**BEFORE THE**
**PUBLIC SERVICE COMMISSION OF UTAH**

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| **In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations, Consisting of a General Rate Increase of Approximately $161.2 Million Per Year, and for Approval of a New Large Load Surcharge** | **Docket No. 07-035-93** |

Direct Testimony and Schedules of

**Maurice Brubaker**

On behalf of

**Utah Industrial Energy Consumers**

April 7, 2008
Project 8923

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

**PUBLIC VERSION**

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## Direct Testimony of Maurice Brubaker

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

**Q WHAT IS YOUR OCCUPATION?**

A I am a consultant in the field of public utility regulation and president of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

**Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A This information is included in Appendix A to my testimony.

**Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

A I am appearing on behalf of the Utah Industrial Energy Consumers (UIEC). Members of UIEC purchase substantial quantities of electricity from Rocky Mountain Power Company (RMP) in Utah, and are vitally interested in the outcome of this proceeding.

**Q WHAT SUBJECTS ARE ADDRESSED IN YOUR TESTIMONY?**

A I address certain economic issues with respect to the wind projects that RMP proposes to include in revenue requirements – namely, Production Tax Credits (PTC) revenues from the sale of "green tags" and capacity factor. I also suggest a procedure to make adjustments for changes to the in-service dates of projects that are not yet in service, and an adjustment to sales of transmission service. Finally, I address jurisdictional allocation issues.

The fact that I am not addressing other issues should not be interpreted as agreement with the positions taken by RMP. It is my understanding that other parties to the proceeding are analyzing numerous other issues in detail, and will likely present the results of those analyses in their direct testimonies. We reserve the right to adopt, in whole or in part, adjustments proposed by other parties.

**Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

A My findings and recommendations may be summarized as follows:

1. Favorable economics for a wind project depend heavily upon the receipt of the PTCs. Under current law, it is my understanding that in order to receive the 2¢/kWh PTC credit, a wind project must go into service prior to the end of calendar year 2008.

2. Four of the wind projects which RMP presents for inclusion in revenue requirements are not yet in service. Two are scheduled to go into service during the summer of this year, and the other two are not scheduled to be in service until sometime in December. Any slippage in schedule which would cause one or

more of these projects not to be in service and not to qualify for PTCs would cause the facility to be uneconomic.

3. If a wind project does not receive PTCs, and in the future RMP presents it for inclusion in revenue requirements, the Commission should impute to the project the full amount of the PTCs that the project would have received for its output had the project gone in service in time to receive the PTCs.

4. RMP assumed the receipt of revenues from selling “green tags” from its wind projects. ***…………………………………………………………………………… ………………………………………………………………………………..***

5. RMP did include a certain amount of green tag revenue credits in the test year. However, for the Goodnoe Hills project, the amount included was significantly less than the amount assumed and included in the present value revenue requirement calculations which RMP used to justify the project. Because the amount included in the test year for this project is ***……..*** below the amount used for project justification, a downward adjustment in revenue requirements in the amount of ***……..*** for the Utah jurisdiction would be warranted. (This adjustment is based on six months of operations. Adjustments in future years would be roughly double this in amount unless RMP increases the amount of green tag revenues actually received.)

6. The economics of wind projects is also heavily dependent upon capacity factor. It is recommended that RMP be required to file periodic reports with the Commission detailing the actual generation and resulting capacity factor from each project so that the Commission may have an opportunity to make adjustments in future cases if it appears that the projects are failing to approach the capacity factors assumed in the project justification.

7. In addition to several wind projects, RMP presents for consideration investments in a number of other projects, including generation, transmission and distribution projects, which are not yet in service. I recommend that adjustments be made to recognize the best available information as to the expected timing and also the expected costs of these projects.

8. Procedurally, I recommend that RMP be required to provide an update of project status in its rebuttal testimony and that other parties respond in surrebuttal. RMP should not be permitted to add projects that have not previously been identified. I also recommend that the Commission set a subsequent date which would allow for one additional update in time to be useful to the Commission in its decision making process.

9. The Utah jurisdictional revenue requirement should be decreased by $305,000 to account for the continued sale of transmission capacity.

