BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company of Joplin, Missouri for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Missouri Service Area of the Company	))))))	**Case No. ER-2008-0093**

STATE OF MISSOURI)
) **SS**
COUNTY OF ST. LOUIS)

Affidavit of Maurice Brubaker

Maurice Brubaker, being first duly sworn, on his oath states:

1. My name is Maurice Brubaker. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000. We have been retained by Explorer Pipeline Company, et al. in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my Late Filed Exhibit No. 32 which was prepared in written form for introduction into evidence in Missouri Public Service Commission Case No. ER-2008-0093.

3. I hereby swear and affirm that the exhibit is true and correct and that it shows the matters and things that it purports to show.

M S Brubaker
Maurice Brubaker

Subscribed and sworn to before me this 29th day of May, 2008.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 14, 2011
Commission # 07024862

Tammy S. Klossner
Notary Public

EMPIRE DISTRICT ELECTRIC COMPANY
MO PSC Case No. ER-2008-0093

Examples of Utilities With Sharing Provisions in FAC Mechanisms

Attached is a summary sheet for the provisions of the fuel adjustment clauses and tariffs, orders and/or stipulations implementing such clauses.

Tariff language is included where the provisions are set forth in the tariff itself.

In the case of several of the Northwestern utilities, the tariff language does not specify the sharing mechanism, but rather only the resulting factor. In these cases, attached are the relevant documents (testimony, stipulations) which explain the operation of the sharing mechanisms.

EMPIRE DISTRICT ELECTRIC COMPANY
MO PSC Case No. ER-2008-0093

Examples of Utilities With Sharing Provisions in FAC Mechanisms

Line	Utility/State	Sharing Provisions: Band	Sharing Provisions: Utility	Sharing Provisions: Customer	Earnings Variation Limit or Cap
1	Rocky Mountain Power (Wyoming)	± $40 million	100%	0%	None
		± $40 million to $100 million	30%	70%	
		± $100 million to $200 million	15%	85%	
		Over ± $200 million	10%	90%	
2	Montana-Dakota Utilities (North Dakota)	All	10%	90%	None
3	Idaho Power Company (Idaho)	All	10%	90%	None
4	Portland General Electric Company (Oregon)	Deadband (-75 bp ROE) (+150 bp ROE)	100%	0%	± 100 bp ROE
		Additional	10%	90%	

EMPIRE DISTRICT ELECTRIC COMPANY
MO PSC Case No. ER-2008-0093

Examples of Utilities With Sharing Provisions in FAC Mechanisms

Line	Utility/State	Sharing Provisions: Band	Utility	Customer	Earnings Variation Limit or Cap
5	Avista Corporation (Washington)	± $4 million	100%	0%	None
		± $4 million to $10 million	50%	50%	
		Over ± $10 million	10%	90%	
6	Puget Sound Energy (Washington)	± $20 million	100%	0%	Maximum ± $40 million over 4 years
		± $20 million to $40 million	50%	50%	
		± $40 million to $120 million	10%	90%	
		Over ± $120 million	5%	95%	

PUGET SOUND ENERGY, INC.

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of PUGET SOUND ENERGY, INC. For Approval of its March 2008 Power Cost Adjustment Mechanism Report	DOCKET NO. UE-08______ PETITION OF PUGET SOUND ENERGY, INC. FOR APPROVAL OF ITS MARCH 2008 POWER COST ADJUSTMENT MECHANISM REPORT

1. This Petition is brought by Puget Sound Energy, Inc. ("PSE" or the "Company"). PSE's representative for purposes of this proceeding is:

Tom DeBoer
Director, Rates and Regulatory Affairs
Puget Sound Energy, Inc.
P.O. Box 97034 PSE-08N
Bellevue, WA 98009-9734
Telephone: 425-462-3495
Facsimile: 425-462-3414
tom.deboer@pse.com

and its legal counsel for purposes of this proceeding is:

Sheree Strom Carson
Jason Kuzma
Perkins Coie LLP
10885 N.E. Fourth Street, Suite 700
Bellevue, WA 98004
Telephone: 425-635-1400
Facsimile: 425-635-2400
SCarson@perkinscoie.com
JKuzma@perkinscoie.com

2. This Petition brings into issue: WAC 480-07-370(1)(b).

I. BACKGROUND

A. The Company's PCA Mechanism Requires Annual True-Up Filings

3. In the Commission's Twelfth Supplemental Order in Docket Nos. UE-011570 and UG-011571 ("Twelfth Supplemental Order"), the Commission approved the parties' Settlement Stipulation for Electric and Common Issues for PSE's 2001 general rate case ("Stipulation"). Among other things, the Twelfth Supplemental Order authorized a Power Cost Adjustment Mechanism ("PCA Mechanism"). Exhibit A to the Stipulation, which is attached to the Twelfth Supplemental Order, sets forth details regarding the PCA Mechanism, and is hereinafter referred to and cited as the "PCA Settlement."

4. Following verification of certain numbers set forth in the exhibits to the PCA Settlement, the Commission ordered that revised pages of Exhibits A, B, D and F be substituted for the corollary pages of Exhibits A, B, D and F of the PCA Settlement. The Commission further ordered that the resulting adjusted calculations be used for purposes of the PCA accounting required by the PCA Settlement beginning July 1, 2002. *See* Fifteenth Supplemental Order in Docket Nos. UE-011570 and UG-011571 (May 13, 2003). A copy of the PCA Settlement, as revised, is attached to this Petition as Exhibit A.

5. The PCA Settlement describes the PCA Mechanism as

> a mechanism that would account for differences in PSE's modified actual power costs relative to a power cost baseline. This mechanism would account for a sharing of costs and benefits that are graduated over four levels of power cost variances . . . .

