Q. Please state your name, employer, and address

A. My name is Frank C. Graves. I am a Principal at the economics consulting firm The Brattle Group, where I am also co-leader of the utility practice group. The firm is located at 44 Brattle Street, Cambridge, MA, 02138.

Q. Have you previously testified in this docket?

A. Yes. I filed Supplemental Direct and Rebuttal Testimony in Phase I of this docket and presented that testimony and answered Commission questions during a hearing in this docket.

Q. What is the purpose of your testimony?

A. I have been asked by Rocky Mountain Power ("Rocky Mountain Power," "RMP," or "the Company") to provide direct testimony in response to an issue raised by the Utah Public Service Commission's ("Commission") March 3, 2011 Corrected Report and Order in this docket ("Commission Order"). Specifically, I have been asked to discuss the merits of including swaps in Rocky Mountain Power's Energy Balancing Account (EBA) and also to discuss the consequences of not allowing swap costs in the EBA. I discuss the important role swaps play in the power industry and use empirical data to document the magnitude of the use of these instruments. Further, I discuss how the price of swaps is determined in competitive markets in a manner that is similar to other power and fuel contracts. As a result, swaps have the same characteristics as other costs allowed in the EBA, i.e. they are volatile, material (financially significant, as normally deployed), and largely uncontrollable. I explain that while swaps may superficially look as if they are fixed and controllable, hence appropriate for base rate cost recovery, this impression is incorrect. The timing and volume of swaps procured (or sold) are partially discretionary by management, but the cost (i.e., the market price) of the swaps and the realized benefits are subject to market movements that are outside of RMP's control. Their value and volatility are derived from the value and volatility of spot fuel and power.

Finally, I discuss the consequences of not allowing swap costs to be recovered in the EBA. Without the use of swaps, hedging may well become impractical or perhaps uneconomical, as other instruments generally are not as useful and also may be more expensive. It is not clear that there is even a well-defined notion of what it would mean to not include swaps in the EBA, such that many paradoxical results and perverse incentives would ensue.

Q. What are your qualifications for the analyses you present?

A. I have been involved in consulting to electric utilities on resource planning and other strategic matters for over 30 years. Portfolio-based resource planning became a particular focus of my support for the industry in the mid-1990s, when federal and state restructuring initiatives put a heightened emphasis on the value and risk of generation assets and wholesale market contracts. Since then, I have been extensively involved in generation planning and in the design of procurement and cost-recovery mechanisms for utilities seeking to cover the costs of serving their residential, commercial and industrial retail customers with managed portfolios or outsourcing strategies. I have testified numerous times on this issue and the related problems of price forecasting, risk management, and service design, including, as mentioned above, appearing in an earlier phase of this proceeding. I am the author of several publications on risk management, and I recently co-authored a white paper on managing gas price volatility.[1] My professional and education qualifications are attached as Appendix A.

Q. How is your testimony organized?

A. In Section II, I provide the background for my testimony and also summarize my findings. Section III introduces swaps and discusses their importance and use in the electric industry for fuel and purchased power risk management. Section IV discusses the volume of swaps used by regulated utilities and how other financial instruments could be used, awkwardly, instead of swaps -- albeit at potentially higher costs and inconvenience. Finally, Section V discusses the likely undesirable consequences of not allowing the inclusion of swaps in the EBA. My testimony should be considered in conjunction with other Company witnesses' testimonies provided by Mr. John A. Apperson and Mr. Gregory N. Duvall.

Summary of the Cost Recovery Rule at Issue

Q. What do you understand the Commission Order to do in regard to restricting the cost recovery of swaps?

A. The Commission Order at p. 81 approved an EBA for the Company but noted that "natural gas and electricity swaps are excluded." While the Commission Order is not specific regarding the treatment of cost incurred for swap transactions, it states that

> … swap transactions should be excluded from the calculation of both base and actual net power cost. We agree swap transactions do not track well with the statutory definition of energy costs. Swap transactions currently approved will remain in base customer rates. We

[1] Frank C. Graves and Steven H. Levine, "Managing Natural Gas Price Volatility: Principles and Practices Across the Industry," *American Clean Skies Foundation*, November 2010.

also conclude these transactions must be reviewed and approved in each general rate case, which is an appropriate proceeding for determining the prudence of Company decisions.[2]

Based on these comments, it appears that the Commission Order excludes variances in costs related to swap transactions from the EBA. The Commission Order indicates that swap costs may be considered as part of a general rate case, presumably to be recovered on a forecasted basis at a fixed cost, to be adjusted only during subsequent rate case without true ups between cases.

