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**

DIRECT TESTIMONY OF

JONATHAN A. LESSER

ON BEHALF OF

UTAH INDUSTRIAL ENERGY CONSUMERS

May 1, 2014

CONTINENTAL ECONOMICS

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In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates In Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations	**))))))**	**Docket No. 13-035-084**

Direct 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. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A. I am an economist with substantial experience in market analysis in the energy industry. I have 30 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government entities. I have provided expert testimony before numerous state utility commissions, as well as before the Federal Energy Regulatory Commission ("FERC"), state legislative committees, Congress, and international venues.

Before founding Continental Economics, I was a Partner in the Energy Practice with the consulting firm Bates White, LLC. Prior to that, I was the Director of Regulated Planning for the Vermont Department of Public Service. Previously, I was employed as a Senior Managing Economist at Navigant Consulting. Prior to that, I was the Manager, Economic Analysis, for Green Mountain Power Corporation. I also spent seven years as an Energy Policy Specialist with the Washington State Energy Office, and I worked for Idaho Power Corporation and the Pacific Northwest Utilities Conference Committee (an electric industry trade group), where I specialized in electric load and price forecasting.

I have extensive experience testifying on rate regulatory matters, including before state public utility commissions, the Federal Energy Regulatory Commission, and before international regulators in Latin America and the Caribbean.

I hold MA and PhD degrees in economics from the University of Washington and a BS, with honors, in mathematics and economics from the University of New Mexico. My doctoral fields of specialization were applied microeconomics, econometrics and statistics, and industrial organization and antitrust. I am the coauthor of three textbooks: *Environmental Economics and Policy* (1997), *Fundamentals of Energy Regulation* (2007, 2d. ed. 2013), and *Principles of Utility Corporate Finance* (2011). I have attached a copy of my curriculum vitae as Exhibit UIEC__ (JAL-1).

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the International Association for Energy Economics, the Energy Bar Association, and the Society for Benefit-Cost Analysis. As part of my Energy Bar Association membership, I am currently serving a three-year term as one of three "Deans" responsible for designing energy industry education seminars, including rate regulation, for new attorneys and energy industry professionals.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Utah Industrial Energy Consumers ("UIEC").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE UTAH PUBLIC SERVICE COMMISSION?

A. Yes. I previously submitted testimony in Docket No. 11-035-200 on cost allocation principles, also on behalf of UIEC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses three issues. First, I address one of the identified major drivers of RMP's proposed $76.3 million rate increase in this proceeding, specifically the $42 million revenue shortfall the Company claims are the result of lower energy sales than were forecast in the Company's 2012 general rate case.[1]

As RMP witness Walje discusses in his testimony, RMP's role is transitioning from that of a simple utility to one of an "energy services company," including, in part

[1] Direct Testimony of A. Richard Walje, January 3, 2014 ("Walje Direct"), p. 4, lines 80-83. He testifies that this shortfall is partially offset by revenue requirement reductions. *Id.*, lines 83-85.

providing "an award-winning portfolio of energy efficiency programs to meet our customers' and policymakers' expectations."[2]

Mr. Walje equates RMP's transition to an energy services company with the transition made by the natural gas industry:

> The transition that we are experiencing is somewhat similar to what happened in the natural gas industry beginning almost 30 years ago as large vertically integrated natural gas utilities underwent structural changes driven by Federal Energy Regulatory Commission orders to open access to markets which ultimately resulted gas utilities restructuring with the distribution function narrowly focused on facilitation the distribution of gas to end-use customers.[3]

However, Mr. Walje fails to discuss in his testimony that an integral part of the transition engineered by the Federal Energy Regulatory Commission ("FERC") included significant changes in rate design for natural gas pipelines. Moreover, FERC has made it quite clear that that a pipeline experiencing a reduction in the demand for transportation services and a resulting increase is surplus ("unsubscribed") capacity can simply shift the costs of that unsubscribed capacity to remaining customers.[4] Similarly, there is no guarantee that a vertically integrated electric utility can recover all of its fixed generation costs when market conditions change and the demand for electricity decreases.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY "GUARANTEED" RECOVERY OF FIXED COSTS?

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[2] *Id*., p. 12, lines 264-266.

[3] *Id*., p. 10, lines 212-217.

[4] *See, e.g., Natural Gas Pipeline Company of America*, 73 FERC ¶ 61,050 (1995) ("*NGPL*")

A. Yes. In this context, "guarantee" refers to allowing a pipeline to simply shift unrecovered costs to remaining customers that are unrelated to the costs associated with providing those customers service. In other words, FERC does not grant natural gas pipelines *carte blanche* to shift costs onto customers which are unrelated to providing those customers transportation services.

Q. IS COST SHIFTING ASSOCIATED WITH A REDUCTION IN DEMAND AN ISSUE WITH RMP IN THIS PROCEEDING?

A. Yes. RMP witness Walje states that the company experienced a $42 million reduction in forecast energy sales revenues.[5] That revenue shortfall is exacerbating the company's recovery of fixed generation and transmission costs. Ironically, in this proceeding, the reduction in electricity consumption has been exacerbated by RMP offering subsidized programs to reduce its customer electric usage.

Moreover, the "75-25" methodology, which allocates fixed generation and transmission costs, in part, based on energy consumption, is exacerbating RMP's fixed cost recovery shortfall. As RMP's role transitions towards one of a "facilitator of energy services," this inefficient cost allocation approach exacerbates fixed cost recovery issues. Moreover, fixed cost recovery issues are being exacerbated by the company's own efforts to reduce its customers' electric usage through subsidized energy efficiency programs.

