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Public Service Commission
Wyoming

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC UTILITY SERVICE RATES IN WYOMING, CONSISTING OF A GENERAL RATE INCREASE OF APPROXIMATELY $40.2 MILLION PER YEAR AND FOR APPROVAL OF AN ALTERNATIVE FORM OF REGULATION OR IN THE ALTERNATIVE FOR APPROVAL OF AN UNCONTROLLABLE COST ADJUSTMENT MECHANISM.	)))))))))))	Docket No. 20000-230-ER-05 (Record No. 10196)

STIPULATION AND AGREEMENT

This Stipulation and Agreement (Stipulation) is entered into between PacifiCorp, the Wyoming Office of Consumer Advocate (OCA), AARP, the Wyoming Industrial Energy Customers (WIEC) and the Big Horn Basin Irrigators, collectively referred to as the Parties.

I. RECITALS

1. On October 14, 2005, PacifiCorp (Company) filed an Application with this Commission in Docket No. 20000-230-ER-05 requesting approval of a general rate increase of approximately $40.2 million per year. The application also requested approval of an alternative form of regulation (AFOR) mechanism. Alternatively, if the Commission did not approve the AFOR mechanism, PacifiCorp sought approval of an Uncontrollable Cost Adjustment Mechanism (UCAM). Both the AFOR and the UCAM were sought in conjunction with and in addition to the requested increase of $40.2 million in base rates.

2. On October 28, 2005, the Commission issued a Notice of Application in Docket No.

20000-230-ER-05. Pursuant to W.S. § 37-3-106, the Commission entered a Suspension Order in Docket No. 20000-230-ER-05 on November 2, 2005, suspending the proposed filing for purposes of investigation. Requests for intervention were to be filed with the Commission on or before November 23, 2005. The following parties were granted intervention status: OCA, AARP, WIEC, Kinder Morgan, Inc., Kinder Morgan Interstate Gas Transportation LLC, Canyon Creek Compression Company and the Big Horn Basin Irrigators.

3. On November 18, 2005, the Commission issued its Order on Motion for Approval of Procedural Schedule in Docket No. 20000-230-ER-05 denying the Company's request for an expedited procedural schedule absent an all-party agreement. In addition, the Commission reminded the parties that they may, at any time, bring to the Commission a stipulation, a settlement, suggested modifications to the procedural schedule, or other motions for relief.

4. On December 16, 2005, the Company filed an Application with this Commission in Docket No. 20000-233-EP-05 requesting approval of a net wholesale purchase power cost increase of approximately $16.1 million per year for net wholesale purchase power costs.

5. The Parties have engaged in discussions regarding PacifiCorp's general rate increase request and wholesale purchase power cost pass-on request. The Parties have reached an agreement that resolves all outstanding issues to their satisfaction.

II. AGREEMENTS REGARDING RESOLUTION OF ISSUES

6. PacifiCorp agrees that, immediately upon approval by the Commission of this Stipulation and Agreement, the Company shall file a request with the Commission to dismiss the pass-on application filed in Docket No. 20000-233-EP-05 and further, the Company agrees that it will not otherwise pursue this application.

7. The Parties stipulate that PacifiCorp will be allowed to increase rates $15 million per year effective March 1, 2006 pursuant to the application filed in Docket No. 20000-230-ER-05.

8. The Parties stipulate that the $15 million March 1, 2006 increase shall be allocated among all service schedules on the basis of cost of service relationships and rate impact mitigation provisions as described further in paragraph 23. A summary illustrating the increase to be effective March 1, 2006 for each rate schedule is included in Stipulation Exhibit 1.

9. The Parties stipulate that PacifiCorp should be allowed to increase rates an additional $10 million per year in Docket No. 20000-230-ER-05, effective July 1, 2006. The Parties agree that the July 1, 2006 increase shall be in addition to the increase effective March 1, 2006. A summary illustrating the effect of the July 1, 2006 increase for each rate schedule is included in Stipulation Exhibit 1.

10. The Parties stipulate that the March 1, 2006 and July 1, 2006 revenue increases will result in an annual ongoing revenue increase of $25 million effective on and after July 1, 2006. The total ongoing annual revenue increase effective July 1, 2006 shall be $25 million in comparison to the revenues in effect on the date that this Stipulation is signed.

11. The Parties stipulate that the $25 million ongoing revenue increase effective July 1, 2006 shall be proportionally assigned to the service schedules using the cost of service relationships proposed in the general rate case application in Docket No. 20000-230-ER-05 as well as on the basis of rate impact mitigation provisions as described further in paragraph 23. A summary illustrating the cumulative $25 million general rate case revenue increase and the percentage increase for each rate schedule is included in Stipulation Exhibit 1.

