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Sent: Wednesday, November 30, 2016 3:45 PM
To: Drabkin, Elisabeth <Elisabeth.Drabkin@bracewelllaw.com>; jayne.riske@blackhillscorp.com; efilingacceptance@ferc.gov
Subject: FERC Acceptance for Filing in ER17-441-000

Notification of Acceptance for Filing

This is to notify that the FERC Office of the Secretary has accepted the following electronic submission for filing (Acceptance for filing does not constitute approval of any application or self-certifying notice):

-Accession No.: 201611305324
-Docket(s) No.: ER17-441-000
-Filed By: Black Hills Power, Inc.
-Signed By: Christopher Mackaronis
-Filing Title: Tariff Filing
-Filing Description: Black Hills Power, Inc. submits tariff filing per 35.13(a)(2)(ii): Powder River Energy Corporation Rate Modification in Joint Tariff to be effective 1/30/2017 under ER17-441 Filing Type : 340
-Type of Filing Code: 340
-Earliest Proposed Effective Date: 1/30/2017
-Submission Date/Time: 11/30/2016 3:37:17 PM
-Filed Date: 11/30/2016 3:37:17 PM

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DEC 05 2016

SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

November 30, 2016

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

Re: Black Hills Power, Inc.
Docket No. ER17-___-000
Rate Modification in Joint Tariff

Dear Secretary Bose:

Powder River Energy Corporation ("PRECorp") hereby tenders for filing a revised tariff sheet (Attachment H) to modify its component of the revenue requirement recovered under the joint open-access transmission tariff of Black Hills Power, Inc. ("Black Hills"), Basin Electric Power Cooperative ("Basin"), and PRECorp (collectively, the "Common Use Utilities"), designated as Black Hills Power, Inc. FERC Electric Tariff, Substitute Revised Volume No. 4 ("Joint Tariff").[1] The modification to the rates is a result of two major transmission upgrades by PRECorp. The first involves the construction of the Bill Durfee Substation, which was built at a cost of $3,742,973 to address increased load and resulting reliability concerns. The second involves the construction of the Teckla Substation Terminal, which was built at a cost of $1,124,308 to support a new west-to-east 230kV Black Hills interstate transmission line. As explained in the testimony of PRECorp's Chief Executive Officer, Michael Easley, these two projects, which are now in service, were designed and constructed to enhance service under the

[1] Black Hills is the tariff administrator of the Joint Tariff. Consequently, any required e-tariff filings will be submitted by Black Hills.

Joint Tariff. PRECorp requests that the Commission accept the revised tariff sheets for filing and make them effective on sixty (60) days notice, January 30, 2017, without suspension. This effective date is to ensure that PRECorp can, as soon as possible, recover the cost of the newly installed facilities which are responsible for the requested rate increase and which have already gone into service.

I. BACKGROUND

PRECorp is a consumer-owned rural regional electric cooperative headquartered in Sundance, Wyoming. PRECorp serves 12,236 residential and industrial members through 11,300 miles of power lines. In addition, PRECorp owns and operates 65 miles of interstate transmission lines, all of which are committed to service under the Joint Tariff. While Black Hills is a public utility as defined in the Federal Power Act, PRECorp is a member cooperative of Basin and is a rural electric cooperative that is not subject to FERC jurisdiction by operation of Section 201(f) of the Federal Power Act, 16 U.S.C. 824(f).[2]

With their filing for the Joint Tariff in September 2003,[3] PRECorp, Black Hills and Basin combined their respective interstate transmission systems located in the Western Interconnection into a single system, the "Common Use System," to provide open access transmission service under the Joint Tariff. PRECorp, Black Hills and Basin taken together own 230-kV and 69-kV transmission facilities in South Dakota, Wyoming, Montana and Nebraska, some of which are jointly owned. The Commission accepted and suspended the Joint Tariff and established hearing

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2 PRECorp is a Rural Utility Service ("RUS") borrower.

3 Docket No. ER03-1354-000.

and settlement judge procedures.[4] By Order dated August 6, 2004, the Commission approved an uncontested settlement that resolved all pending issues regarding the Joint Tariff.[5] The following year, the Commission approved a Revised Attachment H filed by the Common Use Utilities that corrected an error that had been detected in the earlier filed attachment.[6] The approved revised Attachment H (Substitute First Revised Sheet No. 139) provided for an annual transmission revenue requirement for PRECorp of $1,297,602. That amount has remained unchanged until now. The present filing, if accepted by the Commission, will increase PRECorp's annual revenue requirement by approximately $826,000, to $2,123,466.

The annual revenue requirement for service under the Joint Tariff is equal to the sum of the revenue requirements of each of the three Common Use Utilities—PRECorp, Basin and Black Hills. Attachment H provides that each of the Common Use Utilities may unilaterally propose to modify its respective cost of service pursuant to a filing with the Commission. The rates for network transmission service are derived by dividing the monthly revenue requirement by the network customers' monthly load ratio share. The rates for point-to-point service are updated each April 1 by dividing the annual revenue requirement as shown on Attachment H, net of revenue credits for short-term firm and non-firm point-to-point transmission service, by the sum of the monthly network loads and firm point-to-point transmission reservations at the times of the monthly peaks for the previous calendar year.

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4 Order Accepting and Suspending Proposed Joint Open Access Transmission Tariff, as Modified, and Establishing Hearing and Settlement Judge Procedures, 106 FERC ¶ 61,119 (Feb. 12, 2004).

5 Order Approving Uncontested Settlement, 108 FERC ¶ 61,165 (Aug. 6, 2004).

6 Order Accepting Revised Attachment H, 112 FERC ¶ 61,318 (Sept. 20, 2005).

II. THE INSTANT RATE FILING

PRECorp's current revenue requirement under Attachment H has remained the same since 2005. The recent completion of the Bill Durfee Substation and the Teckla Substation Terminal, however, has rendered the historic revenue requirement insufficient to recover the costs of PRECorp's current interstate transmission infrastructure.

This filing includes the testimony of Mr. Alan C. Heintz, Vice President with Brown, Williams, Moorhead & Quinn, Inc. of Washington, D.C. Mr. Heintz testifies that PRECorp's revenue requirement for its facilities included in the Common Use System will increase by approximately $826,000, from $1,297,602 to $2,123,466.[7] Mr. Heintz developed the revenue requirement using 2015 actual costs, with the known and measurable costs associated with the new transmission additions.

Mr. Heintz does not separately justify a return on equity. Rather, he calculated the revenue requirement using as a proxy the same 10.8% return on equity currently in effect for both Black Hills and Basin under the Joint Tariff.[8] The 10.8% rate represents a slight reduction from the rate of 10.85% which PRECorp has used since 2004 when the Commission first accepted the initial Common Use Tariff.[9]

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7 *See generally* Direct Testimony and Exhibits of Alan C. Heintz, Exhibit Nos. PRE-2 through PRE-4 (Attachment D hereto). Exhibit No. PRE-4 at 2 (identifying necessary revenue increase of $825,963.03)

8 *See* Order Accepting Proposed Tariff Sheets, As Amended, 126 FERC ¶ 61,104 (Feb. 10, 2009) (including a 10.8% return on equity); Order Approving Uncontested Settlement, 128 FERC ¶ 61,274 (Sept. 24, 2009) (including a 10.8% return on equity).

9 Order Accepting and Suspending Proposed Refund Plan, Instituting Investigation, Establishing Refund Effective Date and Hearing and Settlement Judge Procedures, and Consolidating Dockets, 112 FERC ¶ 61,165 (Aug. 6, 2004)

The use of a 10.8% return on equity is just and reasonable. Because PRECorp is an RUS borrower, it does not have bond ratings and does not enter the market for debt,[10] factors which the Commission has recognized make it virtually impossible to perform a discounted cash flow analysis.[11] In these circumstances, Black Hills and Basin provide a reasonable proxy.[12] First, a 10.8% return on equity is currently allowed to both Basin and Black Hills for their respective portions of the cost of service under the Joint Tariff. Second, both of the two new PRECorp facilities which occasion this rate increase request were necessary for the integrity of the system. The Durfee Substation replaced an aged and stressed line built in 1957, while the Tekla Substation Terminal was constructed and put into service in response to, and as a result of, facilities constructed by Black Hills.[13] Because of that, and because all of PRECorp's transmission facilities are required for the proper operation of the Common Use System, it is reasonable to apply the same rate of return on equity to recover the costs of all of the facilities that are part of that system. *See, e.g., Citizens Energy Corp.*, 129 FERC ¶ 61,242 (2009) (allowing proxy rate already in effect for joint developer of transmission project).

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10 *See* Testimony of Michael E. Easley, CEO of PRECorp., Exhibit No. PRE-1 at 3-4.

11 *Sw. Power Pool, Inc.*, 153 FERC ¶ 61,367, at P 43 n.73 (Dec. 30, 2015) (citing Opinion No. 479, 111 FERC ¶ 61,092 (2005), *order on reh'g*, Opinion No. 479-A, 112 FERC ¶ 61,207 (2005), *reh'g denied*, Opinion No. 479-B, 115 FERC ¶ 61,297 (2006) and *Sw. Power Pool, Inc.*, 153 FERC ¶ 61,281, at P 11 (2015)).

12 In similar circumstances, the Commission has permitted merchant generators to use the interconnected utility's rate of return as a proxy. *See Columbia Energy LLC*, 124 FERC ¶ 61,189, at P 25 (2008)(citing *Bluegrass Generation Co., L.L.C.*, 118 FERC ¶ 61,214, at P 86 (2007)).

13 Easley Testimony at 3 (Exhibit No. PRE-1).

Further, a 10.8% return on equity is just and reasonable given the financial risks undertaken by PRECorp in constructing the major transmission projects that have prompted this filing. The combined cost of the Bill Durfee and Teckla projects, some $4.87 million, represents an 65% increase in PRECorp's net transmission plant in service subject to the Joint Tariff.[14] This degree of investment, and concomitant risk, in other contexts, would properly support a request for incentive rates in demonstrating that a project is not "routine."[15] PRECorp is not here seeking an incentive rate. However, the relative magnitude of investment demonstrates the risk incurred by PRECorp, especially given that PRECorp's only opportunity to recover the cost of its investment in the Joint Tariff facilities is through the Joint Tariff.

The resulting rate increase under the Joint Tariff is likewise just and reasonable. PreCorp's requested new revenue requirement of $2,123,466 per year remains a small portion (6.3%) of the total revenue requirement for the Joint Use Utilities of $33,713,284.[16] While the requested increase in PRECorp's revenue requirement is significant for PRECorp – an increase of 64% its overall impact on the total revenue requirement for the Common Use Utilities is modest. Because of PRECorp's small contribution to the Common Use System, the rates resulting from accepting PRECorp's rate change reflect only a modest overall increase as well.[17]

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[14] Prior to the investment in the two projects, PRECorp's net investment in transmission facilities subject to the Joint Tariff was $6.1 million. After the new investment, net investment climbs to $10.1 million. *See* Testimony of Alan C. Heintz, Exhibit No. PRE-2 at 5-6.

[15] *See, e.g., Citizens Energy Corp.*, 129 FERC ¶ 61,242 at P 17 (2009); *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084, at P 54 (2007).

[16] *See* Heintz Testimony (Exhibit No. PRE-2) at 4 and 9 and Attachment A.

[17] The revenue requirement requested here "would only result in an increase of $0.11/kw/month ($2.76/kw/month to $2,87/kw/month) in the rate paid by transmission customers." Heintz Testimony at 9 (Exhibit No. PRE-2).

III. MISCELLANEOUS

The Revised Sheets have been paginated and designated in accordance with Designation of Electric Rate Schedule Sheets, Order No. 614, FERC Stats. & Regs. ¶ 31,096 (2000).

No costs or expenses supporting the rates in the Revised Sheets have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative or unnecessary that are demonstrably the product of discriminatory practices.

IV. CONTENTS OF FILING

The following documents are included in this filing:

1. A Revised Tariff Sheet (Attachment A);
2. The currently-effective page of the Joint Tariff, redlined to show the changes being made pursuant to this filing (Attachment B);
3. Prepared Direct Testimony of Michael Easley, Exhibit No. PRE-1, (Attachment C), which includes his attestation of PRECorp's business records as required by 18 C.F.R. §35.13(d)(6);
4. Prepared Direct Testimony and Exhibits of Alan C. Heintz, Exhibit Nos. PRE-2 through PRE-4 (Attachment D); and
5. A List of Recipients (Attachment E).

V. COMMUNICATIONS

Please direct all communications concerning this filing to the following persons and include their names on the Commission's official service list in this proceeding:

Michael Easley, Chief Executive Officer
Power River Energy Corporation
221 Main Street
P.O. Box 930
Sundance, WY 82729-0930
307-283-3531 (Phone)
307-283-3527 (Fax)
mikee@precorp.coop (Email)

Christopher G. Mackaronis
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson Street, NW
Eighth Floor — West Tower
Washington, DC 20007
202-342-0800 (Phone)
202-342-0807 (Fax)
chris.mackaronis@smxblaw.com(E-mail)

Respectfully submitted,

STONE MATTHEIS XENOPOULOS &
BREW, PC

//Christopher G. Mackaronis//
Christopher G. Mackaronis
1025 Thomas Jefferson Street, NW
Eighth Floor — West Tower
Washington, DC 20007
202-342-0800 (Phone)
202-342-0807 (Fax)
chris.mackaronis@smxblaw.com

Enclosures

ATTACHMENT A

REVISED TARIFF SHEET

ATTACHMENT H

MONTHLY NETWORK TRANSMISSION REVENUE REQUIREMENT FOR TRANSMISSION SERVICE ON THE AC TRANSMISSION SYSTEM

1. The Annual Transmission Cost for Transmission Service on the AC Transmission System is:

a.	Black Hills Component:	Annual Transmission Revenue Requirement as determined pursuant to the formula set forth in this Attachment H
b.	Basin Electric Component:	$16,482,130
c.	PRECorp Component:	$2,123,466
d.	Annual Transmission Cost:	$ (a + b + c)

The amounts in (a) (b) and (c) shall be effective until amended by the Transmission Provider or until modified by the Commission. Each of Black Hills, Basin Electric and PRECorp ("Party") may unilaterally modify its component of the Annual Transmission Cost pursuant to a filing with the FERC; provided that it must notify the other two Parties in writing not less than thirty (30) days prior to making such filing.

2. The Monthly Network Transmission Revenue Requirement shall be computed each month as follows:

$$x = (y \div 12) - z$$

x	=	Monthly Network Transmission Revenue Requirement
y	=	Annual Transmission Cost (item 1(d))
z	=	Revenues from all Point-to-Point Transmission Service on the AC Transmission System in the month.

Black Hills Power, Inc.
Annual Transmission Revenue Requirement Formula

Estimate

Service Year 2009

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator (page 4)		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	329,718,108	NA		
2	Transmission	207.58.g	70,930,677	TP	0.73987	52,479,764
3	New Construction CUS Assets	See Workpaper 2 (line 9)	17,247,000	TP	0.73987	12,760,607
4	New Construction CUS Assets	See Workpaper 3 (line 19 col D)	2,974,250	TP	0.73987	2,200,570
5	Distribution	207.75.g	239,729,489	NA		
6	General & Intangible	See Workpaper 4 (line 5 col 1)	31,450,235	W/S	0.07016	2,206,407
7	Allocated Plant	See Workpaper 5 (line 5)	5,054,792	W/S	0.07016	354,621
8	Communication System	207.94.g	6,874,999	T&D	0.21360	1,468,503
9	Common	356.1	0	CE	0.00000	0
10	TOTAL GROSS PLANT	(sum lines 1 - 9)	703,979,550	GP=	10.152%	71,470,473
11						
12	ACCUMULATED DEPRECIATION					
13	Production	219.20-24.c	159,696,980	NA		
14	Transmission	219.25.c	23,826,360	TPA	0.88176	21,009,226
15	Additional Transmission Depr	See Workpaper 2 (line 48)	2,090,423	TPA	0.88176	1,843,259
16	Distribution	219.26.c	79,001,766	NA		
17	General & Intangible	See Workpaper 4 (line 24 col 1)	15,050,577	W/S	0.07016	1,055,881
18	Allocated Plant	See Workpaper 5 (line 11)	2,073,154	W/S	0.07016	145,443
19	Communication System	See Workpaper 4 (line 22 col 2)	2,136,253	T&D	0.21360	456,305
20	Common	356.1	0	CE	0.00000	0
21	TOTAL ACCUM. DEPRECIATION	(sum lines 13 - 20)	283,875,513			24,510,115
22						
23	NET PLANT IN SERVICE					
24	Production	(line 1 - line 13)	170,021,128	Auto		
25	Transmission	(line 2 - line 14)	47,104,317	Auto		31,470,537
26	New Construction CUS Assets	(line 3 - line 15)	15,156,577	Auto		10,917,347
27	New Construction CUS Assets	(line 4)	2,974,250	Auto		2,200,570
28	Distribution	(line 5 - line 16)	160,727,723	Auto		
29	General & Intangible	(line 6 - line 17)	16,399,658	Auto		1,150,526
30	Allocated Plant	(line 7 - line 18)	2,981,638	Auto		209,178
31	Communication System	(line 8 - line 19)	4,738,746	Auto		1,012,199
32	Common	(line 9 - line 20)	0	Auto		0
33	TOTAL NET PLANT	(sum lines 24 - 32)	420,104,037	NP=	11.178%	46,960,358
34						
35	ADJUSTMENTS TO RATE BASE	(Note A)				
36	Account No. 281 (enter negative)	273.8.k	(4,343)	NA	zero	-
37	Account No. 282 (enter negative)	275.2.k	(68,245,483)	NP	0.11178	(7,628,663)
38	Account No. 283 (enter negative)	277.9.k	(8,788,261)	NP	0.11178	(982,375)
39	Account No. 190	234.8.c	7,258,863	NP	0.11178	811,415
40	Account No. 255 (enter negative)	267.8.h	(307,159)	NP	0.11178	(34,335)
41	FAS 109 Adjustment	(232.1.f - 278.1.f - 278.3.f)*.35	806,475	NP	0.11178	90,150
42	TOTAL ADJUSTMENTS	(sum lines 36 - 41)				(7,743,809)
43						
44	LAND HELD FOR FUTURE USE	214.x.d (Note B)	0	DA	0.00000	0
45						
46	WORKING CAPITAL (Notes C & H)					
47	CWC	(1/8 * line 63)	2,437,258	Auto		232,223
48	Materials & Supplies	227.5.c	4,668,225	T&D	0.21360	997,135
49	Materials & Supplies	227.8.c	94,372	TP	0.73987	69,823
50	Prepayments (Account 165)	111.57.c	6,173,396	GP	0.10152	626,745
51	TOTAL WORKING CAPITAL	(sum lines 47 - 50)				1,925,927
52						
53	TRANSMISSION RATE BASE	(sum lines 33, 42, 44, & 51)				41,142,476

Service Year 2009

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator (page 4)		(5) Transmission (Col 3 times Col 4)
	O&M					
54	Transmission	321.112.b	9,746,087	TP	0.73987	7,210,876
55	Less: Account 565 and 561	321.84-92.b & 96.b	9,091,266	TP	0.73987	6,726,391
56	A&G	323.194.b	19,414,837	W/S	0.07016	1,362,058
57	Less FERC Annual Fees (Note D)	350.1.b	201,513	W/S	0.07016	14,137
58	Plus: Fixed PBOP expense	(Note I)	227,200	W/S	0.07016	15,939
59	Less: Actual PBOP expense	(Company Records)	224,882	W/S	0.07016	15,777
60	Less: EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note E)		449,068	W/S	0.07016	31,505
61	Plus Trans Related Reg. Comm. Exp. (Note E)	(Workpaper 1 line 11)	76,667	TP	0.73987	56,724
62	Common	356.1	0	CE	0.00000	0
63	TOTAL O&M (sum lines 54, 56, 58, 61, 62 less lines 55, 57, 59 , 60)		19,498,062			1,857,787
64						
65	DEPRECIATION EXPENSE (Note I)					
66	Transmission	336.7.b	1,650,459	TP	0.73987	1,221,132
67	New Construction CUS Assets	See Workpaper 2 (line 13)	400,130	TP	0.73987	296,046
68	New Construction CUS Assets	See Workpaper 3 (line 23)	69,003	TP	0.73987	51,053
69	General & intangible	336.10.b & 336.1.d&e	2,389,067	W/S	0.07016	167,606
70	Common	336.11.b	0	CE	0.00000	0
71	TOTAL DEPRECIATION (Sum lines 66 - 70)		4,508,659			1,735,837
72						
73	TAXES OTHER THAN INCOME TAXES (Note F)					
74	LABOR RELATED					
75	Payroll	263.3i, 263.4i, 263.12i	1,667,209	W/S	0.07016	116,964
76	Highway and vehicle	263.i	0	W/S	0.07016	0
77	PLANT RELATED					
78	Property	263.23i	4,341,000	GP	0.10152	440,714
79	Gross Receipts	263.i	0	NA	zero	0
80	Other	263.i	0	GP	0.10152	0
81	TOTAL OTHER TAXES (sum lines 75 - 80)		6,008,209			557,677
82						
83						
84	INCOME TAXES	(Note G)				
85	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%			
86	CIT=(T/1-T) * (1-(WCLTD/R)) =		34.99%			
87	where WCLTD=(line 156) and R= (line 159)					
88	and FIT, SIT & p are as given in footnote G.					
89						
90	Total Income Taxes	(line 86 * line 93)				1,363,778
91						
92	RETURN					
93	[Rate Base (line 53) * R (line 159)]			Auto		3,897,187
94						
95	ESTIMATED REVENUE REQUIREMENT (sum lines 63, 71, 81, 90, 93)		30,014,930			9,412,267