In effect, RMP argues that its retail ratepayers should be required to bear all of the risks of the company's recovery of fixed costs. This is both inequitable and inefficient because it fails to align risk and reward. That leads to what economists term "moral

[5] Walje Direct, p. 11, lines 241-242.

hazard." In effect RMP wants to be insulated from its own investment decisions regardless of market changes. That belies RMP's claimed role as an "energy services provider." As RMP disaggregates the services the company offers, as Mr. Walje suggests, sound economic pricing principals take on even greater importance. However, the "75-25" cost allocation formula leads to inefficient cost allocation and thus to inefficient price signals for RMP retail customers. This inefficiency is also noted in the testimony of RMP witness Steward.[6]

Q. WHAT ARE THE OTHER ISSUES YOU DISCUSS IN YOUR TESTIMONY?

A. Second, I address the economic inefficiency caused by RMP's allocation of transmission costs to retail customers. RMP's allocation of transmission costs is inconsistent with the formula rate cost allocation the company uses to allocate transmission costs under its FERC-approved, open access transmission tariff ("OATT"). RMP customers should all be charged the same OATT rate.

Third, I address the influence of economically inefficient rate designs that are exacerbating the fixed cost recovery issue. Because RMP's fixed generation and transmission costs are not allocated efficiently, it is impossible to align prices with those costs. Thus, along with preventing RMP from transferring all of its market risk to ratepayers, cost allocation and rate design should be revised to promote greater economic efficiency.

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?

[6] Direct Testimony of Joelle R. Steward, January 3, 2014 ("Steward Direct"), p. 14, lines 296-300.

A. Yes. I have four main recommendations:

1. RMP should not be guaranteed recovery of 100% of its fixed costs as it is requesting in this proceeding. Instead, RMP and its shareholders should bear the risk of fixed cost recovery shortfalls stemming from reduced energy sales. RMP should be required to bear the financial risk that its wholesale marketing efforts of surplus power are insufficient to recover all of the company's fixed costs, similar to the fixed cost recovery risks FERC imposes on interstate natural gas pipelines. This is especially true because RMP markets energy efficiency programs that exacerbate its fixed cost recovery problem.

2. RMP should charge all retail customers the same FERC-approved OATT rate for transmission services that wholesale transmission customers pay. All customers, whether wholesale or retail, should pay the same price for the same transmission services. Other costs that RMP includes in its retail transmission rates, such as purchases of transmission services from other companies, should be functionalized as generation-related costs.

3. The existing "75-25" cost allocation formula should be abandoned. RMP's fixed costs should not be allocated based on energy consumption because it is economically inefficient, compounds fixed-cost recovery issues, and leads to inefficient rate design. In turn, inefficient rate design exacerbates fixed cost recovery risks.

4. To compensate RMP for bearing the risks of fixed cost recovery, the Commission should consider a more efficient pricing approach, such as a pricing mechanism equivalent to the "straight fixed variable" ("SFV") pricing approach put in place over 20 years ago by FERC for interstate natural gas pipelines. Doing so will reduce the risk to RMP of under-recovery, while also providing more efficient price signals.

II. PRINCIPLES TO GUIDE RECOVERY OF RMP'S FIXED COST SHORTFALL

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. RMP witness Walje himself testifies that RMP is in a transition period "similar to what happened in the natural gas industry beginning almost thirty years ago."[7] I agree. Therefore, in this section of my testimony, I address economic and risk allocation principles FERC used as it transitioned the natural gas pipeline industry into its current competitive structure. The Commission can rely on these same principles to guide recovery of RMP's fixed costs. Specifically, I discuss the reasons why FERC adopted SFV pricing for interstate natural gas pipelines as part of unbundling pipeline services and why FERC does <u>not</u> guarantee pipelines recovery of their fixed costs, contrary to what RMP is requesting in this proceeding.

Q. WHEN RMP WITNESS WALJE REFERENCES CHANGES THAT TOOK PLACE IN THE NATURAL GAS PIPELINE INDUSTRY, WHAT WAS HE REFERRING TO?

A. Beginning in the mid-1980s, FERC began to restructure the natural gas industry, which had been vertically integrated, issuing a series of orders to develop market competition. For example, in 1985, FERC issued Order No. 436, which implemented voluntary open access on US interstate pipeline systems, allowing competing shippers to use transportation capacity.

In 1992, FERC issued Order No. 636, which unbundled transportation from marketing activities and made pipeline-affiliated companies sell their natural gas before entering into the transmission system.[8] (The reason for this is that, under Order No. 436,

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[7] Walje Direct, p. 10, lines 212-213.

[8] *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, Order No. 636, 57 Fed. Reg. 13,267 (April 16, 1992), FERC Stats. and Regs., Regulations Preambles January 1991 - June 1996 ¶ 30,939 (April 8, 1992), *order on reh'g*, Order No. 636-A., 57 Fed. Reg. 36,128

some pipelines had been giving their marketing affiliates preferential access to transport capacity.) FERC's objective in the natural gas pipeline industry was, and still is, to foster market competition among interstate pipelines and thereby improve economic efficiency.

Q. WHAT OTHER CHANGES DID FERC MAKE AS PART OF THIS RESTRUCTURING OF THE INTERSTATE NATURAL GAS PIPELINE INDUSTRY?

A. First, FERC changed how pipeline transportation services were priced. Specifically, as part of Order No. 636, FERC also implemented SFV pricing, changing the long-standing "modified fixed variable" ("MFV") pricing structure that had been in place for many years. Under MFV, a portion of a pipeline's fixed costs, specifically the return on invested capital and taxes, was allocated to the variable usage component. SFV correctly allocated all of a pipeline's fixed costs to the fixed part of the pipeline's tariff (the reservation charge) and all variable costs to the usage charge. The resulting tariff structure was equivalent to a typical two-part tariff, as shown in Figure 1.

