Docket Nos. 13-035-184 and 13-035-196
UIEC Exhibit COS 1.0 (JAL-1.0)
Direct Testimony of Jonathan A. Lesser

BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

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	)	**Docket No. 13-035-184**
In the Matter of: the Application of Rocky Mountain Power for Approval of Revisions to Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31	)	**Docket No. 13-035-196**

DIRECT COST OF SERVICE AND SCHEDULE 31 TESTIMONY OF
JONATHAN A. LESSER
ON BEHALF OF
UTAH INDUSTRIAL ENERGY CONSUMERS

May 22, 2014

NON-CONFIDENTIAL VERSION

CONTINENTAL ECONOMICS

6 Real Place, Sandia Park, NM 87047 • Main: 505.286.8833 • DC Office: 202.446.2062
www.continentalecon.com

TABLE OF CONTENTS

BEFORE THE
PUBLIC SERVICE COMMISSION OF UTAH

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	**)**	**Docket No. 13-035-184**
In the Matter of: the Application of Rocky Mountain Power for Approval of Revisions to Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31	**)**	**Docket No. 13-035-196**

Direct Cost of Service and Schedule 31 Testimony of Jonathan A. Lesser

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jonathan A. Lesser. I am the President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is 6 Real Place, Sandia Park, NM 87047.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I filed testimony in the revenue requirement portion of Docket No. 13-035-084 on May 1, 2014, on behalf of Utah Industrial Energy Consumers ("UIEC"). My current testimony is also on behalf of UIEC. My background and qualifications, including my current *curriculum vita*, can be found my previously filed testimony in this proceeding.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses two topics. First, I review cost-allocation goals and fundamental principles, which I conclude <u>cannot</u> be achieved with the cost allocation method used by Rocky Mountain Power ("RMP" or "the Company") witness Joelle R. Steward to allocate non-fuel generation and transmission costs.[1] The proposed allocation of costs to different rate schedules, and the resulting rates, does not allocate costs based on actual cost-causation. As a result, the resulting rates are economically inefficient and inequitable. As I discuss, I conclude that the alternative cost-allocation approach being proposed by UIEC witness Maurice Brubaker is far more aligned with cost-causation principles, which is a cornerstone of setting just and reasonable cost-based rates.

Second, my testimony addresses RMP's application for approval of changes to partial requirements service, i.e., backup or standby service ("Partial Requirements Service"), available through Schedule 31, Back-Up, Maintenance and Supplementary Power, which is also supported by the testimony of RMP witness Steward.[2]

Q. CAN YOU SUMMARIZE THE MAJOR FINDINGS AND RECOMMENDATIONS IN YOUR TESTIMONY REGARDING COST ALLOCATION?

---

1 Direct Testimony of Joelle R Steward, Docket No. 13-035-184, January 3, 2014 ("Steward COS Direct").

2 Direct Testimony of Joelle R. Steward, Docket No. 13-035-196, December 4, 2013 ("Steward BU Direct").

A. Yes. My findings and recommendations all relate to a fundamental conclusion reached by the Utah Public Service Commission ("PSC" or "the Commission.") Specifically, the Commission has stated that a "cornerstone" of ensuring that rates are just and reasonable is that costs are allocated based on cost-causation.[3] If costs are not allocated properly to cost "causers," it is not possible to design rates and tariffs for retail customers that promote efficient consumption decisions. If prices are not set efficiently, then customers cannot make optimal investment decisions, such as investments in energy efficiency measures. And, if costs are not allocated based on cost-causation, then basic regulatory standards of fairness will be violated.

In light of the Commission's own conclusions about the "cornerstone" role of cost-causation principles in allocating costs leads to the following two findings:

1. RMP's continued use of the inter-jurisdictional allocation ("JA") agreement methodology, as adopted in what is commonly referenced as the 2010 Protocol and its Amendments ("2010 Protocol"),[4] is not economically efficient or equitable.
2. The JA methodology violates cost-causation, which is a fundamental ratemaking and economic principle. Because the JA methodology is not based on cost-causation principles, but is instead a political compromise, the resulting allocation

---

[3] *See, e.g., In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Corrected Report and Order, March 3, 2011 ("EBA Order"), p. 74.

[4] *In the Matter of the Application of PacifiCorp for an Investigation of Inter-jurisdictional Issues*, Docket No. 02-035-04, Report and Order, February 3, 2012.

of costs among RMP's customer classes is not economically efficient. There are at least four reasons why this is the case:

- There is clear evidence that consumption patterns in RMP's Utah service territory have changed significantly over time, and differ from the consumption patterns in other PacifiCorp jurisdictions. Most significantly, summer peak demand has grown rapidly and continues to do so, and the entire PacifiCorp system is now summer-peaking.

- As the Commission discussed in its 2011 Energy Balancing Account ("EBA") Order, RMP's increasing reliance on wind and natural gas resources has increased power cost volatility, and therefore earnings volatility. [5] With the creation of the Energy Balancing Account, RMP transferred the majority of that volatility to its customers. In light of that risk transfer, it is critical that the individual rate schedules accurately reflect their marginal contribution to that volatility. In other words, overall cost-causation must also incorporate what I term "volatility causation."[6] The JA methodology fails to do this.

- Wholesale electric markets inherently reflect cost-causation principles. Wholesale forward prices in summer at the Palo Verde market hub, for example, are greater than prices in shoulder months. Because one of the fundamental goals in rate regulation is to attempt to reflect outcomes similar to those which would occur in a workably competitive market, cost allocation methods used to set cost-based rates should be consistent with price signals in competitive markets.

[5] EBA Order, p. 65: "With the greater reliance on natural gas and wind resources, and greater reliance on the market to manage changes in loads and resources, the Company's net power cost is subject to greater underlying variability, making the financial consequences of forecast error more significant than before."

[6] I discuss "volatility causation" in Section IV.a, *infra*.

- If one takes the JA methodology as a given, then it does <u>not</u> follow that intra-jurisdiction costs should be allocated using this same methodology. In fact, using the same method will reduce overall economic well-being and fail to allocate costs in an efficient and fair manner that ensures just and reasonable rates. Because the JA methodology fails to account for changes in load patterns that have occurred since it was first implemented in 1998, it cannot properly allocate costs based on cost-causation, thus failing to reflect the Commission's own "cornerstone" argument. Moreover, because RMP asserts that the JA methodology's cost allocation approach, which uses a 75% - 25% split of demand and energy costs and a "12-CP" methodology, was a political compromise, applying that same methodology to allocate RMP's generation and transmission costs among its customer classes results in rates that are neither just nor reasonable.

- UIEC witness Brubaker's recommendation that RMP use a 4-CP peak demand approach to allocate fixed generation and transmission capital costs reflects cost causation principles and will lead to economically efficient rates and tariffs.

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS FOR PRICING BACK-UP SERVICE UNDER SCHEDULE 31?

A. Yes. I have three recommendations.

1. The Commission should reject the proposed backup service tariff presented in the testimony of RMP witness Steward.

2. RMP should not be allowed to require that all firms having onsite generation capabilities between 1,000 kW and 15,000 kW, or are QFs under the Public Utilities Regulatory Policy Act of 1978 ("PURPA) take Partial Requirements Service under Schedule 31. RMP should offer back-up service to firms that wish to take advantage of such service, but firms should be free to decline back-up service if they so choose. (Obviously, RMP should not be required to provide back-up service to firms that decline the service.)

3. For firms that *choose* to take back-up service, pricing should include the following elements:

    - For customers taking service at transmission voltages, the Backup Facilities Charge ("BFC") should be based on the FERC-approved Open Access Transmission Tariff ("OATT") network service rate, a generation reserve charge reflecting PacifiCorp's 13% reserve margin, the equivalent forced outage rate ("EFOR") of the customer's generating unit, and the maximum backup demand requested by the customer. For customers taking service from RMP at distribution voltages, the BFC should also include appropriate allocated distribution system costs on a per-kW basis.

    - The Backup Power Charge ("BPC") paid by a customer taking back-up service under Schedule 31 should be based on the prevailing wholesale market price of power during the customer's forced outage. The wholesale market price should be determined in the same manner that participating Balancing Authorities ("BAs") are charged under the Northwest Power Pool's ("NWPP") Reserve Sharing Program, in which PacifiCorp participates.[7]

Q. HOW DOES YOUR TESTIMONY RELATE TO THAT OF UIEC WITNESS MAURICE BRUBAKER?

A. Mr. Brubaker's testimony presents important jurisdictional and class load data that clearly identifies the nature of the changes that have occurred in the PacifiCorp and Utah load shapes, class load shapes and the growth in demand by the major customer classes. Then, building on the fundamental principles I present in my testimony, Mr. Brubaker develops and presents several different class cost of service allocation methods that more accurately reflect cost-causation by Utah customers, and thus promote the

[7] *See* NWPP, *Reserve Sharing Program Documentation*, Current Version, January 9, 2014, Section K.3, p. 28. The applicable balancing authority is known as "PacifiCorp-East."

economic and regulatory goals I discuss herein, as compared to the RMP cost allocation method. I agree that Mr. Brubaker's 4-CP cost allocation proposal best reflects cost-causation principles that the Commission considers to be the "cornerstone" of just and reasonable rates, promotes fairness among customers and customer classes, and will improve overall economic efficiency, thus allowing PacifiCorp to meet the demand for electricity at a lower cost, consistent with the goals of "least-cost" planning.

Q. CAN YOU SUMMARIZE WHY THE PROPOSED ALLOCATION OF COSTS USING THE SAME APPROACH AS USED TO ALLOCATE INTER-JURISDICTIONAL COSTS WILL LEAD TO ECONOMICALLY INEFFICIENT AND INEQUITABLE RATES?

A. Yes. The allocation method used by Ms. Steward is based on the inter-jurisdictional allocation ("JA") agreement methodology, as adopted in what is commonly referenced as the 2010 Protocol and its Amendments ("2010 Protocol").[8] The JA methodology allocates fixed generation and transmission costs based on a 75% - 25% blending of peak demand and energy consumption (the "75-25" approach). In using this 75-25 approach to allocate fixed generation and transmission costs among RMP's rate classes, Ms. Steward assumes that it is efficient and equitable to allocate intra-jurisdiction costs between rate schedules in the same way as inter-jurisdiction costs are allocated. Furthermore, Ms. Steward's testimony about the equity and efficiency of using the JA

8 *In the Matter of the Application of PacifiCorp for an Investigation of Inter-jurisdictional Issues,* Docket No. 02-035-04, Report and Order, February 3, 2012.

methodology to allocate fixed generation and transmission costs directly contradicts her testimony in the Backup case, in which she stresses the need "to ensure that Partial Requirements Service charges adequately reflect the cost of providing this service in order to minimize subsidization from other customers, avoiding cross-subsidies."[9] Using the 75-25 methodology ensures such cross-subsidies exist, which is anathema to proper cost allocation and economic efficiency.

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE GENERATION COST ALLOCATION APPROACH FOR RMP?

A. Yes. As the Commission itself has stated previously, proper cost allocation is the cornerstone of ensuring that retail rates are just and reasonable. By using peak responsibility allocators and an embedded cost of service study to determine customer class cost allocations of the revenue requirement, Mr. Brubaker's proposal, which accounts for the far greater "peakiness" of Utah loads: (1) reflects the principle of cost-causation and associated time-differentiated costs; (2) promotes fairness among customers and customer classes; and (3) moves in the appropriate direction of obtaining some of the positive attributes and benefits associated with economic efficiency. As such, Mr. Brubaker's proposed allocation methodology provides the Commission with the cornerstone for setting just and reasonable rates.

9 Steward BU Direct, p. 6, lines 118-120.

II. COST ALLOCATION PRINCIPLES

Q. WHY IS PROPER COST ALLOCATION SO IMPORTANT IN UTILITY REGULATION?

A. One of the most important goals of utility regulation is to attempt to approximate the results that would take place in a workably competitive retail market, even though the underlying market is not competitive.[10] If costs are not allocated properly, then it is not possible to design rates and tariffs that promote efficient consumption decisions, and are fair. Poorly designed rates, in turn, lead to utilities making economically inefficient investment decisions to meet customer demand. That, in turn, will raise the utilities' overall costs, which must then be paid by retail customers. Additionally, proper cost allocation is a matter of fairness, and allocating costs to groups of customers that are caused by other groups of customers is inequitable. These two principles for evaluating rates and rate structures were set forth over 50 years ago by James Bonbright, in his classic book, *Principles of Public Utility Rates*.[11]

Q. WHAT DOES "ECONOMIC EFFICIENCY" MEAN?

A. Economic efficiency has two components: *productive efficiency* and *allocative efficiency*. Productive efficiency means that goods and services are produced with the least-cost mix of inputs. Allocative efficiency means that goods and services are priced

---

[10] The concept of "workable competition" was developed by the economist John Clark, who developed the concept in recognition that the notion of "first perfect competition" and "perfectly competitive" markets really did not exist. *See* J. M. Clark, "Towards a Theory of Workable Competition," *American Economic Review* 30 (June 1940), pp. 241-256.

[11] James Bonbright, *Principles of Public Utility Rates*, (1961). Principles six and eight are, respectively, "Fairness in apportionment of total costs of service among different consumers;" and "Efficiency in discouraging wasteful use while promoting justified use" (5th ed., 1969, p. 261).

so that consumers reap the most value from them. Of course, because markets are not the "perfectly competitive" markets of economics textbooks, it may never be possible to achieve absolute allocative and productive efficiency. However, workably competitive markets incent improvements in productive and allocative efficiency, benefiting all market participants.

Q. HOW DO STATES WITH RETAIL ELECTRIC COMPETITION IMPROVE PRODUCTIVE EFFICIENCY?

A. In states that have retail electric competition, greater productive efficiency is achieved through the marketplace. Where there is full retail competition for electricity, there is no need to allocate generation costs. The market allocates those costs and reflects those allocations in the market prices charged to retail consumers, just as other markets do. Thus, for example, competitive wholesale and retail electric markets inherently incorporate peak demand and the marginal cost of generation at all times. As such, customers who are most responsible for driving peak demand are automatically allocated appropriate commensurate share of the costs of providing electricity in peak hours.

Of course, even in states with retail electric competition, local electric distribution utilities ("EDUs") must still provide "poles and wires" services to retail customers to ensure that electricity can be delivered safely and reliably, and transmission costs associated with wheeling electricity on the bulk power grid, must be allocated. Thus, the costs associated with transmission and distribution functions must be allocated using traditional methods.

Q. CAN YOU DESCRIBE WHAT ALLOCATIVE EFFICIENCY MEANS IN MORE DETAIL?

A. Yes. Allocative efficiency means that the prices paid by customers are those that maximize the economic value of a market. The economic value of a market is measured as the sum of producers' surplus and consumers' surplus.[12] The former is the overall difference between what it costs producers to provide a good or service and the revenues they obtain from the market; essentially, it represents profits. The latter represents the difference between the overall value consumers place on a good or service and what they actually pay.

If there were no retail electric competition and the local electric utility were not regulated, it would act as a monopolist, setting the price for electricity to maximize its profits. Monopolists do this by restricting supply below what a workably competitive market would provide and raising the market price above the competitive market price that would otherwise prevail. As a result, the overall economic value of the market is less than if the price was set at the competitive level, and is called the "welfare loss" due to monopoly.[13] That is why an important goal of economic regulation is to approximate the outcome that would occur in a workably competitive market. Allocating electric utility

---

[12] A more detailed discussion can be found in J. Lesser and L. Giacchino, *Fundamentals of Energy Regulation, 2d ed.*, (Vienna, VA: Public Utilities Reports, Inc. 2013) ("Lesser and Giacchino 2013"), pp. 21-24.

[13] *Id*., pp. 29-30.

costs appropriately is therefore, not only a cornerstone of establishing just and reasonable rates, but also necessary for improving allocative efficiency.[14]

Q. CAN DECISIONS ON HOW TO ALLOCATE ELECTRIC GENERATION COSTS ALSO AFFECT PRODUCTIVE EFFICIENCY?

A. Yes. As economist Alfred Kahn famously stated many years ago, "The only economic function of price is to influence behavior."[15] Thus, inefficient pricing of electricity will influence behavior and lead to inefficient consumption decisions that, in turn, can lead to inefficient investment decisions. For example, suppose residential customers' increased use of air conditioning is driving increased summer peak demand, and requiring new investments to meet that increased peak demand. Next, suppose that regulators decide to cross-subsidize residential customers and reduce summer electric prices for those residential customers. The cross-subsidy will increase residential demand for electricity, further increasing peak demand. As a result, the utility will need to build additional, higher-cost generating resources to meet the artificially high peak demand. In essence, <u>but for</u> the failure to allocate costs efficiently, the utility could meet

[14] Once costs are allocated among different customer classes, rates must still be designed to ensure customers see the appropriate price signals. Hence, proper cost allocation must be combined with good rate design to improve allocative efficiency.

[15] Alfred Kahn, "Applications of Economics to Utility Rate Structures," *Public Utilities Fortnightly*, January 19, 1978, pp. 13-17, 15. In a 1992 decision, the U.S. Court of Appeals cited Kahn's statement from this article in denying the Town of Norwood, Massachusetts' petition for review of a FERC order allowing New England Power Company to set wholesale electric rates based on marginal prices, rather than average prices. *Town of Norwood Massachusetts v. FERC*, 962 F.2d 20 (1993) (D.C. Circ.) ("*Norwood*").

the demand for electricity with lower-cost resources. Thus, allocative inefficiency can lead to productive inefficiency.

Q. WHY IS IT IMPORTANT FOR REGULATED UTILITY RATES TO PROMOTE ALLOCATIVE AND PRODUCTIVE EFFICIENCY?

A. The most basic reason is cost. In 2012, U.S. retail expenditures on electricity were $363.7 billion.[16] In Utah, total electricity expenditures were over $2.3 billion in 2012, of which over $1.4 billion were expenditures by commercial and industrial customers.[17] From the standpoint of economic competitiveness and job creation, it is important that electricity demand is met in a least-cost manner, and that retail rates accurately reflect cost-causation. As I discuss in Section III, *infra*, competitive wholesale and retail markets do this automatically, because prices adjust constantly to reflect changing supply and demand conditions.

In contrast, if retail rates do not accurately reflect cost-causation and result in extensive cross-subsidies between rate classes, then both production and consumption decisions will be inefficient. Moreover, the rates themselves will not be just and reasonable.

Q. WHAT IS TIME-OF-USE PRICING?

A. Time-of-use ("TOU") pricing is the precursor to real-time pricing. TOU pricing typically takes an overall embedded cost rate and differentiates it into peak and off-peak

---

[16] Source: U.S. Energy Information Administration, Electric Power Annual 2013, Table 2.9. http://www.eia.gov/electricity/annual/html/epa_02_09.html

[17] *Id*.

consumption periods, with rates reflecting the higher costs associated with peak-period consumption. This promotes peak responsibility (i.e., customers who consume more power during peak periods pay relatively more of the overall costs).[18] Although not the same as real-time pricing, in which prices adjust constantly to reflect changes in market conditions, TOU pricing can improve economic efficiency by more accurately reflecting the true cost of electric consumption decisions.

