

BEFORE THE

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IDAHO PUBLIC UTILITIES COMMISSION 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 BRYAN LANSPERY

IDAHO PUBLIC UTILITIES COMMISSION

SEPTEMBER 28, 2007

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

3 A. My name is Bryan Lanspery and my business
4 address 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 as a utility rate analyst.

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

10 A. I received a Bachelor of Arts degree in
11 Economics with a social science emphasis from Boise State
12 University in 2003. I also earned a minor in Geographic
13 Information Systems from Boise State University in the
14 same timeframe. I have also earned a Master of Arts in
15 Economics from Washington State University, received in
16 2005. My Masters work emphasized Labor Economics and
17 Quantitative Econometric Analysis. Concurrent to
18 pursuing my Masters degree, I functioned as an instructor
19 of Introductory and Intermediate Economics as well as
20 Labor Economics.

21 Q. Would you describe your duties with the
22 Commission?

23 A. I was hired by the Commission in late 2005 as a
24 utility analyst. As such, my duties revolve around
25 statistical and technical analysis of Company filings.

1 This includes cost/benefit analysis, resource evaluation,
2 price forecasting, and weather normalization methods.

3 Q. What is the purpose of your testimony?

4 A. There are several aspects of the rate case that
5 I will discuss. The first is the Company's Net Power
6 Cost filing, and my proposed adjustments including the
7 gas swap correction, the Monsanto interrutibility credit
8 and the allocation of irrigation load control program
9 costs. I will also discuss potential improvements in the
10 Company's class cost of service study, and the results of
11 the study when all Staff proposed revenue requirement
12 adjustments are included. I will then discuss the rate
13 design and rate spread, specifically with regard to
14 Staff's adjustments. Finally, I will briefly discuss a
15 handful of issues that are either not contested by Staff,
16 are alterations in tariff language, or need to be
17 addressed in a different venue.

18 **NET POWER COST**

19 **Gas Swap Adjustment**

20 Q. Have you reviewed the Company's net power costs
21 as filed in this rate case?

22 A. Yes, I have.

23 Q. Has the Company submitted net power cost
24 studies other than that included in Company witness
25 Widmer's testimony?

1 A. Yes, it has. Upon review, the Company found
2 that the computer system that it uses to collect data on
3 natural gas sales and purchases had not distinguished
4 between the two, thus coding all transactions as
5 purchases.

6 Q. Has the Company rectified this issue?

7 A. Yes, it has. In response to Staff Audit
8 Request 107, the Company filed a revised net power cost
9 study that corrected the gas swap error. The difference
10 between the original net power cost and the revised is a
11 reduction in cost of \$34,676,640 on a system basis, and
12 \$2,441,363 reduction for the Idaho Jurisdiction.

13 **Monsanto Interruptibility Credit**

14 Q. Do you have any additional adjustments to net
15 power costs?

16 A. Yes. The net power cost includes payments made
17 to Monsanto for providing interruptible products to the
18 Company. In Case No. PAC-E-06-09, the Commission
19 approved moving Monsanto from a contract standard
20 contract to a tariff standard contract. The Commission
21 explicitly stated in Order No. 30197 that Monsanto's
22 rates and it's interruptibility credit are to be
23 addressed in the context of a general rate case.

24 Q. Did the Company propose a change in the value
25 of the interruptibility credit in the case?

1 A. No. While Monsanto's rates are increasing due
2 to the results of the cost of service study, there is no
3 indication that the Company proposes a change in the
4 credit value.

5 Q. Do you believe the credit value should remain
6 at its present level?

7 A. No. The value of the products Monsanto offers
8 are essentially linked to market prices, specifically the
9 Company's official forward price curves. Market prices
10 have risen since the two parties negotiated the contract,
11 thus the value of Monsanto's credit should increase.

