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Direct Testimony of Michael A. Gettings, Appearing on Behalf of the Staff of the Florida Public Service Commission

Date Filed: August 10, 2017

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

ON BEHALF OF COMMISSION STAFF

DIRECT TESTIMONY OF MICHAEL A. GETTINGS

DOCKET NO. 20170057-WS

AUGUST 10, 2017

Q. Please state your name, and employment information.

A. My name is Michael A. Gettings and I am Senior Partner and principal 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, and I testified in Docket 160001-EI before this Commission on the same topic. 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 many 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 have also done this for an investor-owned utility ("IOU") with provider-of-last-resort obligations, as well as other IOUs 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 updated discussion and analysis regarding hedging methodology and the associated regulatory framework that I suggested in Docket 160001-EI. In that testimony I presented a "risk-responsive" hedging approach for the Commission to consider as an alternative to the prior hedging practices that Duke Energy Florida, LLC (DEF), Florida Power & Light (FPL), Gulf Power (Gulf), and Tampa Electric Company (TECO) followed in procuring natural gas to fuel their generating plants. Then and now, I have produced analyses contrasting the calendar-based, "targeted-volume" hedging methods that have been deployed in Florida with a more robust risk-responsive approach that monitors risk and responds to emerging conditions in accordance with preplanned decision protocols. I have utilized the risk-responsive approach in managing client portfolios since the late 1990s. These methods have been supported by quantitative finance methods developed in the early 1990s.

In my testimony in the earlier docket, I deployed a risk-simulation model to illustrate the advantages of measuring and then responding to risk metrics. For this testimony I have improved that model in order to facilitate more efficient strategy comparisons, and to better reflect conditions when hedging should be suspended or hedge ratios reduced in response to the measured potential for hedge losses. I will present results of that analysis.

Certain discussions from my testimony in Docket 160001-EI are integral to my testimony here, so I will incorporate them directly to avoid the necessity of revisiting prior testimony. In that regard, I will reiterate the reasons for hedging and how to structure objectives in a well-conceived hedging program. I will explain in summary the methods and advantages of a risk-responsive approach to hedging, and present simulation results that display graphically the advantageous economics of that approach. Throughout my testimony I will offer arguments as to why some of the criticisms the IOU testimony leveled at risk-responsive methods misstate the concepts and functions of the quantitative-finance based risk-responsive approach.

I will offer opinions as to how regulatory policy could promote the adoption of better hedge programs. In that regard, I will avoid being prescriptive as to the mix of hedges that should be used or what might be appropriate tolerances for the IOUs, but I will strongly assert the case for mandating that companies measure risk weekly, report appropriate metrics, and relate their hedge strategies to those metrics when they formulate plans as well as when they report results.

Finally, I will offer some comments on the out-of-the-money call option strategy ("OTM strategy") that has been proposed by the utility parties. As of this writing I have yet to see the analytical support for the IOU proposal, but I have done some quantification of the magnitude of call-option expenditures necessary to deploy the OTM strategy.

Q. Some of these concepts are complex; are there any key overviews you would hope the Commission might glean from your testimony?

A. Yes. I would like to discuss some basic points before delving into the details.

The first point is that to manage risk, one must measure risk. There are few things that can be managed blindly, particularly when the issues to be managed are likely to result in billion dollar cost swings if done poorly. Some have likened commodity risk management to insurance. But insurance is normally aimed at paying modest premiums to protect against unlikely, but very costly possibilities which are beyond our control. We buy life insurance, health insurance, and car insurance, all protecting unlikely, possibly catastrophic events driven substantially by external forces, and the cost of insurance is always a small fraction of the potential liability.

On the other hand, we manage almost all core functions that could result in a continuum of good or bad outcomes. People manage their careers, their expenses, and their investments; they do not ignore relevant metrics and simply insure those things. And to manage them, people monitor and respond to circumstances; they do not do so blindly.

Companies manage their investments, expenses, hiring practices, their asset performance, etc.; again, they do not buy insurance and turn a blind eye to important metrics. I contend that commodity-cost risk is a function to be actively managed, not an insurable liability.

