

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

3 A. My name is Terri Carlock. 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 as the Deputy Administrator of the Utilities
8 Division responsible for the Accounting/Audit Section.

9 Q. Please outline your educational background and
10 experience.

11 A. I graduated from Boise State University in
12 1980, with B.B.A. Degrees in Accounting and Finance. I
13 have attended various regulatory, accounting, rate of
14 return, economics, finance and ratings programs. I
15 chaired the National Association of Regulatory Utilities
16 Commissioners (NARUC) Staff Subcommittee on Economics and
17 Finance for more than 3 years. Under this subcommittee,
18 I also chaired the Ad Hoc Committee on Diversification.
19 I am currently the Vice-Chair of the NARUC Staff
20 Subcommittee on Accounting and Finance. I have been a
21 presenter for the Institute of Public Utilities at
22 Michigan State University and for many other conferences.
23 Since joining the Commission Staff in May 1980, I have
24 participated in audits, performed financial analysis on
25 various companies, and have presented testimony before

1 this Commission on numerous occasions.

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

4 A. The purpose of my testimony is to discuss
5 policy positions, the Multi-State Process, Renewable
6 Energy Credits and present the Staff's recommendation
7 related to the overall cost of capital for Rocky Mountain
8 Power to be used in the revenue requirement in this case.
9 I will address the appropriate capital structure, cost
10 rates and the overall rate of return.

11 Q. Please summarize your testimony.

12 A. Portions of my testimony are policy related
13 and do not have specific recommendations directly
14 impacting the revenue requirement. I discuss Renewable
15 Energy Credits (RECs) in my testimony, and I recommend
16 recognizing additional REC revenues of \$4,270,923
17 (system) that reduce the Idaho revenue requirement by
18 \$269,344. In my testimony on the overall rate of return,
19 I am recommending a return on common equity in the range
20 of 9.5% - 10.5% with a point estimate of 10.25%. The
21 recommended overall weighted cost of capital is in the
22 range of 7.889% - 8.393% with a point estimate of 8.267%
23 to be applied to the rate base for the test year.

24 Q. Are you sponsoring any exhibits to accompany
25 your testimony?

1 A. Yes, I am sponsoring Staff Exhibit No. 120 and
2 Staff Exhibit No. 121 consisting of 3 schedules.

3 Q. Please identify the REC or green tag
4 adjustments made by Staff in this case.

5 A. Staff has made two adjustments to properly
6 reflect REC or green tag revenues. The first imputes
7 revenue for RECs associated with major new wind projects.
8 The second is a proforma adjustment to better reflect REC
9 revenue credits from sales during the adjusted test
10 period.

11 Q. Please explain the adjustment to impute
12 revenues associated with major new wind projects.

13 A. PacifiCorp assumes that there will be RECs with
14 the energy generated by the Wolverine Creek, Leaning
15 Juniper, Marengo and Goodnoe Hills projects. In the
16 Integrated Resource Plans, the Company's economic
17 analysis uses the sale of RECs to show the economic
18 feasibility of the wind projects for inclusion in the
19 system resource portfolio. Staff utilized and accepted
20 use of these REC revenues to fully accept the inclusion
21 of these plants in rate base and all associated costs in
22 the revenue requirement. The associated REC revenues
23 shown on Staff Exhibit No. 120 are required to make these
24 specific wind projects cost effective. To compute the
25 total REC value, Staff multiplied the Company's assumed

1 value of RECs by the generation for each project for the
2 time period reflected during the proformed 2007 period.
3 These revenues need to be imputed to properly reflect all
4 the components to justify inclusion of these plants in
5 customer rates. The total REC values for these projects
6 are \$3,445,533 (system).

7 Q. Please explain the proforma adjustment to
8 better reflect REC revenue credits from sales during the
9 adjusted test period.

10 A. The proforma test year adjustment reflects a
11 known and measurable adjustment. The 2007 REC revenues
12 through May amounts to \$1,837,075 (system) while the
13 amount booked in 2006 was \$1,011,684 (system). The
14 difference of \$825,390 (system) is the conservative
15 proforma adjustment recommended by Staff. The adjustment
16 is conservative since REC sales in prior years were also
17 made in the last two quarters of the year but the 2007
18 comparison does not include these quarters.

