Q. Please state your name and position.

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.

Q. Please summarize your qualifications and experience briefly.

A. I specialize in regulatory and financial economics, especially for electric and gas utilities. I have assisted utilities in forecasting, valuation, and risk analysis of many kinds of long range planning and service design decisions, such as generation and network capacity expansion, supply procurement and cost recovery mechanisms, network flow modeling, renewable asset selection and contracting, and hedging strategies. I have testified before the FERC and many state regulatory commissions, as well as in state and federal courts, on such matters as integrated resource planning ("IRPs"), the prudence of prior investment and contracting decisions, costs and benefits of new services, policy options for industry restructuring, adequacy of market competition, and competitive implications of proposed mergers and acquisitions. I received an M.S. with a concentration in finance from the M.I.T. Sloan School of Management in 1980, and a B.A. in Mathematics from Indiana University in 1975. A detailed C.V. is attached as Appendix A.

Q. Have you previously testified for Rocky Mountain Power in regard to risk management or service pricing?

A. Yes, I was a witness for Rocky Mountain Power ("RMP") in 2009 in regard to its request for an ECAM mechanism in Utah to recover the costs of fuel and purchased power.

Q. What is the purpose of your testimony?

A. I have been asked to respond to criticisms in the following testimonies regarding views that RMP has misdesigned, or failed to update and modify, its hedging practices over the past few years: Messrs. Douglas D. Wheelwright and Mark W. Crisp on behalf of the Utah Division of Public Utilities ("DPU"); Dr. Lori Smith Schell and Mr. Paul Wielgus on behalf of the Office of Consumer Services ("OCS"); and Dr. J. Robert Malko and Mr. Mark Widmer on behalf of Utah Industrial Energy Consumers ("UIEC"). As a general rule, the DPU witnesses are concerned that RMP's risk management policy and hedge program provide for varying degrees of hedging of the price risk associated with its expected fuel and wholesale purchased power requirements and wholesale power sales up to four years forward, and that it does so primarily with forward contracts and swaps rather than options or collars. It is alleged that this mix of horizons and hedging instruments is inappropriate. Similar concerns are raised in the testimony of Dr. Schell and Dr. Malko.[1] More specifically, the concern is that this practice has exposed RMP customers to some out of the market hedges entered several years ago that are now expensive compared to spot or other short term supplies, and that this strategy leaves little or no opportunity for customers to enjoy cost reductions if short term natural gas prices should fall or if short tem electricity prices should generally rise. This approach is also criticized as being inconsistent with other utilities' common practices (especially hedging by natural gas distribution

[1] Mr. Wheelwright's Testimony, Dr. Malko's Testimony and Dr. Schell's Testimony all discuss both (i) the length of the hedges (magnitude of hedging) and (ii) the method used to hedge. The accuracy of Mr. Wheelwright's description of the Company's hedging program is addressed in the rebuttal testimony of Mr. Bird.

companies). Some also allege that RMP should have foreseen the reduction in natural gas and electric prices that ensued from the recent rapid development of shale gas resources, implying they were imprudent to have entered long-dated natural gas hedge commitments in the past.

Q. What are your general conclusions?

A. The accuracy of the intervener witnesses' description of RMP's hedging practices is discussed in Mr. Stefan A. Bird's and Mr. John A. Apperson's rebuttal testimony. Leaving this issue aside, it is true that in the very recent time frame, RMP's hedging strategy to hedge as far forward as 48 months has resulted in out of the money forward hedges for natural gas. However, I disagree that this indicates the company has been imprudent, or that its customers have even been harmed by this approach.

- The purpose of hedging is not to find the lowest after-the-fact approach to procurement. To the contrary, hedging is designed only to limit the *a priori* range of potential future costs. It is inevitable that non-speculative hedges will sometimes (about half the time) end up out of the money. Recent market conditions have turned dramatically downward, in the economy as a whole and in natural gas and electricity prices in particular, so it is not surprising with *ex pos*t hindsight that older, longer hedges are now above replacement costs.
- It is not appropriate to compare electric company hedging to natural gas companies. Even the comparisons that have been made are in some ways inaccurate in describing natural gas company practices. When storage is

recognized as a physical hedge, natural gas companies tend to hedge almost 100% of their requirements. Moreover, the volatility, price-load correlations and the skewness of electric prices are greater than natural gas, and these can justify being hedged for more than 100 percent of expected volumes.

- There is no intrinsically "best" horizon for hedging, nor any "best" mix of hedging instruments to use. Long term forward contracts or financial hedges will dampen exposure to correspondingly long shifts in energy costs, but that benefit comes with the inevitable possibility of hedges ending up out of the money (more expensive than having been unhedged). It is perfectly reasonable to re-evaluate desired tradeoffs between *ex ante* risk reduction and *ex post* regret exposure (i.e., potential disappointment over outcomes), but this is not a prudence issue. Call options could help reduce regret for the tradeoff of increased risk, but could also increase regret if the option expires unexercised, thus their prudence assessment and cost recovery rules must be thoughtfully articulated in advance.
- The shale gas revolution is an exciting and important one for US natural gas and power markets, but it is not fair to say to that this was a foreseen and foreseeable event that RMP should have anticipated by shortening its hedges. To the contrary, there was a great deal of skepticism about the promise of shale gas, and it has been developed rapidly for reasons that have little to do with its intrinsic value as a natural gas supply resource. Moreover, it would have been speculative for RMP to assume that the

forward prices of natural gas and power did not already reflect the consensus understanding of shale gas impacts.