Yet another approach that is commonly used, especially for larger commercial and industrial customers, is a rate structure that incorporates both demand and energy charges. These rate structures capture the fact that low load-factor customers (i.e., customers with high peak demand relative to their average demand) impose greater costs on an electric system than do high load factor customers, whose demand is much steadier. Combined with coincident peak allocation methods that recognize cost-causation when overall loads peak, and costs are highest, these rate structures can promote efficient consumption decisions.

III. RMP'S COST ALLOCATION SHOULD MORE ACCURATELY REFLECT COST-CAUSATION, IN THE SAME WAY THAT WHOLESALE ELECTRIC MARKETS REFLECT COST-CAUSATION

Q. DO WORKABLY COMPETITIVE WHOLESALE ELECTRIC MARKETS PROMOTE ALLOCATIVE AND PRODUCTIVE EFFICIENCY?

A. Yes. Competitive wholesale energy markets reflect the different costs of generating electricity in any given hour by balancing supply and demand. In peak hours,

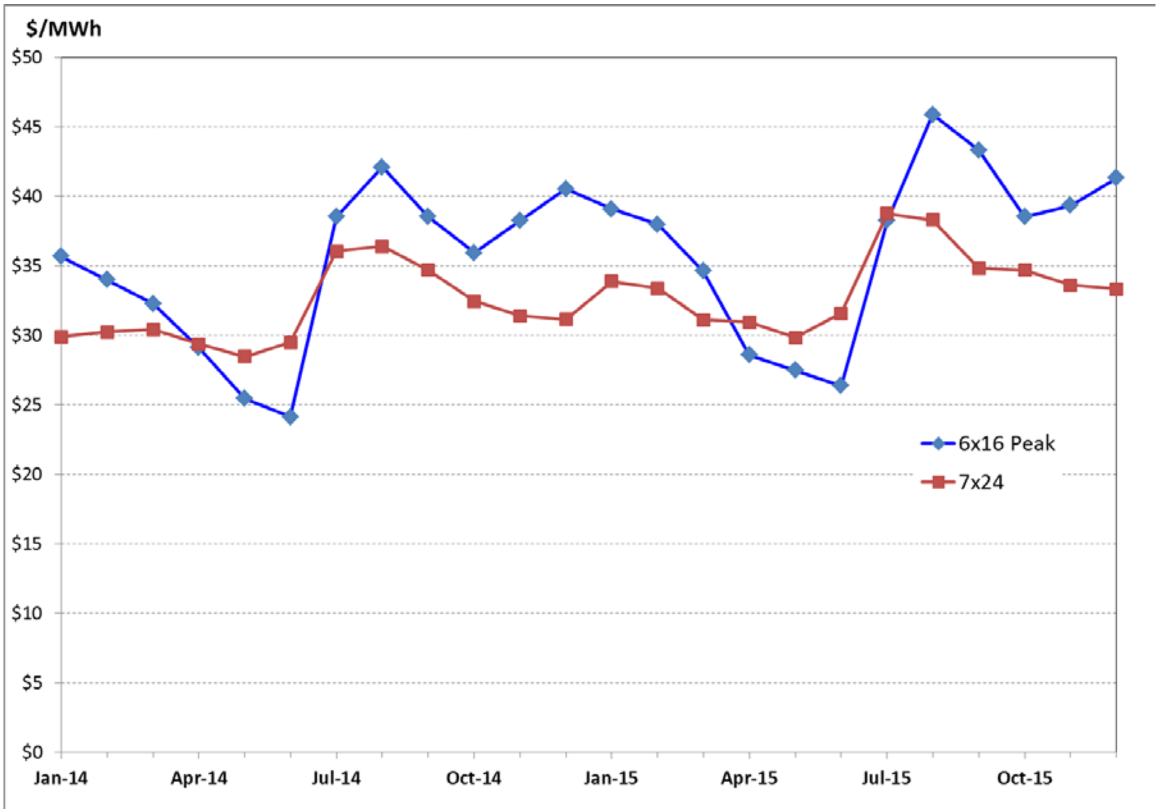
[18] I discuss "peak responsibility" in more detail in Section V.B *infra*.

electricity is produced using higher variable-cost units because the marginal value of electricity to customers is higher than in off-peak hours. Thus, wholesale electric prices are clearly and transparently time-differentiated. In this way, customers who demand more electricity during peak hours pay relatively more than customers who do not, consistent with the responsibility for causing those peaks. Not only is this more efficient, it is consistent with fairness.

For example, Figure 1 shows the average monthly forward prices for on-peak hours (6x16) and round-the-clock (7x24) at the Palo Verde trading hub as of November 8, 2013, which PacifiCorp uses as the basis for establishing the prices on certain retail sales contracts to large commercial and industrial customers. These forward prices were provided in RMP's original Generation Resource Cost ("GRC") filing as its Official Forward Price Curve ("OFPC").[19] Figure 1 shows that the Palo Verde on-peak contract forward prices for 2014 and 2015 are highest in the July – September period and the round-the-clock contract is highest in the July – August period. As can be seen in the figure, these market prices are highest in the summer months, reflecting higher summer demand.

[19] Confidential Attachment R746-700-23.C.8-1.

Figure 1: Palo Verde Hub Spot Market Prices



Source: Confidential Attachment R746-700-23.C.8.1

Q. CAN FORWARD PRICES CHANGE OVER TIME?

A. Yes. Forward prices change on a daily basis as traders incorporate additional information about future market conditions. Moreover, because forward prices cannot incorporate unpredictable events that affect supply and demand, such as a transmission line failure, a forced outage at a generating plant, or extreme weather conditions, actual spot market prices can differ from forward market prices.

Q. DOES PACIFICORP BUY AND SELL GENERATION IN THE WHOLESALE MARKET?

A. Yes. The prices PacifiCorp pays for the electricity it buys in the wholesale market, and the revenues it receives from electricity sold, fully reflect the interaction of supply and demand conditions.

Q. WHY DO THE PRICES AT WHICH PACIFICORP BUYS AND SELLS ELECTRICITY IN THE WHOLESALE MARKET MATTER FOR PURPOSES OF COST ALLOCATION?

A. Wholesale market prices matter for several reasons. First, the purchases and sales made by PacifiCorp in the wholesale market reflect the true economic value of electricity at the time such purchases and sales are made, and cost-causation should, to the extent possible, reflect those values. Second, this wholesale market price variation is not currently reflected in how costs in RMP's Energy Balancing Account ("EBA") are allocated. Specifically, the EBA, in which wholesale market purchases of electricity and generation fuel are recorded, does not account for variation of either wholesale electric or fuel prices. Instead, EBA costs are allocated among customer classes based on the annual EBA totals. This masks cost-causation and reduces economic efficiency. For example, because wholesale electric prices are typically their highest in peak summer hours, cost causation would allocate more of the costs associated with wholesale market power purchases to customers who purchase power during those same hours. Doing so would more closely approximate the actual opportunity costs reflected in the wholesale electric market. Similarly, because fuel prices vary on a daily basis, simply allocating purchases of fuel for the company's generating units on an annual basis, as is now done by RMP, does not accurately reflect cost-causation.

Q. CAN YOU RECOMMEND ANY OTHER CHANGES TO THE EBA THAT WOULD IMPROVE COST ALLOCATION?

A. Yes. Right now, the EBA is based on comparisons between expenditure forecasts. An obvious improvement would be for the EBA to represent the difference between forecast and previously incurred actual expenditures. For example, if RMP projected the cost of purchased fuel to be $5 million in a given month, but the actual expenditure was $5.1 million, then the $100,000 difference would be added to the EBA account for that month and recovered from customers based on their power consumption during that month.

This is the most common approach used by utilities and their regulators to address variable costs, such as fuel expenses, that can be volatile because of market changes and changes in consumer demand. This also would simply calculation of Net Power Costs ("NPC"), which are based on test year forecasts.[20] It is far simpler than comparing differences between expenditure forecasts, as ultimately such forecasts must be reconciled with actual expenditures.

Q. HAVE YOU ANALYZED THE ELECTRIC ENERGY AND PEAK LOAD PATTERNS OF RMP'S CUSTOMERS?

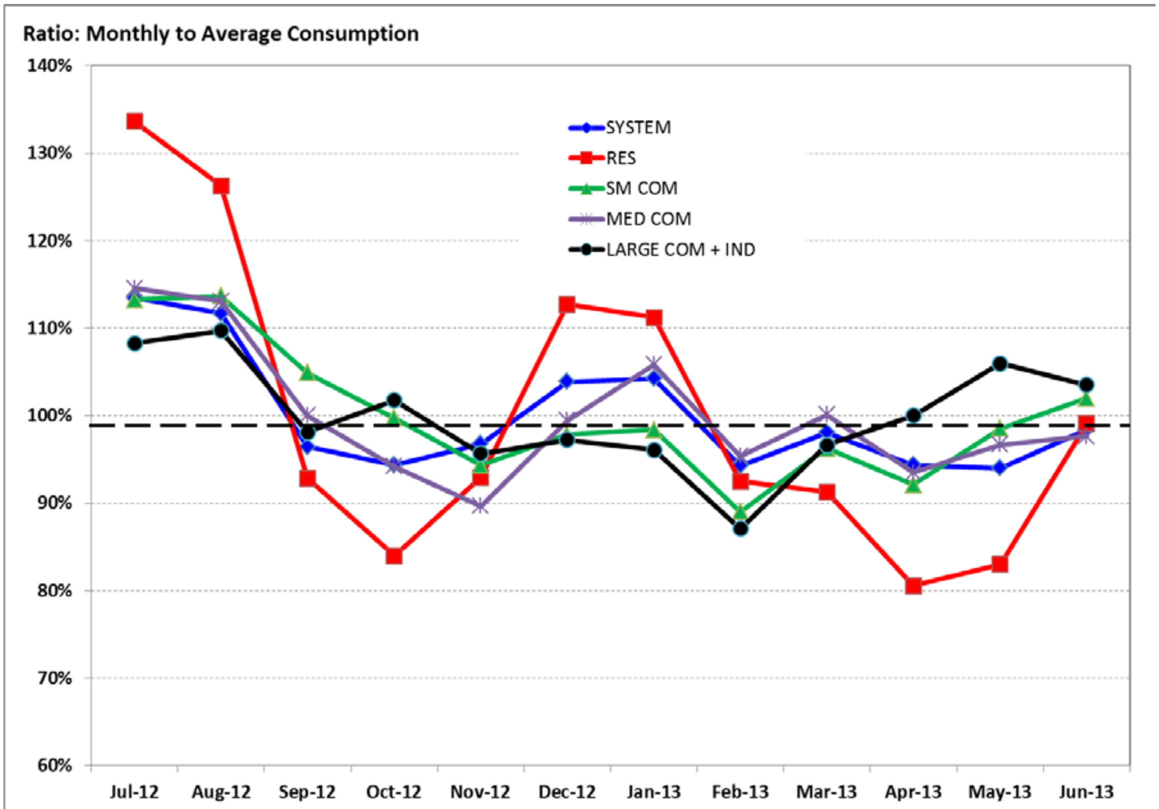
A. Yes. For example, consider the consumption patterns for major rate customer classes for the June 2012 – May 2013 period, and total Utah consumption. Figure 2 shows the ratio of each month's actual consumption for the July 2012 – May 2013 period

[20] *See, e.g., 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*, Docket No. 11-035-200, Report and Order, Exhibit A1, September 19, 2012.

relative to the average monthly consumption for the period. Residential class customers include Rate Schedules 1, 2, and 3. Small commercial is defined as Rate Schedule 6. Large Commercial and Industrial customers include Rate Schedules 8 and 9. Medium Commercial is defined as Rate Schedule 23.

Figure 2 shows that sales to residential class customers are far “peakier” than either sales to general service or industrial service customers. In fact, as shown in Table 1, the standard deviation of the relative monthly consumption for the residential class was 17.2%, whereas the standard deviation for the Large Commercial and Industrial consumption was 6.3%. Volatility of total system sales was 6.8%, again, far less than residential sales volatility. Table 1 also shows that residential consumption in July and August averaged 130% of the annual average monthly residential consumption.

Figure 2: Monthly Energy Consumption Relative to Average Annual Consumption



Source: Attachment UIEC 7.2-3 CONFIDENTIAL

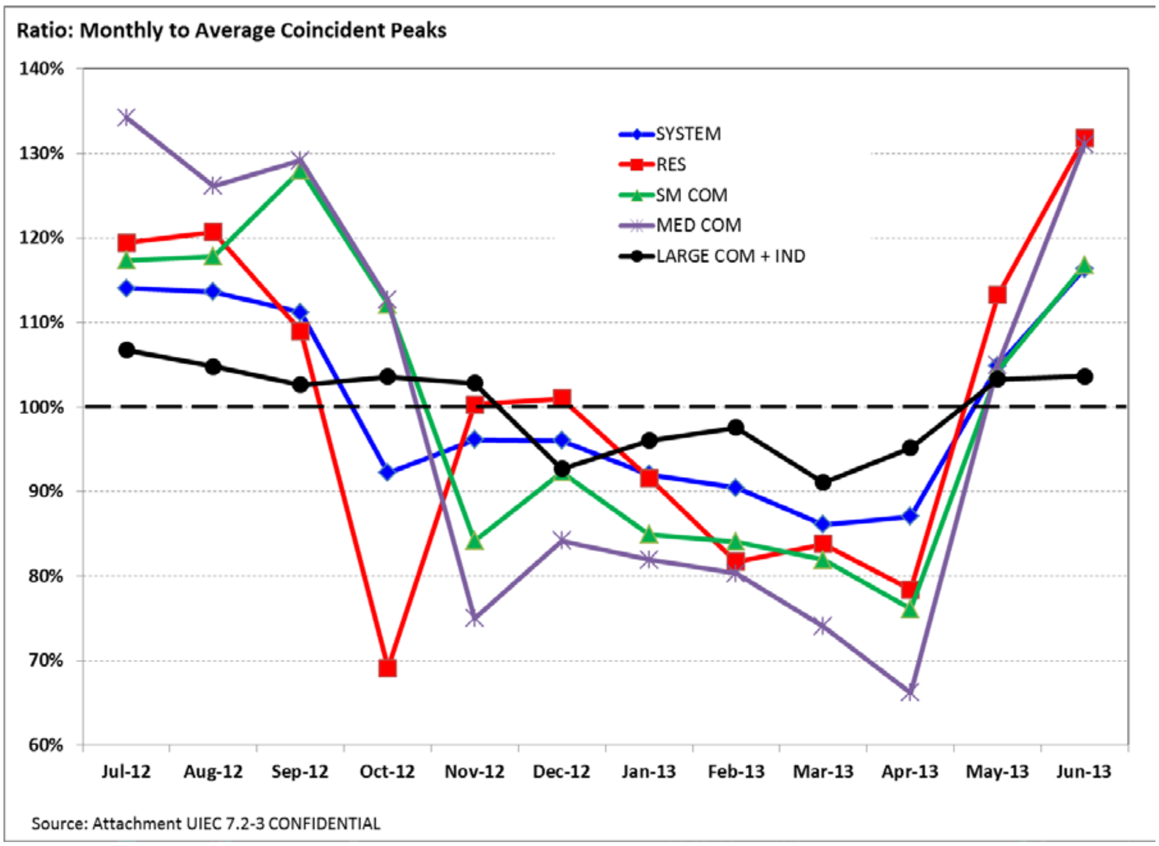
Table 1: Monthly Sales Volatility (Monthly Percent of Average)

	RATIOS OF MONTHLY TO AVERAGE ENERGY CONSUMPTION				
	SYSTEM	RES	SM COM	MED COM	LARGE COM + IND
July-12	113%	134%	113%	115%	108%
August-12	112%	126%	114%	113%	110%
September-12	96%	93%	105%	100%	98%
October-12	94%	84%	100%	94%	102%
November-12	97%	93%	94%	90%	96%
December-12	104%	113%	98%	99%	97%
January-13	104%	111%	98%	106%	96%
February-13	94%	92%	89%	95%	87%
March-13	98%	91%	96%	100%	97%
April-13	94%	81%	92%	93%	100%
May-13	94%	83%	99%	97%	106%
June-13	98%	99%	102%	98%	103%
STD. DEVIATION	**6.8%**	**17.2%**	**7.6%**	**7.6%**	**6.3%**

Q. DID YOU PERFORM A SIMILAR ANALYSIS BASED ON MONTHLY COINCIDENT PEAK LOADS?

A. Yes. Figure 3 provides a similar analysis of monthly coincident peak loads relative to the monthly average coincident peak load for each rate class.

Figure 3: Monthly Coincident Peak Load Relative to Average Coincident Peak



As Figure 3 shows, the primary drivers of monthly system peak load volatility are the Residential and Medium Commercial customer classes, which peak in the summer months of June, July, and August. Similarly, the medium commercial class is contributing significantly to system peak in these same three months, as is the small commercial class. In contrast, Large Commercial and Industrial coincident peak loads exhibit the least variation over the test year and act to reduce variation in the coincident system peaks.

Table 2 presents the values and standard deviations associated with these coincident peak loads. As shown, the coincident peak volatility is the highest for Medium Commercial customers at 25.7%, followed by Residential customers at 19.4%. Large Commercial and Industrial customers have the lowest coincident peak volatility, only 5.2% over the 12-month period.