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.								
	TRANSMISSION PLANT INCLUDED IN JOINT TARIFF RATES							
		Form 1 Reference						
96	Total transmission plant	Column (3) sum lines 2 - 4						91,151,927
97	Less transmission plant excluded from Common Use Facilities	Company Records						25,310,952
98	Less transmission plant included in Ancillary Services							0
99	Transmission plant included in Common Use Facilities (line 96 less lines 97 and 98)							65,840,975
100	Plus Common Use AC Facilities (line 110)							6,150,861
101	Total Gross Plant for the CUS System (line 99 plus line 100)							71,991,836
102	Total CUS Plant (line 96 plus line 110)							97,302,788
103								
104	Percentage of transmission plant included in Common Use Facilities (line 101 divided by line 102)						TP=	0.739874
105								
106	DISTRIBUTION PLANT INCLUDED IN JOINT TARIFF RATES	Form 1 Reference						
107	Total distribution plant	Column (3) line 5						239,729,489
108	Less distribution plant excluded from Common Use Facilities	Company Records						233,578,628
109	Less distribution plant included in Ancillary Services							0
110	Common Use AC Facilities (line 107 less lines 108 & 109)							6,150,861
111								
112	Percentage of distribution plant included in Common Use Facilities (line 107 divided by line 110)						DP=	0.025658
113								
114	ACCUMULATED DEPRECIATION	Form 1 Reference						
115	Total Transmission Accumulated Depreciation	Column (3), sum lines 14 - 15						25,916,783
116	Less transmission plant excluded from Common Use Facilities	Company Records						3,428,179
117	Total Transmission Accumulated Depreciation included in Common Use Facilities (line 115 - line 116)							22,488,604
118	Plus Common Use AC Facilities Accumulated Depreciation (line 127)							3,077,649
119	Total Accumulated Depreciation for the CUS System (line 117 plus line 118)							25,566,253
120	Total CUS Accumulated Depreciation (line 115 plus line 118)							28,994,432
121								
122	Percentage of transmission plant accumulated depreciation included in Common Use Facilities (line 119 divided by line 120)						TPA=	0.881764
123								
124		Form 1 Reference						
125	Total Distribution Accumulated Depreciation	219.26.c						79,001,766
126	Less distribution accumulated depreciation excluded from Common Use Facilities (Company Records)							75,924,117
127	Common Use AC Facilities (line 125 less line 126)							3,077,649
128								
129	Percentage of distribution plant accumulated depreciation included in Common Use Facilities (line 127 divided by line 125)						DPA=	0.038957
130								
131	WAGES & SALARY ALLOCATOR (W&S)							
132		Form 1 Reference	$	TP		Allocation		
133	Transmission	354.21.b	1,171,648	0.74		866,872		
134	Total Wages Expense	354.28.b	14,244,451	0.00		0		W&S Allocator
135	Less: A&G Wages	354.27.b	-1,888,017	0.00		0		($ / Allocation)
136	Adjusted Total (sum lines 134-135)		12,356,434			866,872	WS=	0.07016
137								
138	TRANSMISSION & DISTRIBUTION ALLOCATOR (T&D)		$	%	TP	T&D		
139	Transmission Net Plant	lines 25, 26 & 27	65,235,144	28.87%	74%	21.36%		
140	Distribution Net Plant	line 28	160,727,723	71.13%				
141	Total (sum lines 139 - 140)		225,962,867	100%			T&D =	21.36%
142								
143	RETURN (R)	Form 1 Reference						$
144	Long Term Interest	117, sum of 62.c through 66.c						11,817,050
145								
146	Preferred Dividends	118.29.c (positive number)						-
147								
148	Development of Common Stock:	Form 1 Reference						
149	Proprietary Capital	112.16.c						232,419,703
150	Less: Preferred Stock	112.3.c						-
151	Less: Undistributed Earnings	112.12.c (enter negative)						-
152	Less: Accum Other Comp Inc	112.15.c (enter negative)						1,277,097
153	Adjusted Common Stock		(sum lines 149-152)					233,696,800
154								
155		Form 1 Reference	$	%		Cost		Weighted
156	Long Term Debt	112.24.c	153,217,473	43.00%		7.71%		3.32%
157	Preferred Stock	112.3.c	0	0.00%		0.00%		0.00%
158	Adjusted Common Stock	(see above line 153)	233,696,800	57.00% (Note I)		10.80% (Note I)		6.16%
159	Total (sum lines 156-158)		386,914,273				R =	9.47%

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Note Letter	
A	The balances in Accounts 281, 282, 283 and 190, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 109. Balance of Account 255 is reduced by prior flow through and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated.
B	Identified in Form 1 as being only transmission related.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at line 47, column 5.
D	The FERC's annual charges for the year assessed the Transmission Owner for service since annual charges assessed directly under this tariff.
E	Line 1 - EPRI Annual Membership Dues listed in Form 1 at 335.1.b, all Regulatory Commission Expenses itemized at 351.1.h, and non-safety related advertising included in Account 930.1.
F	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in rates, since they are recovered elsewhere.
G	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 7, line 26).

Inputs Required:			
	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes

H	See Note H for the True-Up calculation.
I	Depreciation rates, PBOP, ROE, and Capital Structure are fixed amounts that can be changed only through a Section 205 filing.

True Up

Service Year 2009

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator (page 4)		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE	(Note H)				
1	Production	205.46.g		NA		
2	Transmission	207.58.g		TP	0.00000	0
3	Distribution	207.75.g		NA		
4	General & Intangible	See Workpaper 4		W/S	0.00000	0
5	Allocated Plant	See Workpaper 5		W/S	0.00000	0
6	Communication System	See Workpaper 4		T&D	0.00000	0
7	Common	356.1		CE	0.00000	0
8	TOTAL GROSS PLANT	(sum lines 1 - 7)	0	GP=	0.000%	0
9						
10	ACCUMULATED DEPRECIATION	(Note H)				
11	Production	219.20-24.c		NA		
12	Transmission	219.25.c		TPA	0.00000	0
13	Distribution	219.26.c		NA		
14	General & Intangible	219.28.c		W/S	0.00000	0
15	Allocated Plant	See Workpaper 5		W/S	0.00000	0
16	Communication System	See Workpaper 4		T&D	0.00000	0
17	Common	356.1		CE	0.00000	0
18	TOTAL ACCUM. DEPRECIATION	(sum lines 11 - 17)	0			0
19						
20	NET PLANT IN SERVICE	(Note H)				
21	Production	(line 1 - line 11)	0	Auto		
22	Transmission	(line 2 - line 12)	0	Auto		0
23	Distribution	(line 3 - line 13)	0	Auto		
24	General & Intangible	(line 4 - line 14)	0	Auto		0
25	Allocated Plant	(line 5 - line 15)	0	Auto		0
26	Communication System	(line 6 - line 16)	0	Auto		0
27	Common	(line 7 - line 17)	0	Auto		0
28	TOTAL NET PLANT	(sum lines 21 - 27)	0	NP=	0.000%	0
29						
30	ADJUSTMENTS TO RATE BASE	(Notes A & H)				
31	Account No. 281 (enter negative)	273.8.k		NA	zero	-
32	Account No. 282 (enter negative)	275.2.k		NP	0.00000	-
33	Account No. 283 (enter negative)	277.9.k		NP	0.00000	-
34	Account No. 190	234.8.c		NP	0.00000	-
35	Account No. 255 (enter negative)	267.8.h		NP	0.00000	-
36	FAS 109 Adjustment	(232.1.f - 278.1.f - 278.3.f)*.35		NP	0.00000	-
37	TOTAL ADJUSTMENTS	(sum lines 31 - 36)				-
38						
39	LAND HELD FOR FUTURE USE	214.x.d (Notes B & H)	0	DA	0.00000	0
40						
41	WORKING CAPITAL (Notes C & H)					
42	CWC	(1/8 * line 58)	0	Auto		0
43	Materials & Supplies	227.5.c		T&D	0.00000	0
44	Materials & Supplies	227.8.c		TP	0.00000	0
45	Prepayments (Account 165)	111.57.d		GP	0.00000	0
46	TOTAL WORKING CAPITAL	(sum lines 42 - 45)				0
47						
48	TRANSMISSION RATE BASE	(sum lines 28, 37, 39, & 46)				0

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator (page 4)		(5) Transmission (Col 3 times Col 4)
	O&M					
49	Transmission	321.112.b		TP	0.00000	0
50	Less: Account 565 and 561	321.84-92.b & 96.b		TP	0.00000	0
51	A&G	323.194.b		W/S	0.00000	0
52	Less FERC Annual Fees (Note D)	350.1.b		W/S	0.00000	0
53	Plus: Fixed PBOP expense	(Note I)		W/S	0.00000	0
54	Less: Actual PBOP expense	(Company Records)		W/S	0.00000	0
55	Less: EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note E)			W/S	0.00000	0
56	Plus Transmission Related Reg. Comm. Exp. (Note E)			TP	0.00000	0
57	Common	356.1		CE	0.00000	0
58	TOTAL O&M (sum lines 49, 51, 53, 56, 57 less lines 50, 52, 54 , 55)		0			0
59						
60	DEPRECIATION EXPENSE (Note I)					
61	Transmission	336.7.b		TP	0.00000	0
62	General & intangible	336.10.b & 336.1.d&e		W/S	0.00000	0
63	Common	336.11.b		CE	0.00000	0
64	TOTAL DEPRECIATION (Sum lines 61 - 63)		0			0
65						
66	TAXES OTHER THAN INCOME TAXES (Note F)					
67	LABOR RELATED					
68	Payroll	263.3i, 263.4i, 263.12i		W/S	0.00000	0
69	Highway and vehicle	263.i		W/S	0.00000	0
70	PLANT RELATED					
71	Property	263.23i		GP	0.00000	0
72	Gross Receipts	263.i		NA	zero	0
73	Other	263.i		GP	0.00000	0
74	TOTAL OTHER TAXES (sum lines 68 - 73)		0			0
75						
76						
77	INCOME TAXES	(Note G)				
78	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%			
79	CIT=(T/1-T) * (1-(WCLTD/R)) =		53.85%			
80	where WCLTD=(line 154) and R= (line 157)					
81	and FIT, SIT & p are as given in footnote G.					
82						
83	Total Income Taxes	(line 79 * line 86)				0
84						
85	RETURN			Auto		0
86	[Rate Base (line 48) * R (line 157)]					
87						
88	REVENUE REQUIREMENT (sum lines 58, 64, 74, 83, 85)		0			0
89						
90	ESTIMATED REVENUE REQUIREMENT (pg. 3 line 95)					
91						
92	TRUE-UP AMOUNT TO BE (REFUNDED)/PAID (line 88 - line 90)					0

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.	Item	Form 1 Reference	$	TP / %	TP	Allocation / T&D / Cost		Amount
	TRANSMISSION PLANT INCLUDED IN JOINT TARIFF RATES							
		Form 1 Reference						
93	Total transmission plant	Column (3) line 2						0
94	Less transmission plant excluded from Common Use Facilities	Company Records						
95	Less transmission plant included in Ancillary Services	Company Records						
96	Transmission plant included in Common Use Facilities (line 93 less lines 94 and 95)							0
97	Plus Common Use AC Facilities (line 107)							0
98	Total Gross Plant for the CUS System (line 96 plus line 97)							0
99	Total CUS Plant (line 93 plus line 107)							0
100								
101	Percentage of transmission plant included in Common Use Facilities (line 98 divided by line 99)						TP=	0.000000
102								
103	DISTRIBUTION PLANT INCLUDED IN JOINT TARIFF RATES	Form 1 Reference						
104	Total distribution plant	Column (3) line 3						0
105	Less distribution plant excluded from Common Use Facilities	Company Records						
106	Less distribution plant included in Ancillary Services	Company Records						
107	Common Use AC Facilities (line 104 less lines 105 & 106)							0
108								
109	Percentage of distribution plant included in Common Use Facilities (line 104 divided by line 107)						DP=	0.000000
110								
111	ACCUMULATED DEPRECIATION	Form 1 Reference						
112	Total Transmission Accumulated Depreciation	Column (3) line 12						0
113	Less transmission plant excluded from Common Use Facilities	Company Records						
114	Total Transmission Accumulated Depreciation included in Common Use Facilities (line 112 - line 113)							0
115	Plus Common Use AC Facilities Accumulated Depreciation (line 124)							0
116	Total Accumulated Depreciation for the CUS System (line 114 plus line 115)							0
117	Total CUS Accumulated Depreciation (line 112 plus line 115)							0
118								
119	Percentage of transmission plant accumulated depreciation included in Common Use Facilities (line 116 divided by line 117)						TPA=	0.000000
120								
121		Form 1 Reference						
122	Total Distribution Accumulated Depreciation	Column (3) line 13						0
123	Less distribution accumulated depreciation excluded from Common Use Facilities (Company Records)							
124	Common Use AC Facilities (line 122 less line 123)							0
125								
126	Percentage of distribution plant accumulated depreciation included in Common Use Facilities (line 124 divided by line 122)						DPA=	0.000000
127								
128	WAGES & SALARY ALLOCATOR (W&S)							
129		Form 1 Reference	$	TP		Allocation		
130	Transmission	354.21.b		0.00		0		
131	Total Wages Expense	354.28.b		0.00		0		W&S Allocator
132	Less: A&G Wages	354.27.b		0.00		0		($ / Allocation)
133	Adjusted Total (sum lines 131-132)		0			0	WS=	0.00000
134								
135	TRANSMISSION & DISTRIBUTION ALLOCATOR (T&D)							
136			$	%	TP	T&D		
137	Transmission Net Plant	line 22	0	0.00%	0%	0.00%		
138	Distribution Net Plant	line 23	0	0.00%				
139	Total (sum lines 137 - 138)		0	0%			T&D =	0.00%
140								
141	RETURN (R)	Form 1 Reference						$
142	Long Term Interest	117, sum of 62.c through 66.c						
143								
144	Preferred Dividends	118.29.c (positive number)						-
145								
146	Development of Common Stock:	Form 1 Reference						
147	Proprietary Capital	112.16.c						
148	Less: Preferred Stock	112.3.c						
149	Less: Undistributed Earnings	112.12.c (enter negative)						
150	Less: Accum Other Comp Inc	112.15.c (enter negative)						
151	Adjusted Common Stock		(sum lines 147-150)					-
152								
153		Form 1 Reference	$	%		Cost		Weighted
154	Long Term Debt	112.24.c		43.00%		0.00%		0.00%
155	Preferred Stock	112.3.c		0.00%		0.00%		0.00%
156	Adjusted Common Stock	(see above line 151)	0	57.00%	(Note I	10.80%	(Note I)	6.16%
157	Total (sum lines 154-156)		0				R =	6.16%

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Note Letter	
A	The balances in Accounts 281, 282, 283 and 190, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 109. Balance of Account 255 is reduced by prior flow through and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated.
B	Identified in Form 1 as being only transmission related.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at line 42, column 5.
D	The FERC's annual charges for the year assessed the Transmission Owner for service since annual charges assessed directly under this tariff.
E	Line 1 - EPRI Annual Membership Dues listed in Form 1 at 335.b, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1.
F	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in rates, since they are recovered elsewhere.
G	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 7, line 26).

Inputs Required:			
	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes

H	For the True-Up calculation only, Gross Plant, Accumulated Depreciation and Net Plant are based on the 13-monthly plant balances. All other rate base items are based on the average of the beginning of the year and end of year balances.
I	Depreciation rates, PBOP, ROE, and Capital Structure are fixed amounts that can be changed only through a Section 205 filing.

Capital True Up

Line No.

1 The True-Up Adjustment component of the Formula Rate for each Rate Year beginning with rates effective January 1, 2010 shall be determined as follows:

3 (i) Beginning with 2009, no later than June 1 of each year, Black Hills Power shall recalculate an adjusted Annual
4 Transmission Revenue Requirement (ATRR) for the previous calendar year based on its actual costs as reflected
5 in its Form No. 1 and its books and records for that calendar year, consistent with FERC
6 accounting policies.

8 (ii) Black Hills Power shall determine the difference between the recalculated ATRR as determined in paragraph (i)
9 above, and ATRR based on projected costs for the previous calendar year (True-Up Adj before Interest).

11 (iii) The True-Up Adjustment shall be determined as follows:

13 True-Up Adjustment equals the True-Up Adjustment before Interest multiplied by (1+i)^18 months.

15 Where: i = Sum of (the monthly rates for the 4 months ending April 30 of the current year and
16 the monthly rates for the 12 months ending December 31 of the preceding year)
17 divided by 16 months.

19 Summary of Formula Rate Process including True-Up Adjustment (Using 2009 as an example)

		Month	Year	Action
21		Month	Year	Action
22	**True-Up Calculation:**			
23	Step 1	May	2010	TO populates the formula with 2009 Actual data and calculates the 2009 True-up Adjustment before Interest
24	Step 2	May	2010	TO compares the revenue received during 2009 to the True-Up calculation done above
25	Step 3	May	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
26	Step 4	July	2010	TO either collects or pays the lump-sum adjustment calculated above
27				
28	**Annual Rate Calculation:**			
29	Step 5	September	2010	TO populates the formula with 2009 Actual data plus known additions placed in service (over $1,000,000) for 2010 (See WP 2 for an example)
30	Step 6	September	2010	TO estimates transmission Capital Additions (over $1,000,000) for 2011 expected to be in service in 2011 (See WP 3 for an example)
31	Step 7	September	2010	TO adds weighted Capital Adds, Accumulated Depreciation and Depreciation Expense to plant in service in Formula
32	Step 8	September	2010	Post results of Step 7 on web site
33	Step 9	October	2010	TO to hold an open meeting for it's customers and representatives to explain the formula rate projections and cost details
34	Step 10	January	2011	Results of Step 7 go into effect

36 Note 1: To the extent possible each input into the Formula Rate used to calculate the actual ATRR included in the True-Up
37 Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form No. 1
38 by the application of clearly identified and supported information. If the reconciliation is provided through a
39 worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency
40 standard, and doing so will satisfy this transparency requirement for the amounts that are output from the
41 worksheet and input to the main body of the Formula Rate.

43 Complete for Each Calendar Year beginning in 2009

			Transmission	Schedule 1
44			Transmission	Schedule 1
45	A	True-Up Amount (Transmission see pg 7 line 92 and Schedule 1 see pg 18 line 12)	-	-
46	B	Future Value Factor (1+i)^18	1.00	1.00
47	C	True-Up Amount to be (Refunded)/Paid based on 2009 Actual Load (A*B)	$0.00	$0.00

49 Where: i = average interest rate as calculated below

51 Interest on Amount of Refunds or Surcharges Interest 35.19a for Current Year

Line	Month	Year	Interest 35.19a for Month
54	January	Year 1	0.0000%
55	February	Year 1	0.0000%
56	March	Year 1	0.0000%
57	April	Year 1	0.0000%
58	May	Year 1	0.0000%
59	June	Year 1	0.0000%
60	July	Year 1	0.0000%
61	August	Year 1	0.0000%
62	September	Year 1	0.0000%
63	October	Year 1	0.0000%
64	November	Year 1	0.0000%
65	December	Year 1	0.0000%
66	January	Year 2	0.0000%
67	February	Year 2	0.0000%
68	March	Year 2	0.0000%
69	April	Year 2	0.0000%
70		Average Interest Rate	0.0000%

Black Hills Power, Inc.
Formula Rate Protocols

Section I. Applicability

The following procedures shall apply to Black Hills Power, Inc.'s ("Black Hills Power") calculation of its projected net revenue requirement, actual net revenue requirement, and True-Up Adjustment (as that term is defined in Section VI.1 of these protocols) for a calendar year ("Service Year").

Section II. Annual True-Up and Projected Net Revenue Requirement

1. On or before June 1 of each year, Black Hills Power shall determine its actual net revenue requirement and True-Up Adjustment (collectively, "Annual True-Up") for the preceding Service Year in accordance with the Black Hills Power formula rate under Attachment H to the Joint Open Access Transmission Tariff of Black Hills Power, Basin Electric Power Cooperative, and Powder River Energy Corporation ("Joint Tariff") and Section VI of these protocols, and shall post its Annual True-Up on the Black Hills Power website and OASIS. Within ten (10) days of such posting, Black Hills Power shall provide notice to Interested Parties (as that term is defined in Section II.6 of these protocols) of such posting via an email exploder list for which Interested Parties may subscribe on the Black Hills Power website.

2. On or before September 30 of each year, Black Hills Power shall determine its projected net revenue requirement for the following Service Year in accordance with the Black Hills Power formula rate under the Joint Tariff, and shall post its projected net revenue requirement on the Black Hills Power website and OASIS. Within ten (10) days of posting the projected net revenue requirement, Black Hills Power shall provide notice to Interested Parties of such posting to an email exploder list for which Interested Parties may subscribe on the Black Hills Power website.

3. If the date for posting the Annual True-Up or the projected net revenue requirement falls on a weekend or a holiday recognized by Federal Energy Regulatory Commission ("FERC"), then the posting shall be due on the next business day. The dates on which posting of the Annual True-Up and the projected net revenue requirement occur shall be that year's "True-Up Publication Date" and "Projected Rate Publication Date," respectively. Any delay in the True-Up Publication Date or Projected Rate Publication Date will result in an equivalent extension of time for the submission of information and document requests discussed in Section III of these protocols.

4. The Annual True-Up shall:

A. Include a workable data-populated formula rate template and underlying workpapers in native format with all formulas and links intact;

B. Be based on Black Hills Power's FERC Form No. 1 for the prior calendar year;

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Annual True-Up that are not otherwise available in FERC Form No. 1;

D. Provide sufficient information to enable Interested Parties to replicate the calculation of the Annual True-Up results from FERC Form No. 1;

E. Identify any changes in the formula references (page and line numbers) to FERC Form No. 1;

F. Identify all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to FERC Form No. 1 and any adjustments not shown in FERC Form No. 1;

G. Provide underlying data for formula rate inputs that provide greater granularity than is required for FERC Form No. 1;

H. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

  a. Identify any Accounting Changes, including:

    i. the initial implementation of an accounting standard or policy,

    ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction,

    iii. correction of errors and prior period adjustments that impact the True-Up Adjustment calculation,

    iv. the implementation of new estimation methods or policies that change prior estimates, and

    v. changes to income tax elections;

  b. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (*e.g.*, fair value adjustments);

  c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the

Annual True-Up; and

d. Provide, for each item identified pursuant to Sections II.4.H.a - II.4.H.c of these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

5. The projected net revenue requirement shall:

A. Include a workable data-populated formula rate template and underlying workpapers in native format with all formulas and links intact;

B. Be based on Black Hills Power's most recent FERC Form No. 1;

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected net revenue requirement that are not otherwise available in FERC Form No. 1;

D. Provide sufficient information to enable Interested Parties to replicate the calculation of the projected net revenue requirement;

E. With respect to any Accounting Change:

a. Identify any Accounting Changes, including:

i. the initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that impact the projected net revenue requirement calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (*e.g.*, fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement; and

d. Provide, for each item identified pursuant to Sections II.5.D.a - II.5.D.c of these protocols, a narrative explanation of the individual impact of such changes on the projected net revenue requirement.

