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Fuel and purchased power cost recovery clause
with generating performance incentive factor.

Witness: Direct Testimony of Michael A. Gettings
appearing on behalf of the staff of the Florida Public Service Commission

Date Filed: September 23, 2016

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION STAFF

DIRECT TESTIMONY OF MICHAEL A. GETTINGS

DOCKET NO. 160001-EI

SEPTEMBER 23, 2016

Q. Please state your name, and employment information.

A. My name is Michael A. Gettings and I am Senior Partner and owner of RiskCentrix, LLC. My address is 225 Good Hope Rd., Bluffton, SC.

Q. Please provide a brief summary of your qualifications, particularly as related to energy hedging practices.

A. I have a Bachelor's degree in Mechanical Engineering from Manhattan College (1971) and an MBA in Financial Management from Pace University (1977). I worked for Orange and Rockland Utilities ("O&R") as manager of economic studies in the regulatory area from approximately 1978 to 1982. Beginning in 1982, I ran O&R's non-regulated oil and gas production assets, and with the advent of FERC Order 436 in 1985, I founded their natural gas marketing and trading company, O&R Energy. As president of O&R Energy, I oversaw the adoption of hedging practices when NYMEX natural gas futures contracts began trading in 1991. Before leaving O&R in 1996, I effected the sale of a minority interest in O&R Energy to Shell Oil.

Beginning in 1996, I joined CC Pace, an energy consulting firm in Fairfax VA, and started an energy management practice there. Hedging strategy formulation, risk quantification systems, and hedge advisories quickly became the most significant offerings of that practice, and around the year 2000, the risk management group was a stand-alone division within the firm. For the last 17 years, I have advised utilities, large industrials, and independent generation companies on the formulation of economically efficient hedging programs. Since 2010, I have done so with my own firm - RiskCentrix, LLC. Most recently I have worked for the Washington State public utility commission and Attorney General's office writing a position paper and testifying at collaborative workshops to encourage more robust hedging practices among gas utilities there.

My resume which includes a description of experience, testimony and publications is attached as Exhibit ____ (MAG-1).

Q. Have you designed and run hedging programs for utilities?

A. Yes. I've designed energy risk mitigation programs and provided ongoing advisory services for numerous large public utilities in New York, California, and other states, as well as Canada. In numerous cases I sat as an ex officio member on the utilities' executive risk management committee. I've also done this for an investor-owned utility with provider-of-last-resort obligations, as well as others who simply wanted to upgrade from fixed-percentage hedge accumulations. Finally, I've designed programs for many industrial firms and sat on the executive risk management committee for one independent power producer.

Q. Please describe the nature of your testimony here?

A. My testimony presents a hedging framework for the Commission to consider as an alternative to the current hedging practices that Duke Energy Florida ("DEF"), Florida Power and Light ("FPL"), Gulf Power ("Gulf"), and Tampa Electric ("TECO") follow in procuring natural gas to fuel their generating plants. The core of my testimony will contrast the "targeted-volume" hedging methods currently deployed in Florida with a more robust "risk-responsive" approach that monitors risk and responds to emerging conditions in accordance with preplanned decision protocols. The risk-responsive approach has been supported by quantitative finance methods developed in the 1990's.

I will also describe the reasons for hedging and how to structure objectives in a well-conceived hedging program. I will explain in some detail the methods and advantages of a risk-responsive approach to hedging, and present simulation results that compare the economics of that approach to the targeted-volume hedge accumulation currently deployed by Florida utilities. Finally, I will offer opinions as to how regulatory policy might inhibit or could promote the adoption of better hedge programs.

Q. How is your testimony organized?

A. My testimony is organized in three parts. **Part I - Background** includes a limited discussion of the current hedging practices of DEF, FPL, Gulf, and TECO and a conceptual discussion as to why hedging is beneficial, the definition of key risk management concepts, and perspectives on market history, objective setting, and the shortcoming of fundamental predictions. **Part II - Strategy** provides more detail as to how hedge programs can be improved, including risk-responsive strategy elements, simulated results, and a discussion of the mechanics within a risk-responsive strategy. Finally, **Part III - Regulation** provides a discussion of the regulatory implications and how small changes in regulation could encourage beneficial change.

<u>Part I - Background</u>

Q. In this docket one issue has been whether or not to hedge at all. Do you have a view on this?

A. Yes I do. The purpose of hedging is to minimize customer pain associated with energy-price (or customer-cost) increases. That is different than simply reducing exposure to volatility because customers' sensitivity to pain is not symmetrical. This characteristic suggests hedging provides a benefit to customers.

Q. Please explain your point as to the customers' asymmetric pain.

A. The asymmetry is due to the fact that tolerance for upside cost exposure in rising markets is different than the tolerance for hedge losses in downward markets. Using a simple analogy for residential customers, taking a $500 better vacation with utility-bill savings would be a good thing and if utility hedge losses moderate those savings so that they are $300 rather than $500 it is still a good net outcome despite the $200 foregone savings. On the other hand, that same customer might struggle to meet necessary expenses if faced with an unmitigated $500 increase in utility costs, and that would be a very bad thing. Said differently, hedge losses occur in low-cost markets, so outcomes are still beneficial but less so; in low-cost markets customer impacts are constrained to discretionary choices regarding alternative uses of reduced savings. Cost increases occur in high-cost markets where unfavorable outcomes, if unmitigated, can be severe; also the customers' budget response is more likely to impact non-discretionary spending. So on balance, customers experience greater value from potential cost mitigation than they forego with potential hedge losses.

Q. Is there any other factor that would influence the customers' value realization?

A. Yes. Natural gas prices are lognormally distributed. That is, relative to the average price, upside outliers are much larger than downside outliers. To illustrate, historical price variations since the year 2000 indicate the average price of Henry Hub natural gas has been about $5.00 per MMBtu. Month-end prices have ranged from under $2.00 per MMBtu to about $15.00 per MMBtu. That is, three dollars lower than average, but ten dollars higher than average. Even using a twelve-month smoothing to reflect a proxy for fuel cost adjustments, smoothed prices ranged from over $9.00 to less than $3.00 per MMBtu; that is four dollars above average versus two dollars below. And price peaks tend to last about a year, while price troughs tend to last longer.

Q. Why does this matter?

A. It is self-evident that gas-related customer cost increases, which are double those of cost decreases when unhedged, would argue in favor of a mitigation program. A hedge program increases the probability of small cost changes and decreases the probability of large changes; customers can absorb small cost changes with disproportionate ease, while large changes can be disproportionately painful.

Q. Have you reviewed the 2017 risk management plans filed by the four Florida Utilities?

A. Yes. The plans cover numerous risk elements as well as governance and management controls.

Q. What observations can you offer regarding those plans and please explain how your observations inform the rest of your testimony?

A. My scope here will deal only with the prospective economic performance of the 2017 Risk Management plans, and how the plans could be improved. I will focus on the core structure of those plans rather than specifics due to confidentiality constraints regarding the detailed risk management plans ("2017 RMPs"). Generally all of the utilities propose to accumulate hedges in accordance with a predetermined timeline using a targeted-volume approach. Some discretion is contemplated, but none of the 2017 RMPs seem to measure the risk being managed in a quantitative fashion. The target hedge ratios specified in the 2017 RMPs are sometimes lower than prior targets. I find this concerning, but when limited to a calendar-based hedge program it is a typical reaction to increased scrutiny following significant hedge losses like those of recent years. I will discuss this concern, but more importantly, I will explain how comparable cost mitigation can be accomplished while better managing the risk of hedge losses. In Part II of my testimony, I will propose an alternative approach to hedging utilizing more robust quantitative tools deployed in a risk-responsive fashion.