- It is not appropriate to use recent *ex post* outcomes to test whether hedging has been prudent or not. The high volatility and (likely) instability of market conditions (and hedging requirements) make such hindsight snapshots uninformative and misleading about the merits of a hedging policy. *Even if a hedging policy has performed very well (saved money) from this hindsight perspective, that does not prove the company has a good risk management policy.* Instead, the Utah PSC, its utilities, and key customer representatives should agree on an *ex ante* approach that reflects agreed goals for risk reductions, and on transparent reporting for monitoring a procurement approach that is expected to achieve those risk management goals. For example, on a going-forward basis it would be appropriate to agree on the risk limits and risk tolerance bands expressed in RMP's risk management policy and hedging program, as well as the metrics and frequency of desired reporting.[2]

Q. How is your report organized?

A. The balance of my report addresses the question of whether too much was hedged, for too long forward, and whether options would have been more appropriate. I also explain what was known about shale gas over the past few

[2] I note that RMP in the past has presented its hedging policies to the Commission. See, for example, PacifiCorp Energy, "Commodity Price Risk Management Presentation," Utah Public Service Commission: Technical Conference May 18, 2009. On May 25, 2010, PacifiCorp provided a confidential update on its hedge program to the Commission (Confidential Hedge Program Update Presentation, Technical Conference May 25, 2010).

years, and I outline an approach to prudence review that should help RMP and its stakeholders have greater confidence in what is being done to manage risks.

Hedging 100 percent of Expected Needs

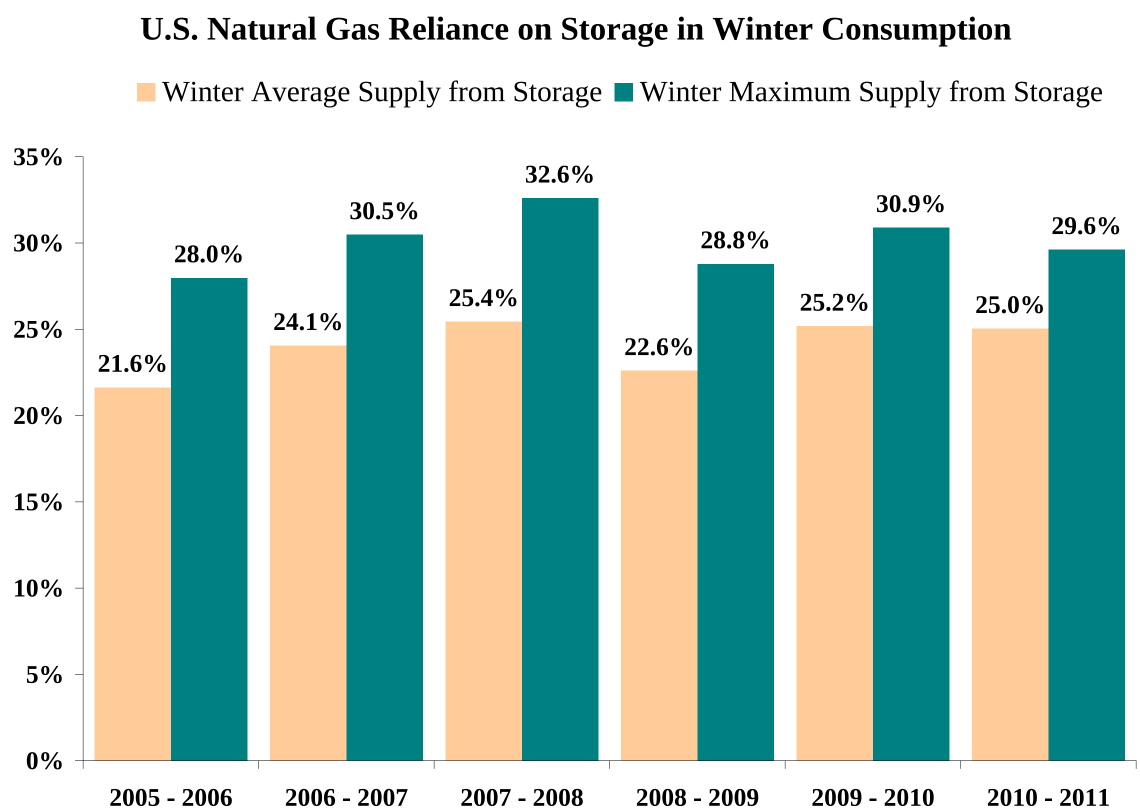
Q. Some intervenors[3] have alleged that natural gas distribution companies hedge only about 50-75 percent of their requirements, much less than the [redacted] hedged by RMP in the one to 12 month period, and that this indicates RMP is being too aggressive. How do you respond?

A. I have worked on hedging with a few gas companies, interviewed others, and I am aware of the trade literature on practices in this sector. My perception of natural gas industry practices is consistent with what intervenors have asserted: a typical gas distribution company will hedge most or all of its "baseload" gas needs for the coming winter or two by buying futures or forwards for gas (and perhaps its transportation costs, i.e. basis risk). This baseload is typically up to the distribution company's minimum load (such as the quantity that might be required in a warm winter), but not the LDC's expected total or maximum. In that sense, LDCs seem to be partially hedged. However, they usually are actually hedged more than it would appear, because nearly all have substantial amounts of physical storage, which effectively hedges winter gas at summer costs plus storage carrying fees. This is often enough to serve their entire peak load, above the amounts already hedged with forward contracts and swaps. Figure FCG - 1 below summarizes this degree of reliance on storage for the US gas industry as a whole. It depicts gross storage withdrawals per month as a percentage of overall

[3] See, for example, J. Robert Malko, "Prefiled Direct Testimony on Revenue Requirement," May 31, 2011 ("Malko Testimony"), pp. 24-26.

delivered gas in winter months for the past five years. On average in winter months (defined as December through March, due to only calendar month data being available), storage is used to serve from 20-25 percent of the total demand, with around 30 percent being supplied from storage in the peak (coldest) month (typically January, but not always). These percentages probably understate the extent to which local gas distribution companies (LDCs) rely on storage, because the denominator is for all gas consumption in the US, not just consumption by distribution companies. About 1/3 of gas demand is from electric utilities,[4] who often do not have much access to storage (or even firm gas, in the case of many electric generators) compared to LDCs. When this 20-30 percent from storage is combined with the tendency to cover most or all of their winter baseload needs with forward gas contracts, most LDCs will be close to 100 percent hedged.