6. Black Hills Power shall hold an open meeting among Interested Parties between the True-Up Publication Date and July 1 each year ("Annual True-Up Meeting"). No less than seven (7) days prior to such Annual True-Up Meeting, Black Hills Power shall provide notice on its website and OASIS of the time, date, and location of the Annual True-Up Meeting, and shall provide notice of such meeting via an email exploder list. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the Joint Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual True-Up Meeting shall: (i) permit Black Hills Power to explain and clarify its Annual True-Up;

and (ii) provide Interested Parties an opportunity to seek information and clarifications from Black Hills Power about the Annual True-Up. Black Hills Power shall provide remote access to Annual True-Up Meetings to allow all Interested Parties the opportunity to remotely participate in such meetings.

7. Black Hills Power shall hold an open meeting among Interested Parties between the Projected Rate Publication Date and October 30 each year ("Annual Projected Rate Meeting"). No less than seven (7) days prior to such Annual Projected Rate Meeting, Black Hills Power shall provide notice on its website and OASIS of the time, date, and location of the Annual Projected Rate Meeting, and shall provide notice of such meeting via an email exploder list. The Annual Projected Rate Meeting shall: (i) permit Black Hills Power to explain and clarify its projected net revenue requirement; and (ii) provide Interested Parties an opportunity to seek information and clarifications from Black Hills Power about the projected net revenue requirement. Black Hills Power shall provide remote access to Annual Projected Rate Meetings to allow all Interested Parties the opportunity to remotely participate in such meetings.

8. In the event that Black Hills Power utilizes a regional cost sharing mechanism with other transmission owners for the recovery of transmission project costs under Black Hills Power's formula rate contained in this Attachment H of the Joint Tariff, Black Hills Power shall endeavor to coordinate with other transmission owners utilizing the same regional cost sharing mechanism to hold an annual joint informational meeting among those transmission owners and Interested Parties to enable all Interested Parties the opportunity to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects. No less than seven (7) days prior to such joint informational meetings, Black Hills Power shall provide notice on its website and OASIS of the time, date, and location of the joint informational

meeting, and shall provide notice of such meeting via an email exploder list. Black Hills Power shall provide remote access to joint informational meetings to allow all Interested Parties the opportunity to remotely participate in such meetings.

Section III. Information Exchange Procedures

Each Annual True-Up and projected net revenue requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have until August 1 following the True-Up Publication Date (unless such period is extended with the written consent of Black Hills Power or by FERC order) to serve reasonable information and document requests on Black Hills Power ("True-Up Information Exchange Period"). If August 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests for the True-Up Information Exchange Period shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

A. the extent or effect of an Accounting Change;

B. whether the Annual True-Up fails to include data properly recorded in accordance with these protocols;

C. the proper application of the formula rate and procedures in these protocols;

D. the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up;

E. the prudence of actual costs and expenditures, including utilized procurement methods and cost control methodologies;

F. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

G. any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula rate.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

2. Interested Parties shall have until November 30 following the Projected Rate Publication Date (unless such period is extended with the written consent of Black Hills Power or by FERC order) to serve reasonable information and document requests on Black Hills Power ("Projected Rate Information Exchange Period"). If November 30 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests for the Projected Rate Information Exchange Period shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

A. the extent or effect of an Accounting Change;

B. whether the projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

C. the proper application of the formula rate and procedures in these protocols;

D. the accuracy of data and consistency with the formula rate of the calculations shown in the projected net revenue requirement;

E. the prudence of projected costs and expenditures, including utilized procurement methods and cost control methodologies;

F. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

G. any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula rate.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

3. Black Hills Power shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. Black Hills Power shall respond to all information and document requests submitted during the True-Up Information Exchange Period by no later than September 1 following the True-Up Publication Date, unless the True-Up Information Exchange Period is extended by Black Hills Power or FERC. Further, Black Hills Power shall respond to all information and document requests submitted during the Projected Rate Information Exchange Period by no later than December 31 following the Projected Rate Publication Date, unless the Projected Rate Information Exchange Period is extended by Black Hills Power or FERC.

4. Black Hills Power will post on its website and OASIS all information and document requests from Interested Parties and Black Hills Power's response(s) to such requests; except, however, if responses to information and document requests include material deemed by Black Hills Power to be privileged and/or confidential, such information will not be publicly posted but confidential information will be made available to requesting parties provided that a confidentiality agreement is executed by Black Hills Power and the requesting party.

5. Black Hills Power shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent

FERC proceeding addressing Black Hills Power's Annual True-Up or projected net revenue requirement.

Section IV. Challenge Procedures

1. Interested Parties shall have until September 15 following the True-Up Publication Date (unless such period is extended with the written consent of Black Hills Power or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify Black Hills Power in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up. The period of time from the True-Up Publication Date until September 15 shall be referred to as the "True-Up Review Period." If September 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges regarding the Annual True-Up shall be extended to the next business day.

2. Interested Parties shall have until January 15 following the Projected Rate Publication Date (unless such period is extended with the written consent of Black Hills Power or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify Black Hills Power in writing, which may be made electronically, of any specific Informal Challenges to the projected net revenue requirement. The period of time from the Projected Rate Publication Date until January 15 shall be referred to as the "Projected Rate Review Period." If January 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges regarding the projected net revenue requirement shall be extended to the next business day.

3. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge within the timelines provided in these protocols regarding any issue as to a given Annual True-Up or projected net revenue requirement shall bar pursuit of such issue with respect to that

Annual True-Up or projected net revenue requirement under the challenge procedures set forth in these protocols, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or projected net revenue requirement. This Section IV.3 in no way shall affect a party's rights under Section 206 of the Federal Power Act as set forth in Section IV.10 of these protocols.

4. A party submitting an Informal Challenge to Black Hills Power must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Black Hills Power shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. Black Hills Power shall appoint a senior representative to work with the party (or its representative) submitting the Informal Challenge toward a resolution of the dispute, and, where deemed necessary, may request the appointment of a FERC Administrative Law Judge that is mutually acceptable to the challenging party to facilitate discussions to attempt to resolve the dispute. If Black Hills Power disagrees with such challenge, Black Hills Power will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge of the Annual True-Up or projected net revenue requirement may be submitted after September 15 and January 15, respectively, following the True-Up Publication Date and Projected Rate Publication Date, unless September 15 or January 15 falls on a weekend or a holiday recognized by FERC, in which case the deadline for submitting all Informal Challenges shall be extended to the next business day. Black Hills Power must respond to: (1) all Informal Challenges of the Annual True-Up by no later than October 15 following the True-Up Publication Date, unless the True-Up Review Period is extended by Black Hills Power

or FERC; and (2) all Informal Challenges of the projected net revenue requirement by February 15 following the Projected Rate Publication Date, unless the Projected Rate Review Period is extended by Black Hills Power or FERC.

5. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements:

A. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the formula rate or protocols;

b. Explain how the action or inaction violates the formula rate or protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

iii. The proper application of the formula rate and procedures in these protocols;

iv. The accuracy of data and consistency with the formula rate of the charges shown in the Annual True-Up or projected net revenue requirement;

v. The prudence of actual or projected costs and expenditures;

vi. The effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

vii. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

e. State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Informal Challenge procedures described these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

B. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on Black Hills Power. Service to Black Hills Power must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with Section 385.2010(f)(3) of FERC's Rules of Practice and Procedure, facsimile, express delivery, or messenger. 18 C.F.R. § 385.2010(f)(3). The party filing the Formal Challenge shall serve the individual listed as the contact person on Black Hills Power's Informational Filing required under Section V of these protocols.

6. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols; (3) the proper application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up and projected net revenue requirement; (5) the prudence of actual or projected costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula rate.

7. Black Hills Power will post on its website and OASIS all Informal Challenges from Interested Parties and Black Hills Power's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by Black Hills Power to be privileged and/or confidential, such information will not be publicly

posted but confidential information will be made available to requesting parties provided that a confidentiality agreement is executed by Black Hills Power and the requesting party.

8. An Interested Party shall have until April 1 following the True-Up Review Period and Projected Rate Review Period (unless such date is extended with the written consent of Black Hills Power to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on Black Hills Power on the date of such filing as specified in Section IV.5.B of these protocols. A Formal Challenge shall be filed in the same docket as Black Hills Power's Informational Filing discussed in Section V of these protocols. Black Hills Power shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable True-Up Review Period or Projected Rate Review Period.

9. In any proceeding initiated by FERC concerning the Annual True-Up or projected net revenue requirement or in response to a Formal Challenge, Black Hills Power shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols, and that it followed the applicable requirements and procedures in Attachment H of the Joint Tariff and these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

10. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Black Hills Power to file unilaterally, pursuant to Federal Power Act Section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to Section

206 of the Federal Power Act and the regulations thereunder.

11. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols, and the Annual True-Up and projected net revenue requirement shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act Section 205 or Section 206 filing.

12. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts or FERC Form No. 1, shall first raise the matter with Black Hills Power in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Informational Filings

1. By March 1 of each year, Black Hills Power shall submit to FERC an informational filing ("Informational Filing") of its projected net revenue requirement and Annual True-Up in connection with the postings performed in accordance with Section II of these protocols during the prior year. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying workpapers; (2) that Black Hills Power has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the net revenue requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of projected costs. The Informational Filing shall include the formula rate template and underlying workpapers in native format fully populated and with formulas intact. The Informational Filing also must describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge

procedures. Within five (5) days of such Informational Filing, Black Hills Power shall provide notice of the Informational Filing via an email exploder list and by posting the docket number assigned to Black Hills Power's Informational Filing on its website and OASIS.

2. Any challenges to the implementation of the Black Hills Power formula rate under Attachment H of the Joint Tariff must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VI. Calculation of True-Up Adjustment

The True-Up Adjustment will be determined in the following manner:

1. The projected net revenue requirement on the Annual Transmission Revenue Requirement Formula Estimate template, line 95, column 5 of Attachment H for the Service Year will be compared to the True-Up net revenue requirement for the same Service Year (Annual Transmission Revenue Requirement True Up template, line 88, column 5 of Attachment H of the Joint Tariff) calculated in accordance with Attachment H of the Joint Tariff using Black Hills Power's FERC Form No. 1 for the same Service Year to determine any over or under recovery. The sum of the excess or shortfall due to the actual versus projected net revenue requirement shall constitute the "True-Up Adjustment" amount. The True-Up Adjustment and related calculations shall be posted to Black Hills Power's website and OASIS no later than June 1 (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day) following the issuance of the FERC Form No. 1 for the previous year, as set forth in Section II of these protocols.

2. The True-Up Adjustment amount to be refunded or paid, as calculated on line 47 of the Annual Transmission Revenue Requirement Capital True Up in Attachment H of the Joint Tariff,

shall be paid in full in July of each year. The amount on any over or under recovery shall be allocated to the customers based on actual billing determinants for the preceding year.

3. Interest on any over recovery of the net revenue requirement shall be determined based on Section 35.19a of FERC's regulations. 18 C.F.R. § 35.19a. Interest on any under recovery of the net revenue requirement shall be determined using the interest rate equal to Black Hills Power's actual short-term debt costs capped at the applicable FERC refund interest rate. In either case, the interest payable shall be calculated using an average interest rate for the sixteen (16) months during which the over or under recovery in the net revenue requirement exists (*i.e.*, January of the year prior through April of the year in which the true-up occurs). That interest rate will be applied, with quarterly compounding, to the principal amount (*i.e.*, the over or under recovery in the net revenue requirement) for the eighteen (18) months during which that over or under recovery exists.

Section VII. Changes to True-Up Adjustment or Projected Net Revenue Requirement

1. Any changes or adjustments made to the True-Up Adjustment after the True-Up Publication Date, including but not limited to changes or adjustments to the data inputs in Black Hills Power's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual True-Up, or as a result of the procedures set forth herein, resulting in a change to Black Hills Power's True-Up Adjustment, shall be: (1) posted on the Black Hills Power website and OASIS, and, within ten (10) days of such posting, Black Hills Power shall provide notice to Interested Parties of such posting via an email exploder; and (2) paid in full within thirty (30) calendar days of the date that any such change or adjustment to the True-Up Adjustment is posted to Black Hills Power's website and OASIS, or in accordance with any FERC order. Interest on any refund or surcharge shall be calculated in accordance with the procedures

outlined in Section VI.3 of these protocols or as FERC may otherwise order.

2. Any changes or adjustments made to the projected net revenue requirement after the Projected Rate Publication Date, including but not limited to changes to the data inputs, or as the result of any FERC proceeding to consider the projected net revenue requirement, resulting in a change to Black Hills Power's projected net revenue requirement, shall be posted on the Black Hills Power website and OASIS, and, within ten (10) days of such posting, Black Hills Power shall provide notice to Interested Parties of such posting via an email exploder. Any such changes or adjustments to the projected net revenue requirement agreed to by Black Hills Power on or before January 15 following the Projected Rate Publication Date will be reflected in the projected net revenue requirement for that Service Year. Any changes or adjustments made to the projected net revenue requirement after January 15 following the Projected Rate Publication Date, including but not limited to changes or adjustments as a result of any FERC proceeding to consider the projected net revenue requirement, shall be reflected in Black Hills Power's projected net revenue requirement invoices to be delivered no later than thirty (30) days from the date of posting such change or adjustment to Black Hills Power's website and OASIS, or in accordance with any FERC order. Invoices delivered prior to any such changes or adjustments being made shall be re-invoiced to reflect such changes or adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VI.3 of these protocols or as FERC may otherwise order.

ATTACHMENT B

CURRENTLY EFFECTIVE TARIFF SHEET REFLECTING REVISIONS MADE PURSUANT TO THIS FILING

ATTACHMENT H

MONTHLY NETWORK TRANSMISSION REVENUE REQUIREMENT FOR TRANSMISSION SERVICE ON THE AC TRANSMISSION SYSTEM

1. The Annual Transmission Cost for Transmission Service on the AC Transmission System is:

a.	Black Hills Component:	Annual Transmission Revenue Requirement as determined pursuant to the formula set forth in this Attachment H
b.	Basin Electric Component:	$16,482,130
c.	PRECorp Component:	$2,123,466 ~~1,297,602~~
d.	Annual Transmission Cost:	$ (a + b + c)

The amounts in (a) (b) and (c) shall be effective until amended by the Transmission Provider or until modified by the Commission. Each of Black Hills, Basin Electric and PRECorp ("Party") may unilaterally modify its component of the Annual Transmission Cost pursuant to a filing with the FERC; provided that it must notify the other two Parties in writing not less than thirty (30) days prior to making such filing.

2. The Monthly Network Transmission Revenue Requirement shall be computed each month as follows:

$$x = (y \div 12) - z$$

x	=	Monthly Network Transmission Revenue Requirement
y	=	Annual Transmission Cost (item 1(d))
z	=	Revenues from all Point-to-Point Transmission Service on the AC Transmission System in the month.

Black Hills Power, Inc.
Annual Transmission Revenue Requirement Formula

Estimate

Service Year 2009

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator (page 4)		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
1	Production	205.46.g	329,718,108	NA		
2	Transmission	207.58.g	70,930,677	TP	0.73987	52,479,764
3	New Construction CUS Assets	See Workpaper 2 (line 9)	17,247,000	TP	0.73987	12,760,607
4	New Construction CUS Assets	See Workpaper 3 (line 19 col D)	2,974,250	TP	0.73987	2,200,570
5	Distribution	207.75.g	239,729,489	NA		
6	General & Intangible	See Workpaper 4 (line 5 col 1)	31,450,235	W/S	0.07016	2,206,407
7	Allocated Plant	See Workpaper 5 (line 5)	5,054,792	W/S	0.07016	354,621
8	Communication System	207.94.g	6,874,999	T&D	0.21360	1,468,503
9	Common	356.1	0	CE	0.00000	0
10	TOTAL GROSS PLANT	(sum lines 1 - 9)	703,979,550	GP=	10.152%	71,470,473
11						
12	ACCUMULATED DEPRECIATION					
13	Production	219.20-24.c	159,696,980	NA		
14	Transmission	219.25.c	23,826,360	TPA	0.88176	21,009,226
15	Additional Transmission Depr	See Workpaper 2 (line 48)	2,090,423	TPA	0.88176	1,843,259
16	Distribution	219.26.c	79,001,766	NA		
17	General & Intangible	See Workpaper 4 (line 24 col 1)	15,050,577	W/S	0.07016	1,055,881
18	Allocated Plant	See Workpaper 5 (line 11)	2,073,154	W/S	0.07016	145,443
19	Communication System	See Workpaper 4 (line 22 col 2)	2,136,253	T&D	0.21360	456,305
20	Common	356.1	0	CE	0.00000	0
21	TOTAL ACCUM. DEPRECIATION	(sum lines 13 - 20)	283,875,513			24,510,115
22						
23	NET PLANT IN SERVICE					
24	Production	(line 1 - line 13)	170,021,128	Auto		
25	Transmission	(line 2 - line 14)	47,104,317	Auto		31,470,537
26	New Construction CUS Assets	(line 3 - line 15)	15,156,577	Auto		10,917,347
27	New Construction CUS Assets	(line 4)	2,974,250	Auto		2,200,570
28	Distribution	(line 5 - line 16)	160,727,723	Auto		
29	General & Intangible	(line 6 - line 17)	16,399,658	Auto		1,150,526
30	Allocated Plant	(line 7 - line 18)	2,981,638	Auto		209,178
31	Communication System	(line 8 - line 19)	4,738,746	Auto		1,012,199
32	Common	(line 9 - line 20)	0	Auto		0
33	TOTAL NET PLANT	(sum lines 24 - 32)	420,104,037	NP=	11.178%	46,960,358
34						
35	ADJUSTMENTS TO RATE BASE	(Note A)				
36	Account No. 281 (enter negative)	273.8.k	(4,343)	NA	zero	-
37	Account No. 282 (enter negative)	275.2.k	(68,245,483)	NP	0.11178	(7,628,663)
38	Account No. 283 (enter negative)	277.9.k	(8,788,261)	NP	0.11178	(982,375)
39	Account No. 190	234.8.c	7,258,863	NP	0.11178	811,415
40	Account No. 255 (enter negative)	267.8.h	(307,159)	NP	0.11178	(34,335)
41	FAS 109 Adjustment	(232.1.f - 278.1.f - 278.3.f)*.35	806,475	NP	0.11178	90,150
42	TOTAL ADJUSTMENTS	(sum lines 36 - 41)				(7,743,809)
43						
44	LAND HELD FOR FUTURE USE	214.x.d (Note B)	0	DA	0.00000	0
45						
46	WORKING CAPITAL (Notes C & H)					
47	CWC	(1/8 * line 63)	2,437,258	Auto		232,223
48	Materials & Supplies	227.5.c	4,668,225	T&D	0.21360	997,135
49	Materials & Supplies	227.8.c	94,372	TP	0.73987	69,823
50	Prepayments (Account 165)	111.57.c	6,173,396	GP	0.10152	626,745
51	TOTAL WORKING CAPITAL	(sum lines 47 - 50)				1,925,927
52						
53	TRANSMISSION RATE BASE	(sum lines 33, 42, 44, & 51)				41,142,476

Service Year 2009

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator (page 4)		(5) Transmission (Col 3 times Col 4)
	O&M					
54	Transmission	321.112.b	9,746,087	TP	0.73987	7,210,876
55	Less: Account 565 and 561	321.84-92.b & 96.b	9,091,266	TP	0.73987	6,726,391
56	A&G	323.194.b	19,414,837	W/S	0.07016	1,362,058
57	Less FERC Annual Fees (Note D)	350.1.b	201,513	W/S	0.07016	14,137
58	Plus: Fixed PBOP expense	(Note I)	227,200	W/S	0.07016	15,939
59	Less: Actual PBOP expense	(Company Records)	224,882	W/S	0.07016	15,777
60	Less: EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note E)		449,068	W/S	0.07016	31,505
61	Plus Trans Related Reg. Comm. Exp. (Note E)	(Workpaper 1 line 11)	76,667	TP	0.73987	56,724
62	Common	356.1	0	CE	0.00000	0
63	TOTAL O&M (sum lines 54, 56, 58, 61, 62 less lines 55, 57, 59 , 60)		19,498,062			1,857,787
64						
65	DEPRECIATION EXPENSE (Note I)					
66	Transmission	336.7.b	1,650,459	TP	0.73987	1,221,132
67	New Construction CUS Assets	See Workpaper 2 (line 13)	400,130	TP	0.73987	296,046
68	New Construction CUS Assets	See Workpaper 3 (line 23)	69,003	TP	0.73987	51,053
69	General & intangible	336.10.b & 336.1.d&e	2,389,067	W/S	0.07016	167,606
70	Common	336.11.b	0	CE	0.00000	0
71	TOTAL DEPRECIATION (Sum lines 66 - 70)		4,508,659			1,735,837
72						
73	TAXES OTHER THAN INCOME TAXES (Note F)					
74	LABOR RELATED					
75	Payroll	263.3i, 263.4i, 263.12i	1,667,209	W/S	0.07016	116,964
76	Highway and vehicle	263.i	0	W/S	0.07016	0
77	PLANT RELATED					
78	Property	263.23i	4,341,000	GP	0.10152	440,714
79	Gross Receipts	263.i	0	NA	zero	0
80	Other	263.i	0	GP	0.10152	0
81	TOTAL OTHER TAXES (sum lines 75 - 80)		6,008,209			557,677
82						
83						
84	INCOME TAXES	(Note G)				
85	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%			
86	CIT=(T/1-T) * (1-(WCLTD/R)) =		34.99%			
87	where WCLTD=(line 156) and R= (line 159)					
88	and FIT, SIT & p are as given in footnote G.					
89						
90	Total Income Taxes	(line 86 * line 93)				1,363,778
91						
92	RETURN					
93	[Rate Base (line 53) * R (line 159)]			Auto		3,897,187
94						
95	ESTIMATED REVENUE REQUIREMENT (sum lines 63, 71, 81, 90, 93)		30,014,930			9,412,267