The Commission references the Utah Industrial Energy Consumers' ("UIEC") submission and Utah Code § 54-7-13.5(1)(b). The UIEC referenced the same section of the Utah Code to argue that the EBA as proposed was not consistent with the Utah Code.[3] Searching the Utah Code, the term "energy cost" appears only three times and always in connection with either energy efficiency or energy savings.[4] As I found no references to swaps or other hedging instruments in the Utah Code and "energy cost" only appear in a different context, I cannot render an opinion on the interpretation of the cited paragraphs. However, based on my experience as a consultant to numerous utilities in the power industry, I regard the costs of reducing risks to be an integral part of a utility's cost of energy or "incurred actual power costs, including: fuel [and] purchased power."[5] Regulators and customers generally expect utilities to take advantage of mechanisms to reduce their risk, and utilities do so in response to and in

[2] Commission Order p. 72.
[3] See, for example, Post-Hearing Brief of UIEC, Docket No. 09-035-15 pp. 3-4, 10, and 25.
[4] A search of the Utah Code (http://le.utah.gov/dtForms/code.html) reveal three instances in which the term "energy cost" is used. In Title 63A, Chapter 5 (2 instances) and Title 11, Chapter 45 (1 instance), it appears that the term is used in connection with energy efficiency or energy savings.
[5] Utah Code Ann. § 54-7-13.5(1)(b).

proportion to that desire. Moreover, I have observed that swaps are often a dominant part of utilities' processes of controlling energy cost risks.

Q. Has the Commission clarified how this prohibition on swaps in the EBA is to affect other costs that are allowed in the EBA, or other possible hedging instruments?

A. I am not aware of any more specific information or clarifications from the Commission as to how other costs which are allowed in the EBA are to be quantified or treated, absent their connection to swaps. It is also not clear to me whether other kinds of hedging instrument costs, such as the premiums on put and call options, are to be allowed in the EBA, or are implicitly proscribed along with swaps. My testimony explains why this may be problematic.

The Use of Swaps in the Electric Utilities Industry

Q. Please explain the role of swaps in fuel and purchased power hedging.

A. Electric utilities such as Rocky Mountain Power need to serve an uncertain load, and they are exposed to uncertain price fluctuations in the cost of the fuel and spot power that may be required. They engage in hedging to protect (or insure) against some of this volume and price uncertainty. There are many contractual instruments available to engage in hedging, such as futures, options, swaps, weather derivatives, and more. Swaps tend to be the dominant contract used not only by RMP, but also by many other utilities, for their energy risk management. Broadly speaking, companies engage in hedging to protect their customers and their financial resources against unexpected, adverse movements in price or volume. This process cannot eliminate all risks, and the costs of the hedging instruments themselves are subject to risk derived from the same kinds of volatile, uncontrollable price movements that affect the fundamental commodities of fuel and power. Swaps are transactions where parties exchange payments at pre-specified, regular intervals based on the price of a commodity or market index to fix the price they pay for the physical commodity.

For example, suppose Utility A purchases a fixed-for-variable electricity swap from Trading Company B to lock in a fixed price of \$38/MWh for 100,000MWh per month for the months of July, August and September. Following the swap transaction, Utility A continues to pay its supplier the spot market price, but if that price goes to \$40/MWh in July, then Trading Company B pays Utility A \$200,000 (calculated as 100,000 MWh × (\$40 - \$38)). If the price drops to \$36/MWh in August, then Utility A pays its supplier \$36 per MWh, but also pays Trading Company B \$200,000 (100,000 MWh × (\$38 - \$36)).

Thus, swaps involve paying the difference between the reference fixed price and the actual spot price, in order to take the volatility out of the purchased fuel or power for the fixed price participant. They are financial contracts, not physical, but they are tied to the prices of physical commodities. Indeed, this decoupling from physical deliveries from a particular supplier is an advantage of swaps, because it makes them more readily transferred or resold, if the buyer's or seller's needs or risk preferences should change. This is not the case for physical contracts. As a result, swaps have much greater liquidity, lower transactions costs[6] and more intense supply competition than equivalent physical contracts would entail. As Mr. Richard

[6] See John A. Apperson's testimony for a discussion on the liquidity of forward contracts.

McMahon stated in testimony on behalf of APPA and EPSA before members of Congress earlier this year:

> The derivatives market has proven to be an extremely effective tool in insulating our customers from this risk and price volatility. Utilities and energy companies use both exchange traded and cleared and OTC swaps for natural gas and electric power to hedge commercial risk.[7]

Q. Representatives from the UIEC have alleged that swap transactions effectively permit RMP "…to speculate on future natural gas prices with impunity. Just like a person gambling with someone else's money…"[8] Do you agree?

A. No, I disagree. First, speculating and hedging are distinctly different activities, and what RMP does is hedging. Speculating is betting that currently offered market prices (e.g. for future gas or power supply) are mispriced and will change in some predictable direction from which the speculator can take profits. Hedging, on the other hand, involves accepting the market price for forward positions in order to reduce risk and cover an obligation that occurs in the due course of business from normal operations. Second, even if there is disagreement with regard to the magnitude, duration, or timing of RMP's hedging activities, that is a concern that should be addressed in a workshop on policy design (or possibly a hearing on prudence), not in a hearing on cost recovery mechanisms. It is important to be able to

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[7] Statement of Richard McMahon on behalf of the American Public Power Association and the Electric Power Supply Association, Before the Subcommittee on General Farm Commodities and Risk Management Committee on Agriculture U.S. House of Representatives, February 15, 2011, page 1.

