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| **Stress Factor Study Proposal<br>In Compliance with Stipulation<br>in Rocky Mountain Power<br>2012 General Rate Case** | )<br>)<br>)<br>)<br>)<br>) | **Docket No. 11-035-200** |

# Comments of Maurice Brubaker on behalf of Utah Industrial Energy Consumers ("UIEC")

August 7, 2013


BAI

BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017


Project 9701

## Comments of Maurice Brubaker on behalf of Utah Industrial Energy Consumers

## Introduction

Brubaker & Associates, Inc. ("BAI") has been retained by the Utah Industrial Energy Consumers ("UIEC") to prepare comments on the Stress Factor Study submitted by Rocky Mountain Power Company ("RMP") in this docket on July 1, 2013. A brief summary of Maurice Brubaker's background and experience is included as Appendix A to these comments.

The Settlement Stipulation in Docket No. 11-035-200 provided, in Paragraph 55, the following:

> "55. For purpose of Utah cost of service studies, the Company agrees to propose a plan for a new Stress Factor study by July 1, 2013 and to request that the Commission hold a technical conference to review the plan and take comments from interested parties. The Company's study plan shall be shared with interveners to the current docket no later than two weeks prior to the scheduled technical conference. The Company shall provide the completed study to intervenors in the current case at least two months before its next general rate case."

The "stress factor" study was not defined as a part of the Stipulation, nor was there any agreement as to what constitutes "stress."

## RMP's Suggestions

On July 1, 2013, RMP made a filing with the Public Service Commission of Utah ("Commission") in which it set forth five candidates for measuring "stress." The filing is silent as to what RMP regards as "stress" and merely consists of a series of possible calculations that have been offered by RMP to comply with Paragraph 55 of the Settlement Stipulation.

The five measures put forth are as follows:

1. **Monthly Firm Peak Demands**. (Highest hourly monthly demand for power use by firm load customers).

2. **Probability of Contribution to Peak (1)**. (Number of hours each month that firm load exceeds a percentage of the annual peak load.)

3. **Probability of Contribution to Peak (2)**. (Number of MWh associated with the hours each month that firm load exceeds a percentage of the annual peak load.)

4. **Monthly Reserve Margins**. (The Company's reserve margin during the peak hour each month.)

5. **Cost of Peak Resources**. (The dollar per MW-hour difference each month that cost of wholesale market purchases exceeds the cost of gas-fired resources.)

## Comments on RMP's Suggestions

A working concept of "stress" that would be useful in determining how to properly allocate the fixed costs associated with generation facilities must focus on a determination of those hours in which the utility is most likely not to be able to serve all firm system load. In this regard, only Analysis 1 above has any claim to usefulness. It is inherently logical that a utility would have the highest chance of failing to serve firm load during those hours when the firm load is at its highest levels. Accordingly, Analysis 1 is at least a first approximation of a determination of the critical loads on the utility's system that contribute to the need to add generation capacity.

The other four suggested analyses are, at best, second or third level approximations, or, as is true in most cases, completely irrelevant.

Analysis 2 (number of hours each month that firm load exceeds a percentage of the annual peak load) tells us nothing about stress, the ability to serve load, or the need to add capacity. This is nothing more than an arithmetic exercise which tallies load levels in relation to arbitrary percentages of the annual peak. As such, it is not instructive, important or useful.

Analysis 3 (number of MWh associated with the hours each month that firm load exceeds a percentage of the annual peak load) suffers from the same shortcomings as Analysis 2, but is even less useful because it focuses on number of MWh rather than kilowatt load values.

Analysis 4 (the Company's reserve margin during the peak hour each month) may be regarded as a second approximation of a stress measure, but it still falls short of providing the information necessary to make judgments as to which loads are stressful because it doesn't recognize the availability of capacity from off-system or other market resources to supply load even if the margin between PacifiCorp's generation resources and load is diminished because of scheduled maintenance or other factors. As such, it does not provide any useful guidance for the determination of stressful loads.

Analysis 5 (the dollar per MW-hour difference each month that cost of wholesale market purchases exceeds the cost of gas-fired resources) provides even less useful information. The cost of wholesale purchases in one month versus the cost of wholesale purchases in another would provide relevant information because it is an expression of how the competitive wholesale market values resources. The price in the wholesale market reflects supply and demand considerations, and hours or periods which exhibit the highest prices obviously are telling the participants when resources are most scarce, and this information therefore represent a logical proxy for utility system stress. However, the comparison of these numbers to the cost of generation from a peaking turbine or from a combined-cycle unit, at an unspecified capacity factor, provides no useful information.