Service Year 2009

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN JOINT TARIFF RATES	Form 1 Reference		
96	Total transmission plant	Column (3) sum lines 2 - 4		91,151,927
97	Less transmission plant excluded from Common Use Facilities	Company Records		25,310,952
98	Less transmission plant included in Ancillary Services			0
99	Transmission plant included in Common Use Facilities (line 96 less lines 97 and 98)			65,840,975
100	Plus Common Use AC Facilities (line 110)			6,150,861
101	Total Gross Plant for the CUS System (line 99 plus line 100)			71,991,836
102	Total CUS Plant (line 96 plus line 110)			97,302,788
103				
104	Percentage of transmission plant included in Common Use Facilities (line 101 divided by line 102)		TP=	0.739874
105				
106	DISTRIBUTION PLANT INCLUDED IN JOINT TARIFF RATES	Form 1 Reference		
107	Total distribution plant	Column (3) line 5		239,729,489
108	Less distribution plant excluded from Common Use Facilities	Company Records		233,578,628
109	Less distribution plant included in Ancillary Services			0
110	Common Use AC Facilities (line 107 less lines 108 & 109)			6,150,861
111				
112	Percentage of distribution plant included in Common Use Facilities (line 107 divided by line 110)		DP=	0.025658
113				
114	ACCUMULATED DEPRECIATION	Form 1 Reference		
115	Total Transmission Accumulated Depreciation	Column (3), sum lines 14 - 15		25,916,783
116	Less transmission plant excluded from Common Use Facilities	Company Records		3,428,179
117	Total Transmission Accumulated Depreciation included in Common Use Facilities (line 115 - line 116)			22,488,604
118	Plus Common Use AC Facilities Accumulated Depreciation (line 127)			3,077,649
119	Total Accumulated Depreciation for the CUS System (line 117 plus line 118)			25,566,253
120	Total CUS Accumulated Depreciation (line 115 plus line 118)			28,994,432
121				
122	Percentage of transmission plant accumulated depreciation included in Common Use Facilities (line 119 divided by line 120)		TPA=	0.881764
123				
124		Form 1 Reference		
125	Total Distribution Accumulated Depreciation	219.26.c		79,001,766
126	Less distribution accumulated depreciation excluded from Common Use Facilities (Company Records)			75,924,117
127	Common Use AC Facilities (line 125 less line 126)			3,077,649
128				
129	Percentage of distribution plant accumulated depreciation included in Common Use Facilities (line 127 divided by line 125)		DPA=	0.038957
130				

Line No.	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP	Allocation		
132		Form 1 Reference	$	TP	Allocation		
133	Transmission	354.21.b	1,171,648	0.74	866,872		
134	Total Wages Expense	354.28.b	14,244,451	0.00	0		W&S Allocator
135	Less: A&G Wages	354.27.b	-1,888,017	0.00	0		($ / Allocation)
136	Adjusted Total (sum lines 134-135)		12,356,434		866,872	WS=	0.07016
137							

Line No.	TRANSMISSION & DISTRIBUTION ALLOCATOR (T&D)		$	%	TP	T&D		
139	Transmission Net Plant	lines 25, 26 & 27	65,235,144	28.87%	74%	21.36%		
140	Distribution Net Plant	line 28	160,727,723	71.13%				
141	Total (sum lines 139 - 140)		225,962,867	100%			T&D =	21.36%
142								

Line No.	RETURN (R)	Form 1 Reference	$	%	Cost		Weighted
143							$
144	Long Term Interest	117, sum of 62.c through 66.c					11,817,050
145							
146	Preferred Dividends	118.29.c (positive number)					-
147							
148	Development of Common Stock:	Form 1 Reference					
149	Proprietary Capital	112.16.c					232,419,703
150	Less: Preferred Stock	112.3.c					-
151	Less: Undistributed Earnings	112.12.c (enter negative)					-
152	Less: Accum Other Comp Inc	112.15.c (enter negative)					1,277,097
153	Adjusted Common Stock		(sum lines 149-152)				233,696,800
154							
155		Form 1 Reference	$	%	Cost		Weighted
156	Long Term Debt	112.24.c	153,217,473	43.00%	7.71%		3.32%
157	Preferred Stock	112.3.c	0	0.00%	0.00%		0.00%
158	Adjusted Common Stock	(see above line 153)	233,696,800	57.00% (Note I)	10.80% (Note I)		6.16%
159	Total (sum lines 156-158)		386,914,273			R =	9.47%

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Note Letter	
A	The balances in Accounts 281, 282, 283 and 190, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 109. Balance of Account 255 is reduced by prior flow through and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated.
B	Identified in Form 1 as being only transmission related.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at line 47, column 5.
D	The FERC's annual charges for the year assessed the Transmission Owner for service since annual charges assessed directly under this tariff.
E	Line 1 - EPRI Annual Membership Dues listed in Form 1 at 335.1.b, all Regulatory Commission Expenses itemized at 351.1.h, and non-safety related advertising included in Account 930.1.
F	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in rates, since they are recovered elsewhere.
G	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 7, line 26).

Inputs Required:			
	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes

H	See Note H for the True-Up calculation.
I	Depreciation rates, PBOP, ROE, and Capital Structure are fixed amounts that can be changed only through a Section 205 filing.

True Up

Service Year 2009

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Line No.	(1) RATE BASE:	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator (page 4)		(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE	(Note H)				
1	Production	205.46.g		NA		
2	Transmission	207.58.g		TP	0.00000	0
3	Distribution	207.75.g		NA		
4	General & Intangible	See Workpaper 4		W/S	0.00000	0
5	Allocated Plant	See Workpaper 5		W/S	0.00000	0
6	Communication System	See Workpaper 4		T&D	0.00000	0
7	Common	356.1		CE	0.00000	0
8	TOTAL GROSS PLANT	(sum lines 1 - 7)	0	GP=	0.000%	0
9						
10	ACCUMULATED DEPRECIATION	(Note H)				
11	Production	219.20-24.c		NA		
12	Transmission	219.25.c		TPA	0.00000	0
13	Distribution	219.26.c		NA		
14	General & Intangible	219.28.c		W/S	0.00000	0
15	Allocated Plant	See Workpaper 5		W/S	0.00000	0
16	Communication System	See Workpaper 4		T&D	0.00000	0
17	Common	356.1		CE	0.00000	0
18	TOTAL ACCUM. DEPRECIATION	(sum lines 11 - 17)	0			0
19						
20	NET PLANT IN SERVICE	(Note H)				
21	Production	(line 1 - line 11)	0	Auto		
22	Transmission	(line 2 - line 12)	0	Auto		0
23	Distribution	(line 3 - line 13)	0	Auto		
24	General & Intangible	(line 4 - line 14)	0	Auto		0
25	Allocated Plant	(line 5 - line 15)	0	Auto		0
26	Communication System	(line 6 - line 16)	0	Auto		0
27	Common	(line 7 - line 17)	0	Auto		0
28	TOTAL NET PLANT	(sum lines 21 - 27)	0	NP=	0.000%	0
29						
30	ADJUSTMENTS TO RATE BASE	(Notes A & H)				
31	Account No. 281 (enter negative)	273.8.k		NA	zero	-
32	Account No. 282 (enter negative)	275.2.k		NP	0.00000	-
33	Account No. 283 (enter negative)	277.9.k		NP	0.00000	-
34	Account No. 190	234.8.c		NP	0.00000	-
35	Account No. 255 (enter negative)	267.8.h		NP	0.00000	-
36	FAS 109 Adjustment	(232.1.f - 278.1.f - 278.3.f)*.35		NP	0.00000	-
37	TOTAL ADJUSTMENTS	(sum lines 31 - 36)				-
38						
39	LAND HELD FOR FUTURE USE	214.x.d (Notes B & H)	0	DA	0.00000	0
40						
41	WORKING CAPITAL (Notes C & H)					
42	CWC	(1/8 * line 58)	0	Auto		0
43	Materials & Supplies	227.5.c		T&D	0.00000	0
44	Materials & Supplies	227.8.c		TP	0.00000	0
45	Prepayments (Account 165)	111.57.d		GP	0.00000	0
46	TOTAL WORKING CAPITAL	(sum lines 42 - 45)				0
47						
48	TRANSMISSION RATE BASE	(sum lines 28, 37, 39, & 46)				0

Service Year 2009

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator (page 4)		(5) Transmission (Col 3 times Col 4)
	O&M					
49	Transmission	321.112.b		TP	0.00000	0
50	Less: Account 565 and 561	321.84-92.b & 96.b		TP	0.00000	0
51	A&G	323.194.b		W/S	0.00000	0
52	Less FERC Annual Fees (Note D)	350.1.b		W/S	0.00000	0
53	Plus: Fixed PBOP expense	(Note I)		W/S	0.00000	0
54	Less: Actual PBOP expense	(Company Records)		W/S	0.00000	0
55	Less: EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note E)			W/S	0.00000	0
56	Plus Transmission Related Reg. Comm. Exp. (Note E)			TP	0.00000	0
57	Common	356.1		CE	0.00000	0
58	TOTAL O&M (sum lines 49, 51, 53, 56, 57 less lines 50, 52, 54 , 55)		0			0
59						
60	DEPRECIATION EXPENSE (Note I)					
61	Transmission	336.7.b		TP	0.00000	0
62	General & intangible	336.10.b & 336.1.d&e		W/S	0.00000	0
63	Common	336.11.b		CE	0.00000	0
64	TOTAL DEPRECIATION (Sum lines 61 - 63)		0			0
65						
66	TAXES OTHER THAN INCOME TAXES (Note F)					
67	LABOR RELATED					
68	Payroll	263.3i, 263.4i, 263.12i		W/S	0.00000	0
69	Highway and vehicle	263.i		W/S	0.00000	0
70	PLANT RELATED					
71	Property	263.23i		GP	0.00000	0
72	Gross Receipts	263.i		NA	zero	0
73	Other	263.i		GP	0.00000	0
74	TOTAL OTHER TAXES (sum lines 68 - 73)		0			0
75						
76						
77	INCOME TAXES	(Note G)				
78	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		35.00%			
79	CIT=(T/1-T) * (1-(WCLTD/R)) =		53.85%			
80	where WCLTD=(line 154) and R= (line 157)					
81	and FIT, SIT & p are as given in footnote G.					
82						
83	Total Income Taxes	(line 79 * line 86)				0
84						
85	RETURN			Auto		0
86	[Rate Base (line 48) * R (line 157)]					
87						
88	REVENUE REQUIREMENT (sum lines 58, 64, 74, 83, 85)		0			0
89						
90	ESTIMATED REVENUE REQUIREMENT (pg. 3 line 95)					
91						
92	TRUE-UP AMOUNT TO BE (REFUNDED)/PAID (line 88 - line 90)					0

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

SUPPORTING CALCULATIONS AND NOTES

Line No.	TRANSMISSION PLANT INCLUDED IN JOINT TARIFF RATES	Form 1 Reference		
93	Total transmission plant	Column (3) line 2		0
94	Less transmission plant excluded from Common Use Facilities	Company Records		
95	Less transmission plant included in Ancillary Services	Company Records		
96	Transmission plant included in Common Use Facilities (line 93 less lines 94 and 95)			0
97	Plus Common Use AC Facilities (line 107)			0
98	Total Gross Plant for the CUS System (line 96 plus line 97)			0
99	Total CUS Plant (line 93 plus line 107)			0
100				
101	Percentage of transmission plant included in Common Use Facilities (line 98 divided by line 99)		TP=	0.000000
102				
103	DISTRIBUTION PLANT INCLUDED IN JOINT TARIFF RATES	Form 1 Reference		
104	Total distribution plant	Column (3) line 3		0
105	Less distribution plant excluded from Common Use Facilities	Company Records		
106	Less distribution plant included in Ancillary Services	Company Records		
107	Common Use AC Facilities (line 104 less lines 105 & 106)			0
108				
109	Percentage of distribution plant included in Common Use Facilities (line 104 divided by line 107)		DP=	0.000000
110				
111	ACCUMULATED DEPRECIATION	Form 1 Reference		
112	Total Transmission Accumulated Depreciation	Column (3) line 12		0
113	Less transmission plant excluded from Common Use Facilities	Company Records		
114	Total Transmission Accumulated Depreciation included in Common Use Facilities (line 112 - line 113)			0
115	Plus Common Use AC Facilities Accumulated Depreciation (line 124)			0
116	Total Accumulated Depreciation for the CUS System (line 114 plus line 115)			0
117	Total CUS Accumulated Depreciation (line 112 plus line 115)			0
118				
119	Percentage of transmission plant accumulated depreciation included in Common Use Facilities (line 116 divided by line 117)		TPA=	0.000000
120				
121		Form 1 Reference		
122	Total Distribution Accumulated Depreciation	Column (3) line 13		0
123	Less distribution accumulated depreciation excluded from Common Use Facilities (Company Records)			
124	Common Use AC Facilities (line 122 less line 123)			0
125				
126	Percentage of distribution plant accumulated depreciation included in Common Use Facilities (line 124 divided by line 122)		DPA=	0.000000
127				

Line No.	WAGES & SALARY ALLOCATOR (W&S)	Form 1 Reference	$	TP	Allocation		
129							
130	Transmission	354.21.b		0.00	0		
131	Total Wages Expense	354.28.b		0.00	0		W&S Allocator
132	Less: A&G Wages	354.27.b		0.00	0		($ / Allocation)
133	Adjusted Total (sum lines 131-132)		0		0	WS=	0.00000
134							

Line No.	TRANSMISSION & DISTRIBUTION ALLOCATOR (T&D)		$	%	TP	T&D		
136								
137	Transmission Net Plant	line 22	0	0.00%	0%	0.00%		
138	Distribution Net Plant	line 23	0	0.00%				
139	Total (sum lines 137 - 138)		0	0%			T&D =	0.00%
140								

Line No.	RETURN (R)	Form 1 Reference		$
142	Long Term Interest	117, sum of 62.c through 66.c		
143				
144	Preferred Dividends	118.29.c (positive number)		
145				
146	Development of Common Stock:	Form 1 Reference		
147	Proprietary Capital	112.16.c		
148	Less: Preferred Stock	112.3.c		
149	Less: Undistributed Earnings	112.12.c (enter negative)		
150	Less: Accum Other Comp Inc	112.15.c (enter negative)		
151	Adjusted Common Stock		(sum lines 147-150)	-
152				

Line No.		Form 1 Reference	$	%	Cost		Weighted
154	Long Term Debt	112.24.c		43.00%	0.00%		0.00%
155	Preferred Stock	112.3.c		0.00%	0.00%		0.00%
156	Adjusted Common Stock	(see above line 151)	0	57.00% (Note I	10.80% (Note I)		6.16%
157	Total (sum lines 154-156)		0			R =	6.16%

Cost of Service
Utilizing FERC Form 1 Data

Black Hills Power, Inc.

Note Letter	
A	The balances in Accounts 281, 282, 283 and 190, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 109. Balance of Account 255 is reduced by prior flow through and excluded if the utility chose to utilize amortization of tax credits against taxable income. Account 281 is not allocated.
B	Identified in Form 1 as being only transmission related.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at line 42, column 5.
D	The FERC's annual charges for the year assessed the Transmission Owner for service since annual charges assessed directly under this tariff.
E	Line 1 - EPRI Annual Membership Dues listed in Form 1 at 335.b, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1.
F	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in rates, since they are recovered elsewhere.
G	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 7, line 26).

Inputs Required:			
	FIT =	35.00%	
	SIT=	0.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes

H	For the True-Up calculation only, Gross Plant, Accumulated Depreciation and Net Plant are based on the 13-monthly plant balances. All other rate base items are based on the average of the beginning of the year and end of year balances.
I	Depreciation rates, PBOP, ROE, and Capital Structure are fixed amounts that can be changed only through a Section 205 filing.

Capital True Up

Line No.

1 The True-Up Adjustment component of the Formula Rate for each Rate Year beginning with rates effective January 1, 2010 shall be determined as follows:

2

3 (i) Beginning with 2009, no later than June 1 of each year, Black Hills Power shall recalculate an adjusted Annual
4 Transmission Revenue Requirement (ATRR) for the previous calendar year based on its actual costs as reflected
5 in its Form No. 1 and its books and records for that calendar year, consistent with FERC
6 accounting policies.

7

8 (ii) Black Hills Power shall determine the difference between the recalculated ATRR as determined in paragraph (i)
9 above, and ATRR based on projected costs for the previous calendar year (True-Up Adj before Interest).

10

11 (iii) The True-Up Adjustment shall be determined as follows:

12

13 True-Up Adjustment equals the True-Up Adjustment before Interest multiplied by (1+i)^18 months.

14

15 Where: i = Sum of (the monthly rates for the 4 months ending April 30 of the current year and
16 the monthly rates for the 12 months ending December 31 of the preceding year)
17 divided by 16 months.

18

19 Summary of Formula Rate Process including True-Up Adjustment (Using 2009 as an example)

20

Line		Month	Year	Action
21		Month	Year	Action
22	**True-Up Calculation:**			
23	Step 1	May	2010	TO populates the formula with 2009 Actual data and calculates the 2009 True-up Adjustment before interest
24	Step 2	May	2010	TO compares the revenue received during 2009 to the True-Up calculation done above
25	Step 3	May	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
26	Step 4	July	2010	TO either collects or pays the lump-sum adjustment calculated above
27				
28	**Annual Rate Calculation:**			
29	Step 5	September	2010	TO populates the formula with 2009 Actual data plus known additions placed in service (over $1,000,000) for 2010 (See WP 2 for an example)
30	Step 6	September	2010	TO estimates transmission Capital Additions (over $1,000,000) for 2011 expected to be in service in 2011 (See WP 3 for an example)
31	Step 7	September	2010	TO adds weighted Capital Adds, Accumulated Depreciation and Depreciation Expense to plant in service in Formula
32	Step 8	September	2010	Post results of Step 7 on web site
33	Step 9	October	2010	TO to hold an open meeting for it's customers and representatives to explain the formula rate projections and cost details
34	Step 10	January	2011	Results of Step 7 go into effect

35

36 Note 1: To the extent possible each input into the Formula Rate used to calculate the actual ATRR included in the True-Up
37 Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form No. 1
38 by the application of clearly identified and supported information. If the reconciliation is provided through a
39 worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency
40 standard, and doing so will satisfy this transparency requirement for the amounts that are output from the
41 worksheet and input to the main body of the Formula Rate.

42

43 Complete for Each Calendar Year beginning in 2009

Line			Transmission	Schedule 1
44			Transmission	Schedule 1
45	A	True-Up Amount (Transmission see pg 7 line 92 and Schedule 1 see pg 18 line 12)	-	-
46	B	Future Value Factor (1+i)^18	1.00	1.00
47	C	True-Up Amount to be (Refunded)/Paid based on 2009 Actual Load (A*B)	$0.00	$0.00

48

49 Where: i = average interest rate as calculated below

50

51 Interest on Amount of Refunds or Surcharges Interest 35.19a for Current Year

52

Line	Month	Year	Interest 35.19a for Month
53	Month	Year	Interest 35.19a for Month
54	January	Year 1	0.0000%
55	February	Year 1	0.0000%
56	March	Year 1	0.0000%
57	April	Year 1	0.0000%
58	May	Year 1	0.0000%
59	June	Year 1	0.0000%
60	July	Year 1	0.0000%
61	August	Year 1	0.0000%
62	September	Year 1	0.0000%
63	October	Year 1	0.0000%
64	November	Year 1	0.0000%
65	December	Year 1	0.0000%
66	January	Year 2	0.0000%
67	February	Year 2	0.0000%
68	March	Year 2	0.0000%
69	April	Year 2	0.0000%
70		Average Interest Rate	0.0000%

Black Hills Power, Inc.
Formula Rate Protocols

Section I. Applicability

The following procedures shall apply to Black Hills Power, Inc.'s ("Black Hills Power") calculation of its projected net revenue requirement, actual net revenue requirement, and True-Up Adjustment (as that term is defined in Section VI.1 of these protocols) for a calendar year ("Service Year").

Section II. Annual True-Up and Projected Net Revenue Requirement

1. On or before June 1 of each year, Black Hills Power shall determine its actual net revenue requirement and True-Up Adjustment (collectively, "Annual True-Up") for the preceding Service Year in accordance with the Black Hills Power formula rate under Attachment H to the Joint Open Access Transmission Tariff of Black Hills Power, Basin Electric Power Cooperative, and Powder River Energy Corporation ("Joint Tariff") and Section VI of these protocols, and shall post its Annual True-Up on the Black Hills Power website and OASIS. Within ten (10) days of such posting, Black Hills Power shall provide notice to Interested Parties (as that term is defined in Section II.6 of these protocols) of such posting via an email exploder list for which Interested Parties may subscribe on the Black Hills Power website.

2. On or before September 30 of each year, Black Hills Power shall determine its projected net revenue requirement for the following Service Year in accordance with the Black Hills Power formula rate under the Joint Tariff, and shall post its projected net revenue requirement on the Black Hills Power website and OASIS. Within ten (10) days of posting the projected net revenue requirement, Black Hills Power shall provide notice to Interested Parties of such posting to an email exploder list for which Interested Parties may subscribe on the Black Hills Power website.

3. If the date for posting the Annual True-Up or the projected net revenue requirement falls on a weekend or a holiday recognized by Federal Energy Regulatory Commission ("FERC"), then the posting shall be due on the next business day. The dates on which posting of the Annual True-Up and the projected net revenue requirement occur shall be that year's "True-Up Publication Date" and "Projected Rate Publication Date," respectively. Any delay in the True-Up Publication Date or Projected Rate Publication Date will result in an equivalent extension of time for the submission of information and document requests discussed in Section III of these protocols.

4. The Annual True-Up shall:

A. Include a workable data-populated formula rate template and underlying workpapers in native format with all formulas and links intact;

B. Be based on Black Hills Power's FERC Form No. 1 for the prior calendar year;

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Annual True-Up that are not otherwise available in FERC Form No. 1;

D. Provide sufficient information to enable Interested Parties to replicate the calculation of the Annual True-Up results from FERC Form No. 1;

E. Identify any changes in the formula references (page and line numbers) to FERC Form No. 1;

F. Identify all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to FERC Form No. 1 and any adjustments not shown in FERC Form No. 1;

G. Provide underlying data for formula rate inputs that provide greater granularity than is required for FERC Form No. 1;

H. With respect to any change in accounting that affects inputs to the formula rate or the resulting charges billed under the formula rate ("Accounting Change"):

a. Identify any Accounting Changes, including:

i. the initial implementation of an accounting standard or policy,

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction,

iii. correction of errors and prior period adjustments that impact the True-Up Adjustment calculation,

iv. the implementation of new estimation methods or policies that change prior estimates, and

v. changes to income tax elections;

b. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (*e.g.*, fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the

Annual True-Up; and

d. Provide, for each item identified pursuant to Sections II.4.H.a - II.4.H.c of these protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

5. The projected net revenue requirement shall:

A. Include a workable data-populated formula rate template and underlying workpapers in native format with all formulas and links intact;

B. Be based on Black Hills Power's most recent FERC Form No. 1;

C. Provide the formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the projected net revenue requirement that are not otherwise available in FERC Form No. 1;

D. Provide sufficient information to enable Interested Parties to replicate the calculation of the projected net revenue requirement;

E. With respect to any Accounting Change:

a. Identify any Accounting Changes, including:

i. the initial implementation of an accounting standard or policy;

ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

iii. correction of errors and prior period adjustments that impact the projected net revenue requirement calculation;

iv. the implementation of new estimation methods or policies that change prior estimates; and

v. changes to income tax elections;

b. Identify items included in the projected net revenue requirement at an amount other than on a historic cost basis (*e.g.*, fair value adjustments);

c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the projected net revenue requirement; and

d. Provide, for each item identified pursuant to Sections II.5.D.a - II.5.D.c of these protocols, a narrative explanation of the individual impact of such changes on the projected net revenue requirement.

