

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

**IN THE MATTER OF THE APPLICATION)
OF PACIFICORP DBA ROCKY MOUNTAIN) CASE NO. PAC-E-10-07
POWER FOR APPROVAL OF CHANGES TO)
ITS ELECTRIC SERVICE SCHEDULES) ORDER NO. 32196
_____)**

Issued February 28, 2011
Boise, Idaho

Portions of this Order Relating to the
Economic Valuation of Monsanto's Interruptible Credit
Are Confidential

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OF PACIFICORP DBA ROCKY MOUNTAIN) **CASE NO. PAC-E-10-07**
POWER FOR APPROVAL OF CHANGES TO)
ITS ELECTRIC SERVICE SCHEDULES) **ORDER NO. 32196**
)

SUMMARY

On May 28, 2010, PacifiCorp dba Rocky Mountain Power (RMP; Company) filed an Application with the Idaho Public Utilities Commission (Commission) for authority to increase its rates and charges for electric service in the State of Idaho. RMP serves more than 70,000 customers in southeastern Idaho. The Company provides electric service to more than 1,000,000 customers in Utah, Wyoming and Idaho. On December 27, 2010, the Commission issued Interlocutory Order No. 32151 that contained our initial findings in this case and authorized changes in the Company's electric rates. We have made numerous revenue requirement decisions and adjustments to the amount allowed in rates. In making these adjustments we address concerns raised by parties and customers and acknowledge the economic conditions and service requirements in the Company's southeast Idaho service territory. In this final Order we affirm the changes in electric rates set out in Order No. 32151 (with Errata), and provide our detailed findings. We also establish a credit value for the interruptible (curtailment) products that Monsanto Company provides to PacifiCorp.

Our prior Order authorized the Company to increase its Idaho electric base revenue by \$13,755,728, or 6.78%. There is no change. The electric rates we approve as just and reasonable are the rates we established in Interlocutory Order No. 32151 (with Errata) and which for ease of reference are set out in attached Attachment A. *Idaho Code* § 61-502. The net amount of actual increase varies by class of customer and usage. With the rate design approved by the Commission in this case, an electric residential Schedule 1 customer using an annual average of 839 kWh per month will realize a \$15.00, or a 1.5% decrease in the customer's annual electric bill.

In this Order the Commission establishes a pro forma electric rate base of \$677,562,962. The Commission reaffirms a return on equity of 9.9% and an overall weighted cost of capital and rate of return of 7.98% as approved in Interlocutory Order No. 32151.

APPLICATION

On May 28, 2010, PacifiCorp dba Rocky Mountain Power (RMP; Company) filed an Application with the Idaho Public Utilities Commission (Commission) for authority to change its electric service schedules to reflect a proposed revenue increase of \$27.698 million, or 13.7%. The Company's request was revised at the technical hearing to \$24.870 million, or 12.3%. Tr. 1171. The Company requests a return on equity (ROE) of 10.6%. The proposed increase is based upon normalized results of operations for the test period ending December 31, 2009, with adjustments for known and measurable changes through December 31, 2010.

Rocky Mountain Power is a public utility engaged in the generation, transmission and distribution of electric power. The Company owns more than 10,000 megawatts of generation from coal, hydro, natural gas-fueled combustion turbines and renewable wind and geothermal power. Without the requested increase in revenues, RMP contends that it will be increasingly difficult for the Company to maintain its utility infrastructure and continue to provide adequate, efficient, just and reasonable service to its Idaho customers. PacifiCorp represents that it is in the midst of a multi-year program of investing in renewable energy, transmission facilities and environmental controls to serve its customers in Idaho and across its six-state system. At a total Company level, the test period includes over \$4 billion of new plant investment and \$87 million in increased power costs.

The Company in its Application requested a Commission Order approving revised electric rates and charges for a proposed effective date of June 28, 2010. The proposed effective date was suspended pending hearing on the Application and further Order of the Commission. Order No. 32001; *Idaho Code* § 61-622. The Company noted that pursuant to special contract, rates under tariff Schedules 400 (Monsanto) and 401 (Nu-West) were to remain unchanged through year-end 2010.¹

¹ In Case No. PAC-E-06-09, Order No. 30197 (approving Monsanto's 2007 Service Agreement), the Commission stated "we expect the parties to address interruptible product valuation in the context of a general rate case when Monsanto's cost of service is determined." In Order No. 32098 (October 22, 2010), we stated our prior direction in Order No. 30197 "was not a suggestion, it was a requirement." In failing to file its interruptible product valuation with its Application, we found that RMP had failed to comply with the Commission's Order. We established additional scheduling for the separated issue of the economic valuation of Monsanto's interruptible products and

APPEARANCES

A technical hearing in Case No. PAC-E-10-07 was held in Boise, Idaho the week of November 30, 2010. The following parties appeared by and through their respective counsel of record:

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| PacifiCorp dba Rocky Mountain Power | Paul J. Hickey, Esq. Daniel Solander, Esq. |
| Monsanto Company | Randall C. Budge, Esq. |
| Idaho Irrigation Pumpers Association, Inc. (IIPA) | Eric L. Olsen, Esq. |
| Idaho Conservation League (ICL) | Benjamin J. Otto, Esq. |
| PacifiCorp Idaho Industrial Customers (PIIC) | Melinda J. Davison, Esq. Ronald L. Williams, Esq. |
| Community Action Partnership Association of Idaho (CAPAI) | Brad M. Purdy, Esq. |
| Commission Staff | Scott D. Woodbury, Esq. D. Neil Price, Esq. |

A continued technical hearing (Economic Valuation of Monsanto Interruptible Products) was held in Boise on February 1, 2011. The following parties appeared by and through their respective counsel of record:

| | |
|--|---|
| PacifiCorp dba Rocky Mountain Power | Paul J. Hickey, Esq. Daniel Solander, Esq. |
| Monsanto Company | Randall C. Budge, Esq. |
| Idaho Irrigation Pumpers Association, Inc. | Eric L. Olsen, Esq. |
| Commission Staff | D. Neil Price, Esq. |

directed the Company to "continue the existing interruptible credit (and terms of service) under the Monsanto contract (2008 Service Agreement) until February 28, 2011."

PUBLIC WORKSHOPS, HEARINGS AND COMMENTS

Prior to the technical hearings in this case, the Commission Staff in September 2010 conducted public workshops in Preston and St. Anthony, Idaho to discuss the Company's Application and to answer customer questions.

Of those who attended hearings or otherwise participated in the public process, nearly 100 people testified at the hearings in eastern Idaho and 4 people testified in the Commission's telephonic hearing. Public testimony hearings were held in Shelley and Rexburg, Idaho on December 14, 2010, and in Grace and Preston, Idaho on December 15, 2010. A telephonic public hearing providing customers with an additional opportunity to offer sworn testimony was held on December 20, 2010.

The Commission also solicited public written comments regarding the Company's Application. Written comments were filed by over 200 customers, area taxing authorities, school districts, municipalities, chambers of commerce, small business owners, farm bureaus, and Idaho Legislators, all concerned about the impact of the rate increase proposed by the Company on the region, communities, area businesses, constituents and families.

As reflected in comments, area businesses, hospitals, schools and homes are struggling financially. It is feared that significant increases in energy costs could cause large employers such as Monsanto to close and that would have a ripple effect through the local communities and economy. Customers of RMP state they have already been asked to tighten their belts. They have been asked to conserve. Many responded by insulating their homes, lowering their thermostats, reducing energy usage, switching to time-of-day rates and off peak usage and installing more efficient light bulbs.

What follows is a small illustrative sampling of comments filed:

- Utility profits should be equal to the state's domestic growth rate.
- Expansion and investment in new plant and equipment need to be adjusted with growth and the economy – we are not in normal times.
- During these economic times, a 10.6% return on equity (ROE) seems absolutely unfair and unreasonable.
- A deviation from time tested and proven hydro and coal generation to wind will create a tremendous financial burden and promote reliability risks for Idaho customers.

- RMP needs to change its attitude and correct the waste in the Company. Wages need to be curtailed and bonus payments need to be curtailed until the economy has returned to normal.
- RMP needs to cut back, spend less and make less just like the rest of the people they serve.
- Costs are going up but our income is staying put. How do you expect us to make it?

DISCUSSION

The Commission has reviewed and considered the filings of record in Case No. PAC-E-10-07 including the transcript of technical proceedings held November 30 through December 2, 2010. We have also considered the public testimony of customers in eastern Idaho and filed public comments. On October 22, 2010, the Commission in Order No. 32098 established further scheduling in this case and tolled the suspension period which was set to expire December 28, 2010. In our Order, we stated our intent to issue an interim or interlocutory Order by December 28, 2010, establishing rates for all tariffs, save and except the interruptible credit portion of Monsanto's Schedule 400. On December 27, 2010, we issued Interlocutory Order No. 32151 establishing new rates. It is those rates and findings that we revisit in this Order. A further technical hearing on the economic valuation of Monsanto's interruptible products was held on February 1, 2011.

The Commission in this Order reaffirms the findings of Interlocutory Order No. 32151. We approve a 12-month test year ending December 31, 2009, adjusted for known and measurable changes through year-end 2010. We approve an average capital structure for RMP through December 31, 2010, consisting of 47.6% debt, 0.3% preferred stock, and 52.1% common equity. We accept a cost of debt of 5.88%, and a preferred stock cost of 5.42%. We approve a return on common equity of 9.9% and an overall weighted cost of capital and rate of return of 7.98%. The interruptible product valuation credit we establish for Monsanto is ■■■■■
■■■■■.

I. TEST YEAR, CAPITAL STRUCTURE AND RATE OF RETURN

A. Test Year

Rocky Mountain Power proposes use of a historic 2009 calendar test year with pro forma adjustments for known and measurable changes through December 31, 2010. Tr. pp. 82, 315. No party opposes the proposed test year.

Commission Findings

The Commission finds use of a 12-month test year ending December 31, 2009 adjusted for known and measurable changes through December 31, 2010 to be reasonable and appropriate. Annualization and normalization adjustments are made to the Company's historical test year revenues and expenses for items that are not reflective of a typical 12-month activity, while other adjustments are made for one-time or nonrecurring items. The matching of test year adjustments will be discussed later with other revenue, expense and rate base adjustments.

B. Capital Structure and Rate of Return

(1) Capital Structure, Cost of Debt (long-term), Cost of Preferred Stock

PacifiCorp's capital structure and cost of debt (long-term) and preferred stock was determined using an average of the five quarters ending balances from the quarter ending December 31, 2009 through the quarter ending December 31, 2010. Tr. p. 315. The Company's proposed capital structure is comprised of the following components: long-term debt, 47.6%; preferred stock, 0.3%; and common stock equity 52.1%.

Commission Staff accepts the Company's proposed capital structure. Tr. pp. 2139, 2145. Staff updates the cost of long-term debt (5.88%) and preferred stock (5.42%) to reflect current information. Tr. pp. 2156, 2157, Exh. 132, Sch. 1, 2. The Company accepts Staff's proposed cost of debt and preferred stock. Tr. p. 328.

Monsanto proposed reducing the Company's common equity component of capital structure from 52.1% to 49.7% by removing equity supporting short-term cash investments (assets not devoted to utility operations). Tr. pp. 855, 856, 866. The Company states these assets are primarily attributable to PacifiCorp's decision to retain all earnings in the utility and build up its common equity balance and are not included in utility plant in service or utility rate base. Tr. p. 856. Monsanto accepts the Company's proposed cost of long-term debt (5.92%) and preferred stock (5.41%). Exh. 202.

RMP contends that Monsanto's recommendation to remove special deposits, short-term investments, and the difference in affiliate notes receivable and payable from the Company's actual common equity component is unreasonable. Monsanto, the Company contends, proposes the use of a hypothetical capital structure without a clear and compelling justification for disregarding PacifiCorp's actual capital structure. Tr. p. 330. RMP disagrees with Monsanto's analysis and conclusions.

As of September 30, 2010, RMP states the Company had exhausted its temporary cash investments, effectively eliminating that aspect of Monsanto's adjustment. Additionally, RMP notes that generally short-term investments are often netted against long-term debt to determine what is known as "net debt." Net debt is used as a financial metric to reflect the Company's net obligation to its bondholders. Nowhere in general finance, RMP contends, is there support for Monsanto's novel proposal to net common equity with cash to derive net common equity. Tr. pp. 330, 331. All of the Company's net cash from operations since acquisition by MEHC, RMP contends, has been reinvested in the business. Furthermore, Monsanto, RMP points out, used a different period of time to determine its proposed hypothetical capital structure. Tr. p. 331.

Commission Findings

The Commission accepts the Company's proposed average capital structure through December 31, 2010, consisting of 47.6% debt, 0.3% preferred stock and 52.1% common equity and Staff's proposed cost of debt (5.88%) and preferred stock (5.42%). We reject Monsanto's adjustments to common equity. RMP rebuttal reflects the nature of these accounts showing that these special deposits and short-term investments were exhausted. The funds have been utilized, therefore no netting is required.

(2) Return on Equity

RMP

Cost of equity is the rate of return that equity investors expect given the risks of an individual security and consistent with returns that are available from other similar investments. The equity return is not directly observable in advance and must be estimated or inferred from capital market data and trading activity. Tr. pp. 366, 367, 371.

RMP estimates the cost of equity for the Company to be 10.6%. Tr. p. 402. The Company's recommendation is supported by discounted cash flow and risk premium analyses

and further review of other economic data. Its discounted cash flow (DCF) analysis generates a resultant return on equity (ROE) range of 10.3% to 10.8%. Exh. 13. Its risk premium analysis indicates a ROE range of 10.39% to 10.59%. Exh. 14. Given what he perceives to be continuing market turbulence, the Company's witness, Samuel Hadaway, contends that RMP's recommended ROE is conservative. Tr. pp. 364, 381, 382; Exh. 11, p. 2; 384, 391. Estimating the cost of equity, he contends, is fundamentally a matter of informed judgment. Tr. p. 366. A combination of DCF and basic equity risk premium methods, Mr. Hadaway contends, provides the most reliable approach for estimating ROE. Tr. p. 374.

Other data considered by the Company in its ROE analysis and assessment of risk includes the volatility in fundamental operating characteristics (Tr. p. 390), credit market gyrations and the volatility of utility shares (Tr. p. 391), the continued transition to more open market conditions and competition (Tr. p. 392), climate change legislation (Tr. p. 392), risks associated with coal-fired generation and greenhouse gas (GHG) emission reduction requirements and permitting requirements for best available control technology for GHGs (Tr. p. 393), fuel price volatility (Tr. p. 393), and ongoing capital requirements (Tr. p. 402).

RMP proposed an 8.357% overall weighted cost of capital.

Monsanto

Monsanto estimates the cost of equity for the Company to be in a 9.1 - 9.9% range with a point value of 9.5%. Monsanto's recommendation is supported by DCF, risk premium and Capital Asset Pricing Model (CAPM) analyses. Tr. pp. 855, 869, 890. Monsanto's witness, Gorman, has applied these models to a group of publicly traded utilities that he has determined reflect investment risk similar to RMP. Tr. pp. 869, 870; Exh. 203. Monsanto's constant growth Discounted Cash Flow (DCF) analysis generates a resultant ROE of 10.45% average and 10.5% median that exceeds the growth rate of the overall U.S. economy or U.S. GDP and are unsustainable. Tr. pp. 874-876. Its sustainable growth DCF analyses generates a resultant ROE of 9.92% average and 9.14% median. A sustainable growth rate is based on the percentage of the utility's earnings that are retained and reinvested in utility plant and equipment. Tr. pp. 876, 877. Its multi-stage growth DCF analysis generates a resultant ROE of 9.87% average and 9.90% median. The multi-stage growth DCF model reflects the possibility of non-constant growth for a Company over time. Tr. p. 878. The results of Monsanto's DCF analyses produce an average DCF return of 9.85%. Tr. pp. 880.881.

Monsanto's risk premium analysis produces a return estimate in the range of 8.98% to 9.94%, with a midpoint estimate of 9.46%. Tr. pp. 881-885. Monsanto's CAPM analysis produces a return in the range of 8.28% to 9.31%, with a midpoint estimate of 8.80%. The CAPM method of analysis is based upon the theory that the market required rate of return for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. Tr. pp. 885-890.

RMP is an operating division of PacifiCorp, which is owned by MidAmerican Energy Holdings Company (MEHC). PacifiCorp issues debt and equity on behalf of RMP. PacifiCorp's current senior secured bond rating from S&P and Moody's are "A" and "A2," respectively. PacifiCorp's corporate credit ratings from S&P and Moody's are "A-" and "Baa1," respectively.

Monsanto believes a 9.5% ROE will support internal cash flows that will be adequate to maintain RMP's current investment grade bond rating. Tr. p. 895. Based on its recommended ROE and capital structure, Monsanto recommends an overall rate of return of 7.70%. Tr. p. 895.

Commission Staff

Staff estimates the cost of equity for the Company to be in a 9.5 to 10.5% range with a point value of 10%. Tr. p. 2138. Staff's recommendation is supported by DCF and comparable earnings analyses. Tr. pp. 2145, 2150. Staff's DCF range is 8.8 - 9.3% (Tr. p. 2155), its comparable earnings range is 9 - 10.5%. Staff's recommended range and 10.0% ROE point estimate is based on a review of market data and comparables; average risk for PacifiCorp operating characteristics and the Company's capital structure. It also considers the reduced risk of PacifiCorp for the Energy Cost Adjustment Mechanism (ECAM) (Tr. pp. 2152, 2153) and the increased risk for PacifiCorp itself for the recovery risk caused by the recommended change in allocation of Irrigation Load Control Program costs. The adjustments proposed by Staff moving plant in service to plant held for future use will delay recovery and impact cash flows. Tr. pp. 2157, 2158. PacifiCorp, Staff contends, continues to be in a better position than many utilities to fund its near-term capital requirements with its current debt authority and equity levels. Tr. p. 2153.

Staff recommends an overall weighted cost of capital for the Company in the range of 7.769 - 8.29% with a point estimate of 8.03% to be applied to rate base for the test year. Tr. p. 2139.