19 Q. What is the total adjustment made by Staff for
20 REC revenue credits?

21 A. The total of these two adjustments is
22 \$4,270,923 (system). Both adjustments would be allocated
23 using the system generation factor of 6.306%, resulting
24 in a reduction of \$269,344 in the Idaho revenue
25 requirement.

1 Q. Have you reviewed the testimony and exhibits of
2 Rocky Mountain Power witnesses Hadaway and Williams
3 associated with the return components?

4 A. Yes. Much of the theoretical approach used by
5 witnesses Hadaway and Williams in their testimonies and
6 exhibits is generally the same as I have used. My
7 judgment in some areas of application results in
8 different outcomes.

9 Q. What legal standards have been established for
10 determining a fair and reasonable rate of return?

11 A. The legal test of a fair rate of return for a
12 utility company was established in the *Bluefield Water*
13 *Works* decision of the United States Supreme Court and is
14 repeated specifically in *Hope Natural Gas*.

15 In *Bluefield Water Works and Improvement Co. v.*
16 *West Virginia Public Service Commission*, 262 U.S. 679,
17 692, 43 S.Ct. 675, 67 L.Ed. 1176 (1923), the Supreme
18 Court stated:

19 A public utility is entitled to such rates as
20 will permit it to earn a return on the value
21 of the property which it employs for the
22 convenience of the public equal to that
23 generally being made at the same time and in
24 the same general part of the country on
25 investments in other business undertakings
which are attended by corresponding risks and
uncertainties; but it has no constitutional
right to profits such as are realized or
anticipated in highly profitable enterprises
or speculative ventures. The return should
be reasonably sufficient to assure confidence

1 in the financial soundness of the utility and
2 should be adequate, under efficient and
3 economical management, to maintain and
4 support its credit and enable it to raise the
5 money necessary for the proper discharge of
6 its public duties. A rate of return may be
7 reasonable at one time and become too high or
8 too low by changes affecting opportunities
9 for investment, the money market and business
10 conditions generally.

11 The Court stated in *FPC v. Hope Natural Gas Company*, 320
12 U.S. 591, 603, 64 S.Ct. 281, 88 L.Ed. 333 (1944):

13 From the investor or company point of view it
14 is important that there be enough revenue not
15 only for operating expenses but also for the
16 capital costs of the business. These include
17 service on the debt and dividends on the
18 stock.

19 ... By that standard the return to the equity
20 owner should be commensurate with returns on
21 investments in other enterprises having
22 corresponding risks. That return, moreover,
23 should be sufficient to assure confidence in
24 the financial integrity of the enterprise, so
25 as to maintain its credit and to attract
capital. (Citations omitted.)

The Supreme Court decisions in *Bluefield Water Works* and *Hope Natural Gas* have been affirmed in *In re Permian Basin Area Rate Case*, 390 U.S. 747, 88 S.Ct 1344, 20 L.Ed 2d 312 (1968), and *Duquesne Light Co. v. Barasch*, 488 U. S. 299, 109 S.Ct. 609, 102 L.Ed.2d. 646 (1989). The Idaho Supreme Court has also adopted the principles established in *Bluefield Water Works* and *Hope Natural Gas*. See *In re Mountain States Tel. & Tel. Co.* 76 Idaho 474, 284 P.2d 681 (1955); *General Telephone Co. v. IPUC*,

1 109 Idaho 942, 712 P.2d 643 1986); *Hayden Pines Water*
2 *Company v. IPUC*, 122 ID 356, 834 P.2d 873 (1992).

3 As a result of these United States and Idaho
4 Supreme Court decisions, three standards have evolved for
5 determining a fair and reasonable rate of return:

6 (1) The Financial Integrity or Credit Maintenance
7 Standard; (2) the Capital Attraction Standard; and,
8 (3) The Comparable Earnings Standard. If the Comparable
9 Earnings Standard is met, the Financial Integrity or
10 Credit Maintenance Standard and the Capital Attraction
11 Standard will also be met, as they are an integral part
12 of the Comparable Earnings Standard.