[4] Energy Information Agency, "2010 Annual Energy Outlook: Energy Consumption by Sector and Source, United States, Reference Case."



Sources:
The Brattle Group.
US Energy Information Administration.

Figure FCG - 1

Q. Are natural gas distribution companies good proxies for electric companies, in regard to hedging needs or common practices?

A. They both face some of the same regulatory challenges in getting approvals for hedging strategies, but their physical and financial problems are different. Notably, gas companies are only concerned with the gas commodity (and its transportation); they do not have to worry about the value of that gas once converted to electricity, or how purchased power might substitute for (or increase) gas usage. That is, electric companies like RMP are more concerned about the "spark spread" between gas and electricity than the price of gas itself (for which they may be sellers, as well as buyers). Spark spread is the spot price of electricity, less the spot price of gas multiplied by the heat rate of a gas-fired generation plant, giving the net value per MWh of burning the gas to produce power. Both the electric and gas price components are uncertain and volatile, though partially correlated, so the spark spread can be positive or negative, and it varies by power plant as well as location of the transaction.

The volume of gas that electric companies need also tends to be more of a peaking or top-of-load requirement that can be quite variable throughout the year, depending on the cost of other fuels. Finally, electric companies also hedge much more than just their fuel costs, because they must buy and sell spot significant quantities of power to balance their system supply against load. (RMP in particular tends to sell more electric energy than it buys.) Thus, the hedging requirements of electric companies are generally more complex than for gas distribution companies.

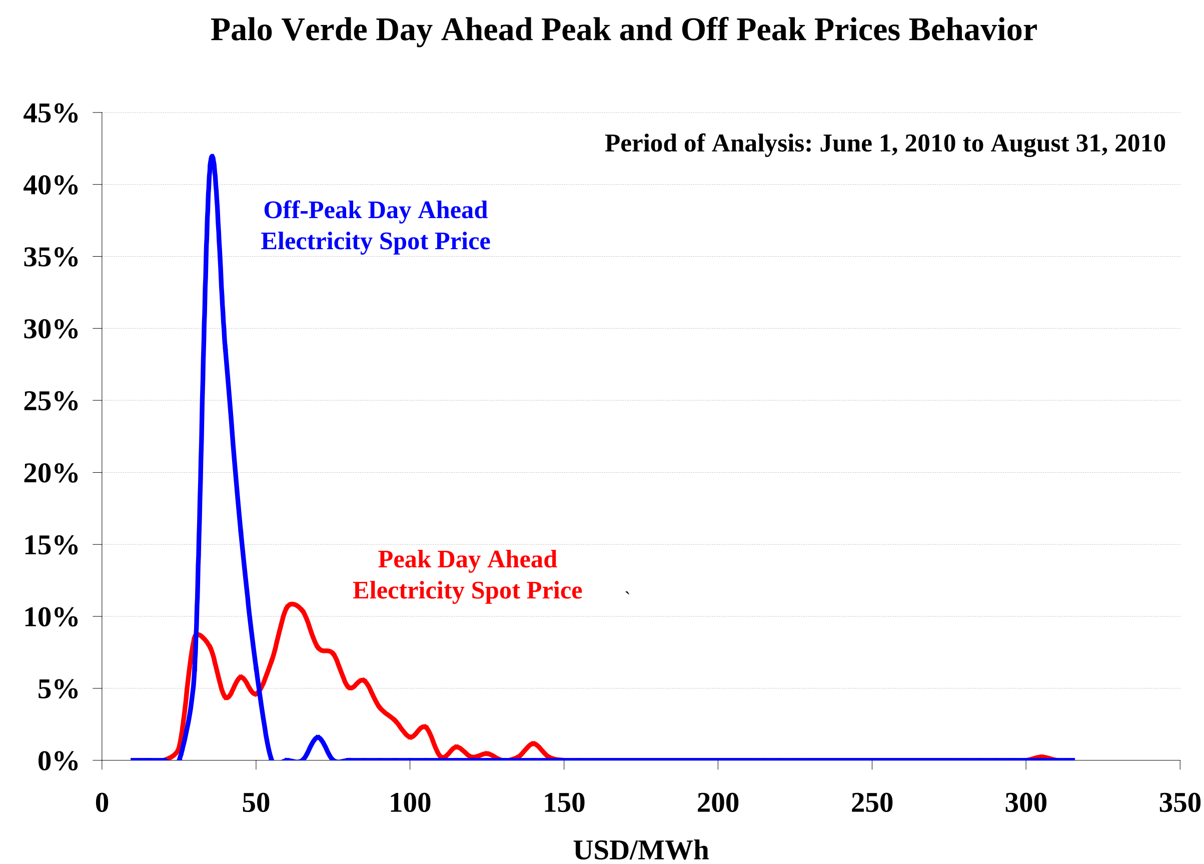
Q. Do these differences affect the extent to which electric companies may want to hedge their expected fuel and purchased power requirements, in terms of quantities or how far in advance to hedge?

A. Yes, some of the risk characteristics of electric markets can justify hedging all or even more than all of the expected volume of fuel or purchased power, which gas companies are less likely to do.

Q. To what electric market risk characteristics are you referring?

A. Electricity prices tend to be skewed, and they also tend to have a fairly high positive correlation between prices and loads, especially during peak periods.

