

Comments of Michael A Gettings, RiskCentrix

Prepared for Washington State Attorney General's Office, Public Counsel

Re: Inquiry into Local Distribution Companies' Natural Gas Hedging Practices and Transaction Reporting, Docket UG-132019

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Preface

These comments are offered in a narrative form, generally following the list of issues identified in the Commission's December 18, 2013 Notice of Opportunity to File Written Comments ("Notice"). My goal is to provide insights into these issues informed by more than 30 years of experience in the field of energy risk management. That experience includes managing a natural gas marketing and trading company before and after the advent of the NYMEX gas futures contract, development of hedging programs as a consultant for dozens of utilities and industrial firms, as well as sitting as an advisor and ex officio member of numerous utility risk management committees.

The scope of these comments does not include review of company-specific hedging activities or results. There is no attempt to evaluate prudence at any level. Comments are directed at improving the regulatory compact and establishing a framework for risk-responsive hedging.

Summary Observations

While there is important nuance in the Discussion section, the key points may be summarized as follows:

1. The reason for hedging is to reduce customer pain in severe upside markets and thereby create marginal utility for customers. Customers derive greater value from upside cost mitigation than they forego from hedge losses because upside cost outcomes tend to require them to make painful adjustments relative to prior expectations, but hedge losses, while still painful, occur in declining markets when the net costs are more favorable than prior expectations, thus moderating the pain. This statement is not meant to understate the real value foregone by high cost hedges; it is meant to put a proper perspective on the relative pain associated with whatever unfavorable outcomes are realized. Unless hedges are always made at market troughs there will always be some degree of unfavorable outcomes relative to retrospective opportunities.
2. Similarly, customers' pain response is not linear. Radical cost increases are disproportionately painful when compared to modest year-to-year changes.
3. Regulated utilities must balance their desire to create customer value via hedging with the obligation to minimize prudence risk for shareholders. This balance is usually resolved by minimizing market-responsive decisions, and that promotes "lock and leave" hedge programs. Such programs do not serve customer interests to the extent that a more professional quantitative-finance approach could.

4. Market-responsive risk-management strategies should not rely on prediction of market movements; they rely on measuring and monitoring prevailing risk conditions. Hedges should be placed based on a “risk view” not a “market view.” A risk view holds that the direction and magnitude of futures price changes is unknown, but the current futures price (market consensus) is known, and the uncertainty of that consensus can be observed through daily futures price fluctuations. If we decide on tolerances for upside costs and downside hedge losses, we can compare the observed risk to our tolerances and take hedge actions accordingly.
5. The tools of quantitative finance can be deployed to design risk-responsive hedge programs. Such programs can customize hedge decision protocols to defend with high, but not absolute confidence, specific tolerances as to potential cost increases and potential hedge losses. Those two-directional tolerances can be tailored individually so long as they are paired in a way that is compatible with market volatility.
6. Hedge decisions can be categorized in four types: programmatic, defensive, contingent and discretionary (defined in Discussion). Programmatic hedges are executed based on the calendar without consideration of prevailing risk conditions. Defensive hedge protocols monitor upside risk and increase hedge levels only when risk conditions warrant. To the extent programmatic hedge volumes can be reduced and replaced with defensive protocols, customers can gain greater participation in declining cost markets. Contingent protocols monitor hedge-loss risk and stand ready to respond to rare risk conditions by unwinding hedges or substituting options for swaps.
7. The incremental administrative costs of a quantitative-finance-based program include investment in information technology and development of specific skills that might not be traditionally held by utility staff or the executives overseeing the program. Software and expertise are both attainable at a cost that is minor compared to the dollars at risk.
8. The closing section (“Regulatory Approach”) outlines a six-step program that could be deployed over a two-year period to move regulatory oversight to a process-oriented prudence standard. It is appropriate for the Commission to require companies to file hedging programs and then subsequently report to the Commission regarding hedging program performance.

Discussion

Why: Why Hedge? Why Not Hedge Well?

The first question raised in the Notice is the most important – “What is the purpose of hedging?” All subsequent decisions as to program design and execution as well as regulatory oversight will derive from this answer, so it is worth exploring in some detail.

