- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	))))))	DOCKET NO. 06-035-21 REPORT AND ORDER

ISSUED: December 1, 2006

SHORT TITLE

PacifiCorp 2006 General Rate Case

SYNOPSIS

The Commission approves the Stipulation Regarding Revenue Requirement and Rate Spread increasing Pacificorp's annual revenue requirement by $115 million, or 9.95 percent, effective December 11, 2006, based on an allowed rate of return on equity of 10.25 percent. The increase in annual revenue requirement is subject to a $30 million rate credit beginning December 11, 2006, and terminating May 31, 2007. Net of the rate credit, customer rates increase by $85 million effective December 11, 2006 and by an additional $30 million on June 1, 2007.

The Commission also approves the Stipulation on Rate Design for Electric Service Schedules 6, 6A and 6B, the Stipulation on Rate Design for Electric Service Schedules 8, 9, and 31, decides contested issues regarding rate design for Electric Service Residential Schedule 1 and approves rate design for the remaining schedules.

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I. PROCEDURAL HISTORY

On March 7, 2006, PacifiCorp ("Company") filed an application for a rate increase of $197.2 million based on a future test period beginning October 1, 2006, and ending September 30, 2007, and a request for a scheduling conference. The application includes direct testimony on test year, capital structure and capital costs, load and retail sales forecast, revenue requirement, cost of service, revenue spread to rate schedules, rate design, and changes to schedules and regulations including increases in the Company's charges for field visits, reconnection services and returned payments.

Prior to the Company's March 7, 2006, application, stipulations were filed relating to this application. On October 20, 2004, the Commission approved the Test Period Stipulation in Docket 04-035-42, "In the Matter of the Application of PacifiCorp for Approval of its Electric Service Schedules and Electric Service Regulations." Paragraph 8 of this stipulation specifies that if issues associated with test period are not resolved by October 1, 2005, the Company, the Utah Division of Public Utilities ("Division"), the Utah Committee of Consumer Services ("Committee") and other interested parties would meet to discuss information to be filed and the test year to be used during the next general rate case. As a follow-up to this condition, on January 30, 2006, the Company filed and moved for its approval, the Stipulation on Filing Requirements, Discovery, and Timing of Test Period Hearing ("Filing Requirement Stipulation"). This stipulation was presented before the Commission at hearing on February 10, 2006, and approved with modification on February 22, 2006. Parties to this stipulation are the Company, the Division, the Committee, and Utah Association of Energy Users Intervention Group ("UAE").

In response to the Company's February 14, 2006, Motion for Protective Order and Request for Expedited Treatment, the Commission issued a Protective Order on February 16, 2006.

On March 14, 2006, UAE filed a Request for Hearing on Test Year. Following a March 16, 2006, scheduling conference, on April 4, 2006, the Commission issued an order setting the schedule for this case. The schedule was subsequently amended as requested by the parties, by the Commission on April 18, 2006, May 1, 2006, June 20, 2006, July 6, 2006, August 1, 2006, and September 15, 2006.

On April 5, 2006, MidAmerican Energy Holdings Company ("MEHC") filed supplemental direct testimony containing a revised revenue requirement in which the Company reduced its requested increase from $197.2 million to $194.1 million. This filing was made in compliance with Commitment U23 of Appendix A to the November 15, 2005, Stipulation in Docket No. 05-035-54, "In the Matter of the Acquisition of the PacifiCorp by MidAmerican Energy Holdings Company." This commitment states the Company will file supplemental testimony by an MEHC witness to discuss and update the Company's revenue requirement and to incorporate any additional adjustments that are appropriate as a result of the acquisition.

On May 5, 2006, the Company filed, and moved for its approval, the Stipulation Regarding Schedule and Revenue Requirement Issues. This stipulation was approved by the Commission with modification on May 24, 2006, and amended on May 31, 2006. Parties to this stipulation are the Company, the Division, the Committee, Utah Industrial Energy Consumers ("UIEC"), Federal Executive Agencies ("FEA"), UAE, American Association of Retired Persons ("AARP"), the Kroger Co. ("Kroger"), Roger Ball, Nucor Steel - a Division of

Nucor Corporation ("Nucor"), Central Valley Water Reclamation Facility ("Central Valley Water"), and Utah Manufacturers Association.

On June 9, 2006, direct testimony on test year was filed by the Division, the Committee, and UAE. Rebuttal testimony on test year was filed by the Company and the Division on June 30, 2006. Surrebuttal testimony on test year was filed by UAE on July 14, 2006. On July 25, 2006, the Company filed a Motion to Vacate Test Period Hearing.

On July 26, 2006, the Company filed a Motion to Amend Procedural Schedule, a Stipulation Regarding Revenue Requirement and Rate Spread ("Revenue Stipulation"), and a Motion for Approval of Stipulation. Parties to this stipulation are the Company, the Division, the Committee, UIEC, FEA, UAE, AARP, Nucor, Utah Manufacturers Association, and Central Valley Water. Direct testimony related to this stipulation was filed by the Company, the Division, and the Committee on August 17, 2006. This stipulation was heard by the Commission on August 28, 2006. At hearing, David Taylor for the Company, Thomas Brill and Charles Peterson for the Division, and Donna Deronne and Reed Warnick for the Committee, presented testimony in support of the stipulation. The Commission questioned the parties and witnesses regarding various aspects of the stipulation and the evidence presented.

On August 25, 2006, the Company filed, and moved for its approval, the Stipulation Regarding Rate Design addressing rate schedules 6, 6A, and 6B ("Schedule 6 Stipulation"). Parties to this stipulation are the Company, the Division, UIEC, AARP, and Kroger. Direct testimony related to this stipulation was filed by the Company on September 15, 2006, and by the Division on October 3, 2006. The Schedule 6 Stipulation was presented before the Commission at hearing on October 12, 2006. At hearing, William Griffith for the Company, and

George Compton for the Division, presented testimony in support of this stipulation. The Commission questioned the parties and witnesses regarding various aspects of this stipulation and the evidence presented.

On September 6, 2006, Roger Ball filed a request with the Commission entitled, "Request to Deny Motion and Reject Stipulation." Responses to Mr. Ball's request were filed by the Company on September 12, 2006, and by the Committee and the Division on September 14, 2006. A Reply to Opposition to Request to Deny Motion and Reject Stipulation was filed by Mr. Ball on September 25, 2006.

On September 15, 2006, the Company filed, and moved for approval, the Stipulation for Rate Design addressing rate schedules 8, 9, and 31 ("Schedule 8/9/31 Stipulation"). Parties to this stipulation are the Company, the Division, UIEC, FEA, UAE, Kroger, Central Valley Water, and Utah Manufacturers Association. Direct testimony related to this stipulation was filed by the Company on September 15, 2006, and by the Division on October 3, 2006. This stipulation was presented before the Commission at hearing on October 12, 2006. At hearing, William Griffith for the Company, and George Compton for the Division, presented testimony in support of the stipulation. The Commission questioned the parties and witnesses regarding various aspects of the stipulation and the evidence presented.

On September 15, 2006, the Commission issued a scheduling order addressing remaining rate design and cost of service issues. Direct testimony on these issues was filed by the Division, the Committee, Utah Ratepayers Alliance, and AARP on September 27, 2006, and rebuttal testimony was filed by the Division on October 16, 2006, and by the Company on October 17, 2006. Surrebuttal testimony was filed by the Committee and Utah Ratepayers

Alliance on October 23, 2006. These issues, including public witness testimony, were presented before the Commission at hearing on October 27, 2006.

Participants in this case are the Company, the Division, the Committee, UAE (including the Utah Association of Energy Users, Alliant Techsystems, Chevron Corporation, ConocoPhillips, Hexcel Corporation, IHC Health Services, Inc., Simplot Phosphates LLC, Swift & Company ~ Miller's Blue Ribbon Beef, Tesoro Refining and Marketing Company and American Pacific Corporation), UIEC (Fairchild Semiconductor, Holcim, Inc., Kennecott Utah Copper Corp., Kimberly-Clark Corp., Malt-O-Meal, Praxair, Inc., and Western Zirconium), FEA, Nucor, AARP, Kroger, Utah Manufacturers Association, Central Valley Water, Roger Ball, Utah Ratepayers Alliance (Crossroads Urban Center and Salt Lake Community Action Program), Questar Gas Company, International Brotherhood of Electrical Workers - Local 57, US Magnesium LLC, Million Solar Roofs Partnership, and Wal-Mart Stores, Inc.

II. STIPULATION ON REVENUE REQUIREMENT AND RATE SPREAD

A. Overview

Without modifying its terms in any way, the following is a brief summary of the Stipulation on Revenue Requirement and Rate Spread ("Revenue Stipulation"). The Stipulation and an attached Exhibit 1 summarizing the revenue changes by rate schedules are included as Appendix I to this order.

The parties to the Revenue Stipulation agree the Company should be authorized to increase its Utah jurisdictional revenues by $85 million effective December 11, 2006, and by an additional $30 million effective June 1, 2007. The Revenue Stipulation states the $115 million total increase in revenues is not based on any agreement as to the test period or specific revenue requirement adjustments. The parties agree the Company's authorized rate of return on common equity for the purposes of the Stipulation will be 10.25 percent. Other capital costs and the capital structure are not addressed by the Revenue Stipulation.

The full projected load for IM Flash Technologies for the period October 2006 to September 2007 is included in the forecast of retail loads used for the purposes of this case. This load forecast is provided as Exhibit 2 to the Revenue Stipulation. Due to concerns of confidentiality regarding this individual customer, this exhibit is not included in Appendix I.

The Company agrees it will not file another rate case before December 11, 2007, ("stay-out provision") and agrees to withdraw its application in Docket No. 05-035-102 seeking approval of a power cost adjustment mechanism ("PCAM"). The parties to the Revenue Stipulation agree they will continue discussions regarding informational filing requirements and master data requests for the Company's next rate case, an effort reflected in the Filing Requirement Stipulation previously approved in this docket. The parties also agree the Revenue Stipulation does not alter or impair the recovery of regulatory assets previously deferred by Utah Commission orders under Financial Accounting Standard 71.

During the period from October 2006 to September 2007, the Company agrees expenditures for distribution maintenance will be not less than 93 percent of the Company's projected amount of $67.5 million and capital costs for distribution pole replacements will be not less than $5.1 million. The Company will provide a report on the status of its compliance with this commitment to the Division and Committee on November 15, 2007.

Finally, the Company agrees to provide summary results of operations for the states of Utah, Idaho and Wyoming comprising the service territory of Rocky Mountain Power in its semi-annual reports.

The Revenue Stipulation allows the Company to increase its annual jurisdictional revenues by $115 million effective December 11, 2006, subject to a $30 million rate credit effective for the period December 11, 2006, through May 31, 2007. Annual revenues at current rates are forecast to be $1,222.389 million. The stipulated $115 million revenue increase yields jurisdictional revenues of $1,337.39 million, amounting to a 9.41 percent revenue increase. The following is a brief description of the spread of the $115 million revenue increase to rate schedules. In addition, the spread of the $30 million rate credit is equal to the spread of the $115 million increase, i.e., each rate schedule's percentage share of the $30 million revenue credit is equal to its percentage share of the $115 million revenue increase. A summary of the spread of the revenue increase and credit by rate schedule, as well as the forecasted number of customers, usage and revenues, is presented in Exhibit 1 of the Revenue Stipulation.

Customers receiving no revenue increase include four special contract customers with total forecast revenues of $64.177 million (because their price changes are subject to the terms and conditions of each contract), three lighting contract customers with revenues of $0.039 million, and the Annual Guarantee Adjustment (line extension contract payments) with revenues of $2.236 million. These account for $66.452 million in forecast revenues. Hence the $115 million revenue increase must be obtained from the remaining customers, whose forecast revenues at existing rates are $1,155.937 million, amounting to a 9.95 percent increase. This overall jurisdictional increase of 9.95 percent is applied to irrigation Electric Service Rate

Schedule No. 10, "Irrigation and Soil Drainage Pumping Power Service," with its time-of-day program option, for an increase of $1.045 million.

Certain rate schedules receive a revenue increase of 9.31 percent, an increase less than the overall jurisdictional increase. These include Electric Service Rate Schedules No. 6, "General Service Distribution Voltage" receiving a $30.298 million increase, No. 6A, "General Service Energy Time-of-Day Option" receiving a $1.704 million increase, No. 6B, "General Service Demand Time-of-Day Option" receiving a $0.058 million increase, and No. 23, "General Service Distribution Voltage - Small Customer" receiving a $7.881 million increase.