This is not unique to electricity, but the extreme volatility of spot electric prices may make it of greater concern. By skewness, I am referring to the asymmetry of price distributions, whereby spot prices are mostly centered around “ordinary” levels but there is a possibility of occasional, very high prices. The distribution of observed spot prices tends to have a long, positive “tail” because on-peak prices can spike to several times ordinary levels. Moreover, such extreme prices are more likely when demand is also unexpectedly high; demand and price uncertainty tend to be positively correlated. As illustrated in Figure FCG - 2, the difference between standard off peak day ahead power prices and the range of potential peak day-ahead power prices can be huge. In the example shown for Palo Verde in the summer of 2010 (a trading hub in Arizona that is relevant to RMP transactions), the maximum peak day-ahead electricity price reached $300 / MWh while the average off-peak price was less than $50 / MWh and is more concentrated around a central value.



Sources: *The Brattle Group* . Bloomberg.

Figure FCG - 2

Q. How do electricity price skewness, high on-peak volatility, and positive price-demand correlations affect desirable hedging practices?

A. These characteristics of power markets cause open (unhedged) positions in on-peak hours to be exposed to potentially very high-priced, extreme events. Off-peak hours often have less volatility and less skewness, so they are less exposed to this problem. As a result, it will tend to be variance-minimizing to hedge for peak load (or peak capacity, if selling) rather than for average or minimum load. This is true regardless of whether a utility is a net buyer or a seller; the risk will be lower, given higher and more skewed volatility on peak, if more than the expected quantity is hedged.

Q. In your experience, do electric utilities tend to hedge 100% or more of their expected future fuel and purchased power requirements?

A. There is not much public information on how electric companies hedge, probably because many have unregulated generation and marketing subsidiaries for which their hedging practices would be commercially sensitive information. Also, because they are more heterogeneous in their needs and asset mixes, they are harder to compare to each other and find general patterns. However, I have advised several electric utilities on hedging alternatives, particularly in states that implemented retail choice and left their distribution companies with a Provider of Last Resort obligation. Those companies were trying to provide a fixed price product, and virtually all of them used forward procurement (mostly of forwards and swaps) that hedged essentially all (or more than all) of their expected load-serving requirements.

Hedging Horizons Up to Four Years Forward

Q. Some intervenors have complained that RMP's purchasing of gas hedges four years in advance is imprudent, or at least ought to be abandoned as a practice going forward. They are concerned that long-dated forwards are illiquid (hence allegedly too costly or too risky) and/or that they represent too big a bet on what the distant future will be like. What is your response?

A. I disagree that there is any per se flaw or problem with hedging four years forward, however it is reasonable to open the discussion for future hedging as to how much forward period risk reduction is desired.

I would first note, however, that RMP does not have volumetric targets for how much it should hedge gas or power four years ahead. Instead of such hedge volume targets, it applies a TeVaR metric to its total cost risk foreseen in future years, up to four years ahead, and hedges as needed to keep that measure of potential costs within acceptable limits. The extent of hedging four years hence can go up or down, according to shifting market conditions (such as changes in expected volatilities or correlations across sources of supply). Nonetheless, RMP has hedged with volume targets in the past, and combined with position and VaR limits in the risk management policy has generally led RMP to be partially hedged with forward contracts and swaps for the fourth year in the future.

Q. Why is there no *per se* reason to hedge four years forward, or to not do so?

A. Hedging does not change the expected costs of future supply. It just changes the range and shape of potential costs around that expected level. There is no intrinsically "best shape" to which those potential costs should be constrained; that is a matter of choice, not of economic value. For the same reason, there is no intrinsically "right" horizon of forward cover (as long as there is reasonable liquidity, as measured by bid-ask spreads and availability of a reasonable number of counterparties.) The relevant horizon depends on the extent of risk reduction and cost predictability that is desired for future periods. This is certainly an appropriate topic for debate about customer needs and preferences, but it is not fair or reasonable to criticize a practice after the fact because it happens to have resulted in some currently out of the money hedges. In fact, as I explain more later, such look-back assessments of hedging "success" or disappointment are not appropriate tests of hedging prudence, nor do they provide much guidance about desirable hedging practices.

Q. How do long-dated hedges help manage risks?

A. Power and gas market conditions over the last decade involved several major adjustments lasting a few years at a time, and long-lived hedges could help smooth out exposure to such large swings. Simplifying history to a few key events, and focusing on natural gas as an example, there were high gas prices in 2000 - 2001 due to the western power crisis, followed by a general drop until around late 2005 when Hurricanes Katrina and Rita hit and pushed gas prices up to $8-10 or more per MMBtu. These abated down to around $5-6/MMBtu for a while, but dramatic global economic expansion and the rapid growth of oil and commodity prices in 2007-2008 caused another spike to around $12. Then the financial crisis and resulting recession, combined with the shale gas revolution, pushed prices back down to much lower, more comfortable levels today. This low cost pattern may last for a few years, but it is certainly plausible that there will be resurgence to high fuel and power prices once the economy picks up steam, tighter environmental regulations take effect, and perhaps inflation sets in.

The point is not that four-year, or even longer term hedges are good or bad, but that they can serve a purpose, if desired, of smoothing out long-wave variations in energy market conditions. This will feel like a benefit when the hedges are in-the-money (below current spot or replacement costs), but may be disappointing when they are more expensive. Unfortunately it is not possible to arrange to be exposed to just one of those two possible outcomes. Hedging inherently comes with the possibilities of both after the fact satisfaction and after the fact regret. Even using one-sided hedges, such as call options, has this same tension, because in a low-cost market, options will end up expiring without being used (so the premium cost is incurred without producing savings, in hindsight).

Q. Are you aware of any examples of gas or electric companies that hedge four or more years forward?

A. Yes. RMP's (15-year) Hermiston power plant has a very long term natural gas hedge for 100 percent of its requirements. While this gas supply contract was slightly out of the money for a brief period in the early years, as Mr. Apperson testifies, it has produced enormous savings for customers for the past decade. Similarly, the Direct Testimony of Mr. Jeff L. Fishman reports that Portland General engages in physical hedges for up to five years.[5] In addition, Portland General appears to hedge 100 percent of its expected requirements.[6] Further, Public Service Company of Colorado recently entered into a ten year fixed price gas supply with an annual adjustment or escalation.[7] Thus, RMP's hedging horizon is not unique.

