

BEFORE THE

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IDAHO PUBLIC UTILITIES COMMISSION IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
PACIFICORP DBA ROCKY MOUNTAIN)
POWER FOR APPROVAL OF CHANGES)
TO ITS ELECTRIC SERVICE SCHEDULES)
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CASE NO. PAC-E-07-5

DIRECT TESTIMONY OF PATRICIA HARMS

IDAHO PUBLIC UTILITIES COMMISSION

SEPTEMBER 28, 2007

1 Q. Please state your name and address for the
2 record.

3 A. My name is Patricia Harms. My business address
4 is 472 West Washington Street, Boise, Idaho.

5 Q. By whom are you employed and in what capacity?

6 A. I am employed by the Idaho Public Utilities
7 Commission (Commission) as a Senior Auditor.

8 Q. Give a brief description of your educational
9 background and experience.

10 A. I graduated from Boise State University, Boise,
11 Idaho in 1981 with a B.A. degree in Business
12 Administration, emphasis in Accounting. I am a Certified
13 Public Accountant licensed by the State of Idaho. Prior
14 to joining the Commission Staff in 2000, I was employed
15 by the State of Alaska as an In Charge Auditor and
16 performed both financial and performance audits of
17 governmental agencies. I have attended many seminars and
18 classes involving auditing and accounting. While at the
19 Commission I have audited a number of utilities including
20 water, electric, gas and telephone utilities and provided
21 comments and testimony in a number of cases that dealt
22 with general rates, hook-up fees, accounting issues, and
23 other regulatory issues. I have also completed the
24 National Association of Regulatory Utility Commissioners'
25 (NARUC) annual regulatory studies program at Michigan

1 State University. I also attend meetings of NARUC's
2 Staff Subcommittee on Accounting and Finance.

3 Q. What is the purpose of your testimony?

4 A. The purpose of my testimony is to present the
5 summary exhibits that reflect all the adjustments of
6 Staff witnesses for Rocky Mountain Power (Company) in
7 this general rate case. I quantify the Idaho revenue
8 requirement and revenue increase proposed for Idaho
9 retail customers in this case.

10 My testimony also describes the proposed
11 calculation of test year rate base and annualizing/pro
12 forma plant adjustments and explains the rationale
13 supporting Staff's position. My testimony further
14 describes the adjustments proposed by Staff as a result
15 of this position.

16 Additionally, my testimony describes Staff's
17 proposed adjustment related to the Company's treatment of
18 costs related to abandoned projects. Finally, my
19 testimony describes Staff's adjustment regarding tax
20 credits related to the Blundell Bottoming Cycle project.

21 Q. What exhibits are you sponsoring?

22 A. I am sponsoring Staff Exhibit Nos. 108-113.
23 Staff Exhibit No. 108 calculates Staff's proposed revenue
24 requirement under the rate mitigation cap stipulated and
25 approved by the Commission in Case No. PAC-E-02-3. Staff

1 Exhibit No. 109 reflects Rocky Mountain Power's
2 Normalized Results of Operations under the Revised
3 Protocol cost methodology as Adjusted by Staff. Staff
4 Exhibit No. 110 calculates the Revised Protocol revenue
5 requirement price increase for Rocky Mountain Power.
6 Staff Exhibit No. 111 reflects Rocky Mountain Power's
7 Normalized Results of Operations under the Rolled-In cost
8 methodology as Adjusted by Staff. Staff Exhibit No. 112
9 lists the adjustments proposed by Staff and the related
10 change to the Idaho revenue requirement under the Revised
11 Protocol cost methodology. Staff Exhibit No. 113 lists
12 the system-wide amounts for capital projects Staff
13 annualized or pro formed into Staff's proposed rate base.

14 Q. What is the purpose of Staff Exhibit No. 108?

15 A. This exhibit shows the Idaho revenue
16 requirement proposed by Staff and reflects the rate
17 mitigation cap as stipulated and approved by the
18 Commission in Case No. PAC-E-02-3.

19 Q. What revenue requirement does Staff propose in
20 this case?

21 A. The revenue requirement proposed is
22 \$190,229,447 as shown on Staff Exhibit No. 108, line 3.
23 This results in an overall net increase of \$11.2 million
24 or 6.28%. The Company proposed in its Application a net
25 increase of \$18.5 million or 10.32% in prices for the

1 Company's Idaho retail customers.

2 Q. How is revenue requirement calculated in this
3 case?

4 A. The \$193,808,268 (Staff Exhibit No. 108, line
5 6) revenue requirement calculated under the Revised
6 Protocol methodology is reduced to the rate mitigation
7 cap of \$190,229,447 (Staff Exhibit No. 108, line 3) as
8 stipulated and approved by the Commission in Case No.
9 PAC-E-02-3. This stipulation states:

10 For all Idaho general rate proceedings
11 initiated after the effective date of this
12 Stipulation and Revised Protocol, and until
13 March 31, 2009, the Company's Idaho revenue
14 requirement to be used for purposes of setting
15 rates for Idaho customers will be the lesser
16 of: (i) the Company's Idaho revenue requirement
17 calculated under the Rolled-In Allocation
18 method multiplied by 101.67 percent, or (ii)
19 the Company's Idaho revenue requirement
20 resulting from use of the Revised Protocol.