## <u>The Real Measure of Stress</u>

The "gold standard" for determining system stress is a loss of load probability ("LOLP") analysis. This is precisely the type of analysis that PacifiCorp conducts as an integral part of its system planning process. It examines the difference between system resources and firm system loads under a variety of conditions, measured by probabilistic techniques that examine a range of values with respect to such important factors as system load, weather conditions, generation unit availability and other key factors.

The conclusion of PacifiCorp's LOLP and related analyses is that only the summer peak is critical in terms of capacity planning. (See the attached memorandum titled "PacifiCorp System Planning Considerations and Implications for Cost Allocation" for the facts and analyses supporting this conclusion.) Therefore, only the summer system peak demands should be considered in allocating generation-fixed costs among customer classes.

## Qualifications of Maurice Brubaker

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

A Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

**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.

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 megawatts. 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.

August 7, 2013

# M E M O R A N D U M

**Re: PacifiCorp System Planning Considerations and Implications for Cost Allocation**

In order to develop a proper method for allocating generation fixed costs to customer classes, it is necessary to understand the cost drivers for PacifiCorp's generation system. Our study of PacifiCorp's capacity planning process clearly reveals that: (1) reliability is the key consideration; and (2) summer peak demands are the most critical in this process, as revealed by PacifiCorp's loss of load probability ("LOLP") analysis and other corroborating information.

The key conclusion from our analysis is that PacifiCorp's own planning documents show that new resources are planned and built to meet the summer peak demands. Therefore, in accordance with cost-causation principles, generation-fixed costs should be allocated to customer classes in proportion to their summer peak demands.

The analysis also clearly shows that allocation of generation fixed costs based on 12 coincident peaks ("12 CP") with a 25% energy weighting is not cost-justified and should be abandoned at the class level.

## Review of PacifiCorp Capacity Planning

An understanding of PacifiCorp's planning process is instructive in respect to understanding what drives costs, and consequently what factors should form the basis for the allocation of fixed generation costs.

PacifiCorp's planning indicators are clearly laid out in its 2013 Integrated Resource Plan ("IRP"), which is formally titled "2013 Integrated Resource Plan, PacifiCorp," dated April 30, 2013.

A key consideration in determining the capacity that PacifiCorp must have available in order to meet its obligation to provide safe, adequate and reliable service, is to determine which loads are most important, and for which capacity must be planned. The gold standard in the industry for making such a determination is an LOLP analysis. An LOLP analysis compares customer loads with resources in every hour of the year, under various scenarios, to determine when the system is most stressed, and therefore when a loss of load is most probable.[1] This is the quintessential stress analysis because it considers loads, resources, and the probabilities associated with load forecast uncertainty, generation outages and other relevant factors. The result of PacifiCorp's analysis is that the only significant LOLP events occur in the summer, near the time of the annual peak load.

Based on this result, PacifiCorp develops a capacity addition determination that is based on its annual peak demand, which occurs in the summer, and not on 12 CP demands. In the "Chapter Highlights" portion of Chapter 5 – Resource Needs Assessment (page 79 of the IRP), PacifiCorp expresses it this way:

> "• On both a capacity and energy basis, PacifiCorp calculates load and resources balances using existing resource levels, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability **at the time of the coincident system peak load hour.**
>
> • For capacity expansion planning, the Company uses a 13-percent planning reserve margin applied to PacifiCorp's obligation (Loads – Interruptible – DSM). The 13-percent planning reserve margin is supported by Stochastic Loss of Load Probability Study in Appendix I." [Emphasis added.]

Throughout the planning process, resource needs are evaluated based on the summer peak firm loads plus a reserve margin of 13%. Loads in other months are not used in the Resource Needs Assessment.

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[1]See the **Appendix** for more detail on LOLP.