10. The rate of growth in Utah now appears to be less than what was forecasted by RMP. Evidence on new customer additions, housing permits, mortgage foreclosures and other economic measures clearly suggest that sales will be lower than forecasted.

11. RMP should be required to adjust its jurisdictional allocation factors to reflect the most recently available weather-normalized actual information. Using recent verifiable actual information, in light of the changes in the economy, would provide for a more equitable result for Utah customers.

## WIND PROJECTS

**Q HOW MANY WIND PROJECTS HAS RMP PRESENTED FOR INCLUSION IN REVENUE REQUIREMENTS IN THIS CASE?**

A RMP has presented six wind projects, totaling 600 megawatts (MW) of capacity.

**Q HAVE YOU REVIEWED THE ECONOMIC JUSTIFICATION FOR THESE WIND PROJECTS?**

A Yes. UIEC submitted a number of data requests to RMP with respect to each of the projects that are discussed in the direct testimony of witness Lasich.

UIEC Data Request Set Nos. 2, 10 and 11 contain most of the pertinent questions and responses. I reviewed responses to these and other data requests, and also reviewed confidential information supporting the economic evaluation of these projects at RMP's offices in Salt Lake City. This latter step was necessary because RMP has designated a significant portion of the economic evaluation of these projects as "highly confidential" and required interested parties to review the information in their offices, and did not provide the majority of the information in either electronic or hard copy form.

**Q FOR PURPOSES OF YOUR TESTIMONY IN THIS CASE, HAVE YOU PREPARED A SCHEDULE TO SHOW SOME OF THE KEY PROJECTS CHARACTERISTICS AND ECONOMICS?**

A Yes. This is attached as UIEC ____ (MEB-1). Some of the information on this schedule is information designated by RMP as confidential, and was provided as part of PDF files.

**Q PLEASE EXPLAIN THE INFORMATION IN THE TOP SECTION OF UIEC ____ (MEB-1).**

A Line 1 shows the in-service date of each wind project. Line 2 shows the MWs of capacity, line 3 shows the annual megawatthours (MWh) of generation which the economic studies use for each wind project, line 4 shows the expected "life of project" MWhs generated, and line 5 shows the expected capacity factor of each project.

**Q WHAT IS CAPACITY FACTOR?**

A Capacity factor is a measure of the level of output from the project as compared to the output that would be produced were a project to operate at its full rated capacity every hour of the year. For example, a capacity factor of 33% would indicate an expectation that the number of kilowatthours (kWh) produced by the project would be the equivalent of running at full output for an average of eight hours per day (8 ÷ 24 = 33%). The higher the capacity factor, the better the economics because the fixed costs are spread over a larger number of kWh as capacity factor increases.

Q **ARE THESE GUARANTEED CAPACITY FACTORS?**

A No. These are essentially estimates based on wind profile studies and represent RMP's estimate based on available information for each project.

Q **HOW DID RMP EVALUATE THE ECONOMICS OF WIND PROJECTS?**

A RMP used the approach of estimating the traditional revenue requirement components of each capital project. These include such items as operation and maintenance expense, depreciation, property taxes, return on investment and related income taxes. There are three offsetting revenues (or cost reductions) associated with each project. These are the estimated production costs avoided by operating the wind projects as opposed to producing the energy from an alternative source, the value of the federal PTCs and an estimated value for "green tags."

In evaluating project economics, RMP determined these values for each year of the project's depreciable life, and then used a present value discounting approach to determine the net present value (NPV) of total revenue requirements for each project. This appears to be the primary decision-making criteria for each project.

Q **HAVE YOU SUMMARIZED ANY OF THIS INFORMATION ON UIEC ____ (MEB-1)?**

A Yes. I have summarized some of the key information. Line 8 shows the NPV of total revenue requirements using this approach. In this presentation, I have maintained RMP's sign convention wherein a negative number indicates a benefit to customers. Thus, if the NPV of total revenue requirements on line 8 is shown as a negative number, that negative number indicates the NPV, over the project's life, of the expected benefits to customers.

## Production Tax Credits

**Q YOU MENTIONED THAT THERE WERE SEVERAL REVENUE SOURCES THAT WERE UTILIZED IN MAKING THESE CALCULATIONS. HAVE YOU SHOWN ANY OF THEM ON UIEC ____ (MEB-1)?**

A Yes. Line 6 shows the NPV of the federal PTCs included in revenue requirements.