I would also note that the natural gas contracts available at Henry Hub and elsewhere are now available for well beyond a four year horizon into the future. This shows that both buyers and sellers do value longer term price certainty. This is especially true of bilateral or customized contracts, because they may be able to

[5] Prefiled Direct Testimony of Jeff L. Fishman on behalf of UAE Intervention Group, May 26, 2011, p. 15.
[6] Portland General's 2009 Integrated Resource Plan states that "as [Portland General] get(s) closer to our fueling needs, purchases are increased to ensure we that we have acquired contracts to meet our expected requirements roughly one year in advance." See PGE 2009 IRP p. 144.
[7] See Public Utilities Commission of the State of Colorado, Decision No. C10-1328, Page 75, Item 219.

avoid the heavy collateralization or mark to market re-valuations that are required on standard exchanges.

Foreseeability of the Drop in Recent Natural Gas Prices

Q. Some intervenors[8] have argued that the recent drop in power prices is substantially driven by natural gas price reductions arising from the development of shale gas, and that this should have caused RMP to hedge less far forward over the past few years. Do you agree?

A. I do not. I have followed the innovations in horizontal drilling, fracking, and shale gas development fairly closely over the past few years, as it is a key factor in forecasting and planning future needs and preferred resources of the industry. My experience has been that this development occurred much faster and had more impact than was generally expected. Moreover, it was by no means an isolated or singularly overwhelming factor in the recent reductions in power and fuel costs. The financial crisis has been a very big driver of those changes as well, and it too was not anticipated to be as deep or as long lasting as it has proven to be so far.

Q. Please describe your understanding of the evolution of shale gas economics.

A. In the middle of the past decade, e.g. around 2005, there was widespread belief that the US was running out of gas and that imported, liquefied natural gas LNG was going to be essential and costly as our long term solution. Partly for this reason, when Hurricanes Katrina and Rita hit the southeast in late summer of 2005, the forward prices of natural gas shot up to unprecedented levels, not just over the time frame it would take to repair the damaged infrastructure, but for a

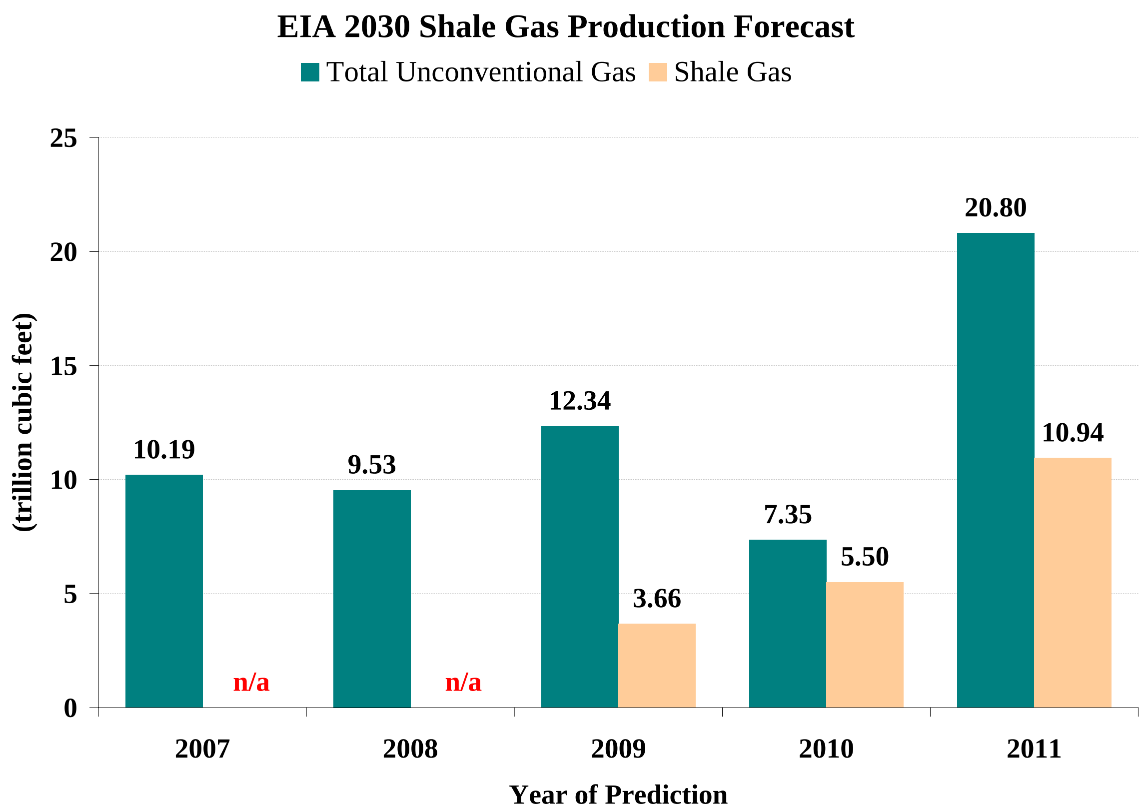
[8] Prefiled Direct Testimony of Mark W. Crisp on behalf of Utah Division of Public Utilities, May 26, 2011 (“Crisp Testimony”) pp. 11-14 and Malko Testimony p. 17 and pp. 20-21 .

few years going forward. Gas prices fell somewhat but still stayed well above previously normal levels throughout late 2006 and early 2007 and shortly thereafter they were rising again to very high levels, in conjunction with very high oil prices (eventually reaching almost $140/bbl).