12 Q. How much do you propose to increase the
13 interruptibility credit?

14 A. I propose to increase the Monsanto credit by
15 roughly 14%.

16 Q. How did you determine the level of increase?

17 A. There are three components of the credit, the
18 economic curtailment, the system integrity component, and
19 the operating reserves component. For the economic and
20 system integrity components, I applied the methods of
21 valuation approved in the aforementioned case to the
22 official forward price curves and hourly scalars that the
23 Company used in this filing.

24 For the economic curtailment, I calculated the
25 800 most expensive hours of market prices at the Palo

1 Verde hub, which the Company uses as a reference for
2 contracts on the east side of its service territory.
3 Multiplying the prices for those hours by the amount of
4 curtailment offered by Monsanto results in a 14% increase
5 in the economic curtailment product.

6 For the system integrity component, I took the
7 yearly average on-peak price at Palo Verde, multiplied
8 that by the amount of curtailment offered by Monsanto.
9 That total is then multiplied by 12 hours, the maximum
10 amount of curtailment offered under the system integrity
11 option to produce a credit increase of approximately 17%.

12 I did not calculate the operating reserve
13 component due to lack of information. Because it is also
14 tied to the increase in market prices, as well as
15 marginal operating costs, I conservatively escalated the
16 operating reserve value by 14% as well.

17 Q. Do you believe an increase of 14% in the credit
18 is reasonably justified?

19 A. Yes, I believe that a 14% increase is justified
20 because the credit value established under the 2006
21 contract increases in value based on the price curves
22 used by the Company to establish costs in this rate case.

23 Q. What is the impact on net power costs of
24 increasing the interruptibility credit to Monsanto?

25 A. The increased credit increases system net power

1 supply costs by \$1,730,160 over the Company's filing.
2 That is an increase of \$109,112 allocated to Idaho.

3 Q. Does the gas swap error correction or the
4 increase in the Monsanto credit affect the determination
5 of power supply costs within the GRID model?

6 A. No. Both values are determined outside the
7 model, and appear as line items in GRID. The adjustments
8 are independent of one another and do not affect any
9 other net power supply costs determined by the GRID
10 model.

11 **Irrigation Load Control Cost Allocation**

12 Q. Do you have any additional adjustments to net
13 power cost?

14 A. Yes, regarding the treatment of the Idaho
15 Irrigation Load Control Program credit payments.

16 Q. How are the credit payments reflected in the
17 Company's filing?

18 A. Currently, in the case as filed, the Idaho
19 jurisdiction is directly assigned all of the costs of the
20 program, including the credit payments.

21 Q. Do you believe that this is the proper method
22 of assigning the credit payments?

23 A. No. Reduced demand resulting from direct
24 payments made to the irrigation customers under the
25 Irrigation Load Control program constitute a system

1 resource. The cost of those direct payments should
2 therefore be allocated as system power costs, as are all
3 other system resources, rather than directly allocated to
4 Idaho.

5 Q. The Revised Protocol allocation methodology
6 states that "(C)osts associated with Demand-Side
7 Management Programs will be [directly] assigned to the
8 State in which the investment is made. Benefits from
9 these programs, in the form of reduced consumption, will
10 be reflected through time in the Load-Based Dynamic
11 Allocation Factors." Is your recommendation contrary to
12 the guidelines of the Revised Protocol?

13 A. No, it is not.

14 Q. Please explain.

15 A. "Demand-Side Management Programs" are loosely
16 defined in Revised Protocol. These programs are defined
17 as "programs that improve the efficiency of electricity
18 use by PacifiCorp's system." There are many programs
19 that easily fit into this category, such as the "See ya
20 later refrigerator" program, which promotes energy
21 efficiency. There are other programs, such as Monsanto's
22 curtailible load, that are demand-side measures that
23 reduce demand under contract. Credits for these demand-
24 side measures are treated as a system resource for the
25 purpose of jurisdictional cost allocation.