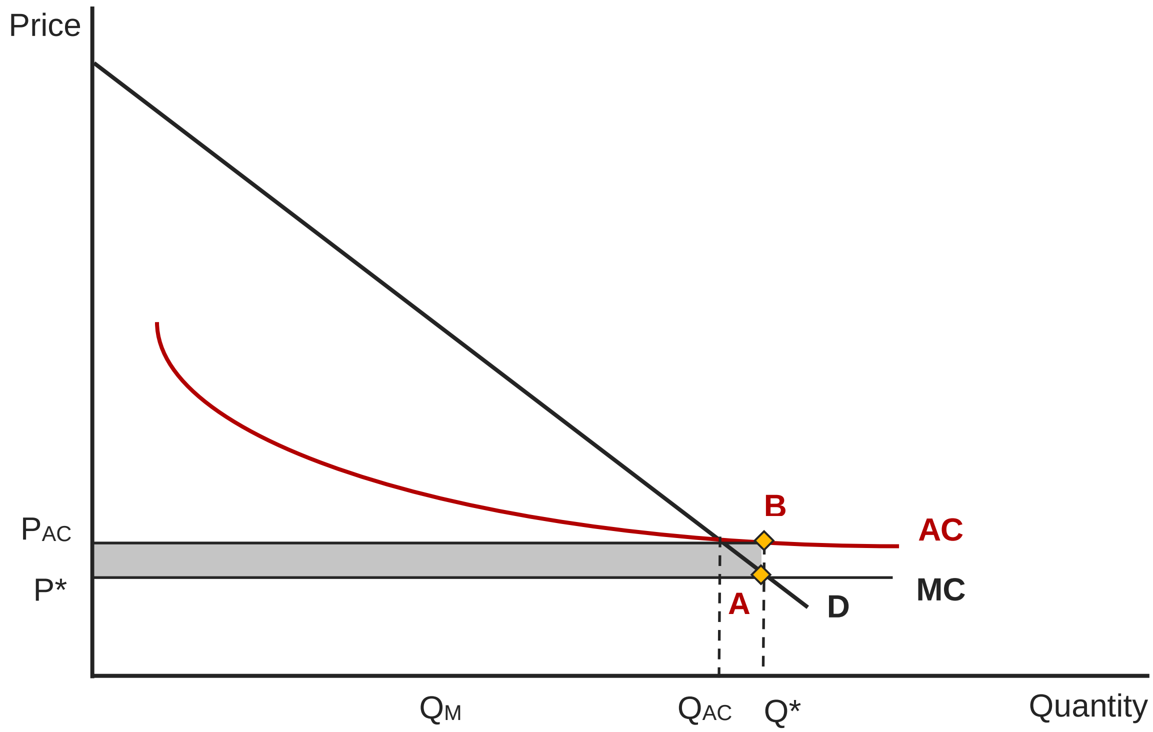
Q. WHY IS THE TWO-PART TARIFF SHOWN IN FIGURE 1 ECONOMICALLY EFFICIENT?

A. The two-part tariff is economically efficient because it correctly charges marginal cost for each increment of transport service used. By recovering fixed costs through a fixed reservation charge, the pipeline recovers its costs while ensuring the highest

(August 12, 1992), FERC Stats. and Regs., Regulations Preambles January 1991 - June 1996 ¶ 30,950 (August 3, 1992), *order on reh'g*, Order No. 636-B, 57 Fed. Reg. 57,911 (Dec. 8, 1992), 61 FERC ¶ 61,272 (1992), *notice of denial of reh'g*, 62 FERC ¶ 61,007 (1993); *aff 'd in part, vacated and 4emanded in part*, *United Dist. Companies v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *order on remand*, Order No. 636-C, 78 FERC ¶ 61,186 (1997).

possible level of economic well-being. This can be seen in Figure 1 on the following page, which illustrates a two-part tariff for a natural gas pipeline.

Figure 1: Two-Part Tariff Pricing for a Pipeline



Basic economics tells us that the efficient market price (i.e., the price at which the value of the market is maximized) is the one that equals marginal cost (**MC**). That is, the efficient price is where the marginal cost of transporting the last dekatherm of natural gas equals a shipper's willingness to pay for that transport.

In Figure 1, the demand for natural gas transportation, D, intersects the marginal cost curve. when transportation sales are **Q*** dekatherms (Point **A**). Charging **P*** = **MC** allows the pipeline to recover all of its variable costs, which consist primarily of compressor fuel and usage-related maintenance expenses. However, charging **P*** does not recover any of the pipeline's fixed costs.

As more natural gas is transported, the pipeline's fixed costs are spread over more sales, which reduces the average cost (**AC**) per dekatherm transported. The fixed costs associated with transport of **Q*** dekatherms equal the shaded area between **P*** and **P**$_{\mathbf{AC}}$

(point **B**) because total costs are just equal to **Q*** times average cost. These are all recovered through the fixed reservation charge. Thus, under SFV pricing, no fixed costs are either allocated or recovered based on consumption.

Q. WHY DID FERC SWITCH TO SFV PRICING FOR PIPELINES?

A. FERC recognized that MFV pricing was economically inefficient. By switching to SFV pricing as part of its pipeline unbundling efforts, it reduced the risks of fixed cost recovery by pipelines and provided better price signals to shippers. Moreover, by reducing the risk of fixed cost recovery, pipelines' allowed returns could be reduced, further benefiting shippers.