Commission Findings

All parties providing testimony on RMP's cost of equity accurately recount the accepted standards to be applied. The standards for determining a fair cost of common equity for a regulated utility have been framed by two decisions of the U.S. Supreme Court: *Bluefield Water Works & Improvement Co. v. Public Serv. Commission of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). The standards to be considered provide that the authorized return should: (1) be sufficient to maintain financial integrity; (2) be sufficient to attract capital under reasonable terms; and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

In this case, the parties have advanced different methodologies to analyze and ascertain a fair rate of return on common equity capital, including Discounted Cash Flow (DCF), risk premium analysis, capital asset pricing model (CAPM) and the comparable earnings method. Each method attempts to establish a rate of return on common equity at a point sufficiently attractive that free market investors will consider purchasing common equity shares in the company. As with other analytical tools used in the ratemaking process, the methods to evaluate a common equity rate of return are imperfect predictors of future requirements and performance. Additionally, the authorized rate of return on equity specified by a regulatory agency is but one factor considered by prudent investors when evaluating a utility's stock. A utility's stock performance in the marketplace is determined by many variables, including management decisions, weather, streamflow conditions, and a host of separate economic factors.

This Commission has found it reasonable in the past to primarily rely on DCF and the comparable earnings method to determine an appropriate rate of return on common equity. We have confidence in these approaches and primarily rely on them in this case. The DCF analysis utilizes the dividend rate, stock price and expected growth rate of a company to quantify the return required by the investor. The comparable earnings method evaluates returns earned by other companies, including utilities, to quantify an investor's expected return, taking into account the risks associated with a particular investment. A third methodology to determine a required rate of return on common equity is the risk premium analysis. The risk premium method starts with the rate of return for a low-risk investment, such as government or utility bonds, and adds a premium based on the relative risk associated with a utility's stock. A fourth method, the capital

asset pricing model (CAPM) measures risks using the Beta coefficient. The return on equity is measured in relation to the market as a whole. As markets change, new concerns develop in various financial circles related to the calculations used to determine the cost of equity.

We find that RMP has, in this case, downplayed the poor economic conditions that exist in its Idaho service territory where many are on fixed incomes, unemployed and underemployed. This Commission cannot discount as simply anecdotal the testimony and comments of RMP customers. While we cannot say "No" to a requested increase in rates because customers are uniform in their opposition, together their testimony serves as the real-life context and backdrop of our decision. Their testimonies and comments remind us that we are not engaged in simply an academic exercise dealing in regulatory principles, generalities and industry averages. Our decision has real consequences. RMP is not immune or shielded from the state of the local economies in its service area. They are a factor in our decision as to what is fair, just and reasonable. RMP is part of the economy, not separate from it. If the economy is ailing, it is reflected in our decisions. We recognize that for some customers any increase may result in economic hardship. That said, we have a dual obligation in rate cases. To customers our task is to establish rates that are fair and reasonable. To the Company we have a statutory obligation to set rates at a level sufficient to allow RMP the opportunity to recover its reasonable expenses of operation and receive a reasonable return on prudent capital investments in utility plant and facilities. Carrying out this duty is necessary for the Company to be financially sound and capable of providing its customers with safe and reliable electric service. Our decision-making requires mindful consideration of our statutory obligations and a balancing of interests.

The Commission has considered all methodologies and rationale in the cost of capital testimony of the witnesses and finds the middle ground position advanced by Staff witness Carlock to be reasonable. The recent rates of return on equity for Idaho Power and Avista cited by the Company are distinguishable. Idaho Power's 10.5% ROE was utilized for Stipulation and was not contested. Avista's 10.25% ROE resulted from and was part of settlement terms. The evidence in this case supports a rate of return on common equity for PacifiCorp ranging from 9.5 - 10.5%. The higher end of this range encompasses the mid-range of PacifiCorp's recommended DCF range of 10.3 - 10.8%. This range also encompasses the middle range of approximating the 9.85% average DCF return recommended by Monsanto. We find PacifiCorp's reasonable required rate of return on common equity to be 9.9%. In authorizing a 9.9% return on common

equity, this Commission reaffirms its desire to maintain PacifiCorp as a financially viable utility with credit ratings at or above the current level.

The use of this cost of common equity together with the cost of long-term debt, cost of preferred stock and capital structure previously found, yields the following overall return for rate base:

| Component | Percentage of Capital Structure | Cost | Weighted Cost |
|------------------|--|-------------|----------------------|
| Debt | 47.6% | 5.88% | 2.80 |
| Preferred Stock | 0.3% | 5.42% | 0.02 |
| Common Equity | <u>52.1%</u> | 9.9% | <u>5.16</u> |
| TOTAL | 100.00% | | 7.98% |

Many of the adjustments accepted by the Commission, summarized below, reduced some of the revenue requirement in this case. However, the majority of Company expenditures are reasonable and have been approved for recovery.

The capital structure authorized is strong. It reflects the business strength of PacifiCorp and the overall regulatory support. This decision supports capitalization requirements by rejecting proposals to reduce equity balances. In separate security filings, the Commission has authorized PacifiCorp to maintain adequate equity and debt authority thereby allowing PacifiCorp to access capital markets at reasonable costs.

The Populus to Terminal adjustment, we note, allows 73% of the investment in rates currently and places 27% of plant investment that was adjusted in the plant held for future use account. This is not a disallowance requiring a write off but a deferral until the project is used and useful.

The coal stockpile adjustment is a reduction in the current case. However, it also allows a three-year transition to increase the coal stockpile. The coal studies referenced by the Company may provide analysis showing appropriate stockpile levels, with appropriate rationale and documentation.

RMP has an energy cost adjustment mechanism (ECAM) approved in Idaho. Decisions where the power costs were not sufficiently known or adequately documented, reduce the power cost level in base rates. However, the actual costs will be included in the ECAM rate changes. This is a deferral of cost recovery not a disallowance.

Finally, contrary to the belief of many of RMP's customers, we recognize that the Company does not have direct access to Berkshire Hathaway money. The cost of common equity we establish above reflects a Company risk which, we find, is tempered by annual adjustments that we have authorized and the Company's ability and stated intention to request rate increases more frequently.

II. ADJUSTMENTS TO TEST YEAR REVENUES, EXPENSES AND RATE BASE

A. Agreed Upon Adjustments

Once a test year is selected, adjustments are made to test year accounts and rate base to reflect known and measurable changes so that test year totals accurately reflect anticipated amounts for the future period when rates will be in effect. The Idaho Supreme Court has described "rate base" as "the utility's capital investment amount." *Industrial Customers of Idaho Power v. Idaho PUC*, 134 Idaho 285, 291, 1 P.3d 786, 792 (2000). Adjustments to test year accounts generally fall into three categories: (1) normalizing adjustments made for unusual occurrences, like one-time events or extreme weather conditions, so they do not unduly affect the test year; (2) annualizing adjustments made for events that occurred at some point in the test year to average their effect as if they had been in existence during the entire year; and (3) known and measurable adjustments made to include events that occur outside the test year but will continue in the future to affect Company income and expenses.

RMP determined revenues and expenses for its 2009 test year in the same way it established a test year rate base. The Company started with 2009 actual figures and made known and measurable adjustments to specific revenue and expense accounts it deemed appropriate for regulatory purposes and made adjustments using extended forecast period through December 31, 2010.

Staff and other parties raised some objections to the Company's 2009 actual revenue and expense items as well to the Company's proposed adjustments. All of the challenges and recommended account adjustments affect the test year revenue requirement.

As reflected in RMP rebuttal Exhibit 79 (tab 11), the Company on rebuttal agreed to a number of adjustments in net operating income and/or rate base proposed by intervenors and Staff. RMP proposed an updated additional adjustment (\$1.8 million bonus depreciation deduction) not included in its initial filing. The updated adjustment proposed by the Company

incorporates a change in bonus depreciation law. The Small Business Jobs Act of 2010 (enacted September 27, 2010) extended the 50% bonus depreciation allowance for qualifying assets for one year (calendar year 2010). Tr. p. 1170. The revised revenue requirement in the Company's rebuttal case reduced its original request of \$27.698 million (13.7%) in increased revenue by \$2.8 million to a rebuttal requested revenue increase of \$24.870 million (12.3%). Tr. p. 1169. The Company's revised request incorporates the following rebuttal adjustments:

| Original Request | Proposed Revenue Increase |
|---|--------------------------------------|
| | \$27,698,000 |
| | (Adjustment figures are in \$1,000s) |
| Rebuttal Adjustments | |
| Cost of Debt and Preferred (Tr. p. 1171) | (127) |
| Bridger Unit 2 Overhaul Liquidated Damages (Tr. p. 1172) | (2) |
| Medicare Subsidy (Tr. p. 1173) | (5) |
| Avian Settlement (Tr. pp. 1174-1176) | (10) |
| Generation Overhaul Expense (Tr. p. 1177) | (82) |
| Major Plant Additions – Plant in Service (Tr. pp. 1179-1180) | (226) |
| Major Plant Additions – Tax Impact | (1,784) |
| Major Plant Additions – Depreciation Expense | (45) |
| Major Plant Additions – Depreciation Reserve | 7 |
| Net Power Costs (Tr. p. 1180) | (274) |
| SO2 Sales (Tr. p. 1180) | (280) |
| Rebuttal Revenue Increase | \$24,870,000 |

Exh. 79, Tab 11; Tr. p. 1171.

Commission Findings

We accept RMP's rebuttal adjustments as fair and reasonable and acknowledge that the Company's requested revenue increase amount has been reduced to \$24,870,000 or 12.3%.

B. Disputed Adjustments

(1) Revenues

(a) Change in Disconnect Policy

RMP has a policy of not physically disconnecting electric service when a customer closes an account and discontinues service until metered usage exceeds a 1,000 kWh threshold (previously 400 kWh). Tr. p. 2061. As a result, energy continues to be used even though there is no customer to bill for that usage. Tr. pp. 2059, 2060.

RMP, Commission Staff contends, maintains that most premises are only vacant for a few days between customers. According to the Company, by not physically disconnecting service after a customer discontinues service, the Company realizes a dollar savings in employee time and vehicle mileage. Tr. p. 2060.

Based on its investigation, Staff contends that the presumed net benefit of RMP's policy of not disconnecting service may be more myth than fact. Tr. p. 2060. In 2009, Staff states there were 835 instances where usage exceeded 1,000 kWh, meaning at least 835,000 kWh was unbilled. The majority of affected accounts were residential. Tr. p. 2061. Staff estimates that in excess of 1,000,000 kWh went unbilled in 2009 due to this policy. Based on the current average residential rate, Staff calculates that more than \$90,000 in revenue was foregone by the Company in 2009. Tr. p. 2062. In promoting conservation and engaging in energy wasting practices, Staff contends the Company is sending mixed signals. Staff recommends that the Company change its policy.

RMP in rebuttal disagrees with Staff's contention that the net benefit of the Company's current policy may be "more myth than fact." The Company believes its current policy is cost-effective. Tr. p. 1051. Of 7,837 accounts closed in 2009, the Company states there were only 835 instances where field orders to disconnect service were generated for unbilled usage of 1,000 kWh or greater. Of these 835 instances, the Company states that approximately 42% of the orders resulted in a customer taking responsibility for the unbilled usage after receiving a notice of disconnection or having the service disconnected. The usage for 2009 lost as a result of the remaining sites where unbilled usage was not recovered, the Company states, was 798,319 kWh. Based on an average of 8¢/kWh, the unbilled revenues would be approximately \$63,866. Tr. p. 2052. Based on current activity rates of the personnel needed to disconnect electric service, the Company estimates the approximate cost for completing the 7,837 requests would be \$178,183. Then, when a new customer requests service at the site, the Company would again need to dispatch personnel to connect the service. This would increase the costs to \$356,366. By comparison, the total cost for the current process is approximately \$180,621. Tr. p. 1503. The Company states that it would seek to recover any additional costs occasioned by following Staff's recommendation through customer rates and/or fees. Tr. p. 1056.

Advancing non-economic reasons for maintaining the current policy, the Company states a change in disconnect policy would present an increase in the safety risks inherent every time a field metering specialist disconnects or connects a meter. Also it would require additional manpower, could cause customer dissatisfaction, and could increase the number of customer guarantee failures. Tr. p. 1056.

RMP does not believe the Company is sending mixed signals to customers when it encourages conservation but leaves service connected when there is no customer. The economic costs of disconnecting the power at all premises, the Company believes, outweigh the benefits realized by a change in policy. Tr. p. 1057.

Commission Findings

The Commission is persuaded that Staff's position is correct. We are concerned that the Company makes part of its economic argument on the fact that in 43% of 835 instances where field orders were generated for unbilled usage of 1,000 kWh or greater, ". . . customers [took] responsibility for the unbilled usage after receiving a notice of disconnection or having services disconnected." This appears to constitute a threat to a connecting or reconnecting customer to pay the unbilled usage, or else. Until this issue can be resolved, we accept Staff's recommendation. The impact of our decision is a revenue requirement adjustment of \$90,161.

(b) Uncollectibles

RMP has included in its filing the actual 2009 test year level of uncollectibles adjusted for known and measurable events (\$472,263). Tr. pp. 1200, 1675. PIIC contends that the 2009 test year amount is the highest in three years and recommends using a historical four-year average of uncollectibles expense. Tr. p. 1639. The following is a table depicting the Company's level of uncollectible expense and recorded revenues from 2006 through 2009.

| Uncollectible Expense by Year | | |
|--------------------------------------|---------------|-----------------|
| Year | Amount | Revenues |
| 2006 | \$529,196 | \$140,250,947 |
| 2007 | 308,510 | 182,699,838 |
| 2008 | 303,856 | 197,505,456 |
| 2009 | 472,263 | 184,995,386 |

RMP in rebuttal contends that this recommendation is another example of an adjustment that isolates a single expense account to produce a reduction to revenue requirement. The Company contends that the proposed adjustment is unreasonable and inappropriate. PIIC's

method, the Company contends, fails to account for conditions during the rate effective period. The Company states it has experienced a steady increase in uncollectible expense since 2008. Tr. pp. 1200, 1201.

The proposed averaging method, RMP states, produces a 2010 uncollectible expense level that is below the actual expense for the first 10 months of 2010 (\$652,554). Adopting PIIC's adjustment, RMP contends, would result in under-recovery of the Company's uncollectible expense. Tr. p. 1201.

Commission Findings

The Commission has considered the arguments presented and finds use of an average of uncollectible expense to be preferable to use of a single test year amount. PIIC recommends four years. To be consistent with our practice elsewhere in this Order, we find it reasonable to require use of a three-year average (2007-2009) for uncollectible expense. A three-year average results in a reduction of \$110,720 (Idaho) from the uncollectible level included in the Company's case.

(c) Other Revenue Adjustments

The other revenue adjustments proposed by parties are either agreed to or the Commission accepts the Company's position. Therefore, we address them together. The Commission accepts use of a five-year average to reflect SO2 emission credit sales revenue. The Commission accepts the Company's rebuttal position related to normalization considerations related to residential and irrigation usage. We also accept that the One Utah Center rental agreement is properly reflected below the line. All of these issues are reflected in the Company's rebuttal numbers, making no further adjustments necessary.

Renewable Energy Credit (REC) revenues will be included as a revenue credit in the Company's ECAM filings. The base level of REC revenue will be \$91,779,696 on a total system basis, \$7,031,166 Idaho.

(2) *Operating Expenses*

(a) Wage Increase

In RMP's filing, actual December 31, 2009 labor related expenses are annualized to reflect any increases that occurred in 2009 as being included for a full 12 months. The annualized 2009 labor expenses were then escalated at either the contractual increase for union employees or the actual increase for non-union employees to reflect a 2010 pro forma budgeted

amount. In 2009, non-union employees received a 3.5% wage increase, while the union employees received between 1.25% and 3%. In 2010, the non-union employees received an increase of 0.88% while the union employees received between 1.5% and 2.5%.

Commission Staff proposes that all wage increases awarded by the Company to its employees during 2009 and 2010 be disallowed in rates, or an employee wage adjustment of (\$14,375.075). This adjustment by Staff sets the level of straight-time labor at the January 1, 2009 level. Tr. p. 2008, Exh. 104. As justification for its adjustment, Staff cites economic conditions in the Company's Idaho service territory. Exh. 115, 116. Unemployment rates have increased. Wages and the consumer price index have remained relatively flat. Those on Social Security received no cost of living adjustments for 2010 and 2011. Many Idaho state employees were forced to take furloughs. While much of the population struggles, Staff argues that it is not prudent for utility companies to continue to grant increases to its employees. Staff believes also that the Company could have done a better job these last two years in controlling costs. Tr. p. 2009.

RMP in rebuttal states that the wage increase levels for its union population are set as part of a collective bargaining process typically covering multiple years and are part of many considerations such as work rules, benefits, and retirement. Together the variables deliver a competitive set of benefits and compensation. The wage levels are part of contracts, the Company argues, that were prudently entered into by management and are known and measurable in the test period and should be provided full cost recovery. Tr. p. 840.

RMP states that the 2009-2010 wage increase levels for its non-union employees are set by reviewing market data for labor wage adjustments and positioned at the market average. For 2009, the Company contends, an increase level of 3.5% was market competitive. Tr. p. 841, Exh. 70. For 2010, the Company states it factored in the economic crisis and conditions facing its customers and implemented a 2010 wage increase slightly below-market practices, awarding increases only to those employees who received a base compensation below \$100,000. Tr. p. 841.

Commission Findings

The Commission finds that in challenging economic times the local economy in the Company's service area is a greater indicator as to the appropriateness of a wage increase than market data and industry averages. We find no demonstration by the Company that the union

and non-union wage increases were required for the Company to be a competitive employer able to retain or attract employees. We find no evidence that without the union and non-union wage increase the service provided by the Company would be degraded and safety compromised. We find that as a certificated provider of service RMP has elected to be a member of the communities it serves. We find Staff's proposed wage adjustment to be reasonable. The Company may choose to implement its wage increases, but we will not allow recovery of that expense from its Idaho customers.

(b) Incentive Compensation

As part of our review of employee compensation we evaluated wage increases, incentive compensation and pension expense. We believe incentive compensation can be an important component of base pay. With our wage adjustments, we accept RMP's position that these incentives are an at-risk piece of base pay. We caution RMP to only reflect incentives tied to operational efficiency, customer service and safety for inclusion in base rates. The at-risk incentives must benefit customers. We find our adjustment to wages to be reasonable making further adjustment to the at-risk incentives unnecessary.

(c) Pension Expenses

RMP in its filing requests recovery of its 2010 actual cash contributions to its pension plan, \$104.8 million for 2010 on a total system basis. Commission Staff stated that, as of the date it prepared testimony, the Company's 2010 actuarial valuation had not been completed. The Company provided no detailed calculations from its actuaries illustrating how the \$104.8 million contribution was calculated. The estimated future contributions calculated by the Company's actuaries, Staff represents, indicate a significant decrease in pension funding in future years, and approximately twice as much in 2011 as in 2010. Staff recommends using a five-year projected average of pension contributions (2010-2014) rather than just 2010 resulting in a total Company adjustment of (\$20,875,647). Tr. pp. 2003, 2004; Exh. 104 and 105; Conf. Exh. 106.

