by Idaho Power of RECs. *See Complaint* at Exhibit 103 at p. 214. Thus, Kootenai decided to sell its output into the Oregon QF marketplace, and determined that transmission was available to Idaho Power's electrical system in Oregon. *Elliott Affidavit* at ¶¶ 22-23.

In October 2011, Kootenai contacted Avista Transmission to secure transmission rights under Avista's OATT for delivery to Idaho Power's electrical system in Oregon over the Lolo-Oxbow interconnection. *Id.* at¶¶ 24-27 and Attached CD. Avista informed Kootenai's transmission consultant that, although the physical point of metering for deliveries over the Lolo-Oxbow line is at Avista's Lolo Substation, Avista owns the transmission line up to Imnaha, Oregon. *Id.* at ¶ 28; *Complaint* at Exhibit 103 at p. 16. By the end of November 2011, Kootenai had proceeded to obtain a Short Term Firm Point to Point Transmission Service Agreement and Non-Firm Point to Point Transmission Service Agreement ("Short Term Transmission Agreement"). *Elliott Affidavit* at ¶ 30; *see also Complaint* at Exhibit 103 at pp. 186-190. With

[4] *See also* Idaho PUC Docket No. IPC-E-11-15 (containing an unresolved complaint by a QF challenging Idaho Power's insistence on a PPA clause clouding a QF's title to RECs). Idaho PUC dockets and orders cited herein can be viewed online at http://www.puc.idaho.gov/internet/cases/summary/IPCE1115.html.

that umbrella agreement in place, Avista informed Kootenai it can quickly purchase short term transmission for up to a year, and can secure a Long Term Firm Transmission Service Agreement for a longer term within a few months. *Elliott Affidavit* at ¶ 31. Either option, however, requires further irretrievable expenditures that Kootenai did not wish to incur prior to Idaho Power's agreement to accept and pay for deliveries pursuant to Schedule 85. *Id.* at ¶¶ 32-33.

On October 19, 2011, Kootenai sent Idaho Power a letter including all information required in Schedule 85 to obtain a draft PPA. *See Complaint* at Exhibit 103 at pp. 1-10. Kootenai explained to Idaho Power its understanding that the point in change in ownership on the 230 kv Lolo-Oxbow line occurred in the State of Oregon and that would be the point of delivery. *Id.* at pp. 6-7.[5] Kootenai also explained that the project would be online in early 2012. *Id.* at pp. 3, 6-7.

Idaho Power's response letter dated November 3, 2011 stated Kootenai must proceed under the Idaho PUC's PURPA rates, rules, and regulations - not those of Oregon. *Id.* at p. 12. Immediately after sending the initial response letter, Idaho Power filed a Petition for Declaratory Order with the Idaho PUC requesting that the Idaho PUC require that Kootenai's requested QF sale to Idaho Power be conducted pursuant to the Idaho PUC's PURPA rules, rates, and regulations. *See* Idaho PUC Case No. IPC-E-11-23. Idaho Power's Petition and its subsequently filed Comments in that docket took the position that the point of delivery was in Idaho, and relied on the assertion that Idaho Power owned certain electrical components in the Lolo

[5] This initial communication expressed Kootenai's understanding at that time that the point of change in ownership occurred in the State of Oregon but "near the Lolo substation." Upon further investigation as set forth above, Kootenai now understands that the point in change in ownership and point of delivery for this transaction is at Imnaha, Oregon, over 60 miles from Lolo Substation.

Substation, including the meter for electric deliveries.[6] *See id*.

Kootenai persisted in its requests for use of OPUC Schedule 85 with letters sent November 17, 2011, December 6, 2011, and December 27, 2011, and even completed the Schedule 85 PPA for Idaho Power's review and comment. *See Complaint* at Exhibit 103 at pp. 14-190, 193-258. Kootenai's December 6 communication also included the executed Interconnection Agreement with Avista and the executed Short Term Transmission Agreement Kootenai with Avista. *See id.* at pp. 148-190. Kootenai stated that it would execute a Long Term Firm Transmission Service Agreement with Avista once Idaho Power confirmed it will accept and pay for deliveries under the Schedule 85 PPA. *See id.* at pp. 83-84. Idaho Power consistently voiced opposition to the OPUC rules and rates, but requested no additional information from Kootenai and made no comments on the PPAs Kootenai provided. *See, e.g.*, *id.* at pp. 191-192. Thus, on December 27, 2011, once Idaho Power confirmed that transmission capacity was available to accept and integrate Kootenai's delivery, Kootenai sent an unconditionally executed Schedule 85 PPA. *See id.* at pp. 193-258. Kootenai's December 27, 2011 letter informed Idaho Power that Kootenai may need to secure a substitute power sale contract with Avista terminable on short notice to allow for start-up testing in early 2012, should Idaho Power continue to reject Kootenai's attempts to sell pursuant to Schedule 85. *See id.* at pp. 194-195. Idaho Power did not change its position. *See id.* at pp. 259-260.

On January 3, 2012, Kootenai secured a contract to sell the QF's electrical output to Avista "as available" pursuant to 18 C.F.R. § 292.304(d)(1), rather than over a specified term pursuant to 18 C.F.R. § 292.304(d)(2), during start-up testing. *See Elliott Affidavit* at ¶ 43. This

[6] Subsequently, Idaho Power realized while responding to Kootenai's discovery requests in this docket that Idaho Power does not in fact own the meter at Avista's Lolo Substation, and Idaho Power amended its Answer in this proceeding and filed a corrective letter filing in the Idaho proceeding to retract the prior assertion that it owns the meter. The Idaho PUC has not ruled on Idaho Power's Petition, and Kootenai has requested that it not rule without the benefit of additional materials that are being obtained in this docket through discovery.

"as available" PPA with Avista requires Avista to pay the lesser of Avista's avoided cost rates or 85% of a market index price. *Id.* at 44. It expires by its terms at the end of 2012, but it also allows Kootenai to terminate its obligation to sell with a 30-day notice to Avista. *Id.* at ¶ 44.

On January 3, 2012, Kootenai also filed its Complaint against Idaho Power. Over a month later, the OPUC prospectively terminated QFs' access to the avoided cost rates requested by Kootenai. *See In Re Idaho Power Co.*, Order No. 12-042, OPUC Docket Nos. UE 244 and UM 1575 (Feb. 14, 2012). Kootenai's Fighting Creek plant has now come online as scheduled and is currently selling at below market prices to Avista pursuant to the "as available" PPA. *Elliott Affidavit* at ¶ 47. Kootenai stands ready to terminate the "as available" PPA it executed with Avista, and commence deliveries to Idaho Power as soon as the OPUC requires Idaho Power to accept and purchase deliveries pursuant to the terms and rates in Schedule 85 to which Kootenai obligated itself. *Id.* at ¶¶ 45, 48-49.

III. REGULATORY BACKGROUND

This dispute falls under the OPUC's implementation of PURPA's mandatory purchase requirements. Section 210(b) of PURPA and FERC's implementing regulations require an electric utility to enter into a long term contract to buy a QF's electrical output at a rate equal to the utility's "avoided costs." 16 U.S.C. § 824a-3 (a), (b), (d); 18 C.F.R. § 292.304(a), (b), (d)(2)(ii). PURPA requires individual States to implement FERC's regulations. *FERC v. Mississippi*, 456 U.S. 742, 751, 759-61 (1982); *Cedar Creek Wind, LLC*, 137 FERC 61,006, ¶ 27 (2011). Oregon law restates, and requires the OPUC to implement, PURPA's mandatory purchase provisions. O.R.S. §§ 758.505-758.555. In Docket No. UM 1129, the OPUC updated Oregon's QF policies and required access to standard tariff contracts and published rates for small QFs sized up to 10 MW. *In re Staff's Investigation into Electric Utility Purchases from*

Qualifying Facilities (“*In re QF Investigation*”), OPUC Docket No. UM 1129, Order No.05-584, pp. 16-17, 59 (2005). Idaho Power filed its Schedule 85 tariff with published avoided cost rates at issue here updated effective December 22, 2010 in Advice No. 10-18.

IV. LEGAL STANDARD

The OPUC rules allow for a motion for summary determination, and the OPUC looks to the court rules in contested case proceedings unless inconsistent with the administrative rules. O.A.R. 860-001-0000(1); O.A.R. 860-001-0420. Oregon Rule of Civil Procedure 47 governs motions for summary judgment and provides: “The court shall grant the motion if the pleadings, depositions, affidavits, declarations, and admissions on file show that there is no genuine issue of material fact and that the moving party is entitled to prevail as a matter of law.” *See Schiele v. Montes*, 231 Or.App. 43, 47-48, 218 P.3d 141, 143-44 (2009). “In this way, dilatory tactics resulting from the assertion of unfounded claims or the *interposition of specious denials or sham defenses can be defeated*, parties may be accorded expeditious justice, and some of the pressure on court dockets may be alleviated.” *Seeborg v. General Motors Corp*., 284 Or. 695, 699, 588 P.2d 1100, 1102 (1978) (internal quotation omitted) (applying prior version of Oregon’s summary judgment rule, which is consistent with the current version, *see Jones v. General Motors Corp*., 325 Or. 404, 413, 939 P.2d 608, 613 (1997)).

V. ARGUMENT

A. FERC’s Regulations Require The OPUC To Compel Idaho Power To Purchase Kootenai’s QF Output Transmitted To A Point Of Delivery To Idaho Power’s Electrical System In The State Of Oregon Just As If Kootenai Were Directly Interconnected At The Point Of Delivery In Oregon.

Section 210(f) of PURPA expressly requires states to implement FERC’s mandatory purchase regulations. 16 U.S.C. § 824a-3(f); *Mississippi*, 456 U.S. at 760-61. And FERC’s regulations require: “Each electric utility shall purchase . . . any electric energy and capacity which is made available from a qualifying facility: . . . (2) Indirectly to the electric utility in accordance with paragraph (d) of this section." 18 C.F.R. § 292.303(a)(2); *accord* O.R.S. § 758.525(2); O.A.R. 860-029-0030(1)(b). Paragraph (d) provides:

> 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*. . . .
>
> 18 C.F.R. § 292.303(d) (emphasis added).

Subsequently, FERC has confirmed that a QF may utilize FERC's orders and tariffs governing open access to transmission to compel a purchase by any utility to which it can transmit its output. *Pub. Serv. Co. of N.H. v. N.H. Elec. Coop., Inc.*, 83 FERC ¶ 61,224, ¶¶ 61,998 – 62,000 (1998).

Thus, the OPUC should treat this transaction the same as if Kootenai's QF were directly interconnecting to Idaho Power's electrical system at the point of delivery where Avista will transmit the QF output to Idaho Power's electrical system. It is important to note that because Kootenai is using a third party utility's transmission system, this case is distinguishable from the OPUC's recent decision not to enforce the PURPA rights of Idaho QFs seeking to use Idaho Power's transmission system to wheel to Idaho Power in Oregon for use of the OPUC Schedule 85. *In Re Tumbleweed Energy II, LLC v. Idaho Power*, OPUC Order No. 12-083, OPUC Docket Nos. UM 1552 and 1553 (Mar. 13, 2012).[7]

[7] The OPUC may also find guidance in Idaho PUC decisions applying the Idaho PUC's PURPA rules, regulations and rates to QFs located outside of Idaho but delivering their output to a purchasing utility in the State of Idaho. *See Island Power Co., Inc. v. PacifiCorp, dba Utah Power & Light Co.*, Case No. UPL-E-93- 4, Order Nos. 25245 (1993), 25528 (1994) (IPUC applied IPUC rules, regulations and rates when QF located in Montana bought transmission service from Idaho Power to wheel its output for sale to PacifiCorp with a point of delivery in Idaho); *Afton Energy, Inc. v. Idaho Power Co.*, IPUC Case No. U-1006-199, Order No. 17478, 12-14 (1982) (same for QF located in Wyoming and paying Bonneville Power Administration to wheel its output to Idaho Power), *affirmed by Afton Energy, Inc. v. Idaho Power Co.*, 107 Idaho 781, 693 P.2d 427 (1984). Notably, PacifiCorp has recently taken

Idaho Power itself states, "This dispute involves whether Avista will deliver Kootenai's energy to Idaho Power in Idaho or Oregon." *Amended Answer* at ¶ 2. Because Kootenai's output will first enter Idaho Power's electrical system at a point of delivery in Oregon, the OPUC has the duty to apply its PURPA rules, regulations, and rates for Idaho Power.

B. The Point of Delivery Of The QF's Output Transmitted By Avista Is At The Point On The 230 Kilovolt Lolo-Oxbow Transmission Line Where Ownership Of The Line Changes At Imnaha, Oregon.

Even absent a contractual agreement specifying a point of delivery, courts have reached the logical conclusion that a point of delivery in an electricity sale is the point where ownership of the transmitting facilities changes. And in this case, the 1958 Interconnection Agreement between the utilities and all subsequent FERC filings conclusively determine that the portion of the Lolo-Oxbow line from Avista's Lolo Substation to Imnaha, Oregon is a part of Avista's transmission system, for which Avista is the transmission provider, and for which Kootenai will pay for transmission service with a point of delivery to Idaho Power at Imnaha, Oregon. Idaho Power's contrary position is without merit.

1. Courts have held that the default point of delivery is the point where ownership in the lines changes, and this common sense approach compels a conclusion here that the point of delivery for Kootenai's QF sale occurs where ownership in the Lolo-Oxbow line changes at Imnaha, Oregon.

The point of delivery in a sale of electricity has long had legal ramifications. Courts have applied the common-sense approach that – absent some contractual agreement to the contrary – the point of delivery is the point in change in ownership of the infrastructure establishing the electric circuit. *See Fickeisen v. Wheeling Electrical Co.*, 67 S.E. 788 (W.Va. 1910). There, the Wheeling Electric Company of Wheeling, West Virginia supplied electricity via a line over a bridge that crossed a river to the Bridgeport Electric Company of Bridgeport, Ohio. The issue

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this same position before the OPUC. *See PacifiCorp's Response Brief on Jurisdiction*, OPUC Docket Nos. UM 1552 and UM 1553, p. 17 (filed Nov. 18, 2011).

was which company was liable for the electrocution of a man by an electric line in Bridgeport. The West Virginia court concluded, "When, under the law of sales, the Wheeling Company delivered electricity into the wires of the Bridgeport Company at the bridge end, the title and possession of the Wheeling Company ceased, and the Bridgeport Company took title and possession then and there." *Id.* at 789. "In this case it was delivered in quantity known by one company to the other. . . . So far as the human mind can realize, it was the property of the Bridgeport Company." *Id.* Absent an agreement for sale or lease of the works of the Bridgeport Company, the Court concluded that the Bridgeport Company was liable. *Id.* at 791.

The Ninth Circuit has reached the same conclusion with regard to a point of delivery. *See Union Pacific Railroad Co. v. Johnson*, 233 F.2d 427 (9th Cir. 1956), *reversed on other grounds by Johnson v. Union Pacific Railroad Co.*, 352 U.S. 957 (1957). There, Johnson was electrocuted while working on a transformer substation, and the dispute was whether liability attached to Union Pacific Railroad Company, which sold the electricity delivered by a line connected to the substation, or Pacific Fruit Express Company, which owned the substation and bought the electricity supplied. *Id.* at 429-30. Johnson argued the "electricity which injured him in the sub-station had not yet passed through the meter of Pacific Fruit, thus it still belonged to Union Pacific and Union Pacific had a duty to take care of the electricity until it reached the meter." *Id.* at 430. The Ninth Circuit disagreed, and held:

> Here there is nothing in the contract clearly delineating at which spot in the wire electricity became property of Pacific Fruit. Under such circumstances, we would think the presumption would be that title to the electricity passed at the point where control and dominion of the electricity passed from one company to the other. Surely, this would be not later than the point where the incoming wires went into the substation enclosure.
>
> *Id.*

The Ninth Circuit concluded that Union Pacific was not liable past the point of delivery. *Id.* at

432.[8] The point of metering was not relevant. Instead, the Ninth Circuit held that the point in change in ownership is the logical default point of delivery.

Therefore, even though Kootenai has been unable to obtain Idaho Power's signature on the Schedule 85 PPA designating Imnaha as the point of delivery, the default point of delivery between Avista and Idaho Power is the point where ownership changes at Imnaha, Oregon.

2. The 1958 Interconnection Agreement on file with FERC and all other FERC filings regarding the deliveries from Avista to Idaho Power over the Lolo-Oxbow 230 kv line compel a conclusion that the point of delivery is the point where ownership changes at Imnaha, Oregon.

As noted above, the 1958 Interconnection Agreement unambiguously designates the point of delivery of the Lolo-Oxbow line as the point where ownership changes. *Richardson Affidavit* at Exhibit 1 at p. 28. It allocates line losses from the point of metering to the point of change of ownership and delivery. *Id*. And it draws the line for liability at the point in change of ownership. *Id.* at p. 30. Idaho Power admits that the 1958 Interconnection Agreement is still in effect in relevant part, and Idaho Power even filed it with FERC in 2003 as its FERC Electric Schedule No. 28. *Id.* at pp. 1, 127-129. There is no dispute that point in change in ownership occurs at Imnaha, Oregon.

Idaho Power is unable to produce any subsequent agreement, or other filing with FERC, altering this contractual arrangement for deliveries from Avista's system.[9] Idaho Power has confirmed line losses are still allocated to Avista from Imnaha, Oregon. *Id*. at pp. 118-119. The

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[8] This determination on liability was reversed after the Idaho Supreme Court held that tort liability could reach beyond a point of delivery and ownership of the facilities. *Union Pacific Railroad Co. v. Johnson*, 249 F.2d 674 (9th Cir. 1957). However, that does not change the common-sense determination that a point in change in ownership is the default point of delivery.

[9] Any change in the identity of the transmission provider for the Lolo-Imnaha Line, or alteration of Avista's ownership and operation of the line would trigger a filing requirement with FERC under the Federal Power Act. *See, e.g.*, 16 U.S.C. § 824b, § 824d(c)-(d); *Idaho Power Company*, 103 FERC ¶ 61,182, ¶¶ 7-10 (2003) (discussing Idaho Power's violation of Federal Power Act for failure to file agreements with FERC, which included the 1958 Interconnection Agreement filed later in 2003 in compliance with FERC's order). The absence of such a filing compels a conclusion the point of delivery is indeed Imnaha, Oregon.

utilities have represented to FERC and Idaho Power has admitted in its Answer in this case that the line from Lolo Substation to Imnaha, Oregon is to be posted as available capacity on Avista's OASIS website as a part of Avista's transmission system. *Amended Answer* at ¶ 40. Likewise, Idaho Power has admitted in its Answer that Avista is responsible for operations and maintenance of the line from Lolo Substation to Imnaha, Oregon.[10] *Id.* at ¶ 37. Further, Idaho Power has admitted that a QF interconnecting at any point along the line between Lolo Substation and Imnaha, Oregon would need an interconnection agreement with Avista. *Richardson Affidavit* at Exhibit 1 at p. 117. By Idaho Power's own admission, therefore, Avista is the Transmission Provider for the Lolo-Imnaha section because under the OATT a generator enters into an interconnection agreement with the utility that is the "Transmission Provider" at the point of interconnection. *See Avista's OATT* at Attachment M, N, O.[11]

It strains law, logic, and common sense to believe that the point between two utilities delineating the ownership of the transmission line, the allocation of line losses, the utility responsible for interconnections, and the utility responsible for operation and maintenance, is not also the point of delivery between the two utilities. The point of delivery for Kootenai's delivery of QF output to Idaho Power is unquestionably at Imnaha, Oregon.

3. Idaho Power's Schedule 85 requires QFs to deliver to Idaho Power's electrical system; and Kootenai will pay Avista transmission rates and line losses which include within them the embedded cost of service over the Lolo-Imnaha section of the line – all the way to Idaho Power's electrical system.

Idaho Power's Schedule 85 tariff itself defines "Point of Delivery" as "the location where

[10] Idaho Power misleadingly confuses this admission with its claim that it has operation and maintenance responsibilities as the balancing authority operator beginning at Lolo Substation. A balancing authority operator merely has responsibility for balancing loads and generation within a metered boundary. Idaho Power's balancing authority area is a sweeping region that contains several utilities' electrical systems within its metered boundaries. It is not at all clear how Idaho Power's status as balancing authority operator somehow allows Idaho Power to take title to all of the electrons as soon as they enter its balancing authority. Idaho Power's status as operator of the balancing authority is completely irrelevant.

[11] Avista's OATT is contained in the record. *See Elliott Affidavit* at Attached CD at Kootenai Response No. 3 Attachment pp. 15-507.

the Company's and the Seller's electrical facilities are inter-connected or *where the Company's and the Seller's host transmission provider's electrical facilities are interconnected*." *Complaint* at Exhibit 103 at p. 249 (emphasis added). Schedule 85 declares its "APPLICABILITY" to any QF that "desires to sell Energy generated by the Qualifying Facility to the Company in compliance with all the terms and conditions of the Standard Contract." *Id.* at 248. And the Schedule 85 off-system Standard Contract defines of Point of Delivery as "The location specified in Appendix B, where the Transmitting Entity delivers the Facility's Net Energy *to the Idaho Power electrical system*." *Id.* at p. 200 (emphasis added). It states, "Idaho Power will purchase and Seller will sell all of the Net Energy produced by the Facility and delivered by the Transmitting Entity to Idaho Power at the Point of Delivery." *Id.* at p. 210 (Art. 6.1). Appendix B-6 requires the QF or Transmitting Entity to bear the cost of line losses to Idaho Power's *electrical system*, not just to its control area. *Id.* at p. 235. Schedule 85 applies by its plain terms for Kootenai's delivery to Imnaha, Oregon. Indeed, it and does not allow Kootenai to deliver anywhere short of Imnaha, Oregon.

Moreover, Kootenai will pay transmission rates to Avista that include within them the embedded costs of ownership, operation, maintenance and line losses for the Lolo-Imnaha section of Avista's transmission system. Avista's OATT allows a Transmission Customer, such as Kootenai, to pay postage stamp transmission rates calculated based on reserved capacity for delivery to any point on Avista's transmission system. *See* Avista's OATT §§ 15.1, 15.7, 17.2(iii), Schedules 7 and 8; *see also Avista Corporation*, FERC Docket No. ER10-169 (containing Avista's filing of its current transmission rates accepted by FERC). When Avista purchased the Divide Creek to Imnaha line, Idaho Power and Avista stated to FERC: "In its next rate case, Avista would record the transferred assets in its transmission plant accounts at the book cost from which it took them from Idaho Power[.]" *Complaint* at Exhibit 102 at pp. 14-15. Consistent with this representation, Avista's FERC Form No. 1 – used to calculate its embedded costs for its transmission rates – includes the line from Lolo Substation to Imnaha, Oregon as a part of Avista's transmission plant. *Richardson Affidavit* at Exhibit 2 at p. 10, lines 20, 21, 34.[12] Idaho Power's FERC Form No. 1 includes only the remainder of the line from Imnaha, Oregon to Oxbow, Oregon, and Idaho Power admits the line "from Lolo substation to Imnaha is not included in Idaho Power's Total Transmission Revenue Requirement or otherwise included in calculation of Idaho Power's transmission rates." *Id.* at Exhibit 1 at pp. 134-135. Idaho Power therefore asks the OPUC to gift to Idaho Power free use of Avista's transmission system at Kootenai's expense for the 63 miles from Lolo Substation to Imnaha, Oregon. The OPUC should rule the point of delivery is at Imnaha, Oregon.

4. The OPUC should reject Idaho Power's shifting arguments.

Idaho Power initially based its defense on its assertion that exchanges between the two utilities over the 108-mile-long Lolo-Oxbow line are metered at the Lolo Substation and the incorrect allegation that Idaho Power owns the meter at the Lolo Substation. *See Answer* at ¶¶ 5, 51, 61 (stating Idaho Power owns the meter at Lolo Substation); *Amended Answer* at ¶¶ 5, 51, 61 (amended to remove the assertion Idaho Power owns the meter). After recognizing that it does not own the meter at Avista's Lolo Substation, Idaho Power had to shift its argument. Idaho Power now appears to rely on the following assertions: (1) Avista's OASIS website posts available transmission over a path named "AVA.SYS to LOLO," and (2) Idaho Power's balancing authority area reaches to the Lolo Substation. The legal relevance of these assertions is so lacking and unapparent that Kootenai must reserve further comment until responsive

[12] Avista's FERC Form No. 1 can be downloaded online at http://www.ferc.gov/docs-filing/forms/form-1/data.asp. Kootenai has provided excerpts to it for the OPUC's convenience, and the document is subject to official notice to the extent its contents may be in dispute. *See* O.A.R. 860-001-0460(1)(a) and O.R.S. § 40.065(2).

briefing. However, Idaho Power's shifting argument and failure to even get the facts straight seriously undermine the credibility of its position.

C. Although Idaho Power's Avoided Cost Rates Have Decreased Since Kootenai Initiated This Action, Kootenai Is Entitled To The Schedule 85 PPA Containing The OPUC's Published Avoided Cost Rates That Were In Effect At The Time Kootenai Attempted To Negotiate, Executed The PPA, And Initiated This Action.

When the published rates become unavailable to a QF before the QF can obtain a written contract, the QF is entitled to pre-existing rates if the QF formed a "legally enforceable obligation" or "LEO" prior to the date the rates became unavailable. *See* 18 C.F.R. 292.304(d)(2)(ii); *Cedar Creek Wind, LLC*, 137 FERC 61,006 at ¶32; *Snow Mt. Pine Co. v. Maudlin,* 84 Or. App. 590, 598-600, 734 P.2d 1366, 1370-71 (1987).