6. Black Hills Power shall hold an open meeting among Interested Parties between the True-Up Publication Date and July 1 each year ("Annual True-Up Meeting"). No less than seven (7) days prior to such Annual True-Up Meeting, Black Hills Power shall provide notice on its website and OASIS of the time, date, and location of the Annual True-Up Meeting, and shall provide notice of such meeting via an email exploder list. For purposes of these procedures, the term Interested Party includes, but is not limited to, customers under the Joint Tariff, state utility regulatory commissions, consumer advocacy agencies, and state attorneys general. The Annual True-Up Meeting shall: (i) permit Black Hills Power to explain and clarify its Annual True-Up;

and (ii) provide Interested Parties an opportunity to seek information and clarifications from Black Hills Power about the Annual True-Up. Black Hills Power shall provide remote access to Annual True-Up Meetings to allow all Interested Parties the opportunity to remotely participate in such meetings.

7. Black Hills Power shall hold an open meeting among Interested Parties between the Projected Rate Publication Date and October 30 each year ("Annual Projected Rate Meeting"). No less than seven (7) days prior to such Annual Projected Rate Meeting, Black Hills Power shall provide notice on its website and OASIS of the time, date, and location of the Annual Projected Rate Meeting, and shall provide notice of such meeting via an email exploder list. The Annual Projected Rate Meeting shall: (i) permit Black Hills Power to explain and clarify its projected net revenue requirement; and (ii) provide Interested Parties an opportunity to seek information and clarifications from Black Hills Power about the projected net revenue requirement. Black Hills Power shall provide remote access to Annual Projected Rate Meetings to allow all Interested Parties the opportunity to remotely participate in such meetings.

8. In the event that Black Hills Power utilizes a regional cost sharing mechanism with other transmission owners for the recovery of transmission project costs under Black Hills Power's formula rate contained in this Attachment H of the Joint Tariff, Black Hills Power shall endeavor to coordinate with other transmission owners utilizing the same regional cost sharing mechanism to hold an annual joint informational meeting among those transmission owners and Interested Parties to enable all Interested Parties the opportunity to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects. No less than seven (7) days prior to such joint informational meetings, Black Hills Power shall provide notice on its website and OASIS of the time, date, and location of the joint informational

meeting, and shall provide notice of such meeting via an email exploder list. Black Hills Power shall provide remote access to joint informational meetings to allow all Interested Parties the opportunity to remotely participate in such meetings.

Section III. Information Exchange Procedures

Each Annual True-Up and projected net revenue requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

1. Interested Parties shall have until August 1 following the True-Up Publication Date (unless such period is extended with the written consent of Black Hills Power or by FERC order) to serve reasonable information and document requests on Black Hills Power ("True-Up Information Exchange Period"). If August 1 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests for the True-Up Information Exchange Period shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

A. the extent or effect of an Accounting Change;

B. whether the Annual True-Up fails to include data properly recorded in accordance with these protocols;

C. the proper application of the formula rate and procedures in these protocols;

D. the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up;

E. the prudence of actual costs and expenditures, including utilized procurement methods and cost control methodologies;

F. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

G. any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula rate.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

2. Interested Parties shall have until November 30 following the Projected Rate Publication Date (unless such period is extended with the written consent of Black Hills Power or by FERC order) to serve reasonable information and document requests on Black Hills Power ("Projected Rate Information Exchange Period"). If November 30 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests for the Projected Rate Information Exchange Period shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:

A. the extent or effect of an Accounting Change;

B. whether the projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

C. the proper application of the formula rate and procedures in these protocols;

D. the accuracy of data and consistency with the formula rate of the calculations shown in the projected net revenue requirement;

E. the prudence of projected costs and expenditures, including utilized procurement methods and cost control methodologies;

F. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

G. any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula rate.

The information and document requests shall not otherwise be directed to ascertaining whether the formula rate is just and reasonable.

3. Black Hills Power shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. Black Hills Power shall respond to all information and document requests submitted during the True-Up Information Exchange Period by no later than September 1 following the True-Up Publication Date, unless the True-Up Information Exchange Period is extended by Black Hills Power or FERC. Further, Black Hills Power shall respond to all information and document requests submitted during the Projected Rate Information Exchange Period by no later than December 31 following the Projected Rate Publication Date, unless the Projected Rate Information Exchange Period is extended by Black Hills Power or FERC.

4. Black Hills Power will post on its website and OASIS all information and document requests from Interested Parties and Black Hills Power's response(s) to such requests; except, however, if responses to information and document requests include material deemed by Black Hills Power to be privileged and/or confidential, such information will not be publicly posted but confidential information will be made available to requesting parties provided that a confidentiality agreement is executed by Black Hills Power and the requesting party.

5. Black Hills Power shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege, in any subsequent

FERC proceeding addressing Black Hills Power's Annual True-Up or projected net revenue requirement.

Section IV: Challenge Procedures

1. Interested Parties shall have until September 15 following the True-Up Publication Date (unless such period is extended with the written consent of Black Hills Power or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify Black Hills Power in writing, which may be made electronically, of any specific Informal Challenges to the Annual True-Up. The period of time from the True-Up Publication Date until September 15 shall be referred to as the "True-Up Review Period." If September 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges regarding the Annual True-Up shall be extended to the next business day.

2. Interested Parties shall have until January 15 following the Projected Rate Publication Date (unless such period is extended with the written consent of Black Hills Power or by FERC order) to review the inputs, supporting explanations, allocations and calculations and to notify Black Hills Power in writing, which may be made electronically, of any specific Informal Challenges to the projected net revenue requirement. The period of time from the Projected Rate Publication Date until January 15 shall be referred to as the "Projected Rate Review Period." If January 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all Informal Challenges regarding the projected net revenue requirement shall be extended to the next business day.

3. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge within the timelines provided in these protocols regarding any issue as to a given Annual True-Up or projected net revenue requirement shall bar pursuit of such issue with respect to that

Annual True-Up or projected net revenue requirement under the challenge procedures set forth in these protocols, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual True-Up or projected net revenue requirement. This Section IV.3 in no way shall affect a party's rights under Section 206 of the Federal Power Act as set forth in Section IV.10 of these protocols.

4. A party submitting an Informal Challenge to Black Hills Power must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. Black Hills Power shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of notification of such challenge. Black Hills Power shall appoint a senior representative to work with the party (or its representative) submitting the Informal Challenge toward a resolution of the dispute, and, where deemed necessary, may request the appointment of a FERC Administrative Law Judge that is mutually acceptable to the challenging party to facilitate discussions to attempt to resolve the dispute. If Black Hills Power disagrees with such challenge, Black Hills Power will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge of the Annual True-Up or projected net revenue requirement may be submitted after September 15 and January 15, respectively, following the True-Up Publication Date and Projected Rate Publication Date, unless September 15 or January 15 falls on a weekend or a holiday recognized by FERC, in which case the deadline for submitting all Informal Challenges shall be extended to the next business day. Black Hills Power must respond to: (1) all Informal Challenges of the Annual True-Up by no later than October 15 following the True-Up Publication Date, unless the True-Up Review Period is extended by Black Hills Power

or FERC; and (2) all Informal Challenges of the projected net revenue requirement by February 15 following the Projected Rate Publication Date, unless the Projected Rate Review Period is extended by Black Hills Power or FERC.

5. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements:

A. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the formula rate or protocols;

b. Explain how the action or inaction violates the formula rate or protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols;

iii. The proper application of the formula rate and procedures in these protocols;

iv. The accuracy of data and consistency with the formula rate of the charges shown in the Annual True-Up or projected net revenue requirement;

v. The prudence of actual or projected costs and expenditures;

vi. The effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

vii. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula rate.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

e. State whether the issues presented are pending in an existing FERC proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Informal Challenge procedures described these protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

B. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on Black Hills Power. Service to Black Hills Power must be simultaneous with filing at FERC. Simultaneous service can be accomplished by electronic mail in accordance with Section 385.2010(f)(3) of FERC's Rules of Practice and Procedure, facsimile, express delivery, or messenger. 18 C.F.R. § 385.2010(f)(3). The party filing the Formal Challenge shall serve the individual listed as the contact person on Black Hills Power's Informational Filing required under Section V of these protocols.

6. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or projected net revenue requirement fails to include data properly recorded in accordance with these protocols; (3) the proper application of the formula rate and procedures in these protocols; (4) the accuracy of data and consistency with the formula rate of the calculations shown in the Annual True-Up and projected net revenue requirement; (5) the prudence of actual or projected costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula rate.

7. Black Hills Power will post on its website and OASIS all Informal Challenges from Interested Parties and Black Hills Power's response(s) to such Informal Challenges; except, however, if Informal Challenges or responses to Informal Challenges include material deemed by Black Hills Power to be privileged and/or confidential, such information will not be publicly

posted but confidential information will be made available to requesting parties provided that a confidentiality agreement is executed by Black Hills Power and the requesting party.

8. An Interested Party shall have until April 1 following the True-Up Review Period and Projected Rate Review Period (unless such date is extended with the written consent of Black Hills Power to continue efforts to resolve the Informal Challenge) to make a Formal Challenge with FERC, which shall be served on Black Hills Power on the date of such filing as specified in Section IV.5.B of these protocols. A Formal Challenge shall be filed in the same docket as Black Hills Power's Informational Filing discussed in Section V of these protocols. Black Hills Power shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge during the applicable True-Up Review Period or Projected Rate Review Period.

9. In any proceeding initiated by FERC concerning the Annual True-Up or projected net revenue requirement or in response to a Formal Challenge, Black Hills Power shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate consistent with these protocols, and that it followed the applicable requirements and procedures in Attachment H of the Joint Tariff and these protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

10. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of Black Hills Power to file unilaterally, pursuant to Federal Power Act Section 205 and the regulations thereunder, to change the formula rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the formula rate with a stated rate, or the right of any other party to request such changes pursuant to Section

206 of the Federal Power Act and the regulations thereunder.

11. No party shall seek to modify the formula rate under the Challenge Procedures set forth in these protocols, and the Annual True-Up and projected net revenue requirement shall not be subject to challenge by anyone for the purpose of modifying the formula rate. Any modifications to the formula rate will require, as applicable, a Federal Power Act Section 205 or Section 206 filing.

12. Any Interested Party seeking changes to the application of the formula rate due to a change in the Uniform System of Accounts or FERC Form No. 1, shall first raise the matter with Black Hills Power in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Informational Filings

1. By March 1 of each year, Black Hills Power shall submit to FERC an informational filing ("Informational Filing") of its projected net revenue requirement and Annual True-Up in connection with the postings performed in accordance with Section II of these protocols during the prior year. This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the formula rate are properly recorded in any underlying workpapers; (2) that Black Hills Power has properly applied the formula rate and these procedures; (3) the accuracy of data and the consistency with the formula rate of the net revenue requirement and rates under review; (4) the extent of accounting changes that affect formula rate inputs; and (5) the reasonableness of projected costs. The Informational Filing shall include the formula rate template and underlying workpapers in native format fully populated and with formulas intact. The Informational Filing also must describe any corrections or adjustments made during that period, and must describe all aspects of the formula rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge

procedures. Within five (5) days of such Informational Filing, Black Hills Power shall provide notice of the Informational Filing via an email exploder list and by posting the docket number assigned to Black Hills Power's Informational Filing on its website and OASIS.

2. Any challenges to the implementation of the Black Hills Power formula rate under Attachment H of the Joint Tariff must be made through the Challenge Procedures described in Section IV of these protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VI. Calculation of True-Up Adjustment

The True-Up Adjustment will be determined in the following manner:

1. The projected net revenue requirement on the Annual Transmission Revenue Requirement Formula Estimate template, line 95, column 5 of Attachment H for the Service Year will be compared to the True-Up net revenue requirement for the same Service Year (Annual Transmission Revenue Requirement True Up template, line 88, column 5 of Attachment H of the Joint Tariff) calculated in accordance with Attachment H of the Joint Tariff using Black Hills Power's FERC Form No. 1 for the same Service Year to determine any over or under recovery. The sum of the excess or shortfall due to the actual versus projected net revenue requirement shall constitute the "True-Up Adjustment" amount. The True-Up Adjustment and related calculations shall be posted to Black Hills Power's website and OASIS no later than June 1 (or if that day falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day) following the issuance of the FERC Form No. 1 for the previous year, as set forth in Section II of these protocols.

2. The True-Up Adjustment amount to be refunded or paid, as calculated on line 47 of the Annual Transmission Revenue Requirement Capital True Up in Attachment H of the Joint Tariff,

shall be paid in full in July of each year. The amount on any over or under recovery shall be allocated to the customers based on actual billing determinants for the preceding year.

3. Interest on any over recovery of the net revenue requirement shall be determined based on Section 35.19a of FERC's regulations. 18 C.F.R. § 35.19a. Interest on any under recovery of the net revenue requirement shall be determined using the interest rate equal to Black Hills Power's actual short-term debt costs capped at the applicable FERC refund interest rate. In either case, the interest payable shall be calculated using an average interest rate for the sixteen (16) months during which the over or under recovery in the net revenue requirement exists (*i.e.*, January of the year prior through April of the year in which the true-up occurs). That interest rate will be applied, with quarterly compounding, to the principal amount (*i.e.*, the over or under recovery in the net revenue requirement) for the eighteen (18) months during which that over or under recovery exists.

Section VII. Changes to True-Up Adjustment or Projected Net Revenue Requirement

1. Any changes or adjustments made to the True-Up Adjustment after the True-Up Publication Date, including but not limited to changes or adjustments to the data inputs in Black Hills Power's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual True-Up, or as a result of the procedures set forth herein, resulting in a change to Black Hills Power's True-Up Adjustment, shall be: (1) posted on the Black Hills Power website and OASIS, and, within ten (10) days of such posting, Black Hills Power shall provide notice to Interested Parties of such posting via an email exploder; and (2) paid in full within thirty (30) calendar days of the date that any such change or adjustment to the True-Up Adjustment is posted to Black Hills Power's website and OASIS, or in accordance with any FERC order. Interest on any refund or surcharge shall be calculated in accordance with the procedures

outlined in Section VI.3 of these protocols or as FERC may otherwise order.

2. Any changes or adjustments made to the projected net revenue requirement after the Projected Rate Publication Date, including but not limited to changes to the data inputs, or as the result of any FERC proceeding to consider the projected net revenue requirement, resulting in a change to Black Hills Power's projected net revenue requirement, shall be posted on the Black Hills Power website and OASIS, and, within ten (10) days of such posting, Black Hills Power shall provide notice to Interested Parties of such posting via an email exploder. Any such changes or adjustments to the projected net revenue requirement agreed to by Black Hills Power on or before January 15 following the Projected Rate Publication Date will be reflected in the projected net revenue requirement for that Service Year. Any changes or adjustments made to the projected net revenue requirement after January 15 following the Projected Rate Publication Date, including but not limited to changes or adjustments as a result of any FERC proceeding to consider the projected net revenue requirement, shall be reflected in Black Hills Power's projected net revenue requirement invoices to be delivered no later than thirty (30) days from the date of posting such change or adjustment to Black Hills Power's website and OASIS, or in accordance with any FERC order. Invoices delivered prior to any such changes or adjustments being made shall be re-invoiced to reflect such changes or adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VI.3 of these protocols or as FERC may otherwise order.

ATTACHMENT C

PREPARED DIRECT TESTIMONY OF MICHAEL E. EASLEY

AND ATTESTATION PURSUANT TO 18 C.F.R. §35.13(D)(6)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

BLACK HILLS POWER, INC.) DOCKET NO. ER17-____

DIRECT TESTIMONY OF MICHAEL E. EASLEY

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

POWDER RIVER ENERGY CORPORATION) DOCKET NO. ER17-____

DIRECT TESTIMONY OF MICHAEL E. EASLEY

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Michael E. Easley and my business address is Powder River Energy Corporation, P.O. Box 930, Sundance, WY 82729.

Q. What is your present occupation?

A. I am employed as Chief Executive Officer of Powder River Energy Corporation ("PRECorp" or "the Cooperative").

Q. What are your duties as Chief Executive Officer of Powder River Energy Corporation?

A. My duties are to supervise the operations of the Cooperative; to make recommendations to the Board of Directors with respect to strategy, policy and to administer the policies adopted by the Board of Directors; to provide both short-term and long range plans for the operation, construction, and financing of the Cooperative; to maintain an adequate and suitable work force; and to keep the Board informed in all aspects of the management of the Cooperative.

Q. Please describe your educational background.

A. I have a BS degree in Electrical Engineering from Oklahoma State University and I am a graduate of the Ken Blanchard Executive MBA program at Grand Canyon University. I am also a graduate of the National Rural Electric Cooperative Association Management Internship Program at the University of Nebraska-Lincoln. I have held various positions of increasing responsibility in the cooperative utility industry and have been the CEO of PRECorp since October of 2000.

II. PURPOSE OF TESTIMONY AND BACKGROUND

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

A. The purpose of my testimony is to provide an overview of the new transmission facilities, the need for the new transmission facilities in PRECorp's net electric plant in service, and provide an overview of the debt structure of PRECorp as a rural electric cooperative.

II. OVERVIEW OF PRECORP TRANSMISSION FACILITIES

Q. Please describe PRECorp transmission facilities.

A. PRECorp, along with Black Hills Corporation and Basin Electric Cooperative, owns 65 miles of interstate transmission lines and seven 230 kV substations throughout Northeast Wyoming.

Q. What facilities has PRECorp built since the Joint Tariff revision of 2005 was approved?

A. In addition to the above mentioned facilities, PRECorp has constructed new facilities, namely the Bill Durfee Substation and a new Teckla Substation Terminal associated with Black Hills Corporation's new Teckla/Osage/Lange 230kV Transmission Line.

Q. Please describe the need for the Bill Durfee Substation.

A. The Bill Durfee Substation facility was built and placed in service on March 31, 2016, to address an aged and stressed 1957 Osage/Sundance 69KV line that was the primary service for the Sundance, WY area. With the new projected loads for the Sundance area, the existing Osage/Sundance 69 kV line was not expected to maintain adequate voltage. To provide the capacity needed and address power reliability concerns, a new 230/69KV substation was deemed the best alternative to address future power requirements.

Q. Please describe the need for the Teckla Substation Terminal Inter-Connect.

A. The new Teckla Substation Terminal was built and placed in service on January 22, 2016, to support Black Hills Power's request to interconnect a new 230 kV line which originated at PRECorp's Teckla Substation, south of Wright, WY and terminates at Black Hill's Lange Substation in Rapid City, SD. You will find attached a fact sheet, developed by Black Hills, outlining the need for this project, the benefits, and route. PRECorp's portion of that project included the addition of fourth 230 kV terminal at the Teckla Substation.

III. Overview of PRECorp Capital Financing Structure

Q. Please describe PRECorp's capital financing structure.

A. As a rural non-profit electric cooperative, PRECorp receives capital from two main sources: the consumer-owners and debt financing from the Rural Utility Service ("RUS").

Each of the 12,236 residential and industrial consumers served by PRECorp are members. The cooperative accounts on a patronage basis all amounts received in excess of operating costs and expenses to each member. All amounts in excess of operating costs and expenses are received with the understanding that they are furnished by the members as capital.

The federal government, through the Rural Utility Service (RUS) and the Federal Financing Bank, is PRECorp's source of borrowing for capital expenditures. Because of PRECorp's status as a federal borrower, PRECorp does not issue common or preferred stock or bonds. Nor does PRECorp enter the public or private markets for debt.

Q. Does this complete your direct testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Powder River Energy Corporation **Docket No. ER17-__**

Sundance, Wyoming:

ATTESTATION

Michael E. Easley, being first duly sworn, deposes and states that he is the Michael E Easley referred to in the document entitled "Direct Testimony of Michael E. Easley," and that the statements set forth therein are true and correct to the best of his knowledge, information and belief in this proceeding. I further testify that the documents relied upon by Alan C. Heintz in this proceeding were true and correct business records of PRECorp that were, and have been, maintained in the regular course of business.

Michael E Easley

Michael E. Easley

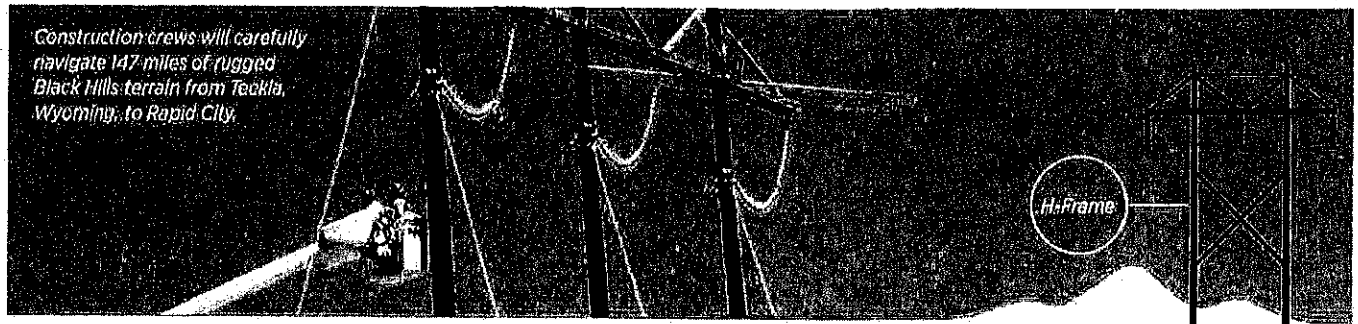
Subscribed and sworn to before me, the undersigned notary public, this 29th day of November, 2016.