21 The test period for this case is based on the
22 historical twelve-month period ending December 31, 2006
23 that has been adjusted for known and measurable
24 adjustments through December 31, 2007 for operating
25 revenues and expenses. Rate base levels are based on a
thirteen-month average using the balances from January
2006 through January 2007 with annualizing and pro forma
adjustments for known and measurable plant additions
placed in service through December 31, 2007. Staff's
adjusted rate base is \$487,197,283.

1 Q. How is the revenue requirement price increase
2 on Staff Exhibit No. 110 calculated?

3 A. Staff calculated the revenue requirement price
4 increase using a Rate Base of \$487,197,283 and an 8.267%
5 overall rate of return described in Staff witness
6 Carlock's testimony. Staff's recommended Idaho revenue
7 requirement price change of \$14,815,425 is shown on Staff
8 Exhibit No. 110. This revenue requirement price increase
9 is also shown on Staff Exhibit No. 109.

10 **Rate of Return**

11 Q. How does Staff's proposed overall return
12 compare to that requested by the Company?

13 A. The 8.267% overall rate of return Staff witness
14 Carlock proposes is based upon a return on equity of
15 10.25%. This return on equity is 0.5% lower than that
16 proposed by Rocky Mountain Power in its Application.

17 Based upon the case filed by the Company, this
18 overall rate of return would result in an Idaho revenue
19 requirement reduction of approximately \$2 million.

20 **Rate Base**

21 Q. How have you provided for recovery of the
22 Company's investments in rate base?

23 A. Staff proposes to establish the revenue
24 requirement for the Company using rate base levels based
25 on a thirteen-month average using the balances from

1 January 2006 through January 2007 with annualizing and
2 pro forma adjustments for known and measurable plant
3 additions through December 31, 2007.

4 Q. How does Staff propose recovery of the
5 Company's investment in plant made during the 2006 test
6 year?

7 A. Staff proposes several ways for the Company to
8 recover plant investments it made in 2006. First, Staff
9 proposes a thirteen-month average rate base for all plant
10 in service investment incurred during 2006. Each plant
11 in service project, regardless of size, is included in
12 Staff's thirteen-month average rate base. In addition,
13 projects in service during 2006 costing over \$100 million
14 system-wide or that are generation facilities reflected
15 in power supply and/or transmission costs related to
16 projects over \$2 million system-wide were annualized.

17 Q. How did Staff determine the dollar threshold
18 for annualizing projects during 2006?

19 A. The Company's Unadjusted Electric Plant in
20 Service for 2006 on a beginning and ending average is
21 \$14,745,911,135 (Exhibit No. 11, page 2.2, line 36)
22 system-wide. Compared to that investment level, Staff
23 considered the Company's \$2 million system-wide threshold
24 for annualizing major projects in 2006 as too low
25 (\$2,000,000 per project divided by \$14,745,911,135 total

1 electric plant in service is .00014 or 0.014%). The \$100
2 million threshold represents a single project as 0.7% of
3 the Company's average Plant in Service during 2006
4 (\$100,000,000 divided by \$14,745,911,135). Based upon a
5 review of the Company's plant additions on Exhibit No.
6 11, pages 8.82 through 8.85 there is a definite
7 difference in the number and magnitude of projects.
8 There are a few large projects and many smaller projects.
9 Those six (three in 2006 and three in 2007) large
10 projects range from \$118 million to \$331 million.
11 Further, the Company has identified that Board of
12 Directors' approval of individual capital expenditure
13 projects has been replaced with the requirement of
14 PacifiCorp CEO approval for projects greater than \$25
15 million.

16 Q. If Staff used the Company's \$25 million
17 threshold for capital expenditure projects requiring
18 PacifiCorp CEO approval, what additional projects would
19 be annualized in 2006?

20 A. None. There are no projects in service during
21 2006 costing more than \$25 million but less than \$100
22 million system-wide according to Company Exhibit No. 11,
23 pages 8.8.2 and 8.8.3. So, effectively, Staff's \$100
24 million threshold for including plant within rate base
25 and the Company's \$25 million threshold for capital

1 expenditures requiring CEO approval has the same impact.