[8] UIEC's Opposition to Rocky Mountain Power's Petition for Clarification and Reconsideration or Rehearing, Docket No. 09-035-15, page 15.

recover reasonable swap costs in the EBA, even if the Commission or interveners disagree with the current or recent swap positions of RMP.

It appears that swaps are being criticized in this proceeding largely because some of them have turned out to be out of the money, not because they are intrinsically unsuitable to an ECAM or the EBA. It is inevitable that over time some hedges will end up "out of the money" (and others in the money). However, if a company is genuinely hedging, the goal should be to smooth out and avoid variation in costs. The standard of success is not whether money is made or lost but whether risk ranges were reduced to acceptable levels.

Q. Why are swaps important to an electric utility such as Rocky Mountain Power?

A. Swaps are fundamental to power and fuel market contracting and hedging throughout the entire industry. For most utilities, they are the primary hedging instrument, as they have been for Rocky Mountain Power.[9] I believe the EBA was approved subject to the Utah Commission's expectations that the Company would continue to hedge its fuel and net purchased power expenses[10] (as it has done in the past, as well) in order to keep the variances in its EBA from becoming too large. In order to continue applying what limited restraint Rocky Mountain Power can bring to bear over its otherwise highly volatile, external cost factors, one of the key instruments available to the Company will be swap contracts.

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[9] Historically, Rocky Mountain Power has relied on swaps for 100% of its gas hedges and until the Commission Order well over 50% of the power hedges were also swaps. See John A. Apperson's testimony for additional details.

[10] RMP is more often a seller of power than a buyer, but the term "purchased power" is widely used in the industry to describe either side of such transactions.

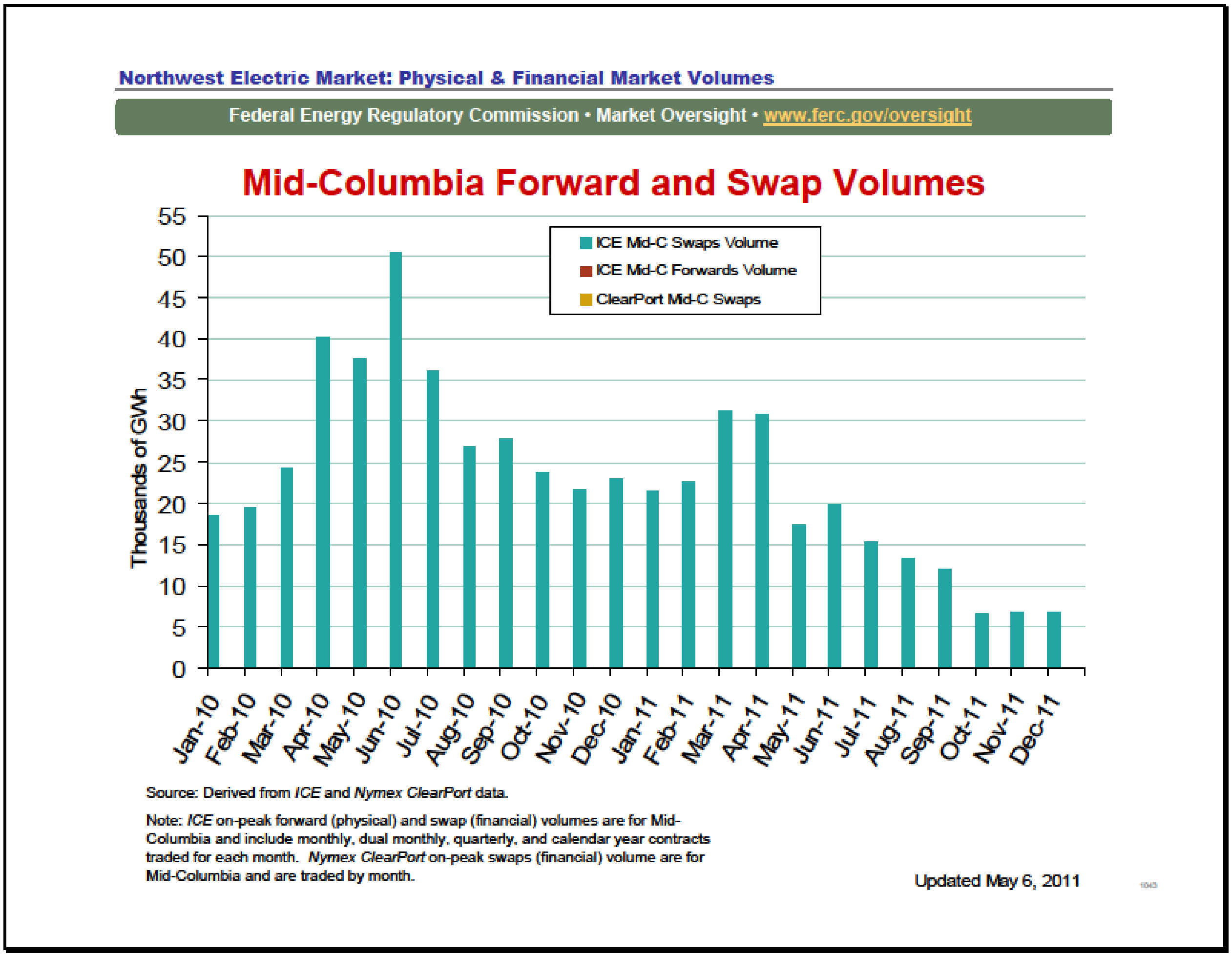
Hedging is of utmost importance to electric utilities because, (i) they face volatile prices and uncertainty in demanded volumes and (ii) unlike many other businesses, have an obligation to serve. Because of the obligation to serve, *a utility cannot withdraw from purchasing power when it becomes very expensive or risky (volatile)*. Therefore, hedging becomes an integral part of managing the risk exposure caused by volatile fuel and power prices. Swaps are flexible and, compared to options or fixed price physicals, are an inexpensive method to insure against price fluctuations. In other words, swaps are often the least cost method that can reduce customers' exposure to price volatility.