12. The Parties stipulate that effective July 1, 2006, total net power costs shall be unbundled from other base costs and recovered on an on-going basis through a Power Cost Adjustment Mechanism (PCAM), as an agreed modification of the power cost recovery mechanisms proposed by PacifiCorp in its application in Docket No. 20000-230-ER-05. The costs tracked and included in the PCAM shall be as identified in the NPC PCAM Tariff attached hereto as Stipulation Exhibit 2.

13. The Parties stipulate that any cost included in a PCAM application may be challenged by any Party or the Commission and it shall be the Company's responsibility and obligation to demonstrate to the Commission that rate adjustments proposed in PCAM applications are just and reasonable. The Parties agree that a PCAM application challenge shall not delay implementation of the proposed PCAM rates, but that those rates shall be implemented on an interim basis, subject to final determination by the Commission after opportunity for hearing. If the Commission determines that the interim rates are not just and reasonable, any excess charges shall be refunded with interest at the rate established

by the Commission pursuant to Section 241 of the Commission's Rules and Regulations for Customer Deposits. In the alternative, if interim rates are authorized by the Commission at a level below that requested in the PCAM application, and the Commission determines after investigation that the interim rates were insufficient; the Company shall be entitled to recover the Commission approved rates with interest at the rate established by the Commission pursuant to Section 241 of the Commission's Rules and Regulations for Customer Deposits.

14. The Parties stipulate that PacifiCorp shall file a PCAM application annually beginning on or before February 1, 2007 and on or before each February 1st thereafter subject to the provisions of Paragraph 15 of this Stipulation. The PCAM application shall be based on a historic 12 month test period beginning December 1st and ending the November 30th preceding each filing date except as provided in Paragraph 16 of this Stipulation. The PCAM annual rate effective date shall be on April 1, 2007 and on April 1st each year thereafter subject to Paragraph 15 of this Stipulation.

15. The Parties stipulate that, unless all of the Parties jointly petition the Commission to implement a change or changes, the PCAM established by Commission approval of this Stipulation and Agreement shall remain in effect and shall be utilized without modification except as set forth in Paragraph 21, for purposes of determining all total net power cost adjustments to PacifiCorp's rates that are to be effective prior to April 1, 2009. The Parties agree that the Company may file applications with the Commission that if approved by the Commission, will allow the Company to track and recover net power

costs after November 30, 2007, differently than in the current PCAM provided that any rate changes resulting therefrom do not occur until on or after April 1, 2009, provided however, that nothing herein obligates any party to support, or waives any Party's right to object to, any such application filed by the Company.

16. The Parties stipulate that the first PCAM application filed on or before February 1, 2007, shall compare adjusted actual total net power costs for the time period July 1, 2006 through November 30, 2006 to base total net power costs which for purposes of this specific one-time period, shall be $336 million on a total Company basis as identified in Stipulation Exhibit 3. The Parties further agree that for PCAM applications filed on or before February 1, 2008 and beyond, subject to the provisions of this agreement, base total net power cost shall be $660 million (total Company) as reflected in the Company's application in Docket No. 20000-230-ER-05 until the Commission authorizes and the Company implements a change in base net power costs through a general rate case. The Parties further agree, however, that in the event that PacifiCorp files a new general rate case on or before February 1, 2007, then the base total net power costs beginning December 1, 2006 shall be $700 million annually for purposes of the deferral calculation only, as shown in Stipulation Exhibit 3, and shall remain in effect at that level until the Commission authorizes a change in base net power costs through a general rate case. The Parties stipulate and agree that the PCAM base total net power costs shall be reset at each general rate case.

17. The Parties stipulate that the PCAM shall utilize a symmetrical annual dead band of plus

or minus $40 million on a total Company basis that shall be applicable on either side of the base total net power cost. The Parties further agree that if less than an annual PCAM comparison period is used, then the dead band shall be computed on the pro rata share of $40 million to the applicable months in the comparison period. Actual total net power costs that fall outside the dead band and within the Customer Proportion shall be recoverable or refundable subject to a symmetrical sharing proportion.

18. The Parties stipulate that the total Company symmetrical sharing proportion of the PCAM shall be computed in a layered manner under the following conditions:

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

The Parties further stipulate that there will be no deferral or accrual of interest for costs which are included in the Company Proportion. Additionally, if less than an annual

PCAM comparison period is used, the thresholds between the various layers shall be prorated based on the number of months in the comparison period.

19. The Parties stipulate that the PCAM shall generally measure the difference between adjusted actual total net power costs and the corresponding Commission approved base total net power cost on a monthly basis as set forth in more detail in the NPC Tariff attached hereto as Stipulation Exhibit 2. The Parties agree that interjurisdictional allocation provisions shall be included in the calculation of the PCAM pursuant to the terms of the NPC PCAM Tariff.