2 Q. What 2006 projects were annualized in rate base
3 as a result of meeting the \$100 million system-wide
4 threshold?

5 A. Three projects met this threshold. The
6 projects are Currant Creek Phase II (\$177 million system-
7 wide), the Leaning Juniper 1 Wind Plant (\$175 million
8 system-wide), and the Huntington Unit II Scrubber (\$118
9 million system-wide).

10 Q. Did Staff consider whether a generation project
11 greater than \$2 million system-wide is included in the
12 power supply model and cost calculation for the Company
13 as one of its criteria for annualizing projects in 2006?

14 A. Yes. Staff also used generation projects
15 included in the power supply model as one of its criteria
16 for annualizing projects in 2006. However, according to
17 the Company, no projects greater than \$2 million but less
18 than \$100 million system-wide produced power supply cost
19 savings.

20 Q. How did Staff propose recovery for transmission
21 projects in 2006?

22 A. In addition to inclusion within Staff's
23 proposed thirteen-month average, Staff annualized the
24 2006 transmission projects listed in Company Exhibit No.
25 11, page 8.8.2. These projects totaled \$75 million

1 system-wide.

2 Q. How does Staff's proposal for 2006 plant
3 additions compare to the Company's case?

4 A. As identified by Staff Exhibit No. 113, Staff
5 annualized 18 projects with a system-wide total of
6 \$546,599,918. This is approximately 85% of the projects
7 listed on Exhibit No. 11, pages 8.8.2 and 8.8.3 when
8 distribution projects that would be allocated situs to
9 other states are removed from the list. This annualizing
10 adjustment incorporates those projects into rate base as
11 if they had been in place for the entire year.
12 Additionally, the associated depreciation and tax effects
13 of this adjustment were calculated and included in
14 Staff's proposed revenue requirement.

15 This methodology was developed under the
16 supervision of Staff witness Carlock, Deputy
17 Administrator of the Utilities Division, to ensure
18 annualizing or adding major plant additions such as this
19 as if it were in service for the entire test year is
20 consistent with the policy used for major plant additions
21 in Idaho Power and Avista rate cases (Case Nos.
22 IPC-E-03-13 and AVU-E-04-1).

23 Q. How does Staff propose recovery of the
24 Company's investment in plant made in 2007 (post test
25 year)?

1 A. Staff has made pro forma adjustments for
2 projects placed in service through December 31, 2007
3 costing over \$100 million system-wide. Staff also
4 adjusted for projects that are reflected in the power
5 supply model and costs and/or transmission projects over
6 \$2 million system-wide. These projects were also pro
7 formed into rate base.

8 Q. What 2007 projects were pro formed into rate
9 base as a result of meeting the \$100 million system-wide
10 threshold?

11 A. Three projects met this threshold. The
12 projects are Lake Side Capital Build (\$331 million
13 system-wide), the Marengo Wind Project (\$259 million
14 system-wide), and the Goodnoe Hills Wind Project (\$197
15 million system-wide). These generation resource
16 investments were weighted by the in service date to align
17 the rate base investment with its inclusion in the
18 calculation of net power supply costs.

19 Q. Did Staff pro form into rate base any 2007
20 projects greater that \$2 million but less than \$100
21 million system-wide that were included in the power
22 supply model and cost calculation?

23 A. Yes. The Blundell Bottoming Cycle project (\$28
24 million system-wide) was also weighted by the in service
25 date to align the rate base investment with its inclusion

1 of the plant, costs and availability in the calculation
2 of net power supply costs.

3 Q. Were there any other adjustments associated
4 with the Blundell Bottoming Cycle project?

5 A. Yes. The Company did not include the Federal
6 Renewable Energy Tax Credit and the Utah State Renewable
7 Energy Credit associated with this plant. The Federal
8 Renewable Energy credit would equal \$312,412 system-wide
9 and \$20,562 would be allocated to Idaho. The Utah State
10 Renewable Energy credit would be \$54,672 system-wide of
11 which \$1,822 would be allocated to Idaho. This
12 adjustment reduces Idaho revenue requirement by
13 approximately \$40,000.

14 Q. How did Staff propose recovery for transmission
15 projects in 2007?

16 A. Staff weighted the Company's investment in 2007
17 transmission projects by the updated in service dates
18 provided for the projects listed in Company Exhibit No.
19 11, page 8.8.4. One third (five of the fifteen) of
20 projects listed in Company Exhibit No. 11, page 8.8.4
21 will not be placed in service during 2007 as originally
22 planned by the Company. One project has been delayed a
23 year. As a result, Staff has excluded these projects
24 from its proposed rate base in this case.

25 Q. Are there any projects included in Staff's rate

1 base that are planned to go into service after the
2 hearing in this case?