Q. Do you have any information about the magnitude of utilities' use of swaps?

A. Yes. Bloomberg provides pricing data on more than 70 different swaps and on six option contracts (in PJM), while the only hedging instrument for which volumetric data is available for the natural gas basis from Henry Hub to Rock Opal is swaps. The magnitude and predominance of swaps relative to physical forwards in these data demonstrate that swaps are critical to trading and hedging in power.

Figure 1 below shows the magnitude of swaps and forward volumes in 2010 – 2011 at one of several important trading hubs, Mid-Columbia which is in PacifiCorp's service territories. Note that the volumes of 5,000 – 50,000 GWH per month are mostly well above PacifiCorp's electricity sales, which average closer to 5,000 GWh per month. Thus, there is clearly substantial trading activity in these instruments -- and this is only one of many active hubs. Also shown (but in fact not visible on this chart due to their negligible volumes) are the physical forward contracts traded on the same months; it is clear that their volume is trivial compared to the volume on swaps.[11] Information about RMP's use of swaps is included in Mr. Apperson's testimony in this proceeding.

Figure 1[12]



Finally, I have advised several utilities on risk management strategies, and in my experience, swaps have been the primary tool relied upon by those utilities to hedge power and fuel risk.

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[11]Data from the FERC report indicate that the same swap dominance prevails at Palo Verde, Southeast California's SP-15, and Cinergy. Source: http://www.ferc.gov/market-oversight/mkt-electric/overview.asp.
[12] FERC – Electric Power Markets: Northwest, May 6, 2011.

Q. If swaps are not allowed in the EBA, wouldn't it be possible for Rocky Mountain Power to rely on other hedging instruments?

A. In principle, this should be possible, though in practice it would likely be difficult and more costly.[13] However, it is not clear why swaps would be disallowed from the EBA while other types of derivatives that are equivalent means of managing financial risk would be acceptable. Put the other way around, it is possible to recreate the effect of swaps with other instruments or contracting terms, so if those alternatives are acceptable, then swaps should be as well.

Q. Please give some examples of swap-equivalent alternatives.

A. Recall that a swap represents the exchange of periodic variable payments for a fixed payment, whereby if the floating fuel or power price exceeds the fixed price, the swap seller pays an amount to the buyer (utility), or the buyer (utility) pays an amount to the seller if the floating fuel or power price is below the fixed price. In practice, fluctuations around the fixed price are often netted over time and only the net difference is exchanged.

In contrast, a call option gives the buyer the right to purchase fuel or power at a fixed price (up to the maturity date), while a put option gives its buyer the right to sell fuel or power at a fixed price (up to the maturity date). Thus, a call option appreciates if prices go up, while a put appreciates if prices go down. Such options could be combined to achieve a fixed cost to the utility which it would otherwise be covering with spot purchases. This combination would involve buying calls and selling puts for the same volume, delivery date, and exercise price as the fixed price

[13] See John A. Apperson's rebuttal testimony in Docket No. 10-035-124 for data on the additional costs of replacing the Company's swaps with options.

that would have prevailed in the disallowed swap (such a combination of options is often called a "costless collar"). Multiple calls and puts would be required, for each delivery date otherwise covered by a swap (e.g, every month for 12 months).[14]

Thus, there is nothing unique about swaps as an instrument to manage price volatility. They can be replicated "synthetically" by using other derivatives. However, swaps are much more heavily traded than options, so they are more available at more locations for farther into the future. This liquidity difference occurs for two reasons: Options are really designed to provide one-sided price protection, not to be used back-to-back as virtual swaps, and there is not nearly as much demand for one-sided protection as for a future fixed price (which appeals to both buyers and sellers). Second, the price of options depends on more variables than the few that determine the price of swaps. Notably, the option price depends on expected future volatility in addition to expected future price levels, and volatility is more difficult to estimate and arbitrage than future price levels. Thus it may be feasible to obtain a three-year swap, but it would be less common to find options for three years out.