20. Interest shall apply to over and under recoveries in a symmetrical manner (paid to customers if actual total net power costs are less than base total net power costs and charged to customers if actual total net power costs are more than base total net power costs) after the dead band threshold is met and the sharing provisions have been applied. The symmetrical interest rate shall be established by the Commission pursuant to Section 241 of the Commission's Rules and Regulations for Customer Deposits. Interest shall continue to accrue as long as there is a net balance in the NPC deferred account. Interest shall also be appropriately included in the deferred cost amortization and recovery period. Any deferred net power cost balance that is collected through a change of rates shall be amortized over a 12 month period and recovered or refunded in a deferred net power cost adjustment, unless the Commission approves a longer or shorter amortization period for good cause to recognize extraordinary circumstances. The Parties agree that if the Commission approves a longer amortization period, interest shall be calculated based on

the Company's most recent authorized weighted average cost of capital. Further, the Parties agree that to ease the administrative burden of preparing and processing a PCAM application for very small cost changes, the Company may elect to defer recovery of a NPC under collection at its discretion and the Company may elect to defer refund of a NPC over recovery if the balance in the deferred account is less than $1 million on a Wyoming jurisdictional basis.

21. The Company agrees that not later than September 1, 2006, it will initiate a collaborative process with the Parties to review how PCAM revenues are tracked and explore whether a more refined method of calculating the revenue variation adjustment can be developed, or an alternative revenue tracking mechanism implemented, for the net power cost comparison period beginning December 1, 2006.

22. The Company agrees that not later than March 15, 2006, it will initiate a collaborative process with the Parties to review the Company's energy risk management strategies and to endeavor to determine which, if any, financial hedging programs, costs and benefits would be supported in PCAM applications. The Company may determine the level of financial hedging costs and associated benefits to include in each PCAM application to manage risk in the best interest of its customers which may be challenged by the Parties when PCAM applications are filed with the Commission, unless the parties previously agreed to the level of financial hedging costs and associated benefits that they would support in the PCAM. The Parties agree that energy risk management programs do not necessarily reduce costs. Upon completion of the collaborative review of its energy risk

management strategies, the Company will file an energy risk management plan with the Commission if requested by the Parties or if the Company, in its sole discretion, chooses to make such a filing. The Parties agree that energy risk management programs may include highly sensitive and confidential information that could jeopardize the Company's interests if revealed to the public or competitive suppliers, and to respect the Company's reasonable need to protect highly sensitive and confidential information.

23. The Parties stipulate to implement one-half of the Schedule 46 Load Size Charge to Schedule 33/218 in rates implemented pursuant to this agreement effective on July 1, 2006. The annualized revenues representing the remaining one-half of the Load Size Charge shall be collected from Schedule 25/206 on a rate impact mitigation basis effective on March 1, 2006. The Parties stipulate that they will support at the next general rate case, implementation of the full Load Size Charge for Schedule 33/218 provided however, that the Load Size Charge shall be supported by cost of service principles. PacifiCorp agrees that not later than July 1, 2006, it will initiate a collaborative process with Wyoming partial requirements customers and other interested Parties, to attempt to reach an agreement on an appropriate cost of service methodology for back-up facilities and back-up demand charges for partial requirements service. If an agreement is not reached in the collaborative process, the Parties shall be free to propose alternative cost of service methodologies and that nothing herein obligates any party to support, or waives any Party's right to object to, any such methodologies in any application filed by the Company. The Stipulation approved by the Commission in

Docket No. 20000-ER-02-184 effective March 6, 2003, shall remain in effect for all aspects of Schedule 33/218 with the exception of back-up facilities and back-up demand charges unless otherwise agreed to by the participants in the collaborative.

24. The Parties stipulate to a one-time opportunity for Schedule 33/218 customers to change the contract level of Supplemental demand with only 3-months notice, if such notice is provided to the Company in writing by Schedule 33/218 customers on or before March 31, 2006, after which the then-current tariff provision with respect to notice shall apply.

25. The Parties stipulate that the rates implemented pursuant to this agreement effective on March 1, 2006 and July 1, 2006, shall include the rate design changes proposed in Docket No. 20000-230-ER-05 to: 1) achieve East-West rate parity for the major customer classes first begun in Docket No. 20000-ER-00-162; 2) eliminate the Short Term Interval Demand billing adjustment for Schedule 46; and 3) to revise the monthly minimum kW charge for Schedule 46.

26. The Parties stipulate that a Force Majeure provision has historically been included in Schedule 217 and that Schedule 217 shall be eliminated as a result of the Rate Parity Plan first begun in Docket No. 20000-ER-00-162. The Parties agree that in rates implemented pursuant to this agreement effective on July 1, 2006, Schedule 217 (primary voltage) customers shall be served under Schedule 46 and Schedule 217 (Transmission voltage) customers shall be served under Schedule 48T. The Parties agree that the same historic Force Majeure provision in Schedule 217 shall be incorporated in Schedules 46 and 48T unless and until that provision is modified in a general rate filing or other formal

proceeding before the Commission.