**Q ARE THE PTCS A MATERIAL COMPONENT OF THE BENEFIT ATTRIBUTED TO THE WIND PROJECTS?**

A Yes. On line 10 of UIEC ____ (MEB-1) I have calculated the NPV of the revenue requirements for each project if each project did not have the benefit of the PTCs. It is obvious that in each case the failure to realize the PTCs would make each project significantly uneconomic from the perspective of customers. While this should not be an issue for those projects that are already in service, it remains an issue for the four projects that have not yet entered service. And, it is especially critical for the two projects that are indicated to have a December 2008 completion date. For example, without PTCs, the Glenrock project would be a ***…………*** detriment to customers, and 7 Mile would be a detriment of ***…………..***

**Q WHAT ACTION SHOULD BE TAKEN IF ANY WIND PROJECT DOES NOT MAKE THE IN-SERVICE DATE OF DECEMBER 2008, AND DOES NOT QUALIFY FOR THE PTCS?**

A First, any project that does not go into service, or subsequently is determined not likely to go into service, by the end of December 2008 would not be used and useful and should not have any revenue requirements included in the test year.

**Q ARE THERE REQUIREMENTS IN THE FEDERAL LAW WITH RESPECT TO QUALIFYING TO RECEIVE PTCS?**

A Yes. It is my understanding that in order to receive the PTCs a project must be in service by the end of calendar year 2008. A project not in service by that time would not qualify for the PTCs.

**Q IN THE FUTURE, WHAT ACTION SHOULD THE COMMISSION TAKE WITH RESPECT TO ANY WIND PROJECT THAT WOULD FAIL TO RECEIVE THE PTCS?**

A To the extent the project would subsequently be included in revenue requirements, RMP should be required to impute the amount of PTCs it would have received each year if the project qualified for and received the PTCs.

**Q WHAT IS THE BASIS FOR THIS RECOMMENDATION?**

A First, as noted above, the PTCs are absolutely critical to making a project economical and beneficial to customers. Second, it is exclusively RMP that is in charge of and responsible for the project, its construction, and its timely completion. Customers have no say and no role in this. Thus, RMP should bear the burden of a failure to meet the criteria required to receive the PTCs.

## Green Tag Revenue

**Q IN ITS NPV ANALYSIS, HOW MUCH REVENUE DID RMP INCLUDE FOR "GREEN TAGS"?**

A The NPV of the "green tag" revenue that RMP included is shown on line 7.

**Q WOULD THESE PROJECTS HAVE BEEN ECONOMICAL WITHOUT THE ATTRIBUTION OF GREEN TAG REVENUES?**

A This is shown on line 9. Four of the six projects have a positive NPV, which means they would **<u>not</u>** have been economical in the absence of the assumed green tag revenues.

**Q DID RMP INCLUDE GREEN TAG REVENUE FROM THESE PROJECTS IN THE TEST YEAR?**

A Yes, it did. The calculations appear on page 3.5.2 of Mr. MacDougal's revenue requirement exhibits. RMP assumed that it could sell green tags on 75% of the generation attributable to Idaho, Utah, Washington and Wyoming. (It assumed that it would bank the remaining portion, or 28.73%, attributable to California and Oregon.) Of the amount available for sale, it assumed it would be able to sell 75% at a sales price of $3.50 per MWh. ***……………………………………………………………….. ……………………………………………………………………………………………..... …………………………………………………………………………………………..…….. ……………………………………………….….***

**Q WHAT IS THE EXCEPTION?**

A The exception is that in order to achieve break-even status, RMP had to attribute substantially higher green tag revenues to the Goodnoe Hills project.

**Q WHAT ASSUMPTIONS DID RMP MAKE WITH RESPECT TO THE GOODNOE HILLS PROJECT?**

A ***…………………………………………………………………………………………………… ……………………..***  Based on test year generation levels (Goodnoe Hills is currently included for six months of the test year), the amount of green tag revenue need to support Goodnoe Hills is approximately ***……………….***

**Q HOW DOES THIS COMPARE TO THE AMOUNT THAT RMP INCLUDED IN THE TEST YEAR?**

A RMP effectively included an amount equal to the kWh generation from Goodnoe Hills times 71.27%, times 75%, times $3.50 per MWh, or about $310,000.