These high prices of gas drove a wave of technology development and exploration for shale gas with horizontal fracturing, which proved to be extremely successful -- to the point where we now appear to have many decades of likely reserves from shale and other nonconventional gas supplies, possibly at $5-6/MMBtu in real terms for several years ahead. However, there was considerable debate (and some persists to the present) over what the true cost of shale gas development was, as some developers were reporting success at $4/MMBtu or so while some engineering studies were showing costs in the $9-10/MMBtu range or higher. Many analysts felt that the rapid pace of development was uneconomical, at current gas prices. This could well have been the case, because a lot of the development occurred in order to retain leasehold rights to shale gas properties, not for the intrinsic value of the gas. This was not widely foreseen, and it has depressed spot prices to date. It is also likely that some of the current development of shale gas is above the levels that are justifiable by gas prices alone, because some shale gas has associated liquids that are very valuable while oil prices are high. This is also somewhat unusual and was not generally foreseen by industry analysts.

While the testimony by Mr. Crisp for the Utah Division of Public Utilities uses data from the Energy Information Agency's (EIA) 2011 Annual Energy

Outlook, a review of the data from EIA beginning a few years back shows that the forecasted shale gas production only very recently reached significant levels. Figure FCG - 3 below shows EIA's forecast in recent years for shale gas production as well as for all unconventional gas in 2010. EIA has increased its forecast in each year.



Source: *The Brattle Group* . EIA Energy Outlook.

Figure FCG - 3

It is also instructive to review the amazing growth rates for shale gas as major source of US gas supply. Shale gas production in 2009 was 2.23 Tcf but that more than doubled to 4.8 Tcf in 2010.[9] The EIA in its 2011 Annual Energy Outlook

[9] EIA, "Annual Energy Outlook for 2011: Oil and Gas Supply – Reference Case."

notes that the production accelerated dramatically after 2006 with an annual growth of 48 percent from 2006 to 2010. This is virtually unprecedented and would have been very hard to foresee. I also note that I found no production volumes for shale gas in EIA's Annual Energy Outlook for 2007 or 2008.[10] This lag in EIA recognition of shale gas shows that it is not reasonable to have expected RMP to have foreseen more of the shale gas success than the market or than the industry data analysis specialists.

Q. Are these debates over the future promise of shale relatively settled today?

A. No. There are ongoing debates about what the environmental costs and limitations will be from water pollution that may be associated with shale gas, and several states are still reviewing their policies for allowing shale gas development. The NY Times recently had an article indicating that there is continuing skepticism about the prospects for the shale gas industry.[11]

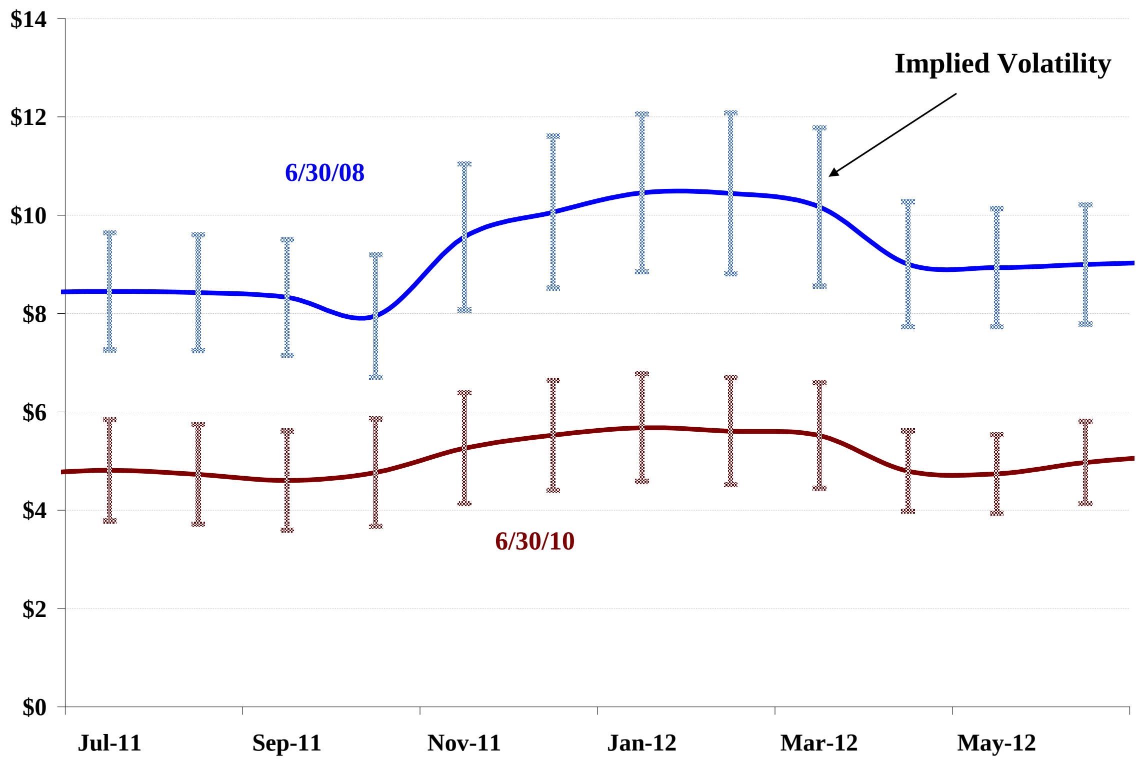
Q. What was the apparent market expectation for shale gas around 2008 compared to more recently?

A. There is no evidence that the market was expecting a shale gas revolution. Figure FCG – 4 below depicts the forward price of gas trading at OPAL near RMP as of early 2008 vs. early 2011. The curve has shifted dramatically downward, but there is little slope to the forward curve in 2008. This means that the dramatic drop in gas supply prices was not expected. This figure also shows vertical bars around the prevailing forward prices in 2008 and 2011, which reflect the expected annualized volatility (plus or minus one standard deviation) in monthly delivered

[10] EIA, "Annual Energy Outlook" for 2007, 2008, 2009, 2010 and 2010.
[11] New York Times, "Insiders Sound an Alarm Amid a Natural Gas Rush," June 25, 2011.

gas prices at the time these forward prices were in effect. One can see here that there is little overlap of the uncertainty bands around the 2008 prices with the realized spot prices for gas in 2011. Thus, the market was not anticipating even a range of risk for what has turned out to happen.