27. The Parties stipulate that rates implemented pursuant to this agreement effective on July 1, 2006, shall include each of the proposed corrections, revisions and modifications to PacifiCorp's Rules and Regulations as proposed by the Company in Docket No. 20000-230-ER-05. These include: 1) several housekeeping changes to provide more clarity, 2) increase the charge for disconnection and reconnection visits to reflect cost, 3) elimination of line extension allowance for transmission level service, and 4) implementation of a new charge for meter verification at multiple meter locations. Tariff sheets implementing these corrections, revisions and modifications are sponsored by William Griffith and included as Exhibit PPL__.1 (WRG-1) in the Company's application in Docket No. 20000-230-ER-05.

28. The Parties stipulate that in its next general rate case application, the Company shall request that new rates be effective only on or after August 1, 2007, provided, however, that nothing in this Stipulation in a future general rate case will prohibit all the Parties from stipulating and agreeing to support an earlier rate effective date.

29. The Parties stipulate on a one-time trial basis only that in the first general rate case filed by the Company following Commission approval of this Stipulation the Parties to this agreement shall support the principle of a forecast test year that extends 20 months past the date of actual historic data included in the general rate case application. The Company agrees to file for informational purposes with the Commission, the Parties and any other parties to such general rate case, as soon as such information becomes

available, actual normalized costs on a total Company basis for the time period six months beyond the date of actual data included in the general rate case application. Nothing herein shall be construed to limit any Party's right to challenge the forecast methodology, assumptions or data in that case. The Company agrees to file with the Commission and the Parties, fully normalized and adjusted historic twelve month results of operations reports on a semiannual basis as soon as such information becomes available for informational purposes.

30. The Parties stipulate that they will work cooperatively in collaborative meetings that shall begin no later than March 15, 2006, on AFOR issues to discuss and consider whether AFOR concepts may be applicable to the Company's operations in Wyoming. The Parties stipulate that the initial AFOR model to be considered in the first collaborative meeting shall be a draft proposal offered by the Company and provided to the Parties no later than March 1, 2006. The Company shall implement an AFOR tracking mechanism that results from the collaborative process for test purposes only and will share information with the Parties regarding the AFOR tracker as that information is developed, subject to reasonable requirements for the protection of confidential information. The Company agrees that any future request it may make for Commission approval of an AFOR will be structured such that no adjustment to rates resulting from approval of the AFOR will occur prior to April 1, 2009. Nothing herein obligates any Party to support, or waives any Party's right to object to, any AFOR application filed by the Company. If all of the Parties to this stipulation agree to an AFOR mechanism, nothing herein restricts the

Company from filing an AFOR application with the Commission and a stipulation that would support the implementation of an AFOR prior to April 1, 2009.

31. The Company agrees that it will meet with the Parties no later than March 15, 2006, to begin dialogue on and evaluation of new Demand Side Management programs and the possible extensions of existing Demand Side Management programs offered by PacifiCorp in other states that could be prudent and cost effective for Wyoming. All classes of service shall be considered in the Demand Side Management evaluation. PacifiCorp agrees to make a best-efforts attempt to file an application with the Commission prior to December 31, 2006, to implement prudent and cost-effective Demand Side Management programs in Wyoming that can be shown to be in the public interest and to propose in the application an appropriate cost recovery mechanism.

32. The Company agrees that not later than July 1, 2006 it will initiate a collaborative process with Wyoming Irrigators for a state specific load research program regarding Wyoming irrigation loads. The Parties agree that due to the inconsistent nature of weather and crop dependent irrigation, the time and cost to install metering to collect load research data, and the time necessary to evaluate and include the load research results in cost of service studies, it may take several years to complete the Wyoming irrigation load research program. PacifiCorp will make reasonable attempts to install data gathering metering for the 2007 irrigation season and once data is available that represents average long-term irrigation load conditions in Wyoming, to utilize Wyoming specific irrigation load data in its cost of service studies in future general rate cases in a reasonable time frame. The

Company agrees that it will continue to monitor the effectiveness of and make adjustments if necessary to the alternative irrigation rate design that was approved by the Commission in Docket No. 20000-ET-04-217.

33. The Company agrees that on or before April 1, 2006, it will make a one-time contribution of $30,000 from shareholder funds to Energy Share of Wyoming for purposes of providing emergency energy assistance to Wyoming utility consumers.

III. GENERAL TERMS AND CONDITIONS

34. The Parties stipulate to support all elements of this Stipulation as being in the public interest in proceedings before the Commission. The Parties agree to advocate and defend the position that this Stipulation should be heard by the Commission on an expedited basis because it is in the public interest.