Q. Would you agree with the goals expressed in the 2017 RMPs?

A. Only in a colloquial sense, but more precision would be very helpful. In all cases the RMP goals are stated as net volatility reduction or some semantic variation of it; some speak of volatility and risk, implying a valid distinction between the two which was never developed in the plans. I think it is important to distinguish volatility from the two-sided risk that derives from volatility, so I will deal with that in my testimony. None of the plans state that they will explicitly measure and manage the upside cost risk for customers, but curiously, the risk management control documents included in the 2017 RMPs do seem to measure the value at risk associated with executed hedge positions. It is self-evident that the primary reason for hedging is to mitigate upside cost exposures, and the potential for hedge losses is an associated consequence which needs to be managed as well. The cost mitigation is primary and the loss potential is possible collateral damage, but the 2017 RMPs only seem to measure the latter. In fact, it was not clear that the risk of loss is being viewed from the customers' perspective; it seemed to focus only on the exposures of trading positions.

At least one company specifies that, its "strategy primarily attempts to enter into hedges on downward gas movements;" yet they assert that they do not attempt to "beat the market." I struggled to reconcile those two assertions, but I will address the issue by discussing the difference between hedging driven by a risk view versus a market view.

Q. Earlier you referred to more robust quantitative tools. What sort of tools do you mean, and would this represent a new skill set for the utilities?

A. I'll explain in some detail, but the most useful of these tools permit the measurement of volatility and the assessment of associated risks, and I believe the companies generally possess capabilities to do so, although the deployment of those tools is not focused on cost mitigation. The governance and controls documents included with the 2017 RMPs generally refer to value-at-risk metrics. Value at Risk (VaR) is a term of art in the field of quantitative finance.

It is a very important concept for managing trading risk or commodity-cost risk. In the governance and controls documents of the 2017 RMPs, VaR is used to control trading risk, but it is never referenced as a driver of a hedge program. I will spend some time discussing its application to natural gas hedging on behalf of customers.

Q. Would you characterize the structure of these plans as typical among utilities in the USA?

A. To answer fairly I will divide the utility industry into segments. There is the regulated investor-owned utility segment which most often deploys targeted-volume hedge accumulation programs like those reflected in the 2017 RMPs. There is the public-power segment which has been far more prone to use risk-responsive programs based on quantitative-finance tools. Finally there is the non-regulated segment consisting of independent power generators and utility affiliates that trade or produce energy for profit, and they too are more prone to use risk-responsive programs.

So, while calendar-based, targeted-volume hedge accumulation is typical of regulated investor-owned utilities, utilities with a different regulatory structure often adopt more sophisticated methods; so do affiliated unregulated operations.

Q. Please explain in more detail what you mean by a risk-responsive hedge program.

A. I will describe more specifics later, but stated simply, risk exposures can be assessed by measuring transient price volatility and the related VaR. Methods to do so were published by a JP Morgan affiliate more than twenty-five years ago. Many companies, including Florida utilities, understand the mathematics of VaR but they often use it to measure risk of credit exposures or as a control on trader activities. The same mathematics can be applied to customers' risk of cost increases or hedge loss potential. A customer-focused, risk-responsive hedge program would establish tolerances for cost increases and separate tolerances for hedge losses, and then formulate a strategy of prescribed responses to defend those tolerances against whatever risk conditions might emerge. In other words, rather than accumulate hedges according to the calendar regardless of how prices and risks might change, risk-responsive programs serve to measure and respond to risk conditions on behalf of customers.

Q. You talk of price volatility as a transient, measurable metric which does not seem to be factored explicitly into the utilities' plans. Can you explain?

A. Yes. Beyond its colloquial meaning, volatility is a term of art in the discipline of financial hedging. It has a very specific meaning. "Observed volatility" is the potential percentage movement in future prices at a specified confidence level over a specified timeframe. For natural gas, when one hears a standardized expression of volatility, it typically refers to the potential for price movements of a specific futures contract or group of contracts over one year at one standard deviation. To illustrate, if the November-2016 NYMEX contract for natural gas exhibited a 30% volatility, that would mean one could be 83% confident that the price of that contract will not increase by more than an indicative 30% in a year. Note that I say indicative because a more precise measure of variability would be asymmetrical, reflecting the lognormal probability distribution (upward magnitude greater than downward), but the single volatility number represents an indicative estimation.

Q. You also referred to value at risk or VaR; how does that relate to volatility and risk?

A. Volatility is a non-directional concept of price variability. Value at Risk is a tangible measurement of volatility-related financial risk; it is directional and it is actionable. VaR can measure cost-increase risks in potential upside markets as well as hedge-loss risk in potential downside markets. These measurements can then serve as the basis for risk-responsive hedging decisions.

Q. Would you elaborate?

A. In hedging, it is useful to articulate cost tolerances for upside markets as well as hedge-loss tolerance for downside markets, and to make risk assessments to determine if those tolerances are at risk of being breached. Hedge decisions can then be guided by those metrics. To facilitate decisions, a useful risk assessment should reflect exposures in aggregate dollar values as well as value per unit; it should consider hedged versus unhedged volumes, the hedger's reasonable response time, and how confidently one would like to prevent painful outcomes. Importantly, it should reflect the asymmetrical risk of price movements; VaR is the metric that does all this. "Cost VaR" measures upward cost risk, while mark-to-market VaR, or "MtM VaR" measures incremental hedge loss potential. Finally, since VaR reflects the incremental risk, the potential for unfavorable outcomes can be calculated by adding VaR to the current position. So a "Cost Outlier" would equal the current forward portfolio cost plus Cost VaR, and the "MtM Outlier" would equal the current forward MtM plus MtM VaR. VaR metrics and the associated outliers measure potential outcomes before they materialize. The lead time is called a "holding period."

The holding period can be set at the discretion of the hedge manager; it should provide reasonable time to execute hedge decisions, but not so long as to render the risk unmanageable. A trading company typically uses a 1-day VaR, but in managing customer costs where the time to execute hedges is longer, something like a 10 or 20-day holding period is more appropriate, but certainly not a full year. And typically metrics would be assessed at some higher confidence than one standard deviation because hedge managers look for higher confidence in acceptable outcomes.

Q. How does this relate to the utilities' objective of reducing volatility?

A. The risk management plans indicate that generally Florida utilities maintain volatility curves and some VaR metrics for control functions, but not to track a customer-cost perspective. A hedge program that accumulates hedge positions in accordance with a calendar schedule pays little attention to these risk metrics because the metrics do not drive hedge responses. Yet the utilities' capability to measure VaR exists or is within easy reach. I believe the phrase "reducing volatility" is being used colloquially in these plans. If volatility were used in a quantitatively disciplined fashion, the assertion of volatility reduction would be far from certain with a targeted-volume hedge ratio.

To illustrate, in early 2008 one-year-forward natural gas market prices exhibited a 25% approximate volatility. A hedge planner who targeted a 50% hedge ratio might have expected a net volatility reduction to 12.5%, but it would not have worked. A year later, market volatility had risen to about 50%, and having attained the 50% hedge ratio the net exposure to prevailing volatility would have been unchanged at 25%. The colloquially stated objective would have led to a measureable risk profile that was unchanged because quantitative discipline was never imposed and the hedge plan did not provide for transient measurements and responses.

The hedge ratio is the tool and the two objectives are tolerable costs and tolerable hedge losses. A fixed target volume of hedges without consideration of the risk conditions permits intolerable outcomes. Florida's principle hedging issue in recent years has been that, following the 2008 price peak, hedging a fixed percentage without consideration of the risk conditions allowed losses to accumulate without a plan for responsive adjustments.

Gas market volatility is like the weather; it is constantly changing. By way of analogy, in Florida and everywhere, air conditioners are not set to target a 50% run rate; they target a temperature. A thermostat measures the temperature and responds by increasing or decreasing the compressor runtime. If a 50% runtime were targeted, the results would be too hot on hot days and too cold on cold days. The objective is comfort on both hot and cold days, and the compressor is the tool, just as tolerable costs and tolerable hedge losses are the objectives and the hedge ratio is the tool.

Q. What conclusion would you draw from this illustration?

A. If the results are important, and clearly they are, a colloquial treatment of volatility will not accomplish fully articulated hedge objectives, and targeting a hedge ratio, which is only a tool, is inferior to targeting explicitly tolerable results. Quantitative discipline is a critical component in attaining tolerable outcomes.

