BEFORE THE UTAH PUBLIC SERVICE COMMISSION

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	))))))	DPU EXHIBIT 11.0 PHASE II DOCKET NO. 09-035-23 PHASE II: RATE DESIGN

Pre-filed Direct Rate Design Testimony

Of

William A. Powell, PhD

On Behalf of

Utah Division of Public Utilities

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Artie Powell, PhD
Direct Rate Design Testimony
Division of Public Utilities
Docket No. 09-035-23

Introduction

Q: Please state your name, business address, and employment position for the record.

A: My name is William "Artie" Powell; my business address is Heber Wells Building, 160 East 300 South, Salt Lake City, Utah; I am employed by the Utah Division of Public Utilities ("Division" or "DPU"); my current position is manager of the energy section.

Q: Are you the same Dr. Powell that filed direct and surrebuttal testimony in Phase I of this proceeding?

A: Yes, I am. I filed direct testimony on behalf of the DPU on October 8, 2009 and surrebuttal testimony on November 30, 2009.

Q: What is the purpose of your rate design testimony?

A: The purpose of my testimony in this phase of Rocky Mountain Power's rate case is to introduce the Division's witnesses and provide supporting testimony for the Division's rate design recommendations. The Division is sponsoring two witnesses in this phase of the case, Dr. Abdinasir Abdulle, a Technical Consultant with the Division, and me. In particular, I will explain the Division's policy for proposing a decoupling tariff for all residential customers, Schedules 1, 2, and 3. Dr. Abdulle provides supporting technical information on both the design of the residential decoupling tariff and the Division's rate design proposals for other customer classes.

Q: Can you please summarize your testimony and the Division's rate design proposals?

A: For the Residential classes, the Division is proposing a decoupling mechanism designed to collect the Company's fixed distribution costs. The Division believes that decoupling will allow flexibility in designing rates that promote energy efficiency while mitigating the risk of cost recovery.

With this proposal, and considering the Commission's order on revenue requirement and rate spread, the Division is proposing that the residential customer charge remain at $3.00 for this rate case. The Division is also proposing a 1% percent increase in the first, second and winter block rates, and an 11% increase in the third block rate. If the Commission decides not to adopt the Division’s decoupling proposal, the Division proposes to increase the customer charge to $3.40 and increase the third block rate the amount necessary (8.5%) to collect the classes’ costs.

For other rate classes, Schedules 6, 8, 9, 10, and 23, the Division is proposing increases in the customer charge and increasing both the demand and energy charges by an equal percent. Dr. Abdulle provides further details for each of the Division’s rate design proposals in his direct testimony.

Q: The Division is proposing a decoupling tariff for the Company's residential customers. Could you explain in general decoupling?

A: Yes. In general, decoupling severs or breaks the link between revenues and sales so that the revenue the Company recovers is not dependent on the volume of sales to its customers. By separating revenue from sales, decoupling removes, or at least mitigates, disincentives for the utility to pursue desirable objectives. For example, when a utility successfully promotes Demand Side Management ("DSM") the utility's profitability will decline, everything else being equal. Thus, the utility has a disincentive to promote DSM. If usage per customer is declining, as is the case in the gas industry, the utility has an even stronger disincentive. Of course, the opposite is also true: if the utility can effectively promote sales of its commodity, its profitability will increase, everything else being equal. By breaking the link between sales and revenue, decoupling mitigates the disincentive that the utility has in promoting DSM or incentives to promote sales. It was for these reasons that the Division supported decoupling for Questar's distribution non-gas costs.

Additionally, rate structures designed to collect fixed costs through volumetric rates are potentially at odds with rate structures designed to promote energy efficiency. For example, the Company's current inverted block rates encourage residential customers to conserve. However, since these rates also collect fixed costs, variations in factors outside of the Company's control such as weather, increase the risk of non-recovery of those costs. This is especially true in the third block where variations in usage are largely due to weather variations. Decoupling can help mitigate recovery risk and removes the incentive for the Company to promote sales. This is the primary reason the Division is promoting a decoupling mechanism at this time.