I submit that the core purpose of hedging is to minimize customer pain associated with price (or cost) changes. That is very different than simply reducing exposure to volatility because customers’ sensitivity to pain is not symmetrical, nor is it linear. The asymmetry is due to the fact that tolerance for upside cost exposure is different than the tolerance for hedge losses in downward markets. This statement is not meant to understate the real value foregone by high cost hedges; it is meant to put

a proper perspective on the relative pain associated with outcomes that cannot be known at the time hedges are executed. It is always easy to fight last year's battles and when hedge programs do that, there is a tendency to swing from hedging too much to hedging too little as backward-looking assessments reflect periods of increasing and decreasing prices respectively. A candid perspective is critical to maintaining an appropriate program without whipsawing from one bad decision to the next.

The non-linearity reflects the customers' relative indifference to small price changes, particularly as attenuated by the PGA, compared to the pain of very large increases that are evident in natural gas markets.

Focus on the asymmetry. Imagine an industrial customer with a \$1 million natural gas cost expectation for 2014. If gas costs rise 20% that customer sees a \$200,000 increase in costs and a commensurate decrease in profitability. If gas costs fall by a like amount, profits rise by the same number. While the marginal utility of the additional profit is helpful, the impact of the incremental loss could be far worse. As illustration, envision additional employee bonuses that might be paid with the incremental profits versus the layoffs that might result from the incremental losses. Or in more general terms, envision the "good" of investing the incremental profit versus the "bad" of making budget cuts. Anyone who has had to manage through a period of significant budget cuts understands the benefit/pain is not symmetrical as to increases and decreases.

While this first illustration focused on an industrial firm, the asymmetrical risk appetite also applies to residential and commercial customers. Using a simple residential analogy, taking a \$500 better vacation with gas-bill savings would be a good thing, but being unable to pay necessary expenses would be a very, very bad thing.

Now consider how hedging relates to this asymmetry. If gas costs were hedged at a 50% level, the potential upside costs would have been mitigated and there would be less bad news to be absorbed by that customer. Potential downside cost participation also would have been reduced, but that would simply mean more moderate good news in a lower cost environment; the customer would still meet his profit objectives or take that vacation. The implication of this asymmetrical risk tolerance is that hedging, when done with a rational perspective, tends to increase the customers' marginal utility.

Another aspect of the customers' pain-response profile is that it is not linear. Price increases of a few percentage points elicit mild discomfort, but large increases are very painful. This fact must influence hedge program design. Natural gas prices have been known to spike from \$2/MMBtu to \$10/MMBtu over a one-year span, so to moderate such spikes meaningfully, maximum hedge ratios must be fairly high. On the other hand, prices can drop just as precipitously, so high hedge ratios can create large hedge losses if not managed through the entire hedge cycle, from execution to settlement. Later discussion will focus on how that life-cycle management process would include making fewer programmatic hedges and maintaining a contingency plan for dealing with prospective losses.

But while customers are the core constituent, there are others. A regulated utility takes some risk whenever it hedges, and that risk is also asymmetrical. In the absence of an explicit regulatory compact, a utility with a multi-million dollar hedge position has the following two-sided risk exposures:

- If costs rise, they save customers money and potentially gain modest goodwill for doing what was expected of them;
- If costs fall customers' bills still fall but by less, yet the utility carries hedge losses which may be subject to prudence issues. Even if no prudence finding has ever been levied, the possibility will influence program design.

Notice that the utility's asymmetry is exactly opposite that of its customers. Customers' risk profiles are improved by rational hedging, but the utility's risk profile is exacerbated. An enlightened regulatory system might attempt to reconcile the conflict in order to extract more value for ratepayers without unfairly treating the utilities that design and execute these programs.

At this point, it is worth making another observation regarding the typical utility's risk profile and its implications. Once the utility chooses to run a hedging program, it must design it to meet explicit and/or implicit objectives. Typically those objectives are explicitly stated in simple terms such as "reduce volatility", but the underlying nuance is usually at least two-fold: (1) reduce the customers' exposure to cost-related pain and (2) minimize the utility's exposure to prudence risk.