Stephanie J. Pribilske

Notary Public

STEPHANIE J. PRIBILSKE - NOTARY PUBLIC
County of Crook
State of Wyoming
My Commission Expires June 2, 2020

My Commission Expires: June 2, 2020



TRANSMISSION LINE PROJECT

FACT SHEET

The need

The transmission line is required to meet a growing demand for energy in the region to maintain industry-leading reliability for our customers. Keeping the energy grid running constantly takes careful planning, maintenance and investments in upgrades or new infrastructure. We must anticipate customer needs well in advance. We can't wait for a system to fail before initiating a process that can take years to complete. With energy use fast approaching the limits of the existing system, the transmission line is critical to our customers.

The benefits

- **Energy you can count on**
- **Stronger energy grid**
- **Infrastructure able to efficiently deliver alternative sources of energy**
- **Ability to meet continuing increases in the demand for energy**
- **Promote economic development in the region; reliable energy is one of the first resources a new or expanding business looks for**

The route

The final route is based on valuable input from landowners, customers and multiple state and federal agencies. In determining the route, we considered land use, the environment, cultural and historical significance, and cost. This route ensures the best path to safe, reliable and efficient energy for all.

- **The route is approximately 147-miles long, from the Teckla Substation, about 30 miles south of Wright, Wyoming, to Rapid City.**
- **The route requires a right-of-way that is approximately 125-feet wide.**
- **Once the route was determined, we began negotiating rights-of-way on private lands. We followed legal and regulatory guidelines and worked directly with landowners along the route. We also obtained all of the necessary permits and approvals from local, state and federal entities.**

Keeping you informed

- **We held seven public meetings in Rapid City and Newcastle, Wyoming.**
- **We mailed detailed information packets to 1,250 landowners.**

Structures

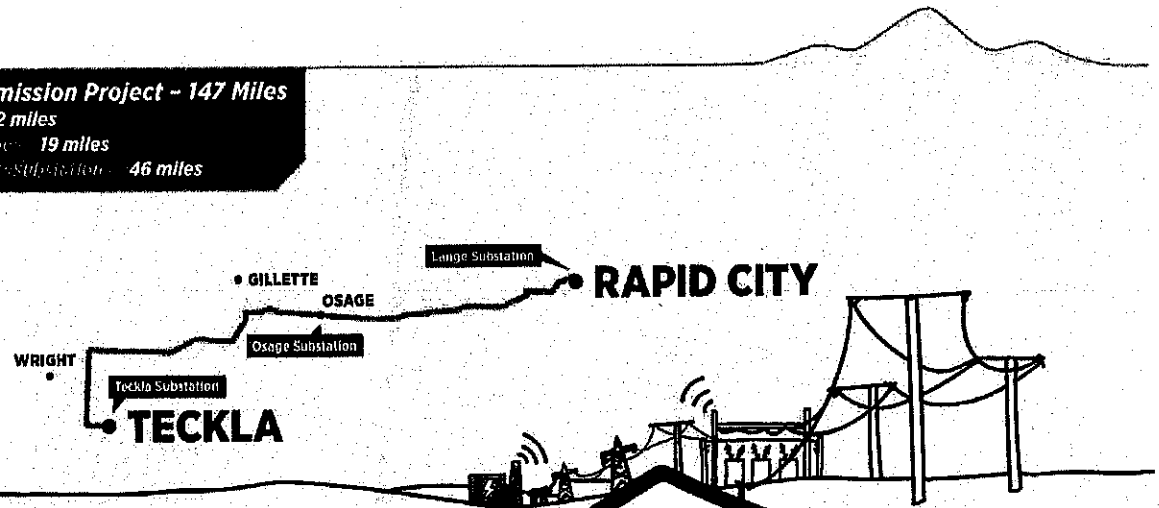
- **Support structures along the 147-mile line are primarily wood H-frame in design. They average 65 to 75-feet in height and are typically about 900 feet apart.**

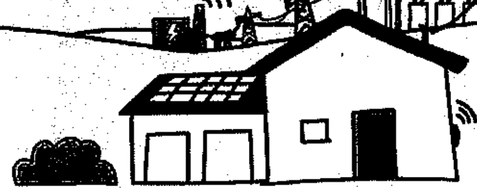
Construction Schedule

- **March 2016 – Contracts awarded for timber clearing and line construction. We worked with Black Hills National Forest on the Special Use Permit to authorize all construction activities.**
- **July 2016 – Construction started on line from South Dakota state line to Rapid City.**
- **September 2016 – Begin construction of line from Osage, Wyoming, to South Dakota state line.**
- **year-end 2016 – Completion of line from Teckla to Osage, Wyoming.**
- **Q2-2017 – Planned completion and energization of line from Osage to Rapid City.**

→ *Follow this project's progress at: www.blackhillsenergy.com/230kv*

Length of Transmission Project ~ 147 Miles
Teckla to Osage – ***82 miles***
Osage to SD State line – ***19 miles***
SD State line to Lange Substation – ***46 miles***

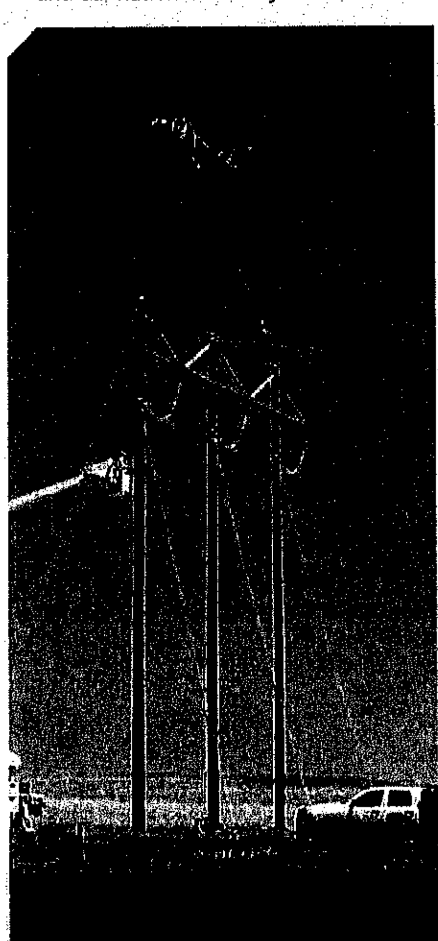




The energy grid makes everything possible
The energy grid is a multibillion dollar array of power lines, transformers, generators, poles and substations that provides electricity when you need it, rain or shine, 24-hours a day. The grid is essential to our lives. Without it, there would be no stop lights, street lamps or ATMs. No televisions, refrigerators, mobile phones or computers. The grid is the nerve center of our economy and our national security.

What is a transmission line?

The transmission line moves energy from a generating site, such as a power plant, to an electrical substation. This is distinct from local or distribution lines between substations and customers. The combined transmission and distribution network is know as the "energy grid" in North America.



Safety along the line

Our first priority is always public safety, employee safety and contractor safety. Our crews are fully trained and equipped to work safely in rough terrain. We take a proactive approach, with daily safety meetings, careful monitoring and sharing safety tips with customers. In July, we provided safety information directly to landowners along the line.

We're here for you

With more than 270 employees and five customer service locations, Black Hills Energy serves 70,000 customers in 32 communities in western South Dakota and parts of Wyoming and Montana.

Our energy is yours at the flip of a switch to charge cellphones, power entertainment systems and turn darkness into light. We're always here, working to keep you comfortable indoors, heat water for bathing and cleaning, and keep cooktops cooking. Our energy is yours, to promote new growth and a vibrant community.

For more information, including how our employees improve life through their volunteer efforts and other contributions, please visit www.blackhillsenergy.com.

ATTACHMENT D

PREPARED DIRECT TESTIMONY AND EXHIBITS
OF
ALAN C. HEINTZ

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

BLACK HILLS POWER, INC) DOCKET NO. ER17-____

DIRECT TESTIMONY OF ALAN C. HEINTZ

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

POWDER RIVER ENERGY CORPORATION) DOCKET NO. ER17-____

DIRECT TESTIMONY OF ALAN C. HEINTZ

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Alan C. Heintz. My business address is Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ"), 1155 Fifteenth Street, NW, Suite 1004, Washington, DC 20005. I am a Vice President of BWMQ.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of Powder River Energy Corporation ("PRECorp").

Q. Please describe your professional experience.

A. I was employed by the Federal Energy Regulatory Commission ("FERC" or "Commission") from November 1985 to February 1995. I served as a Public Utilities Specialist in the [Electric] Rate Filings Branch from November 1985 to October 1989. In November 1989, I was promoted to Section Chief in the Division of [Electric] Applications, and was responsible for supervising the review of the terms, conditions, and rates of electric rate applications for such services as interchange power, requirements power, and transmission. During my tenure with FERC, I prepared or supervised the preparation of memoranda recommending acceptance, rejection, deficiency, or investigation in hundreds of cases. These included cases that set important precedents on electric transmission pricing, such as the merger compliance transmission tariffs for Northeast Utilities, the first generation of open access transmission tariffs ("OATT") filed by utilities such as Entergy Services Inc., Louisville Gas and Electric Co., Florida Power & Light Co., Kansas City Power & Light Co., and American Electric Power Service Corp., as well as the Pennsylvania Electric Company case involving Penntech Papers, Inc. I also taught a one-year course to FERC Staff and gave several presentations to the Edison Electric Institute Interconnection and Interchange Arrangements Committee on the pricing of power and transmission services.

From February 1995 through October 2000, I was a Vice President of Stone & Webster Management Consultants, Inc. In this position, I provided consulting services to numerous electric utilities on matters involving requirements and off-system power rates, rate and implementation strategies for developing OATT filings, and issues concerning the organization of Independent System Operators ("ISO"), and Regional Transmission Organizations ("RTO"). I also assisted several utilities in preparing their retail delivery services filings. In November 2000, I joined R.J. Rudden Associates, Inc. as a Vice President, where I continued providing consulting services to the electric industry. I joined BWMQ in February 2004.

Q. What are your duties in your current position?

A. I provide consulting services on matters relating to power sales, transmission, and ancillary service issues associated with FERC regulation of open access transmission service, including issues arising from FERC's Order Nos. 888, 889, 890, 2000, 679 and 1000. I have been actively involved as a consultant to several ISOs and RTOs, participants in organized electric markets, and transmission-only entities. I have advised these clients on formula transmission rates, transmission and congestion pricing, and the treatment of pre-existing arrangements, losses, and ancillary services. In addition, I have provided advice on transmission pricing matters to several transmission-owning members of the PJM Interconnection, L.L.C. ("PJM"), Midcontinent Independent System Operator, Inc. ("MISO"), California Independent System Operator Corporation, ISO New England Inc., New York Independent System Operator and Southwest Power Pool, Inc. ("SPP").

Q. Have you previously testified before FERC or before other regulatory agencies and courts on utility-related matters?

A. Yes. During my tenure at the FERC, I was assigned to the Commission's advisory staff and, therefore, was precluded from testifying before the FERC. However, while at the FERC, I presented cases publicly to the FERC Commissioners at their bi-weekly public meetings and was the technical contact to the Commissioners in numerous cases. Since leaving the FERC, I have filed testimony before the FERC in numerous proceedings. In addition to the FERC, I have testified before the British Columbia Utilities Commission in Canada, the Illinois Commerce Commission, the Maine Public Utilities Commission, the United States Court of Federal Claims, and the United States District Court in Florida. A table of my prior testimony is attached hereto as Exhibit No. PRE-3.

Q. Please describe your educational background.

A. I received the degree of Bachelor of Science in Business, and the degree of Bachelor of Arts in Economics from the University of Colorado, Boulder, Colorado, in May 1982. I also received the degree of Master of Business Administration in Finance from the George Washington University in Washington, DC in December 1988.

II. PURPOSE OF TESTIMONY AND BACKGROUND

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

A. The purpose of my testimony is to present and support the increase in PRECorp's revenue requirement under an open access transmission tariff ("Joint Tariff") that governs the rates, terms and conditions for the provision of transmission service over the integrated transmission facilities of PRECorp, Black Hills Power, Inc. ("BHP"), and Basin Electric Power Cooperative (BEPC). The Joint Tariff is on file with the Commission as Black Hills FERC Electric Tariff Original Volume No. 4, with a total current revenue requirement of $33.7 million. The increase in the revenue requirement is primarily due to the inclusion of the new transmission facilities in PRECorp's net electric plant in service. In this testimony, I describe and support the reasonableness of the proposed ATRR.

Q. **Q. Please explain how transmission service is provided on the integrated facilities of PRECorp, BHP and PRECorp.**

A. Transmission service on the integrated facilities of PRECorp, BHP and BEPC is provided pursuant to the Joint Tariff that I discussed earlier. FERC initially accepted the Joint Tariff on February 12, 2004 (106 FERC ¶ 61,119 (2004)). The Joint Tariff was modified through an uncontested settlement agreement that was approved by FERC on August 6, 2004 (108 FERC ¶ 61,165 (2004) ("August Settlement"). The Joint Tariff provides that each of the transmission owners may unilaterally modify the cost of service of its transmission facilities over which transmission service is provided pursuant to that Tariff. Through its filing in this proceeding, PRECorp proposes to modify the Joint Tariff to include in PRECorp's revenue requirement for service on the AC transmission system the cost of the construction and operation of a new transmission facilities added to the Joint Tariff.

III. EXPLANATION OF THE INCREASE IN PRECORP'S REVENUE REQUIREMENT

Q. Please explain how the rates for transmission service under the Joint Tariff are developed.

A. A gross revenue requirement is calculated for each Party's facilities that comprise the AC Transmission System. Each Party receives a share of the revenue from short-term and non-firm service based on its contribution to the total unit rate. Accordingly, the short-term and non-firm revenues are allocated to the Parties based on each Party's contribution to the total unit rates and become credits to their revenue requirements. The individual Parties' annual transmission revenue requirements, net of the revenue credits, are then individually divided by the peak load on the AC Transmission System facilities. The annual rate for the AC Transmission System facilities is the sum of the Parties' individual components of the annual rate. In the August Settlement, parties agreed that the rates would be based on the stated revenue requirements of the Parties found in Attachment H divided by the loads during the previous calendar year. Thus, the rates have a formulaic rate design.

Q. Please explain the impact of including the cost of the new transmission facilities in PRECorp's revenue requirement.

A. PRECorp's net transmission plant in service that is subject to the Joint Tariff was $ 7.2 million on December 31, 2015, which included $1.1 million for the Teckla BHP Interconnect. When all the facilities go into service, PRECorp's net electric plant in service will increase to $10.1 million – an increase of about 40%. PRECorp's cost of service will increase from $1.3 million, which is the amount that has been included in Attachment H of the Joint Tariff since 2004, to $2.1 million as a result of the inclusion.

Q. Why did PRECorp choose to include known and measurable changes to the test year?

A. If PRECorp were to perform a cost of service study using a historic 2015 test year, the new facilities would not be fully reflected in rates until the end of calendar 2016. Consequently, PRECorp would not be made whole for the transmission additions if it were to base its rates on a historic test year. Given the magnitude of the increase in its costs, PRECorp proposes to base its cost of service on historic 2015 costs making know and measurable changes to reflect the additional transmission facilities. Since the proposed rate increase is less than $1 million, a Period II future test period is not required under the Commission's regulations.

IV. EXPLANATION OF COST SUPPORT FOR PRECORP'S PROPOSED RATES

Q. Please explain the basis for the cost of service study that supports PRECorp's proposed revenue requirement.

A. PRECorp performed the cost of service study using the same methodology and return on equity that it used to develop the currently-effective rates that were Filed in 2004. The cost of service study is attached hereto as Exhibit No. PRE-4 ("Cost of Service").

Q. Please describe the cost support used for developing PRECorp's proposed rates.

A. The cost support uses standard cost of service practices to develop a rate base upon which return and taxes are calculated and includes functionalized expenses such as transmission operations and maintenance ("O&M"), administrative and general ("A&G"), depreciation, and taxes other than income taxes.

Rate base is developed using 2015 actuals, with the known and measurable costs associated with the new transmission additions. The gross plant and accumulated depreciation are 2015 actuals adjusted for a full year addition of the new transmission plant (Cost of Service - page 1, lines 1 to 29; page and line numbers below refer to the Cost of Service).

Also included in rate base are prepayments, materials and supplies, and cash working capital (calculated as one-eighth of O&M) on lines 30 to 32. Transmission related prepayments and materials and supplies were functionalized to transmission.

Transmission operation and maintenance expenses exclude Account 565 Transmission by Others consistent with FERC precedent adjusted to reflect the new transmission plant, see page 2, lines 1 to 3.

Except for direct assignments, PRECorp has functionalized A&G expenses based on labor ratios (page 2, lines 4 to 6). The transmission depreciation expense was adjusted to reflect the new facilities (page 2, line 9) and the general plant depreciation expense was allocated using the labor ratio (page 2, line 11). Regulatory commission expenses were amortized over a five (5) year period.

Other taxes include labor related other taxes and are allocated based on the labor ratio.

Return is calculated based on the current capital structures, cost of debt and a rate of return on equity of 10.8%, which is the same as the Commission approved in the August Settlement. No allowance for income taxes was included in the cost of service.

The cost of service develops the revenue requirement for all of PRECorp's transmission facilities in Column 5 and allocates the costs to the Joint Tariff (Column 7) based on ratio of the gross plant at issue and the total gross plant, except transmission depreciation expense and regulatory commission expense which were directly assigned to the Joint Tariff.

Q. Please discuss the direct assignments discussed above.

A. The direct assignments are show as "DA" on the cost of service and are consistent with the direct assignments employed by PRECorp in its last rate case. These are the direct assignment of gross plant, the associated accumulated depreciation related to the facilities under the Joint Tariff, regulatory commission expenses related to the Joint Tariff and transmission depreciation expense, all of which are supported by the referenced workpapers.

Workpaper 1 shows the gross plant, accumulated depreciation and depreciation expense for the Joint Tariff facilities. Workpaper 2 shows the total gross plant and accumulated depreciation by function. Workpaper 3 details the projected regulatory commission expenses amortized over 5 years. Workpaper 4 details the depreciation expense by function. Workpaper 5 calculates the deprecation expense for the Joint Tariff facilities. Workpaper 6 details the transmission materials and supplies and Workpaper 7 details the salaries and wages by function.

Q. Is PRECorp proposing to make any modification to rate design of the Joint Tariff rates for point-to-point transmission service?

A. No.

Q. Please summarize the results of PRECorp's transmission cost study.

A. The cost of service analysis demonstrates that the revenue requirement for the portion of the AC Transmission System facilities under the Joint Tariff owned by PRECorp increases by about $826,000 from $1.3 million to $2.1 million. Because PRECorp's revenue requirement is only about 6% of the total revenue requirements associated with the Joint Tariff, the increase in PRECorp's revenue requirement would only result in an increase of $0.11/kw/month ($2.76/kw/month to $2.87/kw/month) in the rate paid by transmission customers.

Q. **In your opinion, has the revenue requirement for transmission service been developed consistent with accepted Commission ratemaking methodologies?**

A. Yes, the revenue requirement and rates both have been developed in a manner that is consistent with the Commission's accepted ratemaking methodologies.

Q. **Does this complete your direct testimony?**

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PRECorp Power Cooperative) **Docket No. ER17-__**

Washington, District of Columbia:

Alan C. Heintz, being first duly sworn, deposes and states that he is the Alan C. Heintz referred to in the document entitled "Direct Testimony of Alan C. Heintz," and that the statements set forth therein are true and correct to the best of his knowledge, information and belief in this proceeding.

Alan C. Heintz

Subscribed and sworn to before me, the undersigned notary public, this 28 th day of November, 2016.