3 A. Yes. The in service dates for the Blundell
4 Bottoming Cycle project, Goodnoe Hills Wind Project, and
5 two transmission projects are December 2007. Although
6 Goodnoe Hills is a \$197 million project system-wide, due
7 to net power cost savings its Idaho revenue requirement
8 is approximately \$60,000.

9 Q. What would be Staff's recommendation if these
10 projects did not go in service before December 31, 2007?

11 A. Staff would recommend removing these projects
12 from rate base if they are not placed in service before
13 December 31, 2007. This would be consistent with other
14 post test year adjustments and assure the projects are
15 used and useful when rates become effective.

16 Q. How does Staff's proposal for 2007 plant
17 additions compare to the Company's case?

18 A. As identified by Staff Exhibit No. 113, Staff
19 included in its case 14 projects with a system-wide total
20 of \$946,738,633. This is over 80% of the projects listed
21 on Exhibit No. 11, pages 8.8.4 and 8.8.5. (Notably this
22 percentage is approximately 90% when the projects now
23 with in service dates in 2008 and distribution projects
24 that would not be allocated to Idaho are removed from the
25 denominator). These pro forma Staff adjustments

1 incorporate those projects weighted by the number of
2 months the plant would be in service during 2007.
3 Additionally, the associated depreciation and tax effects
4 of this adjustment were calculated and included in
5 Staff's proposed revenue requirement.

6 Q. What is the change in Staff's proposed Idaho
7 revenue requirement based upon the proposed treatment of
8 2006 and 2007 rate base/plant additions and associated
9 costs compared to the Company's filing?

10 A. Staff's proposal results in a reduction in
11 Idaho revenue requirement of approximately \$1 million.
12 This still provides a reduction in regulatory lag by
13 including projects to be completed after Staff's prefile
14 but before the effective date of customer rates.

15 Q. You have described Staff's proposal regarding
16 rate base. What historic test year does Rocky Mountain
17 Power use in this case and what adjustments does it
18 propose?

19 A. The Company's case is based on historical data
20 for the twelve-months ended December 31, 2006. The
21 Company then made various normalizing, annualizing and
22 known and measurable adjustments to test year revenues,
23 expenses and rate base. Rate base presented by the
24 Company was initially an average of beginning and ending
25 account balances. The Company proposed annualizing over

1 60 projects listed on Exhibit No. 11, pages 8.8.2 and
2 8.8.3 as if they were in place for the entire year.
3 Because of the Company's beginning and ending average
4 rate base, these projects were already in the Company's
5 filing as if they had been in place for six months of the
6 year even if an individual project's in service date was
7 December 2006.

8 The Company listed almost 60 post-test year
9 projects on Exhibit No. 11, pages 8.8.4 and 8.8.5 to
10 include in rate base for the number of months they would
11 be in service during 2007.

12 Q. How does Rocky Mountain Power's post-test year
13 adjustments compare to those proposed by other companies'
14 when the revenue requirement was not part of a stipulated
15 agreement?

16 A. Idaho Power in Case No. IPC-E-03-13 filed a
17 2003 test year with 6 months of actual expenses, revenues
18 and investments and 6 months estimated. Various
19 normalizing, annualizing and known and measurable
20 adjustments were made to test year revenues and expenses.
21 In addition, a thirteen-month average rate base was used
22 to recognize that some plant was in service for only part
23 of the test year. Finally, less than ten major plant
24 additions were added beyond the end of the test year.
25 These major projects were included in the rate base

1 calculation as if they were in service for the entire
2 test year.

3 In Case No. AVU-E-04-1, Avista used a historic
4 test year from January 1, 2002 to December 31, 2002. The
5 Company then included various normalizing, annualizing
6 and known and measurable adjustments to test year
7 revenues and expenses. It used an average of the monthly
8 averages to establish rate base levels. Avista included
9 only five major plant additions beyond the test year; two
10 generation projects and three transmission projects.
11 These five major projects were included in the rate base
12 calculation as if they were in service for the entire
13 test year.

14 Q. What rate base treatment did the Commission
15 allow in these cases?

16 A. The Commission required rate base be set using
17 a thirteen-month average or the average of the thirteen-
18 monthly averages for the test year. The Commission also
19 allowed these companies to include limited major plant
20 additions completed after the test year as if they had
21 been in service for the entire year provided an
22 adjustment was made to reflect revenue producing or
23 expense reducing benefits from these projects in the
24 revenue requirement.

25 Q. Did the Commission approve the test year with

1 post-test year plant additions as proposed by the
2 companies in these two cases?

3 A. Yes. However, in both cases the Commission
4 expressed specific concern regarding annualizing plant
5 additions added late in the year or after the Company's
6 test year as if it were in place for a full year. In
7 Order No. 29505, in Case No. IPC-E-03-13, the Commission
8 stated:

9 We generally believe that including investment
10 in the calculation of average-year rate base as
11 if it were in service the entire year when it
12 was not... creates a mismatch between test year
13 revenue and expenses.