1 Q. Are you arguing that the Irrigation Load
2 Control Program is akin to the Monsanto contract?

3 A. In many ways, yes. In some ways, it is a
4 better system resource than Monsanto's interruptibility
5 contract. Irrigators enter into a contract with the
6 Company prior to the irrigation season in order to
7 participate. Equipment is in place to prevent the
8 irrigator from using its pumps during the scheduled block
9 of time it agreed to in the contract. This is indicative
10 of a firm contract purchase by the Company, but instead
11 of purchasing to serve load, the Company pays to not
12 serve load during some of the most expensive times of the
13 year. The Company can then use resources previously
14 required to serve Idaho irrigation load during peak
15 periods to serve growing demand in other areas of the
16 Company's service territory. This firm demand reduction
17 is no different than a firm supply side resource acquired
18 to serve new load during peak periods and costs should be
19 similarly allocated.

20 Q. Can the Company count on the amount of demand
21 reduction it will contract during the season?

22 A. Yes. The Company has knowledge of the number
23 of potential sites and customers. The Program has
24 achieved an impressive retention rate from season to
25 season. According to the 2006 Program Final Report, the

1 Company had "recorded 50.8 MW (of) firmed scheduled
2 resource" prior to the dispatch period, and recorded an
3 average peak avoided of 47.1 MW. This demonstrates that
4 the Company's expectations on participation have been
5 quite accurate, enhancing the nature of the Program as a
6 firm, scheduled resource.

7 Q. So you believe the Irrigation Load Control
8 Program is more akin to a contract purchase or
9 acquisition of a peaking resource than a traditional
10 demand-side program?

11 A. Yes. Through the Program, the Company is able
12 to acquire a firm, cost effective resource during times
13 of high marginal costs to serve load. The nature of the
14 Program provides the Company with a firm, reliable load
15 decrement, as predictable as a contract purchase. And in
16 contrast to demand-side programs as defined in revised
17 protocol, there is no lost revenue for the Company
18 according to the end of the year reports filed by the
19 Company regarding the program. Irrigation load is not
20 shed, it is shifted to off-peak times. In fact, there is
21 greater profit for the Company as revenues remain
22 relatively stable, but the energy is consumed during a
23 period of lower average cost.

24 Q. You said in some ways, the contract with the
25 irrigators is better than the contract with Monsanto.

1 Please explain.

2 A. Irrigators do not have a buy-through option.
3 Monsanto can buy through the curtailment if it deems it
4 necessary. The Company therefore must be capable of
5 serving Monsanto's peak needs even if it would rather
6 curtail Monsanto. Once the enrollment date for the
7 Irrigation Load Control Program is final, the Company has
8 knowledge of what the firm needs of the irrigators in
9 Idaho are. The Irrigation load is firm, and cannot be
10 'bought-through'. If an irrigator leaves the program,
11 the payments are reduced. The load is properly reflected
12 for allocation purposes since this is a load-shifting
13 program.

14 Q. Would this argument change if the Irrigation
15 Load Control Program were offered in another state?

16 A. No. Provided the contract with irrigators is
17 binding and reduces system load requirements. It does
18 not matter what state it is located in. It is a purchase
19 power agreement, and should be treated as such.

20 Q. What is the impact on the Idaho jurisdiction
21 and the Irrigation class of the Company's proposed situs
22 allocation of the Irrigation Load Control Program?

23 A. Program costs at or near the marginal cost of
24 new resources are directly assigned to the Idaho
25 jurisdiction. Idaho's allocation of average system costs

1 are reduced by Irrigator reduced demand, as well as the
2 Irrigation class costs.

3 Q. Is it true then that Idaho and irrigators
4 receive a benefit from the program through cost
5 allocation?

6 A. It is true that the irrigation class does see a
7 benefit in the form of reduced demand during coincident
8 peaks for the months the program is in effect. As does
9 Idaho. As does the system. However, unlike a contract
10 purchase that is allocated system wide, this particular
11 cost is directly assigned to Idaho, to all customer
12 classes, including the irrigators.