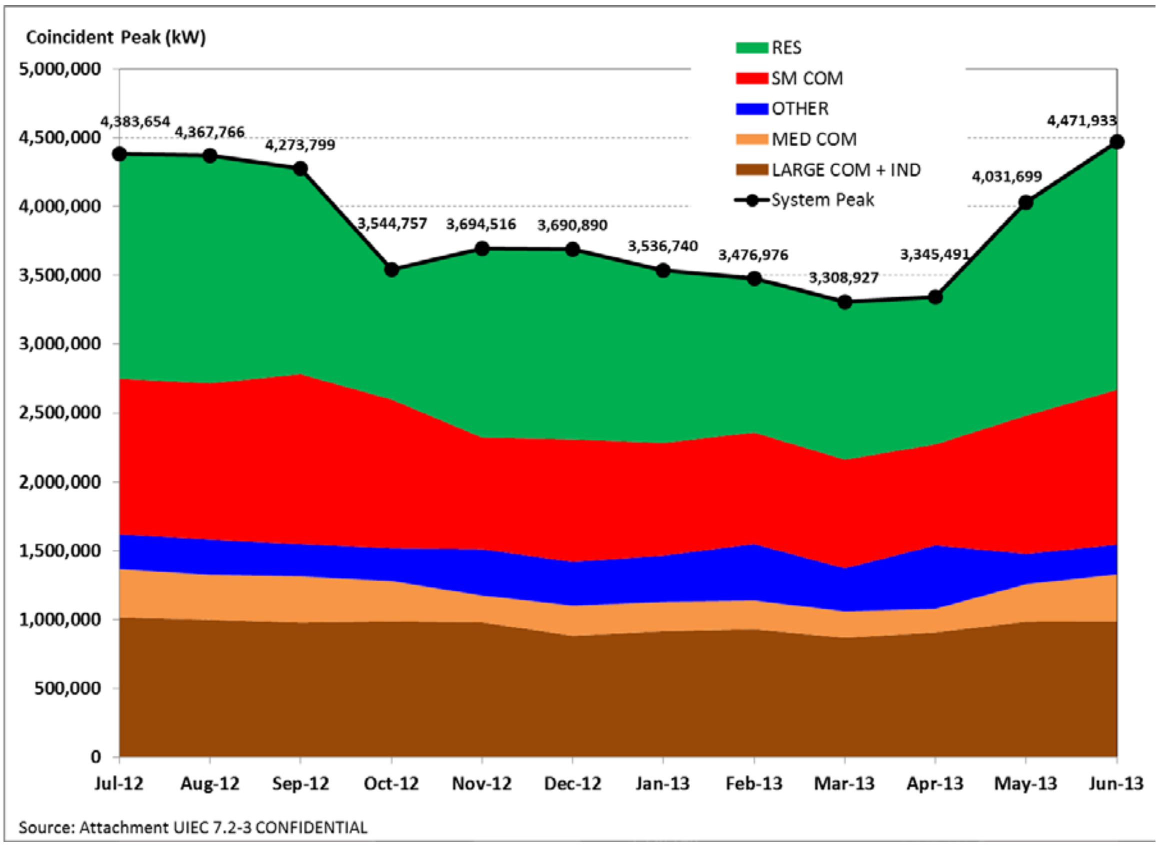
Table 2: Monthly Coincident Peak Volatility (Monthly Percent of Average Annual)

	RATIOS OF MONTHLY COINCIDENT PEAK TO AVERAGE ANNUAL PEAK LOADS				
	SYSTEM	RES	SM COM	MED COM	LARGE COM + IND
July-12	114%	119%	117%	134%	107%
August-12	114%	121%	118%	126%	105%
September-12	111%	109%	128%	129%	103%
October-12	92%	69%	112%	113%	104%
November-12	96%	100%	84%	75%	103%
December-12	96%	101%	92%	84%	93%
January-13	92%	92%	85%	82%	96%
February-13	90%	82%	84%	80%	98%
March-13	86%	84%	82%	74%	91%
April-13	87%	78%	76%	66%	95%
May-13	105%	113%	104%	105%	103%
June-13	116%	132%	117%	131%	104%
STD. DEVIATION	**11.3%**	**19.4%**	**17.9%**	**25.7%**	**5.2%**

Q. FOR THE JULY 2012 – JUNE 2013 PERIOD, DO THE COINCIDENT PEAK LOADS BY RATE CLASS/SCHEDULE INDICATE WHICH CLASSES WERE THE MAJOR DRIVERS OF THE OVERALL SYSTEM PEAK?

A. Yes. Figure 4 shows the monthly coincident peak loads for these same major rate classes over the 12-month period, July 2012 – June 2013. As can be seen, the residential and small commercial classes are the key drivers of the overall coincident system peak in the summer months. Even though medium commercial loads are “peakier,” as shown previously in Figure 3 and Table 2, it is far smaller than either residential or small commercial loads.

Figure 4: Monthly Coincident Peak Loads by Rate Class



Q. DOES RMP PROVIDE ANY EXPLANATION FOR WHY RESIDENTIAL AND PEAK LOADS HAVE GROWN?

A. Yes. According to the testimony of RMP witness Brown, residential customer air conditioning continues to grow, albeit at a smaller pace.[21] Moreover, as RMP witness Walje discusses, RMP has become highly dependent on summer month revenues collected from residential customers:

[21] Direct Testimony of Kelcey A. Brown, Docket No. 13-035-184, January 3, 2014 ("Brown Direct"), p. 6, lines 90-93.

> As a result, recovery of much of the fixed distribution and customer service related costs for the residential class in Utah is shifted to the third block of the energy component of the residential rate. The result is that the Company is dependent upon hot summers and high tail block sales to residential customers to recover its customer related fixed cost of providing basic electric service to residential customers.[22]

Q. DOES THE INCREASED PEAKINESS SUPPORT THE USE OF A NEW COST ALLOCATION METHODOLOGY?

A. Yes. The increased "peakiness" of RMP's system loads because of growth in residential and small-commercial cooling loads provides an empirical basis for using a cost allocation methodology that accurately and fairly reflects the underlying cause of RMP's need for incremental generating capacity. The JA methodology, which uses a 12-CP approach, together with a 75% demand, 25% energy clearly does <u>not</u> do so and, as such, cannot form the basis for establishing either economically efficient or just and reasonable rates.

Q. DOES PEAK LOAD VOLATILITY HAVE ANY OTHER RAMIFICATIONS REGARDING COST-CAUSATION AND APPROPRIATE COST ALLOCATION?

A. Yes. These relative coincident peak volatility values have important ramifications for cost-causation and cost allocation that are not accounted for in JA allocation. For example, greater peak load volatility means additional costs associated with ensuring there are sufficient system reserves and ancillary transmission services. Similarly, higher loads correspond to higher system losses. Thus, rate classes that contribute relatively more to the system peak will also contribute relatively more to the need for spinning and

[22] Direct Testimony of Richard A. Walje, Docket No. 13-035-084, January 4, 2014 ("Walje Direct"), Direct, p. 12, lines 255-260.

non-spinning reserves, as well as to overall system losses, which increase as transmission line loads increase.

Q. IS THERE A SPECIFIC LEVEL OF "PEAKINESS" THAT DETERMINES THE MOST APPROPRIATE CP METHODOLOGY TO APPLY? IN OTHER WORDS, HOW "PEAKY" MUST LOAD BE IN SPECIFIC MONTHS FOR A 12-CP APPROACH NOT TO BE USED?

A. I am not aware of any specific cutoff point, nor do I believe that determining such a cutoff point is important. What *is* important is that costs should be allocated to most closely reflect the true economic value of power, as reflected by prices in the wholesale electric market. The most economically efficient situation would occur if each RMP customer paid the hourly wholesale market price. In states with full retail competition, this is essentially accomplished by customers purchasing power directly from retail electric suppliers who purchased power from wholesale electric suppliers and then offer retail customers specific pricing packages. Allocation of generating costs is then a moot issue.

Utah, of course, does not have retail competition. Nevertheless, Utah can use wholesale markets to guide cost allocation to the extent possible. As Figures 1 and 4 show, wholesale market prices and RMP peak loads both show a clear pattern of peaking in summer. A 12-CP allocation approach does not reflect that pattern. Therefore, the appropriate allocation approach is the one that can most closely reflect the summer peaking nature of the RMP system. As Mr. Brubaker's testimony shows, using a 4-CP cost allocation approach does so.

A. PacifiCorp's Loss of Load Probability Study Shows that Summer Peak Loads Determine Reserve Margins

Q. DOES PACIFICORP PRESENT THE RESULTS OF A LOSS OF LOAD PROBABILITY ("LOLP") STUDY IN ITS 2013 INTEGRATED RESOURCE PLAN?

A. Yes. Appendix I of PacifiCorp's 2013 Integrated Resource Plan ("2013 IRP") presents the results of a LOLP study performed by Ventyx for PacifiCorp, which is presented in Appendix I of the 2013 IRP.

Q. WHY IS THAT LOLP STUDY RELEVANT TO DETERMINING AN ECONOMICALLY EFFICIENT ALLOCATION OF DEMAND-RELATED COSTS?

A. The LOLP study performed by Ventyx measured the ability of the PacifiCorp system to maintain reliability without relying on the rest of the grid. The LOLP study evaluates the frequency of lost load for different capacity reserve margins and the costs of adding new resources to reduce the LOLP.[23] The reserve margin recommended by Ventyx, 13%, is based on this analysis.

The LOLP study began with PacifiCorp's 1 day in 10 year reliability standard, weather-normalized peak load forecast for 2014 of 10,331 MW. In other words, modeled stochastically, there would be a 0.027% probability that this peak load would be exceeded on any given day.[24]

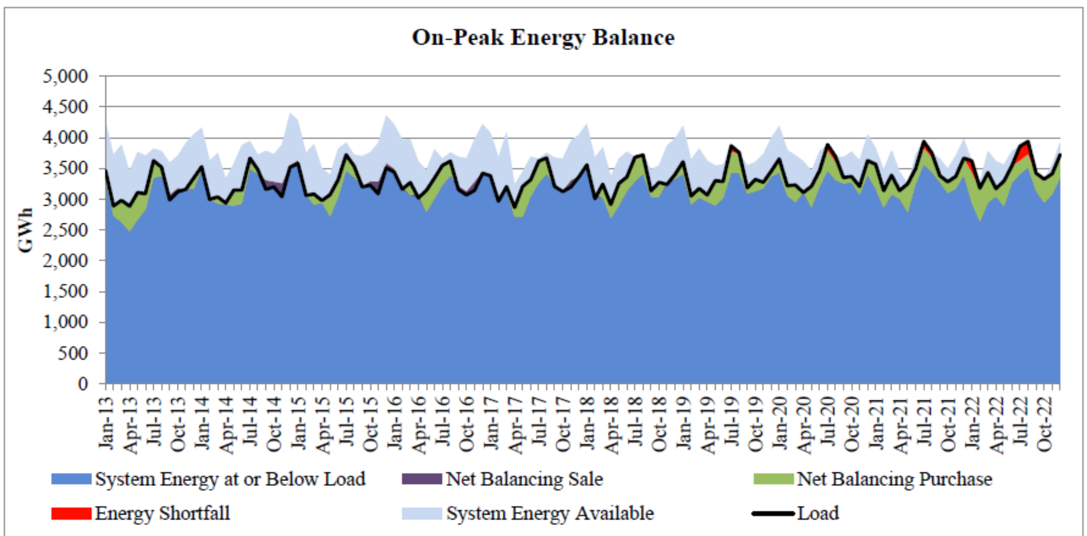
[23] 2013 IRP, Appendix I, p. 15, Figure 7.

[24] 1 / (365 x 10) = 0.00037 = 0.027%.

Q. IN WHAT MONTH DOES PACIFICORP FORECAST THIS PEAK LOAD TO OCCUR?

A. The system peak load is forecast to occur in July of 2014. Moreover, as shown in Figure 5.5 of the 2013 IRP, the system peak load occurs in July or August in each of the 10 years, 2013 – 2022.

Figure 5.5 – System Average Monthly and Annual Energy Positions



Source: PacifiCorp 2013 IRP, p. 102.

Q. DOES THE ON-PEAK ENERGY BALANCE CHART SHOWN ABOVE PROVIDE ANY OTHER INFORMATION ABOUT AN APPROPRIATE COST ALLOCATION METHODOLOGY?

A. Yes. As discussed in the testimony of UIEC witness Brubaker, 90% of the loss of load hours predicted in the LOLP study presented in the 2013 IRP occurred in the June – September timeframe.[25] This provides another empirical demonstration that cost causation should focus on summer peak demand, rather than demand in all months.

[25] UIEC Exhibit COS__(MEB-1.0).

IV. ACHIEVING IMPORTANT REGULATORY GOALS REQUIRES EFFICIENT AND FAIR COST ALLOCATION

Q. WHY IS COST ALLOCATION A CRITICAL COMPONENT OF ACHIEVING IMPORTANT REGULATORY GOALS?

A. The reason is that the *sine qua non* of utility ratemaking is that the rates established by regulators must be just and reasonable. That is not only a matter of economic efficiency, but also one of equity and fairness. Requiring customers to purchase services from a monopoly provider of electricity at rates that are unjust and unreasonable, or unduly discriminatory, is just as inappropriate as forcing an electric utility to sell power below its costs or otherwise imposing an unlawful regulatory taking.[26] The Utah PSC has itself stated that a “cornerstone” of ensuring just and reasonable rates is that costs be allocated based on cost-causation.[27]

There are, of course, no unique or mechanical definitions of “just and reasonable,” nor one of “fairness.” If there were, there likely would be no need for regulatory commissions and regulators (nor expert witnesses). However, ensuring that costs are allocated based on cost-causation promotes both efficiency and fairness, and designing rates that are just and reasonable requires application of basic economic and engineering principles, including principles of cost allocation. If costs are not allocated properly and fairly to cost “causers,” it is not possible to establish just and reasonable rates, nor to establish economically efficient rates for retail customers. If rates are not designed to promote economic efficiency, then customers will not make optimal

[26] *See Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm’n of W. Va.*, 262 U.S. 679 (1923); *Federal Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[27] EBA Order, p. 74.

consumption and investment decisions, including investments in energy efficiency measures. Nor will utilities be able to determine "least-cost" strategies that are truly "least-cost," because retail customers will base their consumption decisions on incorrect prices.

Q. CAN COST ALLOCATION AFFECT ENERGY EFFICIENCY AND SELF-GENERATION INVESTMENTS?

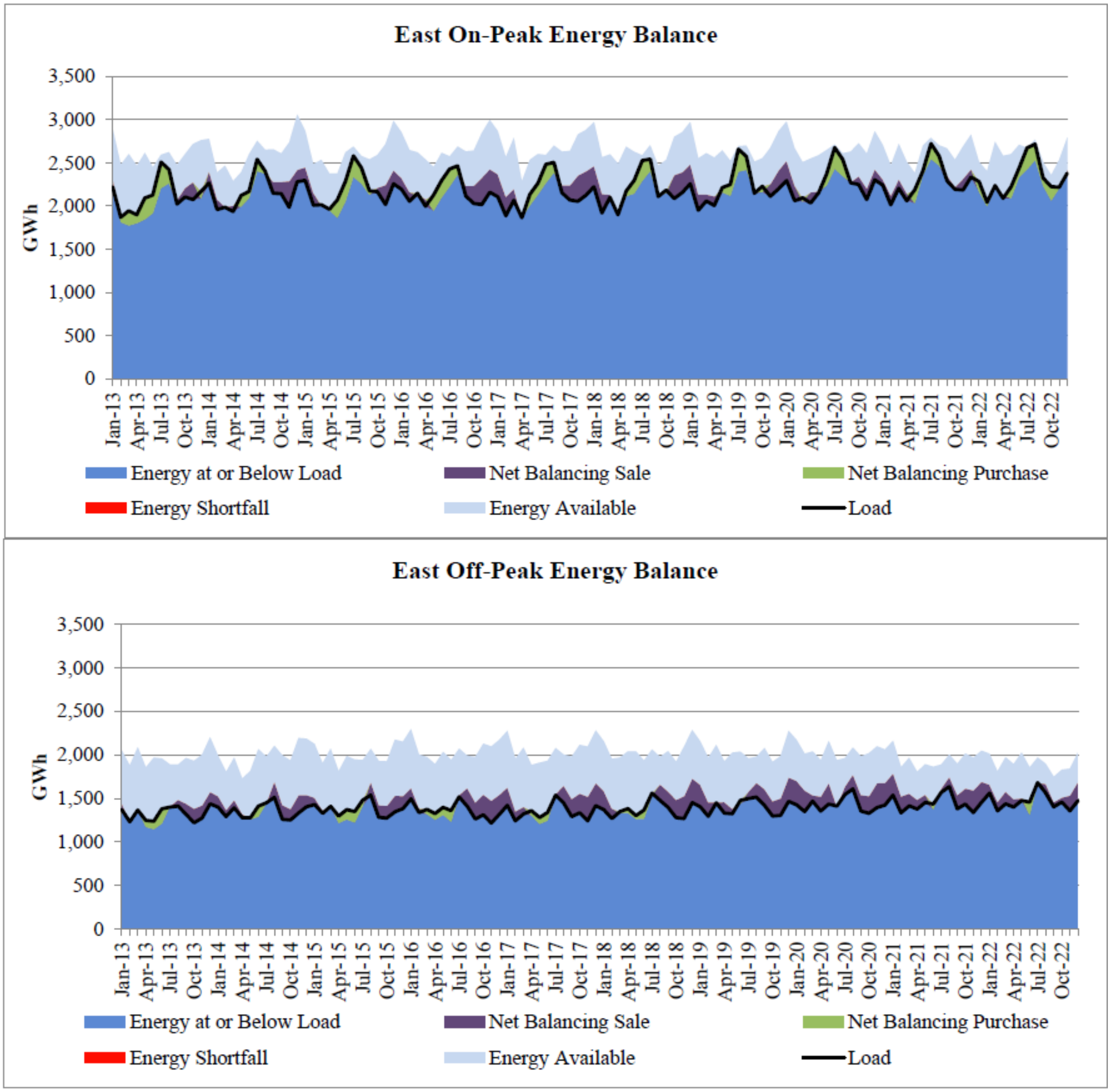
A. Yes. Cost allocation affects not only electric consumption decisions, but also changes the economics of self-generation. From the standpoint of productive efficiency, society prefers that electricity demand be met at the lowest possible cost, consistent with meeting other policy goals. Presumably, that is the goal behind requiring PacifiCorp to prepare a least-cost plan as a part of its Integrated Resource Plan ("IRP"), which states, "PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner 'consistent with the long-run public interest.'"[28]

For example, in its 2013 IRP, PacifiCorp provides several charts showing its "energy position," defined as supply from existing resources, less demand (obligation) less a 13% reserve requirement. The resulting energy position for PacifiCorp's East control area, which includes Utah, is shown in Figure 5.[29]

[28] PacifiCorp 2013 Integrated Resource Plan, April 30, 2013, p. 23 (footnote omitted).

[29] Source: *Id*., p. 105, Figure 5.7.

Figure 5: PacifiCorp East Historic and Projected Energy Balance



The energy balance is defined as the point at which the energy position is zero. As this figure shows, forecast load growth leads to greater negative balances, meaning that the company will require additional resources to meet future load obligations.

Q. DOES THE ENERGY BALANCE SHOWN FIGURE 5 REINFORCE THE SUMMER-PEAKING NATURE OF PACIFICORP EAST LOADS?

A. Yes. The top chart in Figure 5 clearly shows a highly summer peaking system.

Q. WHAT IS THE SIGNIFICANCE OF THE ENERGY BALANCE, ESPECIALLY AS IT SHOWS A HIGHLY SUMMER PEAKING SYSTEM?

A. The energy balance drives PacifiCorp's investments in new resources to meet projected future loads. However, future loads are driven, not only by demographic factors, such as population growth, but also by the prices customers are charged under different rate schedules. RMP witness Walje himself recognizes this in his testimony regarding the need to reduce the portion of RMP's fixed costs recovered through tailblock rates in the summer.[30]

In other words, prices matter and the prices charged different classes and schedules of customers will affect future loads. If residential and small commercial customers, who are driving the increases in summer peak demand, are allocated too few costs and charged too low rates, then RMP will be forced to invest excessively in new generating capacity to meet increasing peak demand caused, in part, by those same too low rates. Similarly, customers who are improperly allocated too large a proportion of costs, and whose rates are set too high, will see an incentive to invest in alternatives that may not be "least-cost" from the utility standpoint, but are least-cost from those customers' standpoint.

[30] Walje Direct, p. 12, lines 255-260.

Q. DOES RMP USE REDUCTIONS IN COINCIDENT SYSTEM PEAK LOAD TO EVALUATE THE COST-EFFECTIVENESS OF SOME ENERGY EFFICIENCY RESOURCES?