14 Q. How does Staff's proposed rate base treatment
15 address this issue?

16 A. Using a thirteen-month average rate base
17 reduces the expense/revenue mismatch identified by the
18 Commission that occurs when the costs of plant
19 adjustments are added as if they were in place for a
20 whole year without adding any benefits.

21 Over 85% of the plant additions annualized by
22 Staff in the 2006 test year were generation resources.
23 These projects are included in the Company's power supply
24 model and reflected in the net power supply costs,
25 producing benefits to customers. The Company has also
included additional maintenance, depreciation and
property taxes for these projects and where applicable,

1 renewable energy tax credits. The remaining projects
2 annualized are transmission related. The availability of
3 these transmission projects is also reflected in the
4 power supply model to improve reliability and to make
5 cost effective purchases or sales that reduce customer
6 costs. Although it may not result in cost savings that
7 have been directly quantified, Staff is familiar with the
8 calculations to assure customer benefits are received
9 from these projects. Therefore, they are included in
10 Staff's proposed rate base.

11 Neither the Company nor Staff proposes to
12 include post test year plant additions in rate base as if
13 they were in place for the whole year. Instead, Staff
14 proposes to include those projects as previously
15 described based upon their in service dates. Again, over
16 85% of these 2007 projects were generation resources that
17 are reflected in the Company's power supply cost model
18 and reflect net power cost savings. The remaining
19 projects are transmission.

20 Q. Please identify other Staff adjustments to rate
21 base that are summarized in your exhibits.

22 A. Staff witness Leckie proposes two adjustments
23 to rate base. He has removed the cost of a coal lease
24 from rate base reducing the Idaho revenue requirement by
25 approximately \$26,000. He has also removed the cost of a

1 Jim Bridger dragline from rate base reducing the Idaho
2 revenue requirement by approximately \$15,000.

3 **Expenses**

4 Q. Has Staff made any adjustments to expenses?

5 A. Yes. Staff has adjusted depreciation expense
6 due to Staff's proposed plant adjustments, reduced
7 expenses for abandoned projects, adjusted power supply
8 costs, removed some costs associated with incentive and
9 severance pay, reduced net lease expenses, removed
10 certain administrative and general expenses, and reduced
11 other expenses.

12 Q. How was depreciation expense calculated for
13 Staff's proposed plant adjustments?

14 A. First depreciation expense changed due to the
15 thirteen-month average Staff proposed compared to the
16 beginning/ending average filed in the Company's case.
17 Second, Staff annualized depreciation expense for major
18 plant additions added during the test year. Third,
19 depreciation expense for pro forma plant additions added
20 to rate base is based on the number of months the plant
21 is included in the test period rate base.

22 Q. How are abandoned projects included in the
23 Company's case?

24 A. The Company expensed approximately \$1.6 million
25 system-wide of costs associated with abandoned projects.

1 According to the Company, many of these costs are
2 associated with projects contemplated by customers but
3 not completed. These costs do not represent assets that
4 are used and useful. Staff proposes removal of these
5 costs as they do not provide service to customers and
6 should not be included in customer rates. On an Idaho-
7 allocated basis, this reduces revenue requirement by
8 approximately \$80,000.

9 Q. Please identify other Staff adjustments to
10 expenses that are summarized in your exhibits.

11 A. Staff witness Lanspery proposes three power
12 supply cost adjustments. The first relates to an error
13 by the Company in extracting data associated with gas
14 purchases. This reduces Idaho revenue requirement by
15 approximately \$2.5 million. Second, he proposes
16 adjusting power supply costs associated with the Monsanto
17 credit. This increases Idaho revenue requirement by
18 approximately \$110,000. Third, Staff witness Lanspery
19 proposes an adjustment associated with the Idaho
20 Irrigators Load Control Program. This reduces Idaho
21 revenue requirement by approximately \$940,000. Staff
22 witness Lanspery's testimony discusses these adjustments
23 in detail.

24 Staff witness Leckie proposes several
25 adjustments. 1) He proposes reducing incentive pay,

1 reducing Idaho revenue requirement by approximately
2 \$160,000. 2) He also proposes reducing net lease
3 expense. This adjustment reduces Idaho revenue
4 requirement by approximately \$7,000. 3) He proposes to
5 remove from the Company's case the costs associated with
6 changing the Company's fiscal year to a calendar year
7 end. This adjustment reduces Idaho revenue requirement
8 by approximately \$25,000. 4) He adjusts for severance
9 costs, reducing Idaho revenue requirement by
10 approximately \$160,000. Staff witness Leckie provides
11 further detail regarding these adjustments in his
12 testimony.