Q: You indicated that the Division's proposed decoupling tariff is similar to Questar Gas Company's ("Questar") Commission approved decoupling tariff. Could you explain what you mean?

A: Yes. Questar's decoupling tariff separates the revenue it collects to cover its distribution non-gas costs from the volume of sales made to customers. In a rate case, such as the one currently before the Commission (Docket No. 09-057-16), the Commission will set an allowed revenue per customer per month based on the projected volumes and costs in the test year. Going forward, that allowed revenue multiplied by the actual number of customers determines the total revenue per month Questar is allowed to collect from its General Service (GS) customers. The difference between the allowed revenue and the actual revenue Questar collects, positive or negative, is then accrued in a deferral account. Upon Commission approval, the balance in the account is amortized over a twelve-month period.

The Division is proposing a similar design for RMP's residential customers. Using the Company's filing, and based on the Commission's revenue requirement order in this case, the Division has determined what it believes is the Company's total distribution costs per customer. Similar to Questar's tariff, this "allowed" revenue per customer is distributed or assigned using a historical average monthly collection to each of the twelve months of the year. Following the design in Questar's tariff, the allowed revenue per customer per month will determine the total revenue the Company is allowed to collect to cover its distribution costs, which will be compared to the actual revenue the Company collects, with the difference being deferred to a specified account. Again, upon Commission approval, the Company will amortize the account balance over a twelve-month period. Dr. Abdulle provides details on the tariff design including examples of its mechanics.

Additionally, as is the case currently with Questar's tariff, the Division proposes limits on the accrual and amortization amounts as safeguards for both residential customers and the Company. The Division proposes limiting the total accrual in any twelve-month period to no more than five percent (5%) of the Company's total distribution fixed costs in that same period. The Division's proposal also limits the amortization, positive or negative, to no more than 2.5% of the Company's distribution fixed costs for the residential classes for that same period. Finally, the Division is proposing that the decoupling tariff be approved under a pilot program to run for three years. During the pilot program, the Division recommends that the Company file monthly reports indicating the month's accrual, the account balance, and the cap limits, both in total and as percentages of the Company's distribution costs.

Q: What is the purpose of having a pilot program?

A: The pilot program serves as further protection for residential ratepayers and the Company by providing a natural forum in which the Commission, Division, Company, or other interested parties may monitor the tariff's performance and make recommendations and changes to the tariff as necessary.

Questar's decoupling tariff was also initiated under a three-year pilot program. In Questar's case, there was a one-year comprehensive review to determine whether the pilot would continue the full three years. The Division recommends that the Commission conduct a similar review for the Company's decoupling pilot. At the end of the first year, the Company would make a filing detailing the accrual and amortization history, a forecast of the second year of the pilot, and its recommendations for continuation of the pilot program. This filing could either be part of a rate case filing or a separate filing if no rate case is warranted.

Q: Do you believe the safeguards, the cap and accrual limits as well as the pilot, are sufficient safeguards for both the Company and its residential ratepayers?

A: Yes. In the case of Questar, these limits and safeguards have worked well. In fact, the accruals in the account and the amortization of the balance have not exceeded the limits. Furthermore, in a recent article in the Electricity Journal, Ms. Pamela Lesh reports that decoupling adjustments, relative to the retail rates at the time of the adjustment, for both gas and electric utilities "have been most often under 2 percent, positive or negative, with the majority under 1 percent."[1] Given our experience with the Questar decoupling pilot, the results of other decoupling programs, and other reasons stated herein, the Division is reasonably confident that a decoupling mechanism for RMP will work well in RMP's circumstance.

Q: You have stated that the comfort level that the Division has developed from implementing the Questar decoupling mechanism at least partly underlies your willingness to pursue decoupling for RMP at this time. Do you expect the proposed decoupling mechanism to work similarly to that of Questar's?