35. The Parties stipulate that this Stipulation represents a compromise in their respective positions and is a result of settlement negotiations. As such, evidence of conduct or statements made in the negotiation and discussion phases of this Stipulation shall not be admissible as evidence in any proceeding before the Commission or court.

36. The Parties stipulate that the positions and agreements of the Parties set forth herein cannot be used to bind or estop any party from arguing any position in a future docket before this Commission.

37. In the event the Commission declines to approve this Stipulation or makes a material change to this Stipulation, or it is otherwise disapproved in whole or in material part by any court of competent jurisdiction, then any Party adversely affected by such action shall

have the right to withdraw from this Stipulation and no Party to this Stipulation shall be prejudiced by its terms and each Party shall be entitled to file any application, testimony and tariffs it chooses, to cross-examine witnesses and, in general, to put on such case as it deems appropriate. The withdrawing Party shall notify the Commission and all other Parties in writing of its intent to withdraw, such notice to be given by mail, e-mail or fax, to be received within three business days of the Commission or court decision. The Parties will meet within five business days of the notice of withdrawal for purposes of determining whether an alternative agreement can be reached or whether Commission proceedings in the captioned dockets should go forward for hearing to the Commission.

38. All negotiations relating to this Stipulation are privileged and confidential, and no Party shall be bound by any position asserted in the negotiations, except to the extent expressly stated in this Stipulation. Execution of the Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory or principle of regulation, and no Party shall be deemed to have agreed that any principle, method or theory of regulation employed in arriving at this Stipulation and Agreement is appropriate for resolving any issue in any other proceeding.

39. The Parties stipulate to the submission of the Company's direct prefiled testimony and exhibits in Docket No. 20000-230-ER-05 and the Parties waive the filing and submission of testimony and exhibits from intervenors. The Parties waive cross examination of Company witnesses regarding general rate case prefiled testimony and exhibits. It is the Parties' intent to make (a) four Company witnesses available to explain the proposed

Stipulation and to address general business and policy matters, revenue requirement, power cost, PCAM mechanics, rate spread, rate design and tariff matters and (b) one OCA witness available. The Parties request notice from the Commission in advance of the hearing if the Commission would request additional witnesses.

40. The Parties stipulate and agree that this Stipulation and Agreement is in the public interest and that all of its terms are reasonable.

41. The Parties shall advocate in good faith that the Commission approve this Stipulation in its entirety. They shall make attorneys or witnesses available to explain and support this Stipulation in whatever level of detail may be desired by the Commission.

DATED this _____ day of February, 2006.

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DATED this 2nd day of February, 2006.

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STIPULATION EXHIBIT 1

STIPULATION EXHIBIT 1
PACIFIC POWER
ESTIMATED EFFECT OF PROPOSED PRICES
ON REVENUES FROM ELECTRIC SALES TO ULTIMATE CONSUMERS IN WYOMING
DISTRIBUTED BY RATE SCHEDULE
HISTORIC TEST PERIOD 12 MONTHS ENDED MARCH 2005
FORECAST TEST PERIOD 12 MONTHS ENDED SEPTEMBER 2006