PCA Settlement, ¶ 2. The PCA Settlement sets forth the various levels of costs and benefits sharing between the Company and its customers, and provides that "[t]he customer's share of the power cost variability will be deferred as described below. . . ." *Id.* at ¶ 3.

6. In order to implement its sharing provisions, the PCA Settlement requires an annual true-up of actual power costs (versus the normalized level set in rates) and an accounting of sharing amounts. To accomplish this, the PCA Settlement provides that "[i]n August of 2003 and each year thereafter, the Company shall file an annual report detailing the power costs included in the deferral calculation, in a form satisfactory to the Commission, for Commission review and approval." PCA Settlement, ¶ 4.

II. PSE'S 2008 PCA REPORT

7. In compliance with the PCA Settlement and the Sixteenth Supplemental Order in Docket Nos. UE-011570 and UG-011571 (changing the annual PCA period to a calendar year rather than a fiscal year), this Petition presents to the Commission PSE's Power Cost Adjustment Mechanism Annual Report for the Twelve Month Time Period January 1, 2007 through December 31, 2007—PCA Period Six ("PCA Annual Report") for the Commission's review and approval. The PCA Annual Report is being filed along with this Petition. Accompanying workpapers are being provided to the Commission

Staff and Public Counsel with this filing. As described below, PSE requests that the Commission approve the PCA Annual Reportas filed.

8. As detailed in PSE's PCA Annual Report, PSE had three different Power Cost Baseline Rates during PCA Period 6. The average power cost baseline rate during PCA Period 6 was $56.692. As further detailed in PSE's 2008 PCA Report, PSE's actual power costs were lower than the average power cost baseline rate during PCA Period 6. In total, actual power costs were lower by $26,594,041 (after adjustment for Firm Wholesale).

9. With respect to the deferral balance, as of December 31, 2006, the Company had deferred $5,101,727 of under-recovered power costs. During PCA Period 6 there was an offset to this amount related to the sharing with customers of an over-recovery of $3,297,022. Therefore, the deferred balance at December 31, 2007 was $1,804,705. Interest of $1,255,088 had been accrued at the end of PCA Period 5, and additional interest of $54,352 has accrued for PCA Period 6 as allowed by the PCA Mechanism. Adding the total accrued interest of $1,309,441 to the deferred balance of $1,804,705, results in a total customer deferral balance under the PCA mechanism at December 31, 2007 of $3,114,146.

10. The Company is not requesting any rate increase as part of this filing as the deferral balance is not at a level where an increase is warranted.

III. REQUESTED ACTION

11. PSE respectfully requests that the Commission issue an order approving PSE's PCA Annual Report, as filed.

DATED: March 31, 2008.

PERKINS COIE LLP

By Sheree Strom Carson
Sheree Strom Carson, WSBA #25349
Jason Kuzma, WSBA #31830
Attorneys for Puget Sound Energy, Inc.

PUGET SOUND ENERGY, INC.

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of PUGET SOUND ENERGY, INC., **For Approval of its March 2008 Power Cost Adjustment Mechanism Report**	**Docket No. UE-08____** **EXHIBIT A TO PETITION OF PUGET SOUND ENERGY, INC. FOR APPROVAL OF ITS POWER COST ADJUSTMENT MECHANISM ANNUAL REPORT**

**SETTLEMENT STIPULATION BY THE
15TH SUPPLEMENTAL ORDER IN
WUTC DOCKET NO. UE-011570, *ET AL.***

**Exhibit A to Petition of
Puget Sound Energy, Inc. For
Approval of Its Power Cost
Adjustment Mechanism Annual Report**

Exhibit A to
Settlement Stipulation

PSE GENERAL RATE CASE
DOCKET NOS. UE-011570 and UG-011571

SETTLEMENT TERMS FOR THE
POWER COST ADJUSTMENT MECHANISM (PCA)

A. Executing Parties

1. The following parties have participated in the Power Cost Adjustment mechanism (PCA) collaborative in Docket Nos. UE-011570 and UG-011571, and have reached consensus on the terms of settlement with respect to such issues, as set forth in this Agreement: Puget Sound Energy, Inc. ("PSE" or the "Company"); the Staff of the Washington Utilities and Transportation Commission; the Public Counsel Section of the Attorney General's Office; Intervenor the Kroger Co.; Intervenor AT&T Wireless Services, Inc.; Intervenor NW Energy Coalition and Natural Resources Defense Council; Federal Executive Agencies; and Intervenor Cogeneration Coalition of Washington (hereinafter referred to collectively as "Executing Parties").

B. Overview of PCA

2. The proposed PCA is a mechanism that would account for differences in PSE's modified actual power costs relative to a power cost baseline. This mechanism would account for a sharing of costs and benefits that are graduated over four levels of power cost variances, with an overall cap of $40 million (+/-) over the four year period July 1, 2002 through June 30, 2006. If the cap is exceeded, costs and benefits in excess of $40 million would be shared at a different level of sharing. The factors influencing the variability of power costs included in the proposal are primarily weather or market related. PSE will be allowed to file for rate increases to implement limited power supply cost increases related to new resources, discussed later.

3. <u>Sharing proposal:</u>

- **First Band (dead band):** $20 million (+/-) annually, 100% of costs and benefits to Company.
- **Second Sharing Band:** $20-$40 million (+/-) annually, 50% of costs and benefits to Company; 50% of costs and benefits to Customers.

- **Third Sharing Band:** $40-$120 million (+/-) annually, 10% of costs and benefits to Company; 90% of costs and benefits to Customers.

- **Fourth Sharing Band**: Greater than $120 million (+/-) annually, 5% of costs and benefits to Company; 95% of costs and benefits to Customers.