The second point is that to manage risk effectively, one must acknowledge reasonable tolerances. And with commodity-price risk, bad things come in two flavors – unacceptable costs or unacceptable hedge losses. Tolerances – statistically attainable tolerances for each directional risk - must be the drivers of the risk strategy.

Finally, building a risk-responsive hedging function takes some time and effort – probably six months to a year depending on systems already in place. Managing anything of importance does, and commodity cost management is a core function for utilities. Banks manage money and there is no large bank that does not run a risk management function steeped in quantitative measurements of risk. Similarly, energy trading companies and non-utility generators manage risk using methods similar to the risk-responsive functions I will describe. Public-entity utilities, because regulatory concerns are less paramount, run such systems as well. Ultimately, Florida's IOUs might decide to use options-heavy tactics to manage their natural gas cost risk, but I would suggest whatever tactics are ultimately deployed, they should be based on risk measurements and responses, not preemptive blind judgments.

Q. How is your testimony organized?

A. My testimony is organized in four parts. **Part I - Background** includes a limited discussion of the prior 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 – Risk-Responsive Strategy** deals with strategy formulation; it provides more detail as to how hedge programs could be improved, including risk-responsive strategy elements, simulated results, and a discussion of the mechanics within a risk-responsive strategy. It should be noted that my discussion of specific strategy parameters is not intended to be prescriptive. Rather, it is meant to illustrate how risks can be managed using value-at-risk metrics. **Part III - Regulation** provides a discussion of the regulatory implications and how small changes in regulation could encourage beneficial change. Finally, **Part IV – OTM Strategy** discusses issues with assertions made by the utilities regarding the risk-responsive approach and their own OTM Strategy proposal.

Q. Are you sponsoring any exhibits for this proceeding?

A. Yes, I am sponsoring the following exhibits:

- MAG-1 – Curriculum Vitae
- MAG-2 – Sample Quarterly Risk Report
- MAG-3 – Glossary of Terms

Part I - Background

Q. 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-than-planned vacation with unexpected utility-bill savings when prices fall 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 seems 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. You've stated in previous testimony that you reviewed the 2017 risk management plans (RMPs) filed by the four Florida utilities. Do you believe they are relevant now, and do you have any observations regarding those plans?

A. The plans are probably only meaningful in terms of the hedging objectives and strategic direction prior to the 2016 workshops, and the implications of at least one detail contained in those plans, i.e., the use of Value-at-Risk (VaR) as a control metric. As I understand it, the Commission will ultimately be deciding at least two issues – will hedging be done and if so, how will it be governed from a regulatory perspective? I am hopeful that one very favorable result of recent workshops has been the refinement of the prior consensus hedging objective which was "mitigating volatility." If consensus exists now that more explicit two-fold objectives are appropriate (constraining costs as well as hedge losses), that is a foundational change. Assuming hedging is continued or, in some cases, resumed on some stipulated schedule, strategies must deal with constraining cost increases as well as the magnitude of potential hedge losses.

The question then becomes how to establish a regulatory framework that encourages successful achievements with respect to new and better articulated objectives. I contend that incorporating the measurement of risk exposures in a new regulatory approach will encourage better practices and outcomes, and that is why the mention of VaR metrics in the RMPs is important. Apparently, the basic quantitative-finance functionality exists and is understood by the IOUs, so implementation of risk monitoring procedures will require a change in design parameters and report formatting, not the adoption of new quantitative methods.

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. 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 seemed to measure the latter. In fact, it was not clear that the risk of loss was viewed from the customers' perspective; it seemed to focus only on the exposures of trading positions.

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 has not been 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. 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 VaR 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 increases, 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.

This problem of human nature exists regardless of what financial instruments are used. The IOUs are currently proposing an out-of-the-money call option strategy (OTM strategy) that simply buys options on a calendar basis. Their new strategy is much like the old one except it uses call options rather than swaps. Later I will explain how call option prices change as gas prices and volatilities rise. I will explain how human nature is likely to render the OTM strategy ineffective during stressful times when risk mitigation is most important.

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.