Certain rate schedules receive a revenue increase of 12.31 percent, an increase greater than the overall jurisdictional increase. These include Electric Service Rate Schedules No. 25, "Mobile Home and House Trailer Park Service - Existing Customers Only" receiving a $0.82 million increase, No. 7, "Security Area Lighting - Closed to New Service" receiving a $0.339 million increase, No. 11, "Street Lighting - Company-Owned Overhead System" receiving a $0.664 million increase, No. 12, "Street Lighting (Customer Owned)" receiving a $0.362 million increase, No. 12, "Traffic & Other Signal Systems" receiving a $0.074 million increase, and No. 13, "Decorative Street Lighting" receiving a $0.128 million increase.

In addition, Electric Service Rate Schedules No. 12, "Metered Outdoor Nighttime Lighting" with revenues of $0.676 million and No. 21, "Electric Furnace Operations - Limited Service - No New Service" with revenues of $0.273 million each receive no revenue increase.

These decisions result in an increase of $42.634 million in revenues, leaving the remainder of the $115 million revenue increase, or $72.366 million, to be spread to the remaining rate schedules. These remaining rate schedules have forecast revenues at existing rates of $702.012 million, hence they are to receive a 10.31 percent increase. These rate schedules include Electric Service Rate Schedules No. 1, "Residential Service" and No. 3, "Low Income Lifeline Program-Residential Service Optional for Qualifying Customers" together receiving a $46.518 million increase, No. 2, "Residential Service Optional Time-of-Day Rider Experimental" receiving a $0.023 million increase, No. 8, "Large General Service - 1,000 kilowatt (kW) and Over - Distribution Voltage" receiving a $10.793 million increase, No. 9, "General Service - High Voltage" receiving a $14.668 million increase, No. 9A, "General Service - High Voltage - Energy Time-of-Day Option - Closed to New Service" receiving a $0.211 million increase, and No. 31, "Back-up, Maintenance, and Supplementary Power" receiving an increase of $0.153 million.

B. Discussion, Findings and Conclusions

Ten parties, the Company, the Division, the Committee, UIEC, FEA, UAE, AARP, Nucor, Utah Manufacturers Association, and Central Valley Water, representing a diversity of Utah customer interests signed the Revenue Stipulation. These parties agree the Revenue Stipulation is in the public interest and all of its terms and conditions, considered together as a whole, will produce fair, just and reasonable results. The Company, the Division and the Committee provide testimony recommending the Commission approve the Revenue Stipulation. No party of record provides testimony in opposition to the Revenue Stipulation.

The Company testifies the increase in revenues will provide the Company with the minimum revenues necessary to recover its costs of providing service during the period when new rates will be in effect. The Company states the key factor driving its need for the revenue increase is the cost associated with serving load growth across its system and particularly the significant growth in Utah in the number of customers, total energy consumption and peak demand. The need to supply peak demand requires the Company to make large investments in new generating resources and transmission lines, and to expand and upgrade its Utah distribution system.

In addition, the Company testifies the Revenue Stipulation is in the public interest because: (1) it is supported by the analyses performed by the auditors and representatives of the Division and Committee; (2) from the perspective of many parties the withdrawal of the Company's PCAM application is a benefit to customers; (3) the stay-out provision provides rate stability for customers; (4) the spending commitments ensure the Company will spend every dollar it requested in this case in the areas related to distribution, maintenance and pole replacement; and (5) the reporting and filing requirements will benefit the regulatory process. Finally, the Company claims, even with this revenue increase, prices in Utah will still be lower than they were twenty years ago and remain among the lowest in the West and in the nation.

The Division testifies it performed an extensive review and analysis of the Company's proposed revenue increase including discovery composed of 16 sets of data requests with more than 253 questions and examined responses to data requests made by other parties. The Division briefly describes its audit of the Company's filing. In addition to making its own auditing adjustments, the Division also investigated forecasting and net power cost assumptions. The Division also analyzed capital structure and capital costs, concluding the stipulated 10.25 percent rate of return on common equity provides an allowed rate of return within a reasonable range. Finally, the Division states the stipulated $115 million revenue increase is well within its settlement range of $108 to $124 million, and allows the Company sufficient revenues to recover the reasonable cost of providing service in Utah. The Division concludes the Revenue Stipulation balances the interests of all parties and therefore is just and reasonable and in the public interest.

The Committee testifies it performed a full review and analysis of the Company's proposed revenue increase including discovery composed of 22 sets of data requests. The Committee also examined the recommendations and adjustments sponsored by other parties. In evaluating the Company's requested revenue increase, the Committee testifies it did not substantially adjust downward any of the capital expenditures or any of the maintenance-type expenditures requested in this case in recognition of the goal of improving system reliability on behalf of customers. The Committee also testifies the other provisions of the settlement agreement, such as the withdrawal of the PCAM application, the stay-out provision and the provisions creating greater utility accountability for expenditures for system maintenance in Utah achieve a result that is fair and very much in the interest of Utah ratepayers. As a whole, the Committee states the Revenue Stipulation results in a fair and reasonable increase in revenues for the Company and particularly for Utah customers.

Both the Division and the Committee support the phase-in of the revenue increase, from $85 million beginning December 11, 2006, to $115 million on June 1, 2007, based on the anticipated commercial operation of the Lakeside plant in May of 2007. In addition, projected transmission and distribution upgrades are expected to occur in the second half of the October 2006 through September 2007 period.

While UIEC and UAE support the stipulated $115 million increase, they did not agree with all the adjustments presented by the Division or Committee and instead support different adjustments. Further, UAE states they use a test year different from that used by other parties.

Roger Ball requests the Commission deny the Company's Motion for Approval of Stipulation and reject the associated Revenue Stipulation. He posits the Company has not proven the Revenue Stipulation will result in just and reasonable rates or that its approval and adoption by the Commission would be in the public interest. He cites the percent increase in allowed revenues since the last fully litigated rate case, such increase being the result of recent stipulations. Moreover, the dollar amount of the requested increase and its percent of the Company's original request are larger than in the previously stipulated cases. He argues a "black box" settlement based on the parties' assurances that the requested revenue increase is reasonable makes it impossible for the Commission to determine independently and on the basis of substantial evidence that the Revenue Stipulation will result in just and reasonable rates. He states the Commission should insist upon ascertaining for itself, based upon substantial evidence, what rates are justified by all the utility's costs and revenues, examined separately and only then taken together.

The Company responds to Mr. Ball by stating his request is not timely and should not be heard, he failed to file testimony to address the merits of the Revenue Stipulation, and he had ample opportunity during the hearing to cross examine witnesses and make known his position. Utah law encourages informal resolution of issues heard before the Commission by means of agreement among the parties. Settlements are consistent with Commission precedent, and are recognized by Utah courts. The Division and Committee have provided substantial evidence through the testimony of their expert witnesses and the parties' participation in armslength negotiations. The Division responds to Mr. Ball by stating he provides no persuasive evidence or valid arguments to support his claim that the Revenue Stipulation will not result in just and reasonable rates and that approval of the Revenue Stipulation is not in the public interest. Furthermore, his request is not timely. The Committee responds by stating Mr. Ball's request is at odds with any authorized or customary Commission procedure and consists of nothing more than bald assertions that do not suffice to prove any material issue of fact or law.

Mr. Ball is clear that his position is not that the Revenue Stipulation will not result in just and reasonable rates, rates resulting from approval of the Revenue Stipulation can be just and reasonable. He advances only the tentative argument or questions whether approval of the Revenue Stipulation in this case, following stipulated revenue requirement settlements of two prior company rate cases, may not be an appropriate procedural step. But, after raising the question, he makes little effort to substantiate that approval of the settlement will result in unjust or unreasonable rates. Throughout Mr. Ball's arguments, he is careful to take no position, make no argument, and make no intimation that if the Revenue Stipulation is rejected, the Commission's ultimate revenue requirement conclusion and rate setting in this case would be any different from those coming from approval of the Revenue Stipulation.

Without Mr. Ball suggesting any distinction, substantive or otherwise, between the facts or circumstances between any of the cases, we can not agree with his position that simply because this is a third revenue requirement settlement, it should be rejected. Approval of a settlement or stipulation is not dependent upon the number of previous settlements, but upon its own terms and the reasons given for and against the reasonableness of those terms in relation to their application during the period in which rates resulting from the settlement will be charged. The only effort Mr. Ball makes to show a distinction between cases is referencing the simple numerical differences and percentages between the revenue change the Company originally requested in a case and the ultimate revenue requirement change granted in a final Commission order. We do not accept Mr. Ball's intimation that a revenue requirement's reasonableness in a case can be judged by simple comparisons with other cases' percentages of Commission ordered revenue requirement vis a vis a utility's requested revenue requirement change. We are not convinced that a percentage increase or decrease from one case has any relevance to a percentage increase or decrease that may arise in another case, each with its own unique facts and circumstances.

Mr. Ball makes his argument on pure numbers, not on any merits of a factual basis. Other parties examined the Company's factual data relating to expenses and revenues and compared the conclusions they derived from such information with the Company's conclusions on the need for a revenue requirement change and the total revenue requirement change that appeared warranted. The Committee and the Division explained their discovery efforts, their examinations and analyses, and why they reached their conclusions that the revenue requirement change called for in the Revenue Stipulation was reasonable in light of the investigation and work they had performed in reviewing the Company's Application, all the information these parties had received, and their preparations for an adjudication of the case. Mr. Ball made no representation that he had done the same, or that he had examined the information and had come to different conclusions regarding a revenue requirement component or the need for a revenue requirement change; e.g., that the expenses the Company represents it will incur for increased generation capacity are wrong, that Mr. Ball has a different expectation of what expenses for additional distribution facilities will be, that revenues from any service or a particular class of customers will be different than those anticipated by the Company, etc., nothing to contradict the efforts and conclusions made by those parties who support adoption of the Revenue Stipulation. We are unable to agree with Mr. Ball and can not reject the Revenue Stipulation based on the arguments he proffers.

Our consideration of the Revenue Stipulation is directed by Utah statutory provisions in U.C.A. §54-7-1 that encourages informal resolution of matters brought before the Commission. Although parties relied upon different test periods and different adjustments to revenue requirement, they all agreed to support the stipulated $115 million revenue increase and its spread to rate schedules after examining the Revenue Stipulation and the evidence contained in the record. The Commission concludes that its terms are just and reasonable and it is just and reasonable in result. We conclude the Revenue Stipulation provides revenues sufficient to recover all costs of service including those associated with new generation, transmission and distribution facilities required to provide safe, reliable and reasonably-priced service to Utah customers. Based upon the foregoing, the Commission approves the Revenue Stipulation. The Commission's approval of the Revenue Stipulation, as in similar cases, is not intended to alter any existing Commission policy nor to establish any precedent by the Commission.

III. STIPULATION ON RATE DESIGN FOR SCHEDULES 6, 6A, AND 6B

A. Overview

Without modifying its terms in any way, the following is a brief summary of the Schedule 6 Stipulation. The Schedule 6 Stipulation and its attached Exhibit A, summarizing the rate changes by rate schedule, are included as Appendix II to this order.

Electric Service Schedule No. 6 provides rates for customers taking "General Service-Distribution Voltage (under 1,000 kW)." Schedules 6A and 6B provide optional time-of-day rates for this class of customers. The stipulated rate design for each of these schedules is based on forecasted billing units for twelve months ending September 30, 2007. Schedule 6 rates consist of a customer charge, an optional minimum seasonal service payment, a voltage discount, seasonal demand rates, and seasonal energy rates. The customer charge increases from $15.00 to $25.00 per month and the voltage discount increases from $0.66 to $0.72 per kW. The demand rate for the summer season, May through September, increases from $12.76 to $13.91 per kW and the demand rate for the winter season, October through April, increases from $10.24 to $11.16 per kW. The year-round energy rate of 2.574 cents per kilowatt hour (kWh) increases to 2.9271 cents per kWh in the summer season, May through September, and to 2.7 cents per kWh in the winter season, October through April. The minimum seasonal payment of $180 is not expressly addressed in the stipulation but the Company testifies this payment is typically set at 12 times the customer charge. Thus, the agreement to increase the customer charge from $15.00 to $25.00 results in the increase in the minimum seasonal payment from $180 to $300. The stipulated rate design represents a 67 percent increase in revenues collected from the customer charge and an approximately 9 percent increase in revenues collected through the demand and energy rates.