Therefore, in order to be consistent with the assumptions used to justify the project, an adjustment of approximately ***………..*** in green tag revenues should be made.  Please note that this is only for the six-month period that generation is included in the test year.  In future years, if the project goes into service, the amount of potential adjustment would be roughly two times that amount.  Applying the 42.3% allocation factor for Utah produces an adjustment of ***…………***

## <u>Capacity Factor</u>

**Q IS THE ACTUAL ACHIEVED CAPACITY FACTOR, OR OUTPUT, OF A WIND PROJECT CRITICAL TO ITS LONG-TERM ECONOMICS?**

A Yes.  As UIEC ____ (MEB-1) shows, under the best of assumptions concerning PTCs and green tag revenue, most of the projects are only slightly break-even for customers.  Even a small shortfall of capacity factor from what was assumed in the present value revenue requirements economic evaluation would cause the projects to become uneconomic.

**Q DO YOU HAVE ANY RECOMMENDATIONS WITH RESPECT TO PROJECT CAPACITY FACTOR AND OUTPUT?**

A Yes. Because of the criticality of this parameter, and the difficulty of projecting what wind conditions will be over a long period of time, it is my recommendation that the Commission require RMP to track, and file periodically with the Commission, with appropriate access for the Committee and customers, the actual generation from each wind project. This will allow a tracking and comparison between the actual MWhs generated by each project and the assumed generation that was used to justify the project. With this information a subsequent evaluation can be made as to whether any adjustment to revenue requirements is warranted such as, for example, imputing additional generation to the wind resource in setting rates in the future.

## IN-SERVICE DATES OF OTHER PROJECTS

**Q ARE ALL OF THE INVESTMENTS THAT RMP HAS PROPOSED TO INCLUDE IN REVENUE REQUIREMENTS ONES THAT ARE ALREADY IN SERVICE?**

A No. I have already discussed the fact that four of the wind projects are not yet in service and are scheduled either for the summer of 2008 or for December of 2008. These projects have an installed cost estimated to be about $745 million. In addition to the wind projects, RMP has proposed to include in the test year estimated costs associated with a number of other projects that have not yet entered service.

The other capital additions are significant as well. For example, in the steam plant category, there is approximately $163 million of investment in Cholla 4 and $13 million associated with Jim Bridger Unit 4. The transmission category contains over $75 million of significant investments. Additional amounts are included in the distribution and general plant categories as well.

It is important that the best available information on project cost and expected in-service dates be used to determine which projects to include in revenue requirements, and for how many months to include them.

Given the dates of testimony filing, hearing dates and Commission decision date, it is obvious that actual information concerning which projects actually go into service by December 31, 2008, and what they actually cost, will not be available.

**Q HOW IS THE REVENUE REQUIREMENT IMPACTED BY THOSE INVESTMENTS?**

A The amount of revenue requirement included in the test year is consistent with the number of months that RMP has estimated the project will be in service during the test year. Thus, a project scheduled to go into service on July 1, 2008 would have included in revenue requirements an amount equal to 50% of the annual revenue requirement. A project schedule to go in service on the first day of October 2008 would have revenue requirements equal to 25% of the annual amount.

**Q WHAT DO YOU RECOMMEND?**

A I recommend that RMP be required to file an update of the status of each of its claimed construction projects in time for the Commission to give consideration to the status of these projects prior to reaching a decision on revenue requirements. The update should include both expected in-service date and expected cost.

**Q WHAT ACTION SHOULD BE TAKEN WITH RESPECT TO THIS INFORMATION?**

A Adjustments to RMP's filing should be made to eliminate entirely from revenue requirements those projects that are no longer expected to be completed and those projects that are still expected to be completed, but not within the test year.

To the extent that any project still scheduled for completion within the test year is to be included in revenue requirements, the best estimate possible of the in-service date and the cost should be utilized in calculating the revenue requirements.