A. Yes. Appendix 1 of RMP's *2012 Annual Energy Efficiency and Peak Reduction Report – Utah*, which was submitted to the PSC on May 1, 2013, states that the cost-effectiveness of the capacity contributions of its "Cool Keeper" and "Irrigation Load Control" load management programs are based on load reductions at the time of the system peak.[31]

Q. WHY IS RMP'S USE OF SYSTEM COINCIDENT PEAK TO DETERMINE CAPACITY COST SAVINGS AND OVERALL PROGRAM COST-EFFECTIVENESS RELEVANT TO THE METHODOLOGY USED TO ALLOCATE GENERATION AND TRANSMISSION COSTS?

A. It is relevant because, whereas RMP proposes to allocate generation and transmission costs based on a 12-CP methodology, the company itself evaluates the cost-effectiveness of load control programs based on a single system peak, which occurs in the summer. Using a single coincident system peak to evaluate the cost-effectiveness of load control programs implies that the key generation and transmission cost driver is summer peak load, not peak loads throughout the year.

Q. CAN SELF-SUPPLY DECISIONS BY INDIVIDUAL CUSTOMERS AFFECT AN ELECTRIC UTILITY'S OVERALL SUPPLY COSTS?

A. Yes. Just as inefficient prices can affect the overall demand for electricity and, hence, the need for capacity investments, inefficient prices can also affect costs when

---

31 *In the Matter of Rocky Mountain Power's Demand-Side Management 2012 Annual Energy Efficiency and Peak Load Reduction Report*, Docket No. 13-035-71, Revised Appendix 1, June 28, 2013, p. 1.

customers have self-generation or other supply options. For example, suppose the electric utility has an industrial customer A with a round-the-clock operation and constant demand of 100 MW. From an electric utility planning standpoint, customers with constant (or near-constant) demand, i.e. high load-factor customers, are the most desirable. Because their loads have little variation, they do not drive investments to meet peak loads.

Next, suppose customer A is allocated costs such that its rate, P_A, exceeds the cost of self-generation. In that case, the economically efficient decision for customer A is to self-generate and leave the utility. As a consequence, the utility's loads become even "peakier," and the utility's remaining customers are forced to absorb the fixed costs previously allocated to customer A. The results are: (1) the cost to meet total electric demand (utility plus customer A) increase over what they would be if customer A took service from the utility; and (2) the increased "peakiness" of the utility's remaining load further increases reliability costs, because peak loads will continue to be driven by other customers.

Q. ARE YOU SUGGESTING THAT CUSTOMERS SHOULD NOT BE ALLOWED TO SELF-GENERATE?

A. No. I am simply pointing out the potential for investment decisions by customers that are inefficient from the utility's standpoint and that would not take place <u>but for</u> inefficient cost allocation and pricing.

Q. DOES INEFFICIENT COST ALLOCATION HAVE OTHER IMPACTS ON CUSTOMERS WHO SELF-GENERATE?

A. Yes. One of the other manifestations of inefficient cost allocation related to self-generation is the proposed Backup power tariff for Schedule 31customers, as I discuss below in Section VI of my testimony.

A. <u>Cost Allocation and the Role of the Energy Balance Account</u>

Q. WHAT ROLE DOES THE ENERGY BALANCING ACCOUNT PLAY IN COST ALLOCATION FOR RMP?

A. The Energy Balancing Account ("EBA") allows RMP to transfer cost volatility and risk to its retail customers.

Q. HOW DOES THE EBA ORDER TRANSFER RISK?

A. As the Commission's EBA Order states,

> We find the Company's current portfolio of resources, its current need for capacity expansion, and its <u>increasing reliance on markets to manage hourly system changes</u> are substantial departures from the conditions existing in the early 1990s. … As in the 1980s, the Company is once again in a capacity expansion period and is exposed to under-earning due to regulatory lag. Further, the Company demonstrates its resource portfolio now includes, and is expected to continue to add, substantial amounts of natural gas and wind resources. The Company shows, and most parties generally concur, the prices of natural gas and wholesale market transactions, and the output of wind resources are volatile.[32]

In addition to the EBA substantially reducing regulatory lag, the Commission refers to the Company's increased reliance on markets, specifically wholesale competitive markets, to meet its need for generating resources. By creating an account that allows

[32] *In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Corrected Report and Order, March 3, 2011 ("EBA Order"), p. 65 (emphasis added).

RMP to track volatile costs and pass those costs onto ratepayers, the EBA transfers cost risk from shareholders to retail ratepayers.

Q. HOW IS THIS RISK TRANSFER LINKED TO COST ALLOCATION?

A. In light of that risk transfer, it is critical that the individual rate schedules accurately reflect their contribution to that volatility. In other words, overall cost-causation should also incorporate what I term "volatility causation."

To explain this, consider again Figures 2 and 3, which show that residential and medium commercial sales and coincident peak loads experience the greatest volatility relative to their annual average values. Imagine if, instead of the patterns shown in these two figures, each rate class' total monthly sales and coincident peaks were always constant. In that case, the Company could theoretically hedge 100% of its fuel and purchased power costs. It would need fewer generation reserves, because it would not need to have additional reserves to meet volatile peak demand. In effect, barring a forced generation or transmission outage, RMP's costs and earnings would be constant.

Thus, the risk transfer provided by the EBA acts as an insurance policy for RMP to reduce its earnings volatility.[33] And, like all other insurance, the "premiums" paid should reflect the contribution to overall risk, and the cost of insuring against that risk. Therefore, cost allocation should be consistent with "volatility causation." In other words, to the extent the EBA provides a form of "insurance" for the company from the adverse impacts of volatile costs, the costs of that insurance should be allocated to customers commensurate with their contribution to the cost of that insurance. Thus, all other things equal, high load factor customers will cause less cost volatility than low load

[33] The company argued that its costs are increasingly volatile, owing to a number of factors. *See* EBA Order, p. 16.

factor customers. Similarly, costs that are caused because of seasonality of demand should be recovered from the customer classes causing that seasonality.

For example, if the Company incurs additional purchase power expenses in July and August due to higher than normal temperatures and an increase in residential and small commercial air conditioning loads, the allocation of EBA costs should reflect that fact. Finally, to the extent that costs recovered under the EBA are allocated using the same JA allocation methodology (i.e., a 12-CP with 75% - 25% demand-energy allocation factor), and to the extent the JA methodology is inappropriate (as I discuss in Section VI *infra*), misallocation of costs will be exacerbated.

Q. THE EBA INCLUDES COSTS ASSOCIATED WITH HEDGING AGAINST VOLATILE POWER AND NATURAL GAS COSTS. HOW DO SUCH HEDGES AFFECT THE COMPANY'S OVERALL EXPECTED POWER SUPPLY COSTS?

A. Hedging is a type of insurance. Therefore, on net, the Company's expected power supply costs will be greater if it purchases hedging instruments than if it does not. Oddly, the Company appears to conclude the opposite. Curiously, the EBA Order states, regarding natural gas swaps, that "the Company maintains … If swaps were eliminated, and the Company had to rely entirely on fixed price forward physical products, net power cost would be higher."[34] Although this is one possible outcome, on an expected basis, the cost of entering swap agreements <u>must be</u> greater than the savings. Otherwise, the Company would have discovered an arbitrage opportunity allowing it to make unlimited profits, which is not possible.

[34] EBA Order, p. 21.

Q. HOW CAN THE COSTS ASSOCIATED WITH RMP'S INCREASED RELIANCE ON WHOLESALE MARKETS BEST BE ALLOCATED?

Because the Company has increased its reliance on wholesale markets to meet the demand for electricity, the costs of the power it purchases should be allocated in a way that reflects cost-causation, that is, those customer classes who are driving the increased market demand and the need for additional wholesale purchases, should bear a proportionate share of those costs, just as those customers would bear the costs if they themselves were purchasing directly from the market. To do otherwise would be to cross-subsidize customers, penalizing customers who are not driving increased peak demand.

V. METHODS TO ALLOCATE COSTS

Q. WHY IS ALLOCATION OF FIXED COSTS OFTEN CONTROVERSIAL IN ELECTRIC UTILITY RATE CASES?

A. The reason is that, in the short-run (but not in the long-run, as I discuss below), cost allocation is a "zero-sum" game for the utility, which pits customer classes against each other. For a given cost of service and revenue requirement, any reduction in the amount allocated to one class of ratepayers must be recovered from all of the other ratepayer classes. In contrast, allocating variable costs, such as fuel, variable operation and maintenance costs, and so forth, is straightforward, as these costs are properly allocated on a pure consumption basis. Of course, as UIEC witness Brubaker's testimony discusses, variable costs also vary during the year. Thus, from a cost-causation standpoint, it is appropriate to allocate those variable costs to reflect these differences.

Q. WHY IS COST ALLOCATION NOT A ZERO-SUM GAME IN THE LONG-RUN?

A. In the long-run, cost allocation is not a zero-sum game because allocative efficiency and efficient pricing will encourage productive efficiency, and ensure that customer demand is met in a "least-cost" manner. Thus, in the long-run, by improving allocative and productive efficiency, proper cost allocation will minimize the overall level of costs that must be allocated, benefitting all retail customers.

Q. CAN YOU SUMMARIZE THE KEY ISSUES ASSOCIATED WITH METHODS TO ALLOCATE COSTS?

A. Yes. The overarching issues are: (1) selecting a method that promotes economic efficiency and (2) ensuring that the resulting rates are just and reasonable. Allocating variable costs, i.e., costs that vary directly with the amount of electricity consumed, is generally straightforward. It is allocation of fixed costs in an accounting cost of service study, such as generating capacity, which can be controversial.

A. <u>Allocating Joint and Common (Fixed) Costs</u>

Q. WHAT ARE "JOINT" AND "COMMON" COSTS?

A. Joint costs are those where providing one type of product or service is an automatic by-product of producing another product or service.[35] The classic economic example of a joint cost is the cost to raise a steer, which produces fixed proportions of beef and leather. Thus, if one spends $200 to raise one steer, it is not possible to

[35] *See* National Association of Regulatory Utility Commissioners ("NARUC"), *Electric Utility Cost Allocation Manual*, January 1992, p. 16.

conclude that the costs associated with the leather portion were $150, or $50, and so forth. In fact, there is no unique method to determine the costs associated with each individual good or service that is produced jointly.

Common costs are those where several goods or services are produced using the same inputs. However, unlike with joint costs for which several goods or services are produced simultaneously, common costs refer to products that <u>cannot</u> be produced simultaneously. For example, an oil refinery can produce different proportions of gasoline and heating oil from the same barrel of oil. The maintenance costs incurred at the refinery so it can produce gasoline and heating oil are common to both products. However, those costs are not joint, because of the inherent trade-off between how much gasoline and how much heating oil can be produced from one barrel of oil. In the case of an electric utility, the salary of a utility accountant is common to the generation, transmission, and distribution functions. The accountant can spend more of his time working on transmission-related matters and less time on generation-related ones, and so forth. Thus, his salary is a common cost.

Q. WHY DOES THE ALLOCATION OF JOINT AND COMMON COSTS MATTER IN THIS PROCEEDING?

A. Joint and common costs are fundamental to this proceeding because the JA Agreement methodology used to allocate these costs is inefficient and inequitable, and thus fails to allocate costs in a just and reasonable manner. This is why UIEC witness Brubaker recommends an alternative methodology that more accurately captures the specific characteristics of the RMP system, notably the increasing summer “peakiness” of system loads, and thus reflects cost-causation more accurately and fairly.

Q. CAN MARGINAL COSTS BE USED TO ALLOCATE JOINT AND COMMON COSTS?

A. While marginal costs, and marginal cost studies, are the "purest" economic method that can be used to allocate common costs, it cannot be used to allocate joint costs.

Q. WHAT ARE THE MAJOR ISSUES ASSOCIATED WITH ALLOCATING GENERATING CAPACITY COSTS?

A. The most complex issue is what economists such as Alfred Kahn term the "peak responsibility" issue.[36] In the short-run generating capacity is fixed. As a result, allocating capacity costs among customers based solely on short-run marginal costs will not recover all of the utility's embedded capacity costs. That is why Kahn, as well as Bonbright, focused on long-run marginal costs ("LRMC"), which reflect changing capacity levels and are a "pure economic" approach to allocating capacity costs.[37]

As Alfred Kahn stated, incremental capacity costs are the result of increases in peak usage, because off-peak users do not impose incremental capacity costs on society. Specifically, he states

> The economic principle here is absolutely clear: if the same type of capacity serves all users, capacity costs *as such* should be levied only on utilization at the peak. Every purchase at that time makes its proportionate contribution in the long-run to the incurrence of those capacity costs and should therefore have the responsibility reflected in its price. No part of those costs should be levied on off-peak users.[38]

[36] For a detailed discussion, *see* Alfred Kahn, *The Economics of Regulation*, (Boston, MA: MIT Press 1988) ("Kahn 1988"), pp. 87-103, and the examples therein.

[37] For a brief introduction to marginal cost study methods, see Lesser and Giacchino 2013, pp. 230-236.

[38] Kahn 1988, p. 89 (italics in original, emphasis added).

If ratepayers were simply purchasing electricity in the competitive market, the prices they would pay would reflect this economic principle. The costs incurred by competitive suppliers of electricity would also reflect the LRMC of supplying additional capacity and energy.

Q. THE QUOTE FROM ALFRED KAHN REFERS TO THE "SAME TYPE OF CAPACITY." BECAUSE PACIFICORP'S GENERATING RESOURCE PORTFOLIO HAS DIFFERENT TYPES OF CAPACITY, IS THE ECONOMIC PRINCIPLE OF "PEAK RESPONSIBILITY" STILL VALID?

A. Yes. When demand peaks, all resources are contributing to meet that demand. Yet, it is the peaking resource that would not be needed, <u>but for</u> the customers most responsible for causing that demand to peak. The fact that there may be multiple types of resources, even multiple types of peaking resources, does not change the peak responsibility standard.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION REQUIRE RMP TO ALLOCATE GENERATING COSTS BASED ON A MARGINAL COST STUDY TO IDENTIFY PEAK RESPONSIBILITY?

A. No. Although marginal cost studies may represent the economic "ideal," in practice they are difficult and time consuming to conduct, and require extensive metered load data for each customer class and schedule. Moreover, as is well known, setting rates at marginal costs will only, by chance, lead to the utility precisely recovering its revenue requirement, which is based on embedded costs. As Lesser and Giacchino state concerning the choice between marginal costs versus embedded costs for pricing, "In our view, which approach is 'best' hinges on several factors, including the quality and accuracy of the available accounting data, the ability to accurately estimate marginal costs (especially in the face of significant uncertainty as to future costs), and the policy objectives of regulators themselves."[39]

In practice, therefore, assigning peak responsibility on an embedded cost basis is simply a more practical adaptation of marginal cost pricing principles that can improve both economic efficiency and fairness. It may not be as "elegant" as pure marginal cost pricing alternatives, but it is far easier to implement.

Q. CAN AN EMBEDDED COST APPROACH TO COST ALLOCATION ALLOCATE COSTS BASED ON COST-CAUSATION AND SET RATES THAT IMPROVE ALLOCATIVE AND PRODUCTIVE EFFICIENCY?

A. Yes. Although an embedded cost approach will not fully capture the "true" marginal cost of providing electricity, from a practical standpoint embedded cost methods that reflect peak responsibility and associated time-differentiated costs clearly are preferable to methods that do not do so. Of course, allocating costs based on peak responsibility and cost-causation are only a first step. Once costs are allocated to each customer class, it is still necessary to design the actual rates that customers in each class are charged in order to incent efficient electricity consumption, help the utility meet demand in a least-cost manner, and meet other pricing goals.

B. <u>Selecting an Appropriate Embedded Cost Allocation Methodology</u>

Q. ARE THERE DIFFERENT EMBEDDED COST METHODOLOGIES THAT CAN BE USED TO ALLOCATE CAPACITY COSTS?

[39] Lesser and Giacchino, p. 236.

A. Yes. However, while there are a number of different methods, only a handful are commonly used. The NARUC *Electric Utility Cost-Allocation Manual*, for example, discusses many different methods that have been used.[40] The common objective of the different methodologies is to allocate costs consistent with cost-causation. For RMP, whose capacity costs are being driven by growth in peak demand, one of the peaking methodologies, as opposed to energy-weighting methodologies are likely to result in more efficient and equitable cost allocation and rate setting.

C. The NARUC Cost Allocation Methodologies

Q. CAN YOU PROVIDE AN OVERVIEW OF THE COST ALLOCATION METHODOLOGIES IN THE NARUC ELECTRIC UTILITY COST ALLOCATION MANUAL?

A. Yes. The methodologies in the NARUC Electric Utility Cost Allocation Manual ("NARUC Cost Allocation Manual") were all developed at a time when there were no competitive wholesale electric markets. The absence of competitive markets required regulators to develop methodologies that could be used, and justified, to allocate costs and set rates in ways that satisfied different policy goals, including market efficiency (although there was no real way to independently gauge market efficiency), equity, fairness, economic development, and so forth.

In this pre-market environment, if all customers had identical usage patterns, then cost allocation would have been a trivial exercise. One could allocate costs based on total consumption levels and be done with the matter. Similarly, on purely hydroelectric

[40] NARUC, Electric Utility Cost Allocation Manual, pp. 39-68.

systems, which are not demand-constrained, cost allocation can be accomplished based on consumption only. Of course, usage patterns differ, and thus the issue of how, in the absence of any outside evidence, to allocate costs and balance various policy goals, led to the development of the alternative cost-allocation methodologies that are discussed in the NARUC Cost Allocation Manual ("NARUC Manual").

The situation today is completely different. Workably competitive wholesale markets now exist and, in many states, competitive retail markets exist as well. These markets automatically operate on marginal pricing principles. Thus, unlike decades ago, regulators and consumers can directly observe the time differentiation of electric prices. Because this information is freely available to regulators, common sense suggests that it be used to inform generation cost allocation and rate design.

Thus, rather than imagining what a competitive market outcome might look like, as regulators had to do decades ago when most cost allocation methodologies were developed, there is ample real-world, and real-time evidence of how competitive electric markets set prices. These markets reflect marginal cost pricing and time differentiation.

Q. WHAT ARE PEAK DEMAND METHODS?

A. Peak demand methods recognize that fixed production costs are driven by peak loads, rather than electric energy consumption. (Variable costs are always driven by consumption, by definition, and can change over time.)

Q. DOES THE NARUC MANUAL DISCUSS DIFFERENT PEAK DEMAND METHODS?

A. Yes.

Q. HOW DO YOU CHOOSE AMONG THE DIFFERENT PEAK DEMAND METHODOLOGIES?

A. In the absence of any wholesale market information, the choice of peak demand methodology should reflect the "peakiness" of demand over the year, and each rate schedule's contribution to peak demand. For example, because street lights operate only at night, when demand is low, it makes little economic sense to assign peak capacity costs to street light rate schedules, because street lights are not contributing to overall system peaks. In fact, with significant quantities of wind generation, street lights may prevent the system from having negative prices and/or forcing back-down of wind power at night because of insufficient demand.[41]

In the presence of workably competitive wholesale markets, the allocation should also reflect the pattern of expected wholesale prices. Thus, because RMP is clearly a summer-peaking system, and because forward market prices show a clear summer peaking pattern, a summer CP demand allocation methodology is the most efficient and equitable approach.