Q. AS PART OF ITS GOAL OF INCREASING MARKET COMPETITION IN THE GAS PIPELINE INDUSTRY, DID FERC GUARANTEE PIPELINES RECOVERY OF ALL FIXED COSTS, INCLUDING COSTS ASSOCIATED WITH REDUCTIONS IN DEMAND FOR TRANSPORTATION CAPACITY?

A. No. For example, in its order in *NGPL*, FERC stated:

> [T]he Commission will not permit a pipeline losing customers simply to shift the costs of resulting unsubscribed capacity to the remaining customers without regard to the adverse effects on those customers. Rather, the pipeline must have an incentive to recover the costs of its unsubscribed capacity from new markets. This principle is an important safeguard for the pipeline's existing customers, particularly captive customers, against pipeline overreaching.[9]

Subsequently, in 1999, FERC issued its new pipeline Construction Policy,.[10] and in a subsequent clarification order, stated:

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9 *NGPL,* 73 FERC ¶ 61,050 at p. 61,129 (1995).

10 *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128 (2000), *clarified*, 92 FERC ¶ 61,094 (2000).

> In the Policy Statement, the Commission explained that as the natural gas marketplace has changed, the Commission's traditional factors for establishing the need for a project, such as contracts and precedent agreements, may no longer be a sufficient indicator that a project is in the public convenience and necessity. The Commission, therefore, changed its policy regarding the pricing of construction projects so that market decisions by pipelines and shippers, as opposed to regulatory tests, would better reveal whether there is sufficient support for the project and whether the project is financially viable.[11]

The Commission's desire to rely more heavily on market forces to guide construction decisions also sought "to place the risk of a new project on the pipeline and the customers for the new project and to protect existing customers from bearing the risk of a project that was not designed for their benefit."[12] From an economic perspective, the goal of the Commission's 1999 Construction Policy was to align pipeline risk and reward, as well as the costs and benefits of new pipeline capacity. That approach represents sound economic policy because, by aligning risk and reward, the adverse impacts of *moral hazard* are limited.

Q. WHAT IS MORAL HAZARD?

A. Moral hazard is an economic concept in which risks and rewards are not aligned. For example, if an individual is allowed to purchase automobile insurance after wrecking his car, and the insurance company cannot account for that fact in the rates it charges him, then the individual effectively has transferred all of the financial risk of having an accident to the insurance company. In the case of decisions to develop new pipeline

[11] 90 FERC ¶ 61,128, at p. 61,390; *see also id.*, at p. 61,392.

[12] *See* 90 FERC ¶ 61,128, at p. 61,390; *see also* 88 FERC ¶ 61,227, at p. 61,746.

capacity or expand existing capacity, FERC sought to ensure that the risks of those capacity investments were borne by the developers, and not by captive pipeline shippers.

Q. WHAT DO YOU MEAN BY "CAPTIVE PIPELINE SHIPPERS?"

A. Captive pipeline shippers are those who, if they wish to continue shipping natural gas, do not have any competitive alternatives to their current pipeline.

Q. ARE THERE ANALOGOUS CAPTIVE CUSTOMERS IN THE ELECTRIC INDUSTRY?

A. Yes. In the electric industry, customers of vertically integrated utilities, including those of RMP, are captive; they cannot select alternative retail generation suppliers. Their only alternative to taking service from their local, vertically integrated utility is to install distributed generation or to disconnect from the utility's grid and self-generate all of their own power.

Q. WHY DOES FERC EXPLICITLY <u>NOT</u> GUARANTEE NATURAL GAS PIPELINES RECOVERY OF ALL FIXED COSTS?

A. If a pipeline were guaranteed recovery of 100% of all capacity costs, event costs associated with capacity that is not used, then all of the of risk of overbuilding capacity would be transferred from the pipeline to captive shippers, while the benefit (*i.e.*, larger overall return on capital investment) would continue to accrue to the pipeline. That would create an obvious economic incentive to overbuild capacity. FERC's Construction Policy was designed to prevent this sort of moral hazard.

Q. ARE THERE OTHER WAYS IN WHICH FERC HAS ADDRESSED MARKET COMPETITION BETWEEN INTERSTATE NATURAL GAS PIPELINES?

A. Yes. Another manifestation of pipeline competition is the ability of pipelines to offer *discounted rates*. As the term implies, these are rates a pipeline can offer to customers that are below the full tariffed rates. Discounted rates allow a pipeline to respond to competition from other pipelines (called "pipe-on-pipe" competition) by offering shippers with competitive alternatives more competitive rates. As pipe-on-pipe competition has increased over time, discounted rates have become more prevalent. This has resulted in concerns that pipelines offering discounted rates to competitive shippers can simply recover all of the revenues they forego from captive shippers, by raising the latters' rates. To do so would be tantamount to a regulatory approach of "robbing Peter to pay Paul" that would reduce economic efficiency by creating moral hazard.

Q. ARE YOU AWARE OF ANY RATES CHARGED BY VERTICALLY INTEGRATED ELECTRIC UTILITIES THAT ARE ANALOGOUS TO DISCOUNTED RATES ON A PIPELINE?

A. Yes. The closest analogy is a situation in which a retail electric customer would otherwise bypass the utility entirely, such as by self-generating all of its power. If the utility can offer a lower rate to prevent this sort of bypass, it can recover some of its fixed costs. Thus, a bypass rate not only benefits the customer who would otherwise bypass the utility, it can benefit other customers and utility shareholders by reducing the amount of otherwise unrecovered fixed costs.