**Q DO YOU HAVE A SPECIFIC PROCEDURE TO RECOMMEND?**

A Yes. I recommend that RMP be required to make a filing of this information in rebuttal testimony on May 9, 2008. This would permit parties to review the information and respond in their May 23, 2008 surrebuttal. I also recommend that the Commission, at the hearings, determine a date for an update filing subsequent to the hearings. The date should be as late in the year as feasible, given the Commission's anticipated schedule for deliberation and decision. A provision should be included to allow parties who take issue with any of the information filed in its update to file a written response with the Commission.

**Q IN ITS UPDATES, SHOULD RMP BE PERMITTED TO INCLUDE PROJECTS NOT PREVIOUSLY PRESENTED AS PART OF TEST YEAR ADDITIONS?**

A No. This would not be fair to the parties. Allowing RMP to include new projects would disadvantage all other parties who would not previously have had notice of them and an opportunity to conduct a reasonableness review of their need and cost. RMP should be restricted to an update of cost and schedule for those projects previously included in the test year.

## TRANSMISSION REVENUE

**Q DO YOU PROPOSE AN ADJUSTMENT TO RMP'S PROPOSED MISCELLANEOUS REVENUES?**

A Yes. I believe that RMP has understated its wheeling revenue. RMP excluded revenue from the sale of 45 MW of transmission capacity that was freed up when a contract with Weyerhaeuser expired. The revenue from this contact was removed from RMP's cost of service, but no replacement transmission capacity sale revenue was included in its place.

RMP has not shown that the 45 MW of transmission capacity that had previously been used by Weyerhaeuser for delivery of qualified energy service, is now needed to serve retail customer load. RMP is free to resell this transmission capacity in the wholesale market and offset the termination of the Weyerhaeuser contract revenue with transmission capacity sales.

**Q HOW DID YOU CALCULATE AN ADJUSTMENT?**

A I relied on RMP's projections for the transmission rate for non-firm short-term transmission capacity sales. Based on RMP's assumptions related to a separate sale from PPM Schute Creek, RMP's filing and data responses indicate an assumed rate for non-firm short-term transmission sales of $1.333 per kW-month (RMP response to UIEC data request 7.1.) For 45 MW of capacity, this equates to $720,000 per year on a total company basis. Hence, I propose to increase miscellaneous revenues by $720,000, which will reduce the claimed revenue deficiency for the Utah jurisdiction by $305,000.

## JURISDICTIONAL ALLOCATION ISSUES

**Q IN LIGHT OF RECENT TRENDS IN THE ECONOMY AND NEW CUSTOMER ADDITIONS, DO YOU HAVE ANY CONCERNS ABOUT THE PROPOSED JURISDICTIONAL ALLOCATION FACTORS?**

A Yes. Exhibit UIEC ____ (MEB-2) summarizes two of the major jurisdictional allocation factors, System Generation (SG) and System Energy (SE). While there are many more allocation factors, these factors are indicative of the major energy allocation factors and the transmission and generation fixed cost allocation factors.

Line 1 shows the starting point, or base data, for the 12 months ended June 30, 2007. Information on line 2 shows RMP's estimates for the ordered test year of calendar year 2008, and line 3 shows the allocation factors for RMP's originally proposed test year, the 12 months ending June 30, 2009. RMP was forecasting a significant increase in the proportion of total system sales and demand that would be accounted for by Utah jurisdictional customers. And, note by comparing the information on lines 2 and 3 that RMP's forecast for December 31, 2008 assumes that nearly all of the growth that it had forecasted through the end of its originally proposed test year would occur in calendar year 2008.

**Q HAVE CUSTOMER ADDITIONS KEPT UP WITH RMP'S FORECAST?**

A No. In response to UIEC Data Request No. 8-8, RMP provided a comparison of actual customers with forecasted customers. The information provided goes through January 2008. It shows that RMP had not achieved the level of customer additions that it had forecasted. In the important residential class, RMP had forecasted that from July 2007 through January 2008 it would add approximately 13,200 residential customers. The information provided by RMP shows that the actual additions for that period of time were 6,570, only about half of what RMP had forecasted.

A recent news article (the Salt Lake Tribune, March 18, 2008) pointed out that builders along the Wasatch Front took out permits for the construction of only 261 homes during February, which was the lowest February since at least 1990. It was also reported that this was a 72% decline from February 2007.