Q. WHAT FACTORS AFFECT THE CHOICE OF EMBEDDED COST ALLOCATION METHODOLOGY?

A. A fundamental factor of the choice of embedded cost allocation methodology is to reflect cost-causation. Thus, the methodology should reflect whether the utility's planning revolves around meeting peak demand, as is the case for thermal systems, or meeting energy demand, such as for hydroelectric systems. The methodology should also

[41] In fact, this was a controversial issue for the Bonneville Power Administration and wind generators on its system in the spring of 2011.

reflect, to the extent possible, how these costs would be allocated in a competitive electric market.

The choice of peak demand allocation method depends on the "peakiness" of peak loads. Generally, the number of coincident peaks used decreases as the "peakiness" increases. Figure 5, for example, shows the forecast RMP monthly system peaks, as prepared by RMP witness Brown, for the period January 2013 – June 2015.

BEGIN CONFIDENTIAL INFORMATION*

Figure 5: RMP Forecast Monthly System Peaks

[redacted]

END CONFIDENTIAL INFORMATION

As Ms. Brown's peak load forecast shows, the RMP system is summer-peaking; the four summer months, June – September, have far higher system peak loads than the remaining months. Within the summer period, July and August peaks are considerably higher than

June and September peaks. The predicted July and August 2013 system peaks are approximately 1.7 standard deviations above the average system peak during the 23-month period, and the July and August 2014 predicted system peaks are approximately 1.85 standard deviations above the average.[42]

Q. IS IT IMPORTANT TO USE CONTEMPORANEOUS DATA TO DETERMINE THE MOST REASONABLE COST ALLOCATION METHOD?

A. Yes. Because the pattern of peak loads can change over time, it is important that the cost allocation method selected reflect up-to-date peak load patterns. As UIEC witness Brubaker discusses, RMP's summer peak loads have increased because of increased cooling loads, especially among the residential and small commercial classes. It would no more make sense to use "stale" peak load data to allocate costs than it would to use stale cost data to determine RMP's revenue requirement.[43]

Q. IS CONTINUED USE OF A 12-CP METHOD CONSISTENT WITH COST-CAUSATION AND ECONOMIC EFFICIENCY?

A. No. Given the "peakiness" of the RMP system, allocating fixed generation costs on the basis of a 12-CP method, in which the averages of all 12 months' coincident peaks are used to allocate costs by rate schedule or class, subsidizes residential and commercial customers who are driving the system peak. As the NARUC Electric Cost Allocation Manual states, "[The 12-CP] method is usually used when the monthly peaks lie within a

[42] The standard deviation of Ms. Brown's projected system peak loads over the period is 488 MW.

[43] This is another weakness of the JA methodology, which was based on vintage (existing) generating capacity, and is now applied to all generation and transmission assets.

narrow range, i.e., when the annual load shape is not spiky."[44] Figure 4 shows clearly that RMP's monthly system peaks do not fall within a narrow range. Thus, I conclude, consistent with NARUC, that the 12-CP method is not an appropriate methodology on which to allocate generating costs in Utah. Instead, the methodology recommended by UIEC witness Brubaker would provide a far more economically efficient and equitable cost allocation.

Q. ARE YOU FAMILIAR WITH THE SO-CALLED "EQUIVALENT PEAKER" METHODOLOGY?

A. Yes. The equivalent peaker methodology ("EPM") is one of many methods described in the NARUC Electric Utility Cost Allocation Manual. The rationale behind the EPM is that, because baseload and intermediate generating units have higher capital costs than peaking units, baseload and intermediate units have nothing to do with meeting peak electric demand. Therefore, adherents of the EPM believe that is appropriate to allocate all of the capital costs of baseload and intermediate units that are greater than the costs of an equivalent peaking unit based on energy consumption. The EPM thus transfers costs from customers driving peak demand – residential and small commercial customers in RMP's case – to all other customers.

Q. IS THE EPM CONSISTENT WITH PRINCIPLES OF ECONOMIC EFFICIENCY?

A. No. Although this approach has an intuitive appeal, it is completely inconsistent with (1) electric system planning, and (2) providing consumers with correct price signals.

[44] NARUC Manual, p. 46.

First, the EPM wrongly assumes a utility can meet all demand with peaking units. Clearly, no such system exists, because it would be inefficient, costly, and imprudent. Moreover, competitive wholesale market prices are determined by the type of generating resource on the margin, whether baseload, intermediate, or peaking unit. The fact that different types of generating units may be on the margin in different hours does not mean that prices are determined by average costs, which is essentially what the EPM does.

Second, the EPM wrongly subsidizes on-peak consumption, it is inconsistent with providing consumers with accurate price signals that encourage efficient consumption. This has been long recognized in the professional literature. For example, economist Alfred Kahn discussed this inconsistency in reference to the cost allocation approach that was used by the Federal Power Commission (the precursor to the Federal Energy Regulatory Commission), in its 1952 decision in *Atlantic Seaboard*.[45]

> The distinctive feature of the Atlantic Seaboard formula is that it requires that capacity costs be distributed 50-50 between the demand and commodity charges instead of incorporated exclusively in the former. Since the demand costs are distributed among customers in proportion to their shares in the volume of sales at the system's (three-day) peak, while the commodity costs are borne in proportion to their annual volume of purchases, the consequence of the 50-50 formula is to shift a large proportion of capacity costs to off-peak users. This produces an uneconomic encouragement to sales at the peak (whose price falls short of the true marginal cost of peak service) and an uneconomic discouragement of off-peak.[46]

[45] *In the Matters of Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation*, Opinion No. 225, 11 FPC 43 (1952).

[46] Alfred Kahn, *The Economics of Regulation*, Vol. 1, (1970), pp. 98-99 (footnotes omitted).

The *Atlantic Seaboard* methodology pre-dated the FERC's modified fixed-variable cost allocation methodology, which FERC abandoned in 1992 in favor of the straight fixed-variable methodology when it issued Order No. 636. [47]

Perhaps the greatest weakness of the EPM is its total inconsistency with how electricity is priced in the wholesale market. Again, market price data provides an intuitive template for cost allocation. The highest market prices almost always take place when demand is greatest and peaking units must be used. The EPM effectively forces customers who do not contribute to peak demand, large commercial and industrial customers in RMP's case, to cross-subsidize customers who do drive peak demand: residential and small commercial customers. Cross-subsidies are obviously inconsistent with sending accurate price signals to customer groups.

VI. THE JA METHODOLOGY SHOULD <u>NOT</u> BE USED TO ALLOCATE RMP'S INTERCLASS GENERATION AND TRANSMISSION COSTS

Q. HOW ARE GENERATION AND TRANSMISSION COSTS ALLOCATED UNDER THE INTER-JURISDICTIONAL COST-ALLOCATION AGREEMENT?

A. The Inter-jurisdictional ("JA") agreement allocates generation and transmission plant, plus non-fuel expenses, using a modified 12-CP methodology. The traditional 12-CP ("coincident peak") methodology averages the monthly coincident peaks for each rate class or schedule for the test year. Then, demand-related (fixed) generation costs are allocated to each rate class or schedule based on their relative contributions to the average system peak. For example, suppose the average monthly coincident peak loads for the

[47] I described these cost allocation methodologies in my testimony in this proceeding that was submitted on May 1, 2014.

Residential, Commercial, and Industrial classes of Utility A are 2,000 MW, 1,000 MW, and 1,000 MW, for an overall average system coincident peak load of 4,000 MW. Then, the 12-CP allocation factors to each class will be 50%, 25%, and 25%, respectively.

Under the JA Agreement, generation and transmission costs are allocated using a weighted average based on 75% of the system capacity ("SC") factor, which is calculated by applying the 12-CP method to temperature-adjusted monthly coincident peak loads, and a 25% weight for the system energy ("SE") factor, which is calculated as the proportion of the annual temperature-adjusted energy sales (at input) for each jurisdiction relative to total energy sales. (I refer to this as the "JA Methodology.")

Q. IS RMP REQUIRED TO USE THE JA METHODOLOGY TO ALLOCATE INTERCLASS[48] GENERATION AND TRANSMISSION COSTS?

A. No. Paragraph 18 of the June 22, 2011, Agreement entered into by PacifiCorp, the Utah Division of Public Utilities, the Utah Office of Consumer Services, and the Utah Association of Energy Users specifically states:

> The parties agree that no part of this Agreement, or any Commission Order acknowledging, adopting, approving or responding to the same, shall in any manner be argued or considered by any party hereto as binding or as precedent in any Utah rate setting context or case with respect to interclass allocations. Every Party to this Agreement hereby agrees not to claim or argue that execution of approval of this Agreement or adoptions of use of the Rolled-in inter-jurisdictional allocation methodology in Utah requires or establishes a presumption ion favor of any particular Utah interclass

[48] For ease of exposition, I use the term "interclass" to mean allocation of costs to RMP's different rate schedules.

> allocation methodology, practice or policy, or any changes to current Utah interclass allocation methodologies, policies or practices.[49]

Although the Commission has expressed a preference for using the JA methodology, the plain meaning of this language does not <u>require</u> RMP to use the JA methodology.

Q. DOES THE JA METHODOLOGY "CAUSE" RMP TO INCUR COSTS? CLARIFY

A. No. The JA methodology is simply used by PacifiCorp to allocate generation and transmission costs to each of the different jurisdictions. The costs themselves are caused by consumers' electric consumption decisions and the resources PacifiCorp uses to meet those consumers' demand for electricity.

Of course, consumption decisions are also affected by rates. Therefore, if the JA methodology is used to allocate costs to individual customer classes and that inefficient allocation forms the basis for the rates RMP's customers are charged, it will affect overall costs. In that sense only, one could conclude that the JA methodology "causes" PacifiCorp (and RMP's Utah service territory) to incur costs. Again, this points to the importance of allocating costs based on cost-causation and peak responsibility, as well as designing rates that incent efficient consumption decisions.

Q. WHY DO YOU CONCLUDE THAT THE JA METHODOLOGY SHOULD NOT BE USED TO ALLOCATE RMP'S GENERATION PRODUCTION PLANT AND TRANSMISSION PLANT COSTS?

---

[49] *Agreement Pertaining to PacifiCorp's September 15, 2010, Application for Approval of Amendments to Revised Protocol Allocation Methodology*, Docket No. 02-035-04, June 22, 2011, par 18.

A. The JA methodology should not be used to allocate RMP's generation and transmission costs among its different customer classes and rate schedules for four reasons First, as I have previously discussed, I am aware of no underlying empirical analysis that supports the JA methodology for class cost allocation.

Second, the JA methodology fails to recognize the "peakiness" of the RMP system.

Third, as discussed previously, there is no analytical basis for assigning a 25% weight of fixed generating costs based on energy consumption. Allocating RMP's share of PacifiCorp's generation and transmission costs based on a political agreement that was designed to share costs among the different jurisdictions is not necessarily consistent with ensuring just and reasonable rates. If, as the Commission has previously stated, cost allocation is the cornerstone of just and reasonable rates, then there must be a factual, empirical basis to support the use of the JA methodology to allocate these costs among RMP's customer classes.

Fourth, assigning a 25% weight based on energy consumption to allocate generation-related fixed production costs and transmission costs unfairly penalizes high load factor industrial customers, while subsidizing residential and small commercial customers who, by RMP's own admission, are driving the rapid increase in system peak loads.

A. <u>Lack of Empirical Basis Supporting the JA Methodology</u>

Q. ARE YOU AWARE OF ANY ANALYTICAL BASIS FOR THE 75% - 25% WEIGHTING USED TO CALCULATE THE SYSTEM GENERATION FACTOR?

A. No. I am not aware of any analysis supporting continued use of the 75% - 25% weighting of the 12-CP and energy allocation factors to derive the system generation factor. Furthermore, Attachment 1 of RMP's response in Docket No. 09-035-23 to UIEC DR10-18(c), which is attached as UIEC Exhibit COS (JAL-1.1), confirms that the 75% - 25% allocation was simply a compromise adopted among the states. As RMP states in its response:

> The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification [sic] could be supported on a technical basis. <u>The demand energy classification was the swing issue employed to balance the sharing of merger benefits between all the states and 75% demand 25% energy was selected because it produced an overall cost allocation result that was acceptable to all the states</u>.[50]

The December 16, 1999 "Allocations Task Force Report to the Utah PSC" simply states that "The PSC has approved the use of the 12 CP to be used in developing the factor to allocate production and transmission plant."[51] The report provides no additional discussion of why the 12-CP method was used, nor mentions the 75% demand – 25% energy factors.

Similarly, a report attached to testimony submitted on October 24, 1997 by Division of Public Utilities ("UDPU") witness Powell in Docket No. 97-035-04, notes that PacifiCorp's least-cost plan was selecting "resources with higher energy availability over resources with lower first cost and lower energy availability. This is an indication

---

50 RMP Response to UIEC-10-18(c), Attachment 1, p. 3 (emphasis added).

51 Allocations Task Force Report to the Utah Public Service Commission, December 16, 1999, p. 15.

that energy needs are still playing some role in capacity expansion. We would not conclude from this data that it has a major role."[52] The report then states:

> So what is the appropriate ratio of energy to include in the generation [SG] allocation factor? We know from RAMPP-5 that the value is not 0% and that it is not 100%. We would conclude that if energy were the specific trigger of capacity expansion some significant percentage of the time, a larger energy factor ought to be used. Since energy shows up only as a factor in selecting the type of resource added, we conclude that it has a relatively minor role. The current level of 25% energy in the allocation factor appears reasonable and should continue to be used.[53]

Thus, rather than providing any specific analysis, the report simply concluded that the 25% energy value "appears reasonable."

Subsequently, in testimony filed in 2001, UDPU witness Compton stated, "To get some kind of quantitative 'feel' for this matter I put together a simplified numerical example to illustrate the concepts involved. That analysis suggests that the 25% figure is reasonable. To perform a definitive analysis employing all (or even a large portion of) the elements of the PacifiCorp customer demand/profile and resources would be horrendously complex."[54] Admitting that an analysis based on actual PacifiCorp data was infeasible, Dr. Compton's instead prepared an ad-hoc analysis, which he concluded "suggested" that the 25% energy value was reasonable.

I am unaware of any other evidence for the 75%-25% allocation. The general statements by these two witnesses, the fact that they are 17 years old and 13 years old,

---

[52] Docket No. 97-035-04, Direct Testimony of Kenneth Powell on behalf of the Utah Division of Public Utilities, October 24, 1997, Exhibit__(DPU-2.2), p. 7.

[53] *Id*.

[54] Docket No. 01-035-01, Direct Testimony of George Compton on behalf of the Utah Division of Public Utilities, August 31, 2001, p. 5, lines 14-18.

respectively, and the fact that, as UIEC witness Brubaker's testimony discusses, the load patterns on the PacifiCorp have changed significantly over time, justify abandoning use of the 75%-25% allocation factors.

Q. IS THE LACK OF ANALYTICAL JUSTIFICATION PROBLEMATIC FOR PURPOSES OF ALLOCATING GENERATION AND TRANSMISSION COSTS BETWEEN THE DIFFERENT RMP CUSTOMER SCHEDULES?

A. Yes. The RMP response quoted previously clearly means that the JA allocation methodology was a political compromise among the different states. The weighting is problematic for the JA methodology itself, again because costs should be allocated based on principles of cost-causation. Because there is no analytical justification for the JA methodology even as it applies to interjurisdictional allocations, and because the choice was a political compromise, there is no factual or empirical basis whatsoever to conclude that the JA methodology follows cost-causation principles that should be applied to allocate generation and transmission costs between RMP's rate classes and schedules.

B. The JA Methodology Fails to Account for the "Peakiness" of RMP's Loads

Q. DOES THE JA METHODOLOGY ADEQUATELY CAPTURE THE LINK BETWEEN PEAK LOADS?

A. No. If one examines Figure 5, it is clear that the 12-CP approach used in the JA does not accurately reflect the "peakiness" of the RMP system and the fact that growth in residential temperature-sensitive loads is the largest driver of higher summer peaks. Because the 12-CP approach does not reflect the "peakiness" of the RMP system, it will fail to allocate these additional ancillary service costs in a manner that adequately reflects cost-causation.

Q. DO WHOLESALE MARKET PRICES FOLLOW THE SAME COST ALLOCATION PATTERN AS IS IMPLICIT IN HOW COSTS ARE ALLOCATED UNDER THE JA AGREEMENT?

A. No. As Figure 1 shows, Palo Verde forward market prices show a clear pattern of peaking in the summer months, reflecting higher production costs and the highest levels of demand. If wholesale market prices followed the pattern implied by the JA Agreement, we would expect much less price seasonality and relatively constant prices year-round.

Q. DOES THE JA METHODOLOGY REFLECT CURRENT CONDITIONS ON THE RMP SYSTEM?

A. No. As I discussed previously, it is important that whatever cost allocation methodology is adopted reflect contemporaneous conditions on the RMP system. The JA methodology was originally put into place in 1998 (later modified somewhat in 2004 and 2010). However, whereas conditions on the RMP system have changed, notably a significant growth in residential summer peak loads that are the main driver of RMP's increasing coincident summer peaks, the JA methodology approach continues to use a 12-CP methodology that is appropriate for utilities with relatively constant monthly system peaks .

Q. ARE YOU SUGGESTING THAT THE JA METHODOLOGY ITSELF BE CHANGED?

A. No. Such a change is clearly outside the scope of the instant proceeding. However, given that RMP itself admits there is no analytical basis for the JA methodology, applying it to the interclass allocations for RMP customers in Utah is problematic for two reasons. First, a methodology that lacks any analytical basis will allocate inter-jurisdictional costs in a manner consistent with cost-causation and allocative efficiency only as a matter of pure chance. Nevertheless, each individual jurisdiction should still determine the most efficient allocation of interclass costs within the jurisdiction, regardless of the total cost allocated to the jurisdiction. Using the same allocation method is likely to be economically efficient only by pure chance, if ever at all. And, if it were not economically efficient, the resulting allocation of costs would fail to reflect the Utah Commission's own statement that cost-causation principles are the "cornerstone" of establishing just and reasonable rates.[55]

Second, even if the JA methodology were analytically sound, there is no basis to assume that the appropriate method to allocate costs across multiple jurisdictions is appropriate to allocate interclass costs within an individual jurisdiction. In fact, it would be appropriate to use the JA methodology only if the pattern of cost-causation within each jurisdiction was the same as between jurisdictions.

Q. BECAUSE PACIFICORP PLANS ON A SYSTEMWIDE BASIS, AND ALLOCATES COSTS BASED ON THE JA METHODOLOGY, ISN'T IT IMPORTANT THAT RMP'S INTERCLASS ALLOCATIONS REFLECT THE PATTERN OF OVERALL SYSTEM COSTS AND LOADS, RATHER THAN THOSE OF RMP ALONE?