RMP in rebuttal rejects Staff's proposed adjustment and recommends continuing on a cash basis. Exh. 2, p. 4, 13. If the Commission finds use of an average reasonable, the Company recommends a three-year historical average (2008-2010) resulting in an adjustment of (\$19.11 million (total Company)). Tr. pp. 1191, 1192, 336, 337.

Actual cash contributions to fund the pension plan in 2010 was \$112.8 million. Tr. p. 335. The Company made an additional \$8 million contribution during 2010 in order to help

improve the funded status of the pension plan. The resulting funded ratio with a 2010 contribution of \$104.8 million would have been 79.45%. Plans with funded ratios below 80% are subject to restrictions and place the plan in "at risk" status as of January 1, 2011, causing a significant increase in the 2011 minimum funding requirement. Tr. p. 335.

If the Commission adopts Staff's forward-looking five-year average proposal, the Company contends it would assure under recovery of 60-80% of the 2010 contributions depending on the timing of the Company's next rate case. Tr. p. 338.

Commission Findings

The Commission will accept as reasonable in this case the three-year historical average of actual pension contributions (2008-2010) identified by RMP in its rebuttal case. We find that the averaging method has merit; that regulation favors a consistent approach; and that regulation should afford a utility a reasonable opportunity to recover its prudently incurred costs.

(d) Supplemental Executive Retirement Plan (SERP) Costs

RMP contends that the Company's Supplemental Executive Retirement Plan (SERP) expense is related to a market competitive benefit offering. The Company's primary objective in establishing employee compensation, it states, is to provide pay at the market average. Compensation at the market average (competitive level), the Company contends, is critical to attracting and retaining qualified employees to support the business and its customers. Tr. p. 825.

Commission Staff recommends that SERP costs in this case (\$2.6 million total system) be disallowed as these benefits, Staff contends, are above and beyond those covered in more conventional retirement plans and are intended to ensure the Company's executives can maintain the same standard of living in retirement. Ratepayers, Staff contends, should not bear costs beyond the retirement benefits available to rank and file employees. Tr. pp. 2005, 2006.

RMP disagrees with Staff's assessment and proposed adjustment. These are not extra, unnecessary or excessive benefits, the Company contends. RMP provides programs/plans, it states, at the market average (no better and no worse). The Company states it no longer offers the SERP benefit to new participants. The expenses sought in this case are related to one active participant (the President of RMP) and past participants who, during their employment, the Company contends, delivered value to then current customers, while also shaping the Company

to benefit future (current) customers. The Company honors its commitment to continue to fund SERP expenses. Tr. p. 842.

Commission Findings

The Commission finds Staff's argument persuasive and finds it reasonable to disallow Company recovery of SERP costs of \$2.6 million (total Company) in this case. The Company has not demonstrated that the costs are related to providing services to southeast Idaho. The responsibility for generous severance benefits for executives, we find, is the responsibility of the Company and its shareholders, not Idaho customers.

(e) MEHC Management Fees

RMP pays an annual "Management Fee" to MidAmerican Energy Holding Company (MEHC) under an "Inter Company Administrative Services Agreement."

Pursuant to MEHC acquisition Commitment I28,

MEHC and PacifiCorp will hold customers harmless for increase in costs retained by PacifiCorp that were previously assigned to affiliates related to management fees . . . this commitment is off settable to the extent PacifiCorp demonstrates to the Commission's satisfaction, in the context of a general rate case the following:

- i. corporate allocations from MEHC to PacifiCorp included in PacifiCorp's rates are less than \$7.3 million.

Tr. p. 1155.

Staff proposes to reduce MEHC management fees allocated to PacifiCorp. Staff acknowledges that the Company limited the amount of allocations from MEHC to PacifiCorp to \$7.3 million. However, Staff contends that included in the \$7.3 million allocation from MEHC is \$2.15 million in Supplemental Executive Retirement Plan (SERP) contributions and bonuses to employees of MidAmerican. Staff's adjustment, it states, is a logical continuation of adjustments recommended for RMP employees. Tr. pp. 2009, 2010. Staff's related adjustment is (\$1,100,635) on a total Company basis. Exh. 107.

PIIC recommends that \$2.1 million (incentive compensation and legislative costs and contributions) on a total Company basis be disallowed, an adjustment of (\$111,601) Idaho. Tr. p. 1667. PIIC contends that the MEHC acquisition commitment cap is the upper limit for these charges, and disallowances should be further reductions below the cap. PIIC contends that since its proposal to remove \$2.1 million is greater than the \$1.1 million reduction the Company made

to arrive at the capped level further adjustment is warranted. Tr. p. 1668. PIIC contends that bonuses paid to MEHC and MEC executives are tied to performance of PacifiCorp's parent company and are not closely aligned to customer-related performance at the utility level. Tr. p. 1669. PIIC believes costs associated with lobbying or influencing legislation should be prohibited from recovery through rates. Tr. p. 1669.

RMP in rebuttal maintains that the SERP and incentive compensation that Staff and PIIC seek to remove are individual components of total compensation packages similar to those provided to PacifiCorp employees and are appropriately included in regulated results. Tr. p. 1193. RMP agrees that costs strictly related to the Company's legislative activity should not be included in regulated results, but contrary to PIIC's assertion, RMP states, the Company has capped the level of MEHC management fee expenses in this case and excluded the \$330,636 in legislative costs from results. Exh. 2, p. 4.8. PIIC, the Company contends, is removing costs that are not included in the case. Tr. pp. 1193-1195.

RMP admits that the Company's downward adjustment reduced the expenses booked above-the-line from \$8.4 million to \$7.3 million, but states PIIC fails to consider that a portion of the \$11.6 million management fee billed to PacifiCorp in 2009 was not booked above-the-line to begin with. Tr. pp. 1194, 1195.

Commission Findings

The Commission finds that RMP has appropriately excluded the legislative costs billed to PacifiCorp by MEHC from the MEHC management fees it seeks to recover. We find Staff's adjustment removing SERP and bonuses to employees of MidAmerican to be reasonable. We find that the Company has failed to demonstrate that these fees are related to the Company's Idaho service obligation and that Idaho customers should be required to pay this expense.

(f) Outside Services Expense

RMP in this case requests inclusion in its base rates the test year level of outside services expense. PIIC contends that the 2009 expense level (\$1,209,260) is too high and recommends that outside services expense be based on a four-year average of expenses from 2006-2009. Tr. p. 1639. The effect of this adjustment reduces revenue requirement by \$327,080 (Idaho). Tr. p. 1640.

Outside services expense includes expenses for outside services such as legal and engineering. The following table reflects the levels of outside services expense assigned to RMP's Idaho operations.

| Outside Services Expense by Year | |
|---|----------------------|
| <u>Year</u> | <u>Amount</u> |
| 2006 | \$1,067,814 |
| 2007 | 580,987 |
| 2008 | 670,661 |
| 2009 | 1,209,260 |
| Four-year Average | 882,181 |

Tr. p. 1670. A four-year average of outside services expense would reduce RMP's Idaho cost of service by \$327,080. Tr. p. 1671.

RMP in rebuttal contends that the level of expense or revenue change over time is, by itself, no reason to use an average. PIIC, the Company states, does not take issue with the prudence of any of the specific costs contained within the base period outside services expense. The Company contends that the level of outside services expense in the base period is reasonable and that fluctuations from year-to-year are normal. Tr. p. 1197. Accepting PIIC's adjustment, RMP contends, would be unfair and would not provide the Company a reasonable opportunity to recover its costs of providing service to customers. Tr. p. 1199.

Commission Findings

The Commission finds that the Company's outside services expense varies significantly from year-to-year. With this type of variation the Commission often utilizes averages. We find the Company's argument against using an average to be unpersuasive. PIIC recommends using a four-year average. We find use of a three-year average of outside services expense to be reasonable and consistent with the approach this Commission follows in this and other rate cases. The three-year average results in a reduction of \$388,957 (Idaho) to the level of outside services included by the Company in this case.

(g) Other Expense Adjustments

The remaining expense adjustments (excluding power supply costs) proposed by the parties are either agreed to or the Commission accepts the Company's position. The Medicare subsidy and a portion of the Avian settlement were agreed to by the Company. We accept the Company's position to use a three-year average for injuries and damages. We also accept the

Company number for the expense portion of the Avian settlement, property tax expense and the incremental 2010 O&M expenses for Company-owned wind projects.

(3) Irrigation Load Control Program

(a) Expenses and Jurisdictional Treatment

The Idaho Irrigation Load Control Program is offered to Idaho irrigation customers receiving retail electric service under Schedule 10. Participants agree to allow the Company to curtail their electricity usage, and in exchange participants receive credits valued on a per kilowatt basis. The Idaho Irrigation Load Control Program is provided under Schedules 72 and 72A. Schedule 72 is a prescheduled service interruption, whereas Schedule 72A is a dispatchable service interruption. Tr. pp. 1940, 1941.

Commission Staff contends that RMP's Idaho Irrigation Load Control Program has evolved since inception to a point that it now provides PacifiCorp a valuable system resource. Dispatchable service interruption, under Schedule 72A contracts, allows PacifiCorp to reduce loads during peak periods and during outages at generation plants. These contracts provide system flexibility. The interruptions are large enough (over 200 MW load reduction capability) and are reliable enough to allow PacifiCorp to utilize these interruptions as a resource for planning purposes in the Company's Integrated Resource Plan (IRP). The Idaho Irrigation Load Control Program contracts are more like power purchase agreements or ancillary service contracts, Staff contends, and should be classified as such and treated the same for allocation purposes. Tr. pp. 2139, 2140.

The current designation, Staff contends, is appropriate for IRP and DSM assessment purposes but is not appropriate for allocation purposes in a state where the state loads are a small percentage of the system operations. The program's success, Staff contends, has outgrown the benefits that can be attributed to Idaho alone. The system operations rather than the state loads are the driver to evaluate cost-effectiveness. Tr. p. 2141. Between 2007 and 2009 with increased participation, the annual megawatts available for interruption increased from 78 MW to 276 MW (a 250% increase). Tr. p. 2144.

As reported by Staff, the PacifiCorp system receives a benefit of approximately \$20 million (2009 DSM Report) due to avoidance or delay of generation. The total program costs, including irrigation payments for interruption, are \$11.4 million. Tr. p. 2141. As calculated by Staff, a simple cost/benefit analysis shows how the costs do not follow the system benefits,

creating a mismatch to the detriment of Idaho customers. This mismatch, Staff contends, needs to be corrected. Tr. p. 2141. Staff recommends that Irrigation Load Control Program costs be assigned as a power supply cost. Staff believes that its proposal is not a violation of the jurisdiction Revised Protocol allocation methodology and advises the Commission that the Multi-State Process Standing Committee is addressing this issue. Reference Revised Protocol, Case No. PAC-E-02-3, Order No. 29708 adopted February 28, 2005. Staff also notes the current in-house Company filing for Revised Protocol amendments, Case No. PAC-E-10-09. Staff in this case accepts the Company's Revised Protocol allocation methodology with the exception of the proposed treatment of Idaho Irrigation Load Control Program costs. Tr. p. 1933. Staff recommends that costs associated with the Idaho Irrigation Load Control Program be treated as system power supply expenses instead of being directly assigned to the Idaho jurisdiction. Tr. p. 1934.

RMP proposes to assign all \$11.4 million in program costs situs to customers in the Idaho jurisdiction. The Company then credits or decrements the Idaho jurisdictional demand allocator used in the allocation of system costs to Idaho. The reduced jurisdictional allocation factor, reflecting the demand reducing effect of the Idaho Irrigation Load Control Program, benefits Idaho customers by reducing the Idaho jurisdictional revenue requirement by approximately \$7.48 million. Tr. pp. 1942, 1943. The net effect is that directly assigned Idaho program costs of \$11.4 million exceed allocated Idaho revenue requirement benefits of \$7.48 million by approximately \$3.9 million a year. Tr. pp. 1943, 1944. Staff contends that the proposed allocation method is unreasonable. Staff proposes that the Company treat the program costs as a system purchase power cost and allocate them just as it would any other system power supply expense. This, Staff contends, will assure that the costs allocated to each jurisdiction follow the benefits received by each jurisdiction. Tr. p. 1945.

The revenue requirement effect of treating Idaho Irrigation Load Control Program costs as a system power supply expense in jurisdictional cost allocation would be a reduction in Idaho's net revenue requirement of approximately \$3.25 million when Idaho Irrigation Load Control Program costs previously collected through the tariff rider are included. Under the Staff's proposal the reduction in revenue requirement collected from Idaho would be collected from PacifiCorp's other jurisdictions through the dynamic system cost allocation of additional system power supply expenses.

RMP in rebuttal agrees with the rationale behind Staff's recommendation but, the Company states it is placed in a difficult position by Staff's proposal. A reallocation of costs would shift program costs away from Idaho to other states before the issue has been addressed and resolved by the Multi-State Process (MSP) Standing Committee or factored into cost recovery filings in its other jurisdictional states. As a result, RMP believes that 2011 should be treated as a transitional year to afford the Company and Staff the opportunity to work together to address the treatment of Class 1 DSM resources with the MSP Standing Committee. Additionally, the Company believes that certain changes need to be made to the Irrigation Load Control Program to increase its cost-effectiveness and resolve operational issues that have been identified during the last two years as the program rapidly expanded. Tr. p. 595.

RMP proposes that the Irrigation Load Control Program continue to be treated as situs assigned costs during 2011 to allow the issue to be addressed with other states through the MSP process. Tr. p. 595.

Commission Findings

The Commission finds that there is inequity in continuing with the current jurisdictional treatment of the Irrigation Load Control Program expenses. Cost recovery from other jurisdictions represent a timing issue for the Company. The Company proposes that 2011 be a transition year. We find that it is unreasonable to expect Idaho customers to continue to bear the costs associated with the current jurisdictional treatment of the Irrigation Load Control Program. We accordingly find it reasonable to adopt Staff's proposed adjustment and change in the Idaho treatment of Irrigation Load Control Program expenses. Our immediate change provides impetus for RMP to act quickly in addressing the change in its other jurisdictional states. We further find our actions to be in accordance with the Commission's authority retained in our approval of the Revised Protocol. These program expenses will no longer be flowed through the Company's tariff rider. Instead, Idaho's share of program costs will be shifted to base rates. We further decline to make Company-proposed modification to the Idaho Irrigation Load Control Program as part of this case. Our decision treating the program costs of the Irrigation Load Control Program as a system cost allows a reduction to the Customer Efficiency Services Tariff Rider from 4.72% to 3.4%.

(4) Net Power Costs

The system base net power cost (NPC) number we establish in this case is derived by making three adjustments to the Company's rebuttal NPC number:

| | System Costs |
|--|----------------------|
| RMP Net Power Costs as Filed (Rebuttal) | 1,063,230,027* |
| Less: Commission Adjustments | |
| Wind Integration Costs | (34,187,931) |
| Cal ISO Wheeling & Service Fees | (4,041,991) |
| Normalization of Call Option Contracts | (1,293,489) |
| Total Adjustments | <u>(39,523,411)</u> |
| Net Power Costs per Commission Order | <u>1,023,706,616</u> |

*Exh. 71; Exh. 79, Tab 11.9.1; 11.9.4

(a) Wind Integration Costs

RMP in this filing uses \$6.50 per megawatt-hour (MWh) to calculate the costs of integrating intermittent wind generation into the Company's system, the same wind integration charge approved by the Commission in Case No. PAC-E-09-07 for setting published avoided cost rates in Idaho for mandatory purchases pursuant to the Public Utility Regulatory Policies Act of 1978 (PURPA). Tr. pp. 926, 934, 935. The Company's net power cost calculation includes approximately \$34.2 million of wind integration costs, exclusive of wind integration costs paid to the Bonneville Power Administration (BPA).

Commission Staff recommends disallowance of wind integration costs in test year operational costs. Staff excepts from its recommendation wind integration costs paid by the Company to BPA (approximately \$5.89 per MWh). Tr. p. 948. Staff's adjustment reduces net power supply expense by approximately \$34.2 million (system). Tr. p. 281.

Staff contends that the Company should not be allowed to include the PURPA wind integration charge (\$6.50 per MWh) as a variable cost to its own wind facilities and power purchase contracts. These are internal costs, Staff states that are neither paid under contract nor to any other utility. For wind resources in service during the 2009 test year, Staff contends that wind integration costs are captured in actual test year expenses. Tr. p. 280. There is no basis to explicitly add wind integration costs into the rate case, Staff argues, because estimates are neither accurate nor predictable. Furthermore, Staff notes that RMP has an energy cost adjustment mechanism (ECAM) in Idaho. According to the Company, the ECAM was designed to capture the volatility in net power costs due to, among other things, wind variability (citing Company

witness Duval's testimony in PAC-E-08-08). The actual costs of wind variability, both on the Company's system and to the extent it provides sales opportunities outside the system, Staff contends, will be captured in the ECAM. Tr. p. 281.

Monsanto recommends that the Commission reject recovery of wind integration costs using the \$6.50 per MWh rate and recommends that wind integration costs be recovered through the Company's ECAM. Tr. p. 1521. Monsanto contends that the rate is not cost-based and the Company has not met its burden of proof regarding recovery of wind integration costs. Tr. p. 1553. This adjustment, Monsanto calculates, reduces NPC by \$1.88 million (Idaho). Tr. p. 1521.

Monsanto contends further that RMP should not be allowed to recover wholesale wheeling customer wind integration costs from retail customers through the ECAM. The Company has included wholesale wheeling customer wind integration costs in the NPC, Monsanto contends, because PacifiCorp failed to request an adjustment to its Open Access Transmission Tariff (OATT) so that these costs can be recovered from wholesale wheeling customers. These costs, Monsanto contends, are not the responsibility of Idaho customers and should be removed from NPC. This adjustment reduces NPC by \$0.35 million (Idaho). Tr. pp. 1521, 1522.

Monsanto contends also that RMP double counted wind integration balancing costs during the period of January 2010 through April 2010. By its proposed adjustment, Monsanto removes the double count reducing NPC by \$0.14 million (Idaho). Tr. pp. 1522, 1558.