Q. Are there other reasons to impose quantitative discipline?

A. Yes, at least two others. Human nature can be insidious when hedging ignores transient quantitative risk metrics, and a quantitative discipline facilitates better targeted objectives.

Q. Please explain your comment on human nature.

A. This goes to my concern with the current trend of hedge ratio reductions. Without a quantitative framework, it is a common response to increase hedge ratios when recent high-price fears have escalated, and to decrease hedge ratios after those fears subside. When annual plans determine target hedge ratios preemptively, and these metrics are not monitored, the focus is typically on prices; fearful sentiments tend to follow price events, so hedge ratios will often increase when prices are already peaking. Placid sentiments follow price troughs so hedge ratios often decrease when prices have already declined. The result is often self-defeating - to hedge more at higher prices and hedge less at lower prices. Under a regulated environment, where prudency issues are an issue, this instinct could be heightened. Once losses have accumulated, the instinct to curtail future losses can become dominant. Recently gas prices have been in a trough, so I would consider that the current trend of reducing hedge ratios might be driven by these instincts.

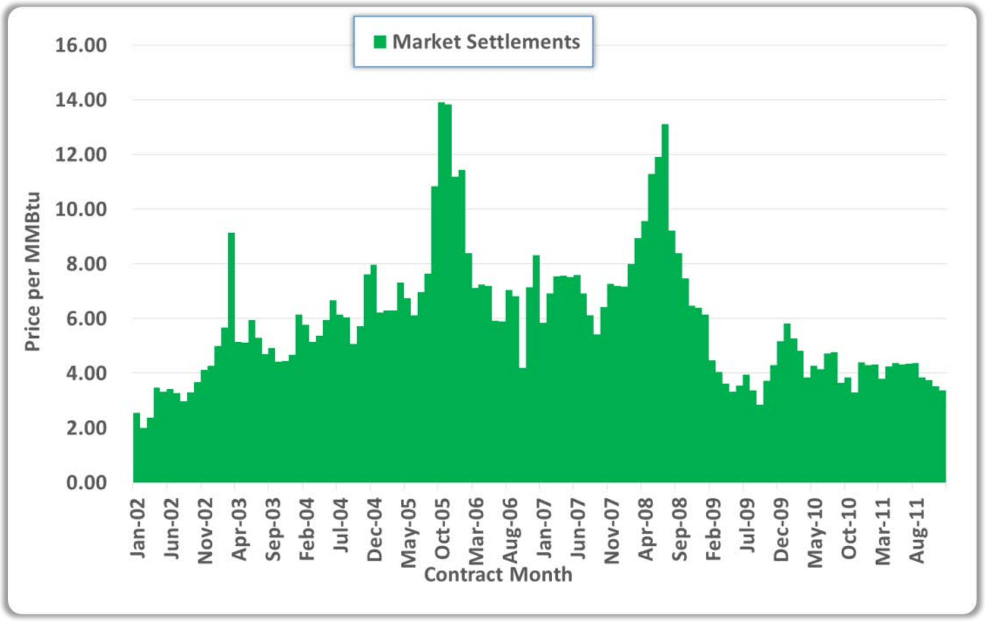
On the other hand, when the hedge manager is focused on volatility and value at risk, hedge responses substantially anticipate price events because VaR measures the potential for price changes before they happen.

Q. Could you put this concern into the context of historical price experience?

A. Yes. Since 2000, there have been two major spikes in natural gas prices; the first was related to hurricane Katrina in 2005 and the second coincided with the financial crisis of 2008.

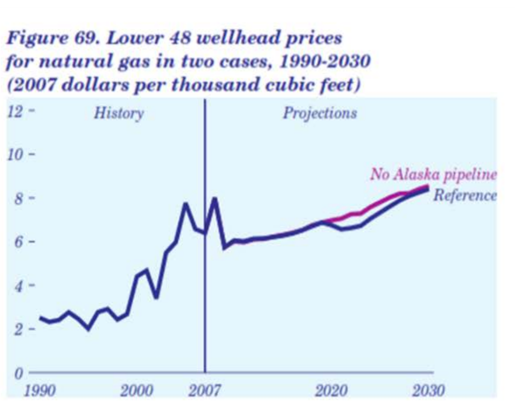
Table 1 shows the magnitude of those spikes in green. In each case conventional wisdom during the price peak held that natural gas prices would continue at higher than historical prices. Consider the EIA forecasts published at the tail end of the 2008 price spike. Table 2 shows the EIA base case forecast (left) and four sensitivity cases (right) published in March of 2009 after the price peak had largely subsided.

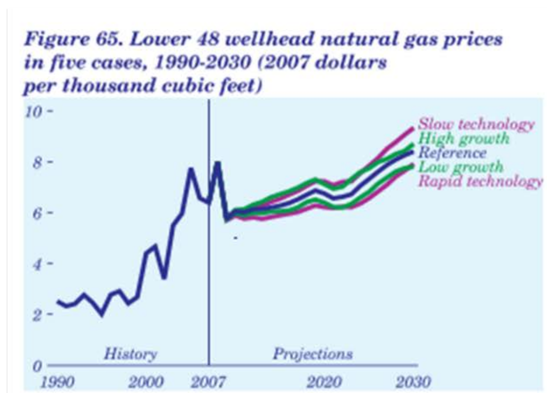
<u>Table 1: Natural Gas Futures Settlements 2002 to 2011</u>



<u>Table 2: EIA 2009 Natural Gas Forecasts</u>

2009 EIA Annual Energy Outlook, March 2009





http://www.eia.gov/forecasts/archive/aeo09/pdf/0383(2009).pdf

Note how, in every EIA scenario, prices were expected to continue at elevated levels compared to historical norms. EIA forecasts are steeped in fundamental analysis. The 2009 Energy Outlook, which covers numerous energy commodities, is 221 pages of facts and projections regarding consumption, production, storage, legislation, regulation, technological evolution, cross-commodity effects, etc. But fundamental confidence in the future is an illusion. Such projections promote a false sense of confidence because our basic instincts find cause-and-effect narratives unrealistically attractive when thinking about the future.

On the other hand, from a quantitative finance perspective, the prompt month price was about $4.00 and prompt month volatility was about 50%, so the 95% confidence range of potential price outcomes over one full year would have been between $1.50 and $10.65. When viewed objectively, the amount of uncertainty is very large, but it can be quantified, and when measured in smaller time increments, it can be managed.

Q. How does a quantitative perspective facilitate better objective setting?

A. Earlier I described how a colloquial view of volatility could result unexpectedly in a net risk position that is no better than the risk posture at the time the strategy was planned, but that only illustrates a symptom. More to the point, when reviewing results of a hedge strategy, the focus is always on two factors: cost increases in upside markets and hedge losses in downside markets. Even when a simple volatility reduction is invoked as the objective, stakeholders will ultimately judge success or failure by those two issues – how much did it mitigate costs or how large were hedge losses. Reinforcing the earlier distinction between tools and objectives, stakeholders will almost never judge success or failure of the hedge program based on whether or not the target hedge ratio was attained; stakeholders instinctively know the difference between the tool (hedge ratio) and the results (tolerable or intolerable outcomes). So the real objectives are two-fold; tolerances should reflect cost limits and hedge loss limits, and objectives should be established to promote results within acceptable dual tolerances. This can only be done using quantitative methods.

Q. Given what you describe, would you view the utilities' calendar-based hedging programs as imprudent?

A. No. In my experience, the vast majority of investor-owned utilities deploy programs of this nature. Without a stated regulatory policy having established higher standards, it would be unreasonable to label such a common practice as imprudent. Yet there is room for substantial improvement.

<u>Part II - Strategy</u>

Q. Please explain how you would structure improvements to a typical hedge program.

A. I would rely on defensive hedges primarily; I'll describe defensive hedge protocols in some detail later. I would use programmatic, or calendar-based hedges, only if the unmitigated risk profile would unduly strain the defensive hedge protocols. Finally I would plan contingent strategies for those rare times when hedge loss potential threatens the hedge-loss tolerance.