In *Cedar Creek, Wind LLC*, the Idaho PUC had determined that the Cedar Creek QF was not entitled to published avoided cost rates in effect on the date that it had signed a PPA because the utility had not also executed the PPA. *Cedar Creek Wind, LLC*, 137 FERC 61,006 at ¶ 30. FERC disagreed with the Idaho PUC. FERC explained:

> Thus, under our regulations, a QF has the option to commit itself to sell all or part of its electric output to an electric utility. While this may be done through a contract, if the electric utility refuses to sign a contract, the QF may seek state regulatory authority assistance to enforce the PURPA-imposed obligation on the electric utility to purchase from the QF, and a non-contractual, but still legally enforceable, obligation will be created pursuant to the state's implementation of PURPA. Accordingly, a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.
>
> *Id.*, 137 FERC ¶ 61,006 at ¶ 32.

FERC further explained "that the phrase legally enforceable obligation is broader than simply a contract between an electric utility and a QF and that the phrase is used to prevent an electric utility from avoiding its PURPA obligations by refusing to sign a contract, or as here, from delaying the signing of a contract, so that a later and lower avoided cost is applicable." *Id.*, 137

FERC ¶ 61,006 at ¶ 36.

There is an OPUC regulation that could be read to require a utility signature to lock in avoided cost rates. O.A.R. 860-029-0010(29). But the *Cedar Creek Wind, LLC* decision preempts state precedent. *Cedar Creek Wind LLC*, 137 FERC ¶ 61,006 at ¶ 35. And the OPUC has also stated if a utility "negotiates in bad faith or with undue delay, a QF may file a complaint with the Commission and if the Commission finds bad faith or undue delay, we may conclude that a LEO was incurred in the absence of a written agreement between the parties." *International Paper v. PacifiCorp*, OPUC Order No. 09-439, p. 6, Docket No. UM 1449 (2009).

Here, Kootenai attempted to use the standard contract form for small QFs on file for Idaho Power. "Standard contracts are designed to minimize the need for parties to engage in contract negotiations." *In re QF Investigation*, OPUC Order No.05-584, at p. 39, Docket No. UM 1129. There was nothing for Idaho Power and Kootenai to negotiate because the tariff PPA terms were acceptable to Kootenai. Schedule 85 requires Idaho Power to provide a Schedule 85 PPA within 15 business days of Kootenai's submittal of all necessary project specific information. *See Complaint* at Exhibit 102 at p. 252. At all times after October 19, 2011 when Kootenai provided that information, Idaho Power refused to provide a Schedule 85 PPA or process Kootenai's request whatsoever under the terms of Schedule 85. Idaho Power's refusal to agree to the point of delivery at Imnaha, Oregon, and its baseless objection to the OPUC's jurisdiction cannot be used to defeat Kootenai's right to a LEO.

Kootenai's fruitless attempts to negotiate with Idaho Power for over two months, followed by the unconditional execution of the Schedule 85 PPA delivered December 27, 2011 and filing of a Complaint at the OPUC were an exercise of Kootenai's right to enter into a LEO prior to the date the rates became unavailable. FERC precedent requires the OPUC to enforce that LEO.

D. The Dormant Commerce Clause Requires The OPUC To Provide An Out-Of-State QF, Such As Kootenai's QF in Idaho, With The Same Access To The OPUC's Rules, Rates, And Regulations For Idaho Power As Those Provided For QFs Located In The State of Oregon.

The Commerce Clause of the United States Constitution provides Congress with the power to regulate interstate commerce. U.S. Const., Art. I, § 8, cl. 3. "It is well settled that actions are within the domain of the Commerce Clause if they burden interstate commerce, or impede its free flow." *C&A Carbone, Inc. v. Town of Clarkstown, N.Y.*, 511 U.S. 383, 389 (1994). A regulatory scheme "can discriminate against out-of-state interests in three different ways: (1) facially; (2) purposefully, or (3) in practical effect." *Nat'l Asssn. of Optometrists & Opticians Lenscrafters, Inc. v. Brown*, 567 F.3d 521, 525 (9th Cir. 2009) (internal quotation omitted). If discrimination is shown, strict scrutiny applies, and the State must demonstrate both that the rule serves a legitimate local purpose, and that this purpose could not be served as well by available nondiscriminatory means. *See Hunt v. Wash. State Apple Advertising Commn.*, 432 U.S. 333, 352-54 (1977). Although a goal may be "legitimate," it cannot "be achieved by the illegitimate means of isolating the State from the national economy." *City of Philadelphia v. New Jersey*, 437 U.S. 617, 626, 627 (1978); *see also Rocky Mountain Farmer's Union v. Goldstene*, --- F.Supp. -----, 2011 WL 6934797 at ** 8-12 (E.D. Cal., Dec. 29, 2011) (invalidating the California Air Resource Board's regulatory scheme that required fuel providers to meet an overall carbon intensity requirement because it discriminated against out-of-state producers by assigning more favorable carbon intensity values to California corn-derived ethanol than to out-of-state corn-derived ethanol).[13]

Here, denial of Kootenai's access to the OPUC QF market would likewise be an obvious

[13] If the State rule is not discriminatory on its face or in practical effect, but nevertheless burdens interstate commerce, courts apply a balancing test from *Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142 (1970). That test would not apply in this case because excluding out-of-state QFs would be discriminatory.

Dormant Commerce Clause violation when its transaction clearly falls within the scope of the rules that would be applicable to an in-state QF. The OPUC's QF rules and rates create a market for goods that are capable of traveling in interstate commerce. "Section 210 of PURPA sets forth the benefit to which QFs are entitled. *It creates a market for their energy* . . . ." *Freehold Cogeneration Assocs., L.P. v. Bd. of Regulatory Commn. of the State of New Jersey*, 44 F.3d 1178, 1191 (3rd Cir. 1995) (emphasis added). Each State has wide discretion to implement its own QF rules. Yet PURPA and FERC's regulations do not authorize states to exclude out-of-state QFs. Kootenai is attempting to avail itself of the OPUC's distinct QF market because Oregon has a Renewable Portfolio Standard ("RPS") and has created a QF market wherein Idaho Power must disclaim ownership of environmental attributes of the QF. *Elliott Affidavit* at ¶¶ 17-23, 37-38. Idaho does not have an RPS, and QFs, including Kootenai, cannot easily obtain clear title to RECs if they sell into the QF market available in Idaho.

The Oregon QF and REC market is demonstrably available for off-system QFs located in Oregon. *See Informational Filing of QF Transactions with City of Cove*, OPUC Docket No. RE 8, § 9.1, Appendix B (October 24, 2011) (containing the standard off-system Schedule 85 PPA executed between the City of Cove, Oregon and Idaho Power wherein the City of Cove QF will arrange and pay for delivery over the facilities of the Transmitting Entities to Idaho Power's electrical system at the LaGrande Substation). Like the City of Cove, Kootenai has proposed a transaction that falls clearly within the existing regulatory framework set by FERC and the OPUC for off-system QFs. The only apparent difference for Kootenai's off-system QF request in the same time frame is that Kootenai is out-of-state. To deny Kootenai access to Oregon's QF and REC market would discriminate against an out-of-state producer facially, purposefully, and in practical effect. There is no legitimate and defensible basis to do so. The OPUC should reject

Idaho Power's invitation to violate the U.S. Constitution in this manner.

VI. CONCLUSION

For the reasons set forth above, Kootenai respectfully requests that the OPUC require Idaho Power to accept and pay for deliveries from Kootenai's Fighting Creek qualifying facility with a point of delivery at Imnaha, Oregon. Kootenai respectfully requests the OPUC order that Idaho Power make such purchases pursuant to the Schedule 85 power purchase agreement, or other legally enforceable obligation, with terms and rates in effect on December 27, 2011, when Kootenai unequivocally obligated itself.

Respectfully submitted this 27th day of April 2012.

RICHARDSON AND O'LEARY, PLLC

/s/ Gregory M. Adams

Peter J. Richardson (OSB No. 06668)
Gregory M. Adams (OSB No. 101779)
Richardson & O'Leary, PLLC
515 N. 27th Street
P.O. Box 7218
Boise, Idaho 83702
Telephone: (208) 938-2236
Fax: (208) 938-7904
peter@richardsonandoleary.com
greg@richardsonandoleary.com

Attorneys for Kootenai Electric Cooperative, Inc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 27th day of April, 2012, a true and correct copy of the within and foregoing **MOTION FOR SUMMARY JUDGMENT** BY KOOTENAI ELECTRIC COOPERATIVE, INC. was served in the manner shown below, to:

Donovan Walker Christa Bearry Idaho Power Company PO Box 70 Boise, Idaho 83707-0070 dwalker@idahopower.com jwilliams@idahopower.com	_X_ Hand Delivery ___ U.S. Mail, postage pre-paid ___ Facsimile _X_ Electronic Mail
Lisa F Rackner McDowell & Rackner & Gibson PC 419 SW 11th Save Ste 400 Portland OR 97205 dockets@mcd-law.com	___ Hand Delivery _X_ U.S. Mail, postage pre-paid ___ Facsimile _X_ Electronic Mail ___ Express/Overnight Mail

/s/ Gregory M. Adams

Gregory M. Adams

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

KOOTENAI ELECTRIC COOPERATIVE, INC., Complainant, vs. IDAHO POWER COMPANY, Defendant.	)))))))))	Docket No. UM 1572 AFFIDAVIT OF PETER J. RICHARDSON IN SUPPORT OF KOOTENAI ELECTRIC COOPERATIVE, INC.'S MOTION FOR SUMMARY JUDGMENT

I, Peter J. Richardson, do declare the following and if called to testify, would and could competently testify thereto:

1. I am over the age of 18, and make this Affidavit based upon personal knowledge.

2. I am an attorney at the law firm of Richardson and O'Leary, PLLC, in Boise, Idaho, and am one of the attorneys of record for Kootenai Electric Cooperative, Inc. ("Kootenai") in the above-captioned docket before the Public Utility Commission of Oregon ("OPUC").

3. True and correct copies of several of Idaho Power's Responses and Supplemental Responses to Kootenai's Data Requests in this docket are attached as Exhibit 1 to this Affidavit. Certain attachments provided by Idaho Power to some of the Reponses have been omitted from Exhibit 1 to this Affidavit to limit the length of the Exhibit, and such omissions are noted within the Exhibit by a page identifying the documents provided by Idaho Power but omitted from the Exhibit.

4. True and correct copies of excerpts of Federal Energy Regulatory Commission

("FERC") Form No. 1 of Avista Corporation, filed for year-end 2010, is attached as Exhibit 2 to this Affidavit. The full document can be downloaded online at http://www.ferc.gov/docs-filing/forms/form-1/data.asp.

Further your affiant sayeth naught.

DATED April 25th, 2012.

Peter J. Richardson

STATE OF IDAHO)
) ss.
COUNTY OF ADA)

On this 25th day of April 2012, before me, a Notary Public in and for the State of Idaho, personally appeared Peter J. Richardson, personally known to me to be the person who executed this instrument and acknowledged it to be his free and voluntary act and deed for the uses and purposes mentioned in the instrument.

IN WITNESS WHEREOF, I have hereunto set my hand and official seal the day and year first above written.

NINA M. CURTIS NOTARY PUBLIC STATE OF IDAHO

Nina M. Curtis
NOTARY PUBLIC for the State of Idaho
Residing at Boise, Idaho
My Commission expires 3/19/15

April 17, 2012

Subject: Docket No. UM 1572
Idaho Power Company's **Supplemental** Responses to Kootenai Electric Cooperative, Inc.'s ("Kootenai") Data Request Nos. 1.2, 1.5, 1.11, and 1.12

KOOTENAI'S DATA REQUEST NO. 1.2:

Reference Kootenai's Complaint Exhibit 102 at page 1, discussing a 1958 Interconnection Agreement between Avista (formerly Washington Water Power Company) PacifiCorp (formerly Pacific Power and Light) and Idaho Power Company.

a) Please provide a copy of the 1958 Interconnection Agreement.

b) Please identify and provide a copy of all amendments to the Agreement that pertain to the Lolo-Oxbow line.

IDAHO POWER COMPANY'S *SUPPLEMENTAL* RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.2:

a) In its February 27, 2012, response to this data request, Idaho Power Company ("Idaho Power") inadvertently failed to include the associated service schedules that were part of the 1958 Interconnection Agreement. Those service schedules are attached hereto as part of a September 12, 2003, compliance filing submitted to the Federal Energy Regulatory Commission ("FERC") in Docket Nos. ER03-953-001, ER03-954-001, and ER03964-001 ("Compliance Filing"). Please note that while Schedule III-A to the 1958 Interconnection Agreement is included, that particular schedule was terminated via Letter Agreement dated April 14, 2000, which is also included in the attached Compliance Filing. Further, the Compliance Filing contains a December 10, 1990, Letter Agreement between Washington Water and Power ("WWP"), Avista Corporation's ("Avista") predecessor, and Idaho Power Company. Please note that while this Letter Agreement refers to a single-line drawing as an attachment, Idaho Power has been unable to locate that attachment after diligently searching. Finally, also attached is the July 26, 2004, correspondence from FERC accepting the Compliance Filing.

b) Please see Idaho Power's response to Data Request No. 1.2(a) above.

ORIGINAL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Idaho Power Company	)	**Docket Nos. ER03-953-001**
	)	**ER03-954-001**
	)	**ER03-964-001**

PART 1 of 2

COMPLIANCE FILING

VOLUME 1 OF 2

J. A. Bouknight, Jr.
Gary A. Morgans
Steptoe & Johnson LLP
1330 Connecticut Avenue, N.W.
Washington, DC 20426
(202) 429-3000
(202) 429-3902 (fax)

Attorneys for Idaho Power Company

Disk/ESEC

STEPTOE & JOHNSON LLP

ATTORNEYS AT LAW

1330 Connecticut Avenue, NW
Washington, DC 20036-1795

Telephone 202.429.3000
Facsimile 202.429.3902
www.steptoe.com

J. A. Bouknight Jr.
202.429.6222
jbouknig@steptoe.com

September 12, 2003

Via HAND DELIVERY

Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: **Idaho Power Company**
Docket Nos. ER03-953-001, ER03-954-001, and ER03-964-001

Dear Secretary Salas:

In compliance with the Letter Order dated August 11, 2003 in Docket Nos. ER03-953-000 and ER03-954-000 and the Letter Order dated August 13, 2003 in Docket No. ER03-964-000 (collectively, "Letter Orders"), Idaho Power Company ("Idaho Power") submits an original and six copies of various documents designated in accordance with Order No. 614, *Designation of Electric Rate Schedule Sheets*, FERC Stats. & Regs. Preambles ¶ 31,096 (2000).

On June 16, 2003, in three separate but concurrent filings, Idaho Power submitted Letter Agreements amending Rate Schedule Nos. 28, 69, 75, 77, and 87; contract demand notices for Rate Schedule Nos. 72, 74, 75, and 77; initial Rate Schedule Nos. 140, 141, 142, 143, 144, 145, and 146; Service Agreement No. 53 under FERC Electric Tariff First Revised Volume No. 6; and Service Agreement Nos. 165 and 166 under FERC Electric Tariff First Revised Volume No. 5. Idaho Power requested effective dates for the documents commensurate with the dates under the terms of the documents.

On August 11, 2003 and August 13, 2003, the Letter Orders accepted these documents for filing, thereby making the documents effective as requested, but directed Idaho Power to comply with Order No. 614 by submitting (1) complete paginated versions of and appropriate designations for the amendments to and/or contract demand notices for Rate Schedule Nos. 28, 69, 72, 74, 75, 77, and 87; (2) appropriate designations for Service Agreement No. 165 under FERC Electric Tariff First Revised Volume No. 5; and (3) Notices of Cancellation for Rate Schedule Nos. 74 and 77, which terminated on June 30, 2002 and December 31, 2002, respectively.

Based on discussions with the Commission's staff regarding Order No. 614 compliance, Idaho Power is issuing first revised versions superseding the existing versions of Rate Schedule Nos. 28, 69, 72, 74, 75, 77, and 87. These first revised versions contain the existing rate schedules conformed with all amendments filed with and accepted by the Commission prior to the June 16, 2003 filings in the instant proceedings. Because the conformed existing rate schedules are being reissued as first revised versions, they contain all original sheets.

In addition, to reflect the revisions effectuated by the amendments in the instant proceedings, Idaho Power is providing first revised sheets superseding the original sheets of the first revised rate schedules, as well as redlined sheets depicting the changes between the original and first revised sheets. In some cases, such as the contract demand notices, second revised sheets supersede first revised sheets, third revised sheets supersede second revised sheets, and so on.

Because the rate schedules are being reissued in first revised versions through this filing, it is necessary to establish effective dates for the first revised versions and the sheets thereto. This filing is being made solely for the purpose of complying with Order No. 614 and does not alter in any respect the dates that the rates, terms, and conditions of the rate schedules became effective. Based on Idaho Power's discussions with the Commission's staff regarding Order No. 614 compliance, the effective dates shown in the first revised rate schedules and on all sheets thereto, including original and revised sheets, are the dates of the Letter Orders that directed Idaho Power to designate the rate schedules and sheets pursuant to Order No. 614. These are the effective dates of the reissued versions of the rate schedules and the sheets thereto, but are not the effective dates of the rates, terms, and conditions of the rate schedules.

By way of example, First Revised Rate Schedule No. 69 contains the May 29, 1981 Interconnection and Transmission Services Agreement between Idaho Power and Sierra Pacific Power Company conformed with a February 14, 1992 amendment. Both the May 29, 1981 agreement and the February 14, 1992 amendment were filed with and accepted by the Commission several years ago and are reflected as original sheets. The revisions caused by the amendment filed June 16, 2003 in the instant proceedings are reflected as first revised sheets. All sheets have an effective date of August 11, 2003.

This compliance filing comprises the following documents:

- Behind Tab 28 is First Revised FERC Electric Rate Schedule No. 28 superseding FERC Electric Rate Schedule No. 28, Interconnection Agreement among Idaho Power Company, the Washington Water Power Company, and Pacific Power and Light Company. In Docket No. ER03-953-000, the Commission accepted for filing an April 14, 2000 Letter Agreement that terminated Service Schedule III-A of Rate Schedule No. 28. Thus, Idaho Power has superseded Original Sheet Nos. 42-44 which contained Service Schedule III-A, with First Revised Sheet Nos. 42-44, which are blank.[1] Idaho Power has not included redlined sheets, since the Letter Agreement terminates Service Schedule III-A in its entirety and does not effectuate changes merely within the text of Service Schedule III-A.

- Behind Tab 69 is First Revised FERC Electric Rate Schedule No. 69 superseding FERC Electric Rate Schedule No. 69, Interconnection and Transmission Services Agreement between Idaho Power Company and Sierra Pacific Power Company. In Docket No. ER03-953-000, the Commission accepted for filing a March 6, 2001 Letter Agreement that terminated Section 4.1 and its subparagraphs of Rate Schedule No. 69. Thus, Idaho Power has superseded Original Sheet Nos. 7-9, which contained Section 4.1 and its subparagraphs, with First Revised Sheet Nos. 7-9, which are blank. Idaho Power has also included redlined sheets depicting Section 4.1 and its subparagraphs with strikethrough.

- Behind Tab 72 is First Revised FERC Electric Rate Schedule No. 72 superseding FERC Electric Rate Schedule No. 72, Transmission Services Agreement between Idaho Power Company and the City of Seattle. In Docket No. ER03-964-000, the Commission accepted for filing six contract demand notices. Idaho Power has designated the first contract demand notice as First Revised Sheet No. 38 superseding Original Sheet No. 38, the second as Second Revised Sheet No. 38 superseding First Revised Sheet No. 38, the third as Third Revised

[1] "When canceling individual sheets, but retaining the tariff or rate schedule, designate a blank sheet as a revised sheet superseding the prior sheets." Order No. 614 at 31,511.

Sheet No. 38 superseding Second Revised Sheet No. 38, the fourth as Fourth Revised Sheet No. 38 superseding Third Revised Sheet No. 38, the fifth as Fifth Revised Sheet No. 38 superseding Fourth Revised Sheet No. 38, and the sixth as Sixth Revised Sheet No. 38 superseding Fifth Revised Sheet No. 38. In this way, each subsequent contract demand notice supersedes the previous one. Idaho Power has not included redlined sheets, since each subsequent sheet replaces the previous sheet in its entirety and does not effectuate changes merely within the text of any previous sheet.

- Behind Tab 74 is First Revised FERC Electric Rate Schedule No. 74 superseding FERC Electric Rate Schedule No. 74, Agreement for Supply of Power and Energy between Idaho Power Company and Washington City, Utah. In Docket No. ER03-964-000, the Commission accepted for filing three contract demand notices. Idaho Power has designated the first contract demand notice as First Revised Sheet Nos. 18-19 superseding Original Sheet Nos. 18-19, the second as Second Revised Sheet No. 18 superseding First Revised Sheet No. 18, and the third as Third Revised Sheet No. 18 superseding Second Revised Sheet No. 18. In this way, each subsequent contract demand notice supersedes the previous one. Idaho Power has not included redlined sheets, since each subsequent sheet replaces the previous sheet in its entirety and does not effectuate changes merely within the text of any previous sheet. Since Rate Schedule No. 74 has terminated, Idaho Power has also included a Notice of Cancellation and a cover sheet appropriately designated to reflect the cancellation.

- Behind Tab 75 is First Revised FERC Electric Rate Schedule No. 75 superseding FERC Electric Rate Schedule No. 75, Agreement for Supply of Power and Energy between Idaho Power Company and the Utah Associated Municipal Systems. In Docket No. ER03-953-000, the Commission accepted for filing a March 3, 2000 Letter Agreement prescribing additional service under Rate Schedule No. 75. Because the Letter Agreement does not rewrite any provisions of Rate Schedule No. 75, Idaho Power has added the Letter Agreement itself to Rate Schedule No. 75 as Original Sheet Nos. 52-53. In Docket No. ER03-964-000, the Commission accepted for filing four contract demand notices. Idaho Power has designated the first contract demand notice as First Revised Sheet No. 20 superseding Original Sheet No. 20, the second as Second

Revised Sheet No. 20 superseding First Revised Sheet No. 20, the third as Third Revised Sheet No. 20 superseding Second Revised Sheet No. 20, and the fourth as Fourth Revised Sheet No. 20 superseding Third Revised Sheet No. 20. In this way, each subsequent contract demand notice supersedes the previous one. Idaho Power has not included redlined sheets, since each subsequent sheet replaces the previous sheet in its entirety and does not effectuate changes merely within the text of any previous sheet.

- Behind Tab 77 is First Revised FERC Electric Rate Schedule No. 77 superseding FERC Electric Rate Schedule No. 77, Transmission Services Agreement Executed by the United States of America Department of Energy, acting by and through the Bonneville Power Administration, and Idaho Power Company. In Docket No. ER03-953-000, the Commission accepted for filing February 6, 1996, December 23, 1997, and June 29, 2000 Letter Agreements concerning billing disputes with respect to Points of Delivery 19 and 20, and April 4, 1996 and April 5, 2001 Letter Agreements concerning billing disputes with respect to Point of Delivery 28. Because the Letter Agreements do not rewrite any provisions of Rate Schedule No. 77, Idaho Power has added the Letter Agreements themselves to Rate Schedule No. 77 as Original Sheet Nos. 218-230. In Docket No. ER03-964-000, the Commission accepted for filing two sets of contract demand notices. Idaho Power has designated the first set as First Revised Sheet Nos. 132-172 superseding Original Sheet Nos. 132-172 and the second as Second Revised Sheet Nos. 132-172 superseding First Revised Sheet Nos. 132-172. In this way, each subsequent set supersedes the previous set. Idaho Power has not included redlined sheets, since each subsequent set replaces the previous set in its entirety and does not effectuate changes merely within the text of any previous set. Since Rate Schedule No. 77 has terminated, Idaho Power has also included a Notice of Cancellation and a cover sheet appropriately designated to reflect the cancellation.

- Behind Tab 87 is First Revised FERC Electric Rate Schedule No. 87 superseding FERC Electric Rate Schedule No. 87, Idaho Power Company and PacifiCorp Electric Operations Restated Transmission Service Agreement. In Docket No. ER03-953-000, the Commission accepted for filing a May 1, 1995 Letter Agreement that amended Section 2.7 to extend the term for providing "Other Services" under

Rate Schedule No. 87. Thus, Idaho Power has superseded Original Sheet Nos. 18-19, which contained Section 2.7, with First Revised Sheet Nos. 18-19 and has inserted an Original Sheet No. 18A. Idaho Power has also included redlined sheets depicting the revisions to Section 2.7.

- Behind Tab 165 is First Revised Service Agreement No. 165 superseding Original Service Agreement No. 165 under Idaho Power's FERC Electric Tariff First Revised Volume No. 5, Service Agreement between Idaho Power Company and Bonneville Power Administration for Firm Point-to-Point Transmission Service under Idaho Power's Open Access Transmission Tariff ("OATT"). In Docket No. ER03-954-000, the Commission accepted for filing Service Agreement No. 165, which was based on the form of service agreement for firm point-to-point transmission service under Idaho Power's OATT. Idaho Power failed to completely fill out the form of service agreement, however, and does so here. Idaho Power has designated the completed form of service agreement as First Revised Service Agreement No. 165 superseding Original Service Agreement No. 165. In addition, Idaho Power has included an appropriately designated cover sheet, although, consistent with Order No. 614, it has not paginated each sheet of Service Agreement No. 165.[2]

Also provided are a form of notice suitable for publication in the *Federal Register* in paper and electronic form as well as a certificate of service.

Respectfully submitted,

J. A. Bouknight, Jr.
Gary A. Morgans

Attorneys for Idaho Power Company

[2] "[T]his rule will not require the individual pages of service agreements to be paginated." Order No. 614 at 31,504.