13 Staff witness Nobbs proposes to remove expenses
14 that are nonrecurring or should not be paid by Idaho
15 utility customers. His adjustments reduce Idaho revenue
16 requirement by approximately \$93,000. His testimony
17 discusses these adjustments in detail.

18 **Revenues**

19 Q. Has Staff made any adjustments to revenues?

20 A. Yes. Staff witness Carlock has imputed revenue
21 associated with the Company's Green Tags. These
22 adjustments reduce Idaho revenue requirement by
23 approximately \$270,000. Her testimony discusses these
24 adjustments in detail.

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Taxes

Q. How did Staff's adjustments change taxes in the case?

A. Staff's adjustments to revenues and expenses change federal and state income taxes as taxable income changes. In addition, federal and state income taxes are changed because interest expense must be "trued up" for changes in rate base such as the adjustments to plant proposed by Staff.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

**ROCKY MOUNTAIN POWER
STATE OF IDAHO
Normalized Results of Operations
12 Months Ended December 2006 with Known and Measurables**

Line No.	(A) Original Filing	(B) Case Proposed by Staff
(1) December 2006 Rolled-In Revenue Requirement	194,215,986	187,104,796
(2) Rate Mitigation Cap	101.67%	101.67%
(3) Capped Revised Protocol Revenue Requirement	197,459,393	190,229,447
(4) Normalized December 2006 General Business Revenues	178,992,843	178,992,843
(5) Capped Revised Protocol Price Change	18,466,550	11,236,604
Revised Protocol		
(6) Filed Revised Protocol Revenue Requirement	201,020,661	193,808,268
(7) Normalized December 2006 General Business Revenues	178,992,843	178,992,843
(8) Revised Protocol Price Change	22,027,818	14,815,425
(9) Capped Revised Protocol Price Change	18,466,550	11,236,604
(10) Reduction to Revised Protocol Revenue Requirement	(3,561,268)	(3,578,821)
Capped Revenue Requirement Increase as a Percentage of Line 7	10.32%	6.28%

Exhibit No. 108
Case No. PAC-E-07-5
P. Harms, Staff
9/28/07

**Rocky Mountain Power
IDAHO**

**Normalized Results of Operations - REVISED PROTOCOL
12 Months Ended DECEMBER 2006**

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	178,992,843	14,815,425	193,808,268
3 Interdepartmental	-		
4 Special Sales	122,881,936		
5 Other Operating Revenues	6,601,123		
6 Total Operating Revenues	<u>308,475,902</u>		
7			
8 Operating Expenses:			
9 Steam Production	51,759,768		
10 Nuclear Production	-		
11 Hydro Production	2,324,572		
12 Other Power Supply	149,261,969		
13 Transmission	9,009,675		
14 Distribution	10,088,461		
15 Customer Accounting	4,586,151	21,784	4,607,935
16 Customer Service & Info	1,661,078		
17 Sales	-		
18 Administrative & General	11,114,389		
19			
20 Total O&M Expenses	<u>239,806,062</u>		
21			
22 Depreciation	24,215,016		
23 Amortization	3,268,986		
24 Taxes Other Than Income	4,932,527	-	4,932,527
25 Income Taxes - Federal	4,754,556	4,942,703	9,697,259
26 Income Taxes - State	771,172	671,631	1,442,804
27 Income Taxes - Def Net	557,970		
28 Investment Tax Credit Adj.	(757,790)		
29 Misc Revenue & Expense	(188,477)		
30			
31 Total Operating Expenses:	<u>277,380,021</u>	5,636,118	283,016,140
32			
33 Operating Rev For Return:	<u>31,095,880</u>	<u>9,179,306</u>	<u>40,275,187</u>
34			
35 Rate Base:			
36 Electric Plant In Service	917,578,857		
37 Plant Held for Future Use	(3,408)		
38 Misc Deferred Debits	3,493,591		
39 Elec Plant Acq Adj	5,019,178		
40 Nuclear Fuel	-		
41 Prepayments	2,922,256		
42 Fuel Stock	6,281,196		
43 Material & Supplies	7,453,023		
44 Working Capital	4,276,120		
45 Weatherization Loans	5,790,713		
46 Misc Rate Base	577,049		
47			
48 Total Electric Plant:	<u>953,388,575</u>	-	953,388,575
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(358,147,663)		
52 Accum Prov For Amort	(20,236,770)		
53 Accum Def Income Tax	(76,841,792)		
54 Unamortized ITC	(2,125,265)		
55 Customer Adv For Const	(465,858)		
56 Customer Service Deposits	-		
57 Misc Rate Base Deductions	(8,373,943)		
58			
59 Total Rate Base Deductions	<u>(466,191,291)</u>	-	(466,191,291)
60			
61 Total Rate Base:	<u>487,197,283</u>	-	<u>487,197,283</u>
62			
63 Return on Rate Base	6.383%		8.267%
64			
65 Return on Equity	6.512%		10.250%
66			
67 TAX CALCULATION:			
68 Operating Revenue	36,421,788	14,793,641	51,215,429
69 Other Deductions			
70 Interest (AFUDC)			
71 Interest	14,974,788	-	14,974,788
72 Schedule "M" Additions	12,357,745	-	12,357,745
73 Schedule "M" Deductions	17,141,075	-	17,141,075
74 Income Before Tax	<u>16,663,669</u>	14,793,641	31,457,310
75			
76 State Income Taxes	771,172	671,631	1,442,804
77 Taxable Income	<u>15,892,497</u>	<u>14,122,010</u>	<u>30,014,507</u>
78			
79 Federal Income Taxes + Other	<u>4,754,556</u>	<u>4,942,703</u>	<u>9,697,259</u>