13 Q. Have you considered these standards in your
14 recommendation?

15 A. Yes. These criteria have been seriously
16 considered in the analysis upon which my recommendations
17 are based. It is also important to recognize that the
18 fair rate of return that allows the utility company to
19 maintain its financial integrity and to attract capital
20 is established assuming efficient and economic
21 management, as specified by the Supreme Court in
22 *Bluefield Water Works*.

23 Q. Please summarize the parent/subsidiary
24 relationships for Rocky Mountain Power.

25 A. Rocky Mountain Power's common stock is not

1 traded. Rocky Mountain Power is a division of PacifiCorp
2 and PacifiCorp is a wholly owned subsidiary of
3 MidAmerican Energy Holdings Company (MEHC). Due to this
4 parent/subsidiary relationship there is no direct equity
5 market data available for utility operations at Rocky
6 Mountain Power or PacifiCorp.

7 Q. What approach have you used to determine the
8 cost of equity for Rocky Mountain Power?

9 A. I have primarily evaluated two methods: the
10 Discounted Cash Flow (DCF) method and the Comparable
11 Earnings method.

12 Q. Please explain the Comparable Earnings method
13 and how the cost of equity is determined using this
14 approach.

15 A. The Comparable Earnings method for determining
16 the cost of equity is based upon the premise that a given
17 investment should earn its opportunity costs. In
18 competitive markets, if the return earned by a firm is
19 not equal to the return being earned on other investments
20 of similar risk, the flow of funds will be toward those
21 investments earning the higher returns. Therefore, for a
22 utility to be competitive in the financial markets, it
23 should be allowed to earn a return on equity equal to the
24 average return earned by other firms of similar risk.
25 The Comparable Earnings approach is supported by the

1 *Bluefield Water Works* and *Hope Natural Gas* decisions as a
2 basis for determining those average returns.

3 Industrial returns tend to fluctuate with
4 business cycles, increasing as the economy improves and
5 decreasing as the economy declines. Utility returns are
6 not as sensitive to fluctuations in the business cycle
7 because the demand for utility services generally tends
8 to be more stable and predictable. However, returns have
9 fluctuated since 2000 when prices in the electricity
10 markets dramatically increased. Electricity prices have
11 not seen the dramatic spikes lately so earnings are more
12 stable.

13 Q. Please evaluate interest rate trends.

14 A. The prime interest rate has increased since the
15 last PacifiCorp rate case but has decreased from 8.25% to
16 the current rate of 7.75%. The federal funds rate and
17 other rates have also decreased this year.

18 Q. Please provide the current index levels for the
19 Dow Jones Industrial Average and the Dow Jones Utility
20 Average.

21 A. The Dow Jones Industrial Average (DJIA) closed
22 at 13,878 on September 26, 2007. The DJIA all-time high
23 of 14,000.41 was reached on July 19, 2007. The Dow Jones
24 Utility Average closed at 512 on September 26, 2007.

25 Q. Please explain the risk differentials between

1 industrials and utilities.

2 A. Risk is a degree of uncertainty relative to a
3 company. The lower risk level associated with utilities
4 is attributable to many factors even though the
5 difference is not as great as it used to be. Utilities
6 continue to have limited competition for distribution of
7 utility services within the certificated area. With
8 limited competition for regulated services, there is less
9 chance of losses related to pricing practices, marketing
10 strategy and advertising policies. The competitive risks
11 for electric utilities have changed with increasing non-
12 utility generation, deregulation in some states, open
13 transmission access, and changes in electricity markets.
14 However, competitive risks are limited for Rocky Mountain
15 utility operations. The demand for utility services is
16 relatively stable and certain or increasing compared to
17 that of unregulated firms and even other utility
18 industries.

19 Competitive risks continue to be lower for
20 Rocky Mountain Power and PacifiCorp than for many other
21 electric companies primarily because of the low-cost
22 source of power and the low retail rates compared to
23 national averages. The risk differential between Rocky
24 Mountain Power and PacifiCorp and other electric
25 utilities is based on the resource mix and the cost of

1 those resources. All resource mixes have risks specific
2 to resources chosen. The demand for electric utility
3 services of Rocky Mountain Power and PacifiCorp is
4 increasing at predictable rates. This low demand risk is
5 partially due to the low-cost power and the customer mix
6 of the power users.