Monsanto disagrees with RMP's claims that one need only look at BPA's wind integration costs to determine that the Company's costs are reasonable. The Company itself in its August 31, 2009 wind integration study, Monsanto states, cautioned against comparing PacifiCorp's costs with other utility studies because

there is 1) no industry standard design, different cost components are incorporated into the studies and different modeling approaches and tools are applied, 2) costing methodologies and understanding of wind impacts is evolving rapidly as utilities gain operating experience, 3) utility system differences, 4) study assumptions (e.g., transmission sufficiency, wind location diversity, regional coordination, wind forecast improvement expectations), and 5) conservative vs. optimistic bias.

Tr. p. 1555. PacifiCorp, Monsanto states, has admitted on numerous occasions that it cannot calculate the actual cost of wind integration and has also stated that they have not estimated

actual costs, which could be used for verification of the reasonableness of wind integration cost forecasts. Tr. pp. 1555, 1556.

PIIC proposes to remove the inter-hour wind integration costs associated with integrating non-owned wind projects that are interconnected to the Company's transmission system because the Company does not have a transmission tariff to recover the costs from those customers. Tr. pp. 1717, 1733. This adjustment, PIIC calculates, would decrease the Company's NPC by approximately \$4.3 million (system).

RMP in rebuttal maintains that wind integration costs are real, necessary and prudent. Tr. p. 948. The Company agrees to remove inter-hour wind integration costs associated with the wind projects that are located in the Company's balancing areas but do not deliver generation to the Company's system. The corrected adjustment, RMP states, includes an accounting for generation from the Stateline wind project recovered under a contract with Salt Lake City and results in a decrease to system NPC of approximately (\$1.4 million). Tr. pp. 940, 950.

Wind integration costs, the Company argues, are not the same as the variation in NPC that the ECAM is designed to capture. Wind integration costs, it contends, are costs incurred due to additional reserve requirements to integrate the intermittent generation from the wind projects into the Company's portfolio of resources (regulation up, regulation down, load following up and load following down). Tr. p. 947.

The Company contends that it operates its resource portfolio to serve all its obligations, and does not differentiate what resources are used for serving which obligations. As such, the Company states it can only estimate the impact of wind integration costs. Tr. p. 949. The Company notes that it has completed a wind integration study in conjunction with its 2010 Integrated Resource Plan and is presently reviewing comments. Tr. p. 951.

RMP states that it cannot charge wholesale transmission customers for wind integration costs without first obtaining FERC approval. The Company is required by federal law to interconnect with new facilities under the terms of its Open Access Transmission Tariff. Once RMP interconnects a new facility to its transmission system, the Company is responsible for integrating it into the system. PacifiCorp states its intention to file a rate case with FERC no later than June 1, 2011, in which the Company will include a proposed wind integration charge in its transmission tariff rates. Tr. p. 951.

As a balancing area authority, RMP states the Company must operate its balancing areas by matching system resources to actual load and generation fluctuations on a moment-to-moment basis through automatic generation control. Load fluctuations, outages, and generation output fluctuations all contribute to the need for balancing resources. The addition of renewable resources such as wind, the Company contends, has the tendency to increase the need for balancing resources. The costs associated with wind integration, it contends, are a prudent expense. Tr. p. 952.

By providing wind integration services in addition to other transmission-related services as a balancing area authority, the Company states it ensures that its customers are served by a reliable system with diverse resources. Tr. p. 952.

With the exception of inter-hour wind integration costs, RMP recommends that the Commission reject the wind integration cost adjustments proposed by Staff, PIIC, and Monsanto.

Commission Findings

No party to this case denies that wind integration costs are real costs; the consensus, however is that they cannot be readily forecast with accuracy, calculated or verified. The record reflects that even PacifiCorp may not have confidence in its own study. The Company, we find, has not presented the Commission with a verifiable study depicting its wind integration costs. We will not allow the Company in this case to use the wind integration cost developed for mandatory PURPA purchases as a surrogate. They are not the specific integration costs of RMP and are not adequately supported by a study. We find it reasonable in this case to deny the inclusion of wind integration costs in the Company's NPC. We exclude from our denial the contractual wind integration costs paid by the Company to BPA. We are not happy with this end result, because we believe these integration costs belong in base rates. We encourage the Company to work with Staff and other interested parties toward a resolution. As part of a new proposal the Company should be prepared to demonstrate how acceptance of its wind integration cost estimate would not lead to over recovery of costs. Until then the Company must look to the ECAM to recover wind integration costs. While RMP is not yet able to calculate wind integration costs with verifiable accuracy, we acknowledge that the costs of integration are embedded in the Company's actual power supply costs.

We find also that the responsibility for recovery of wind integration costs from wholesale transmission customers resides with the Company, not its retail customers.

(b) Cal ISO Wheeling and Service Fees

The Company's filing, Monsanto states, includes a full year estimate of California Independent System Operator (Cal ISO) wheeling and service fees. The fees are incurred when the Company uses the Cal ISO system to balance and optimize its system. Some of the fees are related to the Company's strategy to hedge its long position at Four Corners. However, the Company's filing, Monsanto states, does not include any transactions that would incur Cal ISO fees beyond May 3, 2010. As a result, net power cost includes a full year of Cal ISO costs, but only wholesale transactions that would generate the Cal ISO expense prior to May 4, 2010. Monsanto recommends disallowance of all Cal ISO fees for the period May 4, 2010 through December 31, 2010. Monsanto also recommends that actual Cal ISO fees be included for the period prior to May 4, 2010 to match costs with the actual wholesale transactions included in the Company's filing. This adjustment, Monsanto calculates, reduces NPC by \$.20 million (Idaho). Tr. pp. 1523, 1524, 1540.

RMP urges the Commission to reject this adjustment. Cal ISO fees, the Company states, are incurred for transactions at market points of SP15, NP15, and when the Cal ISO is the counterparty. The bulk of these transactions are short-term transactions made close to the time of delivery. Cal ISO is a major counterparty in the Company's activities to balance its system. Tr. p. 975. The Company continues to do business with Cal ISO and continues to incur Cal ISO fees. Not allowing the Cal ISO fees, the Company maintains, is the same as making the assumption that the Company would not do business with Cal ISO. Removing Cal ISO as a counterparty, the Company contends, limits the options that the Company may use to balance its system economically. The Company states that it expects to do business with the Cal ISO in 2010 and the future and will continue to incur various fees in the markets governed by the Cal ISO. Tr. p. 976. Through September 2010, the Company represents it incurred approximately \$3.2 million of Cal ISO fees, both wheeling fees and service fees, which, it states, are only \$66,265 lower than what the Company included in the filing for the corresponding period. Tr. p. 977.

Commission Findings

The Commission finds Monsanto's argument persuasive. The issue is what should be included in base rates. The reduced amount included in base rates does not assume the Company will not do business with Cal ISO as a counterparty. Transaction data should have been provided

if the Company intended this to be a continuing forward expense. The Commission accepts the adjustment. If Cal ISO wheeling and service fees are incurred, the Company should seek recovery of costs in the ECAM.

(c) Normalization of Call Option Contracts

1. SMUD

A call option is a contract that allows the purchaser the right to pre-schedule energy deliveries based on expected market prices and/or the purchaser's requirements. RMP is both a buyer and seller of call option contracts. The Company models a "call option sale" contract for the Sacramento Municipal Utility District (SMUD) in its GRID power supply model. Tr. p. 1728.

In GRID, inputs specify contractual energy limits on an hourly, daily, weekly, monthly or annual basis. For sales with annual contract energy limits, such as the SMUD contract, PIIC contends that GRID schedules the contract energy during the highest cost hours of the year. Because the contract has an annual energy limit of approximately 350,400 MWh (with a 100 MW maximum hourly take), the Company, PIIC contends, assumes SMUD will call the energy from the contract during the highest cost 3,500 hours in the year. PIIC contends that for SMUD, GRID assumes the counterparty finds the most costly way possible to use the energy available under the contract. In effect, the Company's modeling, PIIC contends, assumes the "worst case scenario." In fact, PIIC states, what the Company's GRID modeling assumes simply does not happen in actual operation. Tr. pp. 1728, 1729. Generally, SMUD uses this resource, PIIC states, in a manner that is far less costly than assumed by the Company's GRID modeling.

This difference, PIIC contends, occurs because SMUD is not using the same forward price curves as RMP. Differences in delivery location, transmission constraints, availability of the SMUD's own generation and many other factors will drive decisions to use the available energy. In the end, SMUD is interested in serving its own customers at the least possible cost (subject to its own constraints), PIIC contends, not in maximizing the cost to PacifiCorp. Tr. p. 1730. To correct this problem, PIIC proposes to substitute actual data for normalized data for the Company's sales contract with SMUD. This adjustment, it calculates, reduces the Company's system NPC by \$1.6 million.

2. Black Hills

Monsanto proposes that the Company's wholesale sales contract with Black Hills Power be modeled based on a four-year average of historical dispatch information. Tr. p. 1549. The Black Hills contract, Monsanto states, is classified a call option contract in GRID and the contract terms for energy such as hourly, daily, weekly, monthly and annual take and delivery points are inputs to GRID. Based on this information and the Company's forward price curve, GRID dispatches the contract during the highest cost hours based on the assumption that this is what the purchasing entity would do. Monsanto disagrees with this assumption. It really depends, it states, on the requirements and assumption of the purchasing entity. In the case of Black Hills, Monsanto states the actual delivery shape of the sale is much flatter than it is modeled in GRID. Tr. p. 1547. The Company's assumption results in a higher contract cost in GRID than occurs on an actual basis. To correct this problem, Monsanto recommends that the energy shape be modeled using the actual delivery shape. Tr. p. 1548.

RMP in rebuttal states that for normalized purposes, the GRID assumes that the counterparty – who control the call options on these two contracts – will maximize the value of the contracts and take power at the most economical time. GRID, the Company states, assumes optimization of all flexible resources, while PIIC's and Monsanto's proposals embody an approach optimizing flexible resources when it lowers NPC and not optimizing flexible resources when it raises NPC. Tr. p. 961. The proposed adjustments, the Company states, depart from modeling power cost on a normalized basis. If this type of modeling adjustment were adopted, then consistency and fairness, the Company contends, require its application to all other flexible purchase or sales contracts that are modeled in a similar fashion. It is not fair or consistent, the Company argues, to normalize different contracts using different rules. Use of any delivery patterns other than the optimized delivery patterns, it states, will always lower net power costs for wholesale sales contracts with flexibility such as SMUD and Black Hills contracts. The opposite is true, it states, for purchased power contracts that give the Company flexibility in how the power is taken. Tr. p. 962.

The only valid assumption with call option contracts, the Company contends, is to assume that all participants in the market are rational and will exercise their rights to the flexible contract to lower their costs. Tr. p. 963. RMP recommends the Commission reject the

adjustments proposed by PIIC and Monsanto on the basis that the adjustments violate the fairness in the optimization of all flexible resources to reduce NPC. Tr. p. 965.

Commission Findings

PIIC and Monsanto, we find, make persuasive arguments to substitute actual data for normalized data for the Company's call option contracts with SMUD and Black Hills Power. The Company's argument that what is proposed violates principles of consistency and fairness cannot justify a GRID modeling assumption that is belied by the options exercised by SMUD and Black Hills. We find it reasonable for these two call option contracts to use an average of exercised options. For purposes of the revenue requirement in this case, we find use of the four-year average recommended by Monsanto to be reasonable. For future cases we will expect the Company to use a three-year average.

(d) Other Net Power Cost Adjustments

For the remaining net power cost adjustments proposed by the parties in this case, we find the Company's rebuttal position to be persuasive. These adjustments include the Idaho Power PTP contract, reserve shutdowns, Energy Gateway transmission, Cholla 4 capacity, Morgan Stanley call premiums, Bear River hydro normalization, Naughton 3 outage, Lake Side outages, Colstrip 4 outages, start up energy valuation, Jim Bridger fuel adjustment, heat rate adjustments, DC Intertie costs, screening for combined-cycle O&M costs, and the treatment of non-firm transmission and other costs in GRID.

Included in the Company rebuttal, net power costs are the adjustments accepted for the Dunlap reserves, part of the APS purchase treatment, GRID commitment logic error and start up costs and Colstrip planned outages in the spring. Although the Company does not agree with the reasoning, it has reflected the impact of the Mona Market cap and generation overhaul in the rebuttal costs. The Company also states it will review these concepts and address them in the future.

Like the wind integration costs, the GRID assumptions and components need additional evaluation. Forums to address greater understanding and modifications to better reflect reality are encouraged.

C. Rate Base

RMP in its rebuttal case proposed a pro forma rate base of \$650,554,859 for its Idaho jurisdiction. Following accepted test period convention, the Company proposed only the

inclusion of capital projects over \$5 million that were expected to be used and useful by December 31, 2010. The change in allocation factors due to the decision related to the Idaho Irrigation Load Control Program, discussed previously, increases rate base. The Commission accepts making three adjustments decreasing rate base from the Company's rebuttal case:

- A. Populus to Terminal
- B. Mine Stripping Carrying Costs
- C. Coal Pile Inventory

We approve an electric pro forma rate base of \$677,562,962,

(1) Populus to Terminal

The Populus to Terminal transmission line is the first of eight proposed new high voltage transmission segments that will make up PacifiCorp's Energy Gateway transmission expansion project. Energy Gateway consists of Gateway West, Gateway South, and Gateway Central. Populus to Terminal is one of three segments that make up Gateway Central. Exh. 33. It is a dual circuit 345 kV, 135-mile long voltage transmission line stretching from Downey, Idaho to Salt Lake City, Utah. Tr. p. 1947. Rocky Mountain Power was granted a Certificate of Public Convenience and Necessity authorizing construction of the Populus to Terminal 345 kV transmission line project in October 2008. Case No. PAC-E-08-03, Order No. 30657.

RMP proposes to rate base its \$801,530,000 investment in the Populus to Terminal transmission line. The project was planned to be completed and in service in November 2010. Exh. 37. The project was online by year-end. The line added significant new incremental transmission capacity (1,400 MW planned) from southeastern Idaho into Utah and helps integrate other future planned resources, market purchases, and sales as necessary to help control energy costs. The investment also improves system reliability. Tr. p. 703.

In 2008, the 1,700-mile Energy Gateway transmission project was estimated at over \$4 billion. In 2010, Energy Gateway is described as a 2,000-mile long project at an estimated cost of approximately \$6.6 billion. PacifiCorp currently has only \$2.2 billion in transmission plant in service. Tr. pp. 1947, 1948.

RMP describes the Populus to Terminal transmission segment as a "key element in Gateway Central," which is described as an essential reliability backbone allowing Gateway West and Gateway South to operate at a higher reliability and an overall higher capacity. The Company maintains that the Energy Gateway investment supports design capacity ratings based

on WECC and NERC planning standards and criteria and will support future generation resource development. Tr. pp. 729, 741.

The additional transmission capacity (1,400 MW planned) of Populus to Terminal, the Company contends, will make it possible to better utilize the market price differentials between the east and west sides of the Company's system, reduces reliance on additional purchases of transmission from third parties, and improves reliability. Tr. pp. 698-700, 709, 929.

The Company maintains that its decision to add transmission capacity is supported by its 2008 Integrated Resource Plan (IRP), which states that PacifiCorp's "mandate is to assure, on a long-term basis, adequate and reliable electricity supply at a reasonable cost and in a manner consistent with the long-run public interest." The IRP analysis is performed by evaluating loads and resources over a 20-year period. PacifiCorp's existing transmission system, as well as the transmission grid across the western region, the Company states, is severely constrained and numerous regional study groups have identified a need for investment in new transmission infrastructure. Tr. pp. 702, 738.

The Company also cites its MEHC acquisition commitment in 2006 to increase the transmission capacity by 300 MW from southeast Idaho to northern Utah. Tr. p. 702.

RMP maintains that the Populus to Terminal line is fully "used and useful" and is the most prudent approach to meet current system electrical demands and those forecasted in the future. Tr. p. 729. The fact that a facility is not fully subscribed, the Company contends, does not mean that it is not "used and useful." The only prudent approach to designing and building utility facilities, it states, is to consider both current and future requirements of that facility. Tr. p. 731. The Populus to Terminal project, RMP contends, provides immediate reliability and capacity benefits to the system well in excess of the 700 MW suggested by Staff. Tr. p. 730. RMP disagrees with Staff's reference also to *Idaho Code* § 61-502A regarding the "used and useful" standard and the implication that the project includes unnecessary capacity. Tr. p. 783.

Staff contends that only 700 MW of the 1,400 MW in planned capacity provided by the Populus to Terminal line is presently used and useful. Commission Staff recommends therefore that only 50% of the Company's investment in the Populus to Terminal line be rate based and that the remaining portion be held as plant held for future use. Staff contends that it is an undisputed fact that the project is oversized and will not be fully utilized unless or until Energy Gateway is completed. Tr. pp. 1953, 1956.

Monsanto contends that the Gateway Central transmission project is but an initial leg of a very speculative and massive undertaking. Tr. p. 1468. Monsanto recommends that the Commission defer the entire amount of the Company's investment in Populus to Terminal to the next rate case, putting incurred expenses to date in plant held for future use with no carrying charge until such time as the degree of used and usefulness is determined. Tr. p. 140. Gateway Central, Monsanto contends, only makes sense if Gateway South is built.

PacifiCorp in rebuttal strongly disagrees with the recommendations of both Staff and Monsanto.

Commission Findings

The Commission has considered the extensive testimony of the parties in this case regarding Populus to Terminal and finds that the Company has not demonstrated that the line is presently "used and useful" in its entirety. *Idaho Code* § 61-502A. The record reflects that the Populus to Terminal line was built to meet not only present needs but future needs. One need only look to the transcript to reach this conclusion:

- In response to Commission Staff Production Request the Company stated "the full benefits of the capacity upgrade will not be realized until additional segments are built as part of Energy Gateway." Tr. p. 1953.
- The Company states "the benefits of adding the transmission line are to meet future load and resource requirements." Tr. p. 697.
- The Company states the purpose of the line is to "integrate with future Energy Gateway segments." Tr. p. 699.
- The Company states the investment [in Populus to Terminal] will provide reliability benefits to future planned high voltage transmission additions." Tr. p. 701.
- The Company states "the Populus to Terminal transmission line segment is designed . . . to meet future customer energy service requirements." Tr. p. 703.
- The Company's 2008 analysis of the Populus to Terminal project shows that "the project and its planned capacity are required in the future." Tr. p. 719.
- The Company states "in the future, [the Populus to Terminal line] will also provide incremental capacity." Tr. p. 753.