Q. Are there limitations on how readily this swap replication can be done?

A. Yes. It can be difficult to obtain a symmetric and costless collar, no less a suite of options over many future periods that are all "at the money" and all displaying the required price-parity relationships between the puts and calls. The difficulties arise because of thinness of trading and shifting perceptions about whether there is more upside potential for price increases than downside potential for price decreases. Thus

[14] See, M. Hampton, "Energy Options," *Managing Energy Price Risk: The New Challenges and Solutions* (V. Kaminski, editor), 3rd Edition, 2004, p. 50.

the two directions of insurance may not be perceived as being equally likely or equally valuable:

> ...the cost of reciprocal options with strike prices equidistant above and below the current price may not be equal. In short, a call option $20 above market is not priced the same as a put option $20 below market. This potential for misinterpretation of skew is by no means academic -- if the marketing pitch for costless collars instead said that one would have to sell $60 of upside to pay for $30 of downside, there might be few eager customers.[15]

I am skeptical that in practice a utility like RMP could use options to hedge price movements as effectively as swaps.[16]

I explain later that physical forwards are also equivalent arrangements to spot gas or power plus swaps, but they are a less liquid or available type of contract.

Q. How are prices for swaps and other hedging instruments determined?

A. The prices of traded hedging instruments change every day on exchanges and bilateral, over the counter markets. Swap and option prices, like spot prices for physical fuel and power, are determined in competitive markets in a manner that Rocky Mountain Power does not control. They are derived (literally, as they are derivatives) from changes in expectations regarding future spot fuel and power prices, i.e., from the line items that have been approved for inclusion in the EBA. These expectations change frequently, hourly or daily, both in the near term and the long term given changes in supply and demand conditions, economic outlook etc. When

[15] Epstein, M. "Costless Collar?" Oil and Gas Investor, May 2009.
[16] See John Apperson's testimony for additional details on the availability of swaps versus other hedging instruments.

such changes occur, the swap prices react immediately, given the multitude of financial players concerned about managing their risk and portfolio value exposure. Swaps are traded at commodities markets such as NYMEX as well as in other settings, and the price of swaps varies with the expected future prices of power.

Q. Why is it relevant to this proceeding that swap prices are determined in competitive markets?

A. For the purpose of determining the costs that customers should be asked to pay for power, it is important that these costs be objective, auditable, and not subject to manipulation. Because swap prices are determined competitively, they represent the market participants' consensus about power costs and cannot be readily manipulated by any one party (absent fraudulent or manipulative behavior). Thus, they behave the same way fuel and purchased power costs do, in regard to suitability for inclusion in an EBA: they are external, objective, not controllable or manipulable by RMP, volatile, and financially material. And as explained above, they are integral to utility fuel and purchased power cost management, so I see no reason not to include them in the EBA.

Q. What about the fact that swaps are financial, while fuel and power are physical?

A. It is true that you cannot burn swaps and produce power. However, it is possible to contract for physical power or fuel at a fixed price, by asking a physical seller for a forward contract under such terms. How would such a seller set the asking price? By checking what the price of swaps were trading for over the same delivery period. Thus, the cost to RMP from contracting at spot with swaps to hedge can be replicated perfectly (in concept, ignoring higher search costs and poorer liquidity for the physical arrangement) by simply buying the physical forward at a price based on the corresponding swap. So if a swap plus spot has a net cost identical to a fixed price physical, customers should not care which kind of supply contracts are allowed in the EBA.

Q. The Commission Order noted that "swap transactions do not track well with the statutory definition of energy costs."[17] How do you respond?

A. As a non-attorney, I cannot render an opinion about the legal definition of "energy costs" in Utah's code, which does not appear to address hedging or swaps.[18] However, my review indicates that the section of the Utah Code that was cited in the Commission Order does not define energy costs or discuss hedging. However, swaps are the most common hedging instrument electric utilities use to manage risk associated with volatile fuel and power prices. Procedurally therefore, swap costs are an integral part of managing energy cost, and in my view as an economist, they are part of the total cost of energy or "incurred actual costs of power, including: fuel [and] purchased power."[19] In addition, and as noted above, swaps can be replicated by combinations of options or by fixed price physicals; i.e., they are economically equivalent. As swaps often are less expensive, disallowing the inclusion of swap costs in the EBA would give Rocky Mountain Power an incentive to use more expensive hedging instruments, or not to hedge, and thus could result in more volatile and circumstantially larger energy costs for customers.

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[17] Commission Order p. 72.
[18] Utah Code, Title 54, Chapter 7, Section 13.
[19] Utah Code Ann. § 54-7-13.5(1)(b).

Regulatory Practice Regarding Hedging

Q. Have you reviewed the fuel adjustment mechanisms of other utilities?

A. Yes. My firm has compiled a database of regulatory decisions on FAC design and process approvals over the past few years from all over the U.S. Fuel Adjustment Clauses (FACs) have been common among electric utilities for decades and FACs were implemented before risk management instruments such as swaps became common. Not too surprisingly, this means there are many FAC decisions and orders that are silent on the issue of whether hedging costs in general or swap costs in particular can be included in the FAC.