- **Overall Cap For Four Year Period July 1, 2002 through June 30, 2006:** As a separate limit, the Company's share of power costs/benefits will not exceed a $40 million (+/-) cumulative net balance, as calculated per the sharing bands discussed above. If this cap is exceeded, sharing thereafter is adjusted to 99% of costs and benefits to Customers and 1% of costs and benefits to Company. The cap is removed at end of the fourth year (June 30, 2006), and any deferred balances associated with the cap are set for refund or collection at that time.

- **Deferral and Interest:** The customer's share of the power cost variability will be deferred as described below, and the balance will accrue monthly interest at the interest rate calculated in accordance with WAC 480-90-233(4). Amounts will be deferred consistent with recovery under the provisions of SFAS 71.

4. <u>Timing of surcharges or credits:</u>

- The sharing amounts will be accounted for, on an annual basis. The first 12 month period will be the period beginning July 1, 2002 and ending June 30, 2003. Subsequent PCA periods will be 12 month period beginning on July 1 of each year. The surcharging of deferrals can be triggered by the Company when the balance of the deferral account is approximately $30 million. The Company shall make a filing to refund deferrals when the balance in the deferral account is a credit of $30 million or more.

- To address financial needs and to provide Customers a price signal to reduce energy consumption, a surcharge can be triggered when the Company determines that, for any upcoming 12 month period, the projected increase in the deferral balance for increased power costs will exceed $30 million. The surcharge will be implemented through a special filing subject to Commission approval detailing the events giving rise to the projected cost variance.

- In August of 2003 and each year thereafter, the Company shall file an annual report detailing the power costs included in the deferral calculation, in a form satisfactory to the Commission, for Commission review and approval. The Commission shall have an opportunity to review the prudence of the power costs included in the deferred calculation, and costs determined to be imprudent can be disallowed at that time. Staff and other interested parties will have the opportunity to participate in the prudence review process. The Company will also provide the

Commission with a quarterly report of the deferral calculation in a form satisfactory to the Commission.

- Unless otherwise determined by the Commission, surcharges or credits will be collected or refunded, as the case may be, over a one year period. If for any reason the PCA shall cease to exist, any balances in the deferred accounts not previously reviewed will be reviewed and set for refund or surcharge to customers at that time.

C. Elements of PCA

5. <u>Power Cost Rate:</u> In order to focus on the component of the Company's rates to be adjusted by a PCA, it is necessary to distinguish between power costs and all other costs in general rates. This will single out the relative portion of the Company's rate to be adjusted by the proposed PCA and in the periodic "Power Cost Only" review. The purpose is for the PCA, and any Power Cost Only case, to measure the cost of power delivered to PSE's system, and to measure the change in this overall cost. The following table illustrates the proposed distinctions among costs in the Company's rates.

ROCKY MOUNTAIN POWER

NPC PCAM Tariff
Schedule 94

Available

In all territory served by the Company in the State of Wyoming.

Applicable

All retail tariff rate schedules shall be subject to two normally scheduled rate elements, a Base NPC charge and Deferred NPC Adjustment that together recover total net power costs (NPC) including fuel, purchased power (including NPC financial hedges), wheeling, and sales for resale for natural gas and electricity and excluding other NPC not specifically modeled in the Company's production cost model.

Definitions and Basic Concepts:

NPC Rate Effective Period shall be the 12-month period beginning April 1st and extending through March 31st following the NPC Comparison Period. The Company may file and the Commission may approve PCAM applications with amortization periods for deferred amounts longer than 12 months to reflect extraordinary circumstances.

NPC Comparison Period shall be the historic 12-month period beginning December 1 and extending through November 30th prior to the NPC Rate Effective Period.

Base NPC is calculated by taking the sum of the twelve monthly total Company NPC as reflected in the most recent (a) Commission-approved stipulated agreement; (b) Commission-approved Wyoming general rate case; or (c) Commission-approved Forecast NPC Adjustment application. The Base NPC shall be recovered from all retail tariff rate schedules through the unbundled rate elements as set forth in this Schedule.

(continued)

Definitions and Basic Concepts *(continued)*:

Embedded Cost Differential (ECD) is part of the currently approved inter-jurisdictional allocation method. It reallocates the differential between the costs of Company owned Hydro, Mid-Columbia Contracts and Qualifying Facility Contracts and all other costs of generation.

PCAM is the power cost adjustment mechanism.

Forecast NPC Adjustment is an application to modify the Base NPC (and Wyoming Base ECD) based on forecasted net power costs and forecasted billing units. The Forecast NPC Adjustment shall be based on a test period beginning December 1st immediately preceding the filing of the Forecast NPC Adjustment application (typically on February 1 of each year) and concluding November 30 immediately following the filing of the Forecast NPC Adjustment application.

Adjusted Actual NPC: Adjusted Actual NPC is the annual sum of the monthly total Company amounts properly recorded in FERC Account Numbers: 501 (Steam Power Generation – Fuel), 503 (Steam Power Generation – Steam from other Sources) and 547 (Other Power Generation – Fuel) for coal, steam and natural gas purchased and or sold; 555 (Purchased Power), 565 (Wheeling); and 447 (Sales for Resale). Adjustments shall be made to actual costs that are consistent with the Company's production dispatch model, to remove prior period accounting entries made during the accrual period, and to include applicable Commission-adopted adjustments from the most recent general rate case. Hydro normalization, forced outages and other operational volatility circumstances shall be excluded from adjustment because these unpredictable events result in net power cost volatility that the PCAM captures for rate making purposes.