7 Under regulation, utilities are generally
8 allowed to recover through rates, reasonable, prudent and
9 justifiable cost expenditures related to regulated
10 services. Unregulated firms have no such assurance.
11 Utilities in general are sheltered by regulation for
12 reasonable cost recovery risks, making the average
13 utility less risky than the average unregulated
14 industrial firm.

15 Considering all of these comparisons, I believe
16 a reasonable return on equity attributed to Rocky
17 Mountain Power and PacifiCorp is 10.0% - 11.0% under the
18 Comparable Earnings method.

19 Q. You indicated that the Discounted Cash Flow
20 method is utilized in your analysis. Please explain this
21 method.

22 A. The Discounted Cash Flow (DCF) method is based
23 upon the theory that (1) stocks are bought for the income
24 they provide (i.e., both dividends and/or gains from the
25 sale of the stock), and (2) the market price of stocks

1 equals the discounted value of all future incomes. The
2 discount rate, or cost of equity, equates the present
3 value of the stream of income to the current market price
4 of the stock. The formula to accomplish this goal is:

$$5 \quad P_o = PV = \frac{D_1}{(1+k_s)^1} + \frac{D_2}{(1+k_s)^2} + \dots + \frac{D_N}{(1+k_s)^N} + \frac{P_N}{(1+k_s)^N}$$

7 P_o = Current Price

8 D = Dividend

9 k_s = Capitalization Rate, Discount Rate, or Required
10 Rate of Return

11 N = Latest Year Considered

12 The pattern of the future income stream is the
13 key factor that must be estimated in this approach. Some
14 simplifying assumptions for ratemaking purposes can be
15 made without sacrificing the validity of the results.
16 Two such assumptions are: (1) dividends per share grow
17 at a constant rate in perpetuity and (2) prices track
18 earnings. These assumptions lead to the simplified DCF
19 formula, where the required return is the dividend yield
20 plus the growth rate (g):

$$21 \quad k_s = \frac{D}{P_o} + g$$

23 Q. Have you factored flotation costs in with your
24 cost of capital analysis?

25 A. Yes, I have considered direct flotation costs

1 in my analysis by increasing the dividend yield component
2 of the DCF analysis. Because only direct costs should be
3 considered, I have used a flotation factor of 4% with 2%
4 assigned to the utility operations. This practice
5 continues to be reasonable because all subsidiaries of
6 MEHC should be responsible for some of the actual
7 flotation costs. I have therefore adjusted the DCF
8 formula to include the direct flotation costs as "df".

$$k_s = \left[\frac{D}{P_0} (1 + df) \right] + g$$

11 Q. What is your estimate of the current cost of
12 capital for Rocky Mountain Power and PacifiCorp using the
13 Discounted Cash Flow method?

14 A. The current cost of equity capital for Rocky
15 Mountain Power and PacifiCorp, using the Discounted Cash
16 Flow method with comparable companies is between 7.7% -
17 11.7%. Due to ongoing capital requirements, I believe a
18 dividend yield of 4.2% with an average growth rate of
19 5.2% is reasonable and representative resulting in a DCF
20 return on equity of 9.4%.

21 Q. How is the growth rate (g) determined?

22 A. The growth rate is the factor that requires the
23 most extensive analysis in the DCF method. It is
24 important that the growth rate used in the model be
25 consistent with the dividend yield so that investor

1 expectations are accurately reflected and the growth rate
2 is not too large or too small.

3 I have used an expected growth rate of 4% - 6%.
4 This expected growth rate was derived from an analysis of
5 various historical and projected growth indicators,
6 including growth in earnings per share, growth in cash
7 dividends per share, growth in book value per share,
8 growth in cash flow and the sustainable growth.

9 Q. What is the capital structure you have used for
10 Rocky Mountain Power and PacifiCorp to determine the
11 overall cost of capital?

12 A. I have utilized the embedded capital structure
13 at December 31, 2007 consisting of 49.1% debt, 0.5%
14 preferred stock and 50.4% common equity as shown on
15 Schedule 3 of Staff Exhibit No. 120. Rocky Mountain
16 Power witness Williams reflects this capital structure in
17 his testimony on page 3. I have accepted the proforma
18 capital structure recommended by Rocky Mountain Power in
19 this case because the proforma changes are adequately
20 known to be included as a known and measurable adjustment
21 in this case and it represents a capital structure
22 consistent with the rate base investment included in the
23 Staff revenue requirement.