FORM OF NOTICE

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Idaho Power Company	)	**Docket Nos.**	**ER03-953-001**
	)		**ER03-954-001**
	)		**ER03-964-001**

NOTICE OF FILING

Take notice that Idaho Power Company, on September 12, 2003, tendered for filing, in compliance with the Letter Order dated August 11, 2003 in Docket Nos. ER03-953-000 and ER03-954-001 and the Letter Order dated August 13, 2003 in Docket No. ER03-964-000 (collectively, "Letter Orders"), submitted the following documents designated in accordance with Order No. 614, *Designation of Electric Rate Schedule Sheets*, FERC Stats. & Regs. Preambles ¶ 31,096 (2000):

- First Revised FERC Electric Rate Schedule No. 28 superseding FERC Electric Rate Schedule No. 28, Interconnection Agreement among Idaho Power Company, the Washington Water Power Company, and Pacific Power and Light Company;

- First Revised FERC Electric Rate Schedule No. 69 superseding FERC Electric Rate Schedule No. 69, Interconnection and Transmission Services Agreement between Idaho Power Company and Sierra Pacific Power Company;

- First Revised FERC Electric Rate Schedule No. 72 superseding FERC Electric Rate Schedule No. 72, Transmission Services Agreement between Idaho Power Company and the City of Seattle;

- First Revised FERC Electric Rate Schedule No. 74 superseding FERC Electric Rate Schedule No. 74, Agreement for Supply of Power and Energy between Idaho Power Company and Washington City, Utah, as well as a Notice of Cancellation of First Revised FERC Electric Rate Schedule No. 74;

CERTIFICATE OF SERVICE

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on those parties on the official service list compiled by the Secretary in this proceedings.

Dated at Washington, D.C. this twelfth day of September 2003.

Jeffrey S. Burk

Jeffrey S. Burk
Steptoe & Johnson LLP
1330 Connecticut Avenue, N.W.
Washington, DC 20036
(202) 429-3000
(202) 429-3902 (fax)

FIRST REVISED FERC ELECTRIC RATE SCHEDULE NO. 28

SUPERSEDING

FERC ELECTRIC RATE SCHEDULE NO. 28

INTERCONNECTION AGREEMENT

AMONG

IDAHO POWER COMPANY

THE WASHINGTON WATER POWER COMPANY

PACIFIC POWER AND LIGHT COMPANY

EFFECTIVE DATE: AUGUST 11, 2003

INTERCONNECTION AGREEMENT

IDAHO POWER COMPANY
THE WASHINGTON WATER POWER COMPANY
PACIFIC POWER & LIGHT COMPANY

0.1 THIS AGREEMENT, made this 23rd day of April, 1958, by and between IDAHO POWER COMPANY, hereinafter called "Idaho Company", a corporation having its principal office and place of business at Boise, Idaho, and THE WASHINGTON WATER POWER COMPANY, hereinafter called "Washington Company", a corporation having its principal office and place of business at Spokane, Washington, and PACIFIC POWER & LIGHT COMPANY, hereinafter called "Pacific Company", a corporation having its principal office and place of business at Portland, Oregon;

WITNESSETH; THAT:

0.2 WHEREAS, each of the parties hereto is a member of the Northwest Power Pool, which includes all the major public and private electric plants and systems which serve the Pacific Northwest area, voluntarily cooperating in the coordinated operation of their systems under various contracts and arrangements for sale and interchange of power, storage and release of water, interconnection of facilities, and coordinated utilization of power resources; and

0.3 WHEREAS, the facilities of Idaho Company are interconnected with the facilities of other Northwest Power Pool systems operating in Idaho, Oregon, Washington, Montana and Utah, and the facilities of both Washington Company and Pacific Company are interconnected with the facilities of each other and other Northwest Power Pool systems operating in Oregon, Washington, Idaho and Montana; and

0.4 WHEREAS, an interconnection of the facilities of the Idaho Company with the facilities of the Washington Company and Pacific Company will enable the operation of the parties' systems to be more effectively coordinated with each other and with other Northwest Power Pool Systems, thereby resulting in important benefits to the areas served by each system, to their electric customers, and to the general public in the Northwest Power Pool area;

NOW, THEREFORE, in consideration of the premises and of the mutual benefits from covenants hereinafter set forth, the parties do hereby agree as follows:

ARTICLE I - TERM OF AGREEMENT

1.1 This Agreement shall become effective upon the date first above written and shall remain in force and effect through August 31, 1988; and, unless terminated by any party by written notice given three years prior to said date, it shall continue in effect thereafter from year to year until terminated by any party as of August 31 of any year subsequent to 1988 by written notice given to the other parties not less than three years in advance of the intended date of termination.

ARTICLE II - OBJECTIVES AND PRINCIPLES

2.1 The objectives and principles of this Agreement for the coordinated operation of the parties' Systems are to make, at all times, the best use of generating, reservoir, transmission and other facilities available to carry both the peak and energy loads of the parties' Systems and of the Coordinated System.

(a) For a period following the effective date of this Agreement, during which hydroelectric plants are the principal source of electric energy for the parties hereto, and the Firm Load Carrying Capability of the Coordinated System is therefore limited by the energy supply during the Critical Period, the main objective will be to provide maximum Firm Load Carrying Capability for the Coordinated System, and to make available to each System its maximum Firm Load Carrying Capability, under adverse water conditions, and, when actual water conditions are favorable, to produce the maximum amount of usable energy for each System. To accomplish this objective, Service Schedules will be adopted as provided in paragraph 4.1 hereof, pursuant to which energy that can be generated on a System or Systems of the parties hereto from Firm Hydro Resources, Firm Resources and Optional Resources, in excess of the Firm Load Carrying Capability of any such System or Systems, shall be made available, as provided in such Service Schedules, to any other party hereto, to the extent required to supply up to such other party's Firm Load Carrying Capability before such energy is made available for any other purpose; and pursuant to which capacity on a System or Systems from Firm Hydro Resources, Firm Resources and Optional Resources, in excess of that required by such System's Firm Load Carrying Capability and up to such System's Firm Capacity, shall be made available, as provided in such Service Schedules, to any other party hereto, to the extent required to supply up to such other party's Firm Load Carrying Capability before such capacity is made available for any other purpose.

(b) In the event that, during the term of this Agreement, peaking capacity of the Coordinated System becomes the controlling economic factor to the extent of requiring a change of objective in the operation of the hydro plants from obtaining maximum Critical Period Energy to producing increased peaking capacity and maximum probable energy, future Service Schedules will be adopted pursuant to paragraph 4.1 hereof to provide for the supply of the peak load requirements of each System and of the Coordinated System in such manner as is consistent with economical power and energy supply.

(c) It is the understanding and intention of the parties that the interconnecting transmission lines and facilities to be provided pursuant to Article VI of this Agreement, together with other interconnecting lines which may hereafter be constructed by the parties, and the lines and facilities comprising the respective Systems of the parties as now or hereafter existing and constructed, shall be utilized and operated in such manner as will fulfill and accomplish the objectives hereinabove set forth, in accordance with Service Schedules to be adopted pursuant to paragraph 4.1.

(d) Any system of a party hereto having load in excess of its Firm Load Carrying Capability shall supply that load from power and energy sources other than the resources used to establish its Firm Load Carrying Capability under this Agreement, and nothing in this Agreement, except as specifically provided for herein or in any Service Schedule adopted pursuant to paragraph 4.1 hereof, shall obligate any party hereto to protect or supply load of a party hereto in excess of that party's Firm Load Carrying Capability.

2.2 In the event that any party hereto has made, or makes, or has control of, headwater improvements that benefit another party owning, or having the use of facilities downstream from such improvements, such parties shall coordinate the operation of the upstream and downstream facilities under the terms of this Agreement and Service Schedules to be adopted pursuant to paragraph 4.1 hereof, which shall provide the terms and conditions for the utilization of such improvements and equitable compensation as between the parties.

2.3 Since maximum Firm Load Carrying Capability for the Northwest Power Pool area can only result from agreement between all systems in the area to coordinate generating and transmission facilities, the operation of all reservoirs and the regulation of controllable streams; to dedicate energy in excess of a system's Firm Load Carrying Capability to the extent necessary to assure the Firm Load Carrying Capability of other systems before such energy is made available for any other purpose; and to coordinate their operations in other respects, the parties hereto shall endeavor:

(1) To collectively negotiate a coordination agreement or agreements with other systems of the Northwest Power Pool to accomplish the purposes and objectives herein set forth; and/or

(2) To individually negotiate voluntary coordination agreements with other systems for said purposes, provided that no such individual agreement shall conflict with or adversely affect such party's obligations under this Agreement, or require the use of system facilities owned by another party hereto without written agreement of such other party therefor.

ARTICLE III - DEFINITIONS

3.1 The following terms, as used in this Agreement and any Service Schedule (unless otherwise specifically provided therein), shall have the following respective meanings:

(a) "Firm Hydro Resources" shall mean those resources available to a System of a party hereto when such party's System does not include steam electric resources either owned, leased or purchased; provided, that a party hereto, whose System does include such steam electric resources, may, at its election under subparagraph (4) of this paragraph 3.1(a), include its resources in this category. Such Firm Hydro Resources shall include the following:

(1) All hydro plants or reservoirs owned, leased, or otherwise controlled by such party;

(2) All resources under an agreement or agreements which provide that such party's System obtains from a hydro plant, or reservoir, a specified portion of all of the various and several benefits available from such hydro plant or reservoir;

(3) Resources under an agreement or agreements which:

(A) when included as a Firm Hydro Resource hereunder at the election of the party, provide for the receipt of energy by such party's System from another system in excess of a specified load on such other system, and the availability of such energy is determined by natural streamflow, or

(B) when included as a Firm Hydro Resource hereunder at the election of the party, provide for the receipt of power and energy by such party's System, provided such receipts shall supply power and energy during the Refill-Hold Period (or the party may supply other power and energy satisfactory to the Operating Committee) in an amount which is a percentage of the Firm Load Carrying Capability of such party in the Refill-Hold Period, for each and all intervals of time, equal to or greater than the percentage such receipts bear to the Firm Load Carrying Capability of such party in the Critical Period.

(4) When included as a Firm Hydro Resource hereunder at the election of the party, any steam-electric resources, or contract for steam-electric resources, provided such resources shall supply power and energy during the Refill-Hold Period (or the party may supply other power and energy resources satisfactory to the Operating Committee) in a percentage of the Firm Load Carrying Capability of such party in the Refill-Hold Period, for each and all intervals of time, equal to or greater than the percentage such resources bear to the Firm Load Carrying Capability of such party in the Critical Period.

Each party shall assume all costs associated with the Firm Hydro Resources of such party's System.

(b) "Firm Resources" shall mean those resources available to a System of a party hereto when such party's System includes steam electric resources either owned, leased, or purchased and not included under paragraph 3.1(a) hereof. Such Firm Resources shall include the following:

(1) All hydro plants or reservoirs owned, leased or otherwise controlled by such party;

(2) All resources under an agreement or agreements which provide that such party's System obtains from a hydro plant, or reservoir, a specified portion of all of the various and several benefits available from such hydro plant or reservoir;

(3) At the election of the party, resources available under agreements, other than those included under 3.1(b)(2) hereof, providing for the purchase or receipt of power and energy;

(4) At the election of the party, steam electric plants owned, leased or otherwise controlled by such party.

Each party shall assume all costs associated with the Firm Resources of such party's System, except as otherwise provided hereafter.

(c) "Optional Resources" shall mean resources which are available to a party's System under agreements providing for the purchase or receipt of power and energy, except those included as Firm Hydro Resources or Firm Resources:

(1) when, with the agreement of the parties hereto, any such resource is included hereunder as an Optional Resource of a party's System having its resources classified as Firm Hydro Resources, at the cost of such party, provided that should such Optional Resource be utilized for the benefit of other parties hereto, said other parties shall reimburse such

party directly for the cost involved, or

(2) when any such resource, not included as an Optional Resource under sub-paragraph (1) immediately preceding, can be made available to another party hereto at its request, and at its cost, as its Optional Resource or Firm Resource, provided the inclusion of any such resource will not adversely affect any of the parties hereto.

(d) "System" shall mean the Firm Hydro Resources and Optional Resources (if any) or the Firm Resources of a party, and the party's load associated therewith (including agreements for the sale and delivery of firm power and energy, except as may be otherwise provided in Service Schedules between the parties hereto), transmission and distribution lines and substations owned or leased by a party hereto, together with any new facilities or new Firm Hydro Resources and Optional Resources, or Firm Resources, acquired by a party hereto during the term of this Agreement, all of which are adequately interconnected by facilities owned or contracted for by said party to accomplish the objectives hereof; and which System is interconnected with the System of another party hereto, by transmission facilities or arrangements, adequate to accomplish the objectives hereof.

(e) "System Load" shall mean the total electrical load of a party hereto associated with its System, which load the party must supply upon demand as a public utility or as provided in the party's agreements to supply power and energy to its customers. In determining the shape of System Load, seasonal sales for resale during the Refill-Hold Period shall be excluded unless otherwise agreed to by the parties hereto.

(f) "Amount of System Load" shall mean the percentage of System Load used in the coordinated operation, under this Agreement, which may be greater or less than such System Load, but which shall be the same percentage of the System Load for each and all intervals of time.

(g) "Coordinated System" shall mean the Systems of the parties hereto operated on a coordinated basis under this Agreement for maximum load carrying capability.

(h) "Coordinated System Load" shall mean the sum of the Amounts of System Loads of the parties hereto.

(i) "Load Duration Curve" of a System Load, or of Amount of System Load of a party, or of the Coordinated System Load, shall mean the clock-hour loads of such System, for a specified period of time, arranged in order of descending magnitude.

(j) "Natural Streamflow" shall mean the inflow to a System's reservoirs or forebays which would exist if there were no change in the elevation of upstream storage reservoirs under the control of a party or parties hereto, except for elevation changes in upstream natural lakes resulting from outlet channel limitations.

(k) "Natural Flow Capability" of the System of a party, or of the Coordinated System, during any specified period, shall mean the energy that can be produced from such System's Firm Hydro Resources and Optional Resources, or Firm Resources, without the use of any stored water from reservoirs under control of the parties hereto, and which is usable in the Coordinated System Load.

(l) "Critical Period" shall mean that period during which the least amount of Firm Load Carrying Capability for the Coordinated System can be obtained from the Firm Hydro Resources and Optional Resources, or Firm Resources, of the parties hereto, determined under the most adverse water conditions of historical record for the Coordinated System, modified for irrigation development and other consumptive uses.

(m) "Critical Period Energy" of a System, or of the Coordinated System, shall mean the average energy which can be produced by such System, including full use of stored water, during the Critical Period, and which can be shaped to the Coordinated System Load during the Critical Period by the machine capacity, pondage and reservoirs of the Coordinated System without a deficiency in capacity or energy.

(n) "Annual Firm Energy" of a System of a party, or of the Coordinated System, shall mean the annual energy by months such System has available from Critical Period Energy during the Drawdown Period, and the energy which such System has available from Firm Hydro Resources and Optional Resources, or Firm Resources, and Integration Energy during the Refill-Hold Period, and which annual energy can be shaped to the Coordinated System Load by machine capacity, pondage and reservoirs of the Coordinated System without a deficiency in capacity or energy.

(o) "Firm Capacity" of the System of a party shall mean its machine capacity and receipts of power together with adequate energy, required to supply the demand requirements of the Amount of System Load of such party throughout an annual period utilizing such System's Annual Firm Energy.

(p) "Firm Load Carrying Capability" of the System of a party, or of the Coordinated System, shall mean the Amount of System Load, or Coordinated System Load, that can be supplied during an annual period or the Critical Period, whichever is longer, determined by the availability of Annual Firm Energy or Firm Capacity, whichever is smaller.

(q) "Drawdown Period" shall mean that period beginning when the Natural Flow Capability of the Coordinated System declines below the load requirements of the Coordinated System, and ending when such Natural Flow Capability rises above such load requirements.

(r) "Refill-Hold Period" shall mean that period beginning at the end of the Drawdown Period and ending when the Natural Flow Capability of the Coordinated System declines below the load requirements of the Coordinated System (the beginning of the next Drawdown Period).

(s) "Operating Energy" shall mean energy transferred between Systems, during a Drawdown Period only, in order to supply a deficiency between a System's actual generation and its load requirements or Firm Load Carrying Capability, whichever is the smaller.

(t) "Integration Energy" shall mean energy transferred between Systems, during a Refill-Hold Period only, in order to supply a deficiency between a System's actual generation and its load requirements or Firm Load Carrying Capability, whichever is the smaller.

(u) "Surplus Peaking Capacity" shall mean the peaking capacity of a System in excess of the Firm Capacity and reserve capacity of such System at times of System maximum capacity requirements.

ARTICLE IV - SERVICE SCHEDULES

4.1 It is understood that service to be rendered by one party to another party in the utilization of the facilities herein provided, and in the obtainment of coordinated operation of the Systems of the parties, will vary from time to time during the term hereof, and such services, including agreements for the purchase and sale of firm power, and the terms, arrangements and charges applicable thereto, must necessarily depend upon area and system load requirements, water supply, generating resources, transmission facilities, and other conditions existing from time to time. It is intended that such services, including agreements for the purchase and sale of firm power, and the terms, arrangements and charges applicable thereto, will be set forth in Service Schedules from time to time formulated and agreed upon between the parties concerned, which Service Schedules, when executed by such parties, will become parts of this Agreement during the period fixed by their respective terms; and except as otherwise specifically stated therein, each Service Schedule shall be subject to the terms and conditions expressed in this Agreement. The initial Service Schedules, designated Service Schedules I-A, II-A, III-A, IV-A, and V-A, are attached hereto and are hereby made parts hereof.

ARTICLE V - OPERATING COMMITTEE AND DUTIES

5.1 Each party shall appoint a representative to act for it in matters pertaining to the interconnected and coordinated operation of the respective Systems, in accordance with the provisions of this Agreement and Service Schedules adopted and entered into as provided in paragraph 4.1, the representatives so appointed being hereafter referred to collectively as the Operating Committee. Each party shall evidence such appointment by written notice to the other parties, and by similar notice, any party may at any time change its representative on the Operating Committee.

5.2 All action taken by the Operating Committee must be by unanimous agreement of all representatives unless otherwise specifically provided herein or in any Service Schedule adopted and entered into as provided in paragraph 4.1. In the event the Operating Committee cannot reach unanimous agreement on operating procedures or determinations of fact or policy which are necessary to the carrying out of the operation as contemplated in this Agreement and the Service Schedules, the dispute shall be submitted immediately to a Board of Arbitration as hereafter provided in Article XIV. In case of emergency, the Operating Committee shall act by majority vote and shall thereafter submit the matter to arbitration for settlement of the account and for future reference. In any event the Amount of System Load of the Systems shall be carried and consent to an operation over protest shall not constitute a waiver in any subsequent settlement.

5.3 The Operating Committee shall make annual and such other studies as may be required from time to time for the coordinated operation and planning of the parties' Systems as provided under Service Schedules adopted pursuant to paragraph 4.1.

5.4 Subject to the adoption of and in accordance with Service Schedules, as provided in paragraph 4.1, covering sales, transfers, interchanges, or displacement of power and energy between the parties, or as provided for in paragraph 5.6 hereof, the Operating Committee shall prepare in advance hourly schedules of power and energy transfers for each day, with simultaneous deliveries of power under various arrangements being properly identified and accounted for each hour. Such scheduled power and energy transfers shall be deemed to have been made at the Point of Delivery, as hereinafter defined, when delivered through the supplying System's interconnections. Operating deviations from schedule shall be held to a minimum, properly accounted for, and corrected under like conditions of water supply and load. Essential hourly metered data shall be exchanged between the parties hereto.

5.5 In the event it is necessary to reduce or interrupt operations hereunder to repair, maintain or replace facilities, such reductions or interruptions will be arranged as far in advance as feasible by mutual agreement of the parties. When such reduction or interruption, or emergency or accidental interruption, restricts or interrupts the delivery or receipt of scheduled power and energy, the Operating Committee shall compensate for such reductions or interruptions by adjusting future schedules of deliveries under like conditions of water supply and load.

5.6 In the event that from time to time power and energy may to advantage be interchanged, or stored by, or sold between any of the parties upon bases not provided for in Service Schedules currently in effect, and under circumstances such that arrangements must be made promptly in order to utilize such resources or in case of emergencies, temporary arrangements for individual transactions may be made by the Operating Committee; provided, however, that no such arrangement made by the Operating Committee shall extend for a period longer than thirty days. The Operating Committee shall prepare a report of each transaction.

ARTICLE VI - FACILITIES TO BE PROVIDED

6.1 The respective parties shall provide, maintain and operate the following facilities for interconnecting their respective systems for the purposes set forth in this Agreement:

(a) Idaho Company: A transmission line, suitable for operation at a nominal voltage of 230 KV, extending from Idaho Company's 230 KV substations at its Brownlee and Oxbow power developments to a terminal structure, owned by Washington Company, located on the bank of the Snake River northwest of Divide Creek, in Idaho County, Idaho (said point hereinafter referred to as "Divide"), suitable and adequate terminal facilities for said line at the Brownlee and Oxbow 230 KV substation; and such communication (including telemetering) and load control devices as may be determined by the parties to be necessary for operation under this Agreement.

(b) Washington Company: A transmission line, suitable for operation at a nominal voltage of 230 KV, extending from Divide to Washington Company's Lolo 230 KV substation located near Lewiston, Idaho (said point hereinafter referred to as "Lolo"), suitable and adequate terminal facilities for said line at said Lolo substation, and such communication (including telemetering) and load control devices as may be determined by the parties to be necessary for operations under this Agreement.

(c) Pacific Company: A transmission line, suitable for operation at a nominal voltage of 230 KV, extending from Lolo to a 230 KV substation located at or near Walla Walla, Washington (said point hereinafter referred to as "Walla Walla"), suitable and adequate terminal facilities for said line at said Walla Walla and Lolo substations, and such communication (including telemetering) and load control devices as may be determined by the parties to be necessary for operations under this Agreement.

6.2 The facilities described in paragraph 6.1(a) and (b) shall be provided and tested for operation by August 1, 1959.

6.3 Pacific Company shall provide, maintain and operate or otherwise arrange for an adequate interconnection between said Walla Walla 230 KV substation and some point on the Northwest 230 KV transmission network.

6.4 The facilities described in paragraphs 6.1(c) and 6.3 above shall be provided by Pacific Company when the Operating Committee determines that such facilities are required for the economic transmission of power and energy within the interconnected transmission network in which the parties operate.

6.5 Throughout the term of this Agreement, each of the respective parties will maintain, or cause to be maintained, the aforesaid interconnecting facilities provided by such party in accordance with good operating practice.

ARTICLE VII - POINTS OF DELIVERY

7.1 The Points of Delivery for energy supplied between the parties hereto, unless otherwise specified, shall be at the place and in the interconnecting circuit between the parties where ownership or control of the facilities changes.

ARTICLE VIII - POWER FACTOR

8.1 Each party hereto shall provide the reactive requirement of its System.

ARTICLE IX - ACCOUNTING

9.1 Accounting for all energy deliveries hereunder shall be based on energy scheduled for delivery in accordance with paragraphs 5.4 and 5.6.

ARTICLE X - METERING

10.1 The amounts of power and energy delivered by any party to another under the provisions of this Agreement at the Points of Delivery during each hour shall be the amounts determined, after making adjustment for losses as may be indicated by using factors agreed upon by the Operating Committee, from measurements made by the parties' watt-hour, var-hour and demand meters, respectively, installed or to be installed, to record the flow of electric energy and reactive power in the interconnecting circuit. All metering equipment required for the purposes of this Agreement shall be provided and maintained in accordance with good practice by the owner of the System in which such metering equipment is located.

10.2 The aforesaid metering equipment shall be tested by the owner at suitable intervals and its accuracy of registration maintained in accordance with good practice. On request of any party concerned, special tests shall be made, representatives of all parties concerned shall be afforded opportunity to be present at all routine or special tests and upon occasions when any readings for purposes of settlements hereunder are taken.

10.3 If at any test of metering equipment an inaccuracy shall be disclosed exceeding two per cent, the account between the parties concerned for service theretofore supplied shall be adjusted to apply to a period of thirty days prior to the date of the test or to the period during which such inaccuracy may be determined to have existed, whichever period be the shorter. Should any metering equipment at any time fail to register, or should the registration thereof be so erratic as to be meaningless, the power and energy delivered shall be determined from the best available data.

ARTICLE XI - BILLINGS AND PAYMENTS

11.1 All bills for amounts owed by one party to another, or to a pool account, hereunder shall be due and payable on the fifteenth day of the month following the monthly or other period to which such bills are applicable, or on the tenth day following receipt of bill, whichever date be later. Unless otherwise agreed upon, a calendar month shall be the standard monthly period for the purposes of settlement hereunder. In the event any bill, or part thereof, be disputed, payment of bill as rendered shall be made when due, with subsequent adjustment for any amount found to be in error.

ARTICLE XII - LIABILITY

12.1 Each party will defend, indemnify, and save harmless the other parties against liability, loss, costs and expenses on account of any injury or damage to persons or property occurring on or adjacent to its facilities on its own side of the aforesaid Points of Delivery, unless such injury or damage was caused by the sole negligence of the other party or parties.

ARTICLE XIII - UNCONTROLLABLE FORCES

13.1 A party shall not be considered to be in default in respect to any obligation hereunder, if prevented from fulfilling such obligation by reason of uncontrollable forces. The term uncontrollable forces, being deemed for the purpose of this agreement to mean any cause beyond the control of the party affected, including, but not limited to, destruction or impairment of facilities resulting from flood, earthquake, storm, lightning, fire, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, proceeding by court or public authority, or act or failure to act by court or public authority, which uncontrollable forces by exercise of due diligence and foresight such party could not reasonably have been expected to avoid. A party rendered unable to fulfill any obligation by reason of uncontrollable forces shall exercise due diligence to remove such inability with all reasonable dispatch, provided, that the removal of such inability is (a) required for the continued performance of this agreement, (b) economical, and (c) will not be unduly burdensome on the party involved.