(continued)

Definitions and Basic Concepts *(continued)*:

Deferred NPC Adjustment is a charge applicable to all retail tariff rate schedules as set forth in this schedule. The Deferred NPC Adjustment is calculated by taking the sum of the monthly differences between the Adjusted Actual NPC and the corresponding monthly Base NPC adjusted to reflect the prorated total Company Dead Band, Sharing Proportions, and Wyoming Allocated Share and include Symmetrical Interest accrual on the Customer Proportion of net Deferred NPC Adjustment balances outside of the Dead Band. Any uncollected or uncredited Deferred NPC Adjustment balance remaining at the end of a NPC Rate Effective Period shall be rolled over into the next NPC Rate Effective Period.

When calculating the Deferred NPC Adjustment the most recent monthly Base NPC approved by the Commission shall be utilized for each specific calendar month.

TABLE 1

Adjusted Actual Total NPC Layer	Customer Proportion	Company Proportion
Over $200 million above Base	Company recovers 90% from Customers	Company absorbs 10%
Over $100 million and up to $200 million above Base	Company recovers 85% from Customers	Company absorbs 15%
Over $40 million and up to $100 million above Base	Company recovers 70% from Customers	Company absorbs 30%
$40 million above Base (Dead Band)	Company recovers 0% from Customers	Company absorbs 100%
$40 million below Base (Dead Band)	Company returns 0% to Customers	Company retains 100%
Over $40 million and up to $100 million below Base	Company returns 70% to Customers	Company retains 30%
Over $100 million and up to $200 million below Base	Company returns 85% to Customers	Company retains 15%
Over $200 million below Base	Company returns 90% to Customers	Company retains 10%

(continued)

Definitions and Basic Concepts *(continued)*:

Dead Band is illustrated in Table 1 above is a total Company annual symmetrical range of plus $40 million above the base and $40 million below the base. There will be no deferral or accrual of interest for costs which fall within the Dead Band. If the NPC Comparison Period is longer or shorter than an annual period, the Dead Band shall be prorated on the basis of the applicable monthly NPC Base included in the NPC Comparison Period.

Sharing Proportion is also illustrated in Table 1 above and is the symmetrical proportion of Deferred NPC Adjustment eligible for recovery from, or repayment to customers. The Sharing Proportion shall be layered to reflect a Customer Proportion and a Company Proportion. There will be no deferral or accrual of interest for costs which are included in the Company Proportion. If the NPC comparison period is longer or shorter than an annual period, the thresholds between the various layers shall be prorated based on the number of months in the comparison period.

Symmetrical Interest shall be computed on the net accumulated Deferred NPC Adjustment balance monthly at the rate determined by the Commission pursuant to Rule 241, Customer Deposits. Interest shall be paid to the Company on net Deferred NPC under-collections and interest shall be paid to Customers on net deferred NPC over-collections. Appropriate provisions for interest during the amortization period shall be included in the calculation of Deferred NPC Adjustments in the NPC Rate Effective Period. If the Commission implements a proposed Deferred NPC Adjustment on an interim basis, any excess charges or under charges shall be refunded to or collected from customers with interest at the rate established by the Commission pursuant to Rule 241. If the Commission approves an amortization period for a Deferred NPC balance of longer than 12 months, interest on any balance not recovered within 12 months shall be calculated based on the Company's most recent authorized weighted average cost of capital.

(continued)

Definitions and Basic Concepts *(continued)*:

Wyoming Allocated Share shall be calculated using Wyoming Allocation Factors. Wyoming Allocation Factors where Wyoming's percent of total system factors prescribed for allocation of net power costs pursuant to the Revised Protocol or current Commission approved interjurisdictional allocation methodology as approved in the most recent general rate case.

Wyoming Actual Adjusted ECD is recalculated for each NPC Comparison Period. The Wyoming Actual Adjusted ECD will be calculated in the same manner that the Wyoming ECD Base was calculated except the only values that will be updated in the recalculation are the amounts from the FERC accounts included in the definition of Adjusted Actual NPC and associated megawatt hours for the NPC Comparison Period.

Wyoming ECD Base is the sum of the ECD adjustments included in the Wyoming revenue requirement as most-recently approved by the Commission either in: (a) a Commission-approved stipulated agreement; (b) as a result of a Commission-approved General Rate Case; or (c) in a Commission-approved Forecast NPC Adjustment application.

Timing

The Company shall file a Deferred NPC Adjustment application and a Forecast NPC Adjustment application on or before February 1st of each year under normal circumstances. The implementation and effective date of the Deferred NPC Adjustment and Forecast NPC Adjustment application shall be April 1st of each year under normal circumstances. Nothing shall prevent the Company from filing out-of-period PCAM applications to reflect extraordinary circumstances. The Company may elect to defer recovery of a NPC under collection at its discretion and the Company may elect to defer refund of a NPC over recovery if the balance in the deferred account is less than $1 million on a Wyoming Jurisdiction allocated basis.

(continued)

Deferred NPC Adjustment and ECD Adjustment:

Deferred NPC for the Comparison Period shall be calculated monthly and recorded on the Company's books, based on the following formula:

Deferred NPC adjustment = ((((Adjusted Actual NPC – (Base NPC)) +/- Dead band) x Sharing Proportion) x Wyoming Allocated Share) + Symmetrical Interest.

At the end of each comparison period, the Deferred NPC Adjustment may also include an ECD Adjustment. An ECD Adjustment shall be included in the Deferred NPC Adjustment if the value of the Deferred NPC Adjustment is not zero. The ECD adjustment formula is as follows:

ECD Adjustment = Wyoming Actual Adjusted ECD – Wyoming ECD Base.

Base NPC and the Deferred NPC Adjustment shall be allocated to all retail tariff rate schedules and, where applicable, to the demand and energy rate components within each schedule based on the applicable allocation factors and cost of service study relationships established in the Company's last GRC. The allocated and classified costs shall then be divided by appropriate billing determinants to calculate the specific rates set forth in this schedule for the Base NPC and Deferred NPC Adjustment. As such, the Deferred NPC adjustment will be spread to customer classes and rate elements in the same proportion as Base NPC.