That second objective carries a corollary which might be stated this way: "any market-oriented decisions could be criticized, so minimize market-responsive decisions to minimize prudence risk." Hence the prevalence of "lock-and-leave" hedge programs, where hedge accumulation decisions are made at a policy level at one point in time for a pre-determined fixed volume; that policy is then executed as specified, and left in place for the full term with no risk-responsive protocols. By way of analogy, this is akin to entering the freeway and locking the cruise control at 70 mph while hoping no other car or hazard arises on a cross-country trip.

So these observations set a backdrop as to why utilities should and do hedge, but also why programs are sometimes less than robust.¹ Subsequent comments here will address how these conflicted objectives, if left unreconciled, often lead to non-robust hedging programs and large losses that, in most cases, could be materially smaller. Perhaps more importantly, comments will address opportunities for improvement of the regulatory compact, but before doing that it will be necessary to explore the design of a more robust hedging program.

A Robust Program

With any hedge program, commodity price risk is two-sided; depending on hedge positions, gas market prices might rise causing cost increases, but if they fall hedge losses mount. Investment in options can mitigate both risks in exchange for a "premium" (option premiums are very substantial in volatile markets like natural gas) but aside from heavy option investments, the goal is to gain more upside cost mitigation with as little loss exposure as can be accomplished. As with most things, this can be accomplished with greater attention to well-designed metrics and more frequent management focus.

One very important perspective is this: any utility's risk tolerance can be expressed as two parts – upside cost exposure and hedge loss exposure. Once the default lock-and-leave program is

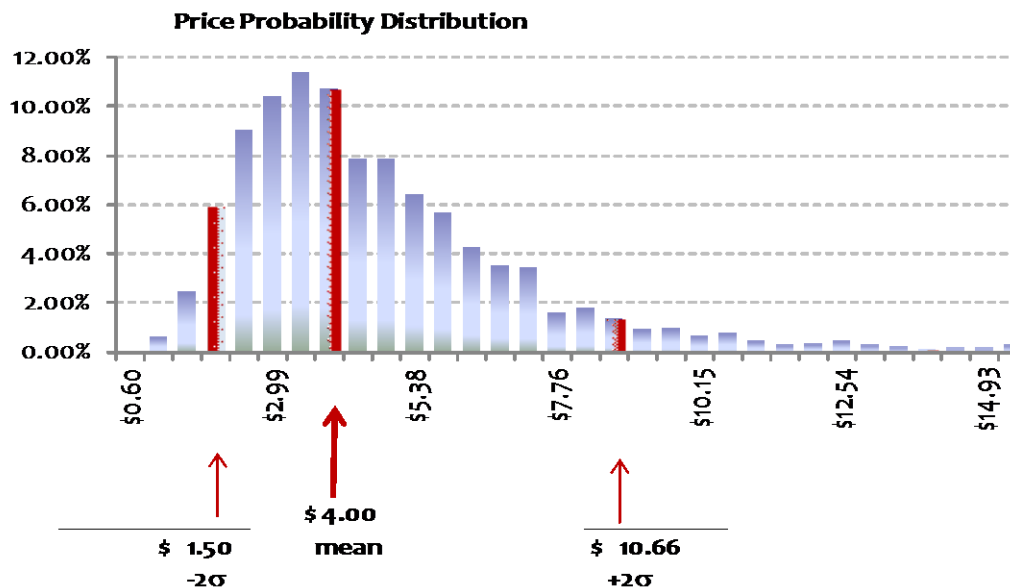
¹ The term "robust" will be used to describe the characteristic of a hedging system that operates effectively under a very broad set of market environments.

discarded, decisions can be tailored to manage either side of the risk to a different tolerance than the other.

An illustration could be helpful. The graph in Figure 1 shows a typical risk distribution for gas prices that might prevail one year from now if today's NYMEX price were \$4.00/MMBtu.