ARTICLE XIV - ARBITRATION

14.1 In the event any dispute shall arise with regard to the interpretation of this Agreement or of any of the Service Schedules adopted and entered into as provided in paragraph 4.1 hereof, or in the event any dispute should arise as to any question of fact or as to any matter which must be determined in order to operate under this Agreement or said Service Schedules, the dispute shall be submitted to a Board of Arbitrators for decision as hereinafter provided. It is the intention of the parties hereto that the matters to be submitted to arbitration are such matters about which the Operating Committee is unable to agree and matters which are necessary to the carrying out of the terms of this Agreement and the Service Schedules adopted and entered into pursuant to paragraph 4.1 hereof, but it is not the intention of the parties that a Board of Arbitrators shall have the authority to make any amendments or changes to the Agreement or Service Schedules or to change the basic conditions under which the parties are to operate thereunder. Changes or matters requiring the agreement of all parties, or specifically depending upon the determination or sole judgment of any single party, shall not be subject to arbitration.

14.2 . The Board of Arbitrators shall be composed of one disinterested person selected by each party, none of whom shall be an employee of any of the parties hereto. A decision rendered by a majority of the Board of Arbitrators shall be final and shall be conclusive and binding on each of the parties hereto. In the event the Arbitrators cannot reach a decision by majority vote, then they shall agree upon a disinterested umpire and the decision of the umpire shall be final and shall be conclusive and binding on each of the parties hereto.

14.3 Any party may initiate arbitration proceedings as herein provided, by giving notice to the other parties, which notice shall designate the Arbitrator selected by the party giving notice. The other parties shall designate Arbitrators as promptly as possible, and all parties shall cooperate in bringing about a determination by arbitration at the earliest possible time. In the event any party does not designate an Arbitrator within ten (10) days of receiving notice of the submission of a matter to arbitration, it shall waive its right to appoint an Arbitrator as herein provided.

ARTICLE XV - NOTICES

15.1 Any notice to be given in accordance with the terms of this Agreement or under any Service Schedule incorporated as a part hereof shall be deemed properly given to the respective parties if mailed, postage prepaid, and addressed to:

1. Idaho - Idaho Power Company,
   P. O. Box 770,
   Boise, Idaho.
   Attention: Secretary

2. Washington - The Washington Water Power Company,
   P. O. Drawer 1445,
   Spokane 10, Washington.

3. Pacific - Pacific Power & Light Company,
   920 S. W. 6th Avenue,
   Portland 4, Oregon.

The designations of the name and address to which any such notice or demand is directed may be changed at any time and from time to time by any party by giving notice to the other parties, as above provided.

ARTICLE XVI - WAIVERS

16.1 Any waiver at any time by any party of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting or enforcing any right shall not be deemed a waiver of such right.

ARTICLE XVII - REGULATORY AUTHORITIES

17.1 This Agreement is subject to the regulatory powers of any State or Federal Agency having jurisdiction.

ARTICLE XVIII - ASSIGNMENT

18.1 This Agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

IN WITNESS WHEREOF, the parties have caused this Agreement to be executed in triplicate by their duly authorized officers, as of the day and year first hereinabove written.

THE WASHINGTON WATER POWER COMPANY

By M. L. Blair
Vice - President

(CORPORATE SEAL)

ATTEST:

J. W. Willis
First Secretary

PACIFIC POWER & LIGHT COMPANY

By E. R. Hidalgo
Vice President

(CORPORATE SEAL)

ATTEST:

Secretary

IDAHO POWER COMPANY

By
Vice President

(CORPORATE SEAL)

ATTEST

J. T. Rogers
Asst. Secretary

SERVICE SCHEDULE I-A

COORDINATION BETWEEN

IDAHO POWER COMPANY
THE WASHINGTON WATER POWER COMPANY
PACIFIC POWER & LIGHT COMPANY

THIS AGREEMENT, Service Schedule I-A, dated April 23, 1958, by and between IDAHO POWER COMPANY, THE WASHINGTON WATER POWER COMPANY, and PACIFIC POWER & LIGHT COMPANY, is agreed to under and as a part of Interconnection Agreement dated April 23, 1958, between the parties, hereinafter referred to as "Interconnection Agreement."

Section 1 - Term

(a) This Service Schedule shall become effective upon the date first above written, and shall remain in force and effect through August 31, 1978; unless terminated by any party by written notice given three years prior to said date, it shall continue in effect thereafter from year to year until terminated by any party as of August 31 of any year subsequent to 1978 by written notice given to the other parties not less than three years in advance of the intended date of termination.

(b) The date of initial service hereunder, and the date upon which coordinated operation of the parties' Systems shall begin, shall be those dates upon which the transmission lines, described in paragraphs 6.1(a) and (b), 6.1(c) and 6.3 of the Interconnection Agreement, necessary to interconnect the Systems of the parties, are completed, tested and ready for operation. It is understood and agreed that prior to the completion of, or arrangement for, all of the interconnecting transmission facilities described in Article VI of the Interconnection Agreement, coordinated operation of the Systems will begin, to the extent possible, upon the date that any of the transmission facilities heretofore described are declared by the parties to be ready for operation; provided, however, at the time transmission facilities are available which will permit Pacific Company to coordinate the operations of any of its resources with the Coordinated System of the other parties hereto, Pacific Company shall designate the resources and load which will be made available for coordination under this Service Schedule, subject to the agreement thereto by the parties owning the Systems comprising the Coordinated System as it exists at that time, and in the event that such facilities are not provided, and the coordinated resources and load are not designated and agreed to as aforesaid by March 1, 1963, this Service Schedule shall thereupon terminate as to Pacific Company, unless said parties otherwise agree.

Section 2 - Determination of System Capabilities

(a) A party must elect annually for the ensuing operating period to classify its System as a System with Firm Hydro Resources and Optional Resources, if any, or as a System with Firm Resources and, except for resources which the party may elect to exclude from Firm Hydro Resources as specifically permitted under paragraphs (3) and (4) of subsection 3.1(a), and from Firm Resources as specifically permitted under paragraphs (3) and (4) of subsection 3.1(b) of the Interconnection Agreement, each party must, unless otherwise agreed to by all of the parties hereto, include all resources in its System which fall within the classification so elected.

(b) The Operating Committee, from data supplied by each party for its own System not later than March 1 each year, including historical streamflows (modified for irrigation development and other consumptive uses), a tabulation of all pertinent data on the resource included in such party's Firm Hydro Resources and Optional Resources, or Firm Resources, that will be in operation in the period under consideration, and estimates of peak and energy loads and load characteristics, shall make a study of the coordinated operation of the parties' Systems not later than April 30 of each year, and shall determine System capabilities for the ensuing operating period. Estimates of System capabilities for planning purposes shall be made annually by October 31 of each year for the five (5) succeeding years from data to be furnished by the parties, which shall include the scheduled completion of any reservoir or generating facility on any of the parties' Systems, or in the Northwest Power Pool which will affect the amounts determined, either by control of water by others not parties hereto or by the execution of a power and energy agreement by a party hereto. The determinations and estimates shall be made in accordance with mutually accepted principles used in the calculation of hydroelectric system capabilities, and as set forth in Section 3 of this Service Schedule, and shall establish the following:

(1) Firm Hydro Resources and Optional Resources.

(2) Firm Resources.

(3) Systems and Coordinated System.

(4) System Load, Amount of System Load, Coordinated System Load and Load Duration Curves.

(5) Critical Period.

(6) Critical Period Energy of the Coordinated System and of each party's System.

(7) Annual Firm Energy of the Coordinated System and of each party's System.

(8) Firm Load Carrying Capability of the Coordinated System and of each party's System.

(9) A composite envelope rule curve for the reservoirs of the Coordinated System and for each of the reservoirs of the parties hereto.

(10) Firm Capacity, Reserve Capacity, and Surplus Peaking Capacity.

(11) Estimates of interchange of Operating Energy and Integration Energy under various water conditions required to assure to each System its Firm Load Carrying Capability or load requirement, whichever is the smaller.

(12) Maintenance schedules.

(c) The determinations made for each ensuing operating period shall be confirmed in writing by and between the parties.

Section 3 - Operational and Computational Criteria

(a) Load Duration Curves - All Firm Hydro Resources, Firm Resources, and Optional Resources are to be fitted and shaped into the System and Coordinated System Load Duration Curves for the determination of the items (5) through (12) of paragraph (b) Section 2 hereof. For the purpose of this agreement, the specified time for the determination of Load Duration Curves shall be a calendar month, unless in the opinion of the Operating Committee a shorter specified time is desirable to better determine the above items.

(b) System Load - The Amount of System Load of a party to be included in the Coordinated System shall not exceed such party's Firm Load Carrying Capability.

(c) Reserve Capacity - The capacity required by the Coordinated System as reserve shall be determined by the Operating Committee from time to time depending on operating conditions of the Coordinated System. Unless otherwise determined by the Operating Committee, the reserve capacity shall be 5% of the Coordinated System Firm Capacity or the capacity of the largest unit in the Coordinated System, whichever is the smaller. Each party hereto will provide a part of such Reserve Capacity in an amount which has the same proportion to the sum of the Reserve Capacities supplied by all parties hereto, that such party's Firm Capacity has to the sum of the Firm Capacities of the other parties hereto.

(d) Drawdown Period - For the purposes of this Service Schedule, the beginning of the Drawdown Period and the end of the Refill-Hold Period shall not be later than September 15 of each year and the beginning of the Refill-Hold Period and the end of the Drawdown Period shall not be earlier than March 15 of each year.

(e) Reservoir Operations - The Operating Committee shall determine the priority of drawdown and refill of reservoirs in order to produce the maximum Firm Load Carrying Capability for the Coordinated System. Power and energy losses to any party's System resulting from said priority of operation shall be replaced proportionately by the Systems gaining therefrom and, unless otherwise agreed to by the parties, the net benefits of power and energy resulting from said priority operation of a reservoir by the addition of said reservoir to the coordinated operation shall be apportioned equally between (1) such party contributing said reservoir, and (2) the other parties hereto.

(f) Rule Curves -

(i) The upper envelope of the Rule Curve for each of the reservoirs, and for the equivalent sum of the Coordinated System's reservoirs, shall be so determined that the sum of the usable energy in the Coordinated System's reservoirs and the Firm Capacity of the Coordinated System shall be sufficient for any given time to supply the Firm Load Carrying Capability of the Coordinated System, or of the respective Systems, and to refill all reservoirs by the beginning of the next Drawdown Period, should there be a recurrence of the most adverse Natural Streamflows of historical record, for the balance of the Drawdown Period and the succeeding Refill-Hold Period.

(ii) The lower envelope of the Rule Curve for each of the reservoirs and for the equivalent sum of the Coordinated System's reservoirs shall be so determined that no additional resources, other than those included in the determination of the Firm Load Carrying Capability, when assuming reservoirs empty at the beginning of the Refill-Hold Period, and assuming the most adverse Natural Streamflows of historical record from the beginning of the Refill-Hold Period to any given time, and assuming a load equal to the Firm Load Carrying Capability of the Coordinated System or of the respective Systems, will be required to supply the Firm Load Carrying Capability of the Coordinated System for the balance of the Refill-Hold Period and of the Drawdown Period.

(g) Other Operating Problems - Operational and computational criteria which may not be clearly covered by the Interconnection Agreement and this Service Schedule, when required to establish the methods of operation or computation to be followed in the performance of coordinated operation under this Service Schedule, when agreed to by the Operating Committee, shall be defined in writing.

Section 4 - Operating Plans

(a) The coordinated operation of the parties' Systems shall be directed by the Operating Committee in accordance with Articles II and V of the Interconnection Agreement and as hereinafter set forth.

(b) Each year, not later than April 30, the Operating Committee shall prepare plans for the coordinated operation of the parties' Systems for the ensuing operating period. Such plans shall be based on the determinations made in paragraph (b) of Section 2 of this Service Schedule, items (1) through (12), and such other necessary data, including operation with other members of the Northwest Power Pool, as the Operating Committee shall deem useful in carrying out the provisions of this Service Schedule.

(c) In directing the operation of the Coordinated System, the Operating Committee shall consider for each System and the Coordinated System: load conditions, available capacity, hydro conditions (including reservoir elevations with respect to the Rule Curves), streamflow probabilities (including forecasts of probable streamflow during the next Refill-Hold Period based on precipitation readings and accumulated snow cover of the respective reservoir watersheds), possibility of waste by spill, requirements for irrigation or other consumptive uses, fishery requirements, flood control or navigation requirements, steam operation, maintenance and spinning reserve requirements, available transmission capacities, voltage control, reactive flow, and other essential operating factors. Purchases of power and energy by the Operating Committee to meet the pool requirements of the Coordinated System shall be made in the best interests of the parties hereto.

(d) The prearranged maintenance outages of System facilities of the parties hereto shall be scheduled in accordance with the operating plan so as to minimize the adverse effect on the operation of the Coordinated System.

Section 5 - Operating Procedures

(a) Whenever the equivalent actual elevations of the Coordinated System's reservoirs are on or above the upper envelope of the equivalent Coordinated System's Rule Curve, and the allocated rate of use of storage with usable Natural Flow Capability of the Coordinated System is in excess, or is conservatively forecasted from known conditions to become in excess, of that required to supply the Firm Load Carrying Capability of the Coordinated System, surplus energy (indicated by the System's usable Natural Flow Capability, allocated rate of use of storage, actual usable reservoir elevations above the upper envelope of its reservoir Rule Curves and the fulfillment of its obligations to return Operating Energy) is available on a System or Systems for use other than to protect or supply the Firm Load Carrying Capability of the Coordinated System.

(b) Whenever the equivalent actual elevations of the Coordinated System's reservoirs, when supplying the Firm Load Carrying Capability, are below the upper envelope Rule Curve and above the lower envelope Rule Curve, the Coordinated System has neither a surplus nor a deficiency in energy. Exchange of energy between the parties hereto, other than under agreements for firm power and energy, shall be for the purpose of repaying Operating Energy and balancing reservoirs, except as provided in Sections 7(a) and 7(b) hereof. No deliveries of energy by the parties hereto to other parties, during this operating condition, shall be made which involve the Firm Hydro Resources, Firm Resources, and Optional Resources used to determine Firm Load Carrying Capability, except firm power and energy supplied by a System's Firm Load Carrying Capability, and except as an exchange by the Coordinated System, which has been authorized by the Operating Committee, in order to conform to necessary Northwest Power Pool operations.

(c) Whenever the usable Natural Flow Capability and allocated rate of use of storage is less than that required to supply the Firm Load Carrying Capability of the Coordinated System, and the equivalent actual elevations of the Coordinated System's reservoirs are below the lower envelope of the Rule Curve, the deficiency in energy is to be supplied by the deficient System or Systems (indicated by a System's deficiency in Natural Flow Capability, allocated rate of use of storage, actual usable reservoir elevations below the lower envelope Rule Curve of its reservoirs, and its Operating Energy account).

(d) A System will be considered as having generation in excess of its Firm Load Carrying Capability whenever its actual reservoir elevations are above its upper envelope Rule Curve and it has energy capability from Natural Flow Capability and allocated rate of use of storage, equal to or greater than its Firm Load Carrying Capability; and a System will be considered as having generation less than its Firm Load Carrying Capability whenever its actual reservoir elevations are below its upper envelope Rule Curve and it has energy capability, from Natural Flow Capability and allocated rate of use of storage, equal to or less than its Firm Load Carrying Capability. Whenever the actual elevations of all the controllable reservoirs of the Coordinated System are below their upper envelope Rule Curves, Operating Energy and Integration Energy will be transferred between reservoirs by the Operating Committee as they deem advisable for the best interests of the parties hereto.

Section 6 - Energy Transfers

(a) Priority on the use of facilities (including machine capacity up to Firm Capacity, reservoirs and transmission capacity of the Systems) of the parties hereto for the transfer of energy between the parties, shall be in the following order unless otherwise agreed to by the parties hereto, with the first item having priority over the following items and each following item having priority over each succeeding following item:

(1) Firm Power and Energy for which an agreement between the parties has been made and for which a Schedule is included as part of this Agreement.

(2) Delivery of Operating Energy and the return of Operating Energy. Section 6(b)

(3) Delivery of Integration Energy. Section 6(e)

(4) Return of Borrowed Energy. Section 7(a)

(5) Return of Integration Energy. Section 6(f)

(6) Return of Borrowed Energy. Section 7(b)

(7) Generation from own storage. Section 7(a)

(8) Delivery of Secondary Energy. Section 2(a) and (b), Schedule II-A

(9) Return of energy stored in a reservoir. Section 7(c)

(10) Delivery of energy for storage in a reservoir. Section 7(c)

(11) Delivery of energy to a borrower by a lender. Section 7(a)

(12) Delivery of secondary energy. Section 2(c) Service Schedule II-A

(b) Operating Energy shall be delivered to any party's System when such System's generation is less than its Firm Load Carrying Capability, from any other party's System when such other party's System's generation is in excess of its Firm Load Carrying Capability, and shall be returned to and received by the supplying System from the first available generation on the receiving System in excess of its Firm Load Carrying Capability, except such return shall be delayed if such energy would be wasted by spill if returned and can be stored by the returning System. If such delayed energy is wasted by spill before it can be returned, all obligations to return such energy shall be considered to have been fulfilled. Provided, however, that a party hereto, with resources classified as Firm Hydro Resources shall first satisfy the needs of other parties hereto, having resources classified as Firm Hydro Resources, before deliveries of energy are made to parties hereto with resources classified as Firm Resources; and provided further, that when Operating Energy required by a party hereto would be supplied from steam electric resources of a party hereto, the Operating Committee may obtain such Operating Energy from other available sources, and if such Operating Energy is supplied from steam electric resources of a party hereto it shall not be returned unless requested by the Operating Committee or the supplying party.

(c) Unless otherwise agreed to by the Operating Committee, Operating Energy shall be delivered or returned during the heavy load hours of the week days and the rate of delivery shall be limited only by the amount of energy available or capacity available to the delivering system, or limited by the ability of the receiving system to receive such power and energy without the danger of impending spill, or without violating minimum water release restrictions, or by the availability of transmission capacity.

(d) At the end of each Drawdown Period, as between Systems whose resources are classified as Firm Hydro Resources, any imbalance between Operating Energy received and Operating Energy returned, due to water conditions resulting in generation less than the Critical Period Energy of a party's System, shall be paid for as provided in Section 8 by the System which was deficient to the System which supplied such deficiency.

(e) Integration Energy shall be delivered to and received by any party's System when such System's generation is less than its Firm Load Carrying Capability, from any other party's System when such System's generation is in excess of its Firm Load Carrying Capability; provided, however, that a party hereto, with resources classified as Firm Hydro Resources, shall first satisfy the needs of other parties hereto, having resources classified as Firm Hydro Resources, before deliveries of energy are made to parties hereto with resources classified as Firm Resources; and provided further, that when Integration Energy required by a party hereto would be supplied from steam electric resources of a party hereto, the Operating Committee may obtain such Integration Energy from other available sources.

(f) Any imbalance of Integration Energy at the end of the Refill-Hold Period between Systems with their resources classified as Firm Hydro Resources shall be returned to the supplying System (for purposes other than Operating Energy) by the receiving System from the generation of such receiving System's Firm Hydro Resources when such generation is in excess of the receiving System's Firm Load Carrying Capability plus the requirements of its interruptible customers in its service area, and the receiving System declares such energy (or portion thereof) available during a stated period and the supplying System accepts the return of such energy (or portion thereof). Unless otherwise agreed to by the parties, and depending on availability, Integration Energy will be returned during the Drawdown Period in such amounts as will enable the receiving System to make maximum use of all energy or to avoid danger of impending spill, and upon the declaration of availability of such energy for return during the Drawdown Period, the obligation of the receiving System to return such energy, in the amounts stated in such declaration or declarations, shall be considered to have been fulfilled.

(g) At the end of each Drawdown Period, between Systems whose resources are classified as Firm Hydro Resources, any imbalance between Integration Energy received and Integration Energy returned shall be paid for as provided in Section 8 by the System which was deficient to the System which supplied such deficiency.

(h) Whenever the supply of Integration Energy at a specified cost is greater than the requirements therefor, and more than one party hereto has such Integration Energy available, deliveries of Integration Energy will be apportioned between the supplying parties in the same percentage as each party's supply is to the total supply; and whenever the supply of Integration Energy is less than the requirements therefor and more than one party requires such energy, the deliveries of Integration Energy to each shall be in that proportion that the requirements of each party bears to the total requirements, provided that the priority of the deliveries of Integration Energy under Section 6(e) shall first be met before any deliveries of Integration Energy are made to parties hereto whose resources are classified as Firm Resources.

(i) Any Operating Energy or Integration Energy supplied to or from parties hereto, whose resources are classified as Firm Resources, or any such energy obtained by a party hereto from sources other than the parties hereto under the provisions of paragraphs 6(b) and 6(e) hereof, shall be recorded in a pooled account. The parties shall designate an agent from time to time to account and bill the energy transactions in the pooled account in accordance with data supplied by the Operating Committee.

(j) Until transmission facilities have been provided which will permit Pacific Company to coordinate and operate within the Coordinated System, the other parties hereto agree to deliver Integration Energy to Pacific Company to the extent it is available from the other parties' Firm Hydro Resources. Such deliveries shall be in the Amount of System Load of Pacific Company interconnected with the other parties hereto and the other parties accept as a limitation on the return of Integration Energy, as provided in Section 6(f) hereof, the availability of transmission capacity or transfer agreements between the non-coordinated resources and loads of Pacific Company's system, and Pacific Company's System; provided, however, that if there is insufficient Integration Energy to supply Pacific Company's System and to refill and hold reservoirs of the Coordinated System, then such Integration Energy shall first be used to refill and hold reservoirs.

Section 7 - Other Coordination Services

(a) A System may store in its own reservoirs and a System with either steam electric resources, firm commitment for receipt of resources, or other assured supply of energy not included in this Service Schedule which, when added to its Firm Load Carrying Capability, provide resources in excess of its firm load carrying requirements; may overdraft its own reservoirs for any purpose and may, with the permission of the Operating Committee, borrow from reservoirs of other Systems to avoid operations of steam units or to supply the requirements of its interruptible customers in its service area, provided that such overdraft or such storing or such borrowing does not jeopardize the Firm Load Carrying Capability of the Coordinated System nor exceed the ability of the borrowing System to restore its own reservoirs from resources other than those included in the coordinated operation to the elevations they would have had if no overdraft had occurred, nor use reservoir storage space required for the operation of the Coordinated System, and provided that such borrowing System shall return the borrowed energy when required to supply the Firm Load Carrying Capability of the Coordinated System at no increased cost to any of the other parties hereto. The operation of the Coordinated System shall be as if no overdraft, storing, or borrowing had occurred.

(b) Such borrowed energy, when borrowed from a reservoir other than a party's own reservoir, when not returned as provided in Section 7(a) above, shall be returned in amounts and at times requested by the lender. Any balance not returned by the end of the Drawdown Period shall be paid for at the rate provided in Section 8.

(c) Any party hereto will accept during the Drawdown Period energy deliveries by another party hereto, in addition to those required for coordinated operation as provided heretofore, which will enable the accepting party to store or hold water in such party's reservoirs; and on request of and as scheduled by the parties, such stored or equivalent water will thereafter be released through the accepting party's plants, whenever in such party's opinion it has generating capacity available for such purpose, and subject to the capacities of interconnecting facilities for the transfer of other power and energy required for coordinated operation as provided heretofore; provided, however, that the obligation to return such energy will terminate whenever the reservoirs on the accepting party's System shall spill. The operation of the Coordinated System shall be as if no additional storage had been made by any party including storage by a party hereto in its own reservoirs from resources other than Firm Hydro Resources, Firm Resources, or Optional Resources.

(d) The use of the reservoirs of the Systems of the parties hereto, for purposes other than coordinated operation provided herein, shall be subject to the first use of the party owning the reservoir, second to the other parties hereto, and last to other parties, and within the limitations provided in paragraph 7(c).

(e) Surplus Peaking Capacity transferred between the parties unless otherwise agreed to shall be paid for as provided in Section 8 hereof.

Section 8 - Charges

(a) Operating Energy

(1) The Operating Energy imbalance between Systems with Firm Hydro Resources shall be paid for at the rate of 2.5 mills per KWH by the party receiving such net energy.

(2) Operating Energy delivered to, or from, a System with Firm Resources from, or to, a System with Firm Hydro Resources or with Firm Resources shall be charged to the pooled account at the following rates:

(i) Firm Hydro Resources and Firm Resources, excepting steam electric plants, at 2.5 mills per KWH, or the incremental cost to the party hereto supplying such energy, whichever is the higher.

(ii) Steam electric plants included as Firm Resources at the incremental cost plus .25 mill per KWH.

(3) Operating Energy received by, or from, a System with Firm Resources through the pooled account shall be paid for by the parties using such pooled energy at the weighted costs for the preceding Refill-Hold Period and Drawdown Period of such pooled energy. Such pooled energy shall be charged out and paid for each month on an estimated basis and readjusted as required from time to time on an estimated basis until rendering of the final annual accounting.

(b) Integration Energy

(1) The Integration Energy imbalance between Systems with Firm Hydro Resources shall be paid for at the rate of 1 mill per KWH by the party receiving such net energy.

(2) Integration Energy delivered to, or from, a System with Firm Resources from, or to, a System with Firm Hydro Resources or with Firm Resources shall be charged to the pooled account at the following rates:

(i) Firm Hydro Resources and Firm Resources, excepting steam electric plants, at 2.5 mills per KWH, or the incremental cost to the party hereto supplying such energy, whichever is the higher.

(ii) Steam electric plants included as Firm Resources at the incremental cost plus .25 mill per KWH.

(3) Integration Energy received by or from a System with Firm Resources through the pooled account shall be paid for by the parties using such pooled energy at the weighted costs for the preceding Refill-Hold Period and Drawdown Period of such pooled energy. Such pooled energy shall be charged out and paid for each month on an estimated basis and readjusted as required from time to time on an estimated basis until rendering of the final annual accounting.

(c) Surplus Peaking Capacity shall be paid for at the rate of twelve dollars ($12) per kilowatt-year.

(d) Borrowed energy not returned shall be paid for at the rate of 2.5 mills per KWH.