Q. Please explain the terms you used in that answer.

A. Hedge strategies consist of a basket of hedge decision rules, and hedge decisions can be categorized in four types: programmatic, defensive, contingent and discretionary. Programmatic hedges are executed based on the calendar regardless of prevailing risk conditions; chronologically they are usually the first executed, but in a well-designed program their importance is dwarfed by the defensive hedge protocols. Defensive hedge protocols monitor cost risk (Cost Outliers described earlier) and execute additional hedges only when risk conditions threaten some tolerance level. To the extent programmatic hedge volumes can be reduced and replaced with defensive protocols, customers can gain greater participation in declining cost markets. Contingent strategies monitor hedge-loss risk (MtM Outliers described earlier) and stand ready to respond to any threatened breach of hedge-loss tolerance by suspending new hedges, using options to constrain hedge loss potential, or unwinding hedges when necessary. A robust program preplans these three hedge responses which together constitute a comprehensive hedge strategy. Finally, some programs make limited use of discretionary hedges – buying hedges when the price is deemed attractive.

Q. While you defined four hedge decision categories, you seemed to deemphasize discretionary hedges in your response. Would you explain why?

A. Yes, a risk management program should measure and manage risk; hedges should be executed based on a "risk view" not a "market view." Responsive risk management strategies do not rely on the prediction of market movements; they rely on measuring and monitoring prevailing risk conditions, so the more precise designation used here is "risk-responsive" programs. A hedge program works most reliably when risk is measured daily or weekly and prospective hedge decisions are pre-planned for risk conditions that might emerge.

Further, the ability to win at market timing is usually illusory. 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 price of gas is likely to rise (or fall) because of today's known fundamental factors. The futures price already reflects a consensus on what those factors mean for the future price of gas, and hedges can only be placed at those prices. All market participants have access to data regarding consumption, production, storage and other factors, and they have reached a consensus on next year's futures price. A given manager might do better or worse than a random guess at market timing, but if that represented a reliable skill, that manager would not be working for a salary. Having said that, a small constrained volume of discretionary hedges does little harm as long as hedge-loss risk is considered and monitored. I will ignore discretionary hedges for the rest of my direct testimony.

Q. Would you explain Defensive Hedge Protocols further?

A. Yes. First, let me state an obvious but important tenet: if no hedges are ever executed, no losses will be incurred, so if practical, the preference would be to hedge only when necessary. That is the nature of defensive hedge protocols. When risk metrics indicate that a defensible cost threshold might be breached over the holding period, hedges would be placed in proportion to the value at risk that must be eliminated – no more often and in no greater quantity. To avoid precipitous hedge accumulation, it is advisable to set interim action boundaries to be defended; the final action boundary would be equal to the ultimate cost tolerance. This might be more easily understood by using graphics to facilitate further discussion.

<u>Table 3: Illustration of Value at Risk as Applied to a Natural Gas Portfolio</u>

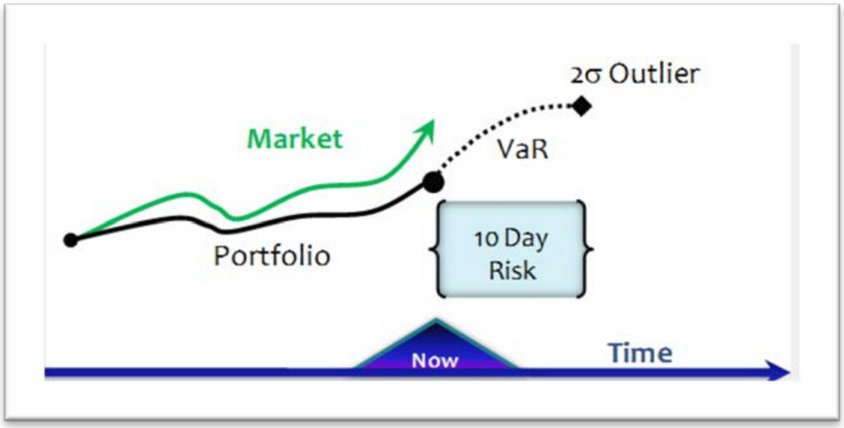


Table 3 illustrates the portfolio's Value at Risk for cost increases as the dotted line over a 10-day holding period. For ease of reference I have called VaR related to cost increases "Cost VaR" and the 2-sigma potential after 10 days, the "Cost Outlier." The portfolio costs and outliers would typically be different from analogous market values because of prior hedges.

<u>Table 4: Comparing Portfolio Risk to a Cost Tolerance or Defensive Action Boundary</u>

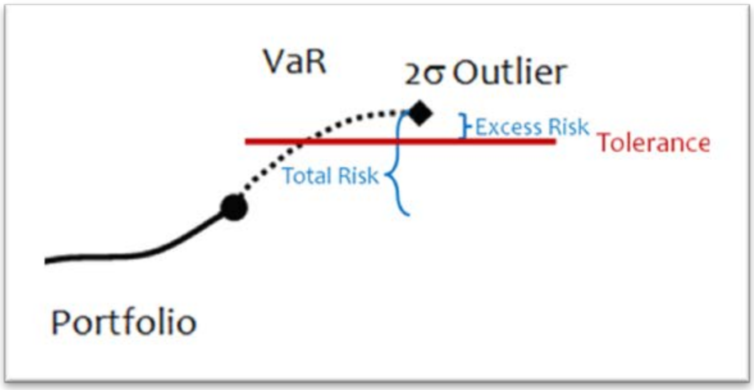


Table 4 illustrates how the Cost Outlier can be compared to a cost tolerance. Note that at any point, if hedges are executed they would be placed at prevailing market values consistent with the then-current portfolio cost; in other words, hedges will not be placed at the higher values burdened by the Cost VaR increment. The total risk reflects price exposure associated with the unhedged portion of the portfolio, so if the hedge manager desired to eliminate the encroachment, he or she would add a volume of hedges in accordance with the formula:

Hedge Increment (%) = Unhedged Ratio (%) x Excess VaR ($)/Total VaR ($)

A hedge of that magnitude would bring the post-hedge 2-sigma outlier down to the action boundary. Using illustrative numbers for clarity, if the portfolio were 40% hedged and 60% unhedged, and the Excess Risk was 5% of the Total Risk, then a 3% hedge increment would constrain the Cost Outlier to the Tolerance (5% times 60%). When the program monitors risk in weekly time spans a 3% hedge increment would be typical of occasional responses; many weeks would call for no hedge increments at all.

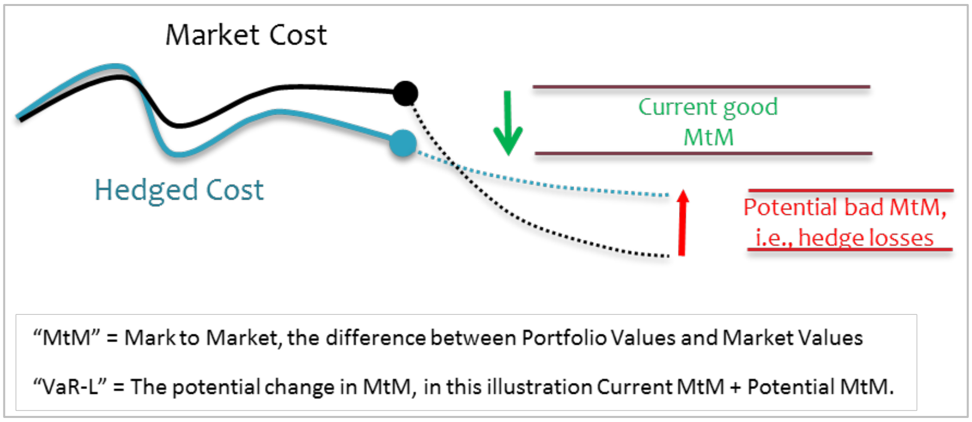
Q. Would you elaborate on the interim defensive action boundaries you referenced?