Of the 1,400 MW of additional capacity that the Populus to Terminal line provides, we note that the record reflects the Company can only presently use between 1,000 MW (rebuttal) and 1,040 MW (surrebuttal). Rather than rate basing 100% of the Company requested \$801.530 million, we find that only 73% of the Company's investment represents plant that is currently "used and useful." We find it reasonable to place \$216.413 million or 27% of the Company's Populus to Terminal investment in plant held for future use. From a capacity standpoint this represents 1,022 MW of the total 1,400 MW that Populus to Terminal can ultimately provide. We find that the remaining 27% may not be fully used and useful until the other Energy Gateway segments are completed. The Energy Gateway project segments, we find, continue to change in scope and timing. Idaho, we find, will pay its fair share to meet the Company's system load and transmission requirements but we will not allow full ratebasing of investment in Populus to Terminal prematurely and we will not require Idaho customers to assume and pay for unused capacity. The "used and useful" issue raised by the parties is perceived by this Commission on the facts of this case to be one of operational and regulatory timing.

(2) Mine Stripping Carrying Costs

In Case No. PAC-E-09-08 (Order No. 30987), the Commission authorized RMP to record, as a regulatory asset, the costs associated with removal of overburden and waste materials at its affiliate coal mines. In this case the Company seeks to recover its removal costs together with a related carrying charge for inclusion in base rates. Tr. p. 1166.

Staff argues that because the regulatory asset was created as a result of an accounting procedural change, it would be inappropriate for the asset to accrue a carrying charge. Staff removed the carrying charges from rate base (\$1,169,114), decreasing the Idaho revenue requirement by \$6,133. Tr. p. 2031.

RMP in rebuttal contends that Staff's adjustment unfairly penalizes the Company for an attempt to reduce the disparity created by timing difference between incurring the stripping costs and the time when the uncovered coal is actually extracted. As approved by the Commission, stripping costs are now deferred to a regulatory asset rather than immediately included in fuel stock inventory and amortization is matched with coal extraction. Without the deferred accounting treatment, the Company is required to reflect stripping costs as variable production costs during the period the stripping costs are incurred. Tr. p. 1202.

Commission Findings

In our Order No. 30987 authorizing creation of a regulatory asset, we deferred a decision regarding the propriety of the deferred coal stripping costs until the Company requested recovery of such costs through rates. It was noted in our Order that the Company's application did not include a request to earn a return on the regulatory asset. Staff nevertheless, we noted, expressed its opinion in that case that such a return was inappropriate. We find it reasonable to approve Staff's adjustment removing carrying charge costs associated with the regulatory asset. Typically this Commission has not allowed carrying charges for deferrals. There is no compelling reason here to depart from this practice. Absent a Commission Order authorizing a regulatory asset, RMP would have to expense these costs. Inclusion of the base deferrals, absent a carrying charge, is the appropriate ratemaking treatment. The revenue requirement impact of this adjustment is (\$8,267) Idaho.

(3) Coal Pile Inventory

The Company increased coal fuel stockpile in Account 151, Fuel Stock, by \$24,644,591 on a system basis with \$1,581,176 allocated to Idaho. Tr. p. 1976. The Company states this increase was due to the cost of coal and the number of tons stored at each site. Tr. p. 1165.

Staff contends the Company provided no acceptable explanation or justification for significant changes in the stockpile tonnage at the different plant sites. Tr. p. 1977. Commission Staff proposes to limit the coal inventory for each plant site to no more than the actual tons as of December 2009. This adjustment removes \$15,970,759 (system) from rate base. Tr. pp. 1974, 1978; Conf. Exh. 102.

RMP contends that Staff adjusted inventory levels in Utah without considering the inter-relationship between stockpiles and the economic benefits of the higher stockpile levels in Utah. Further, the Company contends that Staff's analysis ignores the supply risks associated with maintaining adequate inventory levels, particularly in Wyoming. Tr. pp. 682, 683. The Company states there are no plans to reduce plant inventory levels below test period ending balances. Tr. p. 683. The Company recommends that Staff's proposed adjustment be disallowed.

At the hearing, Staff witness Leckie accepted the need to consider the inter-relationship with the Utah plants. He corrected his adjustment down to \$9,204,118 (system) to reflect this relationship.

Commission Findings

The Commission finds that the record does not demonstrate a reasonable and persuasive explanation for the increase in stockpile tonnage at the different plant sites. The contracted study performed for the Company analyzed inventory levels for the Company's Wyoming coal plants only, not Utah. Tr. p. 682. We appreciate that the Company intends to seek opportunities to manage its fuel cost and quality through inventory management and may revise its inventory targets in Utah. Tr. p. 683. We invite the Company to come back once it completes its study. We find it reasonable in this case to accept Staff's adjusted fuel stockpile adjustment of \$9,204,118. We also find it reasonable to transition the stockpile increases over three years. This transition would allow an additional stockpile amount of \$3,068,039 or a net adjustment of \$6,136,079 in this case. The revenue requirement impact of this adjustment is (\$45,556) Idaho.

(4) Other Rate Base Adjustments

As noted previously, in its rebuttal adjustments the Company accepted the rate base adjustments associated with the Bridger Unit 2 overhaul liquidated damages and major plant additions update. The associated taxes, depreciation expense and depreciation reserve were also reflected in the rebuttal numbers.

We accept the Company's position on the remaining rate base issues including the cost-effectiveness of including the entire Dunlap Ranch property.

Cash working capital using the 2007 lead-lag study is accepted for this case. Usually we will utilize the balance sheet approach where there is a showing of who provides the funds. The Company states it updates the lead-lag study every five years. We believe the Company should show how the lead-lag study can be used while appropriately considering who provides the funds in its next rate case.

Summary of Adjustments to Test Year Revenues, Expenses and Rate Base

Considering all the evidence presented, and including all adjustments, the Commission finds just and reasonable Idaho jurisdictional expenses for the test year in the amount of \$222,670,703, and Idaho jurisdictional operating revenues in the amount of

\$268,177,671. The after tax Idaho revenue requirement increase is \$13,755,728. After all adjustments, we find a total Idaho jurisdictional rate base amount of \$677,562,962 to be just and reasonable.

Calculation of Revenue Deficiency

| | |
|--------------------------------|---------------|
| Rate Base | \$677,562,962 |
| Rate of Return | 7.98% |
| Total Revenue Requirement | \$54,022,366 |
| Operating Income | \$45,506,968 |
| Income Deficiency | \$8,515,398 |
| Conversion Factor | 1.615 |
| Revenue Requirement Deficiency | \$13,755,728 |

Revenue Requirement

The Commission in this case approves a base revenue requirement of \$54,022,366 (Idaho), an increase in electric base rates of \$13,755,728, or 6.78%.

**III. JURISDICTIONAL ALLOCATION, COST OF SERVICE,
REVENUE SPREAD AND RATE DESIGN**

A. Jurisdictional Allocation – Revised Protocol

PacifiCorp is an electrical corporation and public utility and provides electric service in Idaho and five other western states. PacifiCorp owns substantial generation and transmission facilities. Augmented with wholesale power purchases and long-term transmission contracts, these facilities operate as a single system on an integrated basis to provide service to all customers. PacifiCorp recovers costs of owning and operating its generation and transmission system in retail prices established from time-to-time in state regulatory proceedings.

Because all of the Company’s generation and transmission resources are deemed to be used to serve the Company’s customers in all of its state jurisdictions, the Company contends it is necessary to determine what portion of the costs associated with each of the rate based resources ought to be allocated to customers in the state for which prices are being established. To allocate system generation, transmission and distribution costs in its multiple jurisdictions an Inter-jurisdictional Cost Allocation methodology was established. That methodology is presently set forth in what is identified as the Company’s “Revised Protocol.” The Revised Protocol was approved by the Commission on February 28, 2005 (Order No. 29708, Case No.

PAC-E-02-3) for allocation of costs in Idaho, subject to the terms of the filed Stipulation and Agreement.

Importantly as noted by the Commission, “the Revised Protocol does not prejudge issues of prudence, rate spread, rate design or cost recovery. Each state Commission continues to establish fair, just and reasonable rates.” Order No. 29708, p. 10.

Commission Findings

It is in accordance with the Revised Protocol methodology that the Company has filed this rate case. It is pursuant to the power reserved to this Commission that we have determined that costs associated with the Idaho Irrigation Load Control Program should be allocated as system costs and not Idaho or situs costs. In doing so, we have determined that continued treatment of such costs as a DSM-1 resource and as an Idaho situs cost no longer produces results that are fair, just and reasonable and in the public interest.

B. Cost of Service

Once Idaho jurisdictional test year costs are determined with the Company’s Revised Protocol Jurisdictional Cost Allocation methodology, the next step is to allocate the adjusted costs or the revenue requirement to a series of functional costs and then to the different customer classes served by RMP in accordance with recognized principles and generally accepted procedures in order to obtain an indication of relative cost responsibilities of each class of customers. This allocation is done in two parts. First, a class cost of service (COS) study is conducted that identifies what the revenue allocation for each class would be at full COS. Finally, if some increases are considered to be too large, a maximum increase cap is established and unrecovered revenue is spread to other classes.

RMP’s cost of service methodology in this case is set forth in Exhibits 47, 48 and 49. The methodology presented by the Company is the same basic methodology used in the Revised Protocol jurisdictional allocation process. It is also the same methodology accepted by the Commission in recent general rate case decisions for the Company. Tr. p. 2130.

Keeping the methodology the same, Staff contends, simplifies the case and allows the class cost of service results to be driven by class energy, demand and customer characteristics and changes in Company costs. When the methodology is changed, COS results for customer classes, Staff states, may change significantly without any change in customer usage characteristics or underlying service costs. Tr. p. 2130.

PIIC recommends that the demand allocation factors used in the Company's cost of service study be modified to more accurately assign demand-related costs. PIIC recommends the class demand allocation factor be based on the comparable jurisdictional peak hour with a more up-to-date irrigation class demand. The Company's 12 monthly coincident peak factor (12 CP) for assigning generation and transmission-related demand costs, PIIC contends, should be replaced with a winter/summer peak factor (W/S CP) using the peak load months of July and December. The weighted 12 monthly peak factor used by the Company for distribution related demand costs, PIIC contends, should be replaced with the class maximum peak demands (1 NCP) to more accurately assign distribution costs responsibility. PIIC supports a cost based rate spread approach but recommends that it be done using the results of its cost of service study. Tr. pp. 1685, 1686.

Monsanto contends that a proper valuation of Monsanto's curtailment should reflect the avoidance of capacity and energy. Without a valuation of Monsanto's interruptibility, the cost of service study results provided by the Company and treatment of Monsanto's load as "all firm," it states, are incomplete. Tr. pp. 1592, 1602.

PacifiCorp in rebuttal criticizes PIIC's proposed use of a 2 CP method. Such a method, the Company states, fails to recognize how the Company plans and operates its generation and transmission systems; is inconsistent with inter-jurisdictional allocations; has the potential to shift customer costs creating rate volatility; and violates the principle of gradualism which is generally viewed as an important consideration in determining class cost causation. In addition, the Company states that PIIC provides no significant analysis to support its recommendation. PIIC's recommended 1 NCP allocation method, the Company contends, is not appropriate because it ignores the cost causing basis for these facilities, i.e., customers load diversity. Tr. p. 1293.

C. Revenue Spread

Revenue spread is the determination of the revenue amount that needs to be collected from each customer class. It is driven primarily by class cost of service (COS) results. Tr. p. 2131.

RMP proposes to move all customer classes to nearly full COS except the Street and Area Lighting class (Schedules 7, 11, 12) that would receive a rate reduction in a full COS move. The Company proposes no change in the lighting revenue requirement and to respread the

lighting decrease, that would otherwise occur, to all other customer classes to achieve the recovery of the full revenue requirement. Tr. p. 2131.

Staff proposes to use the same methodology presented by the Company with one difference. Staff's proposal is to allow no class revenue requirement decreases while moving customer classes requiring increases toward full cost of service with uniform percentage offsets to balance the revenue requirement for the lighting class reduction not given. Staff would also assign residential customers taking service under Schedules 1 and 36 an equal percentage increase. Tr. pp. 2131, 2132.

Commission Findings

The Commission acknowledges the Company's cost of service study as reasonable and recognizes its use in the Revised Protocol and our use of the study in prior Company rate cases. We find no reason to abandon its use despite the recommendations of other parties.

Cost of service modeling is not an exact science. A cost of service study is not a perfect tool for assigning system and service costs to customer classes. Accepting the COS results as a starting point, we must then determine the appropriate revenue requirement to be recovered in the rates of the different system customer classes. In doing so, we strive to achieve an equitable apportionment of the revenue requirement among the customer classes. We find it reasonable in this economy that the Street and Area Lighting class receive no COS adjustment and that the difference offset the increase to other classes. We also find good cause to limit the COS increase to Monsanto in this case to under 10%. These changes are reflected in the rates we approve. We find the recommendation of Staff to assign residential customers taking service under Schedules 1 and 36 equal percentage increases to be reasonable. Comments and testimony of customers under the two residential service schedules, we note, reflect that they do not understand why the Company proposes separate treatment for Schedules 1 and 36. The revenue increase allocated to each class is depicted in Attachment A.

D. Rate Design and Electric Rates

Schedule 1 – Residential

RMP

For Schedule 1 residential customers, RMP proposes a two-tiered inverted block pricing structure for energy use and a \$12 fixed monthly customer service charge. Currently,

customers served on Schedule 1 pay a flat seasonally differentiated energy charge applied equally to all kilowatt hours. In addition, a monthly minimum charge can apply. Tr. p. 1326.

Under the Company's proposed revisions, seasonal rates will continue to apply and two energy blocks will be implemented in the two billing seasons. The first energy usage block in each season will apply to usage for the first 800 kWh per month. All additional kWh will be billed at the higher second tier price. The Company chose to terminate the first block at 800 kWh in order to reflect current average usage on Schedule 1 (839 kWh per month). Average Idaho residential customers on Schedule 1 would experience an increase well below the average increase in the Company's case. Larger users with more usage would see substantially larger increases. Tr. p. 1326.

The proposed inverted rate design for residential Schedule 1 is submitted by the Company consistent with the terms of the Stipulation approved by the Commission in the Company's 2008 Idaho general rate case (PAC-E-08-07). Tr. p. 1327.

The Company proposes that the current monthly minimum charge for Schedule 1 customers (\$10.64) be eliminated and replaced with a proposed fixed monthly customer service charge of \$12. A customer service charge that achieves a high level of recovery of the fixed costs of serving customers, the Company contends, will more appropriately assure that each customer pays its fair share of costs and will allow the Company a better opportunity to recover the fixed costs of serving customers. Tr. p. 1327. The Company contends that recovery of all fixed costs related to Schedule 1 service would result in a monthly customer service charge of approximately \$29.86 per month. Tr. p. 1328; Exh. 53.

Commission Staff

Commission Staff supports retaining the current seasonal differentiation, but proposes that different tiered rate block thresholds apply in summer and winter – the first block would be comprised of the first 700 kWh in the summer and the first 900 kWh in the winter. Staff maintains that rate design should be based on sending cost-based price signals that promote efficient consumption of energy. Tr. p. 278. Tiered rate design and time-of-use rates, Staff contends, both reflect the variable cost to serve. Tr. p. 288.

When promoting tiered rates, Staff states, one must not lose sight of the general rate design principles: rate equity, rate stability, and opportunity for the utility to recover its approved costs. Tr. p. 289.

Staff supports the Company's proposed removal of the minimum charge and establishing a monthly customer charge for Schedule 1 customers. Staff believes, however, that the \$12 Company-proposed minimum charge is too high. Staff proposes a lower \$5.00 monthly charge for Schedule 1 customers. This amount, Staff contends, sufficiently provides recovery of the Company's meter reading and billing costs. Recovery of meter reading and billing costs is the traditional basis promoted by Staff in setting customer charges. Tr. p. 290. A \$5.00 customer charge would be no higher than that approved for both Idaho Power and Avista.

Idaho Power, Staff notes, has a three-tiered rate structure for residential and commercial customers during the summer and non-summer seasons. Avista has a two-tiered rate structure for residential customers.

ICL

ICL proposes a three-block inverted residential rate design and proposes different energy charge blocks in both the summer and winter months. Tr. p. 1336. In the summer ICL proposes the following blocks: 0 to 700 kWh, 701 to 1800 kWh and greater than 1800 kWh. In the winter it proposes the following blocks: 0 to 1000 kWh, 1001 to 3000 kWh, and greater than 3000 kWh. ICL proposes the same rates in each of the three tiers regardless of season.

RMP believes that the seasonally differentiated tiers proposed by Staff are unnecessary and will have little meaningful impact on customer usage. In fact, the Company believes the rate design may increase customer confusion, particularly during the transition from the existing flat rate to an inverted rate. The Company maintains that the proper way to implement a transition to an inverted rate is to implement a single year-round tier with the seasonally differentiated prices. Tr. p. 1337.

ICL's proposed three-tier rate design, the Company contends, greatly increases rate complexity and volatility and the Company does not support it. ICL's proposal, the Company contends, will introduce even more rate complexity than does Staff's proposal. The Company recommends that it be rejected.

Schedule 36 – Time-of-Use Residential Service

RMP

The Company proposes to retain the existing time-of-use residential rate structure and to apply increases to both the customer service charge and to the on- and off-peak energy

charges. Even with these changes, the Company contends that customers on Schedule 36 will continue to benefit from the time-of-use rate design. Tr. p. 1329.

Commission Staff

Staff supports the Company's proposal to maintain the on-and off-peak differentials for Schedule 36 customers. Staff contends that a flat rate design, in which kilowatt-hour rates are based on average costs and do not vary based on timing or level of consumption, do not reflect the disparity in costs to serve load during peak demand and off-peak period. Tr. p. 288. The Schedule 36 time-of-use rates, Staff contends, are both aggressive and fair. Tr. p. 287.

ICL

ICL proposes to lower the customer charge under TOU Schedule 36 from its current level and to eliminate the current seasonal differential.

RMP criticizes ICL's proposal as "turning back the clock." Idaho TOU customers, the Company states, have paid a higher customer charge than ICL proposes, and they have paid seasonally differentiated energy charges for more than 20 years. The Company believes that during a time of rising costs, ICL's proposal to reduce the current TOU customer charge is unacceptable. It is not cost-based, the Company contends, does not reflect the current cost environment, and sends an incorrect price signal to time-of-use customers. RMP recommends that ICL's proposal be rejected. Tr. p. 1339.