(continued)

Monthly Billing

All charges and provisions of the applicable rate schedule will be applied in determining a Customer's bill except that the Customer's total electric bill will be increased or decreased by an amount equal to the product of all kilowatt demand multiplied by the following dollar per kilowatt rate plus all kilowatt-hours of use multiplied by the following cents per kilowatt-hour rate. The column labeled "Base" equals Base NPC including ECD. The column labeled "Deferred" equals Deferred NPC adjustment including ECD adjustment.

Schedule	Delivery Voltage	Billing Units	Base	Deferred
2	**	Demand per kWh	0.014¢	0.047¢
		Energy per kWh	1.605¢	0.380¢
15	**	Demand per kWh	0.000¢	0.005¢
		Energy per kWh	1.697¢	0.382¢
25	Secondary	Demand in excess of 15 kW per kW	$0.13	$0.30
		Energy per kWh	1.689¢	0.381¢
	Primary	Demand in excess of 15 kW per kW	$0.12	$0.29
		Energy per kWh	1.653¢	0.373¢
33	Primary	Supp. Demand per kW	$0.09	$0.25
		Energy per kWh	1.567¢	0.374¢
33	Transmission	Supp. Demand per kW	$0.09	$0.25
		Energy per kWh	1.499¢	0.365¢
40	**	Demand per kW	$0.15	$0.24
		Energy per kWh	1.696¢	0.389¢

(continued)

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Base	Deferred
46	Secondary	On-Peak Demand per kW	$0.10	$0.26
		Energy per kWh	1.602¢	0.383¢
	Primary	On-Peak Demand per kW	$0.09	$0.25
		Energy per kWh	1.567¢	0.374¢
48T	Transmission	On-Peak Demand per kW	$0.09	$0.25
		Energy per kWh	1.499¢	0.365¢
51	**	Demand per kWh	0.000¢	0.005¢
		Energy per kWh	1.697¢	0.382¢
53	**	Demand per kWh	0.000¢	0.005¢
		Energy per kWh	1.697¢	0.382¢
54	**	Demand per kWh	0.000¢	0.005¢
		Energy per kWh	1.697¢	0.382¢
57	**	Demand per kWh	0.000¢	0.005¢
		Energy per kWh	1.697¢	0.382¢
58	**	Demand per kWh	0.000¢	0.005¢
		Energy per kWh	1.697¢	0.382¢
207	**	Demand per kWh	0.000¢	0.004¢
		Energy per kWh	1.377¢	0.382¢
210	**	Demand per kW	$0.08	$0.23
		Energy per kWh	1.754¢	0.389¢

(continued)

Monthly Billing *(continued)*

Schedule	Delivery Voltage	Units	Billing	Base	Deferred
211	**		Demand per kWh	0.000¢	0.004¢
			Energy per kWh	1.377¢	0.382¢
212-1	**		Demand per kWh	0.000¢	0.004¢
			Energy per kWh	1.377¢	0.382¢
212-2	**		Demand per kWh	0.010¢	0.025¢
			Energy per kWh	1.500¢	0.383¢
212-3	**		Demand per kWh	0.010¢	0.025¢
			Energy per kWh	1.500¢	0.383¢

** Rates will be applicable for all Delivery Voltage levels.

Rules

Service under this Schedule is subject to the General Rules contained in the tariff of which this Schedule is a part, and to those prescribed by regulatory authorities.

MONTANA-DAKOTA UTILITIES COMPANY

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.
400 North Fourth Street
Bismarck, ND 58501

STATE OF SOUTH DAKOTA ELECTRIC RATE SCHEDULE

	SD P.U.C	Volume	3
	5th Revised	Sheet No.	27
Cancelling	4th Revised	Sheet No.	27

FUEL CLAUSE Rate 58

There shall be added to or deducted from the net monthly bill computed according to the applicable schedule .0009¢ (nine ten-thousandths of one cent) per kilowatt-hour for each .001¢ increase above or decrease below the base fuel cost per kilowatt-hour. The base fuel cost shall be 1.4704¢ per Kwh.

The fuel cost shall be the sum of the following for the most recent three month period as herein defined.

1. The cost of fossil and other fuels, including but not limited to tire derived fuel (TDF) and refuse derived fuel (RDF) consumed in the Company's own generating stations and the Company's share of fuel consumed in jointly owned generating stations as recorded in Account 151.

2. The net energy cost of energy purchases as recorded in Account 555 exclusive of capacity or demand charges including but not limited to:

   a. Energy that is purchased on an economic dispatch basis;

   b. Energy purchased from a renewable energy source, including but not limited to hydropower, wood, windpower, and biomass;

   c. Energy related costs associated with the Midwest ISO Energy Market. (C)

3. The actual indentifiable fossil and other fuel costs associated with energy purchased for reasons other than identified in (2) above, less;

4. The cost of fossil and other fuel recovered through intersystem sales, including the fuel costs and/or renewable energy costs related to economy energy sales and other energy sold on an economic dispatch basis.

The kilowatt-hour sales shall be all kilowatt hours sold excluding intersystem sales for the most recent three month period as herein defined.

This adjustment shall be made monthly and shall be based on the average fuel cost per kilowatt-hour for the most recent three month period for which actual cost data is available. The Company shall file with the Commission prior to making an adjustment, a monthly statement, under oath, setting forth the fuel cost per kilowatt-hour for the most recent three month period, as set forth above. Any adjustment in rates occasioned thereby shall be effective with the bills rendered on and after the first day of each month, unless the Commission shall otherwise order.