Q. Based on your review of FAC decisions and orders, please summarize your understanding of whether hedging costs are recoverable in utilities' FAC.

A. I reviewed decisions on FACs for 132 electric companies in 33 states that have not been restructured for retail access. I found six electric decisions that mentioned hedges or specific hedging instruments (futures, options, swaps). In addition, there is evidence that at least another three states (Florida, North Carolina, and Illinois) allow the inclusion of hedging costs.[20] Of the six decisions discussing hedging, all allowed hedging costs as part of the FAC, and several were explicit about allowing swap transaction costs. Among the states that clearly allow for hedging costs in their FAC are Alabama, Colorado, Missouri, Oregon and Wyoming. Although some of the decisions refer to "hedging costs" rather than specific hedging instruments, Alabama and Colorado specifically mention allowing swap transaction costs, while Oregon

[20] Rocky Mountain Power's Petition for Clarification and Reconsideration, Docket No. 09-035-15, pp. 9-10.

refers to including “hedges, options and other financial instruments.”[21]

The following provides a brief description of the inclusion of hedging costs in the six instances I found evidence of any discussion of hedging costs (other than in the Commission Decision).

Alabama Public Service Commission (Alabama Power):

Alabama Power’s Energy Cost Recovery Rate takes into account “gains, losses and costs associated with [Alabama Power’s] utilization of futures, options and over the counter derivatives (including, without limitation, futures contracts, puts, calls, floors, collars, and swaps) for the purpose of hedging its energy and fuel costs.”[22] Thus, the Alabama Public Service Commission clearly allows for the inclusion of swap costs.

Colorado Public Utilities Commission (Public Service Company of Colorado):

Electric rates take into account the Electric Commodity Adjustments, such as the Price Volatility Mitigation Costs. “Actual PVM shall include only those premiums or settlement costs actually incurred by the Company in connection with its use of the following financial instruments: Fixed-for-float swaps, call options, costless collars, and New York Mercantile Exchange future contracts in conjunction with market basis (between Colorado Interstate Gas Company, Northwest Pipeline Company, Henry Hub, or other monthly indices in the areas where the Company regularly procures its natural gas supplies).”[23]

[21] Portland General Electric Company, P.U.C. Oregon No. E-18, Schedule 125: Annual Power Cost Update, p. 1.
[22] Rate ECR – Energy Cost Recovery Rate, by order of Alabama Public Service Commission dated November 5, 2001 in Docket # U-4373, p. 3.
[23] Colorado Electric, Public Service Company of Colorado: Electric Tariff Index, Advice Letter Number 1554, Decision No. C09 – 1453, C09 – 1446, Sheet 111C Issued December 29, 2010.

Missouri Public Service Commission (Empire District and Union Electric):

In its FAC for Empire District, the Missouri PSC states:

> Costs eligible for Fuel Adjustment Clause (FAC) will be the Company's total book costs as allocated to Missouri for fuel consumed in Company generating units, including the costs associated with the Company's *fuel hedging program*; purchased power energy charges, including applicable transmission fees; Southwest Power Pool variable costs, and emission allowance costs during the Accumulation Period.[24]

The Union Electric Company, Fuel and Purchased Power Adjustment docket discussing the FAC also notes the inclusion of hedging costs and notes that for the purpose of factor fuel costs:

> hedging is defined as realized losses and costs minus realized gains associated with mitigating volatility in the Company's cost of fuel and purchased power, including but not limited to, the Company's use of futures, options and over-the-counter derivatives, including, without limitation, futures contracts, puts, calls, caps, floors, collars, and swaps.[25]

Thus, the Missouri PSC is clear that its FAC includes swap costs.

Oregon Public Utility Commission (Portland General Electric Company):

The Oregon PUC specifies the inclusion of "net cost of fuel, fuel transportation, power contracts, transmission/wheeling, wholesale sales, hedges, options and other

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[24] Missouri Public Service Commission, "The Empire District Electric Company: Fuel Adjustment Clause – Schedule FAC," dated August 8, 2008.

[25] Union Electric Company – Electric Service, document issued pursuant to the Order of the MoPSC in Case No. ER-2010-0026, issued June 8, 2010, effective June 21, 2010, Sheet 98.1.

financial instruments incurred to serve retail load."[26] While the Oregon PUC is not specific about exactly which hedging costs, a common financial instrument in utility hedging programs is a swap.