Commercial and Industrial –
Schedules 6 and 6A (General Service – Large); 9 (General Service – High Voltage);
10 (Irrigation)

For general service and irrigation rate design, the Company proposes slightly greater increases to demand rates than to energy rates. Such a result is supported, it contends, by its class cost of service results. Tr. p. 1330.

Schedules 19, 23, 23A, 400 (Monsanto) and 401 (Agrium)

The Company's proposes rate design changes for Schedules 19, 23, 23A, 400 (Monsanto), 401 (Agrium) is a uniform percentage increase to all billing elements. Tr. p. 1330.

Staff supports the Company's proposal to increase all billing components on an equal percentage basis for large industrial customers. Tr. p. 286. Equally spreading the revenue increases to all billing determinants, Staff contends, still provides a significant level of fixed

customer recovery while sending customers a strong price signal through relatively higher energy rates. Tr. p. 287.

Commission Findings

The Commission finds the two-tiered residential RS-1 rate structure proposed by Staff to be a fair, more reasonable and more equitable rate design for sending cost base price signals and encouraging conservation than the other options proposed by ICL and RMP. Recognizing the seasonal energy use data and all-electric heating equipment of many RMP customers, we find it reasonable to establish two seasonal rates for May to October and for November to April with the first tier block capped at 700 kWh for May-October and 1,000 kWh for November-April. We find the Company's proposal to eliminate the Schedule 1 minimum charge and replace it with a fixed monthly customer charge to be reasonable; however, we accept Staff's \$5.00 proposal to be a more reasonable charge and consistent with customer charges approved for Idaho Power (\$4.00) and Avista (\$5.00).

The rate structure and electric rates we approve as just and reasonable are set out in Attachment B. *Idaho Code* § 61-502. They include a two-tiered, seasonal rate structure for residential customers with an average rate increase of 6.8%. We approve a monthly customer charge of \$5.00 for Schedule 1 (Residential) customers and \$14.00 for Schedule 36 (Residential Time-of-Use) customers. This increase in rates will be accompanied by a reduction in the Customer Efficiency Services rate from 4.72% to 3.40%. This reduction in the tariff rider percentage results from our decision to treat the Idaho Irrigation Load Control Program as a power supply cost.

IV. ECONOMIC VALUATION OF MONSANTO'S INTERRUPTIBLE CREDIT

Monsanto is a special contract customer of RMP receiving electric service under tariff Schedule 400 with a total load of approximately 182 MW. Tr. p. 2874. The current Electric Service Agreement (ESA) between RMP and Monsanto contains three distinct interruptible products provided by Monsanto to RMP. These products include the following: (1) a Non-Spinning Reserve Product that allows RMP to interrupt Monsanto's service, upon 10 minutes' notice, for a total of 95 MW and 188 hours per year; (2) an Economic Curtailment Product allowing RMP to interrupt Monsanto, upon two hours notice and for any reason, for a total of 67 MW and 850 hours per year; and (3) a System Integrity Product that permits RMP to interrupt electric service to Monsanto for a total of 162 MW and 12 hours per year. Tr. pp. 2653, 2654.

The System Integrity Product is available, without notice to Monsanto, only if a “double contingency event,” defined in the parties’ contract as two or more forced outages of RMP’s generation assets, happen to occur within a 48-hour period. Tr. p. 2654.

Mandatory reliability standards require that an electric utility hold 5% of its hydro-generation capacity and 7% of thermal generation capacity in reserve. Tr. p. 2928. One half of this capacity held in reserve can be used to meet its spinning reserve requirements and the other half can be utilized to meet its non-spinning reserve requirements. Tr. p. 2928. The spinning reserve requirement can be met with resources that can be applied immediately and ramp up within 10 minutes. Non-spinning reserves must be capable of being applied within 10 minutes of being called upon to meet load. Tr. p. 2928. Western Electricity Coordinating Council (WECC) standards dictate that interruptible loads, like the one Monsanto provides, can only be used to satisfy non-spinning reserve requirements. Tr. p. 2929.

RMP

As an initial premise, RMP believes that “a definition of ‘value’ is the price at which two parties are willing to enter into an agreement.” Tr. p. 2629. Nonetheless, the Company conducted a fairly extensive analysis of Monsanto’s Economic Curtailment, Non-Spinning Operating Reserves, and System Integrity Products, utilizing its recent IRP studies, GRID and Front Office (FO) models as the appropriate methods for establishing a value. Tr. p. 2630. RMP asserts that its most recent IRP studies demonstrated that the “removal of Monsanto interruptible product as a firm resource . . . did not create the need for a new resource” or “avoid the acquisition by the Company of generation resources.” Tr. p. 2631.

RMP arrived at a value for Monsanto’s 12 hours of system integrity interruption by utilizing its FO Model to calculate the average on-peak price for the calendar years of 2011, 2012 and 2013. Tr. p. 2670. RMP’s valuation of the System Integrity product is partially premised on the notion that Monsanto, with or without its ESA, is subject to interruption just like any other customer on RMP’s system. Tr. p. 2638. Additionally, RMP believes that the likelihood of the occurrence of a double contingency event triggering an interruption in order to maintain system integrity is relatively constant throughout year. Tr. p. 2638. Thus, according to RMP, it is highly unlikely that every interruption to maintain system integrity would, as Monsanto claims, occur when the price for electricity is at the market cap of \$400 per MWh. Tr. pp. 2637, 2638.

For the Economic Curtailment and Non-Spinning Reserves Products, the Company used the average of its FO and GRID model runs for that same time period, 2011-2013. Tr. pp. 2662-2664, 2668-2669. According to the Company, the FO amount for the Economic Curtailment Product is equal to the market value of the energy during the highest priced hours. Tr. p. 2668. For the Non-Spinning Reserve Product, the FO amount is determined by what it would cost to replace the product provided by Monsanto with its existing resources. Tr. p. 2662. The Company's GRID model is run with the Non-Spinning Reserves and Economic Curtailment Products present in the model and then later without these products in the model. Tr. pp. 2662-2663, 2666, 2668. The value of the Monsanto credit for each of these products is the difference between each of these runs of the GRID model. *Id.*

In its testimony, RMP cites Appendix D of the Multi-State Revised Protocol (RP). Tr. p. 2601. The RP demands that electric service provided from a utility to special contract customers like Monsanto should be "viewed as two transactions." Tr. p. 2602. Revenues from these customers are calculated as if no interruption occurred and then assigned to the State where the customer is located. *Id.* The second transaction is for the ancillary service, in this case interruptibility, and "allocated among all states on the same basis as other system resources." *Id.*

RMP's Application states that it treats Monsanto's credit for the provision of interruptible products to the Company as a net power cost and values them at the current 2010 contract amount. Tr. pp. 2650-2651. The Company states that it follows a "customer indifference approach" when valuing interruptible products offered by its industrial customers – paying those customers what they would pay if they were to acquire the same products from the market or by virtue of their own existing resources. Tr. p. 2651. The cost of Monsanto's interruptible products is then allocated on a system-wide basis. *Id.*

RMP agrees with Monsanto that "the Monsanto interruptible products defer resources of some type." Tr. p. 2675. However, the Company does not agree with Monsanto's assertion that if it were no longer to provide interruptible service to the Company it would necessitate the construction of a new simple-cycle combustion turbine (SCCT). *Id.* In 2010, RMP believes that it would only have to replace 37% of the operating reserve product provided by Monsanto and that it could accomplish this with its existing generation resources. Tr. pp. 2629-2630.

RMP responded to Monsanto's assertion that the value of its ESA should be based primarily on the avoided cost of a new SCCT by stating that a SCCT is simply "more valuable than the Monsanto interruptible products." Tr. pp. 2631, 2677. According to the Company, a SCCT provides more services than Monsanto interruptible products, including automatic generation control, load following, and spinning reserves. Tr. pp. 2632-2633, 2677-2678.

Combustion turbines also operate more frequently than interruptible products. Tr. pp. 2633-2634. A SCCT is available in excess of 8,000 hours per year as opposed to the roughly thousand hours of curtailment available from Monsanto. Tr. p. 2679. RMP argued that it can curtail a maximum of 116 MW of Monsanto's load during approximately 2% of the total hours of the year. Tr. p. 2613. Moreover, RMP has complete control over when a combustion turbine is used. Tr. p. 2635. In contrast, the Company states that it only has control over when economic curtailment occurs, as opposed to the system integrity or operating reserve products. *Id.*

Fundamentally, the Company believes that the value of its operating reserves should be determined by the "value that could be received for that same megawatt if it were not set aside for operating reserves and instead sold to the market." Tr. p. 2655. RMP goes on to cite the profit that its existing fleet of resources would actually generate when those resources are not providing a reserve product as the appropriate measuring stick. *Id.* For a gas plant, the margin is the price of natural gas and the price of energy, the "spark spread," less variable operating costs. *Id.*

RMP believes that it is unnecessary to add an incremental capacity value to the operating reserve product because the Company's method already adds an implied capacity value for the 2011-2013 time period by including "recent market price curves for firm energy products. . . ." Tr. p. 2640. Additionally, RMP believes that Staff's valuation is flawed because Staff's proposed surrogate, the Currant Creek facility, adds more value to the system than just the provision of operating reserves. Tr. p. 2641. The Company argues that it is incorrect to assign 100% of the capacity cost of a resource to the non-spinning operating reserve product because it inevitably leads to the overvaluation of that product. Tr. p. 2643. RMP argues it is more appropriate to allocate a percentage of the capacity cost of multiple units reflecting the percentage of time these units are called upon in order to meet RMP's non-spinning operating reserve requirements. Tr. p. 2643. RMP claims that a run of its GRID model demonstrates that

its Gadsby and Currant Creek units are utilized, on average, 46.2% of the time to meet Non-Spinning operating reserve requirements. Tr. p. 2643.

The Company countered Monsanto's comparison of its ESA with that of RMP's other two special contract industrial customers in Utah by noting that Monsanto only compared their base retail rates with those other special contract customers and failed to compare the operating reserve product. Tr. p. 2639. RMP's contracts with its QF partners can also be distinguished. Those contracts have availability guarantees, liquidated damages for non-performance and other terms not included in Monsanto's contract with RMP. Tr. p. 2636.

RMP argued that any comparison of the Monsanto-RMP ESA to its Idaho Irrigation Load Control Program is also inapt. Tr. p. 2548. Monsanto relied "solely on peaker units" in its analysis of the credit while RMP included "both peakers and market purchases in the evaluation of the Irrigation Load Control Program." *Id.* Moreover, the Company mentions that the Irrigators' credit for participation in the program is discounted by 59%. *Id.* RMP argues that Monsanto's reliance on peaker units is misplaced because the Company's resource procurement process and the IRP process have shown that "they are not least cost." Tr. p. 2549.

RMP remarked that Monsanto can be interrupted for a total of 1038 hours (12%) in any given year. Tr. p. 2613. For the remaining hours of the year, 88%, RMP must serve Monsanto without interruption. *Id.* The ESA is also structured to provide Monsanto with some flexibility by assigning the curtailment products to different furnaces. *Id.*

Finally, should the Commission adopt Staff's method of valuation, RMP proposes two substantive modifications. Tr. pp. 2642-2645. First, RMP argues that the Commission should make an adjustment to include the cost of other units besides the Currant Creek facility; and, second, the Commission should enter an adjustment to account for the fact that combustion turbines provide other valuable products besides the non-spinning reserve product. Tr. p. 2642. Staff's method must be altered to utilize the capacity costs of multiple resources used by the Company to provide non-spinning operating reserves instead of just Currant Creek, as well as account for the fact that these resources provide other resources besides operating reserves. *Id.*

Monsanto

Monsanto's testimony confirmed its strong desire to achieve "price certainty and stability" going forward. Tr. p. 2763. Monsanto is a long-term, 60-year, customer of RMP receiving interruptible service. Tr. p. 2824. Monsanto believes that RMP's use of the GRID and

FO models for the test year used in the current rate case “reflect only short-term considerations” and “ignore the long-term resource costs that the Company has avoided, and continues to avoid, due to Monsanto’s long-term interruptibility.” Tr. p. 2826.

Monsanto’s assessment of the electrical service it receives differs substantially from RMP. Monsanto asserts that only 9 MW of its load is “served at firm energy and demand rates.” Tr. p. 2874. The remaining portion of its load, approximately 173 MW, is “interruptible and billed under interruptible demand charges.” *Id.* Monsanto points out that the interruptible service it provides to the Company is recognized as a Class 1 DSM resource in RMP’s 2008 IRP. Tr. p. 2821. According to Monsanto, if it ceased to provide that interruptibility, RMP would need to acquire a firm energy resource, a new SCCT unit, to replace the Economic Curtailment and Operating Reserve Product and market purchases for the System Integrity Product if a double-contingency event occurs. Tr. pp. 2816.

Monsanto argued that RMP and Staff’s valuation of its System Integrity product is too low. Among other reasons, the valuation is not appropriate because when an interruption is necessary due to a double contingency event market prices for electricity, if it is available at all, are likely to be much higher than the annual average market price. Tr. p. 2819. Specifically, Monsanto bases its valuation of this product on both the \$400/MWh WECC price cap and the \$1,000/MWh California Independent System Operator’s (CAISO) energy bid cap. Tr. p. 2811. Monsanto intimated in its testimony that it would likely reconsider inclusion of this product from a future ESA with RMP if it could not recover more than the credit proposed, \$ 0.1 million, by RMP and accepted by Staff “for being the first one in dark” if a double contingency event occurs. Tr. p. 2833.

Monsanto bases its valuation of the Economic Curtailment product on the energy and capacity cost of a newly constructed SCCT unit. Tr. p. 2801. According to Monsanto, RMP uses the interruptibility provided in the ESA in much the same way that it utilizes a combustion turbine. *Id.* Monsanto’s “avoided peaker analysis” is appropriate because a SCCT unit has a lower construction cost (\$25.5 million vs. \$28.4 million) than a combined cycle unit. Tr. p. 2830. The quick start capability of a SCCT makes them the ideal replacement for an interruptible customer. *Id.*

Monsanto attempts to rebut RMP’s argument that a CT unit offers more products than Monsanto by asserting that a CT unit does not start 100% of the time. Tr. p. 2832. Therefore,

according to Monsanto, its service is plainly more reliable than a CT unit. *Id.* Moreover, Monsanto's Interruptible Products should be valued much higher than the curtailment provided by RMP's Irrigation Load Control Program (ILCP) participants because ILCP participants offer only 52 hours of interruption during the summer irrigation season while Monsanto offers more than twenty times that amount (1050 hours) with no seasonal limits. Tr. p. 2837.

Monsanto arrived at the value for the non-spinning reserve product by averaging the avoided energy and capacity costs of two SCCT Aero-derivative units. Tr. pp. 2800-2804. The capacity costs include a 12% planning reserve. Tr. p. 2804. Monsanto believes that the amount it requests for this product is supported by the current 20 year levelized rate for Qualifying Facilities (QFs) ordered by the Public Service Commission of Utah. Tr. p. 2810.

Staff

Staff accepted the values presented by RMP for Monsanto's System Integrity and Economic Curtailment Products. Tr. pp. 2924-2927. For the Non-Spinning Reserve Product, Staff believes that RMP has "reasonably estimated the energy value," but an additional incremental capacity value must also be included in order to equitably "value the product." Tr. p. 2928. Staff recommends that the Commission add a yearly capacity value to the Monsanto Non-Spinning Operating Reserve Product. *Id.*

Staff proposes that the Commission use a surrogate resource as a guide to determine the capacity value. Tr. pp. 2931-2932. Staff explain that its analysis led to the examination of the capacity costs of RMP's Gadsby Units 4, 5, 6 (SC aero-derivative units that can provide Non-Spinning Operating Reserves even when cold) and its Current Creek facility (CCCT). *Id.* Staff noted that these units have some of the lowest capacity costs of any of the resources in RMP's generation fleet. Tr. p. 2931. According to Staff, the Currant Creek facility is the most useful surrogate for establishing the capacity value of the non-spinning product because RMP's own studies reveal that, absent the Monsanto contract, Currant Creek would pick up a larger percentage of the displaced reserve requirement than the Gadsby units. Tr. p. 2933.

Commission Findings

The following table demonstrates the value/credit each of the parties would award to Monsanto for the provision of the aforementioned Interruptible Products:

| Monsanto Interruptible Product | RMP | Monsanto | Staff | RMP Modifications to Staff's Position |
|--|------------|-----------------|--------------|--|
| System Integrity | | | | |
| 1 Year Credit (million \$) | 0.1 | | 0.1 | |
| 2 Year Credit (million \$) | 0.1 | | 0.1 | |
| 3 Year Credit (million \$) | 0.1 | | 0.1 | |
| Single Credit Amount (million \$) | | 0.8 | | |
| Economic Curtailment | | | | |
| 1 Year Credit (million \$) | 3.6 | | 3.6 | |
| 2 Year Credit (million \$) | 4.0 | | 4.0 | |
| 3 Year Credit (million \$) | 4.2 | | 4.2 | |
| Single Credit Amount (million \$) | | 11.2 | | |
| Non-Spinning Operating Reserves | | | | |
| 1 Year Credit (million \$) | 2.4 | | 9.7 | 5.4 |
| 2 Year Credit (million \$) | 3.0 | | 10.3 | 6.0 |
| 3 Year Credit (million \$) | 3.3 | | 10.6 | 6.3 |
| Single Credit Amount (million \$) | | 14.3 | | |
| Total 1 Year Credit | 6.1 | | 13.4 | 9.1 |
| Total 2 year Credit | 7.1 | | 14.4 | 10.1 |
| Total 3 Year Credit | 7.6 | | 14.9 | 10.6 |
| Two Year Avg. Credit | | | 13.9 | 9.6 |
| Three Year Avg. Credit | | | 14.2 | 9.9 |
| Single Credit Amount (million \$) | | 26.3 | | |

The valuation of Monsanto's Interruptible Products is an issue the Commission has confronted at various times in the past. Rate design generally follows principles of cost causation and cost allocation but it is not an exact science or a mathematical exercise. Arriving at a specific value for the Monsanto credit is "at least as much art as science." Tr. p. 2954. "The cost of service for firm load customers is an imprecise science and establishing the cost of service for an interruptible load is even more difficult, requiring considerable judgment." Order No. 29157, p. 12.