Date Filed: March 10, 2005
Effective Date: Service rendered on and after April 1, 2005
Issued By: Donald R. Ball
Assistant Vice President - Regulatory Affairs
Docket No.: EL05-007

IDAHO POWER COMPANY

IDAHO PUBLIC UTILITIES COMMISSION
Approved Feb. 29, 2008
Effective March 1, 2008
Per O.N. 30508
Jean D. Jewell Secretary

SCHEDULE 55
POWER COST ADJUSTMENT

APPLICABILITY

This schedule is applicable to the electric energy delivered to all Idaho retail Customers served under the Company's schedules and Special Contracts. These loads are referred to as "firm" load for purposes of this schedule.

BASE POWER COST

The Base Power Cost of the Company's rates is computed by dividing the Company's power cost components by firm kWh load. The power cost components are the sum of fuel expense and purchased power expense (including purchases from cogeneration and small power producers), less the sum of off-system surplus sales revenue. The Base Power Cost is 0.7477 cents per kWh.

PROJECTED POWER COST

The Projected Power Cost is the Company estimate, expressed in cents per kWh, of the power cost components for the forecasted time period beginning April 1 each year and ending the following March 31. The Projected Power Cost is 0.9575 cents per kWh.

TRUE-UP AND TRUE-UP OF THE TRUE-UP

The True-up is based upon the difference between the previous Projected Power Cost and the power costs actually incurred. The True-up of the True-up is the difference between the previous years approved True-Up revenues and actual revenues collected. The total True-up is 0.0531 cents per kWh.

POWER COST ADJUSTMENT

The Power Cost Adjustment is 90 percent of the difference between the Projected Power Cost and the Base Power Cost plus the True-ups.

The monthly Power Cost Adjustment applied to the Energy rate of all metered schedules and Special Contracts is 0.2419 cents per kWh. The monthly Power Cost Adjustment applied to the per unit charges of the nonmetered schedules is the monthly estimated usage times 0.2419 cents per kWh.

EXPIRATION

The Power Cost Adjustment included on this schedule will expire May 31, 2008.

PORTLAND GENERAL ELECTRIC COMPANY

SCHEDULE 126
ANNUAL POWER COST VARIANCE MECHANISM

PURPOSE

To recognize in rates part of the difference for a given year between Actual Net Variable Power Costs and the Net Variable Power Costs forecast pursuant to Schedule 125, Annual Power Cost Update and in accordance with Commission Order No. 07-015. This schedule is an "automatic adjustment clause" as defined in ORS 757.210.

APPLICABLE

To all Customers for Electricity Service except those served on Schedule 76R and 576R, and those served on Schedules 483, 489, 515, 532, 538, 549, 583, 589, 591, 592 and 594, where service under these schedules was received for the entire calendar year that the Annual Power Cost Variance accrued. Customers served on Schedules 538, 583, 589, 591 and 592 who receive the Schedule 128 Balance of Year Transition Adjustment will be subject to this adjustment.

ANNUAL POWER COST VARIANCE (PVC)

Subject to the Earnings Test, the Annual Power Cost Variance (PCV) is 90% of the amount that the Annual Variance exceeds either the Positive Annual Power Cost Deadband for a Positive Annual Variance or the Negative Annual Power Cost Deadband for a Negative Annual Variance.

POWER COST VARIANCE ACCOUNT

The Company will maintain a PCV Account to record Annual Variance amounts. The Account will contain the difference between the Adjustment Amount and amounts credited to or collected from Customers. Interest will accrue on the account at the Company's authorized rate of return. At the end of each year the Adjustment Amount for the calendar year will be adjusted by 50% of the annual interest on the PCV Account calculated at the Company's authorized cost of capital. This amount will be added to the Adjustment Account.

Any balance in the PCV Account will be amortized to rates over a period determined by the Commission. Annually, the Company will propose to the Commission PCV Adjustment Rates that will amortize the PCV to rates over a period recommended by the Company. The amount accruing to Customers, whether positive or negative, will be multiplied by a revenue sensitive factor of 1.0287 to account for franchise fees and uncollectibles.

EARNINGS TEST

The recovery from or refund to Customers of any Adjustment Amount will be subject to an earnings review for the year that the power costs were incurred. The Company will recover the Adjustment Amount to the extent that such recovery will not cause the Company's Actual Return on Equity (ROE) for the year to exceed its Authorized ROE minus 100 basis points. The Company will refund the Adjustment Amount to the extent that such refunding will not cause the Company's Actual Return on Equity (ROE) for the year to fall below its Authorized ROE plus 100 basis points.

Schedule 126 (Continued)

DEFINITIONS

Actual Loads

Actual loads are total annual calendar retail loads adjusted to exclude loads of Customers to whom this adjustment schedule does not apply.

Actual NVPC

Incurred cost of power based on the definition for NVPC described above.

Actual Unit NVPC

The Actual Unit NVPC is the Actual NVPC divided by Actual Loads.

Annual Variance (AV)

The Annual Variance (AV) is the dollar amount calculated annually based on the following formula:

(Actual Unit NVPC - Base Unit NVPC) * Actual Loads

Base Unit NVPC

The Base Unit NVPC is the NVPC used to develop rate schedules for the applicable year divided by the associated calendar basis retail loads. Base NVPC are updated annually in accordance with Schedule 125.

Negative Annual Power Cost Deadband

The Negative Annual Power Cost Deadband is an amount equal to 75 basis points of the Company's return on equity.

Positive Annual Power Cost Deadband

The Positive Annual Power Cost Deadband is an amount equal to 150 basis points of the Company's return on equity.