(e) Energy produced by storage releases:

(1) At times comparable to the time when water was stored will be returned for a charge of 0.5 mill per KWH.

(2) Between 7:00 A M and 11:00 P M, M S T, Monday through Friday, inclusive, and 7:00 A M to 1:00 P M, M S T, on Saturdays, excepting those days on which the following occur (1) New Year's Day, (2) Memorial Day, (3) Independence Day, (4) Labor Day, (5) Thanksgiving Day, and (6) Christmas Day, when water was stored at other times, will be returned for a charge of 1.0 mill per KWH.

(f) Payment between the parties for energy delivered from Optional Resources shall be at the cost to the party hereto supplying the energy.

(g) Settlement of interchange accounts for the past Refill-Hold Period and Drawdown Period of the Coordinated System shall not be later than May 1 of each year.

Section 9 - Applicability of Interconnection Agreement

Except for matters herein otherwise specifically provided for, this Service Schedule is subject to the terms and provisions of the Interconnection Agreement.

Section 10 - Jurisdiction of Regulatory Authorities

This Schedule is subject to the regulatory powers of any State or Federal Agency having jurisdiction.

Executed in triplicate as of the 23rd day of April, 1958.

THE WASHINGTON WATER POWER COMPANY

By W. L. Blair
Vice President

(CORPORATE SEAL)

ATTEST:

J. N. Wiers
asst. Secretary

PACIFIC POWER & LIGHT COMPANY

By R. H. deLucca
Vice President

(CORPORATE SEAL)

ATTEST:

Secretary

IDAHO POWER COMPANY

By A. Inman
Vice President

(CORPORATE SEAL)

ATTEST:

B. M. Rogers
Asst. Secretary

SERVICE SCHEDULE II-A

SECONDARY ENERGY TRANSACTIONS

IDAHO POWER COMPANY
THE WASHINGTON WATER POWER COMPANY
PACIFIC POWER & LIGHT COMPANY

THIS AGREEMENT, Service Schedule II-A, dated April 23, 1958, by and between IDAHO POWER COMPANY, THE WASHINGTON WATER POWER COMPANY and PACIFIC POWER & LIGHT COMPANY, is agreed to under and as a part of Interconnection Agreement dated April 23, 1958, between the parties, hereinafter referred to as "Interconnection Agreement."

Section 1 - Term

This Service Schedule shall become effective upon the date first above written, and shall remain in force and effect through August 31, 1968; unless terminated by any party by written notice given three years prior to said date, it shall continue in effect thereafter from year to year until terminated by any party as of August 31 of any year subsequent to 1968 by written notice given to the other parties not less than three (3) years in advance of the intended date of termination.

Section 2 - Energy supplied between Parties

(a) A party (supplying party) hereto will make available to other parties hereto, upon request of any such other party or parties, within the limits of transmission capacity available as determined by the supplying party, such surplus hydroelectric energy as the supplying party, in its sole judgment, may have available from time to time.

(b) A party (supplying party) hereto will make available to other parties hereto, upon request of any such other party or parties, within the limits of transmission capacity available as determined by the supplying party, such surplus steam electric energy from owned or leased steam electric plants as the supplying party, in its sole judgment, may have available from time to time.

(c) Any party (supplying party) hereto, upon request of any other party hereto, will purchase and make available to such other party hereto, within the limits of transmission capacity available as determined by the supplying party, such surplus energy over and above the supplying party's own needs as the supplying party can schedule and purchase from other supply sources with which it has an interchange agreement.

Section 3 - Charges

(a) The charge for secondary energy supplied in accordance with paragraph 2(a) of this Service Schedule shall be 2.5 mills per kwh or such a rate which provides a delivered cost equal to the delivered cost of secondary energy under any Bonneville Power Administration rate in effect at the time such charge is made.

(b) The charge for surplus energy supplied in accordance with paragraph 2(b) of this Service Schedule shall be the incremental cost of such energy, plus one mill per KWH.

(c) The charge for surplus energy supplied in accordance with paragraph 2(c) of this Service Schedule shall be the amount paid by the supplying party for such surplus energy, including incremental taxes that may be applicable plus the simultaneous supply of incremental losses to be agreed upon at the time delivery of such surplus energy is scheduled.

Section 4 - Applicability of Interconnection Agreement

Except for matters herein otherwise specifically provided for, this Schedule is subject to the terms and provisions of the Interconnection Agreement.

Section 5 - Jurisdiction of Regulatory Authorities

This Schedule is subject to the regulatory powers of any State or Federal Agency having jurisdiction.

Executed in triplicate as of the 23rd day of April, 1958.

THE WASHINGTON WATER POWER COMPANY

By ____________________
Vice President

(CORPORATE SEAL)

ATTEST:

____
Secretary

PACIFIC POWER & LIGHT COMPANY

By ____________________
President

(CORPORATE SEAL)

ATTEST:

____
Secretary

IDAHO POWER COMPANY

By ____________________
Vice President

(CORPORATE SEAL)

ATTEST:

____
Secretary

SERVICE SCHEDULE III-A

TRANSMISSION AGREEMENT

IDAHO POWER COMPANY
THE WASHINGTON WATER POWER COMPANY
PACIFIC POWER & LIGHT COMPANY

THIS AGREEMENT, Service Schedule III-A, dated April 23, 1958, by and between IDAHO POWER COMPANY, THE WASHINGTON WATER POWER COMPANY, and PACIFIC POWER & LIGHT COMPANY, is agreed to under and as a part of Interconnection Agreement dated April 23, 1958, between the parties, hereinafter referred to as "Interconnection Agreement."

Section 1 - Term

This Service Schedule shall become effective upon the date of execution hereof, and shall remain in force and effect through August 31, 1983; unless terminated by any party by written notice given three years prior to said date, it shall continue in effect thereafter from year to year until terminated by any party as of August 31 of any year subsequent to 1983 by written notice given to the other parties not less than three (3) years in advance of the intended date of termination.

Section 2 - Transfer and Displacement of Power and Energy

The interconnecting transmission lines and facilities constructed and available pursuant to Article VI of the Interconnection Agreement, together with the lines and facilities comprising the respective Systems of the parties as now or hereafter existing and constructed, shall, in addition to serving the primary functions as set forth in Service Schedules I-A, IV-A, and V-A, be available to the parties hereto for the simultaneous transfer or displacement of power and energy from a major transmission interconnecting point on the perimeter of a party's System to another major transmission interconnecting point on the perimeter of that party's System at the request of, and for delivery to, another party hereto, subject to the limits of capacity, loading and network operating characteristics of the transmission facilities involved as determined by the owner of the transmission facilities, provided that no such transfers or displacements shall be made to any segregated load of a party hereto when such segregated load is in, or adjacent to, the service area of another party hereto.

Section 3 - Scheduling

Power and energy to be transferred or displaced shall be scheduled with the transmitting party as far in advance as possible. The transmitting party shall not be obligated to deliver more energy than received and shall be entitled to receive a simultaneous supply of additional energy to compensate for incremental losses associated with the delivery of such energy, unless otherwise agreed to by the transmitting party.

Section 4 - Availability of Transmission Capacity

The transmission capacity available on a party's System for the use herein provided shall be that amount determined by such party to be in excess of the capacity required for the party's System load, firm power and energy commitments (including transfer of energy for coordinated operation), and maximum utilization of secondary energy on the party's System.

Section 5 - Charges

In consideration of the mutual benefits obtained by the parties under the Interconnection Agreement and the Service Schedules, through the use of the parties' transmission facilities, there will be no charge for the specific use of the transmission facilities herein provided.

Section 6 - Applicability of Interconnection Agreement

Except for matters herein otherwise specifically provided for, this Service Schedule is subject to the terms and provisions of the Interconnection Agreement.

Section 7 - Jurisdiction of Regulatory Authorities

This Schedule is subject to the regulatory powers of any State or Federal Agency having jurisdiction.

Executed in triplicate as of the 23rd day of April, 1958.

THE WASHINGTON WATER POWER COMPANY

By M. L. Blair
Vice- President ase

(CORPORATE SEAL)

ATTEST:

J W Willis
asst. Secretary

PACIFIC POWER & LIGHT COMPANY

By E. R. H. de Luccia
Vice President

(CORPORATE SEAL)

ATTEST:

Secretary

IDAHO POWER COMPANY

By T. Roach
Vice President

(CORPORATE SEAL)

ATTEST:

Asst. Secretary

SERVICE SCHEDULE III-B

WHEELING AGREEMENT

Idaho Power Company SEP 7 2 41 PM '72

THIS AGREEMENT, Service Schedule III-B, dated July 10, 1972, by and between IDAHO POWER COMPANY and PACIFIC POWER & LIGHT COMPANY, is agreed to under and as a part of Interconnection Agreement dated April 23, 1958, between the parties, hereinafter referred to as "Interconnection Agreement".

Section 1 - Term

This Service Schedule shall become effective upon the date of execution hereof, and shall remain in force and effect through August 31, 1978, unless terminated by either party by written notice given three years prior to said date. It shall continue in effect thereafter from year to year until terminated by either party as of August 31 of any year subsequent to 1978 by written notice given to the other party not less than three (3) years in advance of the intended date of termination.

Section 2 - Transmission Provided by Idaho Company

Subject to the availability of capacity as determined by the Idaho Company, the Idaho Company will, for the account of Pacific Company, accept power and energy scheduled at interconnections at the western side of the Idaho Company's system, and will re-schedule for delivery such power and energy, for the account of Pacific Company, at interconnections at the eastern side of Idaho Company's system.

Section 3 - Compensation for Transmission

Pacific Company will schedule concurrently to Idaho Company an additional amount of energy to compensate Idaho Company for the use of its facilities and to replace losses. Until otherwise mutually agreed, such additional energy shall be equal to 10 percent between October 1 and April 30 and shall be equal to 20 percent between May 1 and September 30 of the energy scheduled for delivery to the account of Pacific Company.

Section 4 - Amount of Power and Energy to be Wheeled

Transfers through Idaho's system shall not exceed 100,000 kilowatts unless otherwise agreed, subject to the availability of capacity as determined by Idaho Company, in which case additional losses if any, will be determined at the time.

Section 5 - Scheduling

Schedules of transfers across the Idaho Company system shall be arranged as far in advance as practicable but may be modified by either system's dispatchers to meet emergency or changing system conditions.

Section 6 - Applicability of Interconnection Agreement

Except for matters herein otherwise specifically provided for, this Service Schedule is subject to the terms and provisions of the Interconnection Agreement.

Section 7 - Jurisdiction of Regulatory Authorities

This Service Schedule is subject to the regulatory powers of any State or Federal Agency having jurisdiction.

Executed in duplicate as of the ____ day of ________, 1972.

IDAHO POWER COMPANY

Vice President

CORPORATE SEAL

Secretary

PACIFIC POWER & LIGHT COMPANY

Vice President

CORPORATE SEAL

Assistant Secretary

APPROVED

Distribution: 7-10-72

1 - Signed R B Lisbakken
PP&LCo

1 - " J E Bruce
IPCo
1 - " G J Hall
1 - Copy R A Hogg
P A Oakes
J W Lewis
JE Garlinghouse
WB Mitchell

SERVICE SCHEDULE VI-B

INTERCHANGE AGREEMENT
BETWEEN
IDAHO POWER COMPANY
AND
PACIFIC POWER & LIGHT COMPANY

THIS AGREEMENT, Service Schedule VI-B, entered into as of this 16th day of September, 1974 between IDAHO POWER COMPANY ("Idaho Company") and PACIFIC POWER & LIGHT COMPANY ("Pacific Company"), said corporations being referred to hereinafter as the "Parties", is agreed to under and as part of Interconnection Agreement dated April 23, 1958, between the Parties, hereinafter referred to as "Interconnection Agreement";

W I T N E S S E T H:

WHEREAS, the Idaho Company is engaged in the generation, distribution and sale of electric power and energy in the states of Idaho and Oregon and its power system is interconnected with other power systems operating in the Intermountain and Northwest areas; and

WHEREAS, the Pacific Company is engaged in generation, distribution and sale of electric power and energy in the states of Oregon, Washington, California, Wyoming, Montana and Idaho and its power system is interconnected with other power systems operating in the Intermountain and Northwest areas; and

WHEREAS, the facilities of the Idaho Company are interconnected with the facilities of the Pacific Company at several points which makes possible the exchange of power and energy between their respective systems to the benefit of the areas served by each system;

NOW, THEREFORE, in consideration of the premises and mutual covenants

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and conditions hereinafter set forth, the Parties agree as follows:

1. Term - This Service Schedule shall be effective as of June 1, 1976 and shall remain in force for an initial term of ten years from said date, and shall continue in effect thereafter unless terminated by either party upon written notice to the other party not less than three years prior to any desired date of termination.

2. Interchange Energy - The term "interchange energy" as used herein shall mean power and energy from power resources available to the supplying party and delivered to the receiving party for system requirements including but not limited to, system loads, emergencies, periods of maintenance of its facilities, delay in starting its generating units not in active service, or displacement of more expensive energy resources.

3. Supply of Interchange Energy - Each party will supply interchange energy when and as requested by the other party in such quantities as the supplying party in its sole judgment may have available from time to time.

4. Delivery Points - The delivery points for energy interchanged hereunder shall be at the existing points of interconnection between the systems or such other points of interconnection as may hereafter be established or designated by mutual agreement.

5. Energy Accounting - An account of energy interchanged shall be maintained by each party, based upon records of the quantities of interchange energy scheduled by the respective load dispatchers hour by hour. Such energy shall be credited to the supplying party in the interchange energy accounts.

6. Return of Energy - Interchange energy delivered by either party to the other hereunder shall be returned, one kilowatt-hour for each kilowatt-hour

delivered, except as hereinafter provided, and shall be scheduled for delivery at the points of interconnection at times and at rates of delivery to be mutually agreed upon by representatives of the Parties.

7. Transfer of Balance in Prior Exchange Account - Any balance remaining in the exchange account established pursuant to Service Schedule VI-A, dated August 3, 1964, is hereby transferred to the interchange energy account established pursuant to Section 5 of this Service Schedule VI-B.

8. Settlement - It is the intent of the Parties that interchange energy accounts shall be balanced by the delivery of energy as promptly as circumstances permit and under conditions similar to that under which the energy was received unless the authorized representatives of the Parties agree that the return of energy may be delayed until a more suitable time. Balances due will be carried forward provided, however, that a party who has remained a creditor party for a period of 18 months or more may request and receive the return of energy from the other party; or such creditor party may request and receive payment for such balance, at a mutually agreed price.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized officers and their corporate seals to be affixed, as of the day and year first herein written.

ATTEST:

Secretary

PACIFIC POWER & LIGHT COMPANY

By

Vice President

ATTEST:

Secretary

IDAHO POWER COMPANY

By W. D. Ames

Title Vice President

TRANSMISSION LINE AGREEMENT

IDAHO POWER COMPANY
THE WASHINGTON WATER POWER COMPANY

THIS AGREEMENT entered into this 23rd day of April, 1958, by and between IDAHO POWER COMPANY (Idaho) and THE WASHINGTON WATER POWER COMPANY (Washington).

WHEREAS, the parties hereto, together with PACIFIC POWER AND LIGHT COMPANY, entered into an Interconnection Agreement dated April 23, 1958, hereinafter referred to as "Interconnection Agreement"; and,

WHEREAS, the Interconnection Agreement provides that each party shall construct a portion of the transmission facilities required to carry out the terms of said agreement; and,

WHEREAS, as partial consideration for the execution of the Interconnection Agreement, the parties hereto have agreed that Washington should advance to Idaho part of its construction costs and reimburse Idaho for part of its expenses, as hereinafter more particularly set forth,

NOW, THEREFORE, the parties agree as follows:

Section 1 - Term

This Agreement shall become effective on the date of execution hereof, and shall remain in force and effect through July 31, 2005.

Section 2 - Washington to Advance Cost of Construction

(a) Washington will advance to Idaho on the basis of Idaho's estimate of construction requirements for each succeeding month, all costs of construction of the section of transmission line between Idaho's Engineer Station 1600 plus 97.3 (on the section line between Sections 16 and 21, Township 1 North, Range 48 East, W M) at Imnaha, and Idaho's Engineer Station 2697 plus 20.8 (in Section 30, Township 29 North, Range 3 West, B M) on or near Divide Creek (which section of transmission line is hereinafter referred to as "line"), being a portion of the transmission line described in Paragraph 6.1(a) of said Interconnection Agreement, such advances to be made within ten (10) days of receipt of statement from Idaho.

(b) Idaho will report all expenditures to Washington in reasonable detail each month, and shall adjust the succeeding month's estimate by the difference between the preceding month's actual expenditures and the estimate previously furnished.

Section 3 - Accounting Provisions

(a) Idaho shall not be required to pay interest on the advances made by Washington.

(b) Washington will reimburse Idaho for all costs of operation and maintenance of said line, all property taxes thereon, and shall advance the cost of any necessary replacements, within ten (10) days after receipt of detailed statements from Idaho.

(c) Idaho will record depreciation of the line on its books, which amount will be charged against the advance received from Washington and concurrently credited to depreciation reserve.

Section 4 - Operation and Maintenance

(a) Idaho agrees to operate and maintain said line in good operating condition in accordance with standard engineering practice in the industry.

Section 5 - Transmission of Power

(a) In consideration of the above advances to be made by Washington and of the other terms of this agreement, Idaho agrees to transfer over said line all power scheduled by Washington within the capacity of the line.

Section 6 - Option to Purchase

(a) In further consideration of said advance by Washington and the terms of this agreement, Idaho hereby grants to Washington, its successors and assigns, the right and option to purchase said line (subject to obtainment of such regulatory authorizations as may at the time be required) at any time during the term of this agreement. Said option to purchase shall be at the original cost of said line, less all depreciation accrued on Idaho's books with respect to said line. On the exercise of said option, the line shall be sold and transferred to Washington, its successors or assigns, and all advances made by Washington to Idaho for the construction or replacements of the line shall be retained by Idaho in payment for the sale and transfer thereof.

(b) The option to purchase herein granted may be exercised by Washington by giving written notice by registered or certified mail directed to Idaho at its home office at Boise, Idaho, which notice shall specify the date and time the transfer is to be effected, which shall not be less than three (3) months from the date of mailing such notice.

Section 7 - Termination

In the event that the option provided in Section 6 hereof, for the purchase by Washington of said line, is not exercised prior to the expiration of the term of this agreement, said option shall terminate, and the remaining balance, if any, of the advances provided by Washington shall be cancelled.

Section 8 - Jurisdiction of Regulatory Authorities

This schedule is subject to the regulatory powers of any state or federal agency having jurisdiction.

EXECUTED in duplicate as of the 23rd day of April, 1958.

IDAHO POWER COMPANY

By ______________________
Vice President.

(CORPORATE SEAL)
ATTEST:

____
asst. Secretary.

THE WASHINGTON WATER POWER COMPANY

By ______________________
Vice - President.

(CORPORATE SEAL)

ATTEST:

____
asst. Secretary.

700 N.E. Multnomah, Suite 550
Portland, Oregon 97232

PACIFICORP
PACIFIC POWER UTAH POWER

April 14, 2000

Randall O. Cloward
Avista Corporation
1411 East Mission Avenue
Spokane, Washington 99220

James M. Collingwood
Idaho Power Company
1211 West Idaho Street
Boise, Idaho 83707

Dear Sirs:

PacifiCorp, Avista Corporation ("Avista") and Idaho Power Company ("Idaho") are "Parties" to an April 23, 1958 Interconnection Agreement. Various services are provided under the Interconnection Agreement pursuant to Service Schedules attached thereto. The Parties hereby mutually agree to terminate Service Schedule III-A, Transmission Agreement, effective May 1, 2000.

PacifiCorp will file a termination notice for Service Schedule III-A with the Federal Energy Regulatory Commission. Avista and Idaho will provide a Certificate of Concurrence to accompany such filing.

Please indicate concurrence with termination of Service Schedule III-A by executing the three originals of this Letter Agreement in the space provided on the second page and return two of the three originals to PacifiCorp, keeping one original for your files. PacifiCorp will forward one original signed by the other party to Avista and Idaho.

Sincerely,

David B. Cory
Transmission Account Manager

DBC/gha

ACCEPTED AND AGREED TO:

Avista Corporation
By: Randall Cloward
Title: Director Transmission Ops
Date: 5/2/00

Idaho Power Company
By: James M Collingwood
Title: GM Operation & Planning
Date: MAY 10, 2000

REVISED SHEETS

Washington Water Power

December 10, 1990 WP-PS90-4551

Mr. Jim M. Collingwood
Manager, Power Operations
Idaho Power Company
P.O. Box 70
Boise, Idaho 83707

Dear Mr. Collingwood:

This Letter Agreement sets forth the construction and O&M responsibilities between Idaho Power Company ("IPC") and The Washington Water Power Company ("WWP") for the proposed IPC Remote Terminal Unit ("RTU") addition and metering replacement at WWP's Lolo Substation. A one-line diagram of the Lolo Substation 230 kV bus is attached hereto and designated as Exhibit A.

Project History

IPC is installing a new Energy Management System at its System Dispatch Center in Boise. In conjunction with this new system, IPC proposes to add a new RTU at WWP's Lolo Substation to monitor the WWP/IPC point of interconnection.

The metering and line loss compensation equipment originally installed under the Interconnection Agreement dated April 23, 1958 no longer meets WWP's accuracy standards and shall be replaced by WWP.

Project Description

WWP and IPC will work together to install RTU equipment for monitoring compensated watts, vars, and kWh quantities on the 230 kV Lolo-Oxbow Transmission Line (OCB R-345). A communications circuit will be provided (by the Bonneville Power Administration) to transmit those quantities from WWP's Lolo Substation to IPC's System Dispatch Center in Boise.

WWP will install new bi-directional watthour and varhour (Scientific Columbus type JEM-1) meters on OCB R-345. The meters will compensate for line loss and charging current, and provide analog MW and Mvar signals to the RTU.

Metering for Auxiliary Bus OCB R-350 will remain unchanged. When the 230 kV Lolo-Oxbow Transmission Line is fed from OCB R-350, uncompensated MW and Mvar shall remain switch selectable as an alternate signal, but no kWh output pulse will be available for the IPC RTU.

Construction Responsibilities at WWP's Lolo Substation

IPC, at its expense, shall:

1. Provide, install, and test the RTU.
2. Assist in the termination of external cables on the RTU.
3. Provide communication circuit and assist in its installation.
4. Provide RTU training to WWP Technicians.
5. Participate with WWP in jointly testing and energizing the project.

WWP, at IPC's expense, shall:

1. Provide a 30 amp, 125 VDC source to power the RTU.
2. Provide, install, and test the 'in' and 'out' kWh pulse splitters.
3. Provide and install a multiplier relay for breaker indication.
4. Modify the existing switchboard panels as necessary, including wiring from switchboard panels and DC service panels to termination blocks on the RTU.
5. Provide and install microwave communication equipment at the Lolo Substation.

WWP, at its expense, shall:

1. Provide floor space for a new 19" RTU rack.
2. Provide a 230 kV Bus voltage analog source from existing transducer.
3. Provide and install bi-directional watthour meter on OCB R-345.
4. Provide and install bi-directional varhour meter on OCB R-345.
5. Provide compensated analog MW and Mvar signals to the RTU.
6. Participate with IPC in jointly testing and energizing the project.

Schedule

This work is scheduled to begin January 7, 1991, and be completed by January 31, 1991.

Metering Discrepancies

The kWh 'in' and 'out' pulses of the watthour meter will be split and fed into two separate accumulating devices for WWP's Supervisory Control and Data Acquisition ("SCADA") system and IPC's Energy Management System. Should discrepancies occur, they will be resolved by WWP and IPC operation staff and/or normal equipment maintenance.

WWP will continue to use the hourly freeze signal generated by BPA for its accumulating device, and IPC shall use an hourly freeze signal generated by the RTU for its accumulating device. If timing discrepancies occur between these two hourly signals, WWP shall install, at IPC's expense, IPC's Common Freeze Module that provides a single source freeze signal for the two separate accumulating devices.

Line Loss Compensation

WWP intends to duplicate the existing compensation network with the new compensated watthour and varhour meters. If an exact duplication is not possible, WWP will use an alternate loss compensation method that is mutually agreeable to WWP and IPC.

Reimbursement

Per the Interconnection Agreement dated April 23, 1958, WWP considers the RTU portion of this project to be a technological upgrade of telemetering and communications equipment (all existing load control equipment continues to be operational and functional), and, hence, not necessary for the operations under the 1958 Agreement.

Therefore, IPC shall reimburse WWP for construction work involved with IPC's RTU installation at WWP's Lolo Substation within 30 days of receipt of an invoice from WWP. The present cost estimate for this work is $13,400, however, IPC will be billed on an actual cost basis, including time, material, travel, lodging (if necessary), and applicable overheads.

The metering replacement portion of this project will be at the sole expense of WWP.

Ownership, Operations and Maintenance

WWP shall operate and maintain the IPC-provided RTU and communications equipment within WWP's Lolo Substation at no expense to IPC. IPC shall retain ownership, provide spare parts as necessary, and replace the RTU if, and when, it becomes obsolete or inadequate.

WWP shall own, operate, and maintain the new metering equipment.

If the above conditions are acceptable, please so indicate in the space provided (on each copy), and return both signed copies to my office. A fully signed original Letter Agreement will be returned to you for your records.

Any questions concerning this project should be addressed to Mr. Hollie Smith of my office at (509) 482-4961.