PacifiCorp provides further evidence of the importance of loads during the summer period in Chapter 7 – Modeling Approach. In that chapter, PacifiCorp explains various performance measures that it applies when evaluating different candidate expansion plans. For the supply reliability portion of the evaluation, PacifiCorp looks at energy not served ("ENS") as part of the evaluation of the Loss of Load Probability ("LOLP"). Page 198 of the IRP states,

> "Loss of Load Probability is a term used to describe the probability that the combinations of online and available energy resources cannot supply sufficient generation to serve the load peak during a given interval of time. For reporting LOLP, PacifiCorp calculates the probability of ENS events, where the magnitude of the ENS exceeds given threshold levels. PacifiCorp is strongly interconnected with the regional network; therefore, **only events that occur at the time of the regional peak are the ones likely to have significant consequences**." [Emphasis added.]

Once again, it is clear that the primary concern about loss of load is associated with the summer period when customer demands are the highest and the system is stressed the most. More detail on Loss of Load Probability can be found in the **Appendix** to this memo.

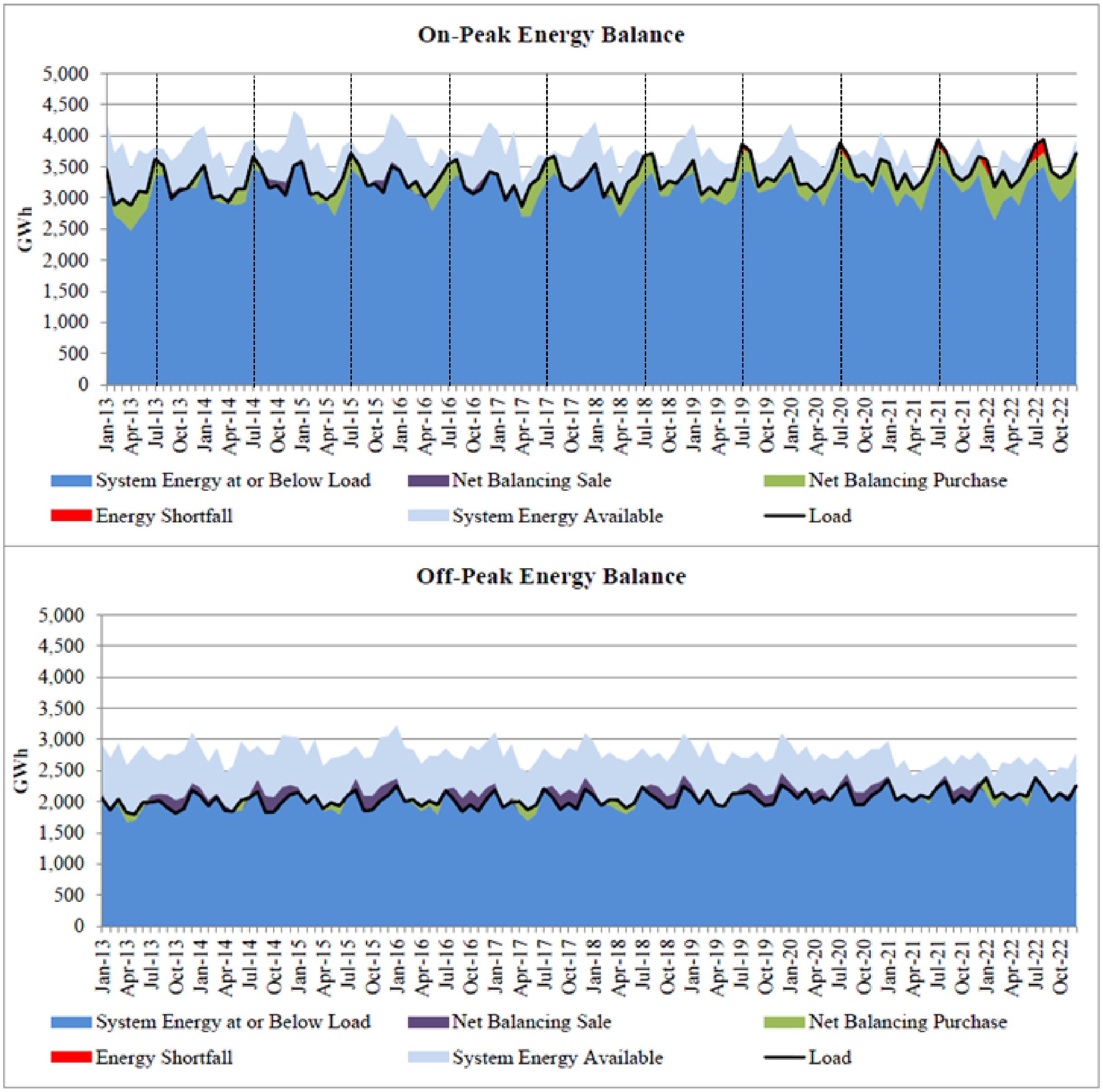
## Additional Evidence

As additional evidence, it is instructive to examine seasonal and time-of-day resource profiles.