Notice that the high-side price outcomes stretch farther than the downside while the probabilities are weighted more heavily to the downside. This is a pattern that has been well established and thoroughly analyzed for decades.² The actual shape of this graph would depend on the prevailing volatility, but this will serve as an illustration; it assumes prevailing volatility³ equal to 50% which is well within the range of volatility experienced for natural gas prices. In this example, if a utility were to leave all gas requirements unhedged, customers would be exposed to \$10.66/MMBtu costs at the 2-sigma upside (that accounts for all but about 2.5% of potential outcomes). If the utility were to hedge all of its requirements, its customers would have the potential to avoid a \$6.66 cost increase (at 2 sigma), and also barring a prudence review would be exposed to a potential loss of \$2.50/MMBtu.

Figure 1: Typical Price Risk Distribution



Notice that a simple 100%-hedge “lock and leave” program under prevailing volatility of 50%, could avoid 2.66 times the upside risk compared to the loss potential (i.e., at 2-sigma, \$6.66/MMBtu upside risk avoidance v. potential hedge losses of \$2.50/MMBtu). Despite this apparently good ratio, small

² The vast majority of analysts use a log normal distribution to analyze natural gas price risk and that is reflected here.

³ For the professional risk manager, volatility has an explicit mathematical meaning. It represents the statistical one-sigma price migration that might occur over a one-year period given empirically observed daily price changes. Despite the single-number value, because natural gas prices are log normally distributed, the upside and downside magnitude is not symmetrical.

losses are more likely than any other outcome because the probability density is greater on the downside, counterbalancing the extended tail to the upside. Obviously a lower-than -100% hedge ratio would have a smaller but proportionate effect.

The question should be how similar cost mitigation might be attained while substantially reducing loss potential. “Lock and leave” is a common strategy, but risk-responsive strategies, when well structured, are typically superior in this regard. A risk-responsive program aims to gain most of the upside mitigation when needed, but substantially constrain hedge-loss potential by hedging smaller volumes programmatically, and being prepared to adjust strategy if downside risk threatens hedge-loss tolerance.

Taking a “Risk View” Instead of a “Market View.”

To be clear, as used here market-responsive strategies do not rely on prediction of market movements; they rely on measuring and monitoring prevailing risk conditions, so a more accurate designation would be “risk-responsive” programs. Hedge programs should manage risk; opportunity management is a different issue. So hedges should be executed based on a “risk view” not a “market view.” A hedge program works most reliably when risk is measured daily or weekly and prospective hedge decision responses are pre-planned for risk conditions that might emerge.

The distinction between risk view and market view is important. Hedges are placed at futures-market prices which reflect all participants’ money-backed consensus as to the future price of natural gas. For the purpose of making hedge decisions, it is meaningless to hold a view that the spot physical price of gas is likely to rise (or fall) because of fundamental factors. One cannot hedge next year’s gas at today’s spot price, and the futures price right now could be dramatically different than the prevailing fundamentals might indicate. A hedge manager who buys on a market view is effectively acting on something far more speculative. If stated properly it would be this: “While all market participants have equal access to data regarding consumption, production, storage and other factors, and they have reached a consensus on next year’s futures price, I know better.”

A risk view is very different. It holds that we do not know the direction or magnitude of futures price changes, but we do know the current futures price (market consensus) and we can observe the uncertainty of that consensus as daily futures-price fluctuations. If we decide on our tolerances for upside costs and downside hedge losses, we can compare the observed risk to our tolerances and take hedge actions accordingly.

Over the last 20-plus years, quantitative finance techniques have been developed to measure risk and they have been applied to the management of volatile commodity costs; natural gas has been one primary focus of these efforts. One relatively simple tool in the quantitative-finance toolkit is the measurement of price volatility and from that, the measurement of “value at risk.” Value at Risk (“VaR”) comes in two directional types – potential dollar exposures to incremental cost run-ups (dubbed VaR-C here) and potential incremental hedge losses (VaR-L for this discussion). VaR is always measured as an increment from the current condition, so the potential “outlier” losses at 95% confidence would be the current tally of forward-looking losses plus VaR-L; the outlier costs in the future would be current forward costs including open positions at futures prices and hedges at their own prices plus VaR-C.

It is a reasonably straight-forward exercise to calculate the volatility of NYMEX natural gas prices for each futures contract month (“futures”) over a recent trading period (e.g., the last 30 days); that volatility can be converted to a potential price migration at a specified confidence as illustrated in Figure 1. Once the potential price migration is measured for each future month, the upside-cost “value at risk” is simply the potential upward price migration multiplied by the unhedged volumes; hedge-loss value at risk is the potential downward price migration times the hedged volumes.