Table 1: Natural Gas Futures Settlements 2002 to 2011

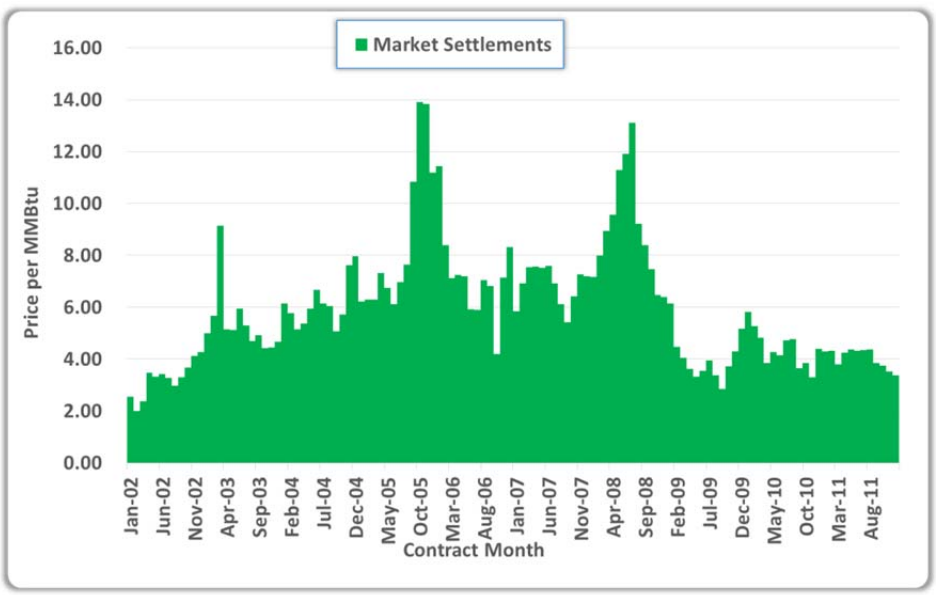


Table 2: EIA 2009 Natural Gas Forecasts

2009 EIA Annual Energy Outlook, March 2009

Figure 69. Lower 48 wellhead prices for natural gas in two cases, 1990-2030 (2007 dollars per thousand cubic feet)

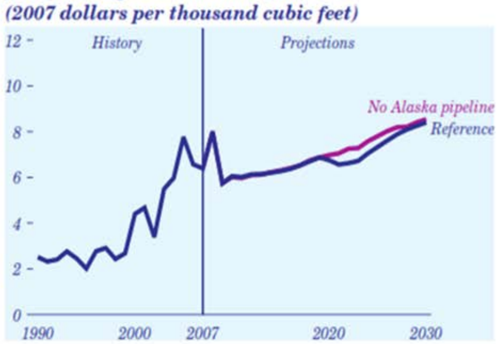
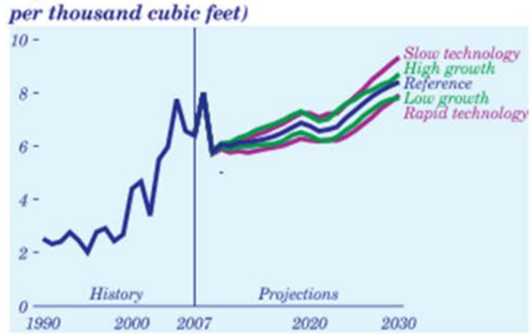


Figure 65. Lower 48 wellhead natural gas prices in five cases, 1990-2030 (2007 dollars per thousand cubic feet)



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.

<u>Part II - Risk-Responsive 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 preplanned 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.

Table 3: Illustration of Value-at-Risk as Applied to a Natural Gas Portfolio

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.

Table 4: Comparing Portfolio Risk to a Cost Tolerance or Defensive Action Boundary

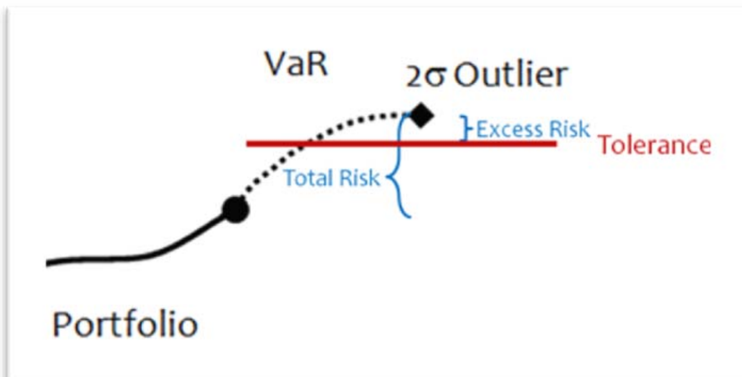


Table 4 illustrates how the Cost Outlier can be compared to a cost tolerance. Note that at any point, if hedges are executed they would be placed at prevailing market values consistent with the then-current portfolio cost; in other words, hedges will not be placed at the higher values burdened by the 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.