24 Q. What are the costs related to the capital
25 structure for debt and preferred stock?

1 A. I have evaluated and accepted the embedded cost
2 rates used in Williams Exhibit Nos. 7 - 10. The cost of
3 debt is 6.26% (Staff Exhibit No. 120, Schedule 1) and the
4 cost of preferred stock is 5.41% (Staff Exhibit No. 120,
5 Schedule 2).

6 Q. You indicated the cost of common equity range
7 for Rocky Mountain Power and PacifiCorp is 10.0% - 11.0%
8 under the Comparable Earnings method and 7.7% - 11.7%
9 under the Discounted Cash Flow method. What is the cost
10 of common equity capital you are recommending?

11 A. The fair and reasonable cost of common equity
12 capital I am recommending for Rocky Mountain Power and
13 PacifiCorp is in the range of 9.5% - 10.5%. Although any
14 point within this range is reasonable, the return on
15 equity granted would not normally be at either extreme of
16 the fair and reasonable range. I utilized a point
17 estimate of 10.25% in calculating the overall rate of
18 return for the revenue requirement.

19 Q. What is the basis for your point estimate being
20 10.25% when your range is 9.5% - 10.5%?

21 A. The 10.25% return on equity point estimate
22 utilized is based on a review of market data and
23 comparables, average risk characteristics for Rocky
24 Mountain Power and PacifiCorp, including past and current
25 impacts in state jurisdictions, operations and the

1 capital structure.

2 Q. What is the overall weighted cost of capital
3 you are recommending for Rocky Mountain Power and
4 PacifiCorp?

5 A. I am recommending an overall weighted cost of
6 capital in the range of 7.889% - 8.393%. For use in
7 calculating the revenue requirement, a point estimate
8 consisting of a return on equity of 10.25% and a
9 resulting overall rate of return of 8.267% was utilized
10 as shown on Schedule 3, Staff Exhibit No. 120.

11 Q. Have you reviewed all of the Staff
12 recommendations in this case to evaluate if they are
13 consistent with Revised Protocol?

14 A. Yes, I have and I believe all of the
15 recommended Staff adjustments are consistent with Revised
16 Protocol.

17 Q. Are there Multi-State Process (MSP) or Revised
18 Protocol items that have influenced Staff recommendations
19 in this case?

20 A. Yes. All Staff recommendations took into
21 consideration, and were therefore influenced by, Revised
22 Protocol to ensure they were consistent. There are items
23 where absent the MSP process and Revised Protocol, Staff
24 may have made different or additional adjustments.

25

1 Q. Please explain the first area where you believe
2 differences would have likely occurred.

3 A. Absent the Revised Protocol, the treatment of
4 Monsanto by Staff would have likely been different.
5 Staff would have likely continued to treat Monsanto
6 completely as a system customer. Staff treatment for all
7 ancillary services where Monsanto and irrigators were
8 given credits would have likely been treated the same as
9 Staff proposes in this case, i.e. as system resources.

10 Revised Protocol allows the costs to serve
11 these customer contracts to be completely allocated to
12 Idaho using dynamic system allocation factors. The bill
13 credit provisions for Monsanto are treated similar to
14 ancillary power supply contracts where they are allocated
15 among states on the same basis as system resources.
16 Staff witness Lanspery proposes the Irrigation Credits be
17 allocated the same as ancillary power supply contracts.

18 The credits to Monsanto and Irrigation
19 customers are given for various ancillary services as set
20 out in the contracts. These ancillary services provide
21 system benefits that are dispatchable by the Company or
22 predetermined by contract thus avoiding the need for
23 additional resources or duplicative services if these
24 contracts were not in place.

25

1 I am pointing out these differences to help
2 explain the thought process as I evaluated the
3 consistency and reasonableness of Staff's positions under
4 Revised Protocol. The Company and all customers continue
5 to receive system benefits from these ancillary services
6 set forth in the contracts. A reasonable price is paid
7 for these services based on market evaluations that are
8 utilized throughout the PacifiCorp models and system
9 operations. The Revised Protocol treatment allows Idaho
10 Commissioners to establish reasonable rates for Idaho
11 customers and it also avoids having Idaho customers pay
12 for any incentive or economic development rates that may
13 be established in other states. To summarize, the
14 Revised Protocol allocation retains the benefits, assures
15 only reasonable costs are being allocated and most of all
16 leaves the rate decisions for Idaho customers with the
17 Idaho Commission without negatively impacting other
18 states.