13 Q. Please expound on the direct assignment to
14 Idaho of the Irrigation Load Control Program costs.

15 A. As a result of the Program being identified as
16 traditional DSM by the Company, all costs are directly
17 assigned to the State. The Program reduces peak demand
18 during the summer. The payments made to irrigators are
19 based on marginal power costs in the summer, when these
20 costs are at their highest. As a result, the Idaho
21 jurisdiction is directly assigned the cost of 35-50 MW of
22 peak power at or near marginal costs.

23 From the benefit side, Idaho's jurisdictional
24 allocation of average system embedded costs decline by
25 the 35-50 MW of peak reduction. But again, this is at an

1 average, embedded cost, a mixture of the highest and
2 lowest costs for power. Therefore, Idaho is allocated
3 the average costs associated with a block of load, and is
4 directly assigned the higher marginal cost for that same
5 block.

6 Q. Is this treatment of the Program costs
7 consistent with the treatment of other contract
8 purchases, specifically the Monsanto curtailment credits?

9 A. No. Under a typical system power purchase,
10 which is made at the margin, allocation is to all
11 jurisdictions at the embedded rate. The Irrigation Load
12 Control Program credit payments are also closer to the
13 margin however they are assigned situs to Idaho, and
14 allocated to all classes. This is inconsistent treatment
15 of the credit payment.

16 The payments to Monsanto are allocated across
17 the system, and are included in the Company's power
18 supply model. The payments are further allocated to all
19 customer classes. This treatment consistently allocates
20 costs to all customers equally and should be similarly
21 applied to recover credit payments to irrigators.

22 Q. What is your recommendation for treating the
23 Irrigation Load Control Program Credit consistently with
24 other contract purchases?

25 A. Similar to the Monsanto contract, and similar

1 to other power purchase contracts, I recommend that the
2 Irrigation Load Control Program Credit be allocated as a
3 system cost to all jurisdictions, and further allocated
4 to all Idaho customer classes.

5 Q. Do you believe all of the costs associated with
6 the program should be allocated on a system basis?

7 A. No, only the credit payments to irrigators.
8 The credit payment is akin to a power purchase, and
9 should be treated as such. The equipment and
10 administrative expenses that facilitate the program are
11 currently deferred expenses to be paid by Idaho
12 customers. This is similar to the expenses incurred by
13 Monsanto in order to provide its interruptibility
14 products. The Company does not remove the equipment at
15 the end of the irrigation season, which helps curb costs
16 associated with the program as many irrigators choose to
17 participate in subsequent years. While program costs do
18 not necessarily change with participation, the credit
19 payment is directly linked to the amount of contracted
20 load reduction the Company acquires.

21 Q. So could you please summarize your position
22 with regard to the treatment of the Irrigation Load
23 Control Program credit payment?

24 A. Yes. The credit payment constitutes a firm
25 contract purchase between the Company and participating

1 Idaho irrigators. This is similar to the contract the
2 Company has with Monsanto to provide its curtailment
3 options. It is essentially indistinguishable from other
4 firm contract purchases the Company includes in its net
5 power costs. I propose that the Company treat the
6 payment in the same fashion it treats other contract
7 purchases.

8 Q. For the test year, what is the amount of
9 payments made to irrigators participating in the program?

10 A. According to the Company's Jurisdictional
11 Allocation Model, the payments total to \$996,370, all of
12 which was allocated to Idaho on a situs basis.

13 Q. Have you quantified the effect of treating the
14 Irrigation Load Control Credit as a system resource
15 rather than situs?

16 A. Yes, and the treatment of the credit in the
17 jurisdictional allocation model is quantified and
18 included in Staff witness Harms' testimony and exhibits.
19 The result of the adjustment is a reduction in the
20 Company's requested revenue requirement for Idaho of
21 \$933,534.

22 Q. Do you have any further adjustments to the
23 Company's proposed revenue requirement?

24 A. No.

25 Q. Please summarize your recommendation for net

1 power costs and Staff's revenue requirement in this case?