A. No. The reason is that using the JA methodology prevents RMP customers from seeing the correct price signals that reflect their own consumption patterns. Without these price signals, individual RMP customers will make inefficient consumption

55 EBA Order, p. 74.

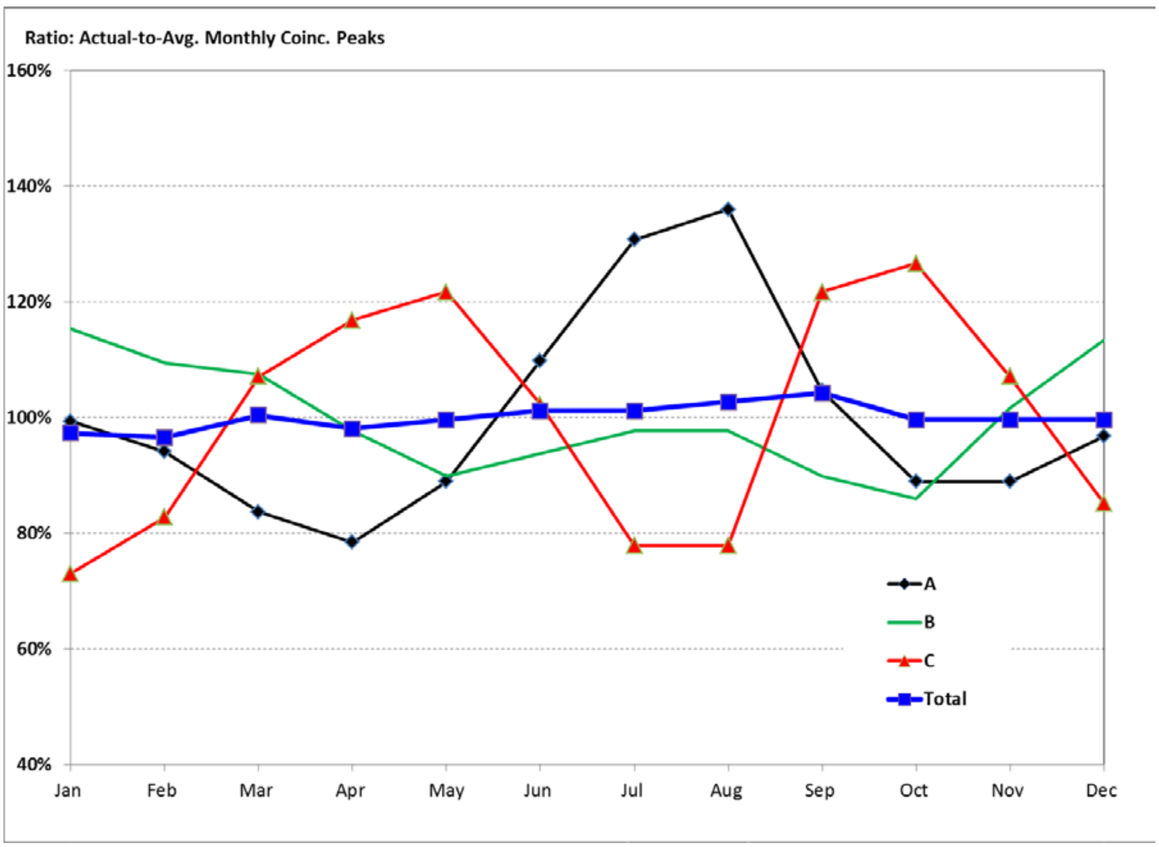
decisions, thus increasing PacifiCorp's overall system planning costs. As UIEC witness Brubaker discusses, the load pattern for PacifiCorp has changed over time from a winter-peaking system to a summer peaking one that more closely resembles the pattern of loads for RMP.[56] However, the underlying 75%-25% JA methodology has not changed and thus fails to reflect the current pattern of loads on the PacifiCorp system.

[56] UIEC Exhibit COS__(MEB-1.0).

Q. CAN YOU PROVIDE AN EXAMPLE OF WHY USING THE SAME METHODOLOGY TO ALLOCATE INTER-JURISDICTIONAL COSTS AND INTRACLASS COSTS WITHIN AN INDIVIDUAL JURISDICTION WOULD NOT BE REASONABLE?

A. Yes. Consider three separate jurisdictions, A, B, and C. To allocate generation costs amongst the jurisdictions, we can examine the overall coincident system peak load, as shown in Figure 6.

Figure 6: Jurisdictional System Peak Loads



As Figure 6 shows, the peak load patterns of the individual jurisdiction are completely different. For example, jurisdiction A shows a clear summer peak in July and August. On the other hand, jurisdiction B is a winter peaking system, and jurisdiction C shows a dual spring-fall peak. Given these differences, there would be no basis for using the same peak demand allocation methodology for each jurisdiction. For example, a 2-CP summer peak demand allocation would be reasonable for jurisdiction A, but not for jurisdiction C, which peaks in spring and fall. Using the same cost-allocation methodology in both jurisdictions would reduce economic efficiency.

Next, consider the overall pattern of system peaks, shown as the blue line labeled "total." In contrast to the individual jurisdiction peak loads, the pattern of the overall system peak is quite flat. Thus, in deciding how to allocate inter-jurisdictional costs, using a 12-CP approach would be reasonable. However, given the "peakiness" of the individual jurisdictions, and the fact that their individual system peaks occur at different times of the year, using a 12-CP methodology to allocate interclass costs in each jurisdiction would not reflect cost-causation, and thus would not lead to just and reasonable rates.

C. The JA Methodology Unfairly Penalizes High Load Factor Customers Who Are Not Driving RMP's Peak Load Growth and Greater Cost Volatility

Q. DOES ALLOCATING GENERATION COSTS BASED ON A 12-CP COINCIDENT PEAK ALLOW RMP CUSTOMERS DRIVING THE INCREASED IN SUMMER PEAK DEMAND TO "FREE RIDE" ON HIGH LOAD FACTOR CUSTOMERS?

A. Yes. As the "peakiness" of demand increases in the summer months, as is the case on the RMP system, using a 12-CP allocation methodology effectively dilutes peak responsibility. Specifically, the 12-CP methodology allows residential and small commercial customers, whose growing use of air conditioning is increasing summer peak demand, to "free ride" on high load factor customers, whose peak demands are not increasing.

Although the 12-CP average for residential and small commercial customers increases as their summer peak demand increases, the increase is clearly dampened by non-summer coincident peaks. A simple numerical example can demonstrate this point. As shown in Table 4, suppose we have two classes of customers: residential and industrial. Initially, each has a monthly coincident peak of 1,000 MW in every month. The resulting allocation of generation fixed costs, using a 12-CP method is 50% to each class, as shown on line 14. If the initial fixed costs are $100 million (based on an existing 2,000 MW of generation installed at a cost of $50/kW-year), each rate class is assigned $50 million of those costs initially, as shown on line 15.

Table 4: Example of Free-Riding by Customers Causing Peak Load Growth

		Coincident Peak			Coincident Peak		
Line No.	Month	Res	Industrial	System	Res	Industrial	System
1	January	1000	1000	2000	1000	1000	2000
2	February	1000	1000	2000	1000	1000	2000
3	March	1000	1000	2000	1000	1000	2000
4	April	1000	1000	2000	1000	1000	2000
5	May	1000	1000	2000	1000	1000	2000
6	June	1000	1000	2000	1000	1000	2000
7	**July**	1000	1000	2000	**2000**	1000	3000
8	**August**	1000	1000	2000	**2000**	1000	3000
9	September	1000	1000	2000	1000	1000	2000
10	October	1000	1000	2000	1000	1000	2000
11	November	1000	1000	2000	1000	1000	2000
12	December	1000	1000	2000	1000	1000	2000
13	**12-CP Average**	**1,000**	**1,000**	**2,000**	**1,167**	**1,000**	**2,167**
14	**Percentage**	**50%**	**50%**	**100%**	**54%**	**46%**	**100%**
15	**Cost Allocation**	**$50.00**	**$50.00**	**$100.00**	**$94.23**	**$80.77**	**$175.00**

		Coincident Peak			Coincident Peak		
	Month	Res	Industrial	System	Res	Industrial	System
16	January	1000	1000	2000	1000	1000	2000
17	February	1000	1000	2000	1000	1000	2000
18	March	1000	1000	2000	1000	1000	2000
19	April	1000	1000	2000	1000	1000	2000
20	May	1000	1000	2000	1000	1000	2000
21	June	1000	1000	2000	1000	1000	2000
22	**July**	1000	1000	2000	**2000**	1000	3000
23	**August**	1000	1000	2000	**2000**	1000	3000
24	September	1000	1000	2000	1000	1000	2000
25	October	1000	1000	2000	1000	1000	2000
26	November	1000	1000	2000	1000	1000	2000
27	December	1000	1000	2000	1000	1000	2000
28	**2-CP Average**	**1,000**	**1,000**	**2,000**	**2,000**	**1,000**	**3,000**
29	**Percentage**	**50%**	**50%**	**100%**	**67%**	**33%**	**100%**
30	**Cost Allocation**	**$50.00**	**$50.00**	**$100.00**	**$116.67**	**$58.33**	**$175.00**

Note: Assumes 2,000 MW of existing baseload capacity @ $50/kW-year and 1,000 MW of new peaking capacity at $75/kW-year

Next, suppose the residential coincident peak load doubles to 2,000 MW in July and August, but remains constant in all other months. To meet that new peak load, the utility adds 1,000 MW of new peaking capacity at a cost of $75/kW-year. Under the 12-CP methodology, the fraction of generating costs allocated to residential customers increases to 54%, and the fraction allocated to industrial customers decreases to 46%, also as shown on line 14. As a result, the costs allocated to industrial customers increases by over $30 million to $80.77 million, whereas the costs allocated to residential customers increase to $94.23 million. Thus, the additional $75 million in costs caused by residential customers' increased summer peak load results in the costs allocated to industrial customers increasing by over 60%, despite no change in their loads.

If, instead, the increased peak load growth is recognized by allocating costs using the 2-CP methodology, the fraction of costs allocated to residential customers will increase to 67%, as shown on line 29. The new cost allocation, as shown on line 30, is $58.33million to industrial customers and $116.67 to residential customers. In this case, although industrial customers still see an increase in the overall generating costs allocated to them, the increase is much smaller.

D. <u>PacifiCorp's Updated Stress Factor Analysis Does Not Support Using the JA Cost Allocation Methodology</u>

Q. WHAT IS THE RELEVANCE OF THE "STRESS FACTOR" ANALYSIS THAT HAS BEEN USED PREVIOUSLY BY PACIFICORP?

A. The original Stress Factor Analysis ("SFA") prepared in 2003 was used by PacifiCorp to justify the JA methodology. As part of the Stipulation in Docket No. 11-035-200, RMP agreed to update this analysis. On November 1, 2013, RMP submitted this updated analysis.

Q. DID YOU REVIEW THE ORIGINAL SFA?

A. Yes. The "stress factor" analysis performed by PacifiCorp in 2003 is a crude and fatally flawed form of LOLP analysis, to the extent that PacifiCorp calculated what it referred to as monthly “probability” values for contribution to peak load. In Docket No. 11-035-200, Commission Staff witness Dr. Artie Powell criticized the original SFA for a variety of reasons, all of which I agree with.[57] In essence, both the original and updated SFAs measure when electric demand has the probability of contributing to peak load.” However, the methods used to calculate these “probabilities” have no statistical basis and the resulting “probabilities” have no statistical meaning. They are not probabilities in the same way that we can estimate the statistical probability of winning the lottery or flipping a fair coin ten times and having the coin land on “heads” each time.

Q. WHAT IS LOLP?

A. LOLP is a statistical measure of the likelihood that there will be insufficient resources to meet electric demand at any given moment in time. PacifiCorp itself offers a definition of LOLP in its 2013 IRP, stating “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.”[58]

Q. DID PACIFICORP DEFINE WHAT SYSTEM “STRESS” MEANS IN ITS ORIGINAL OR UPDATED SFA WRITE-UPS?

A. No. The implicit definition appears to be “the ability of the Company to meet load” at a given time. Although this is superficially consistent with LOLP, it is far

---

[57] *See* Docket No. 11-035-200, Direct Testimony of Artie Powell on Behalf of the Utah Division of Public Utilities, June 22, 2012, p. 17, line 353 – p. 18, line 390.

[58] PacifiCorp 2013 IRP, p. 198.

different from an empirical standpoint because of the arbitrary nature of the "probabilities" calculated by PacifiCorp.

Q. ARE YOU AWARE OF ANY DISCUSSION OF THE "STRESS FACTOR" ANALYSIS IN THE ACADEMIC OR PROFESSIONAL LITERATURE?

A. No. The "stress factor" methodology appears to be a unique construct of PacifiCorp. There is no evidence of this methodology ever being used in any other jurisdiction, and there is no discussion of it in the academic or professional literature. Based on my review of this analysis, the stress-factor methodology, as performed by PacifiCorp in 2003 and updated in 2013, is <u>not</u> a valid approach on which to base cost responsibility.

Q. WHAT TESTS DID RMP PERFORM AS PART OF ITS SFA?

A. PacifiCorp performed five separate tests, along with a Loss of Load Probability ("LOLP") analysis that the Company states were prepared as part of PacifiCorp's 2013 IRP.[59] These tests were: (1) monthly firm peak demand; (2) probability of contribution to peak demand, based on the number of hours each month that firm load exceeds a percentage of the annual peak load, (3) probability of contribution to peak, based on the number of MWh associated with the hours each month that firm load exceeds a percentage of the annual peak load; (4) monthly reserve margins at the time of peak; and

[59] *See RMP 2013 Stress Factor Analysis*, Docket No. 11-035-200, November 1, 2013, Part 6, Loss of Load Probability Study. The public version is attached as UIEC Exhibit COS (JAL-1.2). Although the submission was made by RMP, the "stress factor" analysis was performed for the entire PacifiCorp system.

(5) cost of peak resources, based on the dollar per megawatt-hour difference each month that cost of wholesale market purchases exceeds the cost of gas-fired resources.

PacifiCorp listed the "pros" and "cons" of each of these five approaches as part of the "Stress Factor Study Plan" it submitted to the Commission on July 1, 2013.[60] RMP also prepared a type of LOLP study, based on "monthly energy not served (ENS) data, which represents the amount of load that cannot be met with either system resources or with system balancing market purchases." (This is different than the LOLP study performed by PacifiCorp for its 2013 IRP and discussed previously in Section III.A, which assumed that PacifiCorp had no access to market purchases.)

Q. HOW DID YOU EVALUATE THE FIVE STRESS FACTOR TESTS THAT WERE PEFORMED BY PACIFICORP?

A. I evaluated the five tests based on two separate criteria:

- <u>Consistency with a true LOLP measure</u>. Does the proposed method provide an equivalent proxy estimate for LOLP? Does the method provide statistical probability values?
- <u>Consistency with principles of economic efficiency</u>. Is the proposed measure consistent with how costs are allocated in the competitive wholesale market?

These two criteria are fundamental to cost causation and peak responsibility, which I consider to be the most important principles when allocating fixed costs.

Q. CAN YOU SUMMARIZE YOUR EVALUATION OF THE FIVE TESTS WITH RESPECT TO THESE TWO CRITERIA?

---

60 The study methodology is attached as UIEC Exhibit COS (JAL-1.3).

A. Yes. Method 1 uses monthly firm peak demand as a proxy for system "stress." Method 1 is consistent with a traditional coincident peak ("CP") determination, in that it determines the month(s) in which peak demand is highest. Under a traditional CP cost allocation, fixed generation costs are allocated based on each the relative contribution to the system CP during the highest demand month. Thus, if the results are interpreted correctly, Method 1 is consistent with principles of economic efficiency, although it has nothing do with LOLP.

Method 2 revises this 2003 stress factor analysis simply by changing the 83% value to a range of estimates between 70% and 99% of annual peak load. PacifiCorp recognizes two problems with this approach: (1) the methodology does not measure the magnitude by which load exceeds the annual peak; and (2) the potential for overlap with a system generation allocator that is based, in part, on energy use. This method does not provide a valid LOLP measure. To do that, load must be combined with system operations to analyze LOLP. This method <u>assumes</u> a non-existent linear relationship between hours where load exceeds annual average system load and LOLP. Furthermore, PacifiCorp does not address how the probability of contribution to peak load determines cost allocation. For example, suppose the analysis shows that there is a positive probability of contribution to peak load in all months. Does this mean that fixed generation costs should be based on an average of monthly coincident peaks of each customer class? The link between the probability of contributing to peak and economic efficiency is non-existent.

Q. DOES METHOD 2 MEASURE STATISTICAL PROBABILITIES OF LOAD LOSS?

A. No. To see why, consider a hypothetical example in which the annual system peak load is 10,000 MW. Suppose that, in June, loads exceed 8,000 MW (80% of the annual system peak load) a total of 200 hours. In that case, the "probability of contributing to system peak" would equal 200 hours / 720 hours = 27.8%. Thus, the Method 2 "stress factor" analysis concludes there is a 27.8% "probability" that June will contribute to the peak. This is not a statistical probability. Rather, it is a deterministic measure of the frequency with which load exceeds an arbitrary threshold. One could as easily say that June loads exceed 100 MW (i.e., 1% of the annual system peak) in all hours, and therefore the "probability of contributing to system peak" would equal 100%. This "probability" is meaningless.

Q. PLEASE CONTINUE WITH YOUR DESCRIPTION OF THE REMAINING SFA METHODOLOGIES.

A. Method 3 purports to be a similar LOLP-type of approach as Method 2, except one that is based on energy consumption, not load. As a consequence, it is even more flawed than Method 2. Based on this method, a constant but lower load that occurs over many hours in a month can be "more stressful" to the system than a short duration but far higher load because the former represents more total energy consumption. For purposes of allocating fixed costs, this makes no economic sense because it does not reflect cost causation.

For example, suppose a peaking unit must be operated for ten hours during July when residential air conditioning load peaks. Suppose also there is a 7x24 industrial process load that is greatest in the month of November and that this load means more total MWh in November exceed average load than in July. Under this method, the constant industrial process load places more "stress" on the PacifiCorp system than does the residential air conditioning load driving the need to run the peaking unit, which is counterintuitive to say the least. This method also suffers from same economic efficiency problems as the first probability of contribution to peak method, in that there is no specific relationship between such "probabilities," cost allocation, and economic efficiency.

Method 4 wrongly assumes PacifiCorp is an island. As the Company itself points out, reserve margins may be lower in low-demand months because these are the rational months for planned outages of generators. No utility schedules outages for the highest-demand months. Moreover, as with Method 2, this method assumes there is a linear relationship between reserve margin and LOLP, which is not true.

Method 5 relies on flawed economics and is an "apples to oranges" comparison of PacifiCorp resources to the wholesale market. Specifically, Method 5 compares the marginal cost of wholesale market resources to the embedded costs of PacifiCorp's gas-fired peaking units. This has no relationship whatsoever with LOLP. Furthermore, this comparison has no relationship to economic efficiency, because it does not address how PacifiCorp operates its resources. Under economic dispatch, PacifiCorp dispatches its generating resources in order of their increasing marginal operating costs, not their embedded costs. In the presence of the wholesale market, economic dispatch should also include the marginal cost (i.e., the market price) of wholesale power. Thus, it is economically efficient for PacifiCorp to purchase electricity from the market whenever that power costs less than the marginal cost of operating its own generating units. Purchase decisions in the wholesale market have nothing to do with embedded generation costs. In other words, PacifiCorp does not compare the market price of energy in the wholesale market with the embedded costs of its generating units.