							Proposed for March 1				Unbundled Proposed Revenues - July 1			Proposed for July 1				
Line No.	Description	Present Schedule Number	Proposed Schedule Number	Average No. of Customers Forecast	KWH (000) Forecast	Present Revenues Forecast ($000)	Revenues ($000)	Adjustment ($000)	March 1 Change ($000)	Percent	Base Revenues ($000)	NPC Revenues ($000)	Total Revenues ($000)	July 1 Change ($000)	Total Change ($000)	Total Change Percent	Avg. Cents/ kWh Proposed	Avg. Cents/ kWh Present
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9) (7)-(6)	(10) (9)/(6)	(11) (6)+(15)-(12)	(12)	(13)	(14) (15)-(9)	(15) (13)-(6)	(16) (15)/(6)	(16)/(5)	(6)/(5)
	Residential																	
1	Residential Service	2/18	2/18	86,326	709,998	$50,355	$53,314	$0	$2,958	5.87%	$45,747	$9,429	$55,175	$1,862	$4,820	9.57%	7.77	7.09
2	Residential Service (Optional)	3/18	2/18	5,159	109,995	$6,857	$7,378	$0	$521	7.60%	$6,199	$1,461	$7,659	$282	$802	11.70%	6.96	6.23
3	**Total Residential - East**			91,485	819,994	$57,212	$60,691	$0	$3,479	6.08%	$51,945	$10,890	$62,835	$2,143	$5,622	9.83%	7.66	6.98
4	Residential Service	201	2/18	9,389	74,212	$5,510	$5,612	$0	$102	1.85%	$4,821	$986	$5,807	$195	$297	5.39%	7.82	7.42
5	Residential Service (Optional)	205	2/18	2,254	40,461	$2,673	$2,752	$0	$79	2.95%	$2,318	$537	$2,856	$104	$183	6.84%	7.06	6.61
6	**Total Residential - West**			11,642	114,673	$8,183	$8,364	$0	$181	2.21%	$7,139	$1,523	$8,662	$299	$479	5.86%	7.55	7.14
7	**Total Residential**			103,127	934,667	$65,395	$69,055	$0	$3,660	5.60%	$59,085	$12,412	$71,497	$2,442	$6,102	9.33%	7.65	7.00
	Commercial, Industrial & Irrigation																	
8	General Service	25	25	21,799	1,151,952	$72,249	$74,813	$1,266	$2,564	3.55%	$59,944	$15,512	$75,455	$643	$3,207	4.44%	6.55	6.27
9	Partial Requirements Service	33	33	4	813,814	$31,805	$33,147	($1,450)	$1,342	4.22%	$24,929	$10,337	$35,266	$2,119	$3,460	10.88%	4.33	3.91
10	Agricultural Pumping Service	40	40	380	15,057	$1,067	$1,099	$0	$32	2.95%	$901	$219	$1,120	$21	$52	4.91%	7.44	7.09
11	Large General Service kW>1,000	46	46	85	2,030,687	$84,599	$87,747	$0	$3,149	3.72%	$63,576	$26,265	$89,841	$2,094	$5,243	6.20%	4.42	4.17
12	Large General Service - Transmission	48	48	13	2,062,018	$67,421	$70,816	$0	$3,395	5.04%	$46,642	$25,932	$72,574	$1,757	$5,152	7.64%	3.52	3.27
13	Recreational Field Lighting	54	54	57	577	$41	$44	$0	$3	7.65%	$39	$7	$46	$2	$5	12.75%	8.00	7.10
14	**Total Commercial, Industrial & Irrigation - East**			22,338	6,074,105	$257,182	$267,666	($184)	$10,484	4.08%	$196,031	$78,271	$274,301	$6,635	$17,120	6.66%	4.52	4.23
15	General Service	206	25	2,725	169,780	$10,393	$10,784	$183	$391	3.76%	$8,595	$2,282	$10,877	$93	$484	4.65%	6.41	6.12
16	General Service - High Voltage	209	48	0	0	$0	$0	$0	$0	0.00%	$0	$0	$0	$0	$0	0.00%	0.00	0.00
17	Agricultural Pumping Service	210	210	20	1,905	$118	$131	$0	$12	10.35%	$111	$28	$139	$8	$20	17.23%	7.28	6.21
18	Large Power Service - Primary	217	46	1	9,166	$389	$397	$0	$8	2.11%	$288	$118	$406	$9	$18	4.52%	4.43	4.24
19	Large Power Service - Transmission	217	48	12	832,562	$27,853	$28,126	$0	$274	0.98%	$18,400	$10,416	$28,816	$690	$963	3.46%	3.46	3.35
20	Partial Requirements Service	218	33	2	1,200	$347	$338	$0	($9)	-2.70%	$324	$16	$340	$2	($7)	-2.02%	28.37	28.95
21	**Total Commercial, Industrial & Irrigation - West**			2,759	1,014,613	$39,101	$39,776	$183	$676	1.73%	$27,719	$12,860	$40,579	$802	$1,478	3.78%	4.00	3.85
22	**Total Commercial, Industrial and Irrigation**			25,097	7,088,719	$296,283	$307,443	($1)	$11,160	3.77%	$223,750	$91,131	$314,879	$7,438	$18,598	6.28%	4.44	4.18
	Lighting																	
23	Outdoor Area Lighting Service	15	15	3,144	4,286	$572	$615	$0	$44	7.65%	$593	$52	$645	$29	$73	12.77%	15.04	13.34
24	Street Lighting Service	51	51	181	3,909	$755	$812	$0	$58	7.64%	$804	$47	$851	$39	$96	12.78%	21.77	19.30
25	Street Lighting Service	53	53	287	4,421	$491	$529	$0	$38	7.72%	$501	$53	$554	$25	$63	12.75%	12.53	11.12
26	Street Lighting Service	57	57	34	600	$104	$112	$0	$8	7.64%	$110	$7	$118	$5	$13	12.75%	19.61	17.40
27	Street Lighting Service	58	58	53	1,437	$81	$87	$0	$6	7.65%	$74	$17	$91	$4	$10	12.74%	6.33	5.62
28	**Total Lighting - East**			3,698	14,653	$2,003	$2,156	$0	$153	7.66%	$2,082	$176	$2,258	$102	$256	12.76%	15.41	13.67
29	Security Area Lighting	207	207	256	400	$126	$132	$0	$6	4.66%	$131	$5	$136	$4	$10	7.77%	33.95	31.50
30	Street Lighting - Company	211	211	91	1,340	$441	$462	$0	$21	4.66%	$460	$16	$476	$14	$34	7.76%	35.51	32.95
31	Street Lighting - Customer	212	212	14	90	$15	$16	$0	$1	4.62%	$15	$1	$16	$0	$1	7.75%	17.86	16.57
32	Traffic Signal Systems	212	212	16	76	$3	$3	$0	$0	2.21%	$2	$1	$3	$0	$0	3.60%	3.63	3.50
33	Metered Outdoor Night Lighting	212	212	3	49	$3	$4	$0	$0	2.13%	$3	$1	$4	$0	$0	3.53%	7.39	7.14
34	**Total Lighting - West**			380	1,955	$588	$616	$0	$27	4.63%	$610	$24	$634	$18	$45	7.72%	32.43	30.11
35	**Total Lighting**			4,078	16,607	$2,591	$2,772	$0	$181	6.97%	$2,692	$200	$2,892	$120	$301	11.62%	17.42	15.60
36	**AGA (Revenue Credit)**			0	0	$1,111	$1,111	$0	$0	0.00%	$1,111	$0	$1,111	$0	$0	0.00%		
37	Total Sales to Ultimate Consumers - East			117,521	6,908,752	$317,508	$331,625	($184)	$14,117	4.45%	$251,169	$89,337	$340,505	$8,881	$22,998	7.24%	4.93	4.60
38	Total Sales to Ultimate Consumers - West			14,781	1,131,242	$47,872	$48,756	$183	$884	1.85%	$35,468	$14,406	$49,875	$1,119	$2,003	4.18%	4.41	4.23
39	**Total Sales to Ultimate Consumers**			132,302	8,039,993	$365,380	$380,380	$0	$15,000	4.11%	$286,637	$103,743	$390,380	$10,000	$25,000	6.84%	4.86	4.54