While Figure 1 shows the price-risk for a one-year “holding period,” prospective hedge decisions need to be reviewed more often, so a more appropriate holding period would be something like ten business days. Think of it this way: we can adjust hedge positions today at current futures values, or we could defer a hedge decision and accept the potential price migration. Measuring the potential price migration at high confidence is a necessary calculation to inform that decision.

Stated colloquially, the goal is to measure how badly prices might move against us over the next two weeks (upward movement as to costs, or downward as to losses), and then make hedge decisions to protect specified tolerances.

Price risk over a two-week holding period is about one-fifth of the risk for a full year,⁴ so risk and consequential hedge decisions can be managed in smaller increments. Managing week to week is far superior to buying hedges for a year and hoping for the best.

Components of a Robust Hedge Program

Hedge decisions typically fall under four types and the role of each is important to a robust design. Here they are listed in the order that they are typically executed:

- A. **Programmatic:** Prescribed volumes accumulated per calendar
- B. **Defensive:** In response to risk measurements that threaten an interim or final cost tolerance
- C. **Contingent:** In response to risk measurements that indicate a threat to interim or final hedge-loss tolerance
- D. **Discretionary:** In response to a market opportunity.

These hedge types are discussed below, but now in order of design logic:

Type B, Defensive Hedges: If no hedges are ever executed, no losses will be incurred, so if practical, the preference would be to hedge only when necessary, i.e., Type B, Defensive hedges. Anytime risk metrics indicate that a defensible cost threshold could be breached over the near-term holding period, hedges would be placed in proportion to the value at risk that must be eliminated. In the design process, simulation of random price walks facilitates exploration of the size and frequency of the hedges that would be required.

Natural gas volatility is typically high, so defensive hedge requirements might be precipitously large at times unless our ultimate cost tolerance is defended by interim tiered cost boundaries. Since these tiers are by definition at lower cost thresholds than the ultimate tolerance, they may be called “action boundaries.” Tiered action boundaries work this way: hedge as necessary in defense of Boundary #1 up to a 30% hedge ratio (illustrative), then shift to defense of Boundary #2 up to a 50%

⁴ Price risk is normally proportionate to the square root of the time ratio; i.e., 2 weeks divided by 52 weeks. The square root of (2/52) is .196.

hedge ratio, etc. In this way the hedge manager is not waiting for the potential breach of an ultimate boundary to hedge all needs in a precipitous manner.

Note that defensive hedges are made well before action boundaries are actually breached. Since the action boundary is compared to the sum of the prevailing futures market price plus VaR-C, defensive hedges are made at prices that are 'VaR-C' below the action boundary. Hedge execution takes time so this is an indicative relationship, not a precise formula.

Type A Programmatic Hedges: If concerns persist that defensive hedges will be required in large tranches, programmatic hedges can be accumulated up to a low to moderate level, e.g., 10% or 30% hedge ratio. The programmatic hedges will preempt the need for large defensive hedges later. Volatility tends to grow as each contract month grows closer, so early programmatic hedges provide a dollar-cost-averaging technique before the emergence of severe contract-month volatility. Their main objective is to make the size of defensive hedging tranches manageable in high volatility markets like natural gas.

Type C, Contingent Hedges: Contingent hedges aim to constrain losses in price collapses. If defensive and programmatic hedges are designed correctly and tolerances are compatible with market realities, contingent hedges are almost never necessary. In my experience, the collapsing prices of the 2008 financial crisis presented the only such environment. Contingent hedges are placed in response to a potential breach of a hedge-loss tolerance. Like defensive hedges, it is important to note that the potential for a breach will be recognized long before the actual losses are reflected in market prices. The only time contingent hedges are required is when prices run up very rapidly (driving defensive hedges) and then down very rapidly; in other words volatility is very high. When volatility is very high, so is the value at risk, so the potential for outlier-sized losses would be identified before prices actually go too low. Contingent hedge decisions might consist of overlaying options (premiums, while high, could be a bargain in the rare crisis environment) or simply reversing prior hedges via counter positions.