As a result of this fundamental mismatch, Method 5 has no economic basis. If a company relies on the wholesale market, as PacifiCorp increasingly does, to meet its energy and capacity needs, and doing so is less costly than building new generating resources, then the wholesale market is obviously providing system reliability and reducing "stress."

Table 5 summarizes my evaluation of the five SFA methods in terms of the two evaluation criteria.

Table 5: Evaluation of RMP/PacifiCorp Updated SFA

SFA Method	Consistent with LOLP?	Consistent with Econ. Effic?	Comments
Monthly Firm Peak Demand	YES	NO	Consistent with CP determination
Prob. of Contribution to Peak Demand (Load v. Peak)	NO	NO	Assumes a non-existent linear relationship between hours where load exceeds annual average system load and LOLP
Prob. of Contribution to Peak Demand (Energy)	NO	NO	Does not reflect cost-causation. Constant, but lower load can be more "stressful" than short duration of high load.
Reserve Margin at time of peak	NO	NO	Reserve margins determine LOLP. This approach reverses causation.
Cost of Peak Resources v. Wholesale Market	NO	NO	Wrongly compares the marginal cost of wholesale resources to embedded costs of PacifiCorp gas-fired peaking units. No relationship to LOLP; fails to address dispatch based on marginal costs

Q. CAN YOU SUMMARIZE THE RESULTS OF THESE FIVE TESTS?

A. Yes. The results of Method 1 are presented on pp. 7-25 of RMP's confidential submission[61] and shows that the system will continue to be summer peaking through the year 2027, with the highest peak demands in July and August each year.

The results of Method 2 are shown on pp. 26-62. The analysis shows that July and August consistently have by far the greatest percentage of total hours when load exceeds 80% of peak or higher. When the criterion is percentage of total hours when load exceeds 70% of peak or higher, then January and December can also be included. Of course, the fact that neither January nor December has the highest system peak loads does not factor into the analysis.

The results of Method 3 are shown on pp. 63-98 and are similar to those of Method 2, although as previously discussed this method results in lower, steady loads being more "stressful" than higher, short-duration loads. This is the precise opposite of what the peak-responsibility concept means.

The results of the reserve margin analysis are shown on pp. 99-106. The analysis shows that the months of July and August have negative reserve margins (without IRP resources). With IRP resources, June, July, and August have the lowest positive reserve margins, consistent with the summer-peaking nature of the overall PacifiCorp system, and RMP especially. Moreover, this method reverses causality. In other words, for reliability planning purposes, reserve margins are determined based on LOLP analysis,

[61] *RMP 2013 Stress Factor Analysis*, Docket No. 11-035-200, November 1, 2013.

which takes into account uncertain load. Thus, measured on a load basis, system “stress” determines required reserve margins. Instead, Method 4 appears to reverse this causality.

The results of the analysis of the cost of peaking resources v. wholesale market prices are shown on pp. 107-112. The analysis shows that forecast monthly wholesale market prices are lower than the costs of simple-cycle peaking resources at all of the evaluated capacity utilization levels in all years.[62] The analysis also shows that forecast wholesale market prices are lower than the costs of combined-cycle units in until at least 2022 and assuming capacity utilization of 60% or more. Method 5 relies on flawed economics and is an “apples to oranges” comparison of PacifiCorp resources to the wholesale market. Specifically, Method 5 compares the marginal cost of wholesale market resources to the embedded costs of PacifiCorp’s gas-fired peaking units. This has no relationship whatsoever with LOLP.

Furthermore, this comparison has no relationship to economic efficiency, because it does not address how PacifiCorp operates its resources. Under economic dispatch, PacifiCorp dispatches its generating resources in order of their increasing marginal operating costs, not their embedded costs. In the presence of the wholesale market, economic dispatch should also include the marginal cost (i.e., the market price) of wholesale power. Thus, it is economically efficient for PacifiCorp to purchase electricity from the market whenever that power costs less than the marginal cost of operating its own generating units. Purchase decisions in the wholesale market have nothing to do with embedded generation costs. In other words, PacifiCorp does not compare the

[62] Oddly, the PacifiCorp analysis assumes no monthly variation in the cost of natural gas, even though natural gas prices are seasonal.

market price of energy in the wholesale market with the embedded costs of its generating units. As a result of this fundamental mismatch, Method 5 has no economic basis. If a company relies on the wholesale market, as PacifiCorp increasingly does, to meet its energy and capacity needs, and doing so is less costly than building new generating resources, then the wholesale market is obviously providing system reliability and reducing "stress."

Q. CAN YOU SUMMARIZE THE RESULTS OF THE LOLP ANALYSIS SUBMITTED BY RMP AS PART OF THE SFA?

A. Yes. PacifiCorp did not prepare a standard LOLP analysis for purposes of the SFA. Instead, as the report states, the Company used the results of an LOLP analysis to determine it needed a 13% planning reserve margin, based on an analysis that assumed PacifiCorp could not access the markets to meet demand. Using this margin, PacifiCorp simply took the energy not served ("ENS") data directly from the preferred portfolio identified in the 2013 IRP. However, this cannot be used for the LOLP study submitted with the SFA because the ENS analysis presented by RMP is only meaningful when compared with other resource portfolios analyzed in the same manner. As RMP itself states in its write-up of the LOLP study for the SFA, the ENS results "are not directly comparable to the reliability metrics calculated in the LOLP study, primarily because the IRP simulations allow system balancing market purchases when evaluating portfolio costs."[63] Therefore, the ENS study results do not measure system "stress."

[63] *See* UIEC Exhibit COS__(JAL-1.3), p. 2.

Q. DOES THE SFA SUBMITTED BY PACIFICORP PROVIDE ANY ANALYTICAL JUSTIFICATION FOR USING THE JA METHODOLOGY TO ALLOCATE COSTS AMONG RMP'S CUSTOMER CLASSES?

A. No. Other than the data on monthly peak loads presented under the first method in the updated SFA, which reinforces the fact that PacifiCorp is a summer peaking system, none of the other SFA methods are truly consistent with LOLP, cost causation, or economic efficiency principles. Moreover, as I discussed previously in my testimony, the actual LOLP study prepared by PacifiCorp and presented in its 2013 IRP clearly supports the summer-peaking nature of the system.

VII. DESIGN OF BACKUP SERVICE RATES

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. In this section, I discuss RMP's proposed changes to its Backup Service rates charged to customers under Schedule 31. First, I discuss the flaws in the RMP proposal, as presented in the testimony of RMP witness Steward, including: (1) the design of the tariffs to be equivalent to the costs paid by customers taking full-requirements service, when the services being provided are entirely different; (2) why the proposed backup service charges effectively force self-generation customers to pay RMP twice for the same generating capacity reserves; (3) why the efficient and equitable price for transmission service component is PacifiCorp's filed OATT rate; (4) why RMP is mispricing what is, effectively, a call option on generation; and (5) why there should be no mandate to take backup service.

Second, I present my recommendations for pricing backup service, specifically service associated with forced outages of customer-owned generating facilities. As I will discuss, I recommend that the transmission capacity service component of this service be based on the filed OATT, weighted by the expected forced outage rate ("EFOR") of a customer's generating resources. Customers who take power at the distribution level should also pay a distribution service charge, based on the allocated cost of distribution ($/kW) times the EFOR. The cost of backup generation should be based on the market price of generation, just as the price PacifiCorp itself pays for generation under the Northwest Power Pool Reserve Sharing Program ("NWPP RSP") is based on the market price of power at the Mid-Columbia ("Mid-C") hub. Contrary to the proposal set forth in the testimony of RMP witness Steward, my proposed pricing for backup service is efficient and equitable.

Q. ARE YOU ALSO TESTIFYING ABOUT RMP'S PROPOSED SUPPLEMENTARY SERVICE RATES UNDER SCHEDULE 31?

A. No. My testimony addresses only RMP's proposed Backup Service rate proposal. I am not testifying in regard to either maintenance power or supplementary service.

Q. CAN YOU SUMMARIZE THE RMP BACKUP SERVICE PROPOSAL?

A. Yes. As described in the testimony of RMP witness Steward, RMP proposes that all customers with onsite generation between 1,000 kW and 15,000 kW, plus all QFs with onsite generating capacity greater than 15,000 kW, be required to take Backup Service under Schedule 31.[64] The specific rates RMP proposes to charge customers for Backup Service are set forth in Exhibit K to RMP's application. The charges include: (1) a

[64] Steward BU Direct, p. 6, lines 131-136.

customer charge of $646/month for customers taking service at transmission voltages; and (2) a BFC of $4.94/kW-month (again, for customers taking service at transmission voltages). Customers who actually experience a forced outage will, in addition, pay Backup Power Charges ("BPC") during on-peak hours, differentiated by Summer (May-September) and Winter (October – April) seasons, and Backup Energy Charges as set out in Rate Schedules 8 or 9.

Q. WHAT COSTS DOES THE BFC INCLUDE?

A. RMP witness Steward testifies that the BFC includes "[d]istribution-related costs, demand-related transmission costs plus 13 percent of demand-related generation costs from cost of service."[65]

Q. WHAT COSTS DOES THE BPC INCUDE?

A. The BPC includes the remaining charges so that the sum of the BFC and the applicable BPC equal the sum of the corresponding Schedule 8 or 9 Facilities charges and on-peak or off-peak capacity charges. According to RMP witness Steward, this pricing is "such that in the event the customer's generation was offline for a full billing period, the customer would pay the same amount as a comparable full requirements customer."[66]

Q. WHY DOES RMP WISH TO CHANGE THE PRICING PROVISIONS FOR BACKUP SERVICE?

A. According to the testimony of RMP witness Steward,

[65] Steward BU Direct, p. 11, lines 231-234.

[66] *Id*., p. 12, lines 274-276.

> Because of the vintage of the current Schedule 31, increasing inquiries regarding Partial Requirements Service, and larger onsite generation facilities, a review of the tariff is necessary to ensure that Partial Requirements Service charges adequately reflect the cost of providing this service in order to minimize subsidization from other customers.[67]

Q. DO YOU AGREE THAT MINIMIZING CROSS-SUBSIDIES FROM OTHER CUSTOMERS IS A REASONABLE GOAL?

A. Yes. However, as I have explained previously in this testimony, RMP's entire cost allocation methodology, which applies the JA methodology, *creates* these cross subsidies. Moreover, by forcing customers who self-generate to take backup service, RMP is forcing those customers to cross-subsidize others. In fact, RMP's proposal to require customers to take backup service appears to be a backdoor approach to discourage these customers from self-generating and thus make it easier for RMP to recover its fixed generation and transmissions costs, recovery of which RMP witness Walje testified were problematic:

> [S]ales declines in the residential and industrial classes reflect growth in regulated energy efficiency programs, customer initiated conservation programs, and self-generation elections by some of the Company's large industrial Utah customers as well as changes in their operations. As a result of a reduction in total Utah sales, revenues in the case are $42 million lower than the test period sales in the last general rate case. [68]

A. <u>Flaws in RMP Backup Service Pricing Proposal</u>

Q. WHAT IS THE FIRST FLAW IN RMP'S PROPOSED BACKUP PRICING TARIFF?

---

[67] *Id.*, p. 6, lines 115-120.

[68] Walje Direct, p. 11, lines 236-241.

A. The first flaw in the proposed backup pricing tariff is that there is no basis for treating QF and non-QF customers differently. RMP proposes to exempt non-QF customers with self-generation capacity of 15,000 kW or greater, but not exempt QF generators. RMP witness Steward testifies that the generating capacity and QF status criteria "will ensure Schedule 31 is utilized only for Partial Requirements Service as contemplated and is not used as an arbitrage opportunity."[69] In fact, as I discuss below, by seeking to require customers to take backup service under Schedule 31, as Ms. Steward testifies, it is RMP that may be able to engage in arbitrage by buying low-cost power from the market to serve a customer requiring back-up service and charging that customer a far higher rate for the same energy.

Q. DOES RMP WITNESS STEWARD PROVIDE ANY EVIDENCE THAT ANY CUSTOMERS ARE USING BACKUP SERVICE AS AN ARBITRAGE OPPORTUNITY?

A. No. Nor does Ms. Steward specify the type of arbitrage RMP seeks to prevent, nor how RMP would be harmed by such arbitrage. Instead, in response to UIEC 1.35, RMP suggests a scenario in which a customer will purchase power from RMP rather than self-generate whenever the price of RMP power is lower and, as such, RMP is the provider of last resort ("POLR").

Q. DOES RMP WITNESS STEWARD EXPLAIN WHY A NON-QF CUSTOMER WITH AT LEAST 15,000 KW OF GENERATING CAPACITY COULD NOT USE BACKUP SERVICE AS AN ARBITRAGE OPPORTUNITY WHEREAS A QF

[69] Steward BU Direct, p. 16, lines 347-348.

CUSTOMER HAVING THE SAME GENERATING CAPACITY COULD USE BACKUP SERVICE AS AN ARBITRAGE OPPORTUNITY?

A. No.

Q. DOES RMP WITNESS STEWARD EXPLAIN HOW FORCING CUSTOMERS TO TAKE BACKUP SERVICE ELIMINATES ARBITRAGE OPPORTUNITIES?

A. No.

Q. IS THERE A SOLUTION TO ADDRESS ALLEGED ARBITRAGE BY PARTIAL REQUIREMENTS CUSTOMERS OTHER THAN MANDATING BACKUP SERVICE?

A. Yes. A simple and straightforward solution to the alleged problem RMP identifies is to price such service at the wholesale market price. If a customer's self-generated electricity is priced above market, it is economically rational for the customer to purchase electricity from the market instead. Doing so is not arbitrage. Moreover, market-price purchases do not harm RMP. Moreover, there is no reason why RMP could not enter into a contract with a customer wishing to buy power from the market whenever its own generation is more costly.

Q. IF AN RMP GENERATING UNIT SUFFERS A FORCED OUTAGE, HOW CAN IT OBTAIN ADDITIONAL ENERGY NEEDED TO MEET DEMAND?

A. There are at least three ways. First, RMP/PacifiCorp can ramp up the output of other company-owned generating units to compensate for the forced outage. Second, RMP/PacifiCorp can buy additional electricity from the wholesale market. Third, if the forced outage results in a loss of required contingency reserves, then as a participating Balancing Authority ("BA") in the NWPP Reserve Sharing Program ("RSP"), PacifiCorp

East (and, hence, RMP) can rely on generation supplies from other BAs and pay the wholesale market price for the energy supplied.

Q. CAN YOU DESCRIBE THE NWPP RESERVE SHARING PROGRAM?

A. Yes. The NWPP RSP was instituted in 2006. Much as power pools allow multiple utilities to improve reliability and reduce costs by coordinating their generating resources, the RSP allows participating BAs to share contingency reserves they are required to carry at all times under NERC standard BAL-002-1.[70] Under the RSP, if an event (i.e., a "contingency"), such as a loss of a generator or transmission line, causes a disruption within an individual BA, other participants can provide contingency reserves to ensure the power system remains operational. As set forth in Section D.3.c of the RSP, participants can purchase generation to meet their contingency reserve obligations from other BAs, as well as other suppliers.

Q. IF A PARTICIPATING BA PURCHASES POWER FROM ANOTHER BA, HOW DOES THE PURCHASER SETTLE WITH THE SELLER?

---

[70] NERC Standard BAL-002-1 covers operating reserve, which includes contingency reserve, regulation reserve, and demand-related capacity reserve. A copy of the Standard BAL-002-1 is available at: http://www.nerc.com/files/BAL-002-1.pdf. The Western Electricity Coordinating Council ("WECC") standard BAL-STD-002-0 addresses implementation of NERC Standard BAL-002-1 in the Western Interconnection. A copy is available at: http://www.nerc.com/files/BAL-STD-002-0.pdf.

A. Section K sets forth two alternatives for repayment: the buyer can either physically return an equivalent amount of energy that it received or can settle the obligation financially. The choice is up to the seller.

Q. IF A SELLER WISHES TO BE FINANCIALLY REIMBURSED FOR ENERGY PROVIDED, HOW IS THE PRICE DETERMINED?

A. Section K.3.a states, in its entirety, that:

> for purposes of the Reserve Sharing Program, the "Settlement Price" will be the average of the Powerdex Mid-Columbia hourly price for (1) the hour during which the Participant first requests Assistance Reserve (the "Request Hour") and (2) each of the two hours immediately following the Request Hour; provided, however, that in no event will the Settlement Price be less than zero or greater than the price cap in effect for the WECC in accordance with regulations and orders of the Federal Energy Regulatory Commission (FERC) in effect as of the Request Hour; provided further, that if Assistance Reserve is provided in more than one hour, each hour in which Assistance Reserve is provided shall be deemed to be a Request Hour for purposes of determining the Settlement Price.

Thus, financial settlement is based on the wholesale market price of power.

Q. CAN YOU SUMMARIZE WHY THE NWPP RSP IS SIGNIFICANT FOR PURPOSES OF ESTABLISHING THE PRICE RMP CHARGES FOR BACKUP SERVICE?

A. Yes. Under the NWPP RSP, financial settlements for energy provided during a qualifying event, including a forced outage of a generating unit, are based on the wholesale market price of power. There is no logical reason why, if a customer-owned generating unit suffers a forced outage and that customer takes backup service, RMP should not price the backup energy in the exact same way. And, because a forced outage of customer-owned generation can itself be a qualifying event under the RSP, RMP would itself pay the market price of energy for replacement energy. Were RMP to charge an above-market price for energy to the customer for energy delivered during this qualifying event, RMP would be benefiting from arbitrage. Thus, the only economically efficient and equitable energy price to charge customers who take backup service is the wholesale market price.

Q. WHAT IS THE SECOND FLAW IN THE RMP PROPOSAL?

A. The second flaw is that the transmission demand component of RMP's proposed BFC is inconsistent with PacifiCorp's filed OATT. As I discussed in testimony filed in this docket on May 1, 2014, *all* retail customers should be charged the OATT rates for transmission services provided to them. There is no economic basis to charge wholesale customers the FERC-approved OATT for transmission services while charging retail customers a different, and higher, rate for the same transmission services. For example, a wholesale customer of RMP taking service at a transmission voltage would pay the OATT for all transmission services by definition. Simply changing the designation of a transmission voltage customer from "wholesale" to "retail" does not change the costs to provide such a customer with the transmission services described in the OATT.

Q. WHAT IS THE THIRD FLAW IN THE RMP PROPOSAL?

A. The third flaw is that the generation demand component of RMP's proposed BFC can effectively force customers to pay twice for the same generating capacity. To understand this, consider how RMP can serve a customer needing backup service because of a forced outage. Rather than using its own generating capacity, suppose RMP purchases lower cost firm power from the wholesale market to serve that customer. The cost of the power RMP purchases will be included in RMP's EBA. Moreover, the price for firm power recovers fixed generation capacity costs. Thus, RMP effectively recovers generation capacity costs twice: once for the capacity purchased from the market and recorded in the EBA, and second by recovering the capital costs of RMP's own generating units through the backup rates.