Schedule 6A provides a time-of-day energy rate option consisting of a customer charge, seasonal facilities demand rates, voltage discount, and seasonal and time differentiated energy rates. The customer charge increases from $15.00 to $25.00, the demand rate for the summer season, May through September, increases from $4.61 to $4.99 per kW and the demand rate for the winter season, October through April, increases from $3.86 to $4.18 per kW. The voltage discount increases from $0.43 to $0.47 per kW. The energy rates are differentiated by season and by hours of the day. All of these energy rates are increased by a little more than 8 percent. The difference in peak and off-peak energy rates is about 6 cents per kWh in the summer and about 5 cents per kWh in the winter.

Schedule 6B provides a time-of-day demand rate option and the Schedule 6 Stipulation sets these rates equal to Schedule 6 rates.

Additionally, the parties to the Schedule 6 Stipulation agree PacifiCorp and interested parties will, prior to the next general rate case: 1) Explore alternatives to the current 16 hour on-peak time period during the winter months; 2) analyze, discuss and make a recommendation on the price differential between on-peak and off-peak energy charges for Schedule Nos. 8 and 9; and, 3) explore alternative classification and allocation methods for distribution costs.

B. Discussion, Findings and Conclusions

Five parties, the Company, Division, UIEC, AARP and Kroger, representing a diversity of Schedule 6 interests, signed the Schedule 6 Stipulation. These parties state they held settlement conferences to discuss the rate design issues in this case and that the settlement negotiations were open to all parties. These parties agree the Schedule 6 Stipulation is in the public interest and all of its terms and conditions, considered together as a whole, will produce fair, just and reasonable results. The Company and Division provide testimony recommending the Commission approve the Schedule 6 Stipulation. The Company testifies the Schedule 6 Stipulation introduces a summer/winter seasonal differential to the energy charge which, coupled with the existing seasonally differentiated demand charges, implements clearer price signals to these customers while limiting bill impacts. The Company testifies the parties agree the appropriate energy charge differential between the summer and winter rates is approximately 2.3 tenths of one cent per kWh. The Division testifies it fully briefed the Utah Manufacturers and Utah Retailers Associations on past and proposed rate designs to better understand customer preferences regarding demand versus energy price increases. The Division states the non-uniform increases to rate components agreed to in the Schedule 6 Stipulation provide prices that correspond better to underlying cost factors and send a stronger price signal to motivate appropriate conservation and/or load shifting. Further, the Division states confidence in this settlement was enhanced by consulting customers who did not appear in the last rate case. No party of record provides testimony in opposition to the Schedule 6 Stipulation.

Our consideration of the Schedule 6 Stipulation is directed by Utah statutory provisions in U.C.A §54-7-1 that encourage informal resolution of matters brought before the Commission. After examining the Schedule 6 Stipulation and the evidence contained in the record, the Commission concludes that its terms are just and reasonable and in the public interest and it is just and reasonable in result. Based upon the foregoing, the Commission approves the Schedule 6 Stipulation.

The Commission's approval of the Schedule 6 Stipulation, as in similar cases, is not intended to alter any existing Commission policy nor to establish any precedent by the Commission.

IV. STIPULATION ON RATE DESIGN FOR SCHEDULES 8, 9, AND 31

A. Overview

Without modifying its terms in any way, the following is a brief summary of the Stipulation on Rate Design regarding Schedules 8, 9 and 31, ("Schedule 8/9/31 Stipulation"). The Schedule 8/9/31 Stipulation and its attached Exhibit A summarizing the rate changes by rate schedule are included as Appendix III to this order. The stipulated rate design for each of these schedules is based on forecasted billing units for twelve months ending September 30, 2007.

Electric Service Schedule No. 8 provides for "General Service-Distribution Voltage, 1,000 kW and Over." It consists of a customer charge, a facilities charge, a voltage discount, seasonal on-peak demand rates, seasonal on-peak energy rates, and an off-peak energy rate. The customer charge is increased from $15.00 to $25.00 per month, the facilities charge is increased from $3.15 to $3.47 per kW, and the voltage discount is increased from $0.75 to $0.83 per kW. The on-peak demand rate for the summer season is increased from $10.29 to $11.34 per kW and for the winter season is increased from $7.42 to $8.18 per kW. There is no demand rate for off-peak periods. The summer on-peak energy rate is increased from 3.2776 to 3.6832 cents per kWh, the winter on-peak energy rate is increased from 2.5776 to 2.8832 cents per kWh, and the off-peak energy rate is increased from 2.2776 to 2.4832 cents per kWh. The stipulated rate design for Schedule 8 represents, approximately, a 67 percent increase in revenues collected from the customer charge, a 10 percent increase in revenues collected from demand charges, a 12 percent increase in revenues collected from on-peak energy charges and a 9 percent increase in revenues collected from off-peak energy charges.

Schedule 9 "General Service-High Voltage" rates consist of a customer charge, a facilities charge, seasonal on-peak demand rates, seasonal on-peak energy rates, and an off-peak energy rate. The customer charge is increased from $100 to $170 per month and the facilities charge is increased from $1.40 to $1.54 per kW. The on-peak demand rate for the summer season is increased from $8.78 to $9.68 per kW and for the winter season is increased from $5.95 to $6.56 per kW. There is no demand rate for off-peak periods. The summer on-peak energy rate is increased from 2.8634 to 3.2247 cents per kWh, the winter on-peak energy rate is increased from 2.1634 to 2.4247 cents per kWh, and the off-peak energy rate is increased from 1.8634 to 2.0247 cents per kWh. The stipulated rate design for Schedule 9 represents, approximately, a 70 percent increase in revenues collected from the customer charge, a 10 percent increase in revenues collected from demand charges, a 12 percent increase in revenues collected from on-peak energy charges and an 8.7 percent increase in revenues collected from off-peak energy charges.

Electric Service Schedule No. 31 is for "Back-up, Maintenance, and Supplementary Power." Schedule 31 is available to customers who obtain any part of the usual or regular electric requirements from any source other than the Company and require additional supplementary and back-up or maintenance power and energy from the Company which is not in excess of 10,000 kW. Schedule 31 Back-up and Maintenance rates consist of a customer charge, a facilities charge, a regular back-up charge, a maintenance back-up charge, and an excess power charge. These charges vary by voltage level. For example, the rate changes for primary voltage customers are as follows: The customer charge is increased from $250 to $425 per month and the facilities charge is increased from $2.47 to $2.70 per kW; the regular back-up power charge is increased from $0.421 to $0.46 per on-peak kW day; the maintenance back-up power charge is increased from $0.2105 to $0.23 per on-peak kW day; and the excess power charge is increased from $38.30 to $41.85 per kW month. Rates for Schedule 31 supplemental service are based on Schedules 6, 8 and 9 rates. Thus, the Schedule 8/9/31 Stipulation provides Schedule 31 supplemental rates that will reflect the changes for Schedules 6, 8, and 9 as appropriate.

B. Discussion, Findings and Conclusions

Eight parties, the Company, the Division, UIEC, FEA, UAE, Kroger, Central Valley Water, and Utah Manufacturers Association, representing a diversity of Schedules 8, 9, and 31 interests, signed the Schedule 8/9/31 Stipulation. These parties state they held settlement conferences to discuss the rate design issues in this case and that the settlement negotiations were open to all parties. These parties agree the Schedule 8/9/31 Stipulation is in the public interest and all of its terms and conditions, considered together as a whole, will produce fair, just and reasonable results. The Company and Division provide testimony recommending the Commission approve the Schedule 8/9/31 Stipulation. The Company testifies the Schedule 8/9/31 Stipulation will give customers a stronger signal to minimize on-peak loads while minimizing bill impacts on customers who are unable to shift load. No party of record provides testimony in opposition to the Schedule 8/9/31 Stipulation.

Our consideration of the Schedule 8/9/31 Stipulation is directed by Utah statutory provisions in U.C.A. §54-7-1 that encourage informal resolution of matters brought before the Commission. After examining the Schedule 8/9/31 Stipulation and the evidence contained in the record, the Commission concludes that its terms are just and reasonable and it is just and reasonable in result. Based upon the foregoing, the Commission approves the Schedule 8/9/31

Stipulation. The Commission's approval of the Schedule 8/9/31 Stipulation, as in similar cases, is not intended to alter any existing Commission policy nor to establish any precedent by the Commission.

V. RATE DESIGN FOR RESIDENTIAL SCHEDULE 1

A. Positions of the Parties

Schedule 1 "Residential Service" rates consist of a customer charge, minimum monthly charges, a single energy rate during the winter season, October through April, and a three-block energy rate during the summer season, May through September, with the first block for usage up to 400 kWh, the second block for all usage above 400 kWh up to 1,000 kWh, and the third block for usage above 1,000 kWh. Existing charges and rates are as follows: The customer charge is $0.98 per month, the minimum charge for single-phase service is $3.67 per month, and the minimum charge for three-phase service is $11.01 per month; the energy rate for all usage during the winter season and for the first block of the summer season, is 6.936 cents per kWh; the energy rate for the second block of the summer season, for usage between 400 and 1,000 kWh, is 7.872 cents per kWh, and the energy rate for all summer usage above 1,000 kWh is 9.272 cents per kWh. This summer rate design is referred to as an inverted block rate structure, meaning price increases with blocks of usage.

The Company, Division, Committee and AARP propose Schedule 1 rate designs for Commission consideration; Utah Ratepayers Alliance provides testimony and its position on the rate designs proposed. Parties disagree on the appropriate monthly customer charge, minimum monthly charge, the kWh blocking structure of the summer rate design, and the energy rates for each of the three summer usage blocks and winter usage.

The Company proposes to increase the customer charge to $3.40, eliminate the monthly minimum charge, maintain the structure of the summer inverted blocks for pricing, and applies a uniform increase of 0.451 cents per kWh to both the winter residential energy charge and the summer residential three-block inverted energy charges. This results in a winter rate and summer first block rate of 7.3870 cents per kWh, a summer second block rate of 8.323 cents per kWh and a summer third block or tail block rate of 9.723 cents per kWh.

The Company provides its fully-distributed, embedded cost-of-service study for the forecasted 12 months ending September, 2007, adjusted to reflect the Revenue Stipulation discussed earlier, and the Company's own specific revenue requirement adjustments, as supporting evidence for its proposed customer charge. Based on this study, the Company initially calculated a customer charge of $3.39 per month which, due to an error, was corrected in rebuttal testimony to be $3.84 per month. The Company states this calculation uses the Commission's method for computing a customer charge approved in Docket Nos. 84-035-01 and 90-035-06. The Company believes this calculation differs from the Division's customer charge calculation of $3.75 per month due to differences in assumed rates of return on rate base and number of average customers. The Company continues to advocate approval of the $3.40 monthly customer charge rather than the corrected value because it has provided notice to customers of this requested amount. If the $3.40 per month customer charge is implemented, the Company believes the customer charge is cost-based and therefore the minimum bill can be eliminated, simplifying rate design. Should the Commission set a customer charge less than $3.40 per month, the Company recommends the existing minimum bill of $3.67 per month be increased by the residential class increase of 10.31 percent, which is $4.05 per month.

The Company testifies the $3.40 monthly customer charge does not impede conservation because it is a cost-based rate and therefore sends the correct price signal and allows customers to make their own decisions regarding energy consumption. The higher customer charge, the Company argues, provides a higher likelihood the Company will recover its fixed costs and reduce revenue volatility. Further, the Company states, a higher customer charge will reduce the need for it to file for rate relief if forecasted loads do not materialize and the Company is unable to recover prudently incurred fixed costs. The Company contends the rate impacts of implementing the $3.40 customer charge are not significantly higher than the impact of the implementation of the first $1.00 customer charge due to 21 plus years of inflation.

The Company disputes the need to direct more of the rate increase to customers at higher levels of consumption, stating customers at all levels of consumption increase their usage from spring months to summer months and therefore all customers contribute to energy use growth in Utah. Based on its analysis of an appropriate price signal rate for tail block usage using embedded and avoided costs, the Company testifies 9.12 cents per kWh is a cost-based tail-block rate and thus, there is no avoided cost basis to raise the tail block rate higher than the 9.7 cents it proposes in this case.