Type D, Discretionary "Hedges" are opportunity-focused rather than risk-focused, and they are susceptible to prudence issues if executed early, so they are best left to managing near-term gas needs. In the short term, LDC managers often have specialized knowledge of system and pipeline factors that can influence price and reliability, so discretionary hedges become more an extension of operating discretion. If executed for a longer term, they should be scrutinized by executive management and probably regulators.

Systems and Staffing

Quantitative-finance based hedge programs offer more robust performance (i.e., superior goal attainment under a wider range of environments) at the cost of some incremental investment in expertise, systems and management time. Experience indicates that such a program can be run with an initial IT system investment to track metrics daily, maintenance of that system, and very little increase in staffing. Systems represent the principle investment; they can be outsourced for a few hundred thousand dollars annually, plus an initial investment in set up that could be multiples of that.

The staffing question becomes one of expertise not quantity. Any company that is transacting derivatives (swaps and/or options) will, or certainly should, have a front office to execute

transactions, and a middle office (and/or back office)⁵ to provide daily checks and balances. The number of transactions is not dramatically different from a lock and leave approach, although the defensive hedges require transactions be executed in a matter of days not weeks and they are required in irregular intervals. The analytics required of the front and middle office are somewhat more demanding, but they require more quantitative skills, not significantly more personnel.

Executive time and expertise is another issue. A good program requires executive oversight, probably on a monthly basis. Most companies set up an executive risk oversight committee (known by some name and acronym) consisting of high-level executives, often including the CFO. Given the magnitude of dollars being managed, I would hope this represents either no change, or it should be viewed as a good one.

Miscellaneous Issues

The **hedge horizon** question is important and sometimes counter-intuitive. There are two issues that should be recognized:

1. A longer hedge horizon provides customers greater mitigation, but also a greater risk of hedge losses.
2. Half cycles for natural gas prices (top to bottom or bottom to top) tend to run from 9 to 18 months, so designing a program that executes hedges for 12 to 18 months can lead to volatile results unless hedge accumulation is well diversified.

In recognition of these market realities, most robust programs described above manage a defensive horizon of about two years. This is accomplished by running risk metrics for the current PGA year and the one following. Programmatic hedges might be accumulated for a third forward year, but only up to a modest hedge ratio.

The **maximum hedge ratio** should probably be in the range of 75% to 85% of monthly forecast requirements including storage injections and net of withdrawals, but in most cases under defensive hedge protocols these levels will not be reached with actual hedges. Hopefully it is clear that I would not recommend any programmatic hedge accumulation up to that level. One risk of this hedge ceiling is that when running defensive hedge decision protocols, unhedged volumes beyond the maximum hedge ratio will make it impossible to fully constrain costs in the most severely rising markets. In my own experience, this has not been a big problem at an 85% maximum hedge ratio, but could be if ceilings are set too low.

The other factor is that forecast volumes can be subject to error, particularly due to weather and economic factors. Both of those drivers (weather and economic activity) correlate with natural gas prices; in other words cool weather and slow economic activity tend to produce lower prices. So when actual system volumes are below forecast, gas prices tend to be lower. For this reason and others, over-hedging should be avoided. Most local distribution companies (“LDCs”) can forecast load with reasonably good accuracy for normal weather conditions, and they know the extent of weather sensitivity. So to maximize the opportunity to mitigate costs and yet avoid excess hedge

⁵ A three-office system consists of a middle office that provides routine checks and independent executive reporting as to risk and price analysis, while the back office is more accounting oriented, i.e., settlements, etc. Some companies consolidate these into a two-office system.

volumes, the maximum hedge ratio should be specified by month or at minimum by season, and it should equal the LDC's high-confidence minimum load.

Physical and financial hedges should be combined for hedge program administration and assessment. Both create the same gas-price effects on system costs and ignoring either would provide a distorted view of risk metrics. LDCs typically choose one over the other for reasons other than risk mitigation, e.g., better price, better terms, smaller collateral requirements, greater liquidity, system flow issues, and financial hedges impose some regulatory compliance considerations. Yet both serve to mitigate price risk, and at the time of settlement or delivery, any fixed price commitment will yield an economic benefit or incremental cost compared to market prices regardless of which type of hedge is chosen.