A. Yes. Natural gas volatility is typically high, so defensive hedge requirements might be precipitously large at times unless the ultimate cost tolerance is defended by interim tiered cost boundaries. Since these tiers are by definition at lower cost thresholds than the ultimate tolerance, I have called them "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% hedge ratio, etc. In this way the hedge manager is not waiting for the potential breach of an ultimate tolerance to hedge all needs in a precipitous manner.

Q. Would you explain what a Contingent Strategy might look like?

A. Yes. Recall that the contingent strategy is triggered when quantitative metrics indicate the risk of hedge losses is a serious concern, so first I will describe those metrics. Table 5 illustrates how hedge losses might accumulate in a market decline because the market price will fall more quickly than the hedged portfolio cost.

Table 5: Potential Hedge Loss Metrics



In the particular case illustrated, the portfolio begins with a favorable cost relative to market ("MtM"), but given the difference between potential downside market movements and downside portfolio movements there is a risk that favorable MtM could turn to hedge losses. To define terms analogous to the upside risk, MtM VaR would be the change in MtM in a downside market, and MtM Outlier would be the potential 2-sigma hedge loss. Both metrics refer to a holding period which might be 10 days, but if the firm's appetite is more averse to hedge losses a 90-day holding period could provide earlier warnings and more response time to adjust hedges.

Just as the defensive protocols defend against intolerable costs, a contingent strategy can be devised to defend against intolerable hedge losses. Since the year 2000, contingent strategies have rarely been necessary, most notably in the market environment following the 2008 price peak. At that time, when prices began collapsing, favorable MtMs, which accrued in the peak, provided an initial cushion. But later, as the favorable MtM faded, pre-planned contingent strategies were helpful in avoiding large losses.

Q. If defensive hedge rules require the establishment of cost tolerances, and contingent strategies require hedge-loss tolerances, how would you determine reasonable dual tolerances?

A. First let me explain some market considerations. Rational choices for cost tolerances and hedge-loss tolerances need to be paired in market-feasible sets. Tolerances are only rational if a strategy can attain them. In other words, for a given strategy a very tight cost tolerance must allow for greater hedge-loss tolerance and vice versa. Also market volatility plays a role. In high-volatility markets both tolerances must be wider to be attainable. Finally, the hedge strategy will play a big role in what can be accomplished. Tolerance pairs can be established by simulating hedge strategies against forward price curves for volatile periods, and then choosing the pairing that fits the firms risk appetite. I have done some simulations for the period from 2002 through 2011 to illustrate how improvements to goal setting and hedge strategy could be implemented.

Q. Why 2002 to 2011?

A. I chose those years because they include two major price cycles, and by 2011 the forward price curve and settlement prices had reached equilibrium.

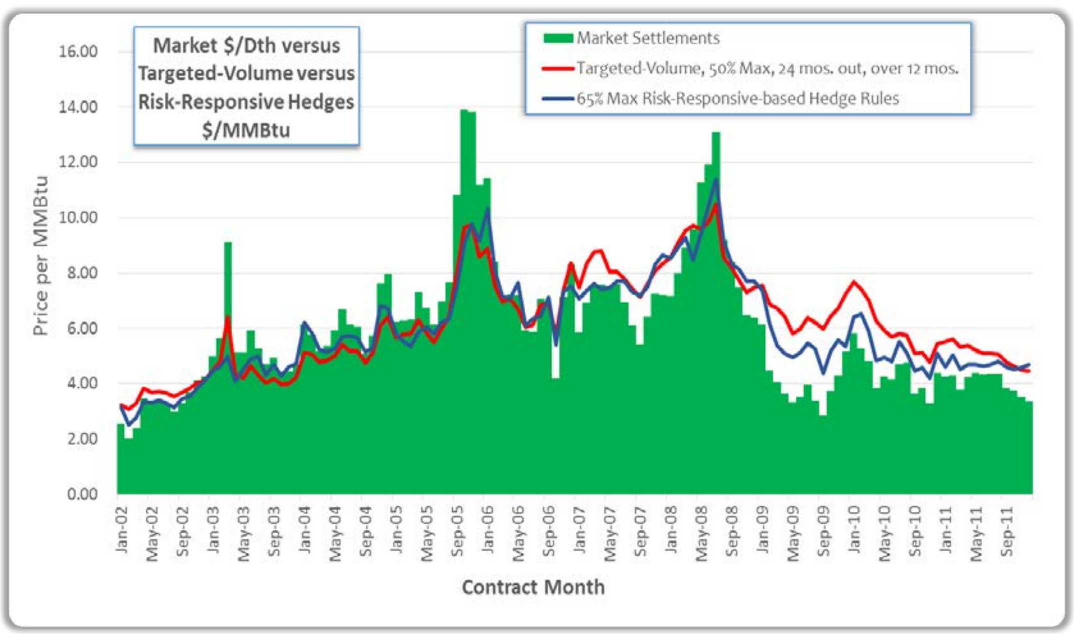
Q. Would you describe the simulations?

A. Yes. I simulated two strategy structures to show comparisons; the first was a targeted-volume strategy, much like those used in Florida to date, beginning 24 months prior to delivery. The second was a risk-responsive set of decision rules emphasizing defensive hedge responses to weekly risk measurements as well as contingent rules that either suspend hedges or unwind them when hedge-loss risk approaches tolerances. In the event of a conflict between defensive and contingent rules, the contingent rules dominated. For the targeted-volume structure, I tested numerous maximum hedge ratios. My objective was to assess worst-case pairings of rolling year-over-year cost increases and rolling 12-month hedge losses. To put the hedge-loss in context, I expressed that metric as a percent of average-year costs. This avoided the distortion which could have been created had hedge losses been expressed as a percent of severely depressed transient costs.

Q. What were the results of those simulations?

A. The graph in Table 6 shows monthly cost outcomes for both structures where targeted-volume hedges reached a maximum 50% hedge ratio and risk-responsive rules were permitted up to a maximum 65% of illustrative generic summer-peaking gas needs. The graph indicates substantially improved participation in the post 2008 downturn of market prices for the risk-responsive hedge rules. For reference, the largest year-over-year cost increase at market prices was about 75%, and obviously no hedge losses would have been incurred at market values. The targeted-volume approach produced a worst-case 38% cost increase and a worst-case 43% hedge loss. The risk-responsive program produced a 37% worst-case cost increase and a worst-case 22% hedge loss as a percent of average-year costs. Expressed as paired "tolerances" for cost increases and hedge losses, targeted volume rules were {38%, 43%} and risk-responsive rules were {37%, 22%}. In other words, the risk-responsive approach produced the same cost mitigation in high-cost periods, while incurring about one-half the hedge losses in the worst market downturns.

Table 6: Monthly Simulation Comparisons



Q. So, would you assert that these programs result in net savings versus market?

A. No. While comparative results have been very favorable compared to targeted volumes and the simulations illustrate this, the goal is not to "beat the market" and it would be inconsistent to assert that these programs do so. In fact, the simulation results indicate that even the risk-responsive hedges were very slightly higher than market costs. The goals are to ensure high confidence as to tolerable outcomes for customer cost increases as well as hedge losses. In other words, regardless of the price turmoil, accept that costs will track the average while ensuring that aberrations in costs and hedge losses conform to the desired risk appetite. In my experience, supported by the simulation results, risk-responsive programs accomplish exactly that. Those are the objectives, and risk-responsive hedging provides a large improvement over market outcomes or targeted-volume programs.

Q. You stated that you tested numerous maximum hedge ratios, what did those results indicate?

A. Table 7 is a plot of the tolerance pairs for various maximum hedge ratios under the targeted-volume structures compared to the risk-responsive strategy. It shows worst-case annual-cost changes increasing from left to right, and worst-over-period annual-loss outcomes increasing from top to bottom. Note that the targeted-volume pairings fall approximately on a diagonal line. This represents the range of choices available at various target hedge ratios under the generic representation of current Florida hedge programs. The blue dots represent the tolerance pairings available under an alternative risk-responsive structure. Only the maximum hedge ratio was varied to show a few blue dots. It should be noted that the risk-responsive structure can be adjusted in numerous ways and the structure shown is not particularly complex; for example, it uses no options. But the blue dots fall to the upside and left of the diagonal line. In other words it is superior as to cost containment and hedge loss containment. Had more strategies been evaluated, an efficient frontier could have been constructed; that is, a line defining superior outcomes so that any tolerance pairing downward and rightward would have inferior merit.