As the parties have acknowledged in their testimony, the Commission has not previously settled upon a definitive methodology for valuing Monsanto's interruptible service. Tr. p. 2833. Indeed, in our Order adopting the settlement reached by the parties following RMP's last general rate case, PAC-E-07-05, we wrote: "The curtailment valuation for Monsanto

is based on a 'black box' determination with no party accepting a specific methodology for setting this valuation." Order No. 30482, p. 8.

The Commission finds that the ability to curtail Monsanto load, one of PacifiCorp's largest, provides a direct benefit to PacifiCorp's system as a whole. Similarly, we find that while PacifiCorp might replace the interruptible services currently purchased from Monsanto using its other existing resources in the short term, the long-term costs to the system would be higher. PacifiCorp's 2008 IRP recognizes Monsanto interruptibility as a firm capacity resource. If it were not recognized in such a manner, the Company would have significantly larger capacity deficits in 2011, 2012 and 2013. Tr. p. 2841.

Consequently, we find that the value of Monsanto interruptibility must consist of forecasted energy prices and, where appropriate, the capital cost of capacity. Our decision regarding the valuation of each interruptible product is set out below.

A. Non-Spinning Reserve Product

The Commission finds that the Non-spinning Operating Reserve product has energy and capacity value. The Commission believes that the energy value is most accurately established using the average of the GRID and Front Office Model runs as proposed by the Company and supported by Staff. The Commission finds this value to be [REDACTED] per year.

The Commission finds the capacity value of Non-spinning Operating Reserve to be \$9.3 million per year. The capacity value was the subject of a considerable difference of opinion among the parties. The Company's position was that its market valuation using the GRID and FO models captured implied capacity values along with the energy value. Therefore, the Company proposed no additional capacity value. The Commission believes that Monsanto's interruptibility is a long-term resource and that any implied capacity values included in market prices are not nearly enough. Monsanto proposed a long-term view that capacity values be established based on the averaged costs of two new SCCT's from the Company's 2008 IRP. The two units were an Aero-Derivative unit and a Frame unit. Staff proposed that the capacity value be based on the cost of an existing unit because analysis indicated that no new resources were needed at this time to supply these reserves. Staff proposed that the Currant Creek CCCT plant be used as a surrogate to represent the capacity value of all resources held over the course of a year for Non-spinning Operating Reserves.

The Commission elects to average the capacity costs of Currant Creek and the Aero-derivative unit proposed by Monsanto (excluding increased planning reserves). The Commission finds that this value properly blends the current condition with the longer term capacity view that corresponds with Monsanto's demonstrated long-term interruptible commitment. The Commission notes that Non-spinning Operating Reserves must be held at all times and, therefore, has not chosen to reduce the value of its chosen resources by the percent of time any one resource is held for reserve purposes.

This approach is also consistent with our desire and expectation that the parties will execute a five-year contract as opposed to the three contracts that have been the norm for the parties in the recent past. In addition to promoting greater price certainty and stability for Monsanto, a large industrial customer and employer in southeast Idaho, it would also allow the Company to plan more effectively into the future. Therefore, the Commission finds that an extended contract period would serve the public interest.

B. Economic Curtailment Product

The Commission finds that the value proposed by RMP, [REDACTED], and accepted by Staff is fair, just and reasonable. *See* Attachment C. The Commission is persuaded that this value is best established in the energy markets. The differences in GRID and FO Model runs, with and without Monsanto Economic Curtailment, fairly estimate this value. The fact that Monsanto can and often does buy through Economic Curtailment at market prices supports this valuation. The Commission does not believe that an additional capacity value as proposed by Monsanto, and opposed by RMP and Staff, is appropriate.

C. System Integrity Product

The Commission finds the value of Monsanto interruptibility to maintain system integrity to be [REDACTED]. RMP and Staff argued for \$0.1 million while Monsanto presented values of \$0.8 million and \$2.0 million. Our finding of a value of \$0.2 million is a compromise that blends our knowledge that all customers are subject to interruption to preserve system integrity, without reimbursement, with an understanding that interruption of a single large load customer like Monsanto in an emergency brings benefit to RMP and other customers. The Commission has also considered the fact that this type of interruption is rare.

V. OTHER ISSUES

A. Energy Cost Adjustment Mechanism

The base net power costs (NPC) we establish in this case for the Company's Idaho Energy Cost Adjustment Mechanism (ECAM) is \$1,023,706,616. The ECAM approved for RMP in Idaho defers the difference between base net power costs set during a general rate case and collected from customers in their retail rates and actual net power costs incurred by the Company to serve its retail customers. The ECAM addresses only power cost expenses and does not include any costs associated with fixed cost recovery (i.e., capital investment in rate base). Case No. PAC-E-08-08 (ECAM methodology), Order No. 30904. Net power supply costs represent a large part of the Company's total revenue requirement and are subject to a high degree of volatility largely outside of the Company's control. The ECAM rate is calculated annually to credit or surcharge to customers the accumulated deferral balance (the difference between the base NPC embedded in rates and actual system NPC).

B. Prudence of DSM Expenditures

RMP offers seven demand-side management (DSM) programs in Idaho as the least cost alternative to the acquisition of supply-side resources. These programs encompass all major customer class factors including residential and low-income, commercial, industrial, and irrigation. Additionally, the Company contributes to the Northwest Energy Efficiency Alliance efforts to transform energy markets in the region. All of the costs associated with programs are eligible for recovery through the Customer Efficiency Service Rate Adjustment (Schedule 191) tariff with the exception of the Irrigation Load Control Service Credits which are recovered through base rates. Tr. pp. 2116, 2117.

RMP contends in this case that its DSM expenses and efforts for 2008 and 2009 were prudently incurred. Tr. p. 2116. Annual expenditures for each program derived from the Company's 2008 and 2009 DSM reports are shown below.

| Program | 2008 Expenditures | 2009 Expenditures |
|--|------------------------------|------------------------------|
| Irrigation Load Control (includes participation credits) | \$ 8,908,216 | \$11,140,894 |
| Low-Income Weatherization | 164,578 | 197,819 |
| Refrigerator Recycling | 113,296 | 108,126 |
| Home Energy Savings | 490,101 | 593,564 |
| Energy FinAnswer | 121,192 | 358,426 |
| FinAnswer Express | 1,302,858 | 263,904 |
| Agricultural Energy Services | 268,068 | 807,238 |

| | | |
|--------------------------------------|---------------------|---------------------|
| Northwest Energy Efficiency Alliance | 317,339 | 287,190 |
| Totals | <u>\$11,685,648</u> | <u>\$13,757,163</u> |

Energy efficiency programs are evaluated using a cost and benefit analysis viewpoint and cost-effectiveness calculations from four major perspectives. These perspectives include the Participant, Ratepayer, Utility and Total Resource Cost. The results of each perspective are expressed in several ways including a cost/benefit ratio and net present value of program impacts over the lifecycle of the energy efficiency measures. Tr. p. 2118. Evaluation results are used to refine pre-program estimates of cost-effectiveness from all perspectives and to find ways to further improve programs as they mature. Tr. p. 2119.

On October 5, 2009, Commission Staff convened a workshop with RMP and other utilities to fully vet the issues of DSM evaluations and cost-effectiveness expectations. The result of the workshop was a Memorandum of Understanding (MOU) signed by all utilities agreeing to formally evaluate all of their programs on regular multiple cycles and to report the results of these evaluations in their annual DSM reports filed with the Commission. In exchange for the utility commitments, Staff agreed that if the evaluation and reporting commitment are fulfilled and if there is no evidence of imprudence, then, when requested by the utilities, Staff would recommend that DSM expenditures be found prudent by the Commission. Tr. pp. 2119, 2120. Although RMP has not yet achieved all of the established goals as outlined in the MOU, Staff is satisfied that the Company has made significant progress. Tr. p. 2120.

After review and verification of all available program results and the Company's progress in satisfying MOU guidelines, Staff concludes that RMP's DSM programs and efforts in 2008 and 2009 were generally prudent and cost-effective. Tr. p. 2120.

Commission Findings

The Commission recognizes the Company's DSM Memorandum of Understanding commitments and its compliance efforts; accepts Staff's analysis of the Company's 2008 and 2009 DSM programs and related expenditures; finds the expenditures to be just, reasonable and in the public interest; and finds the costs to be prudently incurred and appropriate for recovery in the Company's Schedule 191 (Customer Efficiency Services Rate Adjustment) tariff.

C. Tax Issues

The Company and Staff discuss accounting changes related to the deductibility of capital repairs for tax purposes and the normalization of income tax expense. We accept the

proposal to establish a regulatory asset or liability account for changes in taxes associated with the repair deductions. The IRS has yet to review the deductions, making it reasonable to track it. We accept Staff's recommendation that interest received or charged not be included in the regulatory accounts.

The Company also requests approval to move to full normalization treatment of income taxes for purposes of setting rates. Staff supports this recommendation. We accept the Company's recommendation to fully normalize the repairs deduction and all other temporary book-tax differences, with the exception of the equity allowance for funds used during construction ("equity AFUDC").

D. Low-income Weatherization Assistance (LIWA)

Rocky Mountain Power's Low-Income Weatherization Program is set out in tariff Schedule 21. The program is intended to increase conservation thereby reducing electricity consumption in the homes of low-income residential customers. Weatherization services are provided at no charge to eligible households.

In 2005, the Commission authorized an increase in Low-Income Weatherization Assistance (LIWA) annual funding from \$100,000 to \$150,000 (Case No. PAC-E-05-01; Order No. 29837). In 2007, tariff Schedule 21 was revised to expand the scope of allowed weatherization measures (Case No. PAC-E-06-10). Pursuant to Stipulation in that case, allowed conservation measures include all cost-effective measures approved by the U.S. Department of Energy (DOE) with a "savings to investment ratio" (SIR) greater or equal to 1.0 for electrically-heated homes. The parties also agreed to increase RMP's weatherization sharing percentage from 50% to 75% of the total cost of the approved weatherization measures.

As part of the Stipulation in Case No. PAC-E-06-10, CAPAI agreed that it would not intervene or otherwise participate in any future proceedings to modify Schedule 21 or other RMP weatherization programs from April 1, 2007 to March 31, 2009. For its part, RMP agreed to conduct a study to determine the cost-effectiveness of its Weatherization Program after March 31, 2009, and to submit the results of its study to the Commission. RMP's overall annual spending amount for Schedule 21 was to remain unchanged at \$150,000. Reference Order No. 30239, Case No. PAC-E-06-10.

In this case, CAPAI requested an increase in annual LIWA funding from \$150,000 to \$4.08 per residential customer (approximately \$231,000) and proposed eliminating the 75%/25%

matching requirement. Tr. pp. 1902, 1903, 1917. RMP's program requires 75% of each dollar of LIWA come from a non-utility source. RMP opposed any change stating that the Company's weatherization cost-effectiveness study had not been completed and would not be completed and evaluated until early 2011.

Commission Staff agrees that the funding for low-income services should be increased and recommends an annual funding level of \$300,000. Staff agrees that both SEICAA (Southeastern Idaho Community Action Agency) and EICAP (Eastern Idaho Community Action Partnership) maintain waiting lists of eligible clients needing weatherization services. Tr. p. 2105. Of those eligible clients who have electric space heating and are served by RMP, SEICAA identified 741 customers and EICAP identified 233 customers. In 2007, 52 homes were weatherized, while a total of 205 homes were weatherized in 2008 and 2009 due to the availability of American Reinvestment and Recovery Act (ARRA) funding. The expected loss of ARRA funds in March 2011 will decrease the ability of SEICAA and EICAP to leverage utility funds with other sources.

It is clear to Staff that utility funding alone is unlikely to fully meet the need for low-income weatherization services. Increasing the annual funding level to \$300,000, Staff contends, will assist SEICAA and EICAP's efforts to sustain their existing capacity to weatherize homes and will prevent the number of homes weatherized from declining to the pre-ARRA levels of about 50 homes per year.

Staff recommends that the current cap the Company will pay on a home weatherization project be increased from 75% to 85% of the installed costs for approved measures. Staff notes that in Case No. PAC-E-06-10, the Company argued that removing the spending cap would reduce the number of homes weatherized and decrease the cost-effectiveness of the program. This issue was to be addressed by the Company's impact evaluation study. Staff's recommendation to increase the cap to 85% is consistent with Idaho Power's current cap. This change would increase the amount of RMP funds that would be available for each project. Tr. p. 2107.

Commission Findings

Addressing the continued needs in RMP's Idaho service territory of the low-income sector, we find that the record reflects there is a five-year backlog of homes that need and are eligible for weatherization in Idaho. We find that RMP does not dispute the cost-effectiveness of

its Schedule 21 weatherization program for low-income customers. We find it reasonable to increase RMP's current annual funding level for low-income weatherization in this case from \$150,000 to \$300,000 and increase the dollar amount of RMP funds available for each individual project from 75% to 85% of total eligible costs. The Company indicated that an impact evaluation of the LIWA program would be completed by year-end 2010, and the results provided to the Commission in early 2011. This study will provide information that may be used to propose further changes to the program in the future.

E. Miscellaneous Consumer and Customer Service Issues

(1) Disconnect Policy

RMP engages in a practice when a customer account is terminated and a premises is vacated of not physically disconnecting service until metered usage exceeds 1,000 kWh. To reduce unbilled usage between tenants and avoid wasted energy, RMP is directed to change its disconnect policy. RMP is directed to work with Staff to develop an acceptable protocol.

(2) Estimated Bills

RMP is directed to work with Commission Staff to devise a plan to reduce the number of estimated bills that it currently generates.

(3) Tenant Notice

RMP is directed to follow through on its rate case commitment to send a postcard to customers (tenants) when service is initiated by a customer's landlord.

(4) Rebilling Policy

RMP is directed to meet with Commission Staff to discuss the Company's rebilling policy and explore any possibilities for improvements.

(5) Moratorium and Winter Payment Plan

RMP is directed to follow through on its rate case commitment to revise its brochure on Moratorium and Winter Payment Plan to convey a more effective message to customers.

F. Miscellaneous Company Rebuttal Proposals

RMP in rebuttal recommends that "the Northwest Energy Efficiency Alliance (NEEA) program for market transformation and the Agricultural Energy Saver Program be discontinued in Idaho effective January 1, 2011." Tr. p. 597. The Company admits that the Agricultural Energy Saver Program is cost-effective. Tr. p. 592.

RMP in rebuttal proposes changes to the Irrigation Load Control Program to reduce costs and increase effectiveness. Tr. pp. 595-597.

Commission Findings

The above changes proposed by RMP and the late timing of same in this case, we find, preclude any meaningful opportunity for public notice and participation by interested parties. The Company's proposals will therefore not be considered in this case.

VI. INTERVENOR FUNDING

Intervenor funding is available pursuant to *Idaho Code* § 61-617A and Commission Rules of Procedure 161 through 165. Section 61-617A(1) declares that it is the "policy of this state to encourage participation at all stages of all proceedings before this Commission so that all affected customers receive full and fair representation in those proceedings." The statutory cap for intervenor funding that can be awarded in any one case is \$40,000. *Idaho Code* § 61-617A(2). Accordingly, the Commission may order any regulated utility with intrastate annual revenues exceeding \$3.5 million to pay all or a portion of the costs of one or more parties for legal fees, witness fees and reproduction costs not to exceed a total for all intervening parties combined of \$40,000.

Petitions for Intervenor Funding were filed by Community Action Partnership Association of Idaho (\$16,975.75), the Idaho Irrigation Pumpers Association (\$86,855.32), and Idaho Conservation League (\$21,890).

Rule 162 of the Commission's Rules of Procedure provides the form and content requirements for a petition for intervenor funding. The petition must contain: (1) an itemized list of expenses broken down into categories; (2) a statement of the intervenor's proposed finding or recommendation; (3) a statement showing that the costs the intervenor wishes to recover are reasonable; (4) a statement explaining why the costs constitute a significant financial hardship for the intervenor; (5) a statement showing how the intervenor's proposed finding or recommendation differed materially from the testimony and exhibits of the Commission Staff; (6) a statement showing how the intervenor's recommendation or position addressed issues of concern to the general body of utility users or customers; and (7) a statement showing the class of customer on whose behalf the intervenor appeared.

Community Action Partnership Association of Idaho (CAPAI)

CAPAI is a non-profit corporation overseeing a number of agencies that assist with issues related to the causes and conditions of poverty in Idaho. CAPAI receives funding from a variety of sources, including governmental. Its funding sources are unpredictable and impose conditions or limitations on the scope and nature of work eligible for funding. CAPAI contends that even with intervenor funding, participation in this case constitutes a significant financial hardship.

In this case, CAPAI addressed the funding level of the Company's Low-Income Weatherization Assistance (LIWA) program, the funding eligibility limit for individual LIWA projects and the Company's proposed rate design for residential customers.

Idaho Irrigation Pumpers Association, Inc. (IIPA; Irrigators)

IIPA is a non-profit corporation representing farm interests in southern and central Idaho. The Irrigators rely solely upon dues and contributions voluntarily paid by members based on acres irrigated or horsepower per pump. IIPA reports that member contributions have been falling and attributes this to the current depressed economy, increased operation costs and threats related to water right protection issues. IIPA contends that as a result of financial constraints its participation in this case constitutes a financial hardship.

The Irrigators in this case addressed the Company's weather normalization process, the energy allocation factor used to assign cost responsibility to the Idaho jurisdiction, the treatment of irrigation load control programs in the Company's jurisdictional allocation model, the impact of the declining load in the load growth adjustment rate (LGAR) used in the Company's Energy Cost Adjustment Mechanism (ECAM), the Company's cost of service study for the irrigation class and the Company's proposed changes to the irrigation load control program.

Idaho Conservation League (ICL)

ICL is a non-profit member organization working to protect Idaho's clean water, clean air and wilderness. The organization advocates for public values and addresses energy issues including energy efficiency and renewable energy. The organization is funded by charitable donations. In this proceeding ICL advanced a residential Schedule 1 three-tier rate design and rate spread specifically intended to incentivize energy efficiency and conservation. The organization also addressed irrigation load control and pollution control cost issues.

Commission Findings

Submitted for Commission consideration are the Petitions for Intervenor Funding filed by Community Action Partnership Association of Idaho (\$16,975.75), the Idaho Irrigation Pumpers Association, Inc. (\$86,855.32), and the Idaho Conservation League (\$21,890). The Commission has reviewed the Petitions, the post-hearing brief of CAPAI, RMP's response, and the record of proceedings including the testimony of Petitioners and Commission Staff.