The increase in the rate of Utah home foreclosures (up 52% in February from the corresponding period a year earlier) also signifies a weakness in the economy and further calls into question the robust growth numbers asserted by RMP (Deseret Morning News, March 13, 2008).

**Q IN LIGHT OF THESE UNCERTAINTIES, WHAT IS YOUR RECOMMENDATION?**

A It is my recommendation that RMP should be directed to utilize the most recently available weather-normalized jurisdictional information that can be validated, rather than rely upon what appears to be an overly optimistic forecast. In the absence of evidence to support the forecast, reliance upon these jurisdictional allocation factors would not be fair to Utah customers.

**Q DOES RMP HAVE THE DATA NECESSARY TO MODIFY THE ALLOCATION FACTORS TO REFLECT FACTUAL, WEATHER-NORMALIZED RESULTS?**

A Yes. RMP provided some of this information in response to CCS Data Request No. 17.2. I have shown on line 4 of Exhibit UIEC ____ (MEB-2) my calculation of the SG and SE factors for calendar year 2007, based on the actual, weather-normalized information provided by RMP.

In light of the changes taking place in the economy and the optimistic nature of RMP's forecasted growth for Utah, I believe reliance upon this more recent, actual information would provide a more equitable result for Utah customers.

**Q DOES THIS COMPLETE YOUR DIRECT TESTIMONY?**

A Yes, it does.

## Qualifications of Maurice Brubaker

**Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Maurice Brubaker. My business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141.

**Q PLEASE STATE YOUR OCCUPATION.**

A I am a consultant in the field of public utility regulation and President of the firm of Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

**Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation I was employed by the Utilities Section of the Engineering and Technology Division of Esso Research and Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of New Jersey.

In the Fall of 1965, I enrolled in the Graduate School of Business at Washington University in St. Louis, Missouri. I was graduated in June of 1967 with the Degree of Master of Business Administration. My major field was finance.

From March of 1966 until March of 1970, I was employed by Emerson Electric Company in St. Louis. During this time I pursued the Degree of Master of Science in Engineering at Washington University, which I received in June, 1970.

In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis, Missouri. Since that time I have been engaged in the preparation of numerous studies relating to electric, gas, and water utilities. These studies have included analyses of the cost to serve various types of customers, the design of rates for utility services, cost forecasts, cogeneration rates and determinations of rate base and operating income. I have also addressed utility resource planning principles and plans, reviewed capacity additions to determine whether or not they were used and useful, addressed demand-side management issues independently and as part of least cost planning, and have reviewed utility determinations of the need for capacity additions and/or purchased power to determine the consistency of such plans with least cost planning principles. I have also testified about the prudency of the actions undertaken by utilities to meet the needs of their customers in the wholesale power markets and have recommended disallowances of costs where such actions were deemed imprudent.

I have testified before the Federal Energy Regulatory Commission (FERC), various courts and legislatures, and the state regulatory commissions of Alabama, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri, Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia, Wisconsin and Wyoming.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and assumed the utility rate and economic consulting activities of Drazen Associates, Inc., founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It includes most of the former DBA principals and staff. Our staff includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business.

During the past ten years, Brubaker & Associates, Inc. and its predecessor firm has participated in over 700 major utility rate and other cases and statewide generic investigations before utility regulatory commissions in 40 states, involving electric, gas, water, and steam rates and other issues. Cases in which the firm has been involved have included more than 80 of the 100 largest electric utilities and over 30 gas distribution companies and pipelines.

An increasing portion of the firm's activities is concentrated in the areas of competitive procurement. While the firm has always assisted its clients in negotiating contracts for utility services in the regulated environment, increasingly there are opportunities for certain customers to acquire power on a competitive basis from a supplier other than its traditional electric utility. The firm assists clients in identifying and evaluating purchased power options, conducts RFPs and negotiates with suppliers for the acquisition and delivery of supplies. We have prepared option studies and/or conducted RFPs for competitive acquisition of power supply for industrial and other end-use customers throughout the Unites States and in Canada, involving total needs in excess of 3,000 MWs. The firm is also an associate member of the Electric Reliability Council of Texas and a licensed electricity aggregator in the State of Texas.

In addition to our main office in St. Louis, the firm has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

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