Q. HAS FERC ADDRESSED THIS ISSUE FOR NATURAL GAS PIPELINES?

A. Yes. In 2005, FERC issued its *Discount Policy Statement*.[13] In it, FERC stated, "[T]he May 31 Order should not be interpreted as establishing any definitive rule that pipelines will in all instances be permitted a full discount adjustment for discounts given in competition with another pipeline."[14]

Q. DOES FERC PROHIBIT RECOVERY BY PIPELINES OF COSTS ASSOCIATED WITH UNSUBSCRIBED CAPACITY OR DISCOUNTED RATES FROM CAPTIVE SHIPPERS?

A. No. FERC has adopted an approach of balancing investor and ratepayer interests, which is consistent with traditional ratemaking. Under FERC's Construction Policy, pipelines are required to bear 100% of the risk of incremental capacity investments, unless those investments are found to benefit existing captive shippers, such as by providing improved reliability. Under FERC's Discount Policy, the discounts offered to shippers with competitive alternatives must <u>benefit</u> captive shippers. That is, the discounted rates must recover some portion of the pipeline's fixed costs that would otherwise not be recovered and which would otherwise be paid by captive shippers.

Q. HOW WOULD MORAL HAZARD MANIFEST ITSELF IN THE ELECTRIC INDUSTRY?

A. The same situation would occur (and, indeed, has occurred) when a vertically integrated utility is guaranteed recovery of all of its fixed generating capacity costs,

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13 *Policy for Selective Discounting by Natural Gas Pipelines*, 111 FERC ¶ 61,309 (2005) ("Discount Policy Order") *reh'g denied*, 113 FERC ¶ 61,173 (2005).

14 *Id*., 113 FERC ¶ 61,173, P 37.

regardless of changes in demand or changes in the wholesale market that make the utility's own generation uneconomic. As I discuss below, this is the situation with RMP.

Q. BUT DOESN'T A FINDING THAT A GENERATION CAPACITY INVESTMENT IS PRUDENT GUARANTEE A VERTICALLY INTEGRATED UTILITY RECOVERY OF ITS INVESTMENT?

A. No. From an economic perspective, when a utility regulator determines that a generating plant investment is prudent, the utility is provided the <u>opportunity</u> to recover all of its investment costs. Prudence is based on what a reasonable utility would have known at the time it took an action or made an investment.[15] For example, in *Questar Gas*, the Commission stated:

> In conducting a prudence review, we must analyze the decision-making process in light of the circumstances and the facts that the utility knew or reasonably should have known at the time of the decision. We do not substitute our judgment in hindsight for the reasonable decisions made by management, nor do we determine that a reasonable decision is imprudent merely because we conclude that a better, reasonable alternative was available for consideration or action.[16]

[15] For example, Utah Code Ann. § 54-4-4 (4)(a) sets out four standards for making a prudence determination:

(i) ensure just and reasonable rates for the retail ratepayers of the public utility in this state;

(ii) focus on the reasonableness of the expense resulting from the action of the public utility judged as of the time the action was taken;

(iii) determine whether a reasonable utility, knowing what the utility knew or reasonably should have known at the time of the action, would reasonably have incurred all or some portion of the expense, in taking the same or some other prudent action; and

(iv) apply other factors determined by the commission to be relevant, consistent with the standards specified in this section.

[16] *Re Questar Gas Company*, Docket Nos. 04-057-04, 04-057-11, 04-057-13, 04-057-09, and 04-057-01 at 15 (Utah PSC, 2006) (citations omitted).

Prudence determinations are thus designed to avoid hindsight judgments that result in regulatory takings and changes in regulations that could not have been foreseen.

Q. DOES A PRUDENCE DETERMINATION PROTECT A UTILITY AGAINST CHANGES IN MARKETS, INCLUDING CHANGES IN TECHNOLOGIES DRIVEN BY MARKET CONDITIONS?

No. Prudence does not protect against market changes that make investments unrecoverable. That is one reason why regulators set allowed rates of return for regulated utilities that take into account business and financial risks faced by the utility. If utility shareholders were guaranteed full recovery of all investments regardless of changes in market conditions, then such investments would have no business or financial risks and the appropriate rate of return would be a risk-free rate. Moreover, even if regulators *wanted* to protect utilities against these risks, they could not do so.

Q. CAN YOU EXPLAIN?

A. Yes. Suppose, hypothetically, that a new "generator-in-a-box" technology is invented that allows every electric utility customer to generate and store their own electricity at costs far less than the rates charged by their local utility. In light of this technological innovation, the utility is faced with two alternatives: (1) it can attempt to compete with the new technology, by reducing the rates it charges customers; or (2) it can go out of business. Even though the utility's generating plant (and in this example, transmission and distribution plant) may have been prudent and reasonable investments at the time they were made, the utility cannot recover all of its costs. My example illustrates an economic truth: regulators cannot protect regulated firms against changes in markets that reduce the value of their investments.

Q. ARE YOU FAMILIAR WITH ANY CASES IN WHICH SOMETHING SIMILAR ACTUALLY HAS TAKEN PLACE?

A. Yes. For example, in the well-known *Market Street Railway* case, the Supreme Court found that no amount of regulatory intervention could insulate a streetcar company from the effects of market competition.[17] The streetcar company wished to increase its rates to recover its costs. The Court found that any rate increases would result in a more rapid decline in its ridership. Other alternatives, including private automobiles, were available to customers, and no amount of regulatory intervention could change that fact. The Court also stated that, “It was noted in the Hope Natural Gas case that regulation does not assure that the regulated business make a profit.”[18]

Q. ARE THERE EXAMPLES OF MARKET FORCES IN THE ELECTRIC UTILITY INDUSTRY LEADING TO DENIALS OF FIXED COST RECOVERY?

A. Yes. For example, in *Jersey Central Power & Light*,[19] the court of appeals addressed a utility’s attempt to recover the costs of an abandoned nuclear plant. As the court noted, the genesis of the problem included changes in economic, regulatory and market realities.