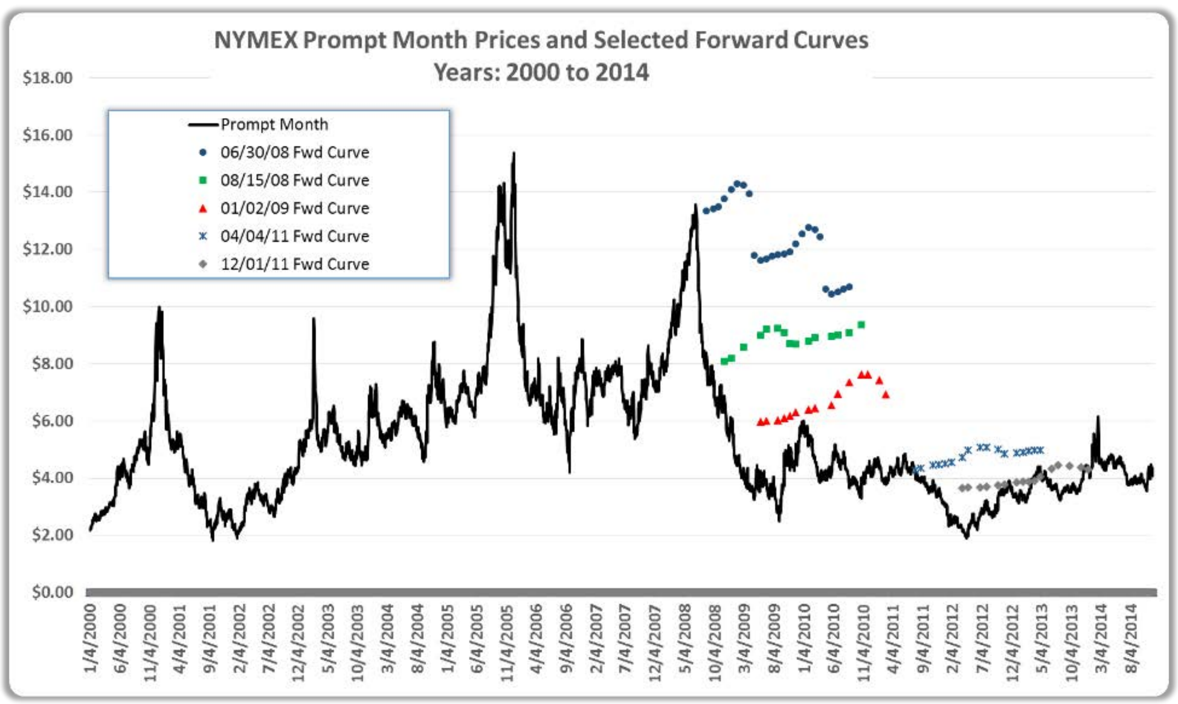
Table 7: Simulated Tolerance Pairs

Q. Given your testimony so far, how would you explain the multi-billion dollar losses experienced in Florida?

A. Calendar-based hedging, or what I have called targeted-volume hedging, exercises no quantitative risk monitoring in deciding to execute hedges. In theory, for a very large sample over a thousand years, if the program used a fixed-hedge ratio, average hedged costs should be about equal to market costs, but over a small history of five years there is no such comfort. Also, as described earlier, human nature can be insidious and hedge ratios rarely stay fixed over the long term.

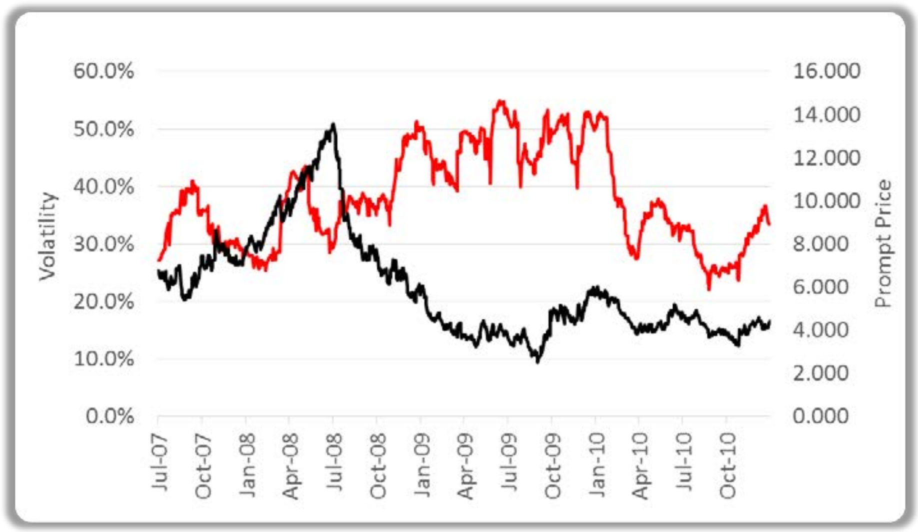
Table 8 will help highlight the small-history problem. Table 8 shows the prompt month price trends from 2000 through 2014 as a black continuous line. The prompt month is the nearest futures contract and it closely resembles spot prices so the graph will look familiar. The focus here is on the forward curves that are also plotted from 2008 onward. The forward curves represent monthly futures-contract values at which hedges could have been placed as of each of the dates shown in the legend. Inspection of this graph makes it obvious that any hedges placed following the emergence of the 2008 price peak would have yielded losses when compared to the contract expiry price, approximated by the prompt month price in black. That was true through the end of 2011, so four of the five years from 2008 to 2012 would have been costly for targeted-volume hedge plans. I did not illustrate the 2005 price period, but I suspect the same would have been true for the 2005 Katrina-related price peak. Since calendar-based hedges do not utilize risk metrics, companies running targeted-volume programs would have hedged throughout this timeframe and suffered the associated hedge losses. While the spot price graph might have been misinterpreted to indicate each price peak passed in little more than 12 months, the legacy of high cost calendar-based hedges actually went on for years.

Table 8: NYMEX Prompt Month Prices and Selected Forward Curves



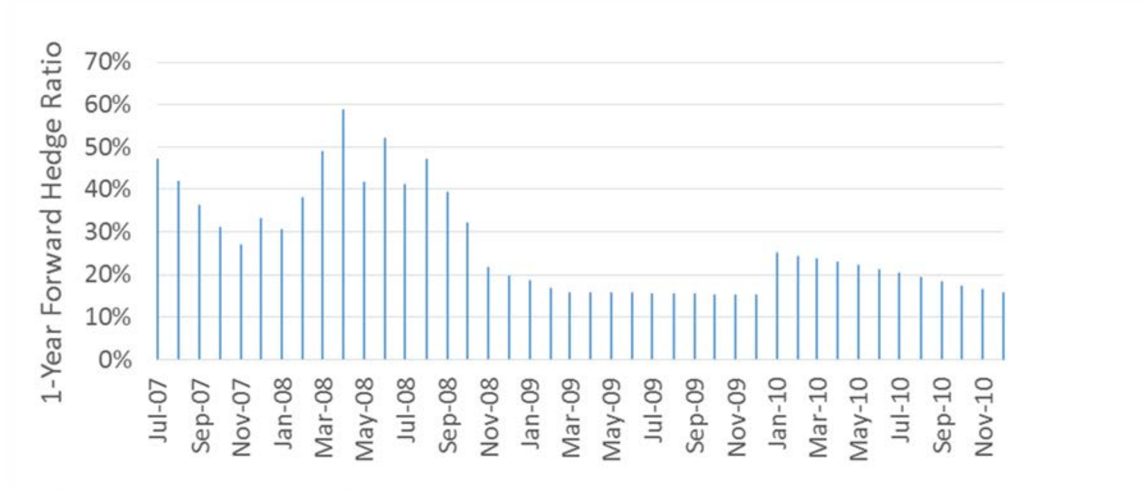
Tables 8 and 9 confirm why risk-responsive programs would have performed better. Table 9 plots the average volatility (red) for the 12 nearest NYMEX contract months at any point in time from 2007 through 2011 along with the prompt-month prices (black). Consider that from 2009 onward, prices were falling but volatility did not fall precipitously until early 2010.