Regulatory Approach

In February 2010, I published a paper for NARUC where I made this statement:

“. . . risk mitigation programs deployed by investor-owned utilities on behalf of customers are often weaker than they could be, and the reason is substantially tied to the regulatory interface. Investor-owned utilities (“IOUs”) fear prudence findings, and they also shy away from complicating regulatory relationships with complex proposals to improve risk mitigation. So typically, IOUs hedge customer exposures in the simplest way, minimizing market-responsive decisions because hedge decisions are subject to retrospective scrutiny.

This can and should change. The only pragmatic way to do so would be for regulators to articulate meaningful guidelines for prudence review of hedge programs.”

And this:

“Public power entities often incorporate many of these insights; such firms work under a different regulatory structure. Merchant generators and energy trading firms almost always utilize risk metrics to protect earnings and constrain losses in a market-responsive fashion. And IOU's very seldom do. I believe that large benefits could be derived from freeing utilities to optimize hedging approaches, and the only way to free that potential would be a proactive regulatory compact.”

Today, I believe that the best approach is to establish prudence standards as to minimum procedures that would encourage greater sophistication in the treatment of risk and, over a period of years, encourage a healthy regulatory compact on the issues. Ultimately, a healthy regulatory compact would include agreement on the framework for the ongoing measurement of (upside and downside) risk and responding to those metrics, but specific tolerances, action boundaries, and hedge decision rules would be the purview of each company.

Prudence standards could focus on the assessment of procedural compliance with risk-responsive programs that were planned, filed with regulators, and approved. This process would require new skills and systems and that could begin as developmental efforts and grow over two years into effective quantitative finance programs. I chose a two-year horizon because systems and expertise can only change and be tested with sufficient time. Each company might develop and submit its own program-development proposals for regulatory approval, but an illustrative proposal might look like this:

1. Establish a maximum hedge ratio for each month or season.
2. Establish the ability to measure volatility weekly as well as Value at Risk (both sides, VaR-C and VaR-L) and the related 2-sigma outliers for potential high-side forward costs and hedge loss potential, as described under “A Robust Program.” Record all metrics for later analysis and review.
3. Plan a risk-responsive system of hedge decision protocols:
 - a. Begin by establishing some programmatic hedge accumulation that is less than the current lock-and-leave level;
 - b. Establish multiple upside action boundaries whereby small tranches of hedges would be executed to defend each boundary only to the extent needed when the sum of forward costs + VaR-C exceeds the boundary.
 - c. Establish hedge loss thresholds at which contingent strategies would be deployed if the combination of current forward losses + VaR-L exceeds any loss threshold.
 - d. Establish the contingent response plan. Initially, that might simply call for reversing hedges as needed to constrain loss potential, but over a two year period LDCs should gain comfort with options strategies.
4. Record all hedge transactions and positions;
5. Record weekly risk metrics; retain supporting analysis, and document the supporting analysis for all defensive or contingent hedge responses.
6. Establish a risk oversight committee (if not already established) to formalize and ratify all key parameters that will guide the program as well as review results and make modifications as deemed appropriate. Maintain meeting minutes including specific documentation of any material decisions.

These six steps do not show a timeline which again would be company specific, but typically steps 2 and 3 would determine the critical path. The effort might take a year to reach functionality, and perhaps operate as a test program for the second year. In my view, such a test program should be “live” but with transitional program parameters. For example, a company that currently uses a 65% solely programmatic hedge accumulation might decide that it should ultimately move to an 85% maximum, as 25% programmatic hedge accumulation with another 60% maximum defensive hedges (only if needed). In the test program it might decide to hedge 50% programmatically and 25% defensively deferring the implementation of full design parameters to year 3 after it gained experience.

The economic effect of this change would be to hedge less in falling markets, but attain the same or greater hedge ratios in rising markets. The process effect of this would be for LDCs to gain experience with risk-responsive methods, and provide regulatory staff with sufficient data to review program efficacy and procedural compliance.

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