19 Q. Are there additional adjustments or issues
20 Staff would have discussed absent the Revised Protocol?

21 A. Yes, there are areas where Staff would have
22 likely proposed specific regulatory treatment or
23 adjustments absent the MSP process and Revised Protocol.
24 These areas include the regulatory treatment and cost
25 allocation for hydro decommissioning and abandonment; the

1 cost prudence of resource choices in general and under
2 Resource Portfolio Standards (RPS); and green tag
3 revenues in addition to the adjustment discussed
4 previously. These additional issues would not have a
5 material revenue requirement impact if they were proposed
6 in this case. In fact I believe the revenue requirement
7 could have been offset by the increasing and decreasing
8 impacts since the rate impacts from these issues are just
9 beginning. Future rate cases and the resulting impacts
10 are where the regulatory treatment will become more
11 important to customers.

12 The MSP Standing Committee and workgroup
13 participants are evaluating these issues. If recommended
14 clarifications, modifications or additions to the Revised
15 Protocol are developed; they will be presented to the
16 various Commissions for approval. If agreement between
17 the states is not achieved, a different process will be
18 followed to bring issues before the Commission. Each
19 state could have different proposals for regulatory
20 treatment presented. Disjointed treatment in different
21 states may have a negative impact on system planning
22 and/or operations and would need to be evaluated at that
23 time.

24 Q. If additional adjustments are not being
25 proposed in this case, why discuss these items?

1 A. These items are discussed for identification
2 purposes. It allows parties in this case that haven't
3 been participating in the MSP workgroup process to be
4 aware of these current and future issues to evaluate
5 future participation levels.

6 Q. Please generally describe the issue associated
7 with hydro decommissioning and abandonment.

8 A. The Regional Resources category in the Revised
9 Protocol includes the Hydro-Endowment for owned hydro
10 resources and Mid-Columbia contracts. The allocation
11 methodology utilizes an Embedded Cost Differential (ECD)
12 adjustment to attribute hydro benefits and costs to the
13 region, West or East, where hydro resources originated.
14 The calculation of the ECD when hydro projects are
15 decommissioned or abandoned is the issue. For example,
16 the Powerdale Hydroelectric Facility was decommissioned
17 for economic reasons following a flood. One reason it
18 was more economic to decommission the facility than to
19 repair it was timing. This facility was part of a
20 settlement agreement to decommission so there was
21 insufficient time before the settlement date for
22 decommissioning to allow repairs to be economic. These
23 circumstances were discussed in Case No. PAC-E-07-4 and
24 Order No. 30344. The discussion topic for MSP evaluation
25 needs to focus on the intent behind the continuation of

1 the hydro-endowment concept in Revised Protocol. The
2 West (the original Pacific Power system) wanted to
3 continue to receive the benefits of the low cost hydro
4 system in the West and was willing to pay costs
5 associated with the hydro system including relicensing
6 costs if they were more expensive, above embedded costs.
7 Settlements to decommission are part of the relicensing
8 process. The intent behind the hydro-endowment along
9 with the ECD formula needs to be evaluated to assure they
10 remain consistent when hydro facilities are
11 decommissioned or abandoned. This includes evaluating
12 costs above the embedded cost. The embedded cost should
13 be calculated for ECD comparison purposes in the hydro-
14 endowment without marginal new resources, including wind,
15 being added to the embedded costs. This will allow the
16 higher costs for relicensing to follow hydro benefits.

17 Q. Please generally describe issues related to
18 resource choices in general and under Resource Portfolio
19 Standards (RPS).