<u>Table 9: Measured Volatility, Average 12 Forward Months, from mid-2007 through 2010</u>



As prices fell and volatility remained high the risk-responsive decision rules shifted from cost concerns to hedge-loss warnings. The strategy's response to that transition is reflected in the simulated hedge ratio which is shown in Table 10. Any risk-responsive program that was averse to hedge-loss tolerances would have substantially reduced or eliminated new hedges shortly after the price peak. In the case of the simulated strategy, hedges were suspended and then shortly later unwound as the price collapse continued. More sophisticated strategies could have used options to navigate these conditions, but computational complexity did not permit this in the Excel simulations.

<u>Table 10: Quantitative-Finance Hedge Ratio, from mid-2007 through 2010</u>



Q. You haven't yet spoken about the hedge window; do the hedge-loss results for programmatic hedges vary much with different hedge windows?

A. Simulated hedge losses do not seem to change much with different hedge windows. Table 11 shows the comparison of worst-year hedge losses for targeted-volume hedging using various hedge windows for the period from 2002 to 2011. The chart indicates that the loss potential was about the same for any reasonable hedge accumulation timeframe.

<u>Table 11: Maximum Losses for Numerous Targeted-Volume Hedge Windows, 2002 - 2011</u>

Programmatic Worst Loss for Various Hedge Accumulation Windows		
Through	Starting	
Mo.# 6	Mo.# 12	-38%
Mo.# 6	Mo.# 18	-41%
Mo.# 12	Mo.# 24	-43%
Mo.# 12	Mo.# 30	-41%
Mo.# 24	Mo.# 36	-40%
Mo.# 24	Mo.# 42	-38%
Mo.# 24	Mo.# 48	-36%

Expressed as % of Average Annual Costs

The reason seems to be related to the recent cycle times from price peaks to price troughs. A careful look at Table 1 reveals that the time from peak to trough for the 2005 and 2008 settlements was about one year. Instinct often leads hedge managers to choose a short hedge window like one year on the theory that a short propagation time should moderate potential losses, but that can result in a lack of smoothing and fairly radical price changes when hedge-to-settlement periods align with market cycle times. Yet longer timeframes allow price migration to propagate longer; the two effects seem to balance, so calendar-based hedging offers little flexibility in addressing loss potential.

<u>Part III – Regulation</u>

Q. Would you describe why you think investor-owned utilities run targeted-volume programs when more sophisticated methods have been available for some time?

A. Customers are a core constituent for utilities but so are shareholders. A regulated utility assumes some shareholder risk whenever it hedges, and that risk is also asymmetrical. In the absence of a more definitive regulatory compact, a utility with a large 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; but if costs fall customers' bills will 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.

The utility's asymmetry is exactly opposite that of its customers' described earlier. Customers' risk profiles are improved by rational hedging, but the utility shareholders' risk profile is exacerbated. Formulation of a new regulatory approach might attempt to reconcile the conflict in order to extract more value for ratepayers by reducing prudence risk for utilities who design and execute more robust programs. I will address this later.

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 implicit objectives. Typically those objectives are 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) constrain 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 calendar-based hedge programs, where hedge accumulation decisions are made at a policy level at a single point in time for a pre-determined target volume; that policy is then executed as specified, and left in place for the full term with no risk-responsive protocols. If the plan is approved and then executed as crafted, prudence risk is virtually non-existent.

Q. Have you considered how a new regulatory approach might be formulated?

A. I have. The goal would be to promote a more robust structure for hedging strategies while not being overly prescriptive. The first step would be to require contemporaneous weekly risk measurement and monitoring from the customers' perspective, to be reported to the Commission quarterly. These metrics would cover the current fuel adjustment year plus two more, no fewer than twenty-five forward months segmented by fuel adjustment years. Those weekly metrics would include the transient value of the forward gas portfolio for each fuel adjustment year, reflecting hedged volumes at their hedged values and unhedged volumes at market prices. Recorded metrics would also include the transient mark to market, Cost VaR and MtM VaR, as well as the related outliers, Cost Outlier and MtM Outlier. These were all described earlier. The very existence of contemporaneous weekly risk metrics will change behavior and eventually inform prudence determinations. Exhibit ____ (MAG-2), at the end of my testimony, shows a sample three-page format for such a report.

Strategy formulation would be left to utility management, but after one year of reporting risk metrics, I would expect strategies to reflect lower programmatic hedge targets, relying more heavily on defensive hedging protocols and contingent response plans to constrain hedge loss potential. The simple act of requiring such measurement and reporting will change the utilities' perspective on prudence risk. I cannot imagine a scenario where any utility identifies unusually high risk of upside cost exposures or potential high-magnitude hedge losses, and then chooses to ignore those metrics without prudence concerns.

I would recommend that the commission specify common parameters for these reports. For example, cost-oriented risk metrics, could use a 20-workday holding period at 2 standard deviations. If the sentiment is more risk-averse with respect to losses, a holding period of 90 workdays would ensure earlier warnings and a longer response time. These were the holding periods used in the simulations described earlier.

After the first year of risk reporting, I would require that each annual filing of risk management strategies relate the strategy to the risk metrics. This would further promote an improved blend of programmatic, defensive, and contingent protocols. Once again, the prudence risk profile would be better articulated. Companies filing a programmatic-dominant plan will face greater prudence exposures than those with more robust strategies.

Later as experience is gained, the Commission might consider making a policy statement indicating a rebuttable presumption of prudence if key strategy elements are incorporated in the risk management plans and then executed per plan.

Q. You have used various terms in your testimony that might be new to some; could you provide a glossary of terms used in your testimony?

A. Yes. Exhibit **____** (MAG-3) lists the terms as I have defined them throughout the testimony.

Q. Does this conclude your testimony?

A. Yes it does.

Curriculum Vitae

Michael A. Gettings
Senior Partner

Industry Experience: 40 years

Qualifications and Experience:

Mr. Gettings is the Senior Partner at RiskCentrix, LLC. In reverse chronological order his career has included:

- 20 years as executive consultant in the energy field, including commodity risk management and risk-cognizant strategic planning with an emphasis on utilities' needs (RiskCentrix and Pace Global)
- 10 years as founder and president of a natural gas marketing and trading company (O&R Energy)
- 10 years in utility ratemaking and financial/economic analysis (Orange and Rockland Utilities)

As a consultant Mr. Gettings has participated as an ex officio member on the executive risk management committees of numerous utilities, including some of the nation's largest public power companies. He established numerous utility and industrial risk mitigation programs and added clarity and discipline to many more. He founded the Risk and Utilities Division of Pace Global (since acquired by Siemens) consisting of risk consulting and advisory services, risk systems integration, and utility strategy development. Mr. Gettings has been an advisor to the executive suite of numerous utilities, Fortune 500 industrials, and wholesale trading companies.

Earlier in his career, following the deregulation of gas markets, Mr. Gettings started O&R Energy, a gas trading and marketing firm, and guided that company through its extraordinary growth as third-party gas supply emerged as a major factor in the energy industry. Perhaps more important to today's environment, following the advent of the NYMEX futures exchange in the early 1990's, Mr. Gettings established a hedging program at O&R Energy which positioned him as an early adopter and ultimately as an expert in the field of risk mitigation.

Finally, his experience in the fields of trading and risk mitigation is supplemented by an early grounding in utility ratemaking, regulatory affairs, and financial analysis for a combination electric and gas utility that operated in three states (NY. NJ, PA).

Examples of Mr. Gettings' relevant experience include:

- Consulted on numerous strategic issues, particularly in the utility industry, including areas related to risk mitigation, resource planning, rating agency issues, acquisitions, ratemaking and regulatory implications, etc.
- Directed development of a rigorous and customizable structure of hedging decision protocols for energy risk mitigation and links to related corporate-level strategic objectives. These protocols consist of programmatic, defensive, and discretionary hedging rules which provide a covenant between executives and hedging managers, thus enabling responsive but well-conditioned risk mitigation tied to P&L, cost-of-service, or other objectives.