Ref. Page 2.2

Exhibit No. 109
Case No. PAC-E-07-5
P. Harms, Staff
9/28/07

Rocky Mountain Power
IDAHO
Normalized Results of Operations - REVISED PROTOCOL
12 Months Ended DECEMBER 2006

Net Rate Base	\$ 487,197,283	Ref. Page 1.1
Return on Rate Base Requested	<u>8.267%</u>	Ref. Page 2.1
Revenues Required to Earn Requested Return	40,275,187	
Less Current Operating Revenues	<u>(31,095,880)</u>	
Increase to Current Revenues	9,179,306	
Net to Gross Bump-up	<u>161.40%</u>	
Price Change Required for Requested Return	<u>\$ 14,815,425</u>	
Requested Price Change	\$ 14,815,425	
Uncollectible Percent	<u>0.147%</u>	Ref. Page 1.3
Increased Uncollectible Expense	<u>\$ 21,784</u>	
Requested Price Change	\$ 14,815,425	
Franchise Tax	0.000%	Ref. Page 1.3
Revenue Tax	0.000%	Ref. Page 1.3
Resource Supplier Tax	0.000%	Ref. Page 1.3
Gross Receipts	0.000%	Ref. Page 1.3
Increase Taxes Other Than Income	<u>\$ -</u>	
Requested Price Change	\$ 14,815,425	
Uncollectible Expense	(21,784)	
Taxes Other Than Income	-	
Income Before Taxes	<u>\$ 14,793,641</u>	
State Effective Tax Rate	4.54%	Ref. Page 2.1
State Income Taxes	<u>\$ 671,631</u>	
Taxable Income	\$ 14,122,010	
Federal Income Tax Rate	35.00%	Ref. Page 2.1
Federal Income Taxes	<u>\$ 4,942,703</u>	
Operating Income	100.000%	
Net Operating Income	<u>61.958%</u>	Ref. Page 1.3
Net to Gross Bump-Up	<u>161.40%</u>	

Rocky Mountain Power
IDAHO
Normalized Results of Operations - REVISED PROTOCOL
12 Months Ended DECEMBER 2006

Operating Revenue	100.000%	
Operating Deductions		
Uncollectible Accounts	0.147%	(1)
Taxes Other - Franchise Tax	0.000%	
Taxes Other - Revenue Tax	0.000%	
Taxes Other - Resource Supplier Tax	0.000%	
Taxes Other - Gross Receipts	<u>0.000%</u>	
Sub-Total	99.853%	
State Income Tax @ 4.54%	<u>4.533%</u>	
Sub-Total	95.320%	
Federal Income Tax @ 35.00%	<u>33.362%</u>	
Net Operating Income	<u><u>61.958%</u></u>	

(1) Computation equals:

Idaho situs uncollectible accounts (FERC904) divided by Idaho general business revenues
(page 2.12, column "Idaho", line 714) divided by (page 2.2, column "adj total", line 1)

Rocky Mountain Power
IDAHO
Normalized Results of Operations - ROLLED-IN
12 Months Ended DECEMBER 2006