Schedule 126 (Continued)

DEFINITIONS (Continued)

Net Variable Power Costs (NVPC)

The Net Variable Power Costs (NVPC) represents the power costs for Energy generated and purchased. NVPC are the net cost of fuel, fuel transportation, power contracts, transmission / wheeling, wholesale sales, hedges, options and other financial instruments incurred to serve retail load. For purposes of calculating the NVPC, the following adjustments will be made:

- Exclude BPA payments in lieu of Subscription Power.
- Exclude the monthly FASB 133 mark-to-market activity.
- Exclude any cost or revenue unrelated to the period.
- Include as a cost all losses that the Company incurs, or is reasonably expected to incur, as a result of any non-retail Customer failing to pay the Company for the sale of power during the deferral period.
- Include fuel costs and revenues associated with steam sales from the Coyote Springs I Plant.
- Include gas resale revenues.
- Include Energy Charge revenues from Schedules 76R, 38, 83, 89, and 91 Energy pricing options other than Cost of Service and the Energy Charge revenues from the Market Based Pricing Option from Schedules 483 and 489 as an offset to NVPC.
- NVPC shall be adjusted as needed to comply with Order 07-015 that states that ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.

ADJUSTMENT AMOUNT

The amount accruing to the Power Cost Variance Account, whether positive or negative will be multiplied by a revenue sensitive factor of 1.0287 to account for franchise fees and uncollectables.

The Power Cost Adjustment Rate shall be set at level such that the projected amortization for 12 month period beginning with the implementation of the rate is no greater than six percent (6%) of annual Company retail revenues for the preceding calendar year.

TIME AND MANNER OF FILING

As a minimum, on July 1st of the following year (or the next business day if the 1st is a weekend or holiday), the Company will file with the Commission recommended adjustment rates for the next calendar year.

Schedule 126 (Continued)

TIME AND MANNER OF FILING (Continued)

Included in this filing will be the following information:

1) A transmittal letter that summarizes the proposed changes.
2) Revised Power Cost Variance Rates.
3) Work papers supporting the calculation of the revised PCV rates.

If the Company finds that the PCV Rates may over or under collect revenues in a particular year, the Company may recommend a modification of the Adjustment Rates to the Commission. The Company may also recommend that the Commission consider Adjustment Rates based on a collection or refund period different than one year based on the balance in the PCV Account.

POWER COST VARIANCE RATES

The PCV Rates will be determined on an equal cents per kWh basis. The PCV Rates are:

Schedule	Adjustment Rate
7	0.000 ¢ per kWh
15	0.000 ¢ per kWh
32	0.000 ¢ per kWh
38	0.000 ¢ per kWh
47	0.000 ¢ per kWh
49	0.000 ¢ per kWh
75	
Secondary	0.000 ¢ per kWh(1)
Primary	0.000 ¢ per kWh(1)
Subtransmission	0.000 ¢ per kWh(1)
83	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
87	
Secondary	0.000 ¢ per kWh(1)
Primary	0.000 ¢ per kWh(1)
Subtransmission	0.000 ¢ per kWh(1)
89	
Secondary	0.000 ¢ per kWh
Primary	0.000 ¢ per kWh
Subtransmission	0.000 ¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

Schedule 126 (Continued)

POWER COST VARIANCE RATES (Continued)

Schedule	Adjustment Rate
91	0.000 ¢ per kWh
92	0.000 ¢ per kWh
93	0.000 ¢ per kWh
94	0.000 ¢ per kWh
483	
Secondary	0.000 ¢ per kWh(2)
Primary	0.000 ¢ per kWh(2)
489	
Secondary	0.000 ¢ per kWh(2)
Primary	0.000 ¢ per kWh(2)
Subtransmission	0.000 ¢ per kWh(2)
515	0.000 ¢ per kWh(2)
532	0.000 ¢ per kWh(2)
538	0.000 ¢ per kWh(2)
549	0.000 ¢ per kWh(2)
575	
Secondary	0.000 ¢ per kWh(1)
Primary	0.000 ¢ per kWh(1)
Subtransmission	0.000 ¢ per kWh(1)
583	
Secondary	0.000 ¢ per kWh(2)
Primary	0.000 ¢ per kWh(2)
Subtransmission	0.000 ¢ per kWh(2)
589	
Secondary	0.000 ¢ per kWh(2)
Primary	0.000 ¢ per kWh(2)
Subtransmission	0.000 ¢ per kWh(2)
591	0.000 ¢ per kWh(2)
592	0.000 ¢ per kWh(2)
594	0.000 ¢ per kWh

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.
(2) Not applicable to Customers where service was received for the entire calendar year that the Annual Power Cost Variance accrued.

SCHEDULE 126 (Concluded)

TERM

Effective for service on and after January 17, 2007 and continuing until terminated by the Commission.

This schedule may only be terminated upon approval or order of the Commission. If this schedule is terminated for any reason, the Company will determine the remaining Adjustment Amount on a prorated basis consistent with the principles of this schedule. In such case, any balance in the PCV Account will be amortized to rates over a period to be determined by the Commission.

AVISTA CORPORATION

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STATE OF WASH.
UTIL. AND TRANSP.
COMMISSION

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-08____

DIRECT TESTIMONY OF

RONALD L. MCKENZIE

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, business address and present position with Avista Corporation ("Avista" or "Company").

A. My name is Ronald L. McKenzie and my business address is East 1411 Mission Avenue, Spokane, Washington. I am employed by Avista as Manager, Regulatory Accounting in the State and Federal Regulation Department.

Q. Would you briefly describe your educational background and professional experience?

A. I graduated from Eastern Washington University in 1973 with a Bachelor of Arts degree in Business Administration majoring in accounting. I joined the Company in September 1974. I obtained a Master of Business Administration Degree from Eastern Washington University in 1989. I have attended several utility accounting and ratemaking courses and workshops. I have held various accounting positions within the Company. I have served in the State and Federal Regulation Department for the majority of my career with the Company.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before this Commission in several prior proceedings.