> The forecasts of both demand and supply proved wrong. Due to conservation, demand did not rise nearly as much as expected, and, with the collapse of the international cartel, the oil market has experienced a world-wide glut and a dramatic decline in prices. Furthermore, the protracted litigation and political controversy which attended the construction of nuclear power projects resulted in extensive delays and dramatic increases in their ultimate cost. Thus, many investments which were prudent, indeed

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17 *Market Street Ry. v. Railroad Comm’n of Cal.*, 324 U.S. 548 (1945).

18 *Id*., 324 U.S. 548, 566, citing *Federal Power Comm’n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

19 *Jersey Central Power & Light v. FERC*, 810 F.2d 1168 (D.C. Cir. 1987).

considered essential, when made, have now by necessity been cancelled.")[20]

The DC Circuit decision was controversial and resulted in three separate opinions. However, there was general agreement that regulated utilities should not be insulated from market forces.[21]

Q. HAVE MARKET FORCES CONTRIBUTED TO RMP'S FORECAST REVENUE SHORTFALL?

A. Yes. As Mr. Walje himself testifies, "Market forces and technological advancements are inducing many electricity customers to look at and implement third party energy efficiency services, non-subsidized energy efficiency investments, and take advantage of self-generation and renewable energy opportunities."[22] He goes on to say, "As our Utah customers increasingly pursue self-generation and energy efficiency, retail sales and revenues will continue to decline."[23]

Mr. Walje is describing changing market conditions that are adversely affecting RMP's ability to recover the fixed costs of its generating resources. Yet, he argues that, despite these changes, which he views as inevitable, "[w]e need to assure that we receive

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[20] *Id.*, p. 1171.

[21] *See id*. (majority opinion) at 1181, fn. 2 ("We have been reminded by the Commission and several of the *amici* that utilities ought not be immunized from the free play of market forces. Their application of this principle is peculiarly selective."); *see id. (*concurring opinion) at 1191 ("As the cases have repeatedly held, the Fifth Amendment does not provide utility investors with a haven from the operation of market forces."); and *see id*. (dissenting opinion) at 1206 ("The [NGA] and its constitutional limits…do not protect the utility from market forces.").

[22] Walje Direct, p. 10, lines 218-221.

[23] *Id*., p. 11, lines 228-229.

the funding that will be necessary to provide the electric infrastructure that enables these opportunities."[24]

Q. DOES MR. WALJE IDENTIFY THAT INFRASTRUCTURE?

A. No. Presumably he is referring to various transmission and distribution system investments discussed by other RMP witnesses. Such infrastructure is quite different than recovering generation cost infrastructure that becomes less necessary as customers pursue self-generation and energy efficiency.

Q. DO RMP'S ENERGY EFFICIENCY PROGRAMS EXACERBATE ITS FIXED COST RECOVERY PROBLEM?

A. Yes. RMP witness Walje himself testifies that RMP's efficiency programs are contributing to its fixed cost recovery problem: "Perhaps illogically we continue to provide an award-winning portfolio of energy efficiency programs to meet our customers' and policymakers' expectations."[25] Mr. Walje testifies that RMP's sales will continue to decline, in part because of the company's energy efficiency programs for its customers. By reducing energy consumption, these programs exacerbate revenue losses, increase the amount of fixed generation and transmission costs not recovered because of the current "75-25" cost allocation methodology.

Mr. Walje's testimony to the "illogical" nature of energy efficiency programs raises a basic question: why does RMP offer subsidized energy efficiency investments that reduce its recovery of fixed generation and transmission costs, only to request

[24] *Id*., p. 11, lines 222-223.

[25] *Id*., p. 12, lines 264-266.

recovery of all of those fixed costs? Not only is this an example of “robbing Peter to pay Paul,” it leads to higher total costs paid by RMP ratepayers.

By reducing electric consumption, RMP’s subsidized energy efficiency programs mean the company has more surplus generation to sell in the wholesale market. If the company cannot sell power at prices that recover all of the fixed costs of its generation (i.e., at prices above P_{AC} shown previously in Figure 1), plus the costs of the efficiency programs themselves, then the programs exacerbate generation and transmission fixed cost recovery issues. (Reductions in recovery of fixed transmission system costs as a result of reduced retail energy sales are not offset by increased wholesale generation sales, unless the additional wholesale generation sales also include wheeling charges at the OATT rate.) The net result is higher overall costs paid by RMP’s retail customers (all fixed costs, plus the costs of the energy efficiency programs themselves).

Q. HOW DOES MR. WALJE PROPOSE TO ENSURE RMP RECEIVES THE NECESSARY FUNDING TO PROVIDE THE ELECTRIC INFRASTRUCTURE NEEDED FOR THE COMPANY’S TRANSITION TO AN ENERGY SERVICES FIRM?

A. Mr. Walje insists that RMP be allowed to recover all of the fixed costs the company did not recover because of lower retail sales and wholesale market prices, including unrecovered fixed costs caused by RMP’s own efficiency programs. This is tantamount to natural gas pipelines requesting recovery of all the fixed costs associated with unsubscribed capacity. If RMP is allowed to recover 100% of all fixed costs, regardless of market conditions, then neither the company nor its parent have an economic incentive to operate more efficiently. This constitutes moral hazard.

On the other hand, Mr. Walje recommends (as does RMP witness Steward) that the design of RMP's rates be changed to reduce the amount of fixed costs recovered through per-kWh charges. This is a sensible proposal. Mr. Walje also discusses changes in existing rate designs to prevent net metering customers, especially residential net metering ones, from being cross-subsidized by customers who do not net meter. If that is true (I have not analyzed the issue), then such changes will improve economic efficiency.