2 A. I recommend that system power supply cost be
3 reduced by \$33 million from the \$861,066,125 filed by the
4 Company to \$828,119,646. The resulting power supply
5 costs allocated to Idaho are therefore reduced by
6 approximately \$2.4 million, from \$57.8 million to \$55.4
7 million.

8 In addition, my recommendation to allocate
9 Irrigation Load Control Credit payments on a system basis
10 rather than directly to Idaho results in a reduction of
11 Idaho revenue requirement of \$933,534. Therefore, my
12 proposed adjustments reduce revenue requirement by a
13 total of approximately \$3.3 million.

14 **CLASS COST OF SERVICE**

15 Q. Have you reviewed the Company's Cost of Service
16 study?

17 A. Yes.

18 Q. Do you believe that the study adequately
19 represents the cost to serve the various classes in
20 Idaho?

21 A. Yes. However, Staff believes PacifiCorp should
22 enhance its load sampling data to assure proper cost
23 assignment to the various classes.

24 Q. What is the problem you see in the load
25 sampling data?

1 A. Staff initiated an informal query earlier this
2 year to the three electric utilities regarding each
3 Company's load sampling methods. Through this query, it
4 was apparent that PacifiCorp does not adequately sample
5 load for customer classes that are not demand metered.

6 Q. What led you to the conclusion that
7 PacifiCorp's load sampling was inadequate?

8 A. Through the Company's responses in that query
9 and reinforced in this case through it's response to
10 Staff Production Request 25, the Company indicated that
11 it currently has 97 sampling meters for the two
12 residential classes, 52 for Schedule 1 and 45 for
13 Schedule 36. That is approximately 0.1% of the
14 population for Schedule 1, and 0.3% of Schedule 36
15 customers.

16 Q. Has the Company acknowledged this issue?

17 A. Yes. The Company indicated that a limited
18 number of sampling meters are installed for Schedule 1
19 and Schedule 36 customers. These meters were placed in
20 service in 2001, with no additional deployment since
21 then. In addition, the Company has agreed in the
22 Supplemental Response to Staff Production Request No. 25
23 to increase its deployment of sampling meters for the
24 residential classes by 24 by the end of the year. Each
25 of the new meters, 12 for Schedule 1 and 12 for Schedule

1 36, will be located on homes built since 2001.
2 Additionally, the Company plans to rotate the locations
3 of the meters periodically, beginning in 2010.

4 Q. Are there other classes of customers that the
5 Company plans to modify its load sampling methodology?

6 A. Yes. The Company indicated in the supplemental
7 response that it would begin rotating the location of the
8 irrigation sample meters in 2008.

9 Q. What impact can limited load sampling data have
10 on class cost of service?

11 A. Sampling data may have an impact on each
12 class's coincident and non-coincident peak measurements,
13 which is used to derive the demand related allocation
14 factors in the allocation of service costs.

15 Q. What can be accomplished by improving sampling
16 data in the residential class?

17 A. Staff believes that improved sampling would
18 help justify the cost allocation and rate differential
19 between Schedules 1 and 36.

20 Q. Both Idaho Power and Avista have embarked on
21 Advanced Meter Reading (AMR) programs to reduce costs and
22 investigate time-of-use rates. Should PacifiCorp
23 investigate AMR deployment?

24 A. Perhaps. First, AMR could provide accurate
25 data for the class cost of service study, thereby

1 removing much of the concerns regarding the inadequate
2 load sampling data. Also, AMR would facilitate expansion
3 of energy efficiency programs to include such options as
4 critical peak pricing or real-time pricing. AMR also
5 allows customers to actively manage their energy
6 consumption by providing access to usage on a more real-
7 time basis, as opposed to waiting until their bill
8 arrives. Finally, AMR could verify and justify time-of-
9 use rate differentials between the two residential
10 classes.

11 Q. Does the Company's cost of service study treat
12 the two residential groups as separate classes or as a
13 single residential class?