PacifiCorp has summarized its monthly energy position for the years 2013 through 2022 in the IRP Figure 5.5. (We have added the vertical lines to show July in each year on the on-peak graph.)[2]

[2]The on-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday, excluding NERC-observed holidays. All other hours define off-peak periods.

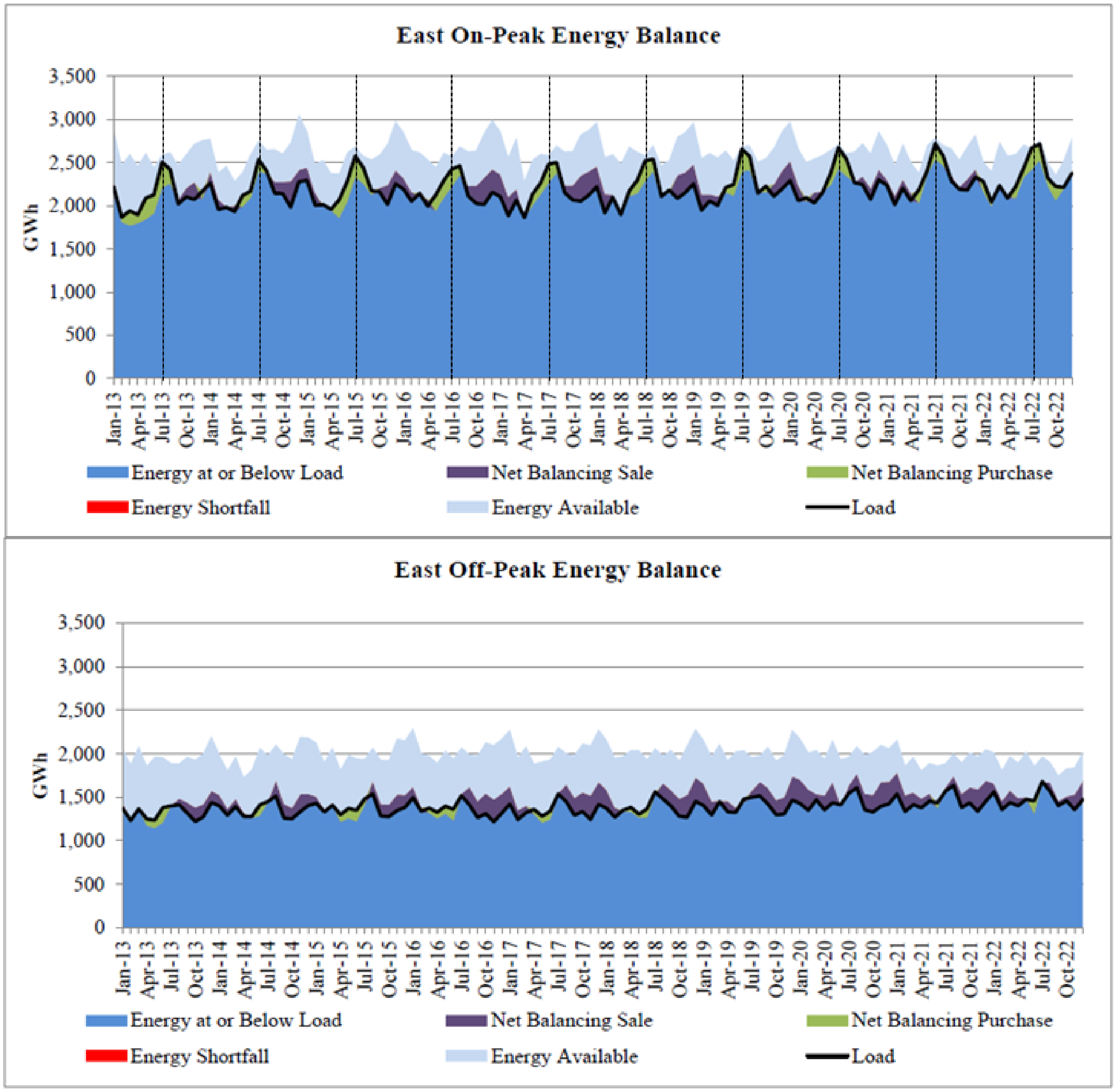
**Figure 5.5 – System Average Monthly and Annual Energy Positions**




The above figure clearly shows that the summer period puts the most stress on the system. As shown by the light blue area, in the years 2013 through 2017, the available system energy is at its lowest levels during the summer on-peak period. Energy availability is plentiful in the on-peak hours of non-summer months, and in the off-peak period during all months.