STIPULATION EXHIBIT 2

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

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

Definitions and Basic Concepts:
NPC Rate Effective Period shall be the 12-month period beginning April 1, 2007 and extending through March 31, 2008 in the first PCAM application filed on or before February 1, 2007. In each succeeding PCAM application, the NPC Rate Effective Period shall be the 12-month period beginning April 1st and extending through March 31st following the NPC Comparison Period. The Company may file and the Commission may approve PCAM applications with amortization periods for deferred amounts longer than 12 months to reflect extraordinary circumstances.

NPC Comparison Period shall be the five-month historic period beginning July 1, 2006 through November 30, 2006 in the first PCAM application filed on February 1, 2007. In each succeeding PCAM application, the NPC Comparison Period shall be the historic 12-month period beginning December 1st and extending through November 30th prior to the NPC Rate Effective Period.

Base NPC is calculated by taking the sum of the monthly total Company NPC as approved by the Commission in a stipulated agreement or as a result of the most recent Wyoming general rate case (GRC). The Base NPC shall be recovered from all retail tariff rate schedules through the unbundled rate elements as set forth in this Schedule. The Base NPC shall not reflect an Embedded Cost Differential (ECD) adjustment.

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

Deferred NPC Adjustment is a charge applicable to all retail tariff rate schedules as set forth in this schedule. The Deferred NPC Adjustment is calculated by taking the sum of the monthly differences between the Adjusted Actual NPC and the corresponding monthly Base NPC adjusted for the Revenue Variation Adjustment, and adjusted to reflect the prorated total Company Dead Band, Sharing Proportions, and Wyoming Allocated Share and include Symmetrical Interest accrual on the Customer Proportion of net Deferred NPC Adjustment balances outside of the Dead Band.

TABLE 1

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

$40 million below Base (Dead Band)	Company returns 0% to Customers	Company retains 100%
Over $40 million and up to $100 million below Base	Company returns 70% to Customers	Company retains 30%
Over $100 million and up to $200 million below Base	Company returns 85% to Customers	Company retains 15%
Over $200 million below Base	Company returns 90% to Customers	Company retains 10%

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

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

Revenue Variation Adjustment is equal to the ratio of actual Wyoming monthly kilowatt-hours sold divided by the Wyoming monthly kilowatt-hours assumed in the load forecast used to calculate the Base NPC rate elements.