Notary Public

My Commission Expires: STEPHANIE J. WILKERSON
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires June 30, 2019

STEPHANIE J. WILKERSON
NOTARY PUBLIC
MY COMMISSION EXPIRES 6/30/2019
DISTRICT OF COLUMBIA

SUMMARY OF TESTIMONY EXPERIENCE
ALAN C. HEINTZ

#	JURISDICTION	CASE OR DOCKET NO.	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
1	FERC	ER95-836-000	Maine Public Service Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
2	FERC	ER95-854-000	Kentucky Utilities Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
3	FERC	ER95-1686-000 ER96-496-000	Northeast Utilities Service Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
4	FERC	ER96--58-000	Allegheny Power Services Corporation	1995 & 1996	Rates, Terms and Conditions for Open Access Transmission Services
5	FERC	OA96-138-000	Consolidated Edison Company of New York, Inc.	1997	Rates, Terms and Conditions for Open Access Transmission Services
6	FERC	ER96-1208-000	Interstate Power Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
7	British Columbia Utilities Commission		Bonneville Power Administration	1997	Rates, Terms and Conditions for Open Access Transmission Services
8	FERC	ER98-1438-000 EC98-24-000	Midwest ISO Transmission Owners	1998 & 1999	Rates, Terms and Conditions for Midwest ISO Tariff
9	FERC	EC98-2770-000 ER98-2770-000 ER98-2786-000	Midwest Independent System Operator Transmission Owners	1999	Reasonableness of the conditions to be placed on the merging parties

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
10	Illinois Commerce Commission	99-0117	Commonwealth Edison Company	1998	Cost of service for Retail Distribution Services Tariff
11	FERC	ER99-3110-000	Nevada Power Company	1998	Rates, Terms and Conditions for Open Access Transmission Services
12	FERC	ER99-4415-000	Illinois Power Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
13	FERC	ER99-4470-000	Commonwealth Edison Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
14	U.S. District Court, FL	92-35-CIV-ORL-3A22	Florida Power and Light Company	1999	Rates, Terms and Conditions for Network Service in an anti-trust case
15	U.S. Court of Federal Claims, DC	97-268C	Carolina Power & Light Company	1999	Cost recovery of Decontamination & Decommissioning Fund Assessments
16	FERC	ER98-496-006 ER98-2160-004	Dynegy	1999	Rates for Must Run units
17	FERC	ER00-980-000	Bangor Hydro Electric Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
18	Maine Public Utilities Commission	99-185	Bangor Hydro Electric Company	2000	Rates, Terms and Conditions for Open Access Transmission Services

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
19	FERC	EL00-98-000, et al.	Dynegy Power Marketing, Inc.	2000	Nexus between fuel and emissions costs and the market prices in California
20	Illinois Commerce Commission	No. 01-0423	Commonwealth Edison Company	2001	Direct, Rebuttal and Surrebuttal: Cost of service for Retail Distribution Services Tariff
21	FERC	ER01-2992	Commonwealth Edison Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
22	FERC	ER01-123.004	Midwest ISO Transmission Owners	2001	Super Region Adjustment for the MISO/ARTO Super Region
23	FERC	ER01-2999	Illinois Power Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
24	FERC	ER01-3142, et. al	Midwest ISO Transmission Owners	2001	Revised treatment of Network Upgrades
25	FERC	ER01-3142, et. al	Midwest ISO Transmission Owners	2001	Uncertainties that support a higher ROE
26	FERC	EL000-95-045, et.al	Dynegy, Mirant, Reliant and Williams	2001 & 2002	Costing of emissions and start-up costs
27	FERC	EC02-23 & ER02-320	Trans-Elect, Inc.	2001 & 2002	Support of rates and ratemaking methodology for new transmission company
28	FERC		Sithe New Boston, LLC	2001 & 2002	Cost of Service for Must Run Unit
29	FERC	RM01-12	SeTrans	2002	Allocation of FTRs/CRRs

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
30	FERC	EL02-111	Midwest ISO Transmission Owners	2002	Through and Out Rates
31	FERC	ER02-2595	Midwest ISO Transmission Owners	2002	Cost Allocation for FTR and Market Administration
32	FERC	ER03-37	Sierra Pacific and Nevada Power	2003	Ancillary Service Rates
33	FERC	ER03-626	Empire District Electric Co.	2003	Cost of Service; Wholesale Requirements Customers
34	FERC	EL-02-25-001, et. al	Public Service Co. of Colorado	2003	Fuel Adjustment Clause
35	FERC	ER03-959	Exelon Framingham LLC, et al.	2003	Production Cost of Service
36	FERC	ER03-1187	Commonwealth Edison	2003	Black Start Rates
37	FERC	ER03-1223	Montana Megawatt	2003	Production Formula Rates
38	FERC	ER03-1335	Commonwealth Edison	2003	Transmission Tariff Rates
39	FERC	ER03-1354	Black Hills Power Company, et al.	2003	Joint transmission Tariff Rates
40	FERC	ER03-1328	Nevada Power	2003	Transmission Tariff Rates
41	FERC	EL02-111, et. Al	Midwest ISO Transmission Owners	2004	Long-term Transmission Pricing Plan
42	FERC	ER05-14	Sierra Pacific	2004	Transmission Tariff Rates
43	FERC	ER05-26	Mirant Kendall, LLC	2004	Reliability Must Run Agreement and Rates

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
44	Illinois Commerce Commission	No.04-0779	NICOR Gas Company	2004	Distribution Service Embedded Cost of Service Study
45	FERC	ER05-163	Milford Power Company LLC	2004	Reliability Must Run Agreement and Rates
46	FERC	EL02-111, et. al	Midwest ISO Transmission Owners	2004	Seams Elimination
47	FERC	EL00-95, et. al	Portland General Electric Company	2005	California Refund Proceeding
48	FERC	ER05-447	Midwest ISO Transmission Owners	2005	Schedule 10 & 17 Recovery for Grandfathered Agreements
49	FERC	EL02-111, et. al	Midwest ISO Transmission Owners	2005	Seams Elimination
50	FERC	ER05-860	Whiting Clean Energy	2005	Cost Based Power Rates
51	FERC	ER05-903	Con. Ed. Energy Mass., Inc.	2005	Reliability Must Run Agreement and Rates
52	FERC	EL02-111, et. al	Midwest ISO Transmission Owners	2005	Seams Elimination
53	FERC	ER05-1050	AmerGen Energy Company, L.L.C.	2005	Reactive power charges
54	Illinois Commerce Commission	No.05-0597	Commonwealth Edison Co.	2005	Distribution Service Embedded Cost of Service Study
55	FERC	ER05-1179	Berkshire Power Company, LLC	2005	Reliability Must Run Agreement and Rates
56	FERC	ER05-1243	Basin Electric Power Cooperative	2005	Revised Transmission Cost of Service

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
57	FERC	ER05-1304 & ER05-1305	Mystic I, LLC and Mystic Development, LLC	2005	Reliability Must Run Agreement and Rates
58	FERC	ER05-273	Midwest ISO Transmission Owners	2005	Proper Pricing for Regional Non-firm Redirects
59	FERC	ER05-515	PHI and BGE	2005	Transmission Formula Rates
60	FERC	EL05-19	Southwestern Public Service Company	2005	Production rates and Fuel Adjustment Clause,
61	FERC	ER06-427	Mystic Development, LLC	2006	Reliability Must Run Agreement and Rates
62	FERC	ER06-822	Fore River Development, LLC	2006	Reliability Must Run Agreement and Rates
63	FERC	ER06-819	Consolidated Edison Energy Massachusetts, Inc	2006	Reliability Must Run Agreement and Rates
64	FERC	ER07-169	Ameren Energy Marketing Company	2006	Ancillary service rates
65	FERC	ER06-1549	Duquesne Light Company	2006	Transmission Formula Rates
66	FERC	ER07-170	Ameren Energy, Inc.	2006	Ancillary service rates
67	FERC	ER06-787	Idaho Power	2006 & 2007	Transmission Formula Rates
68	FERC	ER07-562	Trans-Allegheny Interstate Line Company	2007	Transmission Formula Rates
69	FERC	ER07-583	Commonwealth Edison	2007	Transmission Formula Rates

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
70	FERC	ER07-1171	Arizona Public Service Co.	2007	Transmission Formula Rates
71	Illinois Commerce Commission	No. 07-0566	Commonwealth Edison Co.	2007	Distribution Service Embedded Cost of Service Study
72	FERC	ER07-1371	Sierra Pacific Resources	2007	Transmission Rates
73	FERC	ER08-281	Oklahoma Gas & Electric	2007	Transmission Formula Rates
74	FERC	ER08-313	Southwestern Public Service	2007	Transmission Formula Rates
75	FERC	ER08-386	Potomac-Appalachian Transmission Highline, LLC	2007	Transmission Formula Rates
76	FERC	ER08-374	Atlantic Path 15, LLC	2007	Transmission Rates
77	Illinois Commerce Commission	No. 08-0363	NICOR Gas Company	2008	Distribution Service Embedded Cost of Service Study
78	FERC	ER08-951	PSEG Energy Resources & Trade, LLC	2008	Reactive Power Charges
79	FERC	ER08-1233	Public Service Gas & Electric Company	2008	Transmission Formula Rates
80	FERC	ER08-1457	PPL Electric Utilities Corp.	2008	Transmission Formula Rates
81	FERC	ER08-1584	Black Hills Power	2008	Transmission Formula Rates
82	FERC	ER08-1600	Basin Electric Power Coop	2008	Transmission Rates

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
83	FERC	ER09-36	Prairie Wind Transmission, LLC	2008	Transmission Formula Rates
84	FERC	ER09-35	Tallgrass Transmission, LLC	2008	Transmission Formula Rates
85	FERC	ER09-75	Pioneers Transmission, LLC	2008	Transmission Formula Rates
86	FERC	ER09-255	Nebraska Public Power District	2008	Transmission Formula Rates
87	FERC	ER09-528	ITC Great Plains, LLC	2009	Transmission Formula Rates
88	Illinois Commerce Commission	ER08-0532	Commonwealth Edison Co.	2009	Distribution Service Embedded Cost of Service Study
89	FERC	ER08-370 & EL09-22	Otter Tail Power Co.	2009	Formula Transmission Rate
90	FERC	ER10-152	PPL Electric Utilities Corp.	2009	Revised Depreciation Method
91	FERC	ER09-1727	ALLETE, INC	2009	Formula Transmission Rate
92	FERC	ER10-230	KCP&L	2009	Formula Transmission Rates
93	FERC	ER10-455	Ameren Energy Marketing Company	2009	Reactive Power Rates
94	FERC	ER10-516	SCE&G	2010	Formula Transmission Rates
95	FERC	ER10-962	Union Electric Company	2010	Reactive Power Rates
96	FERC	ER10-1149	FP&L	2010	Formula Transmission Rates

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
97	FERC	ER10-1418	Exelon Generation	2010	Reliability Must Run
98	FERC	ER10-1782	Tampa Electric Company	2010	Formula Transmission Rates
99	FERC	ER10-2061	Tampa Electric Company	2010	Formula Production Rates
100	FERC	ER11-1955	Dairyland Power Coop.	2011	Reactive Rates
101	FERC	ER05-6	MISO Transmission Owners	2010	Seams Elimination
102	FERC	ER11-2127	Terra Gen Dixie Valley	2010	Transmission Rates
103	FERC	ER09-1148	PPL Electric Utilities	2011	Formula Transmission Rates
104	FERC	ER11-3643	PacifiCorp	2011	Formula Transmission Rates
105	FERC	ER11-3826	Black Hills	2011	Transmission Rates
106	FERC	ER11-3643	Puget Sound Energy	2012	Formula Transmission Rates
107	FERC	ER12-1378	CLECO	2012	Formula Transmission Rates
108	FERC	ER12-1593	DATC	2012	Formula Transmission Rates
109	FERC	ER12-2274	PSE&G	2012	Abandonment Costs
110	FERC	ER12-2554	Transource Missouri, LLC	2012	Formula Transmission Rate
111	FERC	ER13-1187	MidAmerican	2013	Depreciation Rates under Formula

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
112	FERC	ER13-1207	PacifiCorp	2013	Regulation Service
113	FERC	EL13-48	PHI Companies	2013	Complaint involving Formula Rates
114	FERC	ER13-1207	PacifiCorp	2013	Depreciation Rates under Formula
115	FERC	ER13-1605	NV Energy	2013	Transmission and Ancillary Service Rates
116	FERC	ER13-782	ITC	2013	Transmission Formula Rate
117	FERC	ER13-1962 & EL13-76	AERG/AEM	2013	Reliability Must Run
118	FERC	ER14-108	Entergy	2013	Reactive Power Rates
119	FERC	ER14-1210	Illinois Power Marketing Company	2014	Reliability Must Run
120	FERC	ER14-1332	DATC Path 15, LLC	2014	Transmission Cost of Service
121	FERC	ER14-1382	Transource Missouri, LLC	2014	Transmission Formula
122	FERC	ER14-1425	Cheyenne L, F & P	2014	Transmission Rates
123	FERC	ER14-1661	MidAmerican Central California Transco, LLC	2014	Transmission Formula
124	FERC	ER14-1956	Panther Creek Power Operating, LLC	2014	Reactive Power Rates
125	FERC	ER14-1969	Public Service Company of Colorado	2014	Ancillary Services for Intermittent Resources

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
126	FERC	ER14-2502	Entergy Power, LLC EAM Nelson Holding, LLC	2014	Reactive Power Rates
127	FERC	ER14-2619	Illinois Power Marketing Company	2014	Reliability Must Run
128	FERC	ER14-2718	Illinois Power Marketing Company	2014	Reliability Must Run
129	FERC	ER14-2751 & ER14-2752	Xcel Energy Transmission Development Company, LLC and Xcel Energy Southwest Transmission Company, LLC	2014	Transmission Formula
130	FERC	ER15-13	Transource Wisconsin, Inc.	2014	Transmission Formula
131	FERC	ER15-279	Nebraska Public Power District	2014	Transmission Cost of Service
132	FERC	ER15-572	New York Transco, LLC	2015	Transmission Formula
133	FERC	ER15-948	Illinois Power Marking Company	2015	Reliability Must Run
134	FERC	ER15-958	Transource Kansas, LLC	2015	Transmission Formula
135	FERC	ER15-949	Southwestern Public Service Co.	2015	Demand Allocator
136	FERC	ER15-1047	R.E. Ginna Nuclear Power Plant, LLC	2015	Reliability Support Services Agreement
137	FERC	ER15-1510	First Energy Solutions Corp.	2015	Reactive Power Rates
138	FERC	EL15-51	City Water And Light Plant Of The City Of Jonesboro	2015	Reactive Power Rates
139	FERC	ER15-1682	TransCanyon DCR, LLC	2015	Transmission Formula
140	FERC	ER15-1719	R.E. Ginna Nuclear Power Plant, LLC	2015	Reliability Support Services Agreement
141	FERC	ER15-1775	Basin Electric Power Coop	2015	Transmission Formula
142	FERC	ER15-1809	ATX Southwest, LLC	2015	Transmission Formula

#	Jurisdiction	Case or Docket No.	Client	Approximate Date	Subject Matter
143	FERC	ER15-2102	New York Power Authority	2015	Transmission Formula
144	FERC	ER15-2239	NextEra Energy Transmission West, LLC	2015	Transmission Formula
145	FERC	ER15-2426	Northern Indiana Public Service Co.	2015	Reactive Power Rates
146	FERC	ER15-2594	South Central MCN LLC	2015	Transmission Formula
147	FERC	EL16-17	City of West Memphis	2015	Reactive Power Rates
148	FERC	EL16-18	Conway Corporation	2015	Reactive Power Rates
149	FERC	ER16-200 & 201	Duke Energy Indiana, Inc.	2015	Reactive Power Rates
150	FERC	EL16-14	Indiana Municipal Power Agency	2015	Reactive Power Rates
151	FERC	ER16-444	Wabash Valley Power Association, Inc.	2015	Reactive Power Rates
152	FERC	ER16-835	New York Power Authority	2015	Transmission Formula
153	FERC	EL15-85	New Hampshire Transmission LLC	2016	Formula Rates
154	FERC	ER16-1832	Entergy Louisiana, LLC	2016	Reactive Power Rates
155	FERC	ER16-2298	Duke Energy Kentucky, Inc.	2016	Reactive Power Rates
156	FERC	ER16-2716	NextEra Energy Transmission, MidAtlantic, LLC	2016	Transmission Formula
157	FERC	ER16-2717	NextEra Energy Transmission, Midwest, LLC	2016	Transmission Formula
158	FERC	ER16-2719	NextEra Energy Transmission, New York, Inc	2016	Transmission Formula
159	FERC	ER16-2720	NextEra Energy Transmission, Southwest, LLC	2016	Transmission Formula

Powder River Energy Corporation
Utilizing RUS Form 7 Data
12/31/2015 (Restated to August 31, 2017)

Line No.	(1)	(2) RUS Form 7 Reference	(3) Company Total		(4) Allocator	(5) Total Transmission		(6) Allocator	(7) Common Use AC Facilities
	Rate Base:								
	GROSS PLANT IN SERVICE								
1	Production	*None*	-	NA		-			-
2	Transmission	*Form 7 Part E, line 5E*	66,362,837	DA	Workpaper 2	66,362,837	DA	Workpaper 1	21,258,039
3	Distribution	*Form 7 Part E, line 1E*	254,235,366	NA	-	-	NA		-
4	General	*Form 7 Part E Line 2E, 3E, 7E*	34,951,380		-	1,508,804			483,316
5	Direct Assign - Transmission	*Accounting Records*	-	DA	1.0000	-	DA	1.0000	-
6	Direct Assign - Distribution	*Accounting Records*	-	NA	-	-	NA		-
7	Other	*Form 7 Part E Lines 2E, 3E, 7E*	34,951,380	WS	0.0432	1,508,804	TP	0.3203	483,316
8	Intangible	*Form 7 Part E Line 4E*	368,367	WS	0.0432	15,902	TP	0.3203	5,094
9	TOTAL GROSS PLANT (sum lines 1-3, 5-8)		355,917,950	GP=	19.1%	67,887,543		6.1%	21,746,449
10	ACCUMULATED DEPRECIATION								
11	Production	*None*	-	NA	-	-		-	-
12	Transmission	*Accounting Records*	34,295,756	DA	1.0000	34,295,756		Workpaper 1	11,190,945
13	Distribution	*Accounting Records*	107,154,457	NA	-	-		-	-
14	General	*Accounting Records*	20,532,846			886,375			283,933
15	Direct Assign - Transmission	*Accounting Records*		DA		-			-
16	Direct Assign - Distribution	*Accounting Records*		NA	-	-			-
17	Other	*Accounting Records*	20,532,846	WS	0.0432	886,375	TP	0.3203	283,933
18	Intangible	*Accounting Records*	142,389	NA	-	-		-	-
19	TOTAL ACCUM. DEPREC. (sum lines 10-13, 15-18)		162,125,449			35,182,131			11,474,878
20	NET PLANT IN SERVICE								
21	Production	*Line 1 - Line 11*	-			-			-
22	Transmission	*Line 2 - Line 12*	32,067,081			32,067,081			10,067,094
23	Distribution	*Line 3 - Line 13*	147,080,909			-			-
24	General	*Line 4 - Line 14*	14,418,534			622,429			199,383
25	Direct Assign - Transmission	*Line 5 - Line 15*	-			-			-
26	Direct Assign - Distribution	*Line 6 - Line 16*	-			-			-
27	Other	*Line 7 - Line 17*	14,418,534			622,429			199,383
28	Intangible	*Line 8 - Line 18*	225,978			15,902			5,094
29	TOTAL NET PLANT (sum lines 21-23 & 25-28)		193,792,501	NP=	16.9%	32,705,411		5.3%	10,271,571
	WORKING CAPITAL								
30	CWC	Calculated	1,080,779	Auto		243,674	Auto		79,756
31	Materials & Supplies	*Accounting Records*	2,040,070	DA	Workpaper 6	2,040,070	TP	0.3203	653,497
32	Prepayments	*Form 7 Part C, Line 24*	289,583	NA		289,583	TP	0.3203	92,762
33	TOTAL WORKING CAPITAL (sum lines 30-32)		3,410,432			2,573,328			826,015
34	RATE BASE (sum lines 29 + 33)		197,202,934			35,278,739			11,097,585

Powder River Energy Corporation
Utilizing RUS Form 7 Data
12/31/2015 (Restated to August 31, 2017)

Line No.	(1)	(2) RUS Form 7 Reference	(3) Company Total	(4) Allocator	(5) Total Transmission	(6) Allocator	(7) Common Use AC Facilities
	O&M						
1	Transmission	Form 7 Part A Line 4b	1,679,300 DA	1.0000	$ 1,679,300 TE	0.3203	$ 537,930.97
2	Less Account 565	Accounting Records	(52,040) DA	1.0000	$ (52,040) TE	0.3203	$ (16,670.11)
3	Distribution	Accounting Records	- NA	0	$ - NA	0	$ -
4	A&G	Form 7 Part A Line 11b	6,998,971 WS	0.0432	$ 302,136 TE	0.3203	$ 96,783.39
5	Add: Regulatory Expense	Workpaper 3	20,000 DA	1.0000	$ 20,000 DA	1.0000	$ 20,000.00
6	Common		- NA	0	$ - NA	0	$ -
8	TOTAL O&M and A&G (sum lines 1-7)		$ 8,646,231		$ 1,949,395.73		$ 638,044.26
	DEPRECIATION EXPENSE						
9	Transmission	Acct #s 405.1 and 403.1	1,726,681 DA	1.0000	$ 1,726,680.92 DA		$ 586,627.91
10	Distribution	Acct #s 405.2 and 403.2	7,630,853 NA	0	$ - NA	0	$ -
11	General	Acct #s 403.4 and 403.5	1,202,445 WS	0.0432	$ 51,907.91 TP	0.3203	$ 16,627.69
	Other Electric Plant	Acct # 405.3	14,730	-			
	Clearing	Accounting Records	698,700	0			$ -
12	TOTAL DEPRECIATION (sum 9-11) (Note C)		$ 11,273,408		$ 1,778,588.83		$ 603,255.59
	TAXES OTHER THAN INCOME TAXES (Note D)						
	LABOR RELATED						
13	Payroll		WS	0.0432	$ - TP	0.3203	$ -
14	Highway and Vehicle		518 WS	0.0432	$ 22 TP	0.3203	$ 7.16
15	PLANT RELATED				$ -		$ -
16	Property				$ -		$ -
17	Property Headquarters		WS	0.0432	$ - TP	0.3203	$ -
18	Property Directly Assigned		DA	1.0000	$ -	1.0000	$ -
19	Production		NA	0	$ -	0	$ -
20	TOTAL OTHER TAXES		$ 518.00		$ 22.36		$ 7.16
21	RETURN		$ 15,677,633	7.95%	$ 2,804,660	7.95%	$ 882,258.02
	(Rate Base (						
22	REV. REQUIREMENT (sum lines 8, 12, 20, 21)		$ 35,597,790.25		$ 6,532,666.70		$ 2,123,565.03

Key	
TP	Transmission Plant
WS	Wages & Salaries
DA	Direct Assignment
NA	Not Applicable

Current Annual CUS Revenues: $ 1,297,602.00

Increase Determined Necessary: $ 825,963.03

Powder River Energy Corporation
Utilizing RUS Form 7 Data
Supporting Calculations and Notes
12/31/2015 (Restated to August 31, 2017)

Line No.	TRANSMISSION PLANT INCLUDED IN JOINT TARIFF RATES		
1	Total Transmission Plant (Form 7, Part E, Line 5e)		$ 66,362,837
2	Less transmission plant excluded from Common Use Facilities		$ 45,104,798
3	Less transmission plant included in Ancillary Services		
4	Transmission plant included in Common Use Facilities (line 1 less 2 and 3)		$ 21,258,039
5	Percentage of transmission plant included in Common Use Facilities (Line 4 / Line 1)	TP=	0.320330477
	TRANSMISSION EXPENSES		
6	Total Transmission Expenses (COSS 1 & 2 of 3)		1,679,300
7	Less transmission expenses included in Ancillary Services		
8	Included transmission expenses (line 6 less line 7)		$ 1,679,300.00
9	Percentage of transmission expenses after adjustment (line 8/line 6)		1
10	Percentage of transmission plant included in Common Use Facilities (Line 5)	TP	0.320330477
11	Percentage of transmission expenses included in Common Use Facilities (Line 9 time Line 10)	TE=	0.320330477

WAGES & SALARY ALLOCATOR (W&S)

Line			Allocation		
12	Production	$ -	-	$ -	
13	Transmission	$ 206,885	1.0000	$ 206,885	WorkPaper 7
14	Distribution	$ 4,585,599	-	$ -	WorkPaper 7
15	Other		-	$ -	($ / Allocation)
16	Total (sum lines 12-15)	$ 4,792,484		$ 206,885	0.043168642