A: Yes. The Division is purposely proposing a decoupling mechanism that is very similar to Questar's decoupling or Conservation Enabling Tariff ("CET"). Given the experience of Questar's CET and the results from other decoupling mechanisms, the Division anticipates that the monthly accruals will be both positive and negative. However, given the fact that usage per customer is increasing for RMP, the Division anticipates that the decoupling tariff will result in more refunds than surcharges. The net effect of the refunds and surcharges will depend on a number of factors that are hard to predict. However, Dr. Abdulle presents several possible scenarios as an indication of what might be expected.

[1] Pamela G. Lesh, "Rate impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review," Electricity Journal, October 2009, Vol. 22, Issue 8, p. 67.

Q: Why has the Division limited the decoupling mechanism to distribution fixed costs?

A: In his direct testimony, the Company's witness Mr. William Griffith proposes to increase the customer charge for Schedule 1 from $3.00 to $5.70. As Mr. Griffith explains, because of the inverted block rate structure, it is important for the customer charge be set to recover a "large proportion of the fixed costs of serving customers."[2] The fixed costs used by the Division in designing the decoupling mechanism largely correspond to the costs used by Mr. Griffith to set the customer charge at the higher level of $5.70. Therefore, the Division's proposed decoupling mechanism achieves similar cost recovery results as if the Company's customer charge were set at "in excess of $23" that Mr. Griffith says is appropriate.

Q: **The Division is proposing to leave the monthly customer charge for residential customers at $3.00 if the Commission orders residential revenue decoupling. However, in prior RMP rate cases, the Division has asked for increasing customer charges. Is the Division changing its position?**

A: No. In general, setting the customer charge at a level consistent with the Commission's approved methodology will help ensure a balance among potentially conflicting rate-making objectives. In recent rate cases, the Division sought to increase the customer charge to recover fixed costs and increase the third block rate to promote conservation and efficiency. While the customer

[2] Direct testimony of William R. Griffith, June 2009, line 104, p. 5.

charge increased from $2 to $3 in Docket No. 08-035-38, the third block rate changed by less than the Division thought necessary to achieve adequate price signals to promote conservation. In this case, the Division's primary objective is to promote a rate design that will send price signals promoting conservation. Therefore, the Division is proposing that if the Commission adopts the decoupling tariff that the third block rate for Schedule 1 be increased relatively more than the first two block rates to encourage conservation. If the Commission rejects the decoupling tariff, the Division has proposed an alternative rate design that increases the customer charge for residential customers. Dr. Abdulle addresses more detail around these alternative rate designs in his direct testimony.

Q: Would you elaborate on your reasons for still seeking to increase the customer charge in future rate cases?

A: Certainly. Even if the Commission adopts decoupling for the residential classes, the Division believes that there are valid reasons for moving the customer charge to a level consistent with the Commission's approved methodology. First, setting the customer charge at a reasonable level will help ensure that the decoupling tariff works as intended or at least will not be the cause of the tariff operating in a contrary manner. For example, large balances in the decoupling deferral account could lead to rate volatility, which is not the intent of the tariff. However, the lower the customer charge the greater the monthly accruals will be and potentially the greater will be the volatility in customer rates and bills. Questar's customer charge is currently $5, which is close to the level using the Commission's approved methodology. As indicated herein, Questar's CET has worked reasonably well: Questar's monthly accruals have been both negative and positive and the total annual accrual and amortization amounts are well within the limits established in the tariff.

Second, the combination of the decoupling tariff and an appropriate customer charge will greatly mitigate the Company's concerns of recovering fixed costs through volumetric rates, especially as the third block rate increases relative to the other rate components.

Third, although the Division is pursuing rate designs that arguably depart from the cost of service in order to promote conservation, the Division believes that cost causation is still a valid rate making principle. As James Bonbright explains, "one standard of reasonable rates can fairly be said to outrank all others in the importance attached to it by experts and by public opinion alike – the standard of cost of service."[3] Setting the customer charge at an appropriate level will help balance these two rate-making principles. Therefore, when possible, the Division still supports moving the customer charge to a level at least consistent

[3] James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, New York, New York, 1961, p. 67.

with the methodology approved by the Commission. For this case, however, raising the tail block is the primary objective the Division focused on.