Forward RockOpal Price Curves and Volatilities



Source: Rocky Mountain Power.

Figure FCG - 4

Q. What are the implications of this history for the foreseeability of gas and electric prices falling so much in the past couple of years?

A. There was a lot of discussion and debate in the trade press about the above issues, so the market likely already incorporated as good a guess about where the prices of gas were headed as was reasonably knowable. Intervenors arguing that RMP managers should or could have had a better forecast of future gas and electric prices than the market was revealing in its forwards are basically insisting that RMP should have speculated in the past few years – a practice that RMP appropriately avoids and that the Commission should strongly discourage.

Greater Use of Options and Collars

Q. Please explain the distinction between risk and regret.

A. Hedging reduces risk, meaning exposure to future uncertain costs (or revenues). The more tightly and the farther forward in time that future range of costs is controlled, the greater the possibility that realized market circumstances will turn out to have a different cost than the hedges. Now, this is precisely what hedging was supposed to accomplish, but when the realized costs are lower than the hedges, we tend to feel frustration or regret over having hedged. However, one cannot minimize both risk and regret, as they are complementary to each other. Instead, you must choose which one you want to control, and let the other one be open. For this reason, it is not useful to evaluate the success of a hedging program in relation to its "winnings" or "losses". Rather, it should be evaluated based on whether it kept the expected range of potential costs within the target boundaries. If there is a desire to reduce the chance of regret with the tradeoff of increased risk, then the appropriate strategy is to hedge less or to rely more on one-sided hedges like options.

Q. Should RMP use, or have used, more call options or collars?

A. There can be no answer to this question apart from evaluating and responding to the preferences of customers for the types of costs and risks that would be involved. The expected cost will be the same, and there is no advantage to RMP from using more or fewer options in its hedging. However, options are a bit more complex to understand than forwards and swaps, and they have a history of being somewhat contentious in regulatory proceedings. Thus, it is not a common practice for electric companies to use significant quantities of call options or collars to manage their fuel and purchased power risk, for several reasons:

- They tend to be less liquid than swaps and standard forwards;
- They have up-front cash payments for the premiums;
- And most importantly, they are often not well understood or consistently evaluated by regulatory commissions and intervenors – Specifically, it is quite common for utilities to face complaints that unused call options (not exercised because they expired out of the money) were unnecessary or imprudent.

This latter problem of objecting to the costs of un-exercised options is somewhat like complaining that your fire insurance was a bad idea because your house did not burn down. However, it is not an uncommon complaint. I understand that RMP has faced some of this kind of inconsistent reactions to its own use of options in the past as well as in the instant case.[12]

It is also important to remember that like any fairly priced hedges, options do not reduce expected costs (nor do they raise them, despite the premium). Instead, they just trim the upside, with the buyer paying a fair price for the

[12] For a discussion of this issue, see the rebuttal testimony of Stefan A. Bird.

truncated high end exposure. It is reasonable to consider using them, but that should be an *ex ante* decision going forward, not an *ex post*, hindsight criticism.

Q. Witness Dr. Schell for the Office of Consumer Service suggests that it would have been better for RMP to rely almost entirely on call options over the past few years, thereby allowing for lots of cost reductions since prices have fallen. She suggests that Henry Hub options would have sufficed.[13] Do you agree?

A. No, I disagree. The gas contracts available at Henry Hub are for deliveries that are roughly 1500 miles away from RMP's Utah service territory. While natural gas is a somewhat correlated product around the nation, the prices at different locations can and do diverge materially from each other, especially over large distances with occasionally constrained pipeline delivery infrastructure. My Figure FCG - 5 below shows the price at Henry Hub versus the price at Opal over the past few years, and the size of the difference (generally called the "basis" risk). Generally, western gas prices have been below those at Henry Hub, so this basis has been negative. It has been as large as $6.66/MMBtu[14] and the average basis constitute about 20 percent of the Henry Hub commodity price itself. RMP would actually have wanted options for delivery to several different locations. This large basis risk means that options tied to prices at Henry Hub could have ended up in or out of the money for reasons that had nothing to do with market conditions at RMP's locations. Moreover, it might not even have been feasible to obtain the full range of needed options to accomplish what swaps and forwards can do, as the latter are traded much more heavily over longer horizons.