14 A. The cost of service study distinguishes between
15 the two residential groups, and assigns costs
16 accordingly. The only instance I noticed of lumping the
17 two classes together was the treatment of metering costs.
18 The Company averages the metering costs and associated
19 billing costs for the classes to use as a benchmark for
20 developing the allocation factors for the other customer
21 classes.

22 Q. Are there any other issues with respect to the
23 class cost of service study that you want to address?

24 A. Yes. Based on Monsanto Data Request No. 9.6,
25 it is apparent that Monsanto's coincident peaks for the

1 months of September, November and December had been
2 overstated by 67 MW in the cost of service study.

3 Q. Why did this occur?

4 A. PacifiCorp curtailed Monsanto's load during
5 these three months, and Monsanto exercised its option to
6 buy-through for replacement energy. The metered sales
7 reflected the buy-through replacement energy, but the
8 Company mistakenly added the replacement energy on top of
9 the metered sales, effectively double-counting 67 MW for
10 the three periods.

11 Q. What is the effect on class cost of service of
12 removing Monsanto's buy-through energy from metered
13 sales?

14 A. The effect on Monsanto compared to the
15 Company's initial filing is a reduction in the Monsanto
16 demand allocation and a decrease in Monsanto's cost of
17 service from 24.13% to 20.92%.

18 Conversely, the cost of service for other Idaho
19 customer classes increases to make up for the Monsanto
20 reduction. Staff Exhibit No. 117 shows the cost of
21 service results before and after the reduction in the
22 Monsanto demand allocation. On average, the other
23 customer classes witness increase in cost of service
24 results of 1.2%

25 Q. Have you conducted a cost of service study that

1 include the revenue requirement adjustments proposed by
2 Staff?

3 A. Yes. Staff Exhibit No. 118 shows cost of
4 service results that includes all of my adjustments and
5 those detailed in the testimonies of Staff witnesses
6 Harms, Carlock, Leckie, and Nobbs.

7 The results indicate that certain customer
8 classes are below cost of service, while some are
9 currently above cost of service. Specifically, the
10 general service classes are slightly above cost of
11 service. The adjustments to revenue requirement reduce
12 the revenue adjustments necessary to bring the
13 residential, irrigation, street lighting, and contract
14 customers to full cost of service. Monsanto's demand
15 allocator adjustment results in slight increases to the
16 revenue adjustment for all other classes.

17 **RATE DESIGN**

18 Q. What is the Staff's recommendation on the rate
19 increase for all Idaho customers?

20 A. Staff proposes an average increase in rates of
21 6.29%

22 Q. The Company has proposed to move the two
23 contract customers and street lighting classes to full
24 cost of service. Do you agree with the Company's
25 proposal?

1 A. I propose moving the street lighting classes to
2 full cost of service. I further propose increasing the
3 rates for the special contract customers to place them
4 near full cost of service. Under the terms of the
5 contracts entered into by Agrium and Monsanto, they are
6 to be treated as tariff customers, whose rates are
7 subject to change should the cost of service study show
8 that a rate change is warranted.

9 Q. What is the Staff's proposed revenue
10 requirement increase for Agrium and Monsanto?

11 A. Staff proposes that Agrium's annual revenue
12 requirement be increased by \$411,882, or 10.3%, and
13 Monsanto's annual revenue requirement be increased by
14 \$7,470,650, or 15.35%.

15 Q. The Company has proposed that customer classes,
16 slightly above cost of service receive no decrease in
17 rates. Do you support the Company's proposal?

18 A. Yes. These classes are shown to be relatively
19 close to cost of service and do not warrant a rate
20 reduction given the imprecise nature of the cost of
21 service results. Cost of service results vary over time
22 and there is not sufficient evidence to support a
23 decrease in rates for a service that is experiencing ever
24 increasing costs.

25 Q. The Company proposes a uniform increase for the

1 two residential classes and the irrigation class. Do you
2 agree with the Company's proposal?