Q: With the exception of Questar, balancing account true-ups and rate adjustments are done annually in most states that have decoupling mechanisms; Questar's is done semiannually. Can you explain why the Division is proposing semiannual true-ups for RMP?

A: Yes. The Division believes that six months is frequent enough to avoid significant rate changes or rate shock and infrequent enough to ease regulatory burden and consumer confusion over frequent rate changes.

Q: You indicated that the Division supports decoupling for Questar to mitigate the disincentives for it to pursue DSM. What are the Division's reasons for proposing decoupling for RMP in this case?

A: The primary reason for the Division proposing decoupling at this time is to allow for flexibility in designing rates that will promote conservation. For example, increasing the third or tail block rate relative to other rate components increases the difficulty of recovering prudent costs. One reason for this difficulty is variation in weather. As the weather varies, customer's usage will vary: in a hotter than normal summer, usage will likely increase; in a milder than normal summer, usage may decline. If fixed costs are being collected in volumetric rates, then the Company may under or over collect its costs. This will be especially true the greater the third block rate where usage is likely driven by weather patterns. The

Division's proposed decoupling tariff will help balance these two rate design objectives, namely, cost recovery and conservation.

Additionally, decoupling mitigates any disincentives that the Company may have in promoting DSM. Unlike Questar, the Company does not operate in a declining usage industry. Nevertheless, the Company's promotion of DSM may potentially affect its profitability. Decoupling, paired with timely recovery of its prudently incurred DSM costs, will help ensure that the Company continues to support cost effective DSM for its Utah ratepayers.

Q: You mentioned flexibility in designing rates as the Division's primary driver in this proposal. What kind of flexibility to do you mean?

A: The promotion of energy efficiency and conservation has become a major policy goal for the Division and the state. The existing inclining block rates for summer usage in the residential classes reflect that, as inclining block rates send a price signal to consumers to reduce usage during those high-cost months. However, the Division and other parties in recent Rocky Mountain Power cases have proposed further increases to tail block rates to strengthen this signal. The Division is also proposing a higher than average increase in the tail block in this case. The Company has generally opposed tail block increases because such increases would increase its risk of recovering fixed costs. With decoupling, increases to the tail block will no longer have so great an effect on the Company's revenue risk.

Q: Why does increasing the tail block rate increase the Company's risk in the absence of decoupling?

A: The volume of sales that fall into the tail block rate varies primarily with summer season weather. Since the majority of the Company's fixed costs are currently collected through volumetric rates, changes in volume will affect fixed cost recovery. By increasing the tail block rate disproportionately to the other rate blocks, an increasing proportion of the Company's revenue from this class will be weather dependent. Thus, with a high tail block rate, a mild summer will lead to an under-collection of revenues.

Q: Can a very hot summer lead to an over-collection?

A: Yes, it could, and that is a risk that is currently placed upon customers. With a decoupling mechanism in place, an unusually hot summer would likely result in a lowering of volumetric rates the next time the balancing account is amortized. Thus, with decoupling, the weather risk reduction is symmetrically reduced for both the Company and ratepayers.

Q: In a recent *Electricity Journal* article, Mr. Steven Kihm, Research Director for the Energy Center of Wisconsin, argues that decoupling may not work in the presence of the Averch-Johnson effect. Are you familiar with this article?

A: Yes I am. The article you are referring to was published in October 2009.[4]

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[4] Steven Kihm, "When Revenue Decoupling Will Work . . . and When it Will Not," Electricity Journal, October 2009, Vol. 22, Issue 8, pp. 19-28.

Q: Would please explain the Averch-Johnson (AJ) effect?