Sincerely,

RL Storro

Richard Storro
Manager,
System & Hydro Operations
RBS

c:	H. G. Smith, WWP	S. V. Fisher, WWP	H. A. Anderson, WWP
	W. K. Miller, WWP	M. S. Nissley, WWP	W. J. Choma, WWP

Idaho Power Company

Accepted by: James M Collingwood Date: December 21, 1990

Title: Manager, Power Operations

AMENDMENT

OMITTED

Idaho Power's Supplemental Response To Kootenai Request No. 1.2

FERC Electric Rate Schedule No. 69

Interconnection and Transmission Services Agreement

Between Idaho Power Company

And

Sierra Pacific Power Company

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

Idaho Power Company
Docket Nos. ER03-953-001,
ER03-954-001, and
ER03-964-001
July 26, 2004

Steptoe & Johnson, LLP
Attorneys at Law
Attention: Gary A. Morgans
Attorney for Idaho Power Company
1330 Connecticut Avenue, NW
Washington, DC 20036-1795

RE: Compliance Filing

Dear Mr. Morgans:

On September 12, 2003, you filed on behalf of Idaho Power Company (Idaho Power) various agreements in compliance with Commission's Letter Orders dated August 11, 2003 in Docket Nos. ER03-953-000 and ER03-954-000, and August 13, 2003 in Docket No. ER03-964-000 (collectively, Letter Orders). The Letter Orders directed Idaho Power to provide designations for the various agreements to comply with Order No. 614 and under Section 35.9 (a) of the Commission's regulations. Idaho Power's submittals are accepted as being in compliance with the Letter Orders and are designated as shown on the enclosure.

This filing was noticed on September 22, 2003 with comments due on October 3, 2003. No protests or adverse comments were received. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.214). Any opposed or untimely filed motion to intervene is governed by the provisions of Rule 214.

This acceptance for filing shall not be construed as constituting approval of the referenced filing or of any rate, charge, classification or any rule, regulation or practice affecting such rate or service contained in your tariff; nor shall such acceptance be deemed as recognition of any claimed contractual right or obligation associated therewith; and such acceptance is without prejudice to any findings or orders which have been or any which may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Idaho Power.

This action is taken pursuant to the authority delegated to the Director, Tariffs and Market Development - West under 18 C.F.R. § 375.307. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713.

Sincerely,

Jamie L. Simler, Director
Division of Tariffs and Market
Development – West

Enclosure

Idaho Power Company
Rate Schedule Designations

Designation	Description
Docket No. ER03-953-001	
(1) First Revised FERC Electric Rate Schedule No. 146 (Original Sheet Nos. 1 - 7)	Letter Agreement with PacifiCorp, Bonneville Power Administration and Washington Water Power Company Effective Date: October 1, 1990
(2) First Revised FERC Electric Rate Schedule No. 87 (Original Sheet Nos. 1 - 110) (Supersedes FERC Electric Rate Schedule No. 87)	Restated Transmission Services Agreement with PacifiCorp Electric Operations Effective Date: August 11, 2003
(3) First Revised Sheet Nos. 18 and 19 and Original Sheet No. 18A under First Revised FERC Electric Rate Schedule No. 87 (Supersedes Original Sheet No. 18 and 19)	Revised Sheets to the Restated Transmission Services Agreement Effective Date: August 11, 2003
(4) Original Sheet Nos. 1 - 217 under First Revised FERC Electric Rate Schedule No. 77 (Supersedes FERC Electric Rate Schedule No. 77)	Transmission Services Agreement with the United States Department of Energy acting by and through Bonneville Power Administration Effective Date: August 11, 2003
(5) Original Sheet Nos. 218 – 230 under First Revised FERC Electric Rate Schedule No. 77 (Supersedes FERC Electric Rate Schedule No. 77)	Amendment to Transmission Services Agreement Effective Date: August 11, 2003
(6) First Revised Sheet No. 1 under First Revised FERC Electric Rate Schedule No. 77 (Cancels First Revised FERC Electric Rate Schedule No. 77)	Notice of Cancellation Effective Date: August 13, 2003

	Designation	Description
(7)	First Revised FERC Electric Rate Schedule No. 75 (Original Sheet Nos. 1 - 51) (Supersedes FERC Electric Rate Schedule No. 75)	Agreement for Supply of Power and Energy with the Utah Associated Municipal Power Systems / Effective Date: August 11, 2003
(8)	Original Sheet Nos. 52 and 53 under First Revised FERC Electric Rate Schedule No. 75	Letter Agreement Amending Exhibit 2 of the Agreement for Supply of Power and Energy with The Utah Associated Municipal Power Systems Effective Date: August 11, 2003
(9)	Service Agreement No. 53 under FERC Electric Tariff, First Revised Volume No. 6	Power Supply Agreement with the Utah Associated Municipal Power Systems / Effective Date: June 16, 2000
(10)	First Revised FERC Electric Rate Schedule No. 28 (Original Sheet Nos. 1 - 56) (Supersedes FERC Electric Rate Schedule No. 28)	Interconnection Agreement with the Washington Water Power Company and Pacific Power & Light Company / Effective Date: August 11, 2003
(11)	First Revised Sheet Nos. 42 – 44 under First Revised FERC Electric Rate Schedule No. 28	Notice of Termination for Service Schedule III-A / Effective Date: August 11, 2003
(12)	First Revised FERC Electric Rate Schedule No. 69 (Original Sheets Nos. 1 – 154) (Supersedes FERC Electric Rate Schedule No. 69)	Interconnection and Transmission Services Agreement with Sierra Pacific Power Company Effective Date: August 11, 2003
(13)	First Revised Sheet Nos. 7 – 9) under First Revised FERC Electric Rate Schedule No. 69 (Supersedes Original Sheet Nos. 7 – 9)	Notice to Terminate Section 4.1 regarding the transfer of Utah Power & Light Company to Sierra Pacific Power Company Effective Date: August 11, 2003

	Designation	Description
		Docket No. ER03-954-001
(14)	FERC Electric Rate Schedule No. 140 (Original Sheet No. 1)	Letter Agreement for Transmission Service to Bonneville Power Administration at Vigilante Electric Cooperative Effective Date: August 18, 1995
(15)	Service Agreement No. 165 under FERC Electric Tariff First Revised Volume No. 5	Firm Point-to-Point Transmission Service Agreement with Bonneville Power Administration Effective Date: August 11, 2003
(16)	Service Agreement No. 166 under FERC Electric Tariff First Revised Volume No. 5	Facilities Agreement with Montana Power Company and Bonneville Power Administration Effective Date: October 1, 1996
(17)	FERC Electric Rate Schedule No. 141 (Original Sheet Nos. 1 – 7)	Letter Agreement which provides a supplemental control area service by Bonneville Power Administration / Effective Date: December 12, 1996
(18)	FERC Electric Rate Schedule No. 142 (Original Sheet Nos. 1 – 4)	Letter Agreement to install thermal relay protection at Idaho Power Company's American Falls Substation as Requested by PacifiCorp Effective Date: February 17, 1999
(19)	FERC Electric Rate Schedule No. 143 (Original Sheet Nos. 1 – 4)	Remedial Action Scheme Agreement with Pacific Gas and Electric Company and PacifiCorp Effective Date: March 8, 1999
(20)	FERC Electric Rate Schedule No. 144 (Original Sheet Nos. 1 – 6)	Enhancement to Pacific Gas and Electric 1999 Remedial Action Scheme / Effective Date: January 30, 2002

Designation	Description
(21) FERC Electric Rate Schedule No. 145 (Original Sheet Nos. 1 – 10)	Letter Agreement proposing a Second Point of Delivery Quartz-Elm Street 69 kV Transmission Line Tap with Oregon Trail Electric Consumers Cooperative, Inc. / Effective Date: February 15, 2002

Docket No. ER03-964-001
Effective Date: August 13, 2003

(22) First Revised Sheet No. 20 under First Revised FERC Electric Rate Schedule No. 75 (Supersedes Original Sheet No. 20)	Amendment to Exhibit 2 of the Agreement for Supply of Power and Energy with the Utah Associated Municipal Power Systems
(23) Second Revised Sheet No. 20 under First Revised FERC Electric Rate Schedule No. 75 (Supersedes First Revised Sheet No. 75)	Amendment to Exhibit 2 of the Agreement for Supply of Power and Energy with the Utah Associated Municipal Power Systems
(24) Third Revised Sheet No. 20 under First Revised FERC Electric Rate Schedule No. 75 (Supersedes Second Revised Sheet No. 20)	Amendment to Exhibit 2 of the Agreement for Supply of Power and Energy with the Utah Associated Municipal Power Systems
(25) Fourth Revised Sheet No. 20 under First Revised FERC Electric Rate Schedule No. 75 (Supersedes Third Revised Sheet No. 20)	Amendment to Exhibit 2 of the Agreement for Supply of Power and Energy with the Utah Associated Municipal Power Systems
(26) First Revised Sheet Nos. 132 - 172 under First Revised FERC Electric Rate Schedule No. 77 (Supersedes Original Sheet No. 132 - 172)	Revised Sheets to the Transmission Services Agreement

Designation		Description
(27)	Second Revised Sheet Nos. 132 - 172 under First Revised FERC Electric Rate Schedule No. 77 (Supersedes First Revised Sheet Nos. 132 - 172)	Revised Sheets to the Transmission Services Agreement
(28)	First Revised FERC Electric Rate Schedule No. 72 (Original Sheet Nos. 1 – 50) (Supersedes FERC Electric Rate Schedule No. 72)	Transmission Services Agreement with The City of Seattle
(29)	First Revised Sheet No. 38 under First Revised FERC Electric Rate Schedule No. 72 (Supersedes Original Sheet No. 38)	Annual Revised Exhibit 1 - Monthly Contract Demand Values
(30)	Second Revised Sheet No. 38 under First Revised FERC Electric Rate Schedule No. 72 (Supersedes First Revised Sheet No. 38)	Annual Revised Exhibit 1 - Monthly Contract Demand Values
(31)	Third Revised Sheet No. 38 under First Revised FERC Electric Rate Schedule No. 72 (Supersedes Second Revised Sheet No. 38)	Annual Revised Exhibit 1 - Monthly Contract Demand Values
(32)	Fourth Revised Sheet No. 38 under First Revised FERC Electric Rate Schedule No. 72 (Supersedes Third Revised Sheet No. 38)	Annual Revised Exhibit 1 - Monthly Contract Demand Values
(33)	Fifth Revised Sheet No. 38 under First Revised FERC Electric Rate Schedule No. 72 (Supersedes Fourth Revised Sheet No. 38)	Annual Revised Exhibit 1 - Monthly Contract Demand Values
(34)	Sixth Revised Sheet No. 38 under First Revised FERC Electric Rate Schedule No. 72 (Supersedes Fifth Revised Sheet No. 38)	Annual Revised Exhibit 1 - Monthly Contract Demand Values

Designation	Description
(35) First Revised FERC Electric Rate Schedule No. 74 (Original Sheet Nos. 1 – 25) (Supersedes FERC Electric Rate Schedule No. 74)	Agreement for Supply of Power and Energy with Washington City, Utah
(36) First Revised Sheet No. 18 under First Revised FERC Electric Rate Schedule No. 74 (Supersedes Original Sheet No. 18)	Annual Revised Part A: Monthly Contract Demand Values
(37) Second Revised Sheet No. 18 under First Revised FERC Electric Rate Schedule No. 74 (Supersedes First Revised Sheet No. 18)	Annual Revised Part A: Monthly Contract Demand Values
(38) Third Revised Sheet No. 18 under First Revised FERC Electric Rate Schedule No. 74 (Supersedes Second Revised Sheet No. 18)	Annual Revised Part A: Monthly Contract Demand Values
(39) First Revised Sheet No. 1 under First Revised FERC Electric Rate Schedule No. 74 (Cancels First Revised FERC Electric Rate Schedule No. 74)	Notice of Cancellation

<u>KOOTENAI'S DATA REQUEST NO. 1.6</u>:

Please admit or deny that the portion of Lolo-Oxbow line from Lolo to Imnaha is not owned by Idaho Power and is not a part of Idaho Power's electrical system. If deny, please explain how a transmission line not owned by Idaho Power is a part of Idaho Power's electrical system.

<u>IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.6</u>:

Idaho Power admits that the portion of the Oxbow to Lolo transmission line from Imnaha to Lolo is not owned by Idaho Power. The portion of the Oxbow to Lolo transmission line from Imnaha to Lolo is in Idaho Power's Balancing Authority Area, meaning Idaho Power has responsibility for operating the line and the transmission paths pursuant to the rules and regulations of the Federal Energy Regulatory Commission ("FERC"), North American Energy Reliability Council ("NERC"), and Western Energy Coordinating Council ("WECC").

<u>KOOTENAI'S DATA REQUEST NO. 1.8</u>:

Please reference Answer at ¶ 40, and Kootenai's Complaint Exhibit 102 at page 38, stating capacity on the portion of the Lolo-Oxbow line from Lolo substation to Imnaha is posted on Avista's OASIS as available transmission capacity on the Avista transmission system.

a) Please explain how the capacity on the line from Lolo substation to Imnaha can be posted as available on Avista's transmission system, as represented to FERC, if the POD for deliveries from Avista's system to Idaho Power's system is at the Lolo substation, as asserted by Idaho Power in its Answer ¶ 53.

b) Please provide any supplemental filings to FERC subsequent to the FERC order in Kootenai's Complaint Exhibit 102 at page 38-39, wherein Idaho Power or Avista have informed FERC that the POD to Idaho Power's system is at the Lolo substation. If none exist, please so specify.

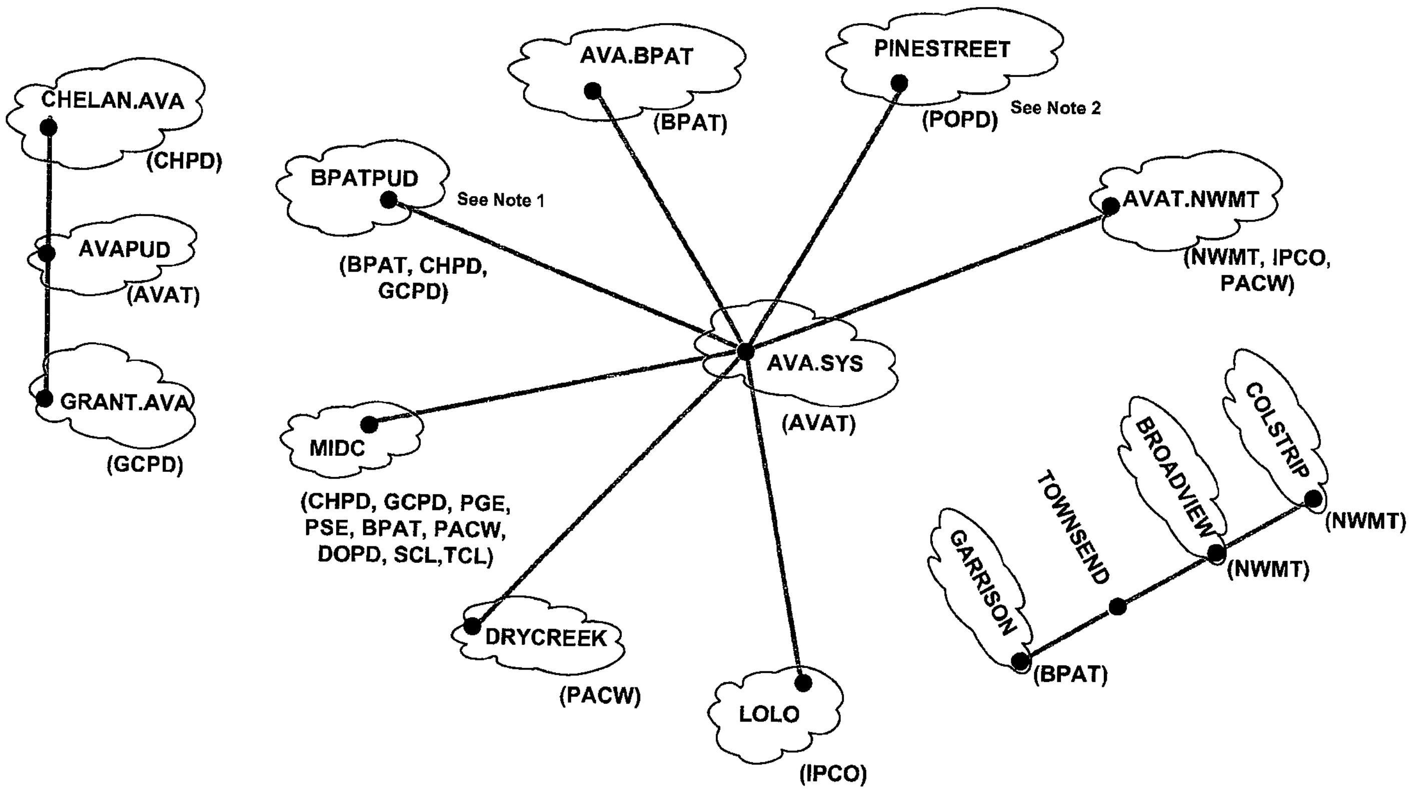
<u>IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.8</u>:

a) On February 16, 2012, Idaho Power could not find any posting of capacity to Imnaha on Avista's OASIS. Moreover, Avista's OASIS map does not show a POR/POD of Imnaha. Avista's Available Transfer Capability Implementation Document ("ATCID") does not reference any capacity from Lolo to Imnaha. Please see the attached documents.

b) Idaho Power is not aware of any supplemental filings.

ATTACHMENT 1 - RESPONSE TO KOOTENAI'S DR 1.8

AVISTA'S OASIS POSTED PATHS



Note 1: BPATPUD can be used for transactions to and from GCPD and CHPD, and for transactions to and from BPA's MIDCRemote. The BPATPUD POR/POD was created for scheduling purposes across the normally open 115 kV transmission system as part of the WOH Agreement between Avista and BPA.

Note 2: Pend Oreille PUD (POPD) resides within the Avista BA. This path was created for dynamic energy service transactions provided to POPD from Avista.

Effective: 04/01/2011

Available Transfer Capability Implementation Document (ATCID)

Posted: March 16, 2011
Effective: April 1, 2011
Version No.: 1

Section 1 – NERC defined terms:

ATC_F is the firm Available Transfer Capability for the ATC Path for that period.

ATC_{NF} is the non-firm Available Transfer Capability for the ATC Path for that period.

CBM is the Capacity Benefit Margin for the ATC Path during that period.

CBM_S is the Capacity Benefit Margin for the ATC Path that has been scheduled during that period.

$counterflows_F$ are adjustments to firm Available Transfer Capability as determined by the Transmission Service Provider and specified in their ATCID.

$counterflows_{NF}$ are adjustments to non-firm Available Transfer Capability as determined by the Transmission Service Provider and specified in its ATCID.

ETC_F is the sum of existing firm commitments for the ATC Path during that period.

ETC_{NF} is the sum of existing non-firm commitments for the ATC Path during that period.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$NITS_F$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

NL_F is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

OS_F is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

$Postbacks_F$ are changes to firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

$Postbacks_{NF}$ are changes to non-firm Available Transfer Capability due to a change in the use of Transmission Service for that period, as defined in Business Practices.

PTP_F is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

ROR_F is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

TRM is the Transmission Reliability Margin for the ATC Path during that period.

TRM_U is the Transmission Reliability Margin for the ATC Path that has not been released for sale (unreleased) as non-firm capacity by the Transmission Service Provider during that period.

TTC is the Total Transfer Capability of the ATC Path for that period.

Section 2 – Avista Application of defined terms:

2.1 **CBM** is currently defined as zero. No Load Serving Entity (LSE) serving load on the Avista system has requested CBM. This ATCID and the applicable calculations will be revised within 30 days of an LSE requesting CBM.

2.2 **CBM_s** will not be a value of anything other than zero since CBM has not been approved. This ATCID and the applicable calculations will be revised within 30 days of an LSE requesting CBM and the possibility of CBM_S becoming operational.

2.3 **counterflows** are equal to counter e-tags that have been submitted and approved in the Scheduling Horizon.

2.4 **OS_F** is currently defined as zero in all cases. Avista provides no other services not defined in Firm Transmission Service. Should Avista begin to provide such service, this ATCID and the applicable calculations will be revised within 30 days.

2.5 **OS_{NF}** is currently defined as zero in all cases. Avista provides no other services not defined in Firm Transmission Service. Should Avista begin to provide such service, this ATCID and the applicable calculations will be revised within 30 days.

2.6 **Postback** is equivalent to a recall, performed by Avista Transmission. A recall will show up as capacity posted back to Available Transfer Capability for the period it has been recalled.

2.7 **TRM** is currently defined as zero in all cases. Avista does not use or reserve TRM capacity for any paths. Should Avista begin to provide such service or decide to include TRM in its ATC calculations, this ATCID and the applicable calculations will be revised within 30 days.

2.8 **TRM_U** is currently defined as zero in all cases. Avista does not use or reserve TRM capacity for any paths. Should Avista begin to provide such service or decide to include TRM in its ATC calculations, this ATCID and the applicable calculations will be revised within 30 days.

Section 3 - Methodology for determining Total Transfer Capability (TTC) and calculating Available Transfer Capability (ATC) by path:

AVA.NWMT to AVA.SYS (associated w/ Path 8, Montana to Northwest in WECC Path Rating Catalog)	**MOD-029**
AVA.SYS to AVA.NWMT (associated w/ Path 8, Montana to Northwest in WECC Path Rating Catalog)	**MOD-029**
AVA.SYS to LOLO (associated w/ Path 14, Idaho to Northwest in WECC Path Rating Catalog)	**MOD-029**
LOLO to AVA.SYS (associated w/ Path 14, Idaho to Northwest in WECC Path Rating Catalog)	**MOD-029**
AVA.SYS to MIDC (associated w/ Path 6, West of Hatwai in WECC Path Rating Catalog)	**MOD-029**
MIDC to AVA.SYS (associated w/ Path 6, West of Hatwai in WECC Path Rating Catalog)	**MOD-029**
AVA.SYS to DRYCREEK (associated w/ Path 6, West of Hatwai in WECC Path Rating Catalog)	**MOD-029**
DRYCREEK to AVA.SYS (associated w/ Path 6, West of Hatwai in WECC Path Rating Catalog)	**MOD-029**
AVA.SYS to BPATPUD (associated w/ Path 6, West of Hatwai in WECC Path Rating Catalog)	**MOD-029**
BPATPUD to AVA.SYS (associated w/ Path 6, West of Hatwai in WECC Path Rating Catalog)	**MOD-029**
AVA.SYS to BPAT.AVA (TTC study performed by AVAT, available upon request)	**MOD-029**
BPAT.AVA to AVA.SYS (TTC study performed by AVAT, available upon request)	**MOD-029**
AVAPUD to CHELAN.AVA (TTC study performed by AVAT, available upon request)	**MOD-029**
CHELAN.AVA to AVAPUD (TTC study performed by AVAT, available upon request)	**MOD-029**
AVAPUD to GRANT.AVA (TTC study performed by AVAT, available upon request)	**MOD-029**
GRANT.AVA to AVAPUD (TTC study performed by AVAT, available upon request)	**MOD-029**
COLSTRIP to BROADVIEW (associated w/ Path 10, West of Colstrip in WECC Path Rating Catalog)	**MOD-029**
BROADVIEW to COLSTRIP (associated w/ Path 10, West of Colstrip in WECC Path Rating Catalog)	**MOD-029**
BROADVIEW to GARRISON (associate w/ Path 9, West of Broadview in WECC Path Rating Catalog)	**MOD-029**
GARRISON to BROADVIEW (associate w/ Path 9, West of Broadview in WECC Path Rating Catalog)	**MOD-029**
AVA.SYS to PINESTREET (TTC study performed by AVAT, available upon request)	**MOD-029**

Section 4 - Implementation of ATC Calculations:

4.1 **Transmission Reservations, expected Interchange and internal counterflows in ATC**
For purposes of calculating ATC for Avista's posted paths, Avista includes confirmed Transmission Reservations, confirmed path and interchange schedules (in the form of e-tags), and confirmed internal and interchange counterflow schedules (e-tags). For the purpose of calculating counterflow schedules, Avista does not include dynamic schedules (dynamic e-tags).

4,2 **Transmission Providers Supplying Data to Avista**
Avista does not use any data supplied by other Transmission Providers to calculate ATC.

4,3 **Avista Supplying Data to other Transmission Providers**
Avista provides data to The Bonneville Power Administration under MOD-001 for the purposes of calculating BPA AFC. Avista also provides forecast and system data to the Western Electricity Coordinating Council's (WECC) Security Coordinator, which BPA aquires in aggregate and uses for the purposes of calculating BPA AFC.

4,4 **Application of Allocation to Path ATC**
Avista is not a participant or joint owner in any paths that results in real time changes in ATC or TTC due to changes in allocation. All allocations are document in the WECC Path Rating Catalog and reflected in Avista's ATC and TTC postings.

4,5 **Impacts of Transmission and Generation Outages**
Avista does not currently have any generation outages which cause an impact to TTC calculations. Should a generation outage occur, Avista Transmission expects that schedules (e-tags) will be adjusted for the appropriate amount of time, thus changing the ATC calculation accordingly.

Avista has certain transmission outages that may affect TTC, and thus affect ATC. If an outage should occur, TTC on the path will be adjusted accordingly through OASIS and schedules using that path (e-tags) may be subject to curtailment.

Section 5 - Generic Algorithms for all Paths:

The ATC Algorithms are presented here as both a generic representation that encompass all OASIS posted paths and also path specific algorithms to allow for easier identification of the actual terms that effect a particular OASIS posted path.

Terms and definitions in the NERC Standard MOD-029-1, Rated System Path Methodology, are consistent with the like terms used in this document. Terms below grouped in **GREEN** are components of the Firm Existing Transmission Commitments (**ETC_F**) as described in the NERC ATC MODs. Terms below grouped in **RED** are components of the Non-Firm Existing Transmission Commitments (**ETC_{NF}**) as described in the NERC ATC MODs.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F) - CBM - TRM + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F) - CBM - TRM + Postbacks_F + counterflows_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F) - CBM - TRM + Postbacks_F + counterflows_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F) - (NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}) - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F) - (NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}) - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F) - (NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}) - CBM_S - TRM_U + Postbacks_{NF} + counterflows_{NF}$

Section 5 - Specific Algorithms by Path

To increase awareness of those components that actually have an impact on a specific path, any parameter that is set to zero or is not applicable for that path will not be displayed in the specific path horizon algorithm.