Wyoming Public Service Commission (Rocky Mountain Power)

Rocky Mountain Power in Wyoming has a FAC that specifies that:

> All retail tariff rate schedules shall be subject to two normally scheduled rate elements, a Base NPC charge and a Deferred NPC Adjustment that together recover total net power costs (NPC) including fuel, purchased power (including NPC financial hedges), wheeling, and sales for resale f natural gas and electricity and excluding other NPC not specifically modeled in the Company's production cost model.[27]

As in Oregon, swaps are not specifically mentioned, but financial hedges are and swaps are the most common financial hedge. Additionally, several utilities make similar comments on the cost recovery of hedging costs. For example, Edison International states in its 2010 10-K that:

> [Southern California Edison Company] recovers its related hedging costs through the ERRA balancing account, and as a result, exposure to commodity price risk is not expected to impact earnings, but may impact cash flows.[28]

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[26] Schedule 125, Annual Power Cost Update, Advice No. 08-23, Issued December 30, 2008, Effective for service on and after January 1, 2009, First Revision of Sheet No. 125-1.
[27] Rocky Mountain Power, First Revision of Sheet No. 94-1, NPC PCAM Tariff, Schedule 94.
[28] Edison International 2010 10-K, page 66.

San Diego Gas and Electric also notes that "[n]atural gas derivative activities are recorded as commodity costs that are offset by regulatory account balances and recovered in rates."[29] Similarly, Questar Gas includes swaps in its balancing account:

> Trying to predict future fair market values is nearly impossible, so Questar Gas contracts for most gas on an index-related basis. When the Company feels it is advantageous to swap the price on index-related gas, the Company will convert the contract with the supplier or use financial instruments.[30]

Q. What other sources have you found that describe fuel adjustment clauses and their recognition of hedge costs?

A. Standard & Poor's (S&P), which monitors the utility industry's financial health closely, has summarized the use of derivatives and recovery mechanisms of a sample of 25 utilities. As shown in Appendix B, this survey finds it is relatively widespread for utilities to recover derivative or hedging costs in a FAC.

Q. UIEC claims that the S&P report states that highly regulated companies use a limited number of derivatives. Do you agree with their interpretation of this report?

A. No. I believe UIEC is referring to the following excerpt from the S&P report:

> As noted by the analysts at Standard & Poor's, "Sample companies that have mostly regulated operations [which includes RMP] have limited derivative use."…This would suggest that RMP is anomalous in its practices, not the standard. Thus, the Standard & Poor's Report is not only inadmissible because

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[29] San Diego Gas & Electric Co 2010 10-K p. 204.
[30] Direct Testimony of Alan J. Walker for Questar Gas Company, Docket Nos. 04-057-04, 04-057-09, 04 057-11, 04-057-13 and 05-057-01.

it is outside the record in this case, it does not stand for the proposition RMP suggests.[31]

However, in my view, UIEC completely mischaracterizes the S&P report, which is more concerned with the accounting for derivatives, rather than utilities' hedging practices.[32] For example, the S&P report references Xcel Energy, Duke Energy, and Wisconsin Energy as having "limited derivative use."[33] However, the UIEC neglects to recognize that "this limited derivative use" is often a result of the accounting practices of those companies and not a sign that they do not use derivatives. For example, Duke Energy's 10-K states affirmatively that the company engages in hedging practices but that most of these hedges simply do not qualify for hedge accounting:

> Duke Energy closely monitors the risks associated with commodity price changes on its future operations and, where appropriate, uses various commodity instruments such as electricity, coal and natural gas forward contracts to mitigate the effect of such fluctuations on operations. Duke Energy's primary use of energy commodity derivatives is to hedge the generation portfolio against exposure to the prices of power and fuel. The majority of derivatives used to manage Duke Energy's commodity price

[31] UIEC's Opposition to Rocky Mountain Power's Petition for Clarification and Reconsideration or Rehearing, Docket No. 09-035-15, page 7.

[32] To this end, I note that FAS 133, paragraph 10 notes a number of exceptions to derivatives accounting including, but not limited to, power purchase or sales agreements whether a forward contract, option contract or both that is a capacity contract and certain contracts that are not traded on an exchange.

[33] S&P, "New Accounting Standards Provide More Insight About the U.S. Electric Utilities' Use of Derivatives." January 28, 2011, page 6.

exposure are either not designated as a hedge or do not qualify for hedge accounting.[34]

Thus, Duke Energy's 10-K confirms that the company uses derivatives to hedge its generation portfolio against volatility in power and fuel prices, for much the same reasons as RMP hedges its fuel and power costs. Wisconsin Energy also use derivatives to manage costs of purchased power and generation.[35]

Q. Are you aware of other evidence that utilities are allowed to include the costs of swaps in the FACs?

A. Yes. Mr Duvall's testimony notes that RMP is allowed to include the cost of swaps in it FACs in Idaho and California as well as in Wyoming. In addition, MidAmerican Energy Company's 10-K indicates that it includes swaps in its FACs in its regulatory jurisdictions.[36]

Q. Based on your review of regulatory decisions, what do you conclude regarding the regulatory precedence for inclusion of swap costs in the FAC?

A. While only a handful of states explicitly describe approving hedge costs in their FAC, I was unable to find any states with decisions excluding swap costs from the FAC. Therefore, the Commission's decision to specifically exclude swap costs from the EBA would be uncommon, if not unique, regulatory treatment of such costs.