- Developed an Enterprise-wide Risk Management ("ERM") approach that linked parametric and contingent-event risk assessments into a financial management process. Related ERM perspectives into development of rating agency storyboards.
- Initiated the development of various trading and risk management tools including proprietary market timing models and models to simulate performance against historical or postulated price environments.
- Initiated the development of web-based information systems for the routine measurement of risk, and tied these systems to business perspectives relating market risks to overarching corporate objectives such as earnings, competitiveness, etc. In addition, developed customized application of these tools to various client cultures and risk appetites.
- Founded and presided over natural gas marketing and trading company. As president of O&R Energy, was responsible for strategy and oversight related to commercial sales and trading activity of approximately $1 billion annually. Also initiated and negotiated the sale of an interest to a major oil company.
- For utilities and industrial concerns, drafted and saw through to board of directors' ratification, risk policy and procedure documentation.

Publications & Testimony

Quoted in Wall Street Journal, U.S. Utilities' Natural-Gas Hedges Turn Sour, Rebecca Smith, April 2016

Natural Gas Utility Hedging Practices and Regulatory Oversight, a white paper prepared for The Washington Utilities and Transportation Commission, July 2015

NARUC Hedging Panel, February 2015 Presentation / Utilities Deserve Clarity as to Prudence Standards

Prudence Standards for Utility Hedging, NARUC Winter Committee Meetings, February 2015 White Paper

By Executive Decision, Public Utilities Fortnightly, October 2005
- Henry Fayne, Michael Gettings, Wes Mitchell, and Gary Vicinus

Provided expert witness testimony in legislative, regulatory, and civil proceedings in NY, NJ, PA, DE, WA, etc. Topics have included:

- In the risk domain: strategy formulation, economics and risk of long term commitments, policies and procedures, trading incentives, evaluation of hedge structures, quantification of damages, etc.
- In the non-risk domain: ratemaking support, capital project economics, off-shore wind power economics, marginal and embedded cost assessments, load research and forecasting, etc.

Boards:

Mr. Gettings serves or has served on the boards of directors of RiskCentrix, Pace Global, O&R Energy, Atlantic Morris Broadcasting, and related holding companies. He serves or has served as ex officio member/advisor to the Executive Risk Management Committees of Long Island Power Authority, New York Power Authority, Duquesne Light Company, and numerous industrial or power development firms.

Education: MBA – Finance, Pace University
BS Mechanical Engineering, Manhattan College

Page 1 of 3
Current Gas Year

2017 Q-1 Report

				Holding Period	Confidence						Holding Period	Confidence	
Parameters:		For Cost Metrics:							For MtM Metrics:				
	Metrics for Week Ending												
Report Date:	1/6/2017	1/13/2017	1/20/2017	1/27/2017	2/3/2017	2/10/2017	2/17/2017	2/24/2017	3/3/2017	3/10/2017	3/17/2017	3/24/2017	3/31/2017
	Where reports include a mix of actual and forecast periods, metrics reflect no risk for settled positions.												
Current Gas Year, Annual													
Projected Supply Needs:													
Hedge Ratio:													
Unhedged Ratio:													
$/MMBtu, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													
$000s, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													

Page 2 of 3
Plus One Gas Year

2017 Q-1 Report

Parameters:	Cost Metrics:	Holding Period	Confidence	MtM Metrics:	Holding Period	Confidence

Report Date:	Metrics for Week Ending												
	1/6/2017	1/13/2017	1/20/2017	1/27/2017	2/3/2017	2/10/2017	2/17/2017	2/24/2017	3/3/2017	3/10/2017	3/17/2017	3/24/2017	3/31/2017
Plus One Gas Year, Annual													
Projected Supply Needs:													
Hedge Ratio:													
Unhedged Ratio:													
$/MMBtu, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													
$000s, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													

2017 Q-1 Report

Parameters:	Cost Metrics:	Holding Period	Confidence	MtM Metrics:	Holding Period	Confidence

	Metrics for Week Ending												
Report Date:	1/6/2017	1/13/2017	1/20/2017	1/27/2017	2/3/2017	2/10/2017	2/17/2017	2/24/2017	3/3/2017	3/10/2017	3/17/2017	3/24/2017	3/31/2017
Plus Two Gas Year, Annual													
Projected Supply Needs:													
Hedge Ratio:													
Unhedged Ratio:													
$/MMBtu, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													
$000s, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													

<u>Glossary of Terms</u>

<u>Action Boundaries</u>

Tiered interim tolerance levels that will trigger incremental hedging before risk metrics threaten ultimate tolerances. 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% hedge ratio, etc.

<u>Confidence Level</u>

A specified probability of the likelihood that prospective outcomes might exceed risk estimates. When risk estimates are specified at a 97.5% confidence level, the assertion is that only 2.5% of outcomes will exceed the risk assessment.

<u>Contingent Strategy</u>

A hedge protocol whereby hedging is suspended or modified to constrain loss potential in response to risk conditions that threaten a hedge-loss tolerance.

<u>Cost Outlier</u>

Measured from the customers' perspective, the potential for unfavorable cost outcomes over a specified holding period at a specified confidence level. Cost Outliers equal the current hedged portfolio value plus Cost VaR.

<u>Cost VaR</u>

Measured from the customers' perspective, the potential change in costs over a specified holding period at a specified confidence level.

<u>Defensive Hedging</u>

A hedge protocol whereby hedges are accumulated in response to risk conditions that threaten a cost tolerance or an interim "action boundary"

<u>Dual Tolerances</u>

An attainable, market-compatible pairing of Cost Outliers and MtM Outliers that would be marginally acceptable in the formulation of hedge strategy. For a given strategy, a very tight cost tolerance must allow for greater hedge-loss tolerance and vice versa.

<u>Holding Period</u>

A finite time period for the measurement of potential value migration. The holding period is typically consistent with the hedger's response time. While the hedge horizon might be multiple years, any risk estimate propagated over long time frames would be unmanageable, the holding period facilitates the management of risks in smaller time increments, from one risk assessment to the next.

Market VaR

The potential change in unhedged market values over a specified "holding period" at a specified "confidence level."

Mark to Market ("MtM")

The difference between market values and hedged values, expressed either as price per MMBtu or aggregate dollars.

MtM Outlier

The potential for unfavorable mark-to-market outcomes over a specified holding period at a specified confidence level. MtM Outliers equal the current portfolio MtM plus MtM VaR.

MtM VaR

The potential change in mark to market over a specified holding period at a specified confidence level.

Programmatic Hedging

A hedge protocol whereby hedges are accumulated on a calendar basis without consideration of transient market conditions. While programmatic protocols could constitute a small part of a risk-responsive strategy, they constitute the entirety of a targeted-volume strategy.

Prompt Month

The first month for which futures contracts trade.

Risk-Responsive Hedge Strategy

A strategy which depends on the measurement of transient risks, with respect to both high cost potential and large hedge loss potential, and utilizes preplanned responses to defend tolerable outcomes.

Targeted-Volume Hedge Strategy

A strategy which depends solely on calendar-based hedge accumulation without measuring transient risk.

Value at Risk ("VaR")

The potential change in value for any position or portfolio over a specified "holding period" at a specified "confidence level." VaR may be expressed in aggregate dollars or value per unit.

Volatility

Volatility is the potential percentage movement in future prices at a specified confidence level over a specified timeframe. For natural gas, when one hears a standardized expression of volatility, it typically refers to the potential for price movements of a specific futures contract or group of contracts over one year at one standard deviation.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.	DOCKET NO. 160001-EI DATED: September 23, 2016

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that the testimony of Michael A. Gettings on behalf of the staff of the Florida Public Service Commission was electronically filed with the Office of Commission Clerk, Florida Public Service Commission, and copies were furnished to the following, by electronic mail, on this 23rd day of September, 2016.

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