Q. ARE YOU SUGGESTING THAT THE PSC PROHIBIT RMP FROM RECOVERING ALL OF ITS FIXED COSTS?

A. No. A blanket prohibition by the PSC preventing RMP from recovering all of its fixed costs would violate basic regulatory principles by not granting RMP an <u>opportunity</u> to recover those costs. I am testifying that RMP should not be <u>guaranteed</u> full fixed recovery and should bear the risk of under-recovery of those fixed costs. However, I also believe that RMP shareholders should be allowed to benefit from improved operating efficiency. In other words, there should be symmetry between risk and reward. Thus, RMP can recover its fixed generation capacity costs in the wholesale market.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING RECOVERY OF RMP'S FIXED COST REVENUE SHORTFALL?

A. First, if RMP is to become an "energy services provider," as Mr. Walje states, then the company should not be granted automatic recovery of fixed costs it failed to collect because of lower sales. This is especially true because, as Mr. Walje admits, the company continues to provide subsidized energy efficiency measures that exacerbate its revenue shortfall. That is giving with one hand and taking away with the other that leads to higher costs than if RMP did not offer such programs. Moreover, guaranteed recovery induces moral hazard and decreases economic efficiency by eliminating the economic incentive for RMP to operate efficiently.

Second, as I discuss in Section IV, RMP's rate design should be made more efficient. This entails adjusting how costs are allocated and reducing the amount of fixed costs recovered in variable rate charges.

III. RMP RETAIL CUSTOMERS SHOULD PAY THE SAME RATE FOR TRANSMISSION SERVICE AS WHOLESALE CUSTOMERS

Q. WHAT RATED DO WHOLESALE CUSTOMERS WHO TAKE TRANSMISSION SERVICE ON PACIFICORP'S TRANSMISSION SYSTEM PAY?

A. Wholesale transmission customers pay the OATT rates, which are approved by FERC. The OATT is developed using what is called a "formula rate." The formula rate is determined using cost data from specific FERC accounts. For example, PacifiCorp submitted its 2013 Transmission Formula Rate last May.[26] The formula rates for firm and non-firm transmission service are based on a calculation of a gross revenue requirement, less revenue credits associated with transmission service PacifiCorp provides for other companies and are recorded in FERC Account 456. The result is a net revenue requirement. The actual dollar/kW transmission rates are then calculated as the net revenue requirement divided by PacifiCorp's 12-CP monthly transmission peak loads for network service, firm point-to-point service, and other service.[27]

Q. IS THE OATT REVENUE REQUIREMENT THE SAME AS THE REVENUE REQUIREMENT FOR PACIFICORP TO PROVIDE TRANSMISSION SERVICE

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[26] *PacifiCorp Informational Filing of 2013 Transmission Formula Rate Annual Update*, Docket No. ER11-3643-000, May 15, 2013.

[27] *Id*., Attachment H-1, Appendix A.

TO ALL OF THE COMPANY'S RETAIL CUSTOMERS, INCLUDING RETAIL CUSTOMERS OF RMP?

A. No. PacifiCorp also purchases transmission services from other companies, primarily the Bonneville Power Administration ("BPA"), as part of its generation purchases. These costs are recorded under FERC Account 565. In calendar year 2013, for example, these costs totaled $137,182,304.[28] Of that amount, $91,564,716 was paid to BPA.[29] Such purchased transmission services are not part of what it costs PacifiCorp to provide wholesale transmission service on its system, and for which it earns revenues.

Q. DOES RMP CALCULATE TRANSMISSION RATES FOR RETAIL CUSTOMERS USING THE SAME OATT FORMULA?

A. No. RMP functionalizes costs to transmission, including the aforementioned costs recorded under Account 565 for transmission used primarily to purchase power from BPA, and then allocates those costs among the different customer groups. Moreover, RMP's allocation uses the 75-25 formula to allocate fixed transmission costs among the different customer groups, once again allocating fixed costs based on consumption levels.

Q. IS RMP'S FUNCTIONALIZATION OF TRANSMISSION COSTS REASONABLE?

A. No. Costs functionalized as transmission should be limited to those necessary to support the fixed and variable costs of operating PacifiCorp's transmission system itself.

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28 Source: PacifiCorp, 2014 FERC Form-1, page 332.

29 *Id*., p. 332.1.

Those costs are properly incorporated into calculation of the OATT. All retail customers should be charged the OATT for transmission services provided by PacifiCorp.

Q. SHOULD ANY COSTS NOT INCLUDED IN THE OATT BE FUNCTIONALIZED AS TRANSMISSION COSTS BY RMP?

A. No. It makes no economic sense to functionalize one set of costs as transmission-related for the purpose of establishing a FERC-approved wholesale transmission rate, while functionalizing a different set of costs as transmission-related for purposes of allocating transmission costs to retail customers. The transmission service provided to wholesale and retail customers uses the exact same facilities. Thus, the costs should be the same.

Q. HOW SHOULD TRANSMISSION COSTS PAID BY PACIFICORP AND RECORDED IN ACCOUNT 565 (TRANSMISSION BY OTHERS) BE FUNCTIONALIZED?

A. The transmission costs paid by PacifiCorp and recorded in Account 565 should be functionalized as *generation* costs, because they are all associated with PacifiCorp's purchases of generation. In other words, *but for* energy purchases from other entities that also entail payments for wheeling power to the PacifiCorp system,[30] PacifiCorp would not record any costs for transmission by others in FERC Account 565.

Q. ARE THERE ANY SPECIFIC TRANSMISSION COSTS BY OTHERS THAT ARE RECORDED IN ACCOUNT 565 THAT SHOULD NOT BE ALLOCATED TO RMP'S UTAH CUSTOMERS?