[34] Duke Energy 2010 10-K, page 73.
[35] Wisonsin Energy 2010 10-K, page 96.
[36] MidAmerican Energy Company 2010 10-K, page 48.

Consequences of Not Allowing the Recovery of Swap Costs

Q. In your introduction, you stated that hedging without swaps may be impractical or uneconomical. Please explain why this might be the case.

A. As discussed above, swaps are the most common financial instrument used to hedge fuel and power price volatility by electric utilities. In addition, swaps are flexible and, relative to other financial instruments, provide relatively inexpensive protection against fuel and power price volatility. (In particular, unlike options, no money is exchanged upfront for swaps. Costs are only incurred as realized spot prices differ from the fixed price.) Therefore, if the Commission were to exclude the recovery of swap costs from the EBA, Rocky Mountain Power would face a choice between (i) reducing its hedging program and exposing customers to more price volatility or (ii) engaging in different types of hedging. Because swaps are the most common instrument used to hedge price volatility risks, alternative hedging instruments are not as readily available and may be more expensive. Therefore, it is plausible that Rocky Mountain Power's hedging program will become ineffective or more expensive if the use of swaps are eliminated or reduced.

Q. What about RMP continuing to use swaps, but just recovering them in base rates? Why would that not work?

A. There are several unresolved implementation questions and resulting problems with this approach. First, what would be the accounting for the fuel and purchased power costs that are recovered in the EBA? If RMP had a swap on them, would the EBA record the spot price, thereby putting all the volatility in the customer's fuel bill that the swap hedges would otherwise have dampened? And when would such cost adjustments be recognized? Continuously over the life of the swap, or at annual intervals (for the net difference), on deliveries, or at the expiration of the last swap period on each contract?

Second, it may appear that swap costs are “fixed” hence good candidates for forecasting and inclusion in base rates, but this is only true of each swap, one at a time, at the time when it is purchased. This is not a correct description of the total number of swaps that may be needed or purchased over a base ratemaking period, such as a year or two. RMP does not buy all of its swaps at the same time, but rather buys them in installments at periodic intervals, so that they are “laddered”. This reduces exposure to forward price conditions that prevail at one point in time but may (will) change. The prices of swaps to be acquired in the future would not be known at the time of a base rate case. Even the total volume of needed swaps is uncertain and evolving, as it depends on such factors as how much hydro runoff is available, whether gas prices are low enough to make running PacifiCorp’s gas-fired plants more economical than purchasing forward power, and so on. Those factors shift over time and cannot be well predicted in advance, for occasional base rate adjustments. Thus putting these costs in base rates virtually un-does the reasons that an EBA was deemed useful and was authorized in the first place: Disallowing swaps is likely to increase customer energy price risk, while also increasing investors’ cash flow and energy cost recovery risk.

Q. Do you believe that denying swaps in the EBA could force RMP to adopt procurement practices that are not in customer interests?

A. Not necessarily, but it could. RMP has two objectives to consider in its fuel and power procurement: 1) obtaining energy at reasonable cost and risk for customers and 2) protecting its financial health to honor its fiduciary responsibilities. These two goals are harmonious over the long-run (because a utility has to be financially healthy in order to serve customers well) but they can diverge in the short-run if risk allocations are unreasonable. Conceivably, this could happen if RMP has no ability to recover swaps or equivalent hedges in its EBA. This could lead RMP to use less effective or less broadly available hedges at greater cost to customers, or simply to hedge less.

Q. If the Utah Commission were to deny swaps in the EBA, could PacifiCorp continue to use swaps generally but simply not allocate their share of portfolio costs to Utah customers?

A. This would be very difficult to do, absent the very strong and undesirable step of separating all of RMP's needs and supply procurement from PacifiCorp's system portfolio. The problem is that power and fuel transactions are hedged in order to achieve acceptable costs and risk levels for the entire PacifiCorp system, taking advantage of diversification benefits from non-coincident demands around the large service territory and economies of scale and scope in procurement. Hedges generally are not targeted for particular subsystem needs (such as just RMP's customers in a particular time period), so the gains and losses from hedging are hard to allocate, other than by share-of-system metrics. If PacifiCorp continued to procure with swaps for the system as a whole, it would achieve overall risk performance that Utah was not willing to support, but which would be difficult to untangle. To be objective about cost allocations under differing hedging tastes, it would probably be necessary to unbundle RMP's Utah operation and procure for it separately.

Q. Please summarize your concerns about disallowing swaps from the EBA.

A. I suspect this is a policy position adopted due to a lack of appreciation for the critical role that swaps play in managing EBA cost risk, and perhaps due to a misunderstanding of how impractical it would be to try to collect swap costs over a base ratemaking period. Some discomfort over past swap positions or outcomes may also be coloring views. However, it is illogical to exclude swaps while allowing other hedging and physical contracting arrangements with very similar effects. More importantly, if swap costs are disallowed, undesirable incentives may arise to forego hedging, or to pursue it with less cost-effective instruments.

Q. Does this conclude your direct testimony on rehearing?

A. Yes.