A: Simply stated, assuming the allowed rate of return is greater than the regulated utility's cost of capital and no regulatory lag, the AJ effect indicates that the regulated utility will invest in too much capital relative to its other inputs, especially labor.[5]

Q: In his article, Mr. Kihm concludes that as long as the AJ effect holds, decoupling is not likely to deter the utility from pursuing supply side resources. Do you agree with Mr. Kihm's conclusion?

A: No. While Mr. Kihm's presentation of the AJ effect is theoretically correct, its extension to decoupling, for several reasons, is unfounded. Primarily, despite Mr. Kihm's claim that the AJ effect is likely to hold for many utilities, little evidence exists to support the presence of the AJ effect. In fact, Dr. Paul L. Joskow concluded, "In my view, students of regulation of legal monopolies wasted at least 15 years extending the Averch-Johnson model of regulatory behavior and trying to test it empirically without much success."[6] While Dr. Joskow did not elaborate on his reasoning, others have reached similar conclusions explaining that many studies purportedly finding evidence of an AJ effect fail to account or test for the

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[5] Harvey A, Averch and LeLand L. Johnson, "Behaviour of the Firm under Regulatory Constraint," American Economic Review, 52, 1962, pp. 1053-1069.

[6] Paul L. Joskow, "Regulation and Deregulation After 25 Years: Lessons Learned for Research in Industrial Organization," p. 31. Accessed from the web February 12, 2010: http://econ-www.mit.edu/files/1173

necessary pre-conditions;[7] or that the studies are too restrictive in scope,[8] exhibit incorrect capital pricing, have problematic definitions of output, or fail to account for the complementary nature of capital and other inputs.[9]

Q: **In the Questar decoupling case, the Commission studied the issue in a separate docket over many months. Why do you feel that it would be appropriate for the Commission to order revenue decoupling within this rate case docket rather than opening a separate case?**

A: First, as previously noted, Questar's CET has worked reasonable well. Both the monthly accruals and the amortizations have been well within the limits designated in the tariff. The average monthly accruals for the 12 months ending October 2007, 2008, and 2009 are $426,117, -$157,393, and -$122,721 respectively. The largest amounts occurred for the 12-month period ending February 2009 with an accrual equal to approximately 30% of the annual 5% cap and an amortization equal to approximately 70% of the 2.5% cap. Second, the conceptual issues of implementing a decoupling tariff were explored by various

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[7] Two primary conditions or assumptions are that the allowed rate of return is greater than the utility's cost of capital and the absence of regulatory lag. Even in the absence of mitigating factors such as incentive-based regulation, these two assumptions alone should give one reason to question whether the AJ effect actually holds.

[8] As originally presented by Drs. Averch and Johnson, the AJ model is a static model. That is, it analysis the utility's incentives at a moment in time. Thus, many of the studies reporting evidence for the presence of the AJ effect have looked only at a single period. Simply stated, these studies ignore the effects of regulatory lag on the incentives or behavior of the regulated utility and, therefore, the conclusions are questionable.

[9] See for example, Stephen M. Law, "Assessing Evidence for the Averch-Johnson-Wellisz Effect for Regulated Utilities." Accessed from the web February 12, 2010: http://www.unb.ca/econ/acea/documents/AJWEffectSLAW.pdf

parties and the Commission in a separate docket, Docket No. 05-057-T01. Third, the Division's proposed tariff is similar to Questar's tariff. Finally, the Division is asking that the tariff be implemented as a pilot program, with a one-year comprehensive review, to allow parties and the Commission to monitor the tariff's performance and recommend any necessary changes.

Q: But gas and electric utilities have different demand and usage profiles. Is the Division concerned that a RMP balancing account for the decoupling accruals could be more volatile than Questar's?