	(1) Total Adjusted Results	(2) Price Change	(3) Results with Price Change
1 Operating Revenues:			
2 General Business Revenues	178,992,843	8,111,953	187,104,796
3 Interdepartmental	-		
4 Special Sales	122,881,936		
5 Other Operating Revenues	6,601,135		
6 Total Operating Revenues	<u>308,475,914</u>		
7			
8 Operating Expenses:			
9 Steam Production	52,078,916		
10 Nuclear Production	-		
11 Hydro Production	2,324,572		
12 Other Power Supply	142,191,189		
13 Transmission	9,009,675		
14 Distribution	10,088,461		
15 Customer Accounting	4,586,151	11,927	4,598,078
16 Customer Service & Info	1,661,078		
17 Sales	-		
18 Administrative & General	11,123,414		
19			
20 Total O&M Expenses	233,063,455		
21			
22 Depreciation	24,215,735		
23 Amortization	3,267,350		
24 Taxes Other Than Income	4,936,717	-	4,936,717
25 Income Taxes - Federal	6,994,229	2,706,300	9,700,529
26 Income Taxes - State	1,127,217	367,741	1,494,958
27 Income Taxes - Def Net	552,155		
28 Investment Tax Credit Adj.	(757,790)		
29 Misc Revenue & Expense	(168,468)		
30			
31 Total Operating Expenses:	273,230,599	3,085,968	276,316,568
32			
33 Operating Rev For Return:	<u>35,245,314</u>	<u>5,025,985</u>	<u>40,271,300</u>
34			
35 Rate Base:			
36 Electric Plant In Service	918,320,604		
37 Plant Held for Future Use	(3,408)		
38 Misc Deferred Debits	3,555,375		
39 Elec Plant Acq Adj	5,019,178		
40 Nuclear Fuel	-		
41 Prepayments	2,924,321		
42 Fuel Stock	6,311,959		
43 Material & Supplies	7,473,953		
44 Working Capital	4,219,413		
45 Weatherization Loans	5,790,713		
46 Misc Rate Base	577,049		
47			
48 Total Electric Plant:	954,189,157	-	954,189,157
49			
50 Rate Base Deductions:			
51 Accum Prov For Deprec	(358,986,583)		
52 Accum Prov For Amort	(20,245,273)		
53 Accum Def Income Tax	(76,837,855)		
54 Unamortized ITC	(2,125,265)		
55 Customer Adv For Const	(465,858)		
56 Customer Service Deposits	-		
57 Misc Rate Base Deductions	(8,378,058)		
58			
59 Total Rate Base Deductions	(467,038,893)	-	(467,038,893)
60			
61 Total Rate Base:	<u>487,150,264</u>	<u>-</u>	<u>487,150,264</u>
62			
63 Return on Rate Base	7.235%		8.267%
64			
65 Return on Equity	8.203%		10.250%
66			
67 TAX CALCULATION:			
68 Operating Revenue	43,161,125	8,100,026	51,261,151
69 Other Deductions			
70 Interest (AFUDC)			
71 Interest	14,973,343	-	14,973,343
72 Schedule "M" Additions	12,377,016	-	12,377,016
73 Schedule "M" Deductions	17,146,019	-	17,146,019
74 Income Before Tax	23,418,779	8,100,026	31,518,806
75			
76 State Income Taxes	1,127,217	367,741	1,494,958
77 Taxable Income	<u>22,291,563</u>	<u>7,732,285</u>	<u>30,023,847</u>
78			
79 Federal Income Taxes + Other	<u>6,994,229</u>	<u>2,706,300</u>	<u>9,700,529</u>

Ref. Page 2.2

Exhibit No. 111
Case No. PAC-E-07-5
P. Harms, Staff
9/28/07

**ROCKY MOUNTAIN POWER
STATE OF IDAHO**

**Revenue Requirement Impact of Staff's Proposed Adjustments
12 Months Ended December 2006 with Known and Measurables**

Line No.	Description of Staff Proposal	Staff Witness	Impact to Company's Revenue Requirement Increase (Decrease)
1	Allow return on equity of 10.25% compared to 10.75% requested by Company.	Carlock	(\$2,000,000)
2	Allow recovery of Company's investment in plant on a 13-month average, annualizing certain projects in 2006 and adding certain projects in 2007.	Harms	(\$1,000,000)
3	Remove coal lease cost not known and measurable at prefile date.	Leckie	(\$26,000)
4	Remove not used and useful mining equipment from rate base.	Leckie	(\$15,000)
5	Include renewable energy tax credits associated with steam production project.	Harms	(\$40,000)
6	Remove cost of abandoned projects from operating expenses.	Harms	(\$80,000)
7	Remove power supply cost error in data extract associated gas purchases.	Lanspery	(\$2,500,000)
8	Adjust power supply cost associated with the Monsanto credit.	Lanspery	\$110,000
9	Allocate Idaho irrigation load control program system-wide.	Lanspery	(\$940,000)
10	Reduce incentive pay costs.	Leckie	(\$160,000)
11	Reduce net lease expense due to economic incentives.	Leckie	(\$7,000)
12	Remove costs associated with changing fiscal year to calendar year.	Leckie	(\$25,000)
13	Reduce severance pay costs.	Leckie	(\$160,000)
14	Remove expenses that are nonrecurring or not Idaho utility related.	Nobbs	(\$93,000)
15	Impute revenue associated with the Company's Green Tags.	Carlock	(270,000)