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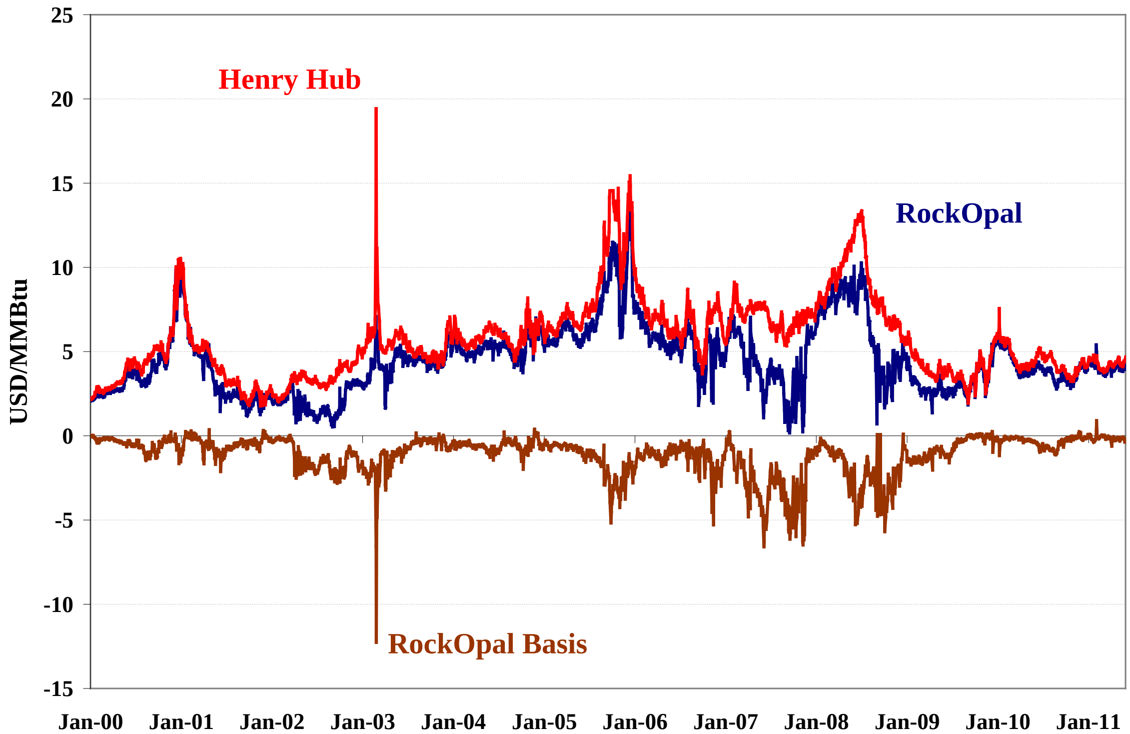
[13] Direct Testimony of Lori Smith Schell on behalf of the Office of Consumer Services, May 26, 2011 ("Schell Testimony"), pp. 13-17.
[14] Using daily data.

Henry Hub / RockOpal Spot Natural Gas Prices



Source: *The Brattle Group* . Bloomberg.

Figure FCG - 5

Prudence Standards

Q. You have mentioned a few times that it is inappropriate to use look-back tests to evaluate a hedging program. Please elaborate on why this is the case.

A. *Ex post* look-backs to see if hedges turned out to be cheaper than unhedged (or differently hedged) positions would have been can be very misleading for prudence review, and they are not very informative for redesigning a hedging policy going forward. The problem is that a single period reviewed in hindsight will rarely have encompassed much of the range of outcomes that the hedging strategy was designed to protect against. Instead, just a small range of conditions will have occurred, which will reveal little about the overall efficacy of the hedging strategy.[15]

For instance, if one is trying to decide if 7 is a good bet for the sum of two thrown dice, a single throw or two will not be very conclusive. It is the expected value, hence the best single bet, but one could easily observe a 2, 5, 12 or other (non-7) outcomes in just a few rolls and gain no insight about the merits of betting on 7. Hindsight review only works if the same kind of review can be applied on many occasions over a long period of time, with the same underlying risk conditions and hedging approach being used consistently throughout.

For power markets, this is a very strong condition to impose. If market conditions are not stationary, system configuration changes (e.g., more gas plants, more renewables on the system, different hydro runoff, etc.), or the company's hedging approach evolves, then hindsight snapshots are purely circumstantial views.

Q. Does this concern apply to comparisons of alternative hedging strategies?

A. Yes, that is just a variation on the same kind of misleading comparison. Intervenors who are suggesting a new strategy based on just the most recent period are not demonstrating that they have a strategy which will perform better in general, just one that would have had better ex post results (less regret) in the most recent period. At the very least, any such proposal needs to be backcast under a wide range of circumstances to see if it has attractive properties in general, not just recently. RMP have done this kind of simulation of the suggestions to

[15] For an exposition of this concept, see also, Jeff. D. Makholm, Eugene T. Meehan, and Julie E. Sullivan, "*Ex Ante* or *Ex Post*? Risk Hedging and Prudence in the Restructured Power Business," *The Electricity Journal* 19, April 2006.

hedge a smaller percentage of needs in its 2009 presentation to the Commission, where it found that depending on the load shape, reducing RMP's hedging to 71 percent electric and 78 percent gas could result in a loss of up to $245 million or a gain of up to $141 million.[16] This does not mean that the intervenor suggestions are bad ones, just that those approaches have different risk reduction benefits and there is no reason to prefer them just because of alleged recent advantages.

Q. What would a better approach look like?

A. A better approach would be to focus on whether the risk-limiting goals appropriate for ratepayers are being monitored and controlled in a non-speculative, transparent fashion by RMP. That is, keep the focus of risk-management prudence on the range of risks and how those were managed, rather than getting distracted by how the costs turned out. Mechanically, this might involve the following steps:

1. Through workshops or other public processes, agree *a priori* with regulators and customer groups on risk-limiting goals for the future.
2. Agree on a risk simulation model for regulatory discussion that can test and demonstrate alternative hedging strategies to achieve the desired risk limitation goals.
3. Formalize a plan for type, timing, and triggers for implementing hedges.
4. Schedule periodic reporting of success in adherence to the agreed plan, and on continuing expectations of being able to achieve the risk goals (perhaps quarterly or semi-annually).

[16] PacifiCorp Energy, "Commodity Price Risk Management Presentation," Utah Public Service Commission, May 18, 2009, p. 23-24.

5. Use unanticipated major changes in market conditions to trigger reviews of whether hedging goals or strategy should be revised.

6. Evaluate prudence based on faithfulness in executing the plan and using good practices for risk management controls.

7. Apply no *ex post* look backs, except to open discussion of revised future goals.

This approach will keep the focus of hedging prudence reviews on whether risks are being reduced, rather than on whether the hedges happened to pay off. It will also increase intervenor and regulatory understanding of market conditions, as well as what can and cannot be accomplished with hedging. Ultimately, it should lead to an improved set of goals for risk reduction that more closely match consumer needs.

Q. Does this conclude your rebuttal testimony?

A. Yes.