A: No. First, natural gas usage is more volatile than electricity usage across seasons. For example, the average monthly usage for Questar changed from 15.2 decatherms in the winter of 2008-2009 to 4.7 decatherms in the summer of 2009, a decrease of 69 percent. As indicated in the Company's filing the average monthly usage for Rocky Mountain Power changed from 842 kWh in the summer to 746 kWh in the winter, a decrease of 11.4 percent. Second, a review of the performance of decoupling mechanisms around the country reveals that electric decoupling is no more volatile than gas decoupling.[10]

Q: In the Questar CET case, the Division and some others justified decoupling, at least in part, by pointing out that declining per customer usage put that Company's collection of fixed distribution costs at risk. Can a similar argument be made for the Company?

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[10] Pamela G. Lesh, "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review," Electricity Journal, October 2009, Vol. 22, Issue 8, pp. 65-71.

A: No, the Company's residential usage continues to increase. However, unlike Questar, the Company has other fixed cost recovery risk that Questar did not have. For example, unlike Questar, the Company does not have a weather normalization mechanism and has inclining block rates for its residential customers. Attempting to promote conservation by increasing the tail block rate increases the risk of cost recovery to the Company. The Division's decoupling tariff will mitigate this risk.

Q: Because the trend of declining usage of natural gas is a national phenomenon, decoupling of gas utilities is common. How many electric utilities have revenue decoupling?

A: The exact number of electric utilities having decoupling is little difficult to pin down —various sources differ depending on the timing or date of the information. However, in her article, Ms. Lesh indicates that she studied the decoupling mechanisms for 12 electric companies across seventeen states. Ms. Lesh also indicates that as of early 2009, six other states have approved decoupling in concept.[11] Ms. Lesh's article was published October 2009 relying on data available in early 2009. According to information found on FERC's web site, four states have adopted decoupling; nine states will consider or have approved decoupling in individual rate cases; six states have opened proceedings or dockets to explore decoupling or approve utility proposals; two states have laws or orders to study

[11] Pamela Lesh, p. 67.

decoupling; and one state has residential pilot program.[12] FERC's web site indicates this information was updated as of July 8, 2009. According to the Regulatory Assistance Project, at least eight states —California, Oregon, Idaho, Wisconsin, New York, Vermont, Massachusetts, and Maryland— have adopted electric decoupling with decoupling pending in as many as 11 more.[13] The information from the regulatory assistance project is dated August 2009.

From these sources, I think it is safe to conclude that at least 12 electric utilities have decoupling in place; at least eight states have adopted, either through legislation or commission order, decoupling in concept; and decoupling is pending or being studied in as many as 17 other states.

Q: Some parties argue that decoupling will lower the Company's risk and that fact should be reflected in a lower rate of return. What is your opinion on this risk and rate of return issue?

A: In general, I agree with this argument. However, a couple of caveats are in order. First, this concept of risk reduction is a *ceteris paribus* or "everything else remains the same" statement. If another factor or factors that affect risk change, even in the presence of a decoupling mechanism, the Company's risk may actually increase. For example, suppose two utilities are identical in every way except one

[12] Federal Energy Regulatory Commission, http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-eeps.pdf

[13] The Regulatory Assistance Project, http://www.raponline.org/docs/NRDC_Decoupling%20Maps%20US_2009_08.pdf

has decoupling and the other does not. The utility with decoupling then should have a lower risk and thus should have a lower cost of capital. However, if the utility with decoupling has greater weather volatility and, thus, a greater risk of recovering its costs through volumetric charges, then the decoupling may make the overall risk profile of the two utilities similar. Second, even if the risk profile of the Company declines due to decoupling, the effect may be difficult to isolate and quantify from other sources that affect risk. Third, alternative approaches to the issue of reduced risk may offer better solutions than directly lowering the Company's return on equity.[14] For example, a lower equity ratio with the same return on equity could produce a similar reduction in the Company's revenue requirement. (See Table 1 for an example of how a lower equity ratio produces lower rates) This type of an approach could benefit both the Company and its ratepayers while avoiding the more controversial aspects of quantifying the risk reduction.

[14] The following discussion and example are adopted from a presentation by the Regulatory Research Project: Jim Lazar, "Decoupling Impacts on the Cost of Capital," Minnesota Public Utilities Commission, April 15, 2008.