The Division's proposed rate design increases the customer charge to $3.75 per month, eliminates the monthly minimum bill, supports the Company's proposal to increase the summer residential three-block inverted energy charges by a uniform increase of 0.451 cents per kWh, and increases the winter residential one-block energy charge by 0.374 cents per kWh. This results in a winter rate of 7.31 cents per kWh and summer rates that are the same as the Company's proposed rates.

The Division testifies its customer charge calculation of $3.75 per month, which it develops from the Company's cost-of-service study using the Commission's method for calculating a residential customer charge, is the correct cost-based customer charge. The Division testifies its rate design appropriately promotes energy conservation because optimal consumption of energy is best achieved by constructing cost-based rates and letting the customer decide how much to consume. The Division recognizes the large percent rate increase to low-usage customers that its recommended customer charge causes but argues the absolute amount of the increase, $2.75 per month, is reasonable. Further, the Division states, to retain the current customer charge at $0.98 per month despite clear evidence supporting substantially higher amounts, is itself a violation of gradualism that creates unintended consequences. The Division explains that as the disparity between the current rate and the true cost-of-service rate increases, the cost of making a correction in the future will also increase, making rate shock an even bigger rate making issue down the road than it is today. With respect to the appropriate spread between the three summer block rates, the Division concurs load factor analysis supports inverted block rates. However, the Division states its analysis of the load factor data does not support the adoption of a proportionately wider difference between the first and tail block rate than is currently in effect. The Division also disputes contentions that approval of a higher customer charge virtually guarantees a larger portion of the Company's revenues. The Division agrees a larger portion of revenue will be recovered through a fixed charge but energy charges will be lower so the revenue change should be neutral. The Division also disputes the contention that a higher customer charge significantly affects the incentive of the Company to control its costs;

the Division states the higher customer charge does not affect the Company's costs and therefore the Company must control costs to achieve its allowed rate of return.

The Committee recommends maintaining the customer charge at $0.98 per month, increasing the minimum bill by 10.31 percent to $4.05 per month, increasing the range of the first summer block to a range of zero to 600 kWh per month, and revising the second summer block to a range of 600 kWh to 1,000 kWh per month. The Committee recommends increasing, by 10.31 percent, both the first summer block energy rate and the single winter rate to 7.651 cents per kWh. The second and third summer block energy rates are increased by 16.15 percent to 9.143 cents per kWh and 10.769 cents per kWh, respectively.

Although the Committee does not dispute the cost-of-service customer charge calculations prepared by other parties, the Committee argues it is a matter of public policy as to how approved revenue requirement is collected. The Committee recommends the Commission place more emphasis on the only rate component upon which a customer has control, i.e., their energy usage, rather than increase the customer charge. It is the Committee's position the revenue increase in this case is driven by the cost of resources necessary to meet summer load growth which in turn is driven by larger homes and greater use by customers of air-conditioning equipment. The Committee argues it is not the lower use customers who are driving summer costs and proposes a rate design that targets larger, air-conditioning usage during the summer months.

The Committee presents its analysis of coincident-peak load factor for customers using different amounts of energy in a month as support for its rate design proposal. The Committee testifies the load factor analysis shows that customer coincident load factor decreases as usage increases, meaning higher use customers impose higher average costs per kWh than smaller use customers, and that there is little difference in load factor between users of 400 kWh per month and users of 600 kWh per month. The Committee disputes the relevance of the Company's testimony that customers at all levels of usage increase use from spring months to summer months. The Committee testifies it is more important what customers' loads are during the summer and especially at the time of peak use. The Committee does not believe air conditioners are being used when consumption is under 600 kWh per month and certainly not under 400 kWh per month and therefore the rate increase for this block of use should be relatively less than the increase in energy charge for higher blocks of use. The Company and Division oppose the Committee's proposal to expand the first summer block to include usage up to 600 kWh per month. They argue this proposal will send the wrong price signals to residential customers using between 400 kWh and 600 kWh; at this level of consumption in summer months, the Committee's proposed rate is less than the current rate so these customers would experience a rate decrease. Further, the Company argues there is no cost-of-service basis for expanding the first block to 600 kWh.

The Committee testifies marginal cost increases are not fully addressed in the Company's embedded cost-of-service study and that they should be given consideration in rate design. The Committee disagrees with the Company's calculation of a cost-based tail block rate using marginal costs based on avoided costs for two reasons. First, the Committee argues the Company excluded some costs which, when included, raises the appropriate price signal for customers using greater than 1,000 kWh to 10.124 cents per kWh. Second, the Committee faults the Company for only looking at avoided costs for purchases of power from qualifying facilities. The Committee cites the cost of certain marginal purchases, included in net power costs in this general rate case, of between 6 and 13 cents per kWh at the generation level, as support for the higher summer tail-block rate the Committee proposes.

AARP recommends increasing the customer charge to $2.50 per month, reducing the monthly minimum bill to $3.40, and collecting remaining costs in per kWh charges designed to result in a nearly even percentage increase in rates across all levels of usage. It does this by using as a starting point, the second and third summer block rates filed by the Company in its initial March 6, 2006, rate case application and then adjusting the first summer block and winter energy rates to collect the stipulated revenues for Schedule 1. AARP testifies this results in a rate for the single winter energy charge and the first summer block of 7.38 cents per kWh, 8.846 cents per kWh for the second summer block and 10.2460 per kWh for the summer tail block.

AARP testifies it is concerned the Company's proposal inappropriately presses much of the revenue requirement increase on the smallest users by the combination of the customer charge change and the resulting kWh rates. AARP states it did not completely analyze the Company's cost-of-service study, but believes the claimed customer charges are probably correct. In order to manage the impacts to lower use customers caused by increasing the customer charge, it proposes a lower customer charge to enact a more gradual change toward cost of service. Further, AARP proposes to place more of the remaining revenue increase on the second and third summer blocks of consumption than the Company proposes. AARP argues this will provide appropriate price signals and intra-class equity because growth in air conditioning is creating marginal rather than average costs. AARP testifies price signals are best when price equals marginal cost.

Utah Ratepayers Alliance testifies in opposition to the Company's and Division's proposed rate design. The Utah Ratepayers Alliance recommends the Commission maintain the residential customer charge at its current level, or more gradually increase it to \$1.50 or \$1.75 per month, keeping with the principle of gradualism, and maintain the minimum monthly bill. The Utah Ratepayers Alliance recommends the Commission approve a rate design that collects more revenues through energy charges than the customer charge in order to send the proper price signals to promote energy efficiency.

Utah Ratepayers Alliance opposes the Company's and Division's proposed customer charge because it imposes a large impact, a 247 percent increase in this one rate element, on low income and low-use households, constitutes a form of front-end loading, creates a disincentive for the utility to minimize resource and delivery costs, imposes an inappropriately larger increase on smaller users, may cause intra-class subsidization, and impedes conservation. Utah Ratepayers Alliance testifies that low income households, on average, use less than the average residential customer, both in terms of overall use and during the peak summer months. Utah Ratepayers Alliance testifies most low income people do not have air conditioning and do not necessarily use more electricity in the summer than in the winter. It argues low-use customers conserve more, have smaller homes or simply lack money to spend more on electricity and should not disproportionately bear the burden of the rate increase. Utah Ratepayers Alliance argues Commission policy has historically placed more weight on other rate making factors than setting a cost-based customer charge and recommends this good policy continue.

B. Discussion, Findings and Conclusions

All parties base their proposed rate designs on the Company's forecasted cost-of-service study filed for the 12 months ending September, 2007, adjusted to reflect the Revenue Stipulation and the Company's revenue requirement adjustments. Although no party critically evaluates this study in testimony before us, neither does any party contest or rebut it. All parties also recognize and cite the various rate making objectives that guide rate design decision making. No party argues any of the objectives are irrelevant but each party stresses its view of the weight each objective should be given. In weighing the parties' arguments and evidence, we conclude the following rate design for Residential Schedule 1 is in the public interest.

To further the objectives of intra-class equity, cost-based rates and revenue stability, we approve an increase in the customer charge. As we have stated in the past, a customer charge results in the payment by each customer of those costs that, on average, each customer imposes upon the system, which are independent of actual energy consumption during a given month. A customer who uses no electricity in a given month, must nonetheless have the meter read, be issued a billing statement, have the meter maintained in good operating condition, and incurs other direct customer-related costs that do not vary with monthly usage. Employing the Commission approved method for calculating this cost, Company and Division witnesses testify the cost-based customer charge is in excess of $3.00 per month for the forecasted period of the 12 months ending September 2007. Indeed, no party challenges these calculations nor testifies the current $0.98 per month customer charge reflects full cost of service. Rather, parties oppose the Company's or Division's customer charge in order to further other public policy objectives such as gradualism, rate stability, energy price signals or conservation of resources.

We concur these other objectives must be considered when designing rates that serve the public interest.

All parties support a seasonal differentiation in rates and an inverted block structure of rates in the summer in order to provide proper price signals to customers regarding the cost of energy during the rate-effective period. The load factor evidence provided by the Company and Committee and reviewed by the Division supports an inverted block structure of rates in the summer. We conclude the current block structure is reasonable and decline to change it now because such a change would result in a rate decrease and inappropriate price signal for certain customers during this time of rising electricity cost.

While we continue to rely on embedded cost-of-service analysis for determining class revenues, we concur with the Company, Committee and AARP that marginal cost information can and should be used to guide rate design. Indeed, we note the Company's originally filed tail block rate for residential customers was 10.2 cents per kWh and the uncontested peak rate proposed for the irrigation class is 10.3 cents per kWh. We agree with AARP that achieving intra-class equity and proper price signals includes more than collecting revenues based on a "snap shot" embedded cost-of-service study but also recognizes the dynamic process that starts once rates are set.

In striking a balance among the multiple public policy objectives in rate design, we find a $2.00 monthly customer charge, maintenance of the minimum bill at its current rate of $3.67 per month for single phase service and $11.01 per month for three-phase service, maintenance of the current block structure, and an 8.6917 percent increase to each energy rate, serves the public interest. Accordingly, the energy rate for both the first summer block and the single winter block is 7.5389 cents per kWh, the second summer block energy rate is 8.5562 cents per kWh and the third summer block energy rate is 10.0779 cents per kWh.

This $1.02 per month increase in customer charge provides reasonable and incremental movement toward a cost-based customer charge consistent with our principle of gradualism. We apply the principle of gradualism not only to mitigate the rate impacts to low use customers but also to recognize the static nature of any given cost-of-service study. Maintenance of the $3.67 monthly minimum charge preserves revenue stability and intra-class equity. Application of the uniform percent increase to all energy charges will maintain the percent difference in price currently in place between winter and summer and between smaller and larger consumers of electric energy, thus providing cost-based price signals, continued incentives for energy conservation, and revenue stability for the Company. Customer acceptance and understanding is also achieved as customers are familiar with and relatively supportive of this rate design.

VI. OTHER RATE SCHEDULE CHANGES

A. Overview

In its rebuttal testimony, the Company filed uncontested rate designs for the remaining rate schedules: Schedule 2, "Residential Time-of-Day"; Schedule 23, "General Service-Distribution Voltage-Small Customer"; Schedule 10, "Irrigation"; Schedule 25, "Mobile Homes"; Lighting and Traffic Signal Schedules 7, 11, 12, and 13, and Schedule 21, "Electric Furnace." A summary of the rate design for several of these schedules follows.

Schedule 10, "Irrigation and Soil Drainage Pumping Power Service" rates consist of customer service charges, a voltage discount, a demand rate during the irrigation season defined to be May 25 to September 15 each year, two-block energy rates, and a post-season energy rate. The annual customer service charge is increased from $80 to $88 for primary service and from $25 to $27 for secondary service. The monthly customer service charge is increased from $10 to $11 per month and the voltage discount is increased from $1.33 to $1.46 per kW. The demand rate for the irrigation season is increased from $4.75 to $5.22 per kW, the energy rate for seasonal usage up to 30,000 kWh is increased from 4.7265 to 5.1972 cents per kWh, the energy rate for seasonal usage in excess of 30,000 kWh is increased from 3.4935 to 3.8414 cents per kWh, and the energy rate for post-season usage is increased from 3.2375 to 3.5599 cents per kWh.

There is also an optional time-of-day Schedule 10 where energy charges differ for peak and off peak hours of consumption. The customer charge, voltage discount, demand rate and post-season energy charges are the same as Schedule 10 described above. Peak energy charges are increased from 9.3377 to 10.2677 cents per kWh and off-peak energy charges are increased from 2.6817 to 2.9609 cents per kWh.