3 A. Yes. The Commission has traditionally
4 supported a uniform increase in rates. Based on the
5 Staff proposed revenue requirement the increase suggested
6 by the cost of service study to bring all classes to full
7 cost of service vary from 3.92% for Schedule 36 to 6.02%
8 for Schedule 1. Staff believes that a uniform increase
9 is simple and reasonably achieves cost of service while
10 recognizing that cost of service is not an exact science.
11 Therefore, in conjunction with our recommendation to
12 maintain existing rates for those customers identified by
13 the study to be below cost of service, Staff is
14 recommending a uniform increase of 3.42% for each of the
15 other three classes to generate the Staff recommended
16 revenue requirement.

17 Q. What increase in annual revenue does Staff
18 recommend for the residential and irrigation classes?

19 A. Staff recommends that the annual revenue for
20 Schedules 1 and 36 be increased by \$1,014,145 and
21 \$730,588, respectively. Staff also recommends that
22 Schedule 10 annual revenue increase by \$1,347,640 per
23 year. The resulting uniform increase for each class is
24 therefore 3.42%.

25 Q. Do you believe that this proposed revenue

1 increase adequately reflects Staff's cost of service
2 study?

3 A. Yes. As seen in Staff Exhibit No. 119, the
4 proposed revenue increase would bring the two residential
5 classes, the irrigation class, and the two special
6 contract customers to 98% of the respective cost of
7 service as proposed by Staff.

8 Q. Do you agree with the Company's proposal to
9 keep the on-peak and off-peak rate differentials for
10 Schedule 36 at the same level?

11 A. At this time, yes. Should the Commission
12 direct the Company to investigate AMR, and should the
13 Company implement an AMR system, Staff will evaluate the
14 rate differentials to ensure that they properly reflect
15 the cost to serve during various hours of the year.

16 Q. Have you prepared an exhibit demonstrating that
17 Staff's proposal will provide the Company with the
18 opportunity to collect Staff's target annual revenue?

19 A. Yes. Staff Exhibit No. 119 demonstrates that
20 the proposed increases allow the Company to recover
21 Staff's recommended revenue requirement.

22 Q. Are you proposing any changes to rate design?

23 A. No.

24 Q. Has the Company submitted revised tariffs to
25 reflect the proposed rates?

1 A. Yes.

2 Q. Do you propose any modifications to tariff
3 language beyond reflecting the new rates?

4 A. I do not have a specific recommendation, but I
5 do believe that the Company needs to clarify the
6 differences between Schedules 6 and 23, small general
7 service and large general service.

8 Q. Why do you believe that the Company should
9 clarify Schedules 6 and 23?

10 A. The tariff has no language to determine what
11 the eligibility criteria are for these classes. The
12 schedules are essentially the same, except for the
13 pricing. I would recommend that the Company file revised
14 tariffs that contain language that would contain the
15 eligibility criteria that the Company presumably uses to
16 discern which schedule a potential customer would fall
17 under.

18 **OTHER ISSUES**

19 Q. Are there any other issues you would like to
20 address in your testimony?

21 A. Yes. I wish to address the elimination of
22 Schedule 94, the Rate Mitigation Adjustment, the contrast
23 of costs of wind facilities assumed by the Company in its
24 IRP with actual costs paid through RFPs, and Company
25 witness Rockney's testimony regarding proposed changes to

1 Regulation No. 12, the line extension policy.

2 Q. What is the Company's proposal regarding
3 Schedule 94?

4 A. As stated on page 4 of Company witness
5 Griffith's testimony, the Company proposes to eliminate
6 the Rate Mitigation Adjustment upon implementation of the
7 proposed rates.