RETURN (R) NOTE E

Line		Source	$ (000)	%	Cost	Weighted
21	Long Term Debt	PREC. Weighted Cost of Debt	$ 129,018	39%	3.5%	1.37%
22	Proprietary Capital	Basin & BHC's FERC Approved Rate	$ 201,346	61%	10.8%	6.58%
23	Total (sum lines 21-22)		$ 330,364	100%		7.95%

Powder River Energy Corporation
Common Use System
12/31/2015 (Restated to August 31, 2017)

Description	Book Cost	12/31/2015 Accum Depr	8/31/2017 Adjusted Accum Depr	8/31/2017 Net Book Value	Depreciation Expense
1 230 kV Transmission Line	$ 6,362,748.54	$ 4,253,135.23	$ 4,538,484.46	$ 1,824,264.08	$ 171,209.54
2 Hughes Sub 230 kV Equipment	$ 2,546,213.14	$ 1,399,753.47	$ 1,516,454.90	$ 1,029,758.24	$ 70,020.86
3 Osage Sub 230 kV Equipment	$ 245,068.40	$ 173,499.77	$ 184,732.07	$ 60,336.33	$ 6,739.38
4 Reno Sub 230 kV Equipment	$ 1,370,485.15	$ 1,052,812.05	$ 1,115,625.95	$ 254,859.20	$ 37,688.34
5 Teckla Sub 230 kV Equipment	$ 1,772,742.48	$ 1,355,270.07	$ 1,436,520.77	$ 336,221.71	$ 48,750.42
6 Teckla II Sub 230 kV Equipment	$ 1,914,840.17	$ 534,945.82	$ 622,709.32	$ 1,292,130.85	$ 52,658.10
7 Barber Creek Sub 230 kV Equipment	$ 463,829.74	$ 179,327.00	$ 210,248.98	$ 253,580.76	$ 18,553.19
8 Wyodak Sub 230 kV Equipment	$ 1,714,830.63	$ 1,353,722.24	$ 1,432,318.65	$ 282,511.98	$ 47,157.84
9 Teckla BHP Inter-Connect	$ 1,124,308.00	$ -	$ 30,918.47	$ 1,093,389.53	$ 30,918.47
10 Bill Durfee Sub 230 kV Equipment	$ 3,742,973.00	$ -	$ 102,931.76	$ 3,640,041.24	$ 102,931.76
TOTAL	$ 21,258,039.25	$ 10,302,465.65	$ 11,190,945.35	$ 10,067,093.90	$ 586,627.91

Powder River Energy Corporation

Work Papers - Gross Plant in Service
12/31/2015 (Restated to August 31, 2017)

Gross Plant in Service - Transmission			
Total Transmission Plant	$	66,362,837.00	*Form 7, Part E, Lines:*
Gross Plant in Service - Distribution			
Total Distribution Plant	$	254,235,366.00	*Form 7, Part E, Line 1e*
Less: Electric Plant Sold			*Form 7, Part E, Lines:*
Total Distribution Plant	$	254,235,366.00	
Gross Plant in Service - Other			
Total General Plant	$	34,951,380.00	*Form 7, Part E, Line 2e + 3e*
Add: Total Leased Plant			*Form 7, Part E, Lines:*
Total General Plant	$	34,951,380.00	
Accumulated Depreciation - Transmission			
Accum. Deprec. - Transmission	$	34,295,756	*See "COSS 1 & 2 of 4"*
Accumulated Depreciation - Distribution			
Accum. Deprec. - Distribution		107,154,457	
Retirement Work in Progress			
Accum. Deprec. - Distribution	$	107,154,457	*See "COSS 1 & 2 of 4"*
Accumulated Depreciation - Other			
Accum. Deprec. - General Plant		20,532,846	
Accum. Deprec. - Leased Plant			
Total Accum. Deprec. General Plant	$	20,532,846	*See "COSS 1 & 2 of 4"*

Powder River Energy Corporation
Work Paper

Regulatory Expense

Legal Fees	$ 60,000.00
Consultant Fees	$ 40,000.00
Salary & Wages (Compliance)	
Travel	$ -
Regulatory Expense - FERC Regulation	**$ 100,000.00**
5 Year Amortization of Regulatory Expense	$ 20,000.00

Powder River Energy Corporation

Work Papers - Depreciation Expense
3/31/2016

	Amortization Land Rights Transmission A/C 405.1	Amortization Land Rights Distribution A/C 405.2	Depreciation Transmission A/C 403.1	Depreciation Distribution A/C 403.2	Depreciation Gen. Plant 403.4 & 403.5	Amorization Other El Plant 405.3	Clearing	Totals
Apr-15	$ 3,077	$ 7,299	$ 141,124	$ 643,251	$ 101,072	$ 1,227	$ 56,112	$ 953,162
May-15	$ 3,088	$ 7,308	$ 141,124	$ 642,890	$ 103,405	$ 1,227	$ 56,512	$ 955,554
Jun-15	$ 3,088	$ 7,378	$ 141,124	$ 641,779	$ 101,420	$ 1,227	$ 57,472	$ 953,488
Jul-15	$ 3,088	$ 7,384	$ 141,124	$ 642,430	$ 101,978	$ 1,227	$ 56,819	$ 954,050
Aug-15	$ 3,089	$ 7,438	$ 141,124	$ 643,027	$ 101,871	$ 1,227	$ 57,673	$ 955,449
Sep-15	$ 3,109	$ 7,456	$ 141,124	$ 630,369	$ 102,131	$ 1,227	$ 59,092	$ 944,508
Oct-15	$ 3,109	$ 7,457	$ 141,124	$ 621,828	$ 100,367	$ 1,227	$ 58,484	$ 933,597
Nov-15	$ 3,124	$ 7,456	$ 140,291	$ 619,576	$ 97,032	$ 1,227	$ 61,184	$ 929,890
Dec-15	$ 3,135	$ 7,468	$ 140,366	$ 613,285	$ 98,619	$ 1,227	$ 60,640	$ 924,740
Jan-16	$ 3,135	$ 7,473	$ 140,282	$ 615,250	$ 98,431	$ 1,227	$ 60,640	$ 926,439
Feb-16	$ 3,135	$ 7,486	$ 140,290	$ 612,853	$ 98,698	$ 1,227	$ 57,239	$ 920,929
Mar-16	$ 3,117	$ 7,492	$ 140,290	$ 615,221	$ 97,419	$ 1,227	$ 56,835	$ 921,602
Total	$ 37,294.22	$ 89,095.25	$ 1,689,386.70	$ 7,541,757.52	$ 1,202,444.79	$ 14,729.88	$ 698,700.01	$ 11,273,408.37

Summary:

Depreciation Expense - Transmission	Accounts 405.1 & 403.1	$ 1,726,680.92
Depreciation Expense - Distribution	Accounts 405.2 & 403.2	$ 7,630,852.77
Depreciation Expense - Other	Accounts 403.4 & 403.5	$ 1,915,874.68
Total Depreciation Expense		$ 11,273,408.37

Powder River Energy Corporation

Work Papers - Depreciation - Common Use Transmission Plant
12/31/2015 (Restated to August 31, 2017)

Account No.	Description		Book Cost	Depreciation Rate		Depreciation Expense
350.4	230 kV trans line - land rights	$	502,138.73	2.00%	$	10,042.77
355.4	230 kV trans line - poles & fixtures	$	2,076,942.59	2.75%	$	57,115.92
356.4	230 kV trans line - OH cond & Devices	$	3,783,667.22	2.75%	$	104,050.85
353.4	Hughes Sub 230 kV Equipment	$	2,546,213.14	2.75%	$	70,020.86
353.4	Osage Sub 230 kV Equipment	$	245,068.40	2.75%	$	6,739.38
353.4	Reno Sub 230 kV Equipment	$	1,370,485.15	2.75%	$	37,688.34
353.4	Teckla Sub 230 kV Equipment	$	1,772,742.48	2.75%	$	48,750.42
353.4	Teckla II Sub 230 kV Equipment	$	1,914,840.17	2.75%	$	52,658.10
353.42	Barber Creek Sub 230 kV Equipment	$	463,829.74	4.00%	$	18,553.19
353.4	Wyodak Sub 230 kV Equipment	$	1,714,830.63	2.75%	$	47,157.84
	Teckla BHP Inter-Connect	$	1,124,308.00	2.75%	$	30,918.47
	Bill Durfee Sub 230 kV Equipment	$	3,742,973.00	2.75%	$	102,931.76
	Total	$	21,258,039.25		$	586,627.91

Powder River Energy Corporation

Transmission Material Inventory
13 Month Average Ending March 31, 2016

Inventory Item	Mar-15	Apr-15	May-15	Jun-15	Jul-15
100 MVA Transformer	1,268,772.50	1,268,772.50	1,268,772.50	-	-
7500 KVA Transformer	81,378.96	81,378.96	81,378.96	81,378.96	81,378.96
Breaker	197,254.65	-	-	-	-
Conductor	321,942.28	321,942.28	321,942.28	321,760.94	304,937.89
Crossarm Brace	47,676.86	47,676.86	47,676.86	47,676.86	47,676.86
Crossarms 10'	3,471.76	3,471.76	3,471.76	3,471.76	3,471.76
Crossarms 12'	1,100.97	1,100.97	1,100.97	1,100.97	1,100.97
Crossarms 13'6"	795.63	795.63	795.63	795.63	795.63
Crossarms 19'	675.46	675.46	675.46	675.46	675.46
Crossarms 22'	8,545.69	8,545.69	8,545.69	8,545.69	8,545.69
Crossarms 25'3"	878.97	878.97	878.97	878.97	878.97
Crossarms 8'	2,476.80	2,476.80	2,476.80	2,476.80	2,476.80
CT	100,554.57	100,554.57	100,554.57	100,554.57	100,554.57
Deadend	6,928.24	6,928.24	6,928.24	6,928.24	6,928.24
Double Crossarms 26'	106,017.06	106,017.06	106,017.06	106,017.06	106,017.06
Insulators	9,628.09	9,628.09	9,628.09	9,628.09	7,452.49
Meter Box	4,073.66	4,073.66	4,073.66	4,073.66	4,073.66
Over-Head Guy Wire	2,696.24	2,696.24	2,696.24	2,652.38	3,148.94
Platform	274.49	274.49	274.49	274.49	274.49
POLE CAP 12"	3,966.68	3,966.68	3,966.68	3,966.68	3,966.68
Poles 100'	24,698.53	21,376.51	21,376.51	21,376.51	21,376.51
Poles 105'	69,963.20	69,963.20	69,963.20	69,963.20	69,963.20
Poles 110'	6,377.05	6,377.05	6,377.05	6,377.05	6,377.05
Poles 40'	2,022.23	2,022.23	2,022.23	2,022.23	2,022.23
Poles 45'	1,252.20	1,252.20	1,252.20	1,252.20	1,252.20
Poles 50'	13,513.96	13,513.96	13,513.96	13,513.96	13,513.96
Poles 55'	12,194.90	12,194.90	12,194.90	12,194.90	12,194.90
Poles 60'	66,584.24	61,251.31	61,109.14	60,920.96	60,589.45
Poles 65'	75,194.82	71,617.33	71,555.69	71,464.35	71,464.35
Poles 70'	103,272.56	103,272.56	102,900.22	100,570.57	97,516.58
Poles 75'	80,881.35	80,851.00	80,534.27	80,652.95	80,652.95
Poles 80'	51,741.03	51,741.03	51,499.34	51,646.33	47,077.62
Poles 85'	52,547.61	52,547.61	52,547.61	52,146.63	52,146.63
Poles 90'	62,717.32	62,717.32	60,319.47	60,319.47	60,319.47
Poles 95'	49,021.66	46,608.24	46,608.24	46,608.24	43,183.94
PT	31,363.60	31,363.60	31,363.60	31,363.60	31,363.60
Socket Clevis	1,854.69	1,264.59	1,264.59	1,264.59	1,264.59
Suspension Clamps	4,997.50	4,997.50	4,997.50	4,997.50	4,997.50
Switches	466,488.03	466,488.03	466,488.03	465,592.95	459,694.13
Tie Angle	7,140.00	7,140.00	7,140.00	7,140.00	7,140.00
Yoke Plate	3,230.85	3,230.85	3,230.85	3,230.85	3,230.85
Total	**3,356,167**	**3,143,646**	**3,140,114**	**1,867,476**	**1,831,697**

Powder River Energy Corporation

Transmission Material Inventory
13 Month Average Ending March 31, 2016

Inventory Item	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15
100 MVA Transformer	-	-	-	-	-
7500 KVA Transformer	81,378.96	81,378.96	81,378.96	81,378.96	81,378.96
Breaker	-	-	-	-	-
Conductor	304,937.89	166,318.85	155,219.65	155,219.65	153,568.03
Crossarm Brace	47,676.86	43,342.60	43,342.60	43,342.60	43,342.60
Crossarms 10'	3,471.76	3,471.76	3,471.76	3,471.76	3,471.76
Crossarms 12'	1,100.97	1,100.97	1,100.97	1,100.97	1,100.97
Crossarms 13'6"	795.63	795.63	795.63	795.63	795.63
Crossarms 19'	337.73	337.73	337.73	337.73	337.73
Crossarms 22'	8,545.69	8,545.69	8,545.69	8,545.69	8,545.69
Crossarms 25'3"	-	-	-	-	-
Crossarms 8'	2,476.80	2,476.80	2,476.80	2,476.80	2,476.80
CT	100,554.57	100,554.57	100,554.57	100,554.57	100,554.57
Deadend	6,928.24	6,928.24	6,928.24	6,928.24	6,928.24
Double Crossarms 26'	106,017.06	89,411.98	89,411.98	89,411.98	89,411.98
Insulators	7,452.49	7,452.49	7,452.49	7,452.49	7,452.49
Meter Box	4,073.66	4,073.66	4,073.66	4,073.66	7,410.41
Over-Head Guy Wire	3,148.94	3,148.94	1,686.94	1,686.94	1,686.94
Platform	274.49	274.49	274.49	274.49	274.49
POLE CAP 12"	3,966.68	3,966.68	3,966.68	3,966.68	3,966.68
Poles 100'	21,376.51	21,376.51	21,376.51	21,376.51	21,376.51
Poles 105'	69,963.20	69,963.20	69,963.20	69,963.20	69,963.20
Poles 110'	6,377.05	6,377.05	6,377.05	6,377.05	6,377.05
Poles 40'	2,022.23	2,022.23	2,022.23	2,022.23	2,022.23
Poles 45'	1,252.20	1,252.20	1,252.20	1,252.20	1,252.20
Poles 50'	13,513.96	13,513.96	13,513.96	13,513.96	13,513.96
Poles 55'	11,762.81	11,762.81	11,762.81	11,762.81	11,762.81
Poles 60'	59,755.54	63,607.44	61,227.77	61,227.77	61,227.77
Poles 65'	70,849.98	72,399.85	71,087.86	71,087.86	71,087.86
Poles 70'	96,653.84	101,963.10	98,982.43	98,982.43	98,982.43
Poles 75'	80,336.55	84,206.85	71,691.85	71,691.85	71,691.85
Poles 80'	46,355.68	52,548.20	50,484.03	50,484.03	50,484.03
Poles 85'	52,106.35	54,638.50	54,638.50	54,638.50	54,638.50
Poles 90'	60,319.47	60,319.47	60,319.47	60,319.47	60,319.47
Poles 95'	43,183.94	43,183.94	43,183.94	43,183.94	43,183.94
PT	31,363.60	31,363.60	31,363.60	31,363.60	31,363.60
Socket Clevis	1,264.59	1,264.59	1,264.59	1,264.59	1,264.59
Suspension Clamps	4,997.50	4,997.50	4,997.50	4,997.50	4,997.50
Switches	459,694.13	420,505.87	420,505.87	420,505.87	420,505.87
Tie Angle	7,140.00	5,670.00	5,670.00	5,670.00	5,670.00
Yoke Plate	3,230.85	3,230.85	3,230.85	3,230.85	3,230.85
Total	**1,826,658**	**1,649,748**	**1,615,935**	**1,615,935**	**1,617,620**

Powder River Energy Corporation

Transmission Material Inventory
13 Month Average Ending March 31, 2016

Inventory Item	Jan-16	Feb-16	Mar-16
100 MVA Transformer	-	-	-
7500 KVA Transformer	81,378.96	81,378.96	81,378.96
Breaker			
Conductor	153,568.03	153,568.03	168,344.78
Crossarm Brace	43,342.60	43,342.60	43,033.01
Crossarms 10'	3,471.76	3,471.76	3,086.00
Crossarms 12'	1,100.97	1,100.97	1,100.97
Crossarms 13'6"	795.63	795.63	1,060.84
Crossarms 19'	337.73	337.73	337.73
Crossarms 22'	8,545.69	8,545.69	8,545.69
Crossarms 25'3"			
Crossarms 8'	2,476.80	2,476.80	2,476.80
CT	100,554.57	100,554.57	100,554.57
Deadend	6,928.24	6,928.24	7,006.97
Double Crossarms 26'	89,411.98	89,411.98	88,134.67
Insulators	7,452.49	8,540.29	9,120.45
Meter Box	7,410.41	7,410.41	4,884.69
Over-Head Guy Wire	1,686.94	1,686.94	2,140.16
Platform	274.49	274.49	274.49
POLE CAP 12"	3,966.68	3,966.68	3,987.56
Poles 100'	21,376.51	21,376.51	21,376.51
Poles 105'	69,963.20	69,963.20	69,963.20
Poles 110'	6,377.05	6,377.05	6,377.05
Poles 40'	2,022.23	2,022.23	2,022.23
Poles 45'	1,252.20	1,252.20	1,252.20
Poles 50'	13,513.96	13,513.96	12,802.70
Poles 55'	11,762.81	11,762.81	11,762.81
Poles 60'	61,227.77	61,227.77	58,899.67
Poles 65'	71,087.86	71,087.86	71,087.86
Poles 70'	98,982.43	98,982.43	96,168.52
Poles 75'	71,691.85	71,691.85	73,358.53
Poles 80'	50,484.03	50,484.03	47,270.91
Poles 85'	54,638.50	54,638.50	55,333.11
Poles 90'	60,319.47	60,319.47	60,319.47
Poles 95'	43,183.94	43,183.94	38,809.67
PT	31,363.60	31,363.60	31,363.60
Socket Clevis	1,264.59	1,407.90	1,407.90
Suspension Clamps	4,997.50	4,997.50	4,997.50
Switches	420,505.87	420,505.87	420,505.87
Tie Angle	5,670.00	5,670.00	5,670.00
Yoke Plate	3,230.85	3,230.85	3,230.85
Total	**1,617,620**	**1,618,851**	**1,619,449**

13 month average **2,040,070**

Powder River Energy Corporation
WorkPaper 7
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Wages & Salary Allocator

	Transmission	Distribution	A & G	Total
Direct	153,734.09	4,445,044.56	2,792,528.72	7,391,307.37
163.00	2.13	10,638.36	-	10,640.49
184.10	703.02	28,411.71	19,369.41	48,484.14
184.20	111.54	4,507.88	3,073.21	7,692.63
184.30	32,557.83	59,689.36	179,068.08	271,315.27
184.31	4,184.34	7,671.28	23,013.84	34,869.46
184.32	13,070.23	23,962.09	71,886.28	108,918.61
184.40	2,521.86	5,674.20	12,819.48	21,015.54
	$ 206,885.05	**$ 4,585,599.44**	**$ 3,101,759.02**	**$ 7,894,243.51**

ATTACHMENT E

A LIST OF RECIPIENTS

LIST OF RECIPIENTS

Ken Rutter
Tom Christensen
Basin Electric Power Cooperative
1717 E Interstate Avenue
Bismark, ND 58503
KRutter@bepc.com
tomc@bepc.com; dsalmonson@bepc.com

Eric Egge
Dory Batka
Black Hills Power, Inc.
P.O. Box 1400
Rapid City, SD 57709-1400
eric.m.egge@blackhillscorp.com
dory.batka@blackhillscorp.com

Billy Cutsor
David Dietz
Municipal Energy Agency of Nebraska
8377 Glynoaks Drive
Lincoln, NE 68516
bjcutsor@nmppenergy.org
ddietz@nmppenergy.org

Shanicee Knutson
General Counsel/Deputy Director
of Policy and Law
Nebraska PSC
shana.knutson@nebraska.gov

Eric Egge
Cheyenne Light Fuel & Power Company
P.O. Box 1400
Rapid City, SD 57709-1400
eric.m.egge@blackhillscorp.com
dory.batka@blackhillscorp.com

Justin Kraske
Chief Counsel/Administrator
Montana PSC
jkraske@mt.gov

Mark Lux
Black Hills Wyoming
P.O. Box 1400
Rapid City, SD 57709-1400
mark.lux@blackhillscorp.com

John Smith
General Counsel
South Dakota PUC
john.j.smith@state.sd.us

Jeanne Hanson
Black Hills State University
BHSU Facilities Services
1200 University Street
Unit 9513
Spearfish, SD 57799-9513
jeannehanson@bhsu.edu

Chris Petrie
Chief Counsel
Wyoming PSC
chris.petrie@wyo.gov

Rosemary Henry
WMPA
P.O. Box 900
Lusk, WY 82225
rosemary@wmpa.org

Michele M. Farris
State Energy Manager
South Dakota West
State of South Dakota
500 E. Capitol Avenue
Pierre, SD 57501

South Dakota Public Utilities Commission
Capitol Building, 1st Floor
500 East Capitol Avenue
Pierre, SD 57501-5070

North Dakota Public Service Commission
Public Utilities Division
600 E. Boulevard, Department 408
Bismarck, ND 58505-0480

Carter Napier
City Administrator
City of Gillette
cartern@gillettewy.gov

David Pomper
Spiegel & McDiarmid
1875 Eye Street, NW
Suite 700
Washington, DC 20006
david.pomper@spiegelmcd.com

Seth Lucia, Esq.
Bracewell & Giuliani LLP
2001 M Street, NW
Suite 900
Washington, DC 20036-3310
seth.lucia@bgllp.com

Thomas L. Blackburn, Esq.
Schiff & Hardin
901 K Street, NW
Suite 700
Washington, DC 20001
tblackburn@schiffhardin.com

Dan Bridges
City of Gillette
Electrical Manager
danb@gillettewy.gov

Charlie Anderson
Pat Davidson
Counsel
City of Gillette
Charlie@gillettewy.gov
patrickd@gillettewy.gov

Bruce Doll
Municipal Energy Agency of Nebraska
Senior Transportation and Regulatory Analyst
8377 Glynoaks Drive
Lincoln, NE 68516