Schedule 23, "General Service-Distribution Voltage-Small Customer" rates consist of a customer charge, an optional seasonal minimum payment, a facilities charge, seasonal demand rates for loads in excess of 15 kW, and seasonal two-block energy rates, with the first block for usage up to 1,500 kWh. The customer charge increases from $4.00 to $6.00 per month, the seasonal minimum payment is increased from $48.00 to $72.00, and the voltage discount is increased from $0.35 to $0.38 per kW. The demand rate for the summer season is increased from $6.27 to $6.76 per kW, and the demand rate for the winter season is increased from $6.32 to $6.81 per kW. The summer energy rate for usage up to 1,500 kWh is increased from 8.4999 to 9.1581 cents per kWh, and the rate for summer usage above 1,500 kWh is increased from 4.7654 to 5.1344 cents per kWh. The winter energy rate for usage up to 1,500 kWh is increased from 7.8236 to 8.4294 cents per kWh, and the rate for winter usage above 1,500 kWh is increased from 4.3864 to 4.7261 cents per kWh.

B. Discussion, Findings and Conclusions

Based on the record, the issues associated with the rate design for these remaining schedules are uncontested. Hearing no opposition by any party to the Company's proposed rate designs for these remaining schedules, we find them just, reasonable and in the public interest and approve them as proposed and filed by the Company.

VII. REGULATION AND REGULATORY FEE CHANGES

A. Overview

Schedule 300, "Regulation Charges" presents the Company's fee schedule for various charges and services. The Company proposes to increase the returned check charge from $15 to $20 to better reflect the cost of processing a returned check and to change the service charge description name from "Returned Check Charge" to "Returned Payment Charge" to more generically describe the charge.

The Company also proposes to increase the field service visit charge from $15 to $20, the residential all other times (i.e., after normal business hours) reconnection charge from $75 to $100, the pole-cut disconnect/reconnect charges in normal business hours from $89 to $125, and the pole-cut disconnect/reconnect charges in all other times from $107 to $250. The Company testifies these changes are needed to reduce subsidies because these charges are currently below cost of service. The Company testifies the cost to provide these services is currently higher than its proposed charges but believes the increased fees brings the charges closer to the cost of service. The Company further testifies, based upon the Company's 2005 records regarding participation in low income programs such as Home Energy Assistance Target, Lend-A-Hand energy assistance and the Low Income Lifeline Program, 90 percent or more of the residential customers assessed charges for field visits, reconnection after hours, and returned payments, were not low income. The Company proposes to increase the non-residential reconnection minimum charge from $25 to $30 to ensure consistency with the $30 normal business hours reconnection charge for residential customers. The Company testifies its recently-instituted electronic transfer of funds program will not impact the returned payment fees and contends the recently-undertaken arrearage management program required by MEHC Commitment U-26 will have little if any impact on the fees.

Utah Ratepayers Alliance opposes the proposed increase in charges for field visits, residential reconnection after hours, and returned checks as these charges are most likely to impact lower income customers who would bear a disproportionate share of the charges. Utah Ratepayers Alliance contends the charges will only serve to curtail service to those who can least afford it rather than keeping the service on and maintaining a paying customer. Utah Ratepayers Alliance further testifies there are many low income households who have not enrolled in the assistance programs named by the Company in its assessment that 90 percent or more of the charges are not paid by low-income customers. Utah Ratepayers Alliance states these programs serve slightly less than 40 percent of the eligible population. No other party commented on these changes.

The Company proposes the following five changes to Regulation No. 12, "Line Extension" to improve its clarity, better describe the application of the regulation, and better communicate longstanding Company practice: 1) In section 1(d), Extension Allowance, change the phrase "does not include" to "does not apply to" to more clearly communicate the application of the regulation; 2) in section 1(f), Extension Limits, remove the phrase "obtaining rights-of-way" as the Company does not consider unusual costs incurred for obtaining rights-of-way a special requirement; 3) in section 1(j), Routes, Easements and Rights-of-Way, extensive wording changes associated with easement documents and responsibility for obtaining easements and rights-of-way in order to reflect the Company's practice of requiring applicants to obtain rights-of-ways, along with the necessary signature(s) for any rights-of-ways, and clarifies that rights-of-ways will be obtained on Company forms; 4) in section 5(a)(1), Applicant Built Line Extension, the Company proposes revised language to indicate the applicant-built line extension provision only applies to new construction and is not available for relocations, conversions, facility capacity increases, or changing from single-phase to three-phase power; the Company maintains these changes clarify the regulation as to its intended application because working in close proximity to energized power lines is a clear safety risk and there is a higher potential for problems to arise while working on an existing facility; and 5) in section 6(a) Relocations of Facilities, the Company proposes to insert new wording requiring the customer requesting the relocation to provide necessary easements if no easement exists or it is insufficient and defining "overhead to underground relocations" as "conversions." No other party commented on these changes.

Finally, in Regulation No. 2, "General Definitions" the Company proposes to change the word "of" to "or" in the Extension definition and change the word "isolate" to "isolated" in the Remote Service definition. No party commented on these changes.

B. Discussion, Findings, and Conclusions

Based on the record, the Commission categorizes the Company's proposed changes to its Electric Service Regulations and Schedule 300 into three types. The first type encompasses spelling or grammatical corrections such as those proposed in Regulation No. 2 or generic wording changes such as replacing "returned check charge" with "returned payment charge" in Schedule 300. The Commission agrees these changes are purely housekeeping in nature and approves them as proposed.

The second type encompasses fee increases for specified services which are currently set at levels below cost of service. No party disputes the Company's testimony regarding the cost to provide these services. Indeed, no party disputes the Company's proposal to increase fees for non-residential and pole-cut disconnect and reconnect services. Rather, the Utah Ratepayers Alliance testifies of its concern that to the extent the fees for returned checks, field visits, and residential after hours reconnection services are paid by low-income customers, this increased fee may have the effect of causing more low-income customers to be disconnected or have greater difficulty getting service restored. We recognize this concern but are not persuaded this potentiality offsets the propriety of having service fees for all customers that are closer to the cost of providing the service. Most customers incurring these costs are not low-income customers. We find it reasonable to set prices for services based on the cost to provide that service so other customers, including low income customers, are not required to subsidize these services. We find the Company's proposed service fees are a reasonable step toward setting cost based fees and approve the fees as proposed by the Company.

However, we note in viewing the Company's electric service regulations and schedules associated with these charges, that the Company's language regarding the terms and conditions for applying these service fees is sometimes vague. For example, it is not clear where normal business hours are defined. We direct the Company, working with the Division, to provide greater clarity with respect to the terms and conditions for imposing these fees in both the language of its relevant electric service regulations and/or Schedule 300, and any other website information that may discuss these fees.

The third type of modification encompasses potentially substantial changes for which there is no testimony in the record providing an analysis of the magnitude or impact of the changes on ratepayers as in the proposed changes to Regulation No. 12, "Line Extensions." While the Company indicates the proposed changes to Regulation No. 12 improve its clarity, better describe its application, and better communicate the Company's longstanding practice, the Commission is concerned the Company's practice is not consistent with the existing tariff language which has been in place since the year 2000. The Commission desires further evidence and review prior to making a decision regarding the proposed modifications to Regulation 12, especially those associated with easements and rights-of-way as they apply to residential extensions. The Commission instructs the Company, the Division, and interested parties to conduct an evaluation of the timing, necessity and benefits of the proposed tariff modifications to Regulation No. 12 in light of the various types of line extensions contained in the tariff.

VIII. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order:

1. The Stipulation Regarding Revenue Requirement and Rate Spread is approved.
2. The Stipulation Regarding Rate Design for Schedules 6, 6A and 6B is approved.
3. The Stipulation Regarding Rate Design for Schedules 8, 9 and 31 is approved.
4. Rate design for Electric Service Residential Schedule No. 1 shall be as described herein.
5. Rate design for the remaining Electric Service Schedules shall be as described herein.
6. The Company's proposed language changes for Regulation No. 2 and Schedule 300 are approved.
7. The Company's proposed charges for pole-cut disconnection and reconnection, non-residential reconnection, field visits, returned checks and residential after hours reconnection services are approved.
8. The Company is directed to provide greater clarity with respect to the terms and conditions for imposing service fees in both the language of its relevant electric service regulations and/or Schedule 300, and any other website information that may discuss these fees.
9. PacifiCorp shall file appropriate tariff revisions increasing Utah jurisdictional revenues by $115 million effective December 11, 2006, including a $30 million rate credit beginning December 11, 2006, and terminating May 31, 2007.

10. The tariff revisions shall reflect the determinations regarding rate increases, charges and other rate design aspects for service schedules and other changes in rates, fees or charges designated and discussed in the Stipulation Regarding Revenue Requirement and Rate Spread, the Stipulation on Rate Design for Schedules 6, 6A, and 6B and the Stipulation on Rate Design for Schedules 8, 9 and 31, and the decisions contained in this Order. The Division shall review the tariff revisions for compliance with the terms of the three approved stipulations and this Order. The tariff revisions are effective December 11, 2006.

11. Study groups shall be established as specified in the Stipulations.

12. Reporting requirements in the Stipulation do not alter previous Commission requirements for filing Semi-Annual Results of Operations.

This Report and Order constitutes final agency action on PacifiCorp's March 7, 2006, Application. Pursuant to U.C.A. §63-46b-12, an aggrieved party may file, within 30 days after the date of this Report and Order, a written request for rehearing/reconsideration by the Commission. Pursuant to U.C.A. §54-7-15, failure to file such a request precludes judicial review of the Report and Order. If the Commission fails to issue an order within 20 days after the filing of such request, the request shall be considered denied. Judicial review of this Report and Order may be sought pursuant to the Utah Administrative Procedures Act (U.C.A. §63-46b-1 et seq.).

DATED at Salt Lake City, Utah, this 1st day of December, 2006.

/s/ Ric Campbell, Chairman

/s/ Ted Boyer, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#51584

APPENDIX I: Revenue Requirement and Rate Spread Stipulation

BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PACIFICORP for Approval of Its Proposed Electric Service Schedules & Electric Service Regulations	DOCKET NO. 06-035-21 **STIPULATION REGARDING REVENUE REQUIREMENT AND RATE SPREAD**

1. This Stipulation ("Stipulation") is entered into by and among the parties whose signatures appear on the signature pages hereof (collectively referred to herein as the "Parties").

I. INTRODUCTION

2. The terms and conditions of this Stipulation are set forth herein. The Parties represent that this Stipulation is in the public interest and recommend that the Public Service Commission (the "Commission") approve the Stipulation and all of its terms and conditions.

II. BACKGROUND

3. On March 7, 2006, PacifiCorp filed an application, together with revenue requirement, cost of service, rate spread and rate design testimony, for a rate increase of $197.2 million based on a 12 month forecast test period ending September 30, 2007. On April 5, 2006, in compliance with the provisions of Commitment U23 of Appendix A to the Stipulation in Docket No. 05-035-54, PacifiCorp filed supplemental testimony that reduced the Company's proposed rate increase from $197.2 million to $194.1 million.

4. On April 4, 2006, the Commission issued an order establishing the procedural schedule for this proceeding. On April 18, 2006, May 1, 2006 and May 24, 2006, the Commission issued orders amending that schedule.

5. The Parties held settlement conferences on July 10, 11 and 12, 2006. The settlement negotiations were open to all parties.

6. As a result of the settlement negotiations, the Parties to this Stipulation have agreed to the revenue requirement, rate spread and other matters specified herein.

III. TERMS OF STIPULATION

7. Revenue Requirement. The Parties agree that, under this Stipulation and upon Commission approval, customer rates should increase by $85 million on December 11, 2006, as shown on the schedule attached hereto as Exhibit 1 and by an additional $30 million on the date specified in paragraph 8. In order to accomplish the same, the Parties agree that PacifiCorp should be allowed to increase its annual Utah jurisdictional revenue requirement by $115 million effective on December 11, 2006, subject to the rate credit specified in paragraph 8. There is no overall agreement as to the test period or revenue requirement adjustments which led to the stipulated revenue requirement increases because different parties relied upon different test periods and adjustments in supporting the agreed upon $115 million increase.

8. Rate Credit. The Parties agree that customers will receive an annualized rate credit of $30 million beginning on December 11, 2006, and terminating on June 1, 2007. The rate credit will be reflected as a line item on customers' bills in accordance with Exhibit 1.

9. Return on Equity. The Parties agree that PacifiCorp's authorized return on common equity for purposes of this Stipulation will be 10.25%.