8 Q. What is the Company's justification for
9 eliminating the Rate Mitigation Adjustment (RMA)?

10 A. Commission Order No. 29034 states that the RMA
11 could be subject to termination upon the earlier of "(1)
12 the expiration of the current electric service Schedule
13 34 BPA Exchange Credit; or (2) the adoption by the
14 Commission of a cost-of-service study for PacifiCorp and
15 the subsequent implementation for all customers of the
16 approved cost of service study by any lawful method."
17 The intent of the RMA was to mitigate rate shock to the
18 irrigation class as the Company moved it to cost of
19 service. After the adjustments Staff has made to revenue
20 requirement and the cost of service study, the rate
21 design I propose moves the irrigation class sufficiently
22 close to cost of service.

23 Q. Do you believe the RMA is still necessary?

24 A. No. I support the Company's request to
25 eliminate Schedule 94.

1 Q. In regard to new resource acquisition,
2 PacifiCorp selected the 64.5 MW Wolverine Creek, the
3 100.5 MW Leaning Juniper, and the 140.4 MW Marengo wind
4 projects through a Request for Proposal (RFP) process.
5 Has Staff reviewed the process used to select the winning
6 bids under the RFP?

7 A. Yes.

8 Q. Do you have any comments or concerns about the
9 process?

10 A. I do not have any concerns about the projects
11 that were selected or the manner in which bids were
12 compared against each other, but I do have concerns about
13 the fact that no comparisons were made between the bids
14 and the costs for new resources that were assumed in the
15 Company's Integrated Resource Plans (IRPs). In response
16 to Staff production requests (IPUC Request No. 15), the
17 Company admits that the capital costs to acquire the
18 Leaning Juniper, Marengo and Goodnoe Hills projects are
19 higher than the capital cost assumptions in PacifiCorp's
20 2003 and 2007 IRPs.

21 The IRP process compares various generation
22 alternatives and serves as a guide to future acquisition
23 of new resources. The decision to pursue acquisition of
24 new wind generation is based on the cost and risk
25 analysis included in the Company's IRPs. When decisions

1 are made to acquire specific wind projects, I believe it
2 is important to insure that the prices being paid to
3 acquire those resources are still consistent with the
4 prices assumed in the IRP, and that wind generation still
5 represents the best new resource alternative. If bid
6 prices exceed IRP assumptions, then the IRP cost
7 assumptions for all new resource types – wind, coal, and
8 natural gas – should be refreshed to make sure that the
9 IRP analysis is still valid.

10 Q. The 94 MW Goodnoe Hills wind project has also
11 recently been selected by the Company, although not
12 through the RFP process. Do you have the same concerns
13 about the process used to select this project?

14 A. Yes, all of the same concerns regarding the
15 other wind projects apply to this one as well.

16 Q. Does the Company propose to make changes to the
17 line extension policy?

18 A. Yes. Company witness Rockney describes several
19 changes to Electric Service Regulation No. 12, Line
20 Extensions.

21 Q. Briefly describe the modifications proposed by
22 the Company.

23 A. The Company proposes to make what it considers
24 "housekeeping changes" to Regulation 12. The Company
25 proposes to clarify language that defines an "Extension",

1 language that addresses the relocation of facilities,
2 standardizing the language regarding allowances and
3 advances for developers with respect to the Company's
4 regulations in other states, and refunds for backbone
5 facilities.

6 The Company also seeks to change the refund
7 methodology for planned developments, allowing the
8 developer to waive small refunds in anticipation of
9 larger refunds based on load size. Also, the proposal
10 would affect refunds to residential customers. The
11 Company proposes that the contract remain with the
12 initial customer for five years or four successive
13 customers rather than each successive customer assuming
14 the contract. This would impact the method in which the
15 initial customer receives its refund.

16 The Company also proposes to change the
17 allowance for customers receiving service at 44,000 volts
18 or greater, or transmission delivery customers. Under
19 the proposal, these customers will receive an allowance
20 for metering only.

21 Q. Do you believe that the Company has correctly
22 characterized these as "housekeeping changes"?

23 A. No. The Company proposes to restructure the
24 methods of allocating refunds and allowances, going well
25 beyond adding clarification to existing regulations. The