Q. WHAT IS THE FOURTH FLAW IN THE RMP PROPOSAL?

A. The fourth flaw is the premise that backup service rates should be designed such that customers who take back-up service for a month pay exactly the same amount as corresponding full requirements customers. Although this premise seems intuitive and reasonable, the premise is fundamentally flawed. Backup service customers are *not* taking comparable service as full requirements customers and thus there is no economic basis for charging them the same rates as full requirements customers.

Q. WHAT IS THE FIFTH FLAW IN THE RMP PROPOSAL?

A. The fifth flaw stems from RMP's proposed contract demand for certain customers to take backup service. Contrary to Ms. Steward's testimony about preventing arbitrage and cross-subsidies, the proposed mandate to take backup service forces backup service customers to cross subsidize full requirements customers and provides RMP with arbitrage opportunities.

Q. DOES RMP WITNESS STEWARD EXPLAIN WHY REQUIRING CERTAIN LARGE GENERAL SERVICE CUSTOMERS TO TAKE BACKUP SERVICE IS NEEDED TO MINIMIZE SUBSIDIZATION?

A. No. Ms. Steward fails to provide any explanation of how requiring customers to take backup service is efficient or equitable. Moreover, requiring customers to take service they do not want effectively forces such customers to cross-subsidize other customers on the RMP system, in direct contradiction to Ms. Steward's testimony.

Q. ARE YOU AWARE OF OTHER UTILITIES THAT FORCE CUSTOMERS TO TAKE BACKUP SERVICE?

A. No. I have never encountered another utility that has required customers who self-generate to take backup service. In states with direct retail electric competition, some local distribution utilities ("LDCs") have attempted to include nonbypassable charges on customers who purchase electricity from competitive retail suppliers to compensate the LDC for serving POLR service in case the customer returns to the LDC's standard offer service. This, however, is entirely different from a local utility *requiring* customers who self-generate electricity to pay for backup service.

B. <u>Recommended Backup Pricing Tariff</u>

Q. CAN YOU DESCRIBE YOUR PROPOSED BACKUP PRICING APPROACH?

A. Yes. My proposed backup pricing methodology is economically efficient, based on cost-causation, and straightforward. The proposal consists of five components:

1. A base annual BFC charge to cover transmission-related costs, which can be thought of as a fixed "reservation charge" tied to the forced outage rates of a customer's generating units, based on PacifiCorp's filed OATT formula rate for network service (Schedule 7), plus a charge to cover the 13% generation planning reserve maintained by PacifiCorp, also adjusted relative to a customer's generating unit's forced outage rate. In effect, the base annual BFC charge would "entitle" a customer to transmission capacity for a set number of forced outage hours per year and compensate RMP for providing generation planning reserve.

3. An annual distribution charge, for customers who take service at distribution-level voltages, based on proper allocation of RMP's distribution system costs and calculation of an appropriate per-kW distribution charge.

4. Additional transmission charges should a forced outage take place, based on the filed OATT Schedules 1, 2, 3, 5, and 6 rates during peak and non-peak hours. In addition,

if the total forced outage hours were greater than the expected hours of required backup given the generator's forced outage rate, the customer would also pay for additional transmission network service (Schedule 7) for each additional hour.

5. A BPC charge equivalent to the market price of power when a forced outage takes place, similar to the pricing established under the NWPP's RSP. Because backup generation is based solely on generation purchased from the wholesale marketplace, including a generation component in the facilities charge, as RMP proposes, would amount to charging customers twice for the same capacity.

Moreover, as I previously discussed, no customers should be *forced* to take backup service. Of course, RMP should not be required to provide service to any customer who foregoes backup service under RMP Rate Schedule 31.

Q. CAN YOU EXPLAIN WHY YOUR PROPOSAL IS ECONOMICALLY EFFICIENT?

A. Yes. First, as I have already discussed in detail in my testimony, RMP's use of the JA methodology to allocate fixed generation and transmission-related costs is not economically efficient. RMP's approach results in inefficient allocation of costs and, therefore, inefficient prices. My approach charges customers who wish to take back-up service in the event of forced outages of their own generating units the true opportunity cost of providing that service. My approach requires customers to purchase transmission capacity through a charge mechanism similar to the reservation charge interstate natural gas pipelines shippers pay to secure firm pipeline capacity.[71] My approach is also fully consistent with cost-causation principles that underlie economic efficiency by basing a

[71] See my testimony in Docket No. 13-035-184 filed on May 1, 2014.

customer's transmission reservation charge on the likelihood that the customer will need backup services during the year.

Second, my proposal uses wholesale market electric prices as the basis for the price of electricity that backup services customers will pay. This is fully consistent with the concept of economic opportunity cost. If a customer suffers a forced outage at his generating plant on a hot summer's day when electricity demand is high, the price that customer is charged for backup power should reflect the corresponding market price. Moreover, my energy pricing proposal is the same as what PacifiCorp itself pays for replacement power from the market under the NWPP's Reserve Sharing Program. Customers requiring backup service should pay that same market price. If RMP can purchase power in the wholesale market to serve a customer needing backup service, there is no economic basis why that customer should be charged a higher price.

Q. CAN YOU EXPLAIN THE CONCEPT OF A TRANSMISSION RESERVATION CHARGE IN MORE DETAIL?

A. Yes. In testimony I submitted in this proceeding on May 1, 2014, I described how FERC sets natural gas pipeline transportation tariffs using a straight fixed-variable pricing approach.[72] Under my proposal, customers who choose to take backup service under Schedule 31 will pay a transmission reservation charge based on: (1) the magnitude of the backup capacity requested (kW), (2) the calculated (or estimated) equivalent forced

---

[72] *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 Regulation*, Docket No. 13-035-084, Direct Testimony of Jonathan A. Lesser, May 1, 2014, p. 8, line 159 – p. 11, line 214.

outage rate(s) of the customer's applicable generating unit(s); and (3) PacifiCorp's filed OATT rates for network service.[73]

Establishing a transmission reservation charge in this manner recognizes that the costs imposed by a customer on the PacifiCorp transmission system should reflect the likelihood of needing to use the service, much as insurance companies base the rates they charge customers for policies on actuarial analysis. In this case, the actuarial basis is the forced outage rates of customer-owned generation. The more likely a customer is to need backup service because of forced outages, the more such a customer should pay to reserve transmission capacity. Thus, a customer's BFC would be calculated as:

$$BFC = [OATT_7 \bullet EFOR \bullet MW] + \left[\frac{GENRES \bullet EFOR \bullet MW}{0.13}\right]$$

where:

$OATT_7$ = PacifiCorp's filed Schedule 7 OATT formula rate ($/MW-year);[74]
GENRES = appropriate charge for the 13% generation operating reserves;
EFOR = the equivalent forced outage rate of the customer's generating resource; and
MW = the amount of customer-owned generating capacity requested for backup.

Q. WHAT IS THE BASIS FOR THE GENERATION OPERATION RESERVES PRICE?

[73] In reality, backup service customers would be taking network service. However, under PacifiCorp's filed OATT, the pricing for network service and point-to-point service under Schedule 8 is identical. See Informational Filing of 2013 Transmission Formula Rate Annual Update, Docket No. ER11-3643-000, May 15, 2013, Attachment H-1, Appendix A. A summary of all of the applicable transmission rates, which were effective as of June 1, 2013, can be found on the PacifiCorp OASIS website: http://www.oasis.oati.com/PPW/PPWdocs/Pricing_for_FAQ_20130601.pdf. These rates are also attached as UIEC Exhibit COS (JAL-1.4).

[74] Note that the PacifiCorp OATT rates for non-firm and firm network transmission service (Schedules 7 and 8, respectively) are identical.

A. The generation operation reserves price component, GENRES, reflects the 13 percent of demand-related generation costs, or $1.19/kW-month under the proposed backup service tariff. Although Ms. Steward's 12-CP, 75-25 allocation on which this demand-related generation cost charge is based is incorrect, the concept of generation reserve is captured in my proposal and I am using her calculated Schedule 9 generation planning reserve value for ease of exposition. However, under my proposal, the payment for generation reserves is a function of the reliability of the customer's generating units.

Q. HOW IS EFOR ESTIMATED?

A. EFOR is based on the observed forced outage rate(s) of the customer's generating unit(s) and the requested amount of backup service. If a customer has one generating plant, then EFOR is just the historic forced outage rate for that plant over a specific time period. For example, if the observed FOR had been 5% for a particular generating plant over the previous year, that would be a reasonable estimate of EFOR. For generators with multiple units, the appropriate EFOR value to use should be based on the largest unit's forced outage rate. This is equivalent to what is called a "N-1" contingency.

Q. WHY WOULD THE EFOR USED FOR A CUSTOMER REQUESTING BACKUP SERVICE TO COVER THE OUTPUT OF MULTIPLE GENERATING NOT REFLECT BOTH UNITS?

A. The reason is that the probability of a forced outage at both units will be less than the probability of an outage of a single unit. In other words, the probability of either a "N-2" event (both units fail independently) or a "N-1-1" event (a second unit fails as the result of the first unit's failure) is less than the probability of the "N-1" event itself. Therefore, the most reasonable EFOR value is that of the largest single generating unit.

Q. DO YOU HAVE A RECOMMENDED TIME PERIOD ON WHICH TO ESTIMATE EQUIVALENT FORCED OUTAGE RATES?

A. I suggest the Commission review how certain Regional Transmission Organizations ("RTOs"), such as the PJM Interconnection, calculate historic FORs that are the basis on which payments for generators participating in the installed capacity markets, such as the PJM Reliability Pricing Model. These calculations are all approved by FERC before taking effect. PJM, for example, evaluates historic FORs based on one to five-year periods.

Q. CAN YOU PROVIDE AN EXAMPLE OF HOW THE BACK-UP FACILITIES CHARGE WOULD BE PRICED?

A. Yes. Suppose we consider a customer who takes service at the transmission voltage level and who has a single, 10 MW generating plant with an observed forced outage rate of 5% per year. The customer wishes to purchase backup service for the entire 10 MW. Under my proposal, and using Ms. Steward's $1.19/kW-month ($1,190/MW-month) generation reservation amount, the customer would pay a monthly BFC of $5,654.27/month, consisting of a transmission facilities charge of $1,077.35/month (= $2,154.69/MW-month *x* 0.05 *x* 10 MW) and a generation facilities charge of $4,576.92/month (= $1.19/kW-month *x* 10,000 kW *x* 0.05 / 0.13), as shown in Table 3.

Q. WHAT WOULD THIS HYPOTHETICAL CUSTOMER PAY UNDER RMP'S PROPOSED BFC?

A. As shown in Exhibit K to RMP's application, the company proposes a BFC of \$4.94/kW-month for customers taking service at transmission voltages. Thus, under RMC's proposal, the hypothetical customer requesting 10 MW of backup in my example would pay a \$49,400 monthly BFC, regardless of the EFOR of the customer's generating units.

Q. WOULD A CUSTOMER TAKING BACKUP SERVICE STILL PAY THIS AMOUNT EVEN IF THERE WERE NO FORCED OUTAGES DURING THE YEAR?

A. Yes. Like insurance, the customer pays the premium even if he does not use the service.

Q. WHAT ADDITIONAL CHARGES WOULD THE CUSTOMER IN YOUR PREVIOUS EXAMPLE PAY IF THERE WERE AN ACTUAL FORCED OUTAGE, FOREXAMPLE, A 24 CONTIGUOUS HOUR OUTAGE?

A. Table 3 sets out the additional transmission related charges that this customer would pay for backup transmission service, plus replacement energy. The example assumes that the wholesale market price of on-peak generation averages \$60/MWh during the outage and the cost of off-peak generation averages \$40/MWh.

Table 3: Outage-Related Transmission Cost (10MW backup, 24 hour outage)

OATT Rate (June 1, 2013)	Service Description	Price		Cost
Backup Facilities Charge (Assumed EFOR = 5%)				
Transmission	OATT, Schedule 7 Firm Network Service	$ 2,154.69	MW-month	$ 1,077.35
Generation	Steward, Schedule 9, 13% Generation Reservation	$ 1.19	kW-month	$ 4,576.92
Total BFC				**$ 5,654.27**
Transmission Usage Charges, 24 contiguous hour outage		**On- Peak ($/MWh)**	**Off-Peak ($/MWh)**	
Schedule 1	Scheduling, System Control and Dispatch Service	$ 0.130	$ 0.060	$ 20.80
Schedule 2	Reactive Supply and Voltage Control from Generation or Other Sources Service	$ 0.132	$ 0.062	$ 21.12
Schedule 3	Regulation and Frequency Response Service	$ 0.697	$ 0.332	$ 111.52
Schedule 5	Operating Reserves - Spinning Reserve Service	$ 0.390	$ -	$ 62.40
Schedule 6	Operating Reserves - Supplemental Reserve Service	$ 0.340	$ -	$ 54.40
Schedule 7	Firm Network Transmission Service	$ 6.220	$ 2.960	
Subtotal, Transmission Charges, 24-hour outage				**$ 270.24**
Subtotal, Energy Charges, 24 hour outage		$ 60.00	$ 40.00	**$ 12,800.00**
TOTAL OUTAGE-RELATED COSTS PAID				**$13,070.24**

As Table 3 shows, the customer would pay an additional $270.24 in transmission-related charges associated with using PacifiCorp's transmission system during the 24-hour outage. The customer would also pay $12,800 for energy purchased from the marketplace.

In effect, with a 5% EFOR, the customer would purchase, in effect, 10 MW of transmission capacity for 438 hours (0.05 *x* 8,760) per year and generation operating reserve prorated by the customer's EFOR. If the customer's generating units had forced outages beyond 438 hours per year, transmission service for those hours would be priced in the same manner, except on a per-MWh basis. For example, as previously shown in UIEC Exhibit COS (JAL-1.5), the current OATT Schedule 7 rate for firm network transmission service during on-peak hours is $6.22/MWh and $2.96/MWh during off-peak hours. Thus, if the customer suffered forced outages totaling 450 hours in a given year, the customer would pay additional Schedule 7 costs for the 12 hours above the expected 438 hours of forced outages, with the actual charges depending on whether the additional 12 hours took place in on-peak or off-peak hours.

Q. WOULD YOUR PROPOSAL ASSESS ADDITIONAL MONTHLY CHARGES ON THE CUSTOMER IF A FORCED OUTAGE LASTED LONGER THAN THE EQUIVALENT MONTHLY OUTAGE HOURS?

A. No. For example, to take the customer whose generating unit has a 5% annual EFOR, the equivalent monthly hours of an outage would equal (438 / 12) = 36.5 hours per month. Under such a monthly allotment scheme, a customer whose generator suffered a forced outage of 48 hours' duration during a given month, but no other outages the entire year, would have an EFOR of just 0.55% for the year, yet be penalized for "excessive" outages. This is unreasonable and inequitable.

Q. SUPPOSE RMP COULD SUPPLY THE CUSTOMER WITH BELOW-MARKET COST GENERATION. COULD THE CUSTOMER PAY THE LOWER COST INSTEAD OF THE WHOLESALE MARKET PRICE?

A. No. My backup service proposal is designed to send economically efficient price signals. Customers who suffer a forced outage should pay the true opportunity cost of generation during the outage. That opportunity cost is the wholesale market price.

Q. WOULD YOU ALSO SUPPORT CHARGING CUSTOMERS A SMALL, COST-BASED ADMINISTRATIVE FEE IF RMP PURCHASED POWER FROM THE MARKET WHEN A FORCED OUTAGE TOOK PLACE?

A. Yes. Of course, RMP would have to demonstrate that the administrative fee it intended to charge was just and reasonable, just like other cost of service components.

Q. ARE YOU AWARE OF ANY REGULATED ELECTRIC UTILITIES IN THE PACIFIC NORTHWEST WHICH TODAY OFFER BACKUP SERVICE TO CUSTOMERS WHO SELF-GENERATE AND PRICE ENERGY BASED ON PREVAILING MARKET PRICES?

A. Yes. Attached as Exhibit UIEC COS__(JAL-1.5) and Exhibit UIEC COS__(JAL-1.6) are the applicable tariffs for two utilities, Portland General Electric ("PGE") and Puget Sound Energy ("PSE"). The applicable PGE tariff is Schedule 75, Partial Requirements Service. As shown on page 4 of the tariff, unscheduled energy provided to customers taking service under this tariff is priced at the Powerdex Mid-C Hourly Firm index. (There are also charges for wheeling, which in this proceeding is covered under the PacifiCorp OATT and losses.) Under PSE Schedule 449, customers who self-generate pay an "Index" price equal to the market prices reported in the Dow-Jones Mid-Columbia Electricity Index.[75]

Q. IF A CUSTOMER INSTALLS HIS OWN GENERATION, HOW IS EFOR DETERMINED WHEN THERE IS NO HISTORICAL BASIS?

A. For a customer with newly-installed generation, EFOR can be calculated based on the type of generating unit installed. Again, this is the approach taken by RTOs with installed capacity markets, such as PJM.

[75] *See* Exhibit UIEC COS__(JAL-1.6), First Revised Tariff Sheet 449-O for the Index price definition.

Q. ARE YOU AWARE OF ANY PUBLICATIONS THAT ADDRESS THE DESIGN OF BACKUP SERVICE PRICING?

A. Yes. In February of this year, the Regulatory Assistance Project ("RAP") published a report for Oak Ridge National Laboratory, on the design of standby rates.[76] The report includes recommendations for rate designs in five states, including RMP's Rate Schedule 31 in Utah.

Q. WHAT WAS THE RAP REPORT'S ASSESSMENT OF SCHEDULE 31?

A. The RAP Report states, "Schedule 31 does not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as self-dispatch, market-priced power purchases for backup power, or special contracts."[77]

Q. DOES THE RAP REPORT INCLUDE ANY RECOMMENDED MODIFICATIONS OF SCHEDULE 31?

A. Yes. The RAP Report contains seven recommendations for the design of Schedule 31. The second recommendation addresses backup power for forced outages of customer generation, stating:

> Customer-generators should have the option to buy backup power from the utility at market prices and thereby avoid the backup charge for standby generation service. Under this approach, the standby customer would purchase backup capacity and energy from the utility only on an as-needed basis. Such purchases would be priced at market prices at the appropriate trading hub. In addition, the customer would pay a share of any transmission

---

76 James Silecki, et al., "Standby Rates for Combined Heat and Power Systems Economic Analysis and Recommendations for Five States," ORNL/TM-2013/583, February 2014 ("RAP Report"). Available at: www.raponline.org. A copy of the RAP Report is attached as Exhibit UIEC COS__(MEB-1.10).

77 *Id*., p. 36.

> and ancillary services costs, as well as a small administrative fee to cover the utility's procurement cost.[78]

This recommendation is fully consistent with the approach I have taken in my testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[78] *Id*. (emphasis added).