AVA.NWMT to AVA.SYS Path:

This is a system import path between the NorthWestern Energy (NWE) Balancing Area Authority (BAA) and the Avista BAA, and is a component of Path 8, Montana to the Northwest, in the Western Electricity Coordinating Council (WECC) Path Rating Catalog. Path 8 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog. The Path 8 rating is based on studies conducted by the Montana Power Company (now NWE) and the Bonneville Power Administration (BPA) in 1993. This study was reviewed by an Ad Hoc Review Group under the auspices of the WECC. WECC Path 8 has been granted an Accepted Rating.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F}$

Operating Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

Planning Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}}$

Operating Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

Planning Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

AVA.SYS to AVA.NWMT Path:

This is a system export path between the Avista BAA and the NWE BAA, and is a component of Path 8, Montana to the Northwest, in the Western Electricity Coordinating Council (WECC) Path Rating Catalog. Path 8 TTC in the west to east direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog. The Path 8 rating is based on studies conducted by the Montana Power Company (now NWE) and the BPA) in 1993. This study was reviewed by an Ad Hoc Review Group under the auspices of the WECC. The West to East rating of 1350 MW was studied and approved by the three-phase rating process. WECC Path 8 has been granted an Accepted Rating.

FIRM ATC CALCULATIONS:

Scheduling Horizon:
- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F}$

Operating Horizon:
- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

Planning Horizon:
- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:
- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}}$

Operating Horizon:
- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

Planning Horizon:
- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

LOLO to AVA.SYS

This is a system export path between the Avista BAA and the Idaho Power Company (IPCO) BAA, and is a component of Path 14, Idaho to the Northwest, in the WECC Path Rating Catalog. Path 14 TTC in the west to east direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog. The WECC Path 14 west to east rating was established in 1981 and reconfirmed in 1986 by joint studies performed by BPA, IPCO, PacifiCorp (PAC) and Avista. The WECC Path 14 west to east transfer rating was studied with high hydro conditions in the Northwest with low to moderate eastern thermal resources. In addition, the west to east rating cannot be fully utilized simultaneous with heavy Hells Canyon complex generation because of steady state thermal overloads and/or post disturbance voltage change in IPCO's internal transmission system. WECC Path 14 has been granted an Existing Rating.

FIRM ATC CALCULATIONS:

Scheduling Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

AVA.SYS to LOLO

This is a system import path between the IPCO BAA and the Avista BAA, and is a component of Path 14, Idaho to the Northwest, in the WECC Path Rating Catalog. Path 14 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog. The WECC Path 14 east to west was established in August, 1989 by joint studies performed by BPA, IPCO, PAC and Avista, with the publication of Idaho Power Company to Pacific Northwest Intertie Capacity Study. The WECC Notification Procedures for Changes in Facility Ratings and/or Operating Procedures was followed. The Path 14 east to west transfer rating was studied with light load conditions in Idaho with heavy eastern thermal resources, and moderate generation on the remaining hydro plants in Idaho. Studies were performed with both north to south and south to north on the PACI and near maximum transfers on parallel paths; i.e. transfers to Northwest and Arizona to California. WECC Path 14 has been granted an Existing Rating

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F}$

Operating Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

Planning Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}}$

Operating Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

Planning Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

AVA.SYS to MIDC

This is an export path between Avista and the Mid-Columbia trading hub, and is a component of Path 6, West of Hatwai, in the WECC Path Rating Catalog. Path 6 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog and Lolo-Walla Walla-Wanapum 230kV MOU between PacifiCorp (PAC) and Avista. Avista limits sales on the aggregate of the MIDC, DRYCREEK and BPATPUD paths to the Avista allocated rights of 600 MW. The WECC Path 6 west to east rating was established in 2005 through studies performed by the West of Hatwai Review Group, and approved by WECC. WECC Path 6 has been granted an Accepted Rating.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

MIDC to AVA.SYS

This is an import path between the Mid-Columbia trading hub and Avista, and is a component of Path 6, West of Hatwai, in the WECC Path Rating Catalog. Path 6 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog and Lolo-Walla Walla-Wanapum 230kV MOU between PacifiCorp (PAC) and Avista. The Path 6 west to east rating has not been established and is deemed to the equal to the east to west rating per MOD-029, R2.2 because of the inability to develop a reliability-limited flow in a direction counter to prevailing flows Avista limits sales on the aggregate of the MIDC, DRYCREEK and BPATPUD paths to the Avista allocated rights of 600 MW.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F}$

Operating Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

Planning Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}}$

Operating Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

Planning Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

AVA.SYS to DRYCREEK

This is a system export path between the Avista BAA and PAC BAA, and is a component of Path 6, West of Hatwai, in the WECC Path Rating Catalog. Path 6 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog and Lolo-Walla Walla-Wanapum 230kV MOU between PacifiCorp (PAC) and Avista. Avista limits sales on the aggregate of the MIDC, DRYCREEK and BPATPUD paths to the Avista allocated rights of 600 MW. The WECC Path 6 west to east rating was established in 2005 through studies performed by the West of Hatwai Review Group, and approved by WECC. WECC Path 6 has been granted an Accepted Rating.

FIRM ATC CALCULATIONS:

Scheduling Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

DRYCREEK to AVA.SYS

This is a system import path between the PAC BAA, and the Avista BAA, and is a component of Path 6, West of Hatwai, in the WECC Path Rating Catalog. Path 6 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog and Lolo-Walla Walla-Wanapum 230kV MOU between PacifiCorp (PAC) and Avista. The Path 6 west to east rating has not been established and is deemed to the equal to the east to west rating per MOD-029, R2.2 because of the inability to develop a reliability-limited flow in a direction counter to prevailing flows Avista limits sales on the aggregate of the MIDC, DRYCREEK and BPATPUD paths to the Avista allocated rights of 600 MW.

FIRM ATC CALCULATIONS:

Scheduling Horizon:
- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F}$

Operating Horizon:
- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

Planning Horizon:
- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:
- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}}$

Operating Horizon:
- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

Planning Horizon:
- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

AVA.SYS to BPATPUD

This is a system export path between the Avista BAA and the BPA BAA, Chelan County Public Utility District (Chelan PUD) BAA, and Grant County Public Utility District (Grant PUD) BAA, and is a component of Path 6, West of Hatwai, in the WECC Path Rating Catalog. Path 6 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog. Avista limits sales on the aggregate of the MIDC, DRYCREEK and BPATPUD paths to the Avista allocated rights of 600 MW. The WECC Path 6 west to east rating was established in 2005 through studies performed by the West of Hatwai Review Group, and approved by WECC. WECC Path 6 has been granted an Accepted Rating.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F}$

Operating Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

Planning Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}}$

Operating Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

Planning Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

BPATPUD to AVA.SYS

This is a system import path between the BPA BAA, Chelan PUD BAA, and Grant PUD BAA and the Avista BAA, and is a component of Path 6, West of Hatwai, in the WECC Path Rating Catalog. Path 6 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog. The Path 6 west to east rating has not been established and is deemed to the equal to the east to west rating per MOD-029, R2.2 because of the inability to develop a reliability-limited flow in a direction counter to prevailing flows Avista limits sales on the aggregate of the MIDC, DRYCREEK and BPATPUD paths to the Avista allocated rights of 600 MW.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

AVA.SYS to BPAT.AVA

This is a system export path between the Avista BAA and the BPA BAA. For this path, TTC has been defined by system performance studies in accordance with NERC/WECC planning criteria (cite specific MOD line) and performed by Avista. Those TTC studies are posted on the Avista OASIS site and available upon request.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

BPAT.AVA to AVA.SYS

This is a system import path between the BPA BAA and the Avista BAA. For this path, TTC has been defined by system performance studies in accordance with NERC/WECC planning criteria (cite specific MOD line) and performed by Avista. Those TTC studies are posted on the Avista OASIS site and available upon request.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

AVAPUD to CHELAN

This is a system export path between the Avista BAA and the Chelan PUD BAA. For this path, TTC has been defined by system performance studies in accordance with NERC/WECC planning criteria (cite specific MOD line) and performed by Avista. Those TTC studies are posted on the Avista OASIS site and available upon request.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

CHELAN to AVAPUD

This is a system import path between the Chelan PUD BAA and the Avista BAA. For this path, TTC has been defined by system performance studies in accordance with NERC/WECC planning criteria (cite specific MOD line) and performed by Avista. Those TTC studies are posted on the Avista OASIS site and available upon request.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

AVAPUD to GRANT

This is a system export path between the Avista BAA and the Grant PUD BAA. For this path, TTC has been defined by system performance studies in accordance with NERC/WECC planning criteria (cite specific MOD line) and performed by Avista. Those TTC studies are posted on the Avista OASIS site and available upon request.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F}$

Operating Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

Planning Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}}$

Operating Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

Planning Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

GRANT to AVAPUD

This is a system import path between the Grant PUD BAA and the Avista BAA. For this path, TTC has been defined by system performance studies in accordance with NERC/WECC planning criteria (cite specific MOD line) and performed by Avista. Those TTC studies are posted on the Avista OASIS site and available upon request.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F}$

Operating Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

Planning Horizon:

- $\mathbf{ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F}$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}}$

Operating Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

Planning Horizon:

- $\mathbf{ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}}$

COLSTRIP to BROADVIEW

This is a jointly owned path associated with Avista's share of the jointly owned Colstrip Transmission project, and is a component of Path 10, West of Colstrip, in the WECC Path Rating Catalog. Path 10 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog and by the Colstrip Project Transmission Agreement. The WECC Path 10 east to west rating was established in 1980 through studies performed for the Colstrip participants. WECC Path 10 has been granted an Existing Rating.

FIRM ATC CALCULATIONS:

Scheduling Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

BROADVIEW to COLSTRIP

This is a jointly owned path associated with Avista's share of the jointly owned Colstrip Transmission project, and is a component of Path 10, West of Colstrip, in the WECC Path Rating Catalog. Path 10 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog and by the Colstrip Project Transmission Agreement. The Path 10 west to east rating has not been established and is deemed to the equal to the east to west rating per MOD-029, R2.2 because of the inability to develop a reliability-limited flow in a direction counter to prevailing flows.

FIRM ATC CALCULATIONS:

Scheduling Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

BROADVIEW to GARRISON

This is a jointly owned path associated with Avista's share of the jointly owned Colstrip Transmission project, and is a component of Path 9, West of Colstrip, in the WECC Path Rating Catalog. Path 9 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog and by the Colstrip Project Transmission Agreement. The WECC Path 9 east to west rating was established in 1980 through studies performed for the Colstrip participants. WECC Path 10 has been granted an Existing Rating.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

GARRISON to BROADVIEW

This is a jointly owned path associated with Avista's share of the jointly owned Colstrip Transmission project, and is a component of Path 9, West of Colstrip, in the WECC Path Rating Catalog. Path 9 TTC in the east to west direction, and Avista's allocated rights, have been defined in the WECC Path Rating Catalog and by the Colstrip Project Transmission Agreement. The Path 9 west to east rating has not been established and is deemed to the equal to the east to west rating per MOD-029, R2.2 because of the inability to develop a reliability-limited flow in a direction counter to prevailing flows.

FIRM ATC CALCULATIONS:

Scheduling Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:

- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:

- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

AVA.SYS to PINESTREET

This is an export path between Avista and the Pend Oreille County PUD system located within the Avista BAA. For this path, TTC has been defined by system performance studies in accordance with NERC/WECC planning criteria (cite specific MOD line) and performed by Avista. Those TTC studies are posted on the Avista OASIS site and available upon request.

FIRM ATC CALCULATIONS:

Scheduling Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F + counterflows_F$

Operating Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

Planning Horizon:
- $ATC_F = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) + Postbacks_F$

NON-FIRM ATC CALCUATIONS:

Scheduling Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF} + counterflows_{NF}$

Operating Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Planning Horizon:
- $ATC_{NF} = TTC - (NL_F + NITS_F + GF_F + PTP_F + ROR_F) - (NITS_{NF} + GF_{NF} + PTP_{NF}) + Postbacks_{NF}$

Section 6 – Changes and Notification of Changes to ATCID

6.1 Changes or Modifications to the ATCID

Avista will post on OASIS, in draft form, and notify all parties listed in requirement R4 any changes it plans to make to this ATCID 30 days or more prior to an implementation date. Notification will be made via email to the manager of each party's compliance department, or other similarly positioned employee. Notification will include a request that each party listed in requirement R4 respond via email that such notification has been received.

6.1.1 Applicable Parties

Planning Coordinator associated with the Transmission Service Provider's area:
Not applicable

Reliability Coordinator associated with the Transmission Service Provider's area:
Not applicable

Transmission Operator associated with the Transmission Service Provider's area:
Not applicable

Planning Coordinators adjacent to the Transmission Service Provider's area:
Bonneville Power Administration
Idaho Power Company
PacifiCorp
Northwestern Energy
Chelan County PUD
Grant County PUD
Pend Oreille County PUD

Reliability Coordinators adjacent to the Transmission Service Provider's area:
WECC RC

Transmission Service Providers whose area is adjacent to the Transmission Service Provider's area:
Bonneville Power Administration
Idaho Power Company
PacifiCorp
Northwestern Energy

6.2 Availability of ATCID to Parties

Avista will maintain a current copy of its ATCID on its OASIS site. Additionally, Avista will supply an electronic copy to all parties listed in requirement R4 on or before the effective date of MOD-001 (April 1, 2011). Notification will be made via email to the manager of each party's compliance department, or other similarly positioned employee. Notification will include a request that each party listed in requirement R4 respond via email that such notification has been received.

KOOTENAI'S DATA REQUEST NO. 1.9:

Please explain with which utility (Avista or Idaho Power) a QF would be able to execute an interconnection agreement, and interconnect to, for a generation project interconnecting to the Lolo-Oxbow Line at the following points:

a) Any point between Lolo substation and the engineer station at Imnaha, Oregon.

b) Any point between the engineer station at Imnaha, Oregon and Oxbow substation.

Please explain the basis for the response with reference to any controlling agreements between Avista and Idaho Power, and examples of past interconnection requests on the line, if any exist.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.9:

A request for interconnection between Lolo substation and Imnaha would be made to Avista. A request for interconnection between Imnaha and Oxbow would be made to Idaho Power. This is based upon ownership of the facilities at the point of connection. The Company is not aware of any controlling agreements. In addition, there have been no interconnection requests on this line. Regardless of the point of interconnection, Idaho Power, as the Balancing Authority, is responsible for operation of the Lolo-Oxbow line.

KOOTENAI'S DATA REQUEST NO. 1.11:

Please reference Idaho Power's Answer at page 3, stating "the majority of the power moving across the 230 kv Lolo-Oxbow line consists of power transferred from Avista to Idaho Power." Please describe and document which party (Idaho Power or Avista) assumes the costs of line losses on the Lolo to Imnaha portion of the Lolo-Oxbow line. Please describe the same for the Imnaha to Oxbow section of the line. Please provide the line loss factor used for the line. Include copies of all agreements and studies related to line losses on the line, and any correspondence or documents filed with FERC regarding line losses for the entire Lolo-Oxbow line. Please identify the page number where line losses are discussed in all such documents.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.11:

Idaho Power, as a Transmission Provider, uses a system average loss factor. As such, Idaho Power does not have a loss factor that is used for individual lines. The factor used is a system average of 3.6 percent of energy scheduled. Avista's share of the line losses are imputed to Imnaha through metering compensation. Please see Idaho Power's Open Access Transmission Tariff ("OATT") at Section 15.7 for Point to Point Transmission Real Power Losses and Section 28.5 for Network Transmission Real Power Losses.

KOOTENAI'S DATA REQUEST NO. 1.11:

Please reference Idaho Power's Answer at page 3, stating "the majority of the power moving across the 230 kv Lolo-Oxbow line consists of power transferred from Avista to Idaho Power." Please describe and document which party (Idaho Power or Avista) assumes the costs of line losses on the Lolo to Imnaha portion of the Lolo-Oxbow line. Please describe the same for the Imnaha to Oxbow section of the line. Please provide the line loss factor used for the line. Include copies of all agreements and studies related to line losses on the line, and any correspondence or documents filed with FERC regarding line losses for the entire Lolo-Oxbow line. Please identify the page number where line losses are discussed in all such documents.

IDAHO POWER COMPANY'S *SUPPLEMENTAL* RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.11:

In addition to Idaho Power's response to Kootenai's Data Request No. 1.11 submitted on February 27, 2012, please also see Idaho Power's response and supplemental response to Kootenai's Data Request No. 1.2.

KOOTENAI'S DATA REQUEST NO. 1.12:

Please describe and document which party (Idaho Power or Avista) assumes the risk of loss or injury to person or property by virtue of operation and maintenance of the Lolo to Imnaha portion of the Lolo-Oxbow line. Please describe the same for the Imnaha to Oxbow section of the line. Include copies of all agreements and studies related to the assumption of the risk of loss or injury to person or property on the sections of the line, and any correspondence or documents filed with FERC regarding the same for the entire Lolo-Oxbow line. Please identify the page number where assumption of risk is discussed in all such documents.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.12:

Avista maintains the Lolo-Oxbow line between Lolo and Imnaha; Idaho Power maintains the Imnaha to Oxbow section. Regardless of which party maintains which portion of the line, the entirety of the Lolo-Oxbow (including the Avista maintained Lolo to Imnaha portion) is in Idaho Power's Balancing Authority, meaning Idaho Power has responsibility for operating the line and the transmission paths pursuant to the rules and regulations of the FERC, NERC, and WECC.

Risk of loss or injury to person or property by virtue of operation and maintenance of the entire Lolo-Oxbow line would be a fact specific inquiry dependent upon the circumstances of the loss or injury. No agreements or studies related to the assumption of the risk of loss or inquiry to person or property on the Lolo-Oxbow line or any correspondence or documents filed with the FERC pertaining to the same exist.

KOOTENAI'S DATA REQUEST NO. 1.12:

Please describe and document which party (Idaho Power or Avista) assumes the risk of loss or injury to person or property by virtue of operation and maintenance of the Lolo to Imnaha portion of the Lolo-Oxbow line. Please describe the same for the Imnaha to Oxbow section of the line. Include copies of all agreements and studies related to the assumption of the risk of loss or injury to person or property on the sections of the line, and any correspondence or documents filed with FERC regarding the same for the entire Lolo-Oxbow line. Please identify the page number where assumption of risk is discussed in all such documents.

IDAHO POWER COMPANY'S *SUPPLEMENTAL* RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.12:

In addition to Idaho Power's response to Kootenai's Data Request No. 1.12 submitted on February 27, 2012, please also see Idaho Power's response and supplemental response to Kootenai's Data Request No. 1.2.

KOOTENAI'S DATA REQUEST NO. 1.13:

Please admit that Idaho Power serves no customers between the Lolo substation and the point on the Lolo-Oxbow line where the line crosses into the State of Oregon. If deny, please provide a copy of the Company's certificate of public convenience and necessity from the Idaho Public Utilities Commission and all other documentation in your possession giving Idaho Power the right to serve customers on the described line.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.13:

Idaho Power admits there are no retail customers connected between Lolo substation and the state line.

KOOTENAI'S DATA REQUEST NO. 1.14:

Paragraph 51 of the answer states that "Idaho Power has facilities located in the Lolo substation including the meter for transactions like that proposed by Kootenai."

a) Please describe the meaning of the word "has" in the context of Paragraph 51 of the Answer.

b) Please provide an inventory of all facilities Idaho Power "has" in the Lolo substation and a description of the use to which Idaho Power puts each such facility.

c) Identify the party that maintains, and the party that operates, the facilities Idaho Power "has" at the Lolo substation.

d) Please provide copies of all documents and/or agreements pertaining to said facilities.

e) Please provide the book value of the facilities listed in item (b) and the combined book value of all facilities owned by any party at the Lolo substation.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.14:

a-d) The word "has" means that there are facilities at Lolo substation that Idaho Power owns and uses for the operation of its system. As a correction to paragraph 51 of Idaho Power's Answer in this proceeding, Idaho Power does not own the meter at the Lolo substation. NERC Reliability Standard BAL-005 requires Balancing Areas that share a tie have common primary metering equipment. Because Lolo Substation is owned by Avista and is the POD/POR/interchange point, Avista owns and maintains that common metering equipment that provides both Idaho Power and Avista the real time megawatt value flowing on the Lolo to Oxbow line. NERC Reliability Standard BAL-006 requires Balancing Authorities to equip their points of interconnection with other Balancing Authorities with common megawatt-hour meters. Because Lolo substation is owned by Avista and is the POD/POR/interchange point, Avista owns and maintains that megawatt-hour meter. Idaho Power owns and maintains some communication equipment at Lolo as a backup for telemetering the real time megawatt value to the Company's system. The Company also has a "port" off of Avista's Supervisory Control and Data Acquisition ("SCADA") remote terminal unit that acts as a remote terminal unit to the Company's Energy Management System ("EMS") system to provide Idaho Power indication of the Lolo to Oxbow circuit breaker. Idaho Power is not aware of any documented formal agreement for these facilities.

Idaho Power will be filing an amendment to its Answer to correct the error in paragraph 51.

e) Idaho Power objects to this Request as it is irrelevant, beyond the scope, and unduly burdensome. Additionally, Idaho Power has no information regarding book value for Avista's facilities.

KOOTENAI'S DATA REQUEST NO. 1.16:

Paragraph 1.12 of Idaho Power's Schedule 85 ESA defines losses as "occurring as a result of the transformation and transmission of energy between the point where the Facility's energy is metered and the point the Facilities energy is delivered to the Idaho Power electrical system by the Transmitting Entity." Reference also Kootenai's Complaint Exhibit 103, at pages 21, 89, and 199, containing the same term.

a) Please provide a detailed map of "the Idaho Power electrical system" as that term is used in the referenced sections of the tariff contract.

b) Please provide the line loss factor used for the Lolo-Oxbow line.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.16:

a) Idaho Power objects to this Request because it seeks Critical Energy Infrastructure Information ("CEII").

b) Idaho Power, as a Transmission Provider, uses a system average loss factor. As such, Idaho Power does not have a loss factor that is used for individual lines. The factor used is a system average of 3.6 percent of energy scheduled. Avista's share of the line losses are imputed to Imnaha through metering compensation. Please see Idaho Power's OATT at Section 15.7 for Point to Point Transmission Real Power Losses and Section 28.5 for Network Transmission Real Power Losses.

April 6, 2012

Subject: Docket No. UM 1572
Idaho Power Company's **Supplemental** Response to Kootenai Electric Cooperative, Inc.'s ("Kootenai") Data Request 1.16(a)

KOOTENAI'S DATA REQUEST NO. 1.16:

Paragraph 1.12 of Idaho Power's Schedule 85 ESA defines losses as "occurring as a result of the transformation and transmission of energy between the point where the Facility's energy is metered and the point the Facilities energy is delivered to the Idaho Power electrical system by the Transmitting Entity." Reference also Kootenai's Complaint Exhibit 103, at pages 21, 89, and 199, containing the same term.

a) Please provide a detailed map of "the Idaho Power electrical system" as that term is used in the referenced sections of the tariff contract.

b) Please provide the line loss factor used for the Lolo-Oxbow line.

IDAHO POWER COMPANY'S *SUPPLEMENTAL* RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.16:

a) Other than the map that was attached as Exhibit 1 to Idaho Power Company's Amended Answer, there are no other maps responsive to this Request.

KOOTENAI'S DATA REQUEST NO. 1.17:

Please identify the number of QF projects located in any state for which Idaho Power is party to a currently effective power purchase agreement for delivery of electricity to Idaho Power (please do not list all projects; just provide the number). Please explain whether any of these QFs' power purchase or interconnection contracts provide for a point of delivery and/or point of sale to Idaho Power at a point separated from Idaho Power's electrical system by a transmission or distribution line owned by any party other than Idaho Power. Please identify and provide the power purchase and interconnection contracts for any such QF projects, and identify the party (Idaho Power or the QF) responsible for the cost of line losses over the line(s) owned by the party other than Idaho Power.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 1.17:

Idaho Power currently has 119 qualifying facility ("QF") projects under contract to sell energy to Idaho Power. Of those 119 QF projects, six projects are located outside of Idaho Power's service territory, physically interconnect with a utility other than Idaho Power, and have arrangements with transmission providers to deliver energy to a point of delivery on Idaho Power's electrical system.

Two of these projects are located within the state of Oregon and have Oregon standard QF contracts, two of these projects are located in Montana and have QF contracts based upon state of Idaho rules and regulations as approved by the Idaho Public Utilities Commission ("IPUC"), and two of these projects are located within the state of Idaho but not located within Idaho Power's service territory and have QF contracts based upon state of Idaho rules and regulations as approved by the IPUC.

The six projects are not directly interconnected to the Idaho Power electrical system, the interconnection agreements are between the project and the host utility; thus, there is no interconnection agreement with Idaho Power. In all cases, Idaho Power purchases only the energy that is produced by the facility and received by Idaho Power at the Idaho Power point of receipt.

Idaho Power considers information provided by QFs as well as their contracts to be confidential information unless and until the contract is filed with the utility commissions and becomes public information. All state of Idaho QF agreements are filed at the IPUC for approval; thus, copies of those agreements can be obtained from the IPUC. Oregon QF contracts are filed informationally at both the Idaho and Oregon commissions. Generator Interconnection Agreements are not publicly filed and are confidential.

IDAHO POWER®
An IDACORP Company

April 6, 2012

Subject: Docket No. UM 1572
Idaho Power Company's Responses to Kootenai Electric Cooperative, Inc.'s ("Kootenai") Second Set of Data Requests (2.1-2.5)

KOOTENAI'S DATA REQUEST NO. 2.1:

Reference Attachment to Idaho Power's Response to Kootenai's Data Request 1.2 (containing the 1958 Interconnection Agreement and a single Amendment to Transmission Line Agreement dated July 31, 1964).

(a) Please confirm that these agreements are still in effect, and that no other amendments exist.