20 A. Resource choices in general and under RPS
21 requirements are topics being explored in the MSP
22 Resource Choice workgroup. The workgroup is evaluating
23 issues that may impact cost allocations. Areas of
24 concern with workgroup participants range from no
25 concern, to concern when different resource preferences

1 emerge among states. Workgroup participants note that
2 the Revised Protocol does address divergent resource
3 portfolio standards in the event that a state chooses a
4 higher cost resource than contained in the IRP. Some
5 workgroup participants note that the resulting
6 operational effects could remain a problem. In addition,
7 the Revised Protocol language may not cover scenarios
8 where a state did not choose a different resource but
9 rejected a resource in the Integrated Resource Plan or
10 Request for Proposal. The workgroup is ongoing.

11 Q. What Renewable Energy Credit or Green Tag
12 issues are being discussed within MSP?

13 A. As Renewable Portfolio Standards are
14 established in numerous states, the availability of
15 renewable resources and/or Renewable Energy Credits,
16 RECs, to meet those requirements becomes an issue. RECs
17 or Green Tags are tradable commodities even though the
18 market isn't very liquid. Most terms and conditions
19 associated with REC transactions are established in
20 bilateral contracts. RECs represent the environmental
21 "green" attributes associated with the generation of one
22 megawatt-hour of renewable energy from an eligible
23 renewable resource. Since the state RPS requirements
24 differ, the need and regulatory treatment may not be
25 consistent even between states with RPS requirements.

1 In states where RPS requirements have not been
2 established, such as Idaho, the issue is slightly
3 different. Meeting RPS requirements means that RECs will
4 not be sold in the same manner as they were previously
5 sold and the associated revenue credit dollars to Idaho
6 will most likely decline. Available RECs will only be
7 sold when they are not needed to meet RPS requirements.
8 An allocation methodology is needed to provide revenue
9 credits to states that have available RECs allocated to
10 it and charge states for the transfer of needed RECs.
11 This is one way to maintain or enhance the revenue stream
12 associated with RECs in states where RPS requirements
13 haven't been established and provide a win-win scenario
14 for all customers.

15 Another issue deals with the actual revenue
16 credits from the sale of RECs. Unless the allocation of
17 REC sales revenue is changed to be more closely aligned
18 with the states that have RECs available for sale, the
19 revenue credits will go to all customers in the system
20 rather than customers in states with available RECs.
21 These are issues also being discussed within the ongoing
22 MSP and workgroup meetings.

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

25 A. Yes, it does.

Imputed Revenue for Green Tags Associated with Major new Wind Projects

Project Name	In-Service Date	No. Months Operational in Test Year		Imputed System Revenue
Wolverine Creek	12/1/2005	12	\$	875,000
Leaning Juniper	8/1/2006	12	\$	1,527,365
Marengo	8/1/2007	5	\$	791,508
<u>Goodnoe Hills</u>	12/1/2007	1	\$	<u>251,660</u>
Total			\$	3,445,533

PACIFICORP
Electric Operations
Pro Forma Cost of Long-Term Debt Summary
December 31, 2007

LINE NO.	DESCRIPTION	AMOUNT CURRENTLY OUTSTANDING	ISSUANCE EXPENSES	REDEMPTION EXPENSES	NET PROCEEDS TO COMPANY	ANNUAL DEBT SERVICE COST	INTEREST RATE	ALL-IN COST	ORIG LIFE	YIM	LINE NO.
1											1
2	Total First Mortgage Bonds	\$3,784,835,000	(\$34,537,272)	(\$38,145,597)	\$3,712,152,131	\$247,986,033	6.33%	6.55%	21.8	16.0	2
3											3
4	Subtotal - Pollution Control Revenue Bonds secured by FMBs	\$400,470,000	(\$10,560,810)	(\$9,550,194)	\$380,358,996	\$18,967,516	4.39%	4.74%	28.0	13.5	4
5	Subtotal - Pollution Control Revenue Bonds	\$337,900,000	(\$4,294,232)	(\$7,621,229)	\$325,984,539	\$16,046,592	4.51%	4.75%	27.8	10.2	5
6	Total Pollution Control Revenue Bonds	\$738,370,000	(\$14,855,042)	(\$17,171,423)	\$706,943,535	\$36,014,109	4.45%	4.74%	27.8	12.0	6
7											7
8	Total Cost of Long Term Debt	\$4,523,205,000	(\$49,392,314)	(\$55,317,020)	\$4,418,495,666	\$283,000,142	6.02%	6.26%	22.8	15.3	8
9											9