Q. What is the scope of your testimony in this proceeding?

A. My testimony addresses the accounting associated with the power cost deferrals under the Energy Recovery Mechanism ("ERM") approved by the Commission in Docket No. UE-011595. I also explain what is contained in the monthly reports that are filed with the Commission.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. ___(RLM-2), which consists of a copy of the December 2007 monthly ERM report for informational purposes.

II. ACCOUNTING ASSOCIATED WITH ERM DEFERRALS

Q. Would you please describe the accounting associated with the Company's ERM deferral mechanism?

A. Yes. Company witness Mr. William G. Johnson discusses, in his direct testimony, the procedure to calculate the monthly variations between actual and authorized power supply revenues and expenses. The ERM deadband and sharing mechanism were modified effective January 1, 2006 pursuant to Order 03 in Docket UE-060181 dated June 16, 2006. Under the revised mechanism, monthly variations are accumulated until the calendar-year deadband of $4.0 million is exceeded. Once the deadband is exceeded, 50% of the cumulative variation between actual and authorized net power supply costs between $4.0 million and $10.0 million is deferred. Once the cumulative power supply cost variance from the amount included in base rates exceeds $10.0 million, 90% of the cost variance is deferred for future surcharge or rebate. When actual net power supply costs exceed authorized costs, entries are made to record the deferral amount by crediting Account 557.28 - Other Power Supply Expenses, thereby decreasing recorded power supply expenses, and debiting Account 186.28 - Miscellaneous Deferred Debits. If actual net power supply costs are less than authorized costs in a given month, an entry is made to record the difference by debiting Account 557.28 - Other Power Supply Expenses, thereby increasing recorded power supply expenses, and crediting Account 186.28 - Miscellaneous Deferred Debits. An accumulated debit balance in Account 186.28 represents a surcharge balance, while an accumulated credit balance represents a rebate balance.

Q. How is interest recorded on the deferral balances?

A. Interest is calculated pursuant to the Settlement Stipulation approved by the Commission's Fifth Supplemental Order in Docket No. UE-011595, dated June 18, 2002. Interest is applied to the average of the beginning and ending month balances in Account 186.28 net of associated deferred federal income tax. The Company's weighted cost of debt is used as the interest rate. The interest rate is updated semi-annually and interest is compounded semi-annually. The interest rate used for the period January 1, 2007 through June 30, 2007 was 7.825%, the Company's weighted cost of debt at December 31, 2006. The interest rate used for the period July 1, 2007 through December 31, 2007 was 7.843%, the Company's weighted cost of debt at June 30, 2007.

Q. How are income taxes accounted for under the deferred power cost mechanism?

A. The power cost deferral entries are not recognized in the determination of taxable income for federal income tax purposes. Therefore, deferred federal income taxes are recorded. Account 283.28 – Accumulated Deferred Federal Income Tax reflects a credit balance of 35% of the debit balances in Account 186.28. When Account 283.28 is credited, Account 410.10 – Deferred FIT Expense in debited. Likewise, when Account 283.28 is debited, Account 410.10 is credited.

Q. In 2007 what were the amounts deferred, absorbed by the Company, and the balance in the 2007 deferral account, Account 186.28, at December 31, 2007?

A. For the 2007 calendar year actual net power costs exceeded authorized net power costs for the Washington jurisdiction by $24,826,407. Of that amount $16,343,766 was deferred, with the remaining $8,482,641 being absorbed by the Company. The amount absorbed by the Company consists of the $4,000,000 deadband, plus 50% of the variation between $4.0 million and $10.0 million, or $3,000,000, plus 10% of the amount exceeding $10.0 million, or $1,482,641 ($4,000,000+$3,000,000+$1,482,641=$8,482,641 absorbed by Company). There was a balance in the 2007 deferral account at December 31, 2007 of $16,564,895, consisting of the $16,343,766 amount that was deferred during the year plus $221,129 of interest on the deferred costs.

III. ERM MONTHLY AND ANNUAL REPORTS

Q. Would you please describe the monthly reports that the Company submits to the Commission?

A. The Company submits monthly reports to the Commission, Public Counsel, and ICNU that include the monthly power cost deferral journal entries together with backup workpapers and other supporting documentation. The cover letter to the monthly report contains a brief explanation of the factors causing the variance between actual and authorized power costs. The beginning of the month account balances, the recorded activity within the accounts, and the ending month account balances are shown. The January and July reports contain the supporting workpapers for the semi-annual updates of the weighted cost of debt used in the interest calculations. The monthly reports also include any new power contracts of one-year or longer, entered into during the month. Attached as Exhibit No. ___(RLM-2) is a copy of the December 2007 report for informational purposes.

Q. What are the requirements associated with the annual filing to review deferrals?

A. The Company is required to make an annual filing, on or before April 1 of each year, regarding the power costs deferred in the prior calendar year under the ERM. The filing consists of testimony, exhibits, and supporting documentation. Since its inception in 2002, the Company has made six such annual filings, including the present filing covering the 2007 calendar year.

Q. What is the review period for the annual ERM filing?

A. The Commission Staff and interested parties have the opportunity to review the deferral information during a 90-day review period ending June 30th each year. The 90-day review period may be extended by agreement of the parties participating in the review, or by Commission order.

Q. When was the last annual ERM filing addressed by the Commission?

A. The annual ERM filing covering the 2006 calendar year was reviewed in Docket No. UE-070623. Order 01 was issued in that docket on June 27, 2007, and the Commission found that the power cost deferrals for 2006 were prudent.

Q. Have the 2007 ERM calculations and accounting entries been made in a manner consistent with the ERM methodology approved by the Commission?

A. Yes.

Q. Does this conclude your pre-filed direct testimony?

A. Yes, it does.