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[30] By "wheeling costs," I am also including ancillary transmission services that may be required, such as costs associated with frequency control and voltage support.

A. Yes. RMP retail customer should not be forced to pay for costs associated with reserved, but unused, transmission capacity, because such costs are equivalent to unsubscribed pipeline capacity.

Q. ARE YOU AWARE OF ANY ORDERS IN WHICH UNSUBSCRIBED TRANSMISSION CAPACITY WAS DEEMED UNRECOVERABLE?

A. Yes. One recent example is the Idaho Public Utilities Commission ("IPUC") decision in RMP's 2010 Idaho Rate Case.[31] In its Order, the IPUC found that only 73% of RMO's investment in the Populus to Terminal transmission line (part of PacifiCorp's Gateway Transmission Project), was used and useful. As a consequence, the IPUC denied $216.4 million of RMP's request to place the full $810.5 million cost of the project in ratebase, and ordered RMP to account for the $216.4 million as plant held for future use.

Q. ARE THERE ANY OTHER ISSUES ASSOCIATED WITH ALLOCATION OF TRANSMISSION COSTS BY OTHERS TO RMP UTAH CUSTOMERS?

A. Yes. One other potential issue concerns the disposition of below-market cost federal preference power generated in the Columbia River System, i.e., power generated at federally-owned hydroelectric facilities such as Grand Coulee and Bonneville Dams. Under the Regional Preference Act of 1964[32] and the Pacific Northwest Conservation and

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[31] *In the Matter of the Application of PacifiCorp d/b/a/ Rocky Mountain Power for Approval of Changes to its Electric Service Schedules,* Case No. PAC-E-10-07, Order No. 32196, February 28, 2011.

[32] 16 U.S.C. § 837.

Electric Power Act of 1980 ("Northwest Power Act"),[33] such power is designated only for retail electric customers within the Pacific Northwest.

A portion of this preference power is allocated for purchase by PacifiCorp. However, it is unclear how the benefits of this below-market cost preference power are treated, specifically whether the benefits are fully rolled-in to Utah customers, partially rolled-in, or not rolled-in at all and reserved entirely for PacifiCorp's Oregon and Washington customers.

The uncertainty over the treatment of preference power means that the appropriate allocation of transmission service purchased from BPA is also uncertain. For example, if, in fact, the benefits of preference power accrue solely to Pacific Northwest States, then under application of a "beneficiary pays" approach to cost allocation <u>none</u> of the costs PacifiCorp pays to BPA for wheeling that preference power would be properly allocated to RMP customers. In such a case, for RMP's customers, the transmission capacity associated with wheeling preference power would not be used and useful.

Q. SUPPOSE A RMP TRANSMISSION SERVICE CUSTOMER DIRECTLY PURCHASED ELECTRICITY FROM AN ALTERNATIVE GENERATION PROVIDER. WHAT TRANSMISSION COSTS WOULD THAT CUSTOMER PAY?

A. If the customer purchased power from RMP as a wholesale transaction, that customer would pay PacifiCorp's applicable OATT rate for wheeling services provided

[33] 16 U.S.C. § 839. A brief discussion of the legal history of preference power can be found in Jonathan Lesser, "The Economics of Preference Power," *Research in Law and Economics* 12 (1989), pp. 131-151. More detailed discussions can be found in the references therein. PacifiCorp itself previously argued that the geographic scope of preference power was limited by the Northwest Power Act. *See PacifiCorp v. Bonneville Power Administration*, 856 F.2d 94 (9th Circ., 1988).

by the company. If the customer purchased power from a different supplier for which power was required to be wheeled over another power system, the customer would pay that supplier's applicable OATT rate plus PacifiCorp's OATT rate. Avoiding such transmission rate "pancaking" is one reason for development of Regional Transmission Organizations (RTOs), including the California Independent System Operator.

IV. THE PSC SHOULD ADOPT MORE ECONOMICALLY EFFICIENT RATE DESIGN FOR RMP

Q. WHAT DO YOU MEAN BY AN "ECONOMICALLY EFFICIENT" RATE DESIGN?

A. An economically efficient rate design is one which provides consumers with prices signals that reflect the true opportunity cost of their consumption decisions. For example, charging RMP ratepayers the actual market price of power in every hour would improve those ratepayers' electric consumption decisions, because those decisions would reflect the true opportunity cost of power.

Q. DOES RECOVERING FIXED COSTS THROUGH VARIABLE CHARGES REDUCE ECONOMIC EFFICIENCY?

A. Yes. If fixed costs are recovered on a variable-rate basis then, all other things equal, ratepayers will pay an inefficiently high price for electricity. In other words, consumers will consume too little electricity. Ironically, many regulators and policy makers seem to stress reducing electric consumption over all other goals. This ignores the value of electric consumption itself.

Q. DO YOU SUPPORT RMP'S EFFORTS TO ADJUST ITS RATE DESIGN?

A. Yes. As RMP witness Steward testifies: "For customers, recovery of a significant portion of fixed costs in volumetric energy charges distorts price signals and inequitably places a larger burden of fixed cost recovery on larger users."[34] I agree with her testimony on this point.

Q. DOES THE 75-25 COST ALLOCATION FORMULA INHIBIT EFFICIENT RATE DESIGN?

A. Yes. Not only does that cost allocation formula increase the risk to RMP of fixed cost recovery, but to the extent fixed costs are allocated based on energy consumption, those costs are misallocated. Coupled with a rate design that recovers fixed costs through volumetric energy charges, the result is even greater inefficiency and price distortion.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[34] Steward Direct, p. 15, lines 326-328.