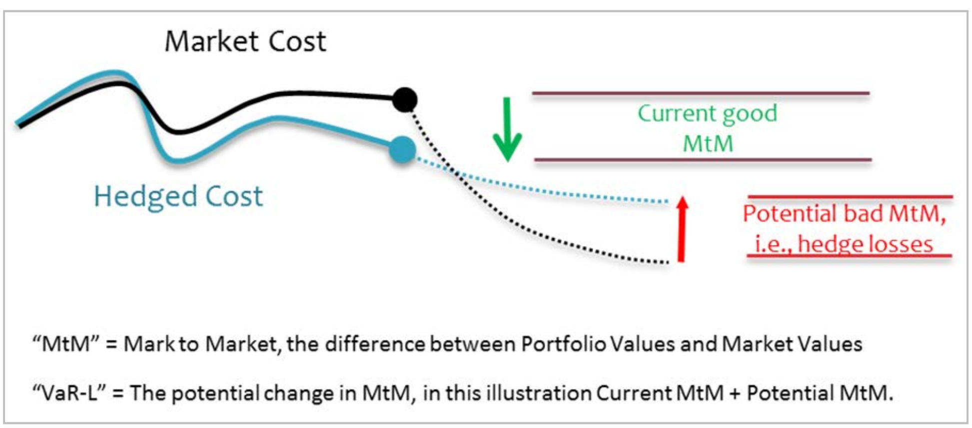
Q. Would you elaborate on the interim defensive action boundaries you referenced?

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.

<u>Table 5: Potential Hedge Loss Metrics</u>



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 20 days, but if the firm's appetite is more averse to hedge losses a longer 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, preplanned 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 2001 through 2016 to illustrate how improvements to goal setting and hedge strategy could be implemented.

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 suspend hedges and unwind them when hedge-loss risk approaches tolerances. In the event of a conflict between defensive and contingent rules, the contingent rules dominated.