PacifiCorp presents a similar analysis for the eastern part of its system.

**Figure 5.7 – East Average Monthly and Annual Energy Positions**




It again is obvious that available energy is at its lowest levels during the on-peak hours of the summer months. This is expected as the loads are their highest levels and the summer ratings of the generating resources are diminished due to hot weather.

PacifiCorp also relies on demand-side management programs to reduce its demand during the summer. There are currently two such programs in place; Utah's "Cool Keeper" program which is an air conditioner program and Idaho's and Utah's dispatchable irrigation load management programs. The programs are utilized during the summer and accounted for over 350 MW of load reduction during the summer of 2012. Furthermore, there are three existing curtailment contracts with Monsanto, US Magnesium, and Nucor that provide about 324 MW of load interruption capability at the time of system peak.

## Prior Studies

The evidence from the 2013 IRP is consistent with the 2011 IRP. RMP provided similar evidence in a response to a data request in its most recent rate case, Docket No. 11-035-200. In response to DPU Data Request No. 6.39, RMP explicitly stated that only summer loads were considered in its resource acquisition planning because only summer loads contributed to a resource adequacy concern.

> **"DPU Data Request 6.39**
>
> **COST ALLOCATION:** Please provide any references in the Company's IRP to the need to acquire new capacity in order to meet peak loads in months other than peak summer months.
>
> **Response to DPU Data Request 6.39**
>
> There are no references in the IRP to meeting peak loads for non-summer months, as the Company's capacity position is based on the system coincident peak load hour, which typically occurs in late July."

## Conclusion

The system planning information discussed above clearly demonstrates that summer peak demands place the most stress on the system and are, in fact, the only demands considered by PacifiCorp in planning its capacity resources. Consequently, customer class demands during the summer peak period are the relevant demands to be used for allocating the fixed costs associated with generation facilities.

BRUBAKER & ASSOCIATES, INC.

*Maurice Brubaker*

Maurice Brubaker

*Brian Andrews*

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## Loss of Load Studies

Loss of load studies are performed by utilities to determine how much capacity is required to reliably meet demand in any given hour. There are two important measurements that result from these studies, the Loss of Load Probability ("LOLP"), and the planning reserve margin. The industry standard for LOLP is to have enough generating resources such that firm load is expected to be interrupted for no more than one day in ten years ("1-in-10"). Generally these studies are conducted for only one calendar year; therefore, the 1-in-10 standard is reduced to 2.4 hours per year. The planning reserve margin is the amount of capacity, expressed as a percentage, that must exist above the expected annual peak demand. The minimum planning reserve margin is usually set to meet the 1-in-10 LOLP standard.

Loss of Load studies are performed by running hundreds or thousands of iterations of an hourly dispatch model. In each iteration, the following inputs are varied using Monte Carlo techniques: load, weather, generating unit capacities, generating unit forced outages, and transmission line outages. The number of hours that load is not met is recorded for each iteration and these results are then averaged. If the average number of hours that load is not served does not meet the 1-in-10 standard, then the planning reserve margin must be increased and the dispatch model must be run again until the 1-in-10 standard is satisfied.

Loss of load studies are commonly performed on an hourly basis to allow the utility companies to determine when the critical or most stressed hours occur during the year. For most utilities, the hours during the year that put the most stress on the system generally occur during the summer months when customers have their air conditioners running. Some utilities experience their annual peak during the cold winter months, due to having large amounts of customers with electric heating. These times of stress occur because the amount of system resources available is very near what is demanded. Therefore, the slightest mishap on the system could result in demand exceeding the amount of available resources resulting in the interruption of firm load.

Loss of Load studies allow the utility companies to plan their system and to provide reliable service to their customers. A reliable system is one that can be reasonably expected to meet all of its firm demand at the times of the highest stress.