10. Rate Spread. The Parties agree that the allocation of revenues to customer classes to recover PacifiCorp's increased revenue requirement should be in accordance with the schedule attached to this Stipulation as Exhibit 1. The Parties agree that, for the purposes of revenue allocation in this case, all rate increase revenues will be allocated to tariff customer classes and not to special contract customers. This paragraph does not modify any rate change or other provisions of any special contract.

11. Retail Load Forecast. Consistent with the Commission's Order dated May 19, 2006, in Docket 06-035-26, PacifiCorp included in its retail load forecast used for purposes of this rate case the full projected load for the Utah County facilities of IM Flash Technologies, LLC ("IM Flash"). The full projected IM Flash load for the time period October 2006 to September 2007, is specified in Exhibit 2. The Parties agree that IM Flash's projected load should properly be included in PacifiCorp's retail load forecast for ratemaking purposes.

12. Next Rate Case. PacifiCorp agrees that it will not file another Utah general rate case before December 11, 2007, which would result in an anticipated rate effective date no earlier than August 7, 2008. PacifiCorp will provide notice to the Parties of its intention to file its next general rate case at least 60 days prior to the date that it actually files its next general rate case.

13. Power Cost Adjustment Mechanism. PacifiCorp agrees that it will withdraw its application in Docket No. 05-035-102. PacifiCorp also agrees that it will not file another application for approval for any kind of a power cost adjustment mechanism prior to December 11, 2007.

13. Filing Requirements. In its February 22, 2006, Order in Docket No. 06-035-21, the Commission approved a Stipulation on Filing Requirements, Discovery and Timing of Test Period Hearing ("Filing Requirements Stipulation"). In the Filing Requirements Stipulation, PacifiCorp agreed, for the purposes of this docket only, to provide the additional revenue requirement filing

information, additional cost-of-service filing information, and response to the revenue requirement data requests, cost-of-service data requests and other data requests specified in Attachments A, B, C, D and E to the Filing Requirements Stipulation. The Parties agree that they will hold discussions regarding appropriate revenue requirement and cost-of-service information filing requirements and master data requests for PacifiCorp's next Utah general rate case. If PacifiCorp and the parties participating in those discussions are unable to reach agreement on new information filing requirements, PacifiCorp agrees that it will provide with the application in its next general rate case the additional revenue requirement filing information, additional cost-of-service filing information and data responses, all as adjusted for the test period proposed in that general rate case, specified in Attachments A, B, C, D and E to the Filing Requirements Stipulation and within the time frames specified in such Stipulation.

14. Regulatory Assets. Certain expenses incurred by the Company have been deferred as regulatory assets on the Company's balance sheet. This Commission has previously issued orders allowing the deferral and amortization of regulatory assets and subsequent recovery in rate proceedings. This Stipulation does not alter or impair the recovery of these regulatory assets previously deferred by Utah Commission orders under FAS 71.

15. Utah System Maintenance and Capital Expenses. In its filing in this docket, PacifiCorp provided forecasts of the expenditures for its proposed test period required for the operation and maintenance of PacifiCorp's Utah electrical transmission and distribution system. Although the Parties have not agreed on specific revenue requirement adjustments to comprise the $115 million revenue requirement increase, and although PacifiCorp may, in the exercise of its managerial discretion and in order to operate and maintain its system in a reasonable and prudent manner, make expenditures that are different than its forecasts, PacifiCorp agrees as follows:

a. During the period from October 2006 to September 2007, PacifiCorp's expenditures for distribution maintenance set forth in Federal Energy Regulatory Commission ("FERC") accounts 590 through 598 will be not less than 93% of $67.5 million;

b. During the period from October 2006 to September 2007, PacifiCorp's capital costs for distribution pole replacements will be not less than $5.1 million.

PacifiCorp further agrees that it will provide a report of the status of its compliance with this commitment to the Division of Public Utilities ("DPU") and the Committee of Consumer Services ("CCS") on November 15, 2007. The report on the status of compliance will include the actual expenses in FERC accounts 590 to 598 for the twelve months ended September 2007 at the same level of detail and format consistent with the information included in the forecast test year in this case, including the consistent treatment of the capital clearing amount in FERC account 593 in the comparison. The net revenue requirement impact of the expenditures below 93% of the amount specified in subparagraph (a.) and below 100% of the amount specified in subparagraph (b.) above will be deferred for treatment in a future rate case.

16. Reporting Requirement. The Company agrees to provide summary actual results of operations for the states of Utah, Idaho and Wyoming comprising Rocky Mountain Power's service territory in its semi-annual results of operations reports. The information will be similar in format on a FERC account basis with the information provided in Tab 2 of the semi-annual results of operations reports, with a column included for the actual costs allocated or assigned to the Rocky Mountain Power service territory.

17. Rate Design. This Stipulation does not address rate design. The Parties agree that they will continue to negotiate in good faith to reach agreement on the rate design issues in this case.

If the Parties are unable to reach agreement, rate design issues will be tried in accordance with the procedural schedule in this Docket.

18. Obligations of the Parties. The Parties agree that their obligations under this Stipulation are subject to the Commission's approval of this Stipulation.

19. Recommendation and Support. The Parties recommend that the Commission approve and adopt this Stipulation in its entirety. If this Stipulation is approved by the Commission in its entirety, no Party shall appeal any portion of this Stipulation and no Party shall oppose the adoption of this Stipulation in any appeal filed by any person not a party to the Stipulation. The Company, the Division and the Committee shall make witnesses available to testify in support of this Stipulation and other parties may make such witnesses available. In the event other parties introduce witnesses opposing approval of the Stipulation, the Parties agree to cooperate in cross-examination and in providing testimony as necessary to rebut the testimony of opposing witnesses.

20. Reservation of Right to Withdraw from Stipulation. In the event the Commission rejects any or all of this Stipulation, or imposes any additional material conditions on approval of this Stipulation, or in the event the Commission's approval of this Stipulation is rejected or conditioned in whole or in part by an appellate court, each Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding delivered no later than five (5) business days after the issuance date of the applicable Commission or court order, to withdraw from this Stipulation. Prior to that election, Parties agree to meet and discuss the Commission's order or court's decision. In the event that no new agreement is reached, no Party shall be bound or prejudiced by the terms of this Stipulation, and each Party shall be entitled to undertake any steps it deems appropriate.

21. Public Interest. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions, considered together as a whole, will produce fair, just and reasonable results.

22. No Waiver or Precedent. No Party is bound by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of the rights of any Party unless such rights are expressly waived herein. Execution of this Stipulation shall not be deemed to constitute an acknowledgement by any Party of the validity or invalidity of any particular method, theory or principle of regulation or cost recovery, and no Party shall be deemed to have agreed that any method, theory or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future and shall not be deemed to constitute precedent nor prejudice the rights of any party in future proceedings. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

Dated this 21st day of July, 2006.

PACIFICORP
DBA Rocky Mountain Power
/s/ Mark C. Moench
Mark C. Moench
Senior Vice President & General Counsel

UTAH DIVISION OF PUBLIC UTILITIES
/s/ Michael Ginsberg
Michael Ginsberg
Patricia Schmid
Assistant Attorney General

UTAH COMMITTEE OF CONSUMER SERVICES
/s/ Reed Warnick
Reed Warnick
Paul Proctor
Assistant Attorney General

UTAH INDUSTRIAL ENERGY CONSUMERS
/s/ F. R. Reeder
F. Robert Reeder
Vicki M. Baldwin
Attorneys for UIEC, an Intervention Group

FEDERAL EXECUTIVE AGENCIES
/s/ Karen S. White
Lt. Col. Karen White, USAF
Capt. Williams, USAF

UAE INTERVENTION GROUP
/s/ Gary A. Dodge
Gary Dodge

AARP
/s/ Dale Gardiner
Dale Gardiner
Thomas Forsgren

NUCOR
/s/ P. J. Mattheis
Peter J. Mattheis
Jeremy Cook

UTAH MANUFACTURERS ASSOCIATION
/s/ Thomas Bingham
Thomas Bingham

CENTRAL VALLEY WATER
/s/ Ronald J. Day
Ronald J. Day

EXHIBIT 1 to Revenue Requirement and Rate Spread Stipulation

Effect of Stipulated Changes on Revenues from Electric Sales to Ultimate Consumers in Utah
Forecast Test Period 12 Months Ending September 2007

Description	Sch No.	No. of Customers Forecast	MWh Forecast	Present Revenues ($000)	Stipulated Rate Increase Revenues ($000)	Permanent Change[1] ($000)	Permanent Change[1] (%)	Credit[2] ($000)	Credit[2] (%)
Residential									
Residential	1,3	671,954	6,070,040	$451,259	$497,776	$46,518	10.31%	($12,135)	-2.44%
Residential-Optional TOD	2	385	3,066	$221	$244	$23	10.31%	($6)	-2.44%
Residential-Mobile Homes	25	11	11,148	$667	$749	$82	12.31%	($21)	-2.86%
AGA/Revenue Credit				$18	$18	$0	0.00%	$0	0.00%
Total Residential		672,350	6,084,253	$452,165	$498,787	$46,623	10.31%	($12,162)	-2.44%
Commercial & Industrial[3]									
General Service-Distribution	6	12,260	5,503,545	$325,491	$355,790	$30,298	9.31%	($7,904)	-2.22%
General Service-Distribution-Energy TOD	6A	1,793	230,575	$18,310	$20,015	$1,704	9.31%	($445)	-2.22%
General Service-Distribution-Demand-	6B	26	10,611	$622	$680	$58	9.31%	($15)	-2.22%
subtotal Schedule 6		14,079	5,744,732		$376,484	$32,061	9.31%	($8,364)	-2.22%
General Service-Distribution>1,000 kW	8	241	2,057,688	$104,704	$115,498	$10,793	10.31%	($2,816)	-2.44%
General Service-High Voltage	9	140	3,939,593	$142,292	$156,960	$14,668	10.31%	($3,826)	-2.44%
General Service-High Voltage-Energy	9A	10	42,256	$2,049	$2,260	$211	10.31%	($55)	-2.44%
subtotal Schedule 9		150	3,981,849	$144,341	$159,220	$14,879	10.31%	($3,882)	-2.44%
Irrigation	10	2,192	185,191	$9,550	$10,501	$950	9.95%	($248)	-2.36%
Irrigation TOD	10A	237	18,994	$949	$1,044	$94	9.95%	($25)	-2.36%
subtotal Irrigation		2,429	204,185	$10,500	$11,544	$1,045	9.95%	($272)	-2.36%
Electric Furnace	21	5	3,610	$273	$273	$0	0.00%	$0	0.00%
General Service-Distribution-Small	23	65,312	1,211,535	$84,660	$92,540	$7,881	9.31%	($2,056)	-2.22%
Back-up, Maintenance, & Supplementary	31	4	19,539	$1,487	$1,640	$153	10.31%	($40)	-2.44%
Special Contracts		4	2,130,166	$64,177	$64,177	$0	0.00%	$0	0.00%
AGA/Revenue Credit				$2,213	$2,213	$0	0.00%	$0	0.00%
Total Commercial & Industrial		82,225	15,353,303	$756,778	$823,590	$66,812	8.83%	($17,429)	-2.12%
Total Commercial & Residential (excluding special contracts, AGA)		82,221	13,223,137	$690,388	$757,200	$66,812	9.68%	($17,429)	-2.30%
Public Street Lighting									
Security Area Lighting	7	8,751	13,851	$2,755	$3,095	$339	12.31%	($88)	-2.86%
Street Lighting - Company Owned	11	1,245	22,661	$5,393	$6,057	$664	12.31%	($173)	-2.86%
Street Lighting - Customer Owned	12	651	30,568	$2,939	$3,301	$362	12.31%	($94)	-2.86%
Traffic Signal Systems	12	2,018	8,954	$598	$672	$74	12.31%	($19)	-2.86%
Metered Outdoor Lighting	12	299	9,557	$676	$676	$0	0.00%	$0	0.00%
Decorative Street Lighting	13	162	14,706	$1,042	$1,170	$128	12.31%	($33)	-2.86%
Subtotal Public Street Lighting		13,126	100,297	$13,403	$14,969	$1,567	11.69%	($409)	-2.73%
Security Area Lighting Contracts (PTL)		72	277	$21	$21	$0	0.00%	$0	0.00%
Street Lighting-Contracts (66, 77)		2	142	$18	$18	$0	0.00%	$0	0.00%
AGA/Revenue Credit				$5	$5	$0	0.00%	$0	0.00%
Total Public Street Lighting		13,200	100,716	$13,446	$15,012	$1,567	11.65%	($409)	-2.72%
Total Sales to Ultimate Customers		767,775	21,538,272	$122,238	$1,337,390	$115,001	9.41%	($30,000)	-2.24%
Total Sales to Ultimate Customers (Excluding special contracts, AGA)		767,697	19,407,688	$1,155,93	$1,270,938	$115,001	9.95%	($30,000)	-2.36%

1. The $115 million permanent increase will be reflected in customer prices beginning on June 1, 2007
2. The $30 million rate credit will be reflected in customer prices from December 11, 2006, through May 31, 2007
3. Includes Other Sales to Public Authorities

EXHIBIT 1 to Revenue Requirement and Rate Spread Stipulation (cont.)