Q. What were the results of those simulations?

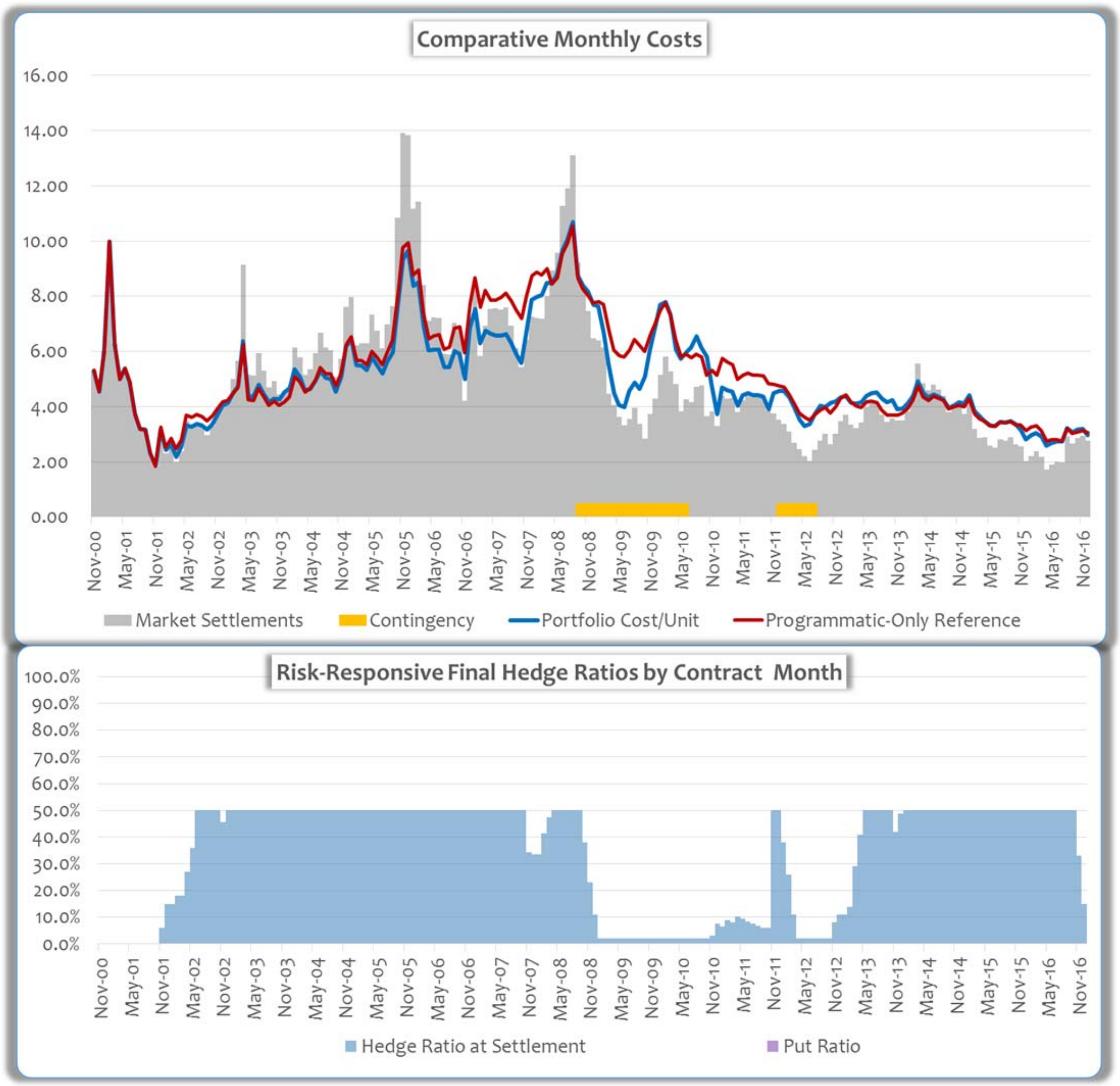
A. The graph in Table 6 shows monthly cost outcomes for both structures using a maximum 50% hedge ratio; I used a 200 billion cubic feet (Bcf) volume profile that was summer peaking; average costs over the 16-year period were $1 billion per year. The graph indicates upside cost mitigation comparable to the 50% targeted-volume approach used by Florida IOUs in recent years, but with substantially improved participation in the post-2005 and post-2008 market price downturn. Both strategies limit hedges to 50%, but depending on objectives as to mitigation versus hedge-loss avoidance, that ratio, or other design factors could be changed.

The key to the performance is adjusting the hedge ratio in response to weekly-monitored risk metrics. Increase hedges when potential future costs are unacceptable, and decrease the hedge ratio when the potential for future hedge losses becomes unacceptable. As stated earlier, tolerable outcomes are the objective, the hedge ratio is a tool, and that tool can be modulated in response to conditions.

It is important to note that the methodology does not rely on market predictions. At any point in time we do not project prices rising or falling, we simply assess the statistical magnitude of potential changes in either direction based on measured volatility.

It is also worth noting that, in rare periods of very high volatility, hedge-loss risk metrics could indicate that hedge ratios be reduced even though cost-risk metrics might indicate undesirable exposures to higher costs. So it is important to decide whether the company is more risk averse with respect to cost increases or hedge losses, and then, when a conflict occurs, to act only on the dominant risk metric while ignoring the subordinate metric. This rare condition is simply a reflection of market realities in high stress times. It is not a consequence of the methodology; rather the methodology successfully identifies the condition and a good strategy is prepared to deal with it. In Florida, I believe aversion to hedge losses would be the dominant motivation should the condition ever occur in the future.

<u>Table 6: Monthly Simulation Comparisons</u>



Q. 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. 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 7 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 7: NYMEX Prompt Month Prices and Selected Forward Curves