Symmetrical Interest shall be computed on the net accumulated Deferred NPC Adjustment balance monthly at the rate determined by the Commission pursuant to Rule 241, Customer Deposits. Interest shall be paid to the Company on net Deferred NPC under–collections and interest shall be paid to Customers on net deferred NPC over-collections. Appropriate provisions for interest during the amortization period shall be included in the calculation of Deferred NPC

Adjustments in the NPC Rate Effective Period. If the Commission implements a proposed Deferred NPC Adjustment on an interim basis, any excess charges or under charges shall be refunded to or collected from customers with interest at the rate established by the Commission pursuant to Rule 241. If the Commission approves an amortization period for a Deferred NPC balance of longer than 12 months, interest on any balance not recovered within 12 months shall be calculated based on the Company's most recent authorized weighted average cost of capital.

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

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

Wyoming ECD Base is the sum of the ECD adjustments included in the Wyoming revenue requirement as most-recently approved by the Commission either in a stipulated agreement or as a result of a GRC.

Timing

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

Deferred NPC Adjustment:

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

Deferred NPC Adjustment = ((((Adjusted Actual NPC – (Base NPC x Revenue Variation Adjustment)) +/- Dead Band) x Sharing Proportion) x Wyoming Allocated Share) + Symmetrical Interest.

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

ECD Adjustment = (Wyoming Actual Adjusted ECD – (Wyoming ECD Base x Revenue Variation Adjustment))

The initial Base NPC will be set at $660 million on an annual basis. For purposes of the first comparison period from July 1, 2006 through November 30, 2006 an adjustment will be made in the deferral calculation, which increases the Base NPC for those months from $321 million to $336 million. If the Company has not or will not file a new general rate case prior to February 1, 2007, the Base NPC will remain $660 million for the new NPC Comparison Period starting December 1, 2006 and shall remain at that level until rates are set in the Company's next general rate case. Otherwise, the Base NPC will be revised to $700 million on an annual basis on December 1,2006 for purposes of the deferral calculation only.

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

Monthly Billing

All charges and provisions of the applicable rate schedule will be applied in determining a Customer's bill except that the Customer's total electric bill will be increased or decreased by an amount equal to the product of all kilowatt demand multiplied by the following dollar per kilowatt rate plus all kilowatt-hours of use multiplied by the following cents per kilowatt-hour rate:

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
2	**	Demand per kWh	0.148¢	0.000¢
		Energy per kWh	1.180¢	0.000¢
15	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
25	Secondary	Demand per kW	$0.89	$0.00
		Energy per kWh	1.185¢	0.000¢
	Primary	Demand per kW	$0.87	$0.00
		Energy per kWh	1.159¢	0.000¢
33	Primary	Demand per kW	$0.78	$0.00
		Energy per kWh	1.160¢	0.000¢
	Transmission	Demand per kW	$0.77	$.000

		Energy per kWh	1.135¢	0.000¢
40	**	Demand per kW	$0.74	$0.00
		Energy per kWh	1.210¢	0.000¢

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
46	Secondary	Demand per kW	$0.79	$0.00
		Energy per kWh	1.186¢	0.000¢
	Primary	Demand per kW	$0.78	$0.00
		Energy per kWh	1.160¢	0.000¢
48T	Transmission	Demand per kW	$0.77	$0.00
		Energy per kWh	1.135¢	0.000¢
51	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
53	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
54	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
57	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
58	**	Demand per kWh	0.017¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
207	**	Demand per kWh	0.013¢	0.000¢

		Energy per kWh	1.186¢	0.000¢
210	**	Demand per kW	$0.73	0.000¢
		Energy per kWh	1.209¢	0.000¢

Monthly Billing (continued)

Schedule	Delivery Voltage	Billing Units	Base NPC	Deferred NPC Adj.
211	**	Demand per kWh	0.013¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
212-1	**	Demand per kWh	0.013¢	0.000¢
		Energy per kWh	1.186¢	0.000¢
212-2	**	Demand per kWh	0.076¢	0.000¢
		Energy per kWh	1.189¢	0.000¢
212-3	**	Demand per kWh	0.076¢	0.000¢
		Energy per kWh	1.189¢	0.000¢

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

Rules

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

STIPULATION EXHIBIT 3

Stipulation Exhibit 3

Month	July to November 2006	Dead Band (+/-)	Baseline $660 M	Dead Band (+/-)	Baseline $700 M	Dead Band (+/-)
January			41,644	2,524	44,168	2,524
February			42,936	2,602	45,538	2,602
March			40,536	2,457	42,993	2,457
April			46,069	2,792	48,861	2,792
May			44,195	2,679	46,874	2,679
June			65,327	3,959	69,286	3,959
July	89,930	5,207	85,922	5,207	91,129	5,207
August	79,930	4,628	76,369	4,628	80,997	4,628
September	61,507	3,562	58,766	3,562	62,328	3,562
October	55,885	3,236	53,394	3,236	56,630	3,236
November	49,330	2,857	47,132	2,857	49,989	2,857
December			57,705	3,497	61,202	3,497
Total	**336,582**	**19,490**	**659,995**	**40,000**	**699,995**	**40,000**