(b) Please provide any changes to the terms of these Agreements filed with FERC. If no such changes have been filed with FERC, please state so.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 2.1:

The 1958 Interconnection Agreement is still in effect and Idaho Power Company ("Idaho Power" or "Company") is not aware of any amendments to it. The Transmission Line Agreement is no longer in effect. Also, please see the attached Federal Energy Regulatory Commission ("FERC") filing.

OMITTED

Attachment to Idaho Power's Response To Kootenai Request No. 2.1

Containing

FERC Filings Regarding Sale of Divide Creek to Imnaha Line Segment

(Documents already included in Kootenai's Complaint at Exhibit 102)

IDAHO POWER®
An IDACORP Company

April 17, 2012

Subject: Docket No. UM 1572
Idaho Power Company's **Supplemental** Response to Kootenai Electric Cooperative, Inc.'s ("Kootenai") Data Request No. 2.1

KOOTENAI'S DATA REQUEST NO. 2.1:

Reference Attachment to Idaho Power's Response to Kootenai's Data Request 1.2 (containing the 1958 Interconnection Agreement and a single Amendment to Transmission Line Agreement dated July 31, 1964).

(a) Please confirm that these agreements are still in effect, and that no other amendments exist.

(b) Please provide any changes to the terms of these Agreements filed with FERC. If no such changes have been filed with FERC, please state so.

IDAHO POWER COMPANY'S *SUPPLEMENTAL* RESPONSE TO KOOTENAI'S DATA REQUEST NO. 2.1:

In addition to Idaho Power Company's ("Idaho Power") response to Kootenai's Data Request No. 2.1 submitted on April 6, 2012, please also see Idaho Power's response and supplemental response to Kootenai's Data Request No. 1.2.

KOOTENAI'S DATA REQUEST NO. 2.2:

Reference Idaho Power's Responses to Kootenai's Data Requests 1.6 and 1.12.

(a) Please identify and list the electric utilities that have service territory within Idaho Power's balancing authority area.

(b) Please provide a map depicting Idaho Power's entire balancing authority area, and if available also depicting the service territories of the electric utilities listed in item (a).

(c) Please explain whether Idaho Power delivers electricity to other utilities located within its balancing authority area.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 2.2:

(a) Please see Attachment 1.

(b) Balancing Area boundaries are electrical points, not geographic points. They are defined by the metered interconnections with other Balancing Areas. As such, Idaho Power's metered interconnections are listed in confidential Attachment 2 and the confidential map provided as Attachment 3.

The confidential attachments produced in response to Request 2.2 (b) will be provided separately in accordance with Protective Order No. 12-066.

(c) As a Transmission Provider, Idaho Power does deliver energy to other electric utilities in its balancing area in accordance with Idaho Power's Open Access Transmission Tariff.

ATTACHMENT 1 - RESPONSE TO KOOTENAI'S DR 2.2

Idaho Power Company

PacifiCorp

Bonneville Power Administration acts as the agent for the following entities that have load in Idaho Power's balancing area;

- Raft River Electric Cooperative
- City of Albion
- City of Burley
- City of Declo
- City of Heyburn
- City of Minidoka
- City of Rupert
- City of Weiser
- East End Mutual Electric Co.
- Farmers Electric Company
- Riverside Electric Co. Ltd.
- South Side Electric
- United Electric Coop.
- Wells Rural Electric Coop.
- Oregon Trail Electric Consumers Cooperative
- The United States Bureau of Reclamation

OMITTED

Attachment to Idaho Power's Response To Kootenai Request No. 2.2(b)

Containing

Confidential Map of Idaho Power's Balancing Authority Area

KOOTENAI'S DATA REQUEST NO. 2.3:

Reference Idaho Power's Responses to Requests 1.7 and 1.8(b). Please provide any documents submitted to FERC, NERC, or WECC by Idaho Power (or Idaho Power acting in concert with Avista or any other utilities), whereby Idaho Power explained the basis for designation of the point of scheduling over the Lolo-Oxbow interconnection path to be defined as "Lolo." Please include any documents requesting, designating, or describing the point of delivery as the Lolo substation, not just "Lolo." If no such documents exist, please state so.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 2.3:

Idaho Power is not aware of any such documents filed with FERC, the North American Electric Reliability Corporation, or the Western Electricity Coordinating Council other than the aforementioned FSIN registries.

KOOTENAI'S DATA REQUEST NO. 2.4:

For purposes of calculating Idaho Power's current Network Transmission rates charged to Idaho Power's Network Transmission Customers, please admit or deny that the portion of the Lolo-Oxbow 230 kv line from Lolo substation to Imnaha is not included in Idaho Power's Total Transmission Revenue Requirement or otherwise included in calculation of Idaho Power's transmission rates. If denied, please provide the work papers or other filing with FERC demonstrating that the section of the 230 kv line from Lolo substation to Imnaha is included in Idaho Power's current Total Transmission Revenue Requirement used to calculate its Formula Rates.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 2.4:

For purposes of calculating Idaho Power's current Network Transmission rates charged to Idaho Power's Network Transmission Customers, Idaho Power admits that the portion of the Lolo-Oxbow 230 kilovolt ("kV") line from the Lolo substation to Imnaha is not included in Idaho Power's Total Transmission Revenue Requirement or otherwise included in calculation of Idaho Power's transmission rates.

KOOTENAI'S DATA REQUEST NO. 2.5:

Please admit or deny that the portion of the Lolo-Oxbow 230 kv line from Lolo substation to Imnaha is not included as a part of Idaho Power's electrical system in Idaho Power's current FERC Form 1. If deny, please provide the FERC Form 1 and associated work papers or other documents necessary to demonstrate that the line is included as a part of Idaho Power's plant, as reported to FERC. Please identify the location (section, page, line numbers, etc.) in such documents demonstrating inclusion of the Lolo substation to Imnaha section of the line.

IDAHO POWER COMPANY'S RESPONSE TO KOOTENAI'S DATA REQUEST NO. 2.5:

The portion of the Lolo-Oxbow 230 kV line from the Lolo substation to Imnaha is not owned by Idaho Power and is not included as part of the Company's electrical system in the current FERC Form 1.

Name of Respondent Avista Corporation	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	N/A
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent Avista Corporation	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	N/A
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	N/A
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	
56	Amounts included in ISO/RTO Settlement Statements	397	N/A
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	N/A
65	Generating Plant Statistics Pages	410-411	
66	Transmission Line Statistics Pages	422-423	

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Kootenai Electric Cooperative, Inc.
Richardson Affidavit Exhibit 2
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- Privileged Data

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	N/A
70	Footnote Data	450	
	Stockholders' Reports Check appropriate box: ☒ Two copies will be submitted ☐ No annual report to stockholders is prepared		

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Kootenai Electric Cooperative, Inc.
Richardson Affidavit Exhibit 2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2010/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	44,478,295	152,088
4	(303) Miscellaneous Intangible Plant	3,968,847	174,780
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	48,447,142	326,868
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,230,746	
9	(311) Structures and Improvements	124,903,704	344,352
10	(312) Boiler Plant Equipment	166,294,776	2,460,691
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	48,239,041	42,045
13	(315) Accessory Electric Equipment	26,930,014	3,545
14	(316) Misc. Power Plant Equipment	15,650,932	23,630
15	(317) Asset Retirement Costs for Steam Production	585,276	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	384,834,489	2,874,263
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	56,519,003	845
28	(331) Structures and Improvements	40,656,073	1,839,019
29	(332) Reservoirs, Dams, and Waterways	117,796,318	5,443,778
30	(333) Water Wheels, Turbines, and Generators	141,170,373	8,413,432
31	(334) Accessory Electric Equipment	34,096,337	108,176
32	(335) Misc. Power PLant Equipment	7,318,628	17,928
33	(336) Roads, Railroads, and Bridges	1,999,562	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	399,556,294	15,823,178
36	D. Other Production Plant		
37	(340) Land and Land Rights	903,118	5,988
38	(341) Structures and Improvements	15,743,240	400,035
39	(342) Fuel Holders, Products, and Accessories	21,064,681	105,457
40	(343) Prime Movers	21,876,780	
41	(344) Generators	198,781,330	790,153
42	(345) Accessory Electric Equipment	15,994,108	1,101,775
43	(346) Misc. Power Plant Equipment	1,389,422	198,568
44	(347) Asset Retirement Costs for Other Production	351,682	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	276,104,361	2,601,976
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,060,495,144	21,299,417

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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	16,092,056	3,623,034
49	(352) Structures and Improvements	16,040,755	752,665
50	(353) Station Equipment	177,678,840	17,804,118
51	(354) Towers and Fixtures	17,113,029	7,792
52	(355) Poles and Fixtures	131,611,436	3,628,228
53	(356) Overhead Conductors and Devices	106,341,896	1,893,064
54	(357) Underground Conduit	2,605,488	
55	(358) Underground Conductors and Devices	2,330,071	
56	(359) Roads and Trails	1,872,246	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	471,685,817	27,708,901
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,336,127	1,086,034
61	(361) Structures and Improvements	14,029,847	495,999
62	(362) Station Equipment	93,198,468	4,866,342
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	214,302,534	15,321,278
65	(365) Overhead Conductors and Devices	139,008,612	13,271,577
66	(366) Underground Conduit	74,816,416	2,986,849
67	(367) Underground Conductors and Devices	123,155,633	7,118,187
68	(368) Line Transformers	169,574,920	10,887,227
69	(369) Services	115,182,247	5,077,737
70	(370) Meters	45,007,149	1,348,471
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	29,342,489	2,503,071
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,022,084,149	64,962,772
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	124,681	
87	(390) Structures and Improvements	3,432,419	188,676
88	(391) Office Furniture and Equipment	1,163,669	834,808
89	(392) Transportation Equipment	11,406,205	5,023,432
90	(393) Stores Equipment	383,459	6,918
91	(394) Tools, Shop and Garage Equipment	3,455,055	38,717
92	(395) Laboratory Equipment	1,467,560	29,070
93	(396) Power Operated Equipment	25,194,583	12,328,274
94	(397) Communication Equipment	39,099,709	2,662,744
95	(398) Miscellaneous Equipment	8,849	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	85,736,189	21,112,639
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	85,736,189	21,112,639
100	TOTAL (Accounts 101 and 106)	2,688,448,441	135,410,597
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	2,688,448,441	135,410,597

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	536,766	514,450
5	(501) Fuel	28,352,582	22,358,344
6	(502) Steam Expenses	4,265,708	2,614,109
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	838,347	699,318
10	(506) Miscellaneous Steam Power Expenses	2,468,855	2,783,706
11	(507) Rents	15,498	29,773
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	36,477,756	28,999,700
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	501,359	500,139
16	(511) Maintenance of Structures	610,113	546,526
17	(512) Maintenance of Boiler Plant	4,899,998	5,457,086
18	(513) Maintenance of Electric Plant	645,697	2,565,316
19	(514) Maintenance of Miscellaneous Steam Plant	661,490	937,372
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	7,318,657	10,006,439
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	43,796,413	39,006,139
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,349,973	2,278,227
45	(536) Water for Power	900,793	815,150
46	(537) Hydraulic Expenses	5,932,977	4,390,300
47	(538) Electric Expenses	5,726,408	5,604,151
48	(539) Miscellaneous Hydraulic Power Generation Expenses	733,429	630,038
49	(540) Rents	6,529,629	6,068,605
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	22,173,209	19,786,471
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	376,904	249,607
54	(542) Maintenance of Structures	522,921	343,445
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,290,854	646,541
56	(544) Maintenance of Electric Plant	1,789,839	1,937,827
57	(545) Maintenance of Miscellaneous Hydraulic Plant	177,024	1,835,745
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,157,542	5,013,165
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	26,330,751	24,799,636

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	873,063	846,899
63	(547) Fuel	115,449,329	68,656,659
64	(548) Generation Expenses	2,463,056	2,215,456
65	(549) Miscellaneous Other Power Generation Expenses	505,589	456,697
66	(550) Rents	33,433	-33,811
67	TOTAL Operation (Enter Total of lines 62 thru 66)	119,324,470	72,141,900
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	798,646	775,889
70	(552) Maintenance of Structures	8,426	1,850
71	(553) Maintenance of Generating and Electric Plant	1,691,146	1,893,421
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	116,403	100,412
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,614,621	2,771,572
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	121,939,091	74,913,472
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	277,079,128	303,784,778
77	(556) System Control and Load Dispatching	555,351	528,673
78	(557) Other Expenses	126,323,056	69,198,479
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	403,957,535	373,511,930
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	596,023,790	512,231,177
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,210,636	2,436,974
84	(561) Load Dispatching	2,192,996	2,224,918
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System		
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	272,063	190,291
94	(563) Overhead Lines Expenses	447,185	543,042
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,742,126	13,350,741
97	(566) Miscellaneous Transmission Expenses	1,617,125	1,387,100
98	(567) Rents	120,946	152,055
99	TOTAL Operation (Enter Total of lines 83 thru 98)	24,603,077	20,285,121
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	665,430	566,082
102	(569) Maintenance of Structures	275,169	330,766
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,157,114	1,127,999
108	(571) Maintenance of Overhead Lines	1,751,805	1,528,641
109	(572) Maintenance of Underground Lines	11,590	17,566
110	(573) Maintenance of Miscellaneous Transmission Plant	-2,754	38,785
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,858,354	3,609,839
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	28,461,431	23,894,960

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,495,137	1,367,048
135	(581) Load Dispatching		
136	(582) Station Expenses	715,019	546,953
137	(583) Overhead Line Expenses	1,402,987	1,577,717
138	(584) Underground Line Expenses	581,320	710,346
139	(585) Street Lighting and Signal System Expenses	226,745	218,441
140	(586) Meter Expenses	1,773,001	1,619,021
141	(587) Customer Installations Expenses	790,470	861,022
142	(588) Miscellaneous Expenses	6,426,792	5,871,255
143	(589) Rents	294,788	375,764
144	TOTAL Operation (Enter Total of lines 134 thru 143)	13,706,259	13,147,567
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,261,570	1,326,210
147	(591) Maintenance of Structures	396,786	280,729
148	(592) Maintenance of Station Equipment	785,071	1,030,655
149	(593) Maintenance of Overhead Lines	7,948,732	6,823,635
150	(594) Maintenance of Underground Lines	845,853	1,067,148
151	(595) Maintenance of Line Transformers	1,094,896	1,040,344
152	(596) Maintenance of Street Lighting and Signal Systems	652,322	638,654
153	(597) Maintenance of Meters	138,937	160,883
154	(598) Maintenance of Miscellaneous Distribution Plant	270,915	315,281
155	TOTAL Maintenance (Total of lines 146 thru 154)	13,395,082	12,683,539
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	27,101,341	25,831,106
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	592,956	567,832
160	(902) Meter Reading Expenses	2,739,310	2,624,185
161	(903) Customer Records and Collection Expenses	7,798,575	8,243,568
162	(904) Uncollectible Accounts	1,674,638	2,735,983
163	(905) Miscellaneous Customer Accounts Expenses	131,019	244,871
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,936,498	14,416,439

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Name of Respondent Avista Corporation	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	27,971,131	25,449,316
169	(909) Informational and Instructional Expenses	874,830	67,743
170	(910) Miscellaneous Customer Service and Informational Expenses	168,978	146,608
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	29,014,939	25,663,667
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	4,734	506,252
176	(913) Advertising Expenses	452	114,294
177	(916) Miscellaneous Sales Expenses	192,237	307,957
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	197,423	928,503
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	25,316,910	22,474,374
182	(921) Office Supplies and Expenses	4,127,587	3,928,835
183	(Less) (922) Administrative Expenses Transferred-Credit	50,151	49,301
184	(923) Outside Services Employed	15,053,420	11,313,636
185	(924) Property Insurance	1,300,926	1,283,269
186	(925) Injuries and Damages	5,380,816	3,543,277
187	(926) Employee Pensions and Benefits	1,098,670	1,053,264
188	(927) Franchise Requirements	6,027	6,704
189	(928) Regulatory Commission Expenses	5,550,292	4,999,707
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	204,098	264,628
192	(930.2) Miscellaneous General Expenses	3,269,466	3,129,106
193	(931) Rents	872,289	393,144
194	TOTAL Operation (Enter Total of lines 181 thru 193)	62,130,350	52,340,643
195	Maintenance		
196	(935) Maintenance of General Plant	7,655,998	7,960,364
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	69,786,348	60,301,007
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	763,521,770	663,266,859

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) ☐ An Original (2) ☐ A Resubmission	/ /	End of 2010/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,544.00		
4								
5	Beacon Sub #4	BPA Bell Sub	230.00	230.00	Steel Tower	1.00		1
6	Beacon Sub	BPA Bell Sub	230.00	230.00	H Type	5.00		1
7	Beacon Sub #5	BPA Bell Sub	230.00	230.00	Steel Pole	4.00		1
8	Beacon Sub #5	BPA Bell Sub	230.00	230.00	H Type	2.00		1
9	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Tower		1.00	1
10	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Pole	26.00		2
11	Beacon	Cabinet Gorge Plant	230.00	230.00	H Type	53.00		1
12	Beacon Sub	Lolo Sub	230.00	230.00	Steel Tower	1.00		1
13	Beacon Sub	Lolo Sub	230.00	230.00	H Type	104.00		1
14	Benewah	Shawnee	230.00	230.00	Steel Pole	60.00		1
15	Noxon Plant	Pine Creek Sub	230.00	230.00	Steel Pole	29.00		2
16	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	14.00		1
17	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	19.00		1
18	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	Steel Tower			1
19	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
20	Divide Creek	Lolo Sub	230.00	230.00	Steel Tower			1
21	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
22	N. Lewiston	Walla Walla	230.00	230.00	H Type	43.00		1
23	N. Lewiston	Walla Walla	230.00	230.00	Steel Pole	4.00		1
24	N. Lewiston	Shawnee	230.00	230.00	Steel Pole	7.00		1
25	N. Lewiston	Shawnee	230.00	230.00	H Type	27.00		1
26	Walla Walla	Wanapum	230.00	230.00	Alum			1
27	Walla Walla	Wanapum	230.00	230.00	H Type	78.00		1
28	BPA (Libby)	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
29	BPA/Hot Springs #1	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
30	BPA/Hot Springs #2	Noxon Plant (dead)	230.00	230.00	Steel Tower		2.00	1
31	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	68.00		1
32	BPA Line	West Side Sub	230.00	230.00	Steel Pole	2.00		2
33	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
34	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
35	Colstrip Plant	Broadview	500.00	500.00				
36					TOTAL	2,207.00	3.00	33

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STATE OF WASHINGTON				
2					
3	Airway Heights	Distr. Unattended	115.00	13.80	
4	Barker Road	Distr. Unattended	110.00	13.80	
5	Beacon	Trnsm. & Distr Unatt	230.00	115.00	13.80
6	Boulder	Trnsm. Unattended	230.00	115.00	13.80
7	Chester	Distr. Unattended	115.00	13.80	
8	Chewelah 115Kv	Distr. Unattended	115.00	13.80	
9	Colbert	Distr. Unattended	115.00	13.80	
10	College & Walnut	Distr. Unattended	115.00	13.80	
11	Colville 115Kv	Distr. Unattended	115.00	13.80	
12	Critchfield	Distr. Unattended	115.00	13.80	
13	Deer Park	Dist. Unattended	115.00	13.80	
14	Dry Creek	Transm. Unattended	230.00	115.00	13.80
15	Dry Gulch	Distr. Unattended	115.00	13.80	
16	East Colfax	Distr. Unattended	115.00	13.80	
17	East Farms	Distr. Unattended	115.00	13.80	
18	Fort Wright	Distr. Unattended	115.00	13.80	
19	Francis and Cedar	Distr. Unattended	115.00	13.80	
20	Gifford	Distr. Unattended	115.00	34.00	
21	Glenrose	Distr. Unattended	115.00	13.80	
22	Greenwood	Distr. Unattended	115.00	13.80	
23	Hallett & White	Distr. Unattended	115.00	13.80	
24	Indian Trail	Dist. Unattended	115.00	13.80	
25	Industrial Park	Dist. Unattended	115.00	13.80	
26	Kettle Falls	Distr. Unattended	115.00	13.80	
27	Lee & Reynolds	Distr. Unattended	115.00	13.80	
28	Liberty Lake	Distr. Unattended	115.00	13.80	
29	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
30	Lyons & Standard	Distr. Unattended	115.00	13.80	
31	Mead	Distr. Unattended	115.00	13.80	
32	Metro	Distr. Unattended	115.00	13.80	
33	Milan	Distr. Unattended	115.00	13.80	
34	Millwood	Dist. Unattended	115.00	13.80	
35	Ninth & Central	Distr. Unattended	115.00	13.80	
36	Northeast	Distr. Unattended	115.00	13.80	
37	Northwest	Distr. Unattended	115.00	13.80	
38	Opportunity	Dist. Unattended	115.00	13.80	
39	Othello	Distr. Unattended	115.00	13.80	
40	Post Street	Distr. Unattended	115.00	13.80	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Pound Lane	Distr. Unattended	115.00	13.80	
2	Pullman	Dist Unattended	115.00	13.80	
3	Ross Park	Distr. Unattended	115.00	13.80	
4	Roxboro	Distr. Unattended	115.00	24.00	
5	Shawnee	Trans. Unattended	230.00	115.00	13.80
6	Silver Lake	Distr. Unattended	115.00	13.80	
7	Southeast	Distr. Unattended	115.00	13.80	
8	South Othello	Distr. Unattended	115.00	13.80	
9	South Pullman	Distr. Unattended	115.00	13.80	
10	Sunset	Distr. Unattended	115.00	13.80	
11	Terre View	Dist. Unattended	115.00	13.80	
12	Third & Hatch	Distr. Unattended	115.00	13.80	
13	Waikiki	Distr. Unattended	115.00	13.80	
14	West Side	Trans. Unattended	230.00	115.00	13.80
15	Other: 72substa less than 10MVA	Distr. Unattended			
16					
17	STATE OF IDAHO				
18	Appleway	Dist. Unattended	115.00	13.80	
19	Avondale	Dist. Unattended	115.00	13.80	
20	Benewah	Trans. Unattended	230.00	115.00	13.80
21	Big Creek	Distr. Unattended	115.00	13.80	
22	Blue Creek	Distr. Unattended	115.00	13.80	
23	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
24	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
25	Clark Fork	Distr. Unattended	115.00	21.80	
26	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
27	Cottonwood	Distr. Unattended	115.00	24.90	
28	Dalton	Distr. Unattended	115.00	13.80	
29	Grangeville	Distr. Unattended	115.00	13.80	
30	Holbrook	Distr. Unattended	115.00	13.80	
31	Huetter	Distr. Unattended	115.00	13.80	
32	Idaho Road	Distr Unattended	115.00	13.80	
33	Juliaetta	Distr. Unattended	115.00	13.80	
34	Kamiah	Dist. Unattended	115.00	13.80	
35	Kooskia	Distr. Unattended	115.00	13.80	
36	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
37	Moscow	Distr. Unattended	115.00	13.80	
38	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
39	North Moscow	Distr. Unattended	115.00	13.80	
40	North Lewiston 230kV	Trans Unattended	230.00	115.00	13.80

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	North Lewiston	Distr. Unattended	115.00	13.80	
2	Oden	Distr. Unattended	115.00	21.80	
3	Oldtown	Distr. Unattended	115.00	21.80	
4	Orofino	Distr. Unattended	115.00	13.80	
5	Osburn	Distr. Unattended	115.00	13.80	
6	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
7	Pleasant View	Distr. Unattended	115.00	13.80	
8	Plummer	Dist Unattended	115.00	13.80	
9	Post Falls	Distr. Unattended	115.00	13.80	
10	Potlatch	Distr. Unattended	115.00	13.80	
11	Prarie	Distr. Unattended	115.00	13.80	
12	Priest River	Distr. Unattended	115.00	20.80	
13	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
14	Sagle	Dist. Unattended	115.00	20.80	
15	Sandpoint	Distr. Unattended	115.00	20.80	
16	South Lewiston	Distr. Unattended	115.00	13.80	
17	Sweetwater	Distr. Unattended	115.00	24.90	
18	St. Maries	Distr. Unattended	115.00	23.90	
19	Tenth & Stewart	Distr. Unattended	115.00	13.80	
20	Wallace	Distr. Unattended	115.00	13.80	
21	Other: 28 substa less than 10 MVA	Distr. Unattended			
22					
23	STATE OF MONTANA				
24	1 substation less than 10 MVA	Distr. Unattended			
25					
26	SUBSTA. @ GENERATING PLANTS				
27	STATE OF WASHINGTON				
28	Boulder Park	Trans. Attended	115.00	13.80	
29	Kettle Falls	Trans. Attended	115.00	13.80	
30	Long Lake	Trans. Attended	115.00	4.00	4.00
31	Nine Mile	Trans. Attended	115.00	13.80	2.30
32	Little Falls	Trans. Attended	115.00	4.00	
33	Northeast	Trans. Attended	115.00	13.80	
34	Post Street	Trans. Attended	13.80	4.00	35.00
35					
36	STATE OF IDAHO				
37	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
38	Post Falls	Trans. Attended	115.00	2.30	
39	Rathdrum	Trans. Attended	115.00	13.80	
40	STATE OF MONTANA				

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Name of Respondent Avista Corporation	This Report Is: (1) [ ] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2010/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Noxon	Trans. Attended	230.00	13.80	
2					
3	STATE OF OREGON				
4	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
5					
6	SUMMARY:				
7	Washington:				
8	4 subs	Trans. Unattended			
9	119subs	Distr. Unattended			
10	1 subs	Tran & Dist Unattnd			
11	7 subs	Trans. Attended			
12	Idaho:				
13	3 subs	Trans. Unattended			
14	63 subs	Distr. Unattended			
15	4 subs	Tran & Dist Unattnd			
16	3 subs	Trans. Attended			
17	Montana: 1 sub	Trans. Attended			
18	1 sub	Distr. Unattended			
19	Oregon: 1 sub	Trans. Unattended			
20	System: 207 subs				
21					
22					
23					
24					
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