Intervenor funding is available pursuant to *Idaho Code* § 61-617A and Commission Rules of Procedure 161-165. Rule 162 of the Commission's Rules of Procedure provides the form and content requirements for a petition for intervenor funding.

Idaho Code § 61-617A includes a statement of policy to encourage participation by intervenors in Commission findings. The Commission determines an award for intervenor funding based on the following considerations:

- (a) A finding that the participation of the intervenor has materially contributed to the decision rendered by the Commission; and
- (b) A finding that the costs of intervention are reasonable in amount and would be a significant financial hardship for the intervenor; and
- (c) The recommendation made by the intervenor differed materially from the testimony and exhibits of the Commission Staff; and
- (d) The testimony and participation of the intervenor addressed issues of concern to the general body of users or consumers.

Idaho Code § 61-617A; IDAPA 31.01.01.165. We find that the Petitions for Intervenor Funding filed by CAPAI, IIPA and ICL comport with the procedural and technical requirements set forth in Rules 161-165 of the Commission's Rules of Procedure.

CAPAI is a non-profit corporation that regularly participates in RMP's rate cases. It addresses tariff and program issues related to causes and conditions of poverty in Idaho. It is important given the economic conditions that prevail in RMP's service territory for low-income customers to have an effective advocate for their interests. The Company in reply brief at page 3 states "RMP did not propose any changes to LIWA and, therefore, did not have any burden to address the existing low-income programs or tariffs."

CAPAI's request for intervenor funding in this case is comprised of the following elements: Attorney fees, \$15,080; Expert Witness fees, \$1,750; and \$145.75 in office and

postage for total itemized expenses of \$16,975.75. We find that the Petition of CAPAI satisfies the substantive findings we are required to make to justify an award. IDAPA 31.01.01.165.01.a-e. We make a small adjustment in authorized expenses and find it fair, just and reasonable to approve funding for CAPAI in the amount of \$16,400. In awarding nearly the full amount requested, we find that the public is well served by such an award. We find that the costs for CAPAI should be assessed for later recovery to the residential Schedule 1 and 36 customer classes. We find the itemized costs of CAPAI to be reasonable and recognize that the cost of CAPAI participating in these proceedings constitutes a significant financial hardship to the organization. We find that CAPAI was professional and economical in the marshaling of its time and efforts.

IIPA is a non-profit corporation representing farm interests and a regular participant in RMP's rate cases. We appreciate the participation of the Irrigators in this case and recognize their contribution to the ultimate resolution of issues. The Irrigators have submitted an accounting of costs totaling \$86,855.32 comprised of Attorney fees, \$22,644; Expert Witness fees, \$60,625; and \$3,586.32 in office, lodging, postage, transportation and meals. IIPA claims entitlement to an award of costs in the maximum amount allowable. We provide no comment as to the overall reasonableness of the submitted accounting by IIPA. As the Irrigators recognize, we are limited in the amount we can award.

ICL is a non-profit corporation addressing energy, conservation and environmental issues. We appreciate their participation. In this case, ICL has requested \$21,890 in intervenor funding comprised of \$13,460 in Expert Witness fees and \$8,430 in Attorney fees.

We find that the Petitions of IIPA and ICL satisfy the substantive findings that we are required to make to justify an award. IDAPA 31.01.01.165.01.a-e. We find that the participation and presentation of each, as reflected in their respective testimonies materially contributed to the Commission's decision. Both add informed perspectives to the hearing record. We find that the recommendations and perspectives of each differed materially from the testimony and exhibits of Commission Staff and contributed to our decision. We find it fair, just and reasonable to split the remaining amount of available intervenor funding between IIPA and ICL, and award \$11,300 to each. We find that the costs for IIPA should be assessed for later recovery to the Company's irrigation class; and that the cost for ICL be assessed to the residential Schedule 1 and 36 customer classes.

The Commission finds that the intervenor funding awards to CAPAI, IIPA and ICL are fair, just and reasonable and will further the purpose of encouraging “participation at all stages of all proceedings before the commission so that all affected customers receive full and fair representation in those proceedings.” *Idaho Code* § 61-617A(1).

CONCLUSIONS OF LAW

The Idaho Public Utilities Commission has jurisdiction over PacifiCorp dba Rocky Mountain Power, an electric utility, its Application in Case No. PAC-E-10-07 and over the issues raised in these proceedings pursuant to Idaho Code, Title 61, and the Commission’s Rules of Procedure, IDAPA 31.01.01.000 et seq.

ORDER

In consideration of the foregoing and as more particularly described above, IT IS HEREBY ORDERED that the tariffs filed in conformance with Interlocutory Order No. 32151 (with Errata) and approved by Minute Order dated December 28, 2010, for effective date December 28, 2010 and January 1, 2011 (Schedules 400 (Monsanto) and 401 (Agrium)) are reaffirmed and authorized for continued service. For Monsanto the Schedule 400 interruptible credit (as more particularly described above and detailed in Attachment C) is changed to [REDACTED] [REDACTED] for an effective date March 1, 2011. Rocky Mountain Power is directed to file a conforming Schedule 400 tariff to be effective on March 1, 2011 for service rendered on and after that date. The authorized rates are set forth in Attachment A.

IT IS FURTHER ORDERED and Rocky Mountain Power is directed to increase its annual funding level for Schedule 21 low-income weatherization assistance in Idaho to \$300,000 and increase the dollar amount of RMP funds available for each individual project from 75% to 85% of total eligible costs.

IT IS FURTHER ORDERED that the Commission provides the foregoing guidance regarding the valuation of Monsanto’s interruptible products. In order to assist the parties in preparing a new Energy Sales Agreement (ESA), the Commission establishes a total interruptible product value of [REDACTED] and shows the components and some of the calculations in Attachment C. Further, the Commission expects the parties to craft an agreement that establishes a value for Monsanto’s interruptible products that extends for a period of five years.

IT IS FURTHER ORDERED and the Petitions for Intervenor Funding are partially granted in the amounts of \$16,400, Community Action Partnership Association of Idaho;


\$11,300, Idaho Conservation League; and \$11,300, Idaho Irrigation Pumpers Association, Inc. Reference *Idaho Code* § 61-617A. Our Interlocutory Order No. 32151 and direction to the Company in this regard is reaffirmed.

Rocky Mountain Power shall include the cost of the awards of intervenor funding to CAPAI and ICL as an expense to be recovered in the Company's next general rate case from the residential customer class. *Idaho Code* § 61-617A(3).

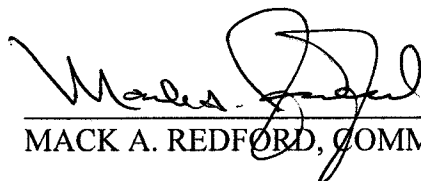
Rocky Mountain Power shall include the cost of the award of intervenor funding to IIPA as an expense to be recovered in the Company's next general rate case from the irrigation customer class. *Idaho Code* § 61-617A(3).

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.


DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 28th day of February 2011.


JIM D. KEMPTON, PRESIDENT


MARSHA H. SMITH, COMMISSIONER


MACK A. REDFORD, COMMISSIONER

ATTEST:


Jean D. Jewell
Commission Secretary

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CASE NO. PAC-E-10-07
 IDAHO PUBLIC UTILITIES COMMISSION
 ESTIMATED IMPACT OF COMMISSION APPROVED
 REVENUES BY RATE SCHEDULE
 12 MONTHS ENDING DECEMBER 2010

| Line No. | Description (1) | Sch. (2) | Average Customers (3) | MWH (4) | Revenue (\$000) | | | Change (7) (6)-(5) | % (8) (7)/(5) | Avg. Rate (\$/kWh) | |
|------------------------------------|--|-------------|--------------------------|------------------|------------------|------------------|---------------------------|--------------------------|---------------------|-----------------------------|--|
| | | | | | Present (5) | Proposed (6) | Present (9) (5)/(4) | | | Proposed (10) (6)/(4) | |
| Residential Sales | | | | | | | | | | | |
| 1 | Residential Service | 1 | 42,506 | 427,907 | \$39,005 | \$41,658 | \$2,653 | 6.8% | 9.12 | 9.74 | |
| 2 | Residential Optional TOD | 36 | 15,050 | 280,407 | \$20,624 | \$22,027 | \$1,403 | 6.8% | 7.36 | 7.86 | |
| 3 | AGA Revenue | -- | -- | 0 | \$4 | \$4 | \$0 | 0.0% | | | |
| 4 | Total Residential | | 57,556 | 708,314 | \$59,633 | \$63,689 | \$4,056 | 6.8% | 8.42 | 8.99 | |
| Commercial & Industrial | | | | | | | | | | | |
| 5 | General Service - Large Power | 6 | 1,059 | 280,497 | \$17,659 | \$18,962 | \$1,303 | 7.4% | 6.30 | 6.76 | |
| 6 | General Svc. - Lg. Power (R&F) | 6A | 243 | 33,001 | \$2,325 | \$2,496 | \$171 | 7.4% | 7.04 | 7.56 | |
| 7 | Subtotal-Schedule 6 | | 1,302 | 313,498 | \$19,983 | \$21,458 | \$1,475 | 7.4% | 6.37 | 6.84 | |
| 8 | General Service - High Voltage | 9 | 12 | 106,486 | \$5,062 | \$5,432 | \$370 | 7.3% | 4.75 | 5.10 | |
| 9 | Irrigation | 10 | 4,810 | 545,290 | \$39,846 | \$41,007 | \$1,161 | 2.9% | 7.31 | 7.52 | |
| 10 | Comm. & Ind. Space Heating | 19 | 135 | 7,769 | \$534 | \$563 | \$29 | 5.4% | 6.88 | 7.25 | |
| 11 | General Service | 23 | 6,692 | 134,294 | \$10,731 | \$11,216 | \$485 | 4.5% | 7.99 | 8.35 | |
| 12 | General Service (R&F) | 23A | 1,494 | 18,907 | \$1,579 | \$1,648 | \$69 | 4.4% | 8.35 | 8.72 | |
| 13 | Subtotal-Schedule 23 | | 8,186 | 153,201 | 12,310 | 12,864 | 554 | 4.5% | 8.03 | 8.40 | |
| 14 | General Service Optional TOD | 35 | 3 | 1,883 | \$92 | \$99 | \$7 | 7.4% | 4.90 | 5.26 | |
| 15 | Special Contract 1 | | 1 | 1,385,173 | \$59,524 | \$65,249 | \$5,725 | 9.6% | 4.30 | 4.71 | |
| 16 | Special Contract 2 | | 1 | 101,450 | \$4,466 | \$4,884 | \$418 | 9.4% | 4.40 | 4.81 | |
| 17 | AGA Revenue | -- | -- | 0 | \$681 | \$681 | \$0 | 0.0% | | | |
| 18 | Total Commercial & Industrial | | 14,451 | 2,614,750 | \$142,499 | \$152,237 | \$9,738 | 6.8% | 5.45 | 5.82 | |
| Public Street Lighting | | | | | | | | | | | |
| 20 | Security Area Lighting | 7 | 204 | 264 | \$97 | \$97 | \$0 | 0.0% | 36.81 | 36.81 | |
| 21 | Security Area Lighting (R&F) | 7A | 153 | 131 | \$52 | \$52 | \$0 | 0.0% | 39.62 | 39.62 | |
| 22 | Street Lighting - Company | 11 | 30 | 101 | \$44 | \$44 | \$0 | 0.0% | 43.87 | 43.87 | |
| 23 | Street Lighting - Customer | 12 | 323 | 2,313 | \$407 | \$407 | \$0 | 0.0% | 17.60 | 17.60 | |
| 24 | AGA Revenue | -- | -- | 0 | \$0 | \$0 | \$0 | 0.0% | | | |
| 25 | Total Public Street Lighting | | 710 | 2,809 | \$601 | \$601 | \$0 | 0.0% | 21.38 | 21.38 | |
| 26 | Total Sales to Ultimate Customers | | 72,717 | 3,325,873 | \$202,733 | \$216,527 | \$13,794 | 6.8% | 6.10 | 6.51 | |

CASE NO. PAC-E-10-07
 IDAHO PUBLIC UTILITIES COMMISSION
 COMPARISON OF PRESENT AND
 COMMISSION APPROVED RATE STRUCTURE
 AND RATES

| Line No. | Description | Sch. | Billing Component | Present | Commission Approved |
|------------------------------------|------------------------------------|-------|--------------------------|----------|---------------------|
| | (1) | (2) | (3) | (4) | (5) |
| <u>Residential Sales</u> | | | | | |
| 1 | Residential Service | 1 | Minimum Charge | \$10.64 | none |
| 2 | | | Customer Charge | none | \$5.00/month |
| 3 | | | <u>May-Oct</u> | | |
| 4 | | | First Block kWh Rate | 10.4093 | 0-700: 9.5761 |
| 5 | | | Second Block kWh Rate | 10.4093 | > 700: 12.9277 |
| 6 | | | <u>Nov-Apr</u> | | |
| 7 | | | First Block kWh Rate | 8.015 | 0-1,000: 7.3300 |
| 8 | | | Second Block kWh Rate | 8.015 | > 1,000: 9.8955 |
| 9 | Residential Optional TOD | 36 | Customer Charge | \$13.63 | \$14.00 |
| 10 | | | May-Oct On-Peak | 11.3497 | 12.1845 |
| 11 | | | May-Oct Off-Peak | 3.873 | 4.1579 |
| 12 | | | Nov-Apr On-Peak | 9.695 | 10.4081 |
| 13 | | | Nov-Apr Off-Peak | 3.5447 | 3.8054 |
| <u>Commercial & Industrial</u> | | | | | |
| 14 | General Service - Large Power (a) | 6, 6A | Cust. Charge (Secondary) | \$30.97 | \$33.00 |
| 15 | | | Cust. Charge (Primary) | \$97.91 | \$99.00 |
| 16 | | | Demand (May-Oct) (KW) | \$11.34 | \$12.18 |
| 17 | | | Demand (Nov-Apr) (KW) | \$9.33 | \$10.02 |
| 18 | | | kWh Rate | 3.138 | 3.3702 |
| 19 | | | Voltage Discount | (0.53) | (0.57) |
| 20 | | | | | |
| 21 | General Service - High Voltage (a) | 9 | Customer Charge | \$301.10 | \$323.00 |
| 22 | | | Demand (May-Oct) (KW) | \$7.88 | \$8.46 |
| 23 | | | Demand (Nov-Apr) (KW) | \$5.96 | \$6.40 |
| 24 | | | kWh Rate | 3.2519 | 3.4887 |

(a) Rocky Mountain Power proposes a greater increase in demand components than energy components. The Commission approves a uniform increase to all components.
 NO. PAC-E-10-07

**IDAHO PUBLIC UTILITIES COMMISSION
 COMPARISON OF PRESENT AND
 COMMISSION APPROVED RATE STRUCTURE**

AND RATES

| Line No. | Description (1) | Sch. (2) | Billing Component (3) | Present (4) | Commission Approved (5) |
|----------|------------------------------|----------|-------------------------------|-------------|-------------------------|
| 25 | Irrigation (a) | 10 | In-Season (June 1-Sept 15) | | |
| 26 | | | Small Cust. Charge | \$11.74 | \$12.00 |
| 27 | | | Large Cust. Charge | \$34.14 | \$35.00 |
| 28 | | | Demand (KW) | \$4.55 | \$4.68 |
| 29 | | | First 25,000 kWh | 7.1315 | 7.3388 |
| 30 | | | Next 225,000 kWh | 5.275 | 5.4284 |
| 31 | | | All add'l kWh | 3.9095 | 4.0411 |
| 32 | | | Post Season (Sept 16- May 31) | | |
| 33 | | | Customer Charge | \$18.08 | \$19.00 |
| 34 | | | kWh Rate | 6.0315 | 6.2069 |
| 35 | Comm. & Ind. Space Heating | 19 | Customer Charge | \$20.10 | \$21.00 |
| 36 | | | kWh Rate (May-Oct) | 7.8457 | 8.2723 |
| 37 | | | kWh Rate (Nov-Apr) | 5.8133 | 6.1294 |
| 38 | General Service | 23, 23A | Customer Charge Secondary | \$13.72 | \$14.00 |
| 39 | | | Customer Charge Primary | \$41.16 | \$43.00 |
| 40 | | | kWh Rate (May-Oct) | 7.6737 | 8.0424 |
| 41 | | | kWh Rate (Nov-Apr) | 6.6985 | 7.0204 |
| 42 | | | Voltage Discount | (0.3706) | (0.3884) |
| 43 | General Service Optional TOD | 35, 35A | Customer Charge Secondary | \$54.75 | \$59.00 |
| 44 | | | On-Peak Demand (KW) | \$13.48 | \$14.47 |
| 45 | | | kWh Rate | 4.0167 | 4.3130 |
| 46 | | | Voltage Discount | (0.69) | (0.74) |

(a) Rocky Mountain Power proposes a greater increase in demand components than energy components. The Commission approves a uniform increase to all components.

**IDAHO PUBLIC UTILITIES COMMISSION
COMPARISON OF PRESENT AND
COMMISSION APPROVED RATE STRUCTURE
AND RATES**

| Line No. | Description (1) | Sch. (2) | Billing Component (3) | Present (4) | Commission Approved (5) |
|----------|-------------------------------|-----------|-----------------------|-------------|-------------------------|
| 47 | Special Contract 1 (b) | 400 | Customer Charge | \$1,227.00 | \$1,345.00 |
| 48 | | | Demand (KW) | \$12.27 | \$13.45 |
| 49 | | | kWh Rate | 2.381 | 2.6100 |
| 50 | | | Excess KVar | \$0.75 | \$0.82 |
| 51 | Special Contract 2 | 401 | Customer Charge | \$341.33 | \$373.00 |
| 52 | | | <u>May-October</u> | | |
| 53 | | | HLH kWh Rate | 2.808 | 3.0710 |
| 54 | | | LLH kWh Rate | \$2.11 | 2.3030 |
| 55 | | | Demand (KW) | \$13.60 | \$14.87 |
| 56 | | | <u>November-April</u> | | |
| 57 | | | HLH kWh Rate | 2.336 | 2.5540 |
| 58 | | | LLH kWh Rate | 2.106 | 2.3030 |
| 59 | | | Demand (KW) | \$10.97 | \$12.00 |
| 60 | <u>Public Street Lighting</u> | 7, 11, 12 | All Components | N/A | No Change |

(b) Does not contain rate adjustments due to interruptibility credit.

CONFIDENTIAL

ATTACHMENT C