Effect of Stipulated Changes on Revenues from Electric Sales to Ultimate Consumers in Utah
Forecast Test Period 12 Months Ending September 2007 (cont.)

Description	Sch No.	Stipulated Rate Increase Net Change[2]	Change	(%)	Ave ¢/kWh
Residential					
Residential	1,3	$485,641	$34,383	7.62%	8.00
Residential-Optional TOD	2	$238	$17	7.62%	7.77
Residential-Mobile Homes	25	$727	$61	9.10%	6.52
AGA/Revenue Credit		$18	$0	0.00%	
Total Residential		$486,625	$34,460	7.62%	8.00
Commercial & Industrial[3]					
General Service-Distribution	6	$347,886	$22,394	6.88%	6.32
General Service-Distribution-Energy TOD	6A	$19,570	$1,260	6.88%	8.49
General Service-Distribution-Demand-	6B	$665	$43	6.88%	6.26
subtotal Schedule 6		$368,120	$23,697	6.88%	6.41
General Service-Distribution>1,000 kW	8	$112,682	$7,978	7.62%	5.48
General Service-High Voltage	9	$153,134	$10,842	7.62%	3.89
General Service-High Voltage-Energy	9A	$2,205	$156	7.62%	5.22
subtotal Schedule 9		$155,339	$10,998	7.62%	3.90
Irrigation	10	$10,253	$702	7.35%	5.54
Irrigation TOD	10A	$1,019	$70	7.35%	5.36
subtotal Irrigation		$11,272	$772	7.35%	5.52
Electric Furnace	21	$273	$0	0.00%	7.57
General Service-Distribution-Small	23	$90,484	$5,825	6.88%	7.47
Back-up, Maintenance, & Supplementary	31	$1,600	$113	7.62%	8.19
Special Contracts		$64,177	$0	0.00%	3.01
AGA/Revenue Credit		$2,213	$0	0.00%	
Total Commercial & Industrial		$906,161	$49,383	6.53%	5.25
Total Commercial & Residential (excluding special contracts, AGA)		$739,771	$49,383	7.15%	5.59
Public Street Lighting					
Security Area Lighting	7	$3,006	$251	9.10%	21.70
Street Lighting - Company Owned	11	$5,884	$491	9.10%	25.96
Street Lighting - Customer Owned	12	$3,206	$267	9.10%	10.49
Traffic Signal Systems	12	$652	$54	9.10%	7.29
Metered Outdoor Lighting	12	$676	$0	0.00%	7.07
Decorative Street Lighting	13	$1,136	$95	9.10%	7.73
Subtotal Public Street Lighting		$14,561	$1,158	8.64%	14.52
Security Area Lighting Contracts (PTL)		$21	$0	0.00%	7.48
Street Lighting-Contracts (66, 77)		$18	$0	0.00%	12.52
AGA/Revenue Credit		$5	$0	0.00%	
Total Public Street Lighting		$14,604	$1,158	8.61%	14.50
Total Sales to Ultimate Customers		$1,307,389	$85,001	6.95%	6.07
Total Sales to Ultimate Customers (Excluding special contracts, AGA)		$1,240,938	$85,001	7.35%	6.39

2. The $30 million rate credit will be reflected in customer prices from December 11, 2006, through May 31, 2007

APPENDIX II: Rate Design Stipulation for Schedules 6, 6A and 6B

BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PACIFICORP for Approval of Its Proposed Electric Service Schedules & Electric Service Regulations	DOCKET NO. 06-035-21 **STIPULATION REGARDING RATE DESIGN**

1. This Stipulation ("Stipulation") is entered into by and among the parties whose signatures appear on the signature pages hereof (collectively referred to herein as the "Parties").

I. INTRODUCTION

2. The terms and conditions of this Stipulation are set forth herein. The Parties represent that this Stipulation is in the public interest and recommend that the Public Service Commission (the "Commission") approve the Stipulation and all of its terms and conditions.

II. BACKGROUND

3. On March 7, 2006, PacifiCorp filed an application, together with revenue requirement, cost of service, rate spread and rate design testimony, for a rate increase of $197.2 million based on a 12 month forecast test period ending September 30, 2007. On April 5, 2006, in compliance with the provisions of Commitment U23 of Appendix A to the Stipulation in Docket No. 05-035-54, PacifiCorp filed supplemental testimony that reduced the Company's proposed price increase from $197.2 million to $194.1 million.

4. On April 4, 2006, the Commission issued an order establishing the procedural schedule for this proceeding. On April 18, 2006, May 1, 2006 and May 24, 2006, the Commission issued orders amending that schedule.

5. On July 26, 2006, PacifiCorp filed a stipulation ("Revenue Requirement and Rate Spread Stipulation") which resolves the revenue requirement and rate spread issues in this proceeding. Under the terms of the Revenue Requirement and Rate Spread Stipulation, customer rates will increase by $85 million on December 11, 2006 and by an additional $30 million on June 1, 2007. The Revenue Requirement and Rate Spread Stipulation also provides that the allocation of revenues to customer classes to recover the increased revenue requirement will be in accordance with the schedule attached to the Revenue Requirement and Rate Spread Stipulation as Exhibit 2 ("Rate Spread Exhibit"). The Revenue Requirement and Rate Spread Stipulation does not address rate design.

6. The Parties held settlement conferences to discuss the rate design issues in this proceeding. The settlement negotiations were open to all parties.

7. As a result of the settlement negotiations, the Parties have agreed to the rate design for Electric Service Schedules 6, 6 A and 6 B and the other matters specified herein.

III. TERMS OF STIPULATION

8. Rate Design. The Parties agree that the portion of the $115 million increase in customer rates specified in the Revenue Requirement and Rate Spread Stipulation which is allocated, as specified in Rate Spread Exhibit, to Electric Service Schedules 6, 6 A and 6 B should be recovered from the customers taking service on Electric Service Schedules 6, 6 A and 6 B in accordance with the schedule attached hereto as Exhibit A.

9. Winter On-peak period. The Parties agree that after the conclusion of this case, but prior to filing its next general rate case, PacifiCorp and interested parties will explore alternatives to current 16 hour on-peak time period during the winter months.

10. On-peak, Off-Peak Price Differential. The Parties agree that after the conclusion of this case, but prior to filing its next general rate case, PacifiCorp and interested parties will analyze, discuss, and make a recommendation on the price differential between on-peak and off-peak energy charges for Electric Service Schedules 8 and 9.

11. Classification and Allocation of Distribution Costs. The Parties agree that after the conclusion of this case, but prior to filing its next general rate case, PacifiCorp and interested parties will explore alternative classification and allocation methodologies for distribution costs.

12. Obligations of the Parties. The Parties agree that their obligations under this Stipulation are subject to the Commission's approval of this Stipulation and the Revenue Requirement and Rate Spread Stipulation.

13. Recommendation and Support. The Parties recommend that the Commission approve and adopt this Stipulation in its entirety. If this Stipulation is approved by the Commission in its entirety, no Party shall appeal any portion of this Stipulation and no Party shall oppose the adoption of this Stipulation in any appeal filed by any person not a party to the Stipulation. PacifiCorp and the Division shall make witnesses available to testify in support of this Stipulation and other parties may make such witnesses available. In the event other parties introduce witnesses opposing approval of the Stipulation, the Parties agree to cooperate in cross-examination and in providing testimony as necessary to rebut the testimony of opposing witnesses.

14. Reservation of Right to Withdraw from Stipulation. In the event the Commission rejects any or all of this Stipulation, or the Revenue Requirement and Rate Spread Stipulation, or

imposes any additional material conditions on approval of this Stipulation or the Revenue Requirement and Rate Spread Stipulation, or in the event the Commission's approval of this Stipulation or the Revenue Requirement and Rate Spread Stipulation is rejected or conditioned in whole or in part by an appellate court, each Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding delivered no later than five (5) business days after the issuance date of the applicable Commission or court order, to withdraw from this Stipulation. Prior to that election, Parties agree to meet and discuss the Commission's order or court's decision. In the event that no new agreement is reached, no Party shall be bound or prejudiced by the terms of this Stipulation, and each Party shall be entitled to undertake any steps it deems appropriate.

15. Public Interest. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions, considered together as a whole, will produce fair, just and reasonable results.

16. Waiver. No Party is bound by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of the rights of any Party unless such rights are expressly waived herein. Execution of this Stipulation shall not be deemed to constitute an acknowledgement by any Party of the validity or invalidity of any particular method, theory or principle of regulation or cost recovery, and no Party shall be deemed to have agreed that any method, theory or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future and shall not be deemed to constitute precedent nor prejudice the rights of any party in future proceedings. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

Dated this 25th day of August, 2006.

PACIFICORP
DBA ROCKY MOUNTAIN POWER
/s/ Mark C. Moench
Mark C. Moench
Senior Vice President & General Counsel

UTAH DIVISION OF PUBLIC UTILITIES
/s/ Michael Ginsberg
Michael Ginsberg
Patricia Schmid
Assistant Attorney General

UTAH INDUSTRIAL ENERGY CONSUMERS
/s/ F. R. Reeder
F. Robert Reeder
Vicki M. Baldwin
Attorneys for UIEC, an Intervention Group

AARP
/s/ Dale Gardiner
Dale Gardiner
Thomas Forsgren

THE KROGER CO.
/s/ M.. L. Kurtz
Michael L. Kurtz

EXHIBIT A to Rate Spread Stipulation for Schedules 6, 6A and 6B

Rocky Mountain Power - State of Utah
2007 Test Period Forecasted Loads, Target Annual Revenues, Proposed Prices
Schedules 6, 6B & 6A Blocking
General Service - Distribution Voltage
Settlement - Proposed Rate Design

Schedules 6 & 6B

Rate Component	Forecasted Units 9/30/07	Present Prices	Present Revenues	Proposed Prices	Proposed Revenues
Customer Charge	147,432	$15.00	$2,211,480	$25.00	$3,685,800
All kW (May - September)	7,372,775	$12.76	$94,076,609	$13.91	$102,555,300
All kW (October - April)	8,615,316	$10.24	$88,220,836	$11.16	$96,146,927
Voltage Discount	500,398	$(0.66)	($330,263)	$(0.72)	($360,287)
All kWh (May - September)	2,448,021,699	$0.025740	$63,012,079	$0.029271	$71,656,043
All kWh (October - April)	3,066,134,374	$0.025740	$78,922,299	$0.027000	$82,785,628
Total			$326,113,039		$356,469,411

Schedule 6A

Rate Component	Forecasted Units 9/30/07	Present Prices	Present Revenues	Proposed Prices	Proposed Revenues
Customer Charge	21,519	$15.00	$322,785	$25.00	$537,975
Facilities kW (May - Sept)	753,624	$4.61	$3,474,207	$4.99	$3,760,584
Facilities kW (October - April)	840,190	$3.86	$3,243,133	$4.18	$3,511,994
Voltage Discount	97,990	$(0.43)	($42,136)	$(0.47)	($46,055)
On-Peak kWh (May - Sept)	45,711,014	$0.084174	$3,847,679	$0.091143	$4,166,239
Off-Peak kWh (May - Sept)	53,018,661	$0.025342	$1,343,599	$0.027440	$1,454,832
On-Peak kWh (October - April)	67,679,911	$0.070360	$4,761,959	$0.076185	$5,156,194
Off-Peak kWh (October - April)	64,165,849	$0.021183	$1,359,225	$0.022958	$1,473,120
Total			$18,310,451		$20,014,882

APPENDIX III: Rate Design Stipulation for Schedules 8, 9 and 31

BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of PACIFICORP for Approval of Its Proposed Electric Service Schedules & Electric Service Regulations	DOCKET NO. 06-035-21 **STIPULATION REGARDING RATE DESIGN**

1. This Stipulation ("Stipulation") is entered into by and among the parties whose signatures appear on the signature pages hereof (collectively referred to herein as the "Parties").