Table 1: How a Lower Equity Ratio Produces Lower Rates

Without Decoupling			
	Ratio	Cost	Weighted
Equity	51.00%	10.60%	5.41%
Debt	49.00%	6.00%	2.94%
		Total	8.35%
Revenue Requirement on $1 Billion Rate Base			
	Return $	83,460,000	
With Decoupling			
Equity	48.50%	10.60%	5.14%
Debt	51.50%	6.00%	3.09%
		Total	8.23%
Revenue Requirement on $1 Billion Rate Base			
	Return $	82,310,000	
	Savings $	1,150,000	

Q: Does this not increase the risk that the Company could, some day, over earn its allowed return?

A: Perhaps. However, there is a symmetrical risk that the Company could under earn if costs increase unexpectedly. Under the decoupling mechanism proposed by the

Division, the Commission will set the allowed revenue that the Company can recover to cover its fixed distribution costs in each rate case. If costs change, up or down, between rate cases, the allowed revenue will reflect that change. This is one reason the Division is proposing the implementation of the decoupling tariff on a pilot basis. Depending on the performance of the tariff over the pilot, parties can explore whether regular rate cases are warranted.

Q: Decoupling as the Division proposes stabilizes that portion of the Company's revenues that will cover fixed distribution costs. Would this not reduce the Company's incentive for prudence in incurring such costs?

A: No. Since the decoupling being proposed by the Division only affects revenues that the Company can collect to cover its fixed costs, the Company is still at risk to control those costs between rate cases.

Q: Many advocates of revenue decoupling have supported it as a means of incenting a utility to undertake demand side management programs. Is this the primary driver of the Division's recommendation?

A: No. As previously explained, the primary reason is to gain flexibility in pursuing rate designs that promote energy conservation. However, to the extent that there is any disincentive for the Company to pursue demand side management programs, the Division believes that it is in the public interest to mitigate or remove that disincentive. Strictly speaking, decoupling removes or mitigates the disincentive but does not provide an incentive for the Company to pursue demand side management.

Q: Does the Division feel that removing such a disincentive should be undertaken because the Company has not been diligent or sufficiently supportive of its DSM programs?

A: No. The Division believes the Company has generally been supportive of demand side management and, in conjunction with the DSM Advisory Group, continues to pursue cost effect programs.

Q: Is there an alternative to the kind of decoupling mechanism that you are proposing that could similar result that you have discussed?

A: Yes. A straight fixed variable rate design accomplishes similar risk reduction to the Company, but makes it more difficult to send price signals through volumetric rates. However, history suggests that reaching an agreement on a straight fixed variable rate design that would collect fixed distribution costs of approximately $23 would be difficult in Utah.

Q: You have at several points discussed how decoupling will remove risks to the Company from increasing tail block rates and weather-related demand volatility. Would it be fair to say that this represents a shifting of risks onto consumers?

A: Not necessarily. This is a typical argument that opponents of decoupling often raise. However, one study of California decoupling mechanisms concludes that, "The record in California indicates that risk shifting accounted for by ERAM

[Electric Rate Adjustment Mechanism] is small or non-existent."[15] Even if such risk shifting exists, the costs of that risk shifting must be weighed against the benefits consumers receive from having a financially healthy utility and, thus, is an empirical question.[16]

Q: Does that conclude your testimony?

A: Yes it does.

[15] Joseph Eto, Steven Stoft, and Timothy Belden, "The Theory and Practice of Decoupling," LBL-34555, UC-350, Energy and Environment Division, Lawerence Berkeley Laboratory, January 1994, p. xvi.

[16] For example, risk aversion models could provide estimates of the cost of the risk shifting to ratepayers. (See, David Newberry and Joseph Stiglitz, The Theory of Commodity Price Stabilization, A Study in the Economics of Risk, Oxford, Clarendon Press, 1981). These costs could be compared to a range of estimates of the benefits associated with increased bond ratings.