I. INTRODUCTION

2. The terms and conditions of this Stipulation are set forth herein. The Parties represent that this Stipulation is in the public interest and recommend that the Public Service Commission (the "Commission") approve the Stipulation and all of its terms and conditions.

II. BACKGROUND

3. On March 7, 2006, PacifiCorp filed an application, together with revenue requirement, cost of service, rate spread and rate design testimony, for a rate increase of $197.2 million based on a 12 month forecast test period ending September 30, 2007. On April 5, 2006, in compliance with the provisions of Commitment U23 of Appendix A to the Stipulation in Docket No. 05-035-54, PacifiCorp filed supplemental testimony that reduced the Company's proposed price increase from $197.2 million to $194.1 million.

4. On April 4, 2006, the Commission issued an order establishing the procedural schedule for this proceeding. On April 18, 2006, May 1, 2006 and May 24, 2006, the Commission issued orders amending that schedule.

5. On July 26, 2006, PacifiCorp filed a stipulation ("Revenue Requirement and Rate Spread Stipulation") which resolves the revenue requirement and rate spread issues in this proceeding. Under the terms of the Revenue Requirement and Rate Spread Stipulation, customer rates will increase by $85 million on December 11, 2006 and by an additional $30 million on June 1, 2007. The Revenue Requirement and Rate Spread Stipulation also provides that the allocation of revenues to customer classes to recover the increased revenue requirement will be in accordance with the schedule attached to the Revenue Requirement and Rate Spread Stipulation as Exhibit 2 ("Rate Spread Exhibit"). The Revenue Requirement and Rate Spread Stipulation does not address rate design.

6. On August 25, 2006, PacifiCorp filed a stipulation which resolves rate design issues for Electric Service Schedules 6, 6 A and 6 B.

7. The Parties have held settlement conferences to discuss the remaining rate design issues in this proceeding. The settlement negotiations were open to all parties.

8. As a result of those negotiations, the Parties have reached agreement on rate design for Electric Service Schedules 8, 9, and 31 and the other matters specified herein.

III. TERMS OF STIPULATION

9. Rate Design. The Parties agree that the portion of the $115 million increase in customer rates specified in the Revenue Requirement and Rate Spread Stipulation which is allocated, as specified in the Rate Spread Exhibit, to Electric Service Schedules 8, 9 and 31 should

be recovered from the customers taking service on those Electric Service Schedules in accordance with the schedule attached hereto as Exhibit A.

10. Obligations of the Parties. The Parties agree that their obligations under this Stipulation are subject to the Commission's approval of this Stipulation and the Revenue Requirement and Rate Spread Stipulation.

11. Recommendation and Support. The Parties recommend that the Commission approve and adopt this Stipulation in its entirety. If this Stipulation is approved by the Commission in its entirety, no Party shall appeal any portion of this Stipulation and no Party shall oppose the adoption of this Stipulation in any appeal filed by any person not a party to the Stipulation. PacifiCorp and the Division shall make witnesses available to testify in support of this Stipulation and other parties may make such witnesses available. In the event other parties introduce witnesses opposing approval of the Stipulation, the Parties agree to cooperate in cross-examination and in providing testimony as necessary to rebut the testimony of opposing witnesses.

12. Reservation of Right to Withdraw from Stipulation. In the event the Commission rejects any or all of this Stipulation, or the Revenue Requirement and Rate Spread Stipulation, or imposes any additional material conditions on approval of this Stipulation or the Revenue Requirement and Rate Spread Stipulation, or in the event the Commission's approval of this Stipulation or the Revenue Requirement and Rate Spread Stipulation is rejected or conditioned in whole or in part by an appellate court, each Party reserves the right, upon written notice to the Commission and the other Parties to this proceeding delivered no later than five (5) business days after the issuance date of the applicable Commission or court order, to withdraw from this Stipulation. Prior to that election, Parties agree to meet and discuss the Commission's order or court's decision. In the event that no new agreement is reached, no Party shall be bound or

prejudiced by the terms of this Stipulation, and each Party shall be entitled to undertake any steps it deems appropriate.

13. Public Interest. The Parties agree that this Stipulation is in the public interest and that all of its terms and conditions, considered together as a whole, will produce fair, just and reasonable results.

14. Waiver. No Party is bound by any position asserted in the negotiation of this Stipulation, except to the extent expressly stated herein, nor shall this Stipulation be construed as a waiver of the rights of any Party unless such rights are expressly waived herein. Execution of this Stipulation shall not be deemed to constitute an acknowledgement by any Party of the validity or invalidity of any particular method, theory or principle of regulation or cost recovery, and no Party shall be deemed to have agreed that any method, theory or principle of regulation or cost recovery employed in arriving at this Stipulation is appropriate for resolving any issues in any other proceeding in the future and shall not be deemed to constitute precedent nor prejudice the rights of any party in future proceedings. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Stipulation.

Dated this 31st day of August, 2006.

PACIFICORP
DBA ROCKY MOUNTAIN POWER
/s/ Mark C. Moench
Mark C. Moench
Senior Vice President & General Counsel

UTAH DIVISION OF PUBLIC UTILITIES
/s/ Michael Ginsberg
Michael Ginsberg
Patricia Schmid
Assistant Attorney General

UTAH INDUSTRIAL ENERGY CONSUMERS
/s/ F. R. Reeder
F. Robert Reeder
Vicki M. Baldwin
Attorneys for UIEC, an Intervention Group

FEDERAL EXECUTIVE AGENCIES
/s/ Damund E. Williams
Lt. Col. Karen White
Capt. Damund E. Williams

UAE INTERVENTION GROUP
/s/ Gary Dodge
Gary Dodge

THE KROGER CO.
/s/ M. L. Kurtz
Michael L. Kurtz

CENTRAL VALLEY WATER
/s/ Ronald J. Day
Ronald J. Day

UTAH MANUFACTURERS ASSOCIATION
/s/ Thomas Bingham
Thomas Bingham

EXHIBIT A: Rate Spread Stipulation for Schedules 8, 9 and 31

Rocky Mountain Power - State of Utah
2007 Test Period Forecasted Loads, Target Annual Revenues, Proposed Prices
Stipulated Rate Design

Schedule 8 Blocking
Large General Service - Distribution Voltage

Schedule 8

Rate Component	Forecasted Units 9/30/07	Present Prices	Present Revenues	Proposed Prices	Proposed Revenues
Customer Charge	2,892	$15.00	$43,380	$25.00	$72,300
Facilities Charge	4,610,618	$3.15	$14,523,447	$3.47	$15,998,844
On-Peak kW: May-Sep	1,996,971	$10.29	$20,548,832	$11.34	$22,645,651
On-Peak kW: Oct-April	2,637,826	$7.42	$19,572,669	$8.18	$21,577,417
Voltage Discount	1,971,570	$(0.75)	$(1,478,678)	$(0.83)	$(1,636,403)
On-Peak kWh: May-Sep	321,101,128	$0.032776	$10,524,411	$0.036832	$11,826,797
On-Peak kWh: Oct-April	472,539,509	$0.025776	$12,180,178	$0.028832	$13,624,259
Off-Peak kWh	1,264,047,565	$0.022776	$28,789,947	$0.024832	$31,388,829
Total			$104,704,186		$115,497,694

Schedule 9 Blocking
General Service - High Voltage

Schedule 9

Rate Component	Forecasted Units 9/30/07	Present Prices	Present Revenues	Proposed Prices	Proposed Revenues
Customer Charge	1,683	$100.00	$168,300	$170.00	$286,110
Facilities Charge	7,212,080	$1.40	$10,096,912	$1.54	$11,106,603
On-Peak kW: May-Sep	3,084,159	$8.78	$27,078,916	$9.68	$29,854,659
On-Peak kW: Oct-April	4,034,672	$5.95	$24,006,298	$6.56	$26,467,448
On-Peak kWh: May-Sep	421,919,546	$0.028634	$12,081,244	$0.032247	$13,605,640
On-Peak kWh: Oct-April	1,104,052,023	$0.021634	$23,885,061	$0.024247	$26,769,949
Off-Peak kWh	2,413,621,582	$0.018634	$44,975,425	$0.020247	$48,868,596
Total			$142,292,157		$156,959,006

EXHIBIT A: Rate Spread Stipulation for Schedules 8, 9 and 31 (cont.)

Schedule 31 Blocking
Back-Up, Maintenance, and Supplimentary Service

Schedule 31

Rate Component	Forecasted Units 9/30/07	Present Prices	Present Revenues	Proposed Prices	Proposed Revenues
Secondary Voltage					
Customer Charge per month	0	$55.00	$0	$94.00	$0
Facilities Charge, per kW month	0	$3.15	$0	$3.44	$0
Back-Up Power Charge					
Regular, per On-Peak kW day	0	$0.4327	$0	$0.4728	$0
Maintenance, per On-Peak kW	0	$0.2164	$0	$0.2364	$0
Excess Power, per kW month	0	$40.76	$0	$44.54	$0
Primary Voltage					
Customer Charge per month	36	$250.00	$9,000	$425.00	$15,300
Facilities Charge, per kW month	60,366	$2.47	$149,103	$2.70	$162,987
Back-Up Power Charge					
Regular, per On-Peak kW day	373,609	$0.4210	$157,289	$0.4600	$171,860
Maintenance, per On-Peak kW	49,529	$0.2105	$10,426	$0.2300	$11,392
Excess Power, per kW month	1,262	$38.30	$48,342	$41.85	$52,823
Transmission Voltage					
Customer Charge per month	12	$280.00	$3,360	$476.00	$5,712
Facilities Charge, per kW month	198,964	$1.40	$278,549	$1.53	$304,415
Back-Up Power Charge					
Regular, per On-Peak kW day	69,689	$0.3308	$23,053	$0.3614	$25,186
Maintenance, per On-Peak kW	0	$0.1654	$0	$0.1807	$0
Excess Power, per kW month	0	$28.29	$0	$30.91	$0
Subtotal	0		$679,122		$749,675

EXHIBIT A: Rate Spread Stipulation for Schedules 8, 9 and 31 (cont.)

Schedule 31 Blocking (cont.)
Back-Up, Maintenance, and Supplimentary Service

Schedule 31

Rate Component	Forecasted Units 9/30/07	Present Prices	Present Revenues	Proposed Prices	Proposed Revenues
Supplemental billed at Schedule					
Schedule 6					
All kW (May - September)	3,418	$12.76	$43,614	$13.91	$47,544
All kW (October - April)	329	$10.24	$3,369	$11.16	$3,672
Voltage Discount	3,747	$(0.66)	$2,473	$(0.72)	$(2,698)
All kWh	1,362,755	$0.025740	$35,077		
kWh (May-Sept)	*306,003*			*$0.029271*	*$8,957*
kWh (Oct-Apr)	*1,056,752*			*$0.027000*	*$28,532*
Schedule 8					
On-Peak kW (May - September)	0	$10.29	$0	$11.34	$0
On-Peak kW (October - April)	21,494	$7.42	$159,485	$8.18	$175,821
Facilities kW	0	$3.15	$0	$3.47	$0
Voltage Discount	21,494	$(0.75)	($16,121)	$(0.83)	$(17,840)
On-Peak kWh (May - September)	956,379	$0.032776	$31,346	$0.036832	$35,225
On-Peak kWh (October - April)	7,415,566	$0.025776	$191,144	$0.028832	$213,806
Off-Peak kWh	8,786,884	$0.022776	$200,130	$0.024832	$218,196
Schedule 9					
Facilities kW	0	$1.40	$0	$1.54	$0
On-Peak kW (May - Sept)	0	$8.78	$0	$9.68	$0
Est. On-Peak kW (Oct - April)	23,659	$5.95	$140,771	$6.56	$155,203
On-Peak kWh (May-Sept)	126,987	$0.028634	$3,636	$0.032247	$4,095
Est. On-Peak kWh (Oct-April)	444,225	$0.021634	$9,610	$0.024247	$10,771
Est. Off-Peak kWh	445,788	$0.018634	$8,307	$0.020247	$9,026
Schedule 31 Total	19,538,583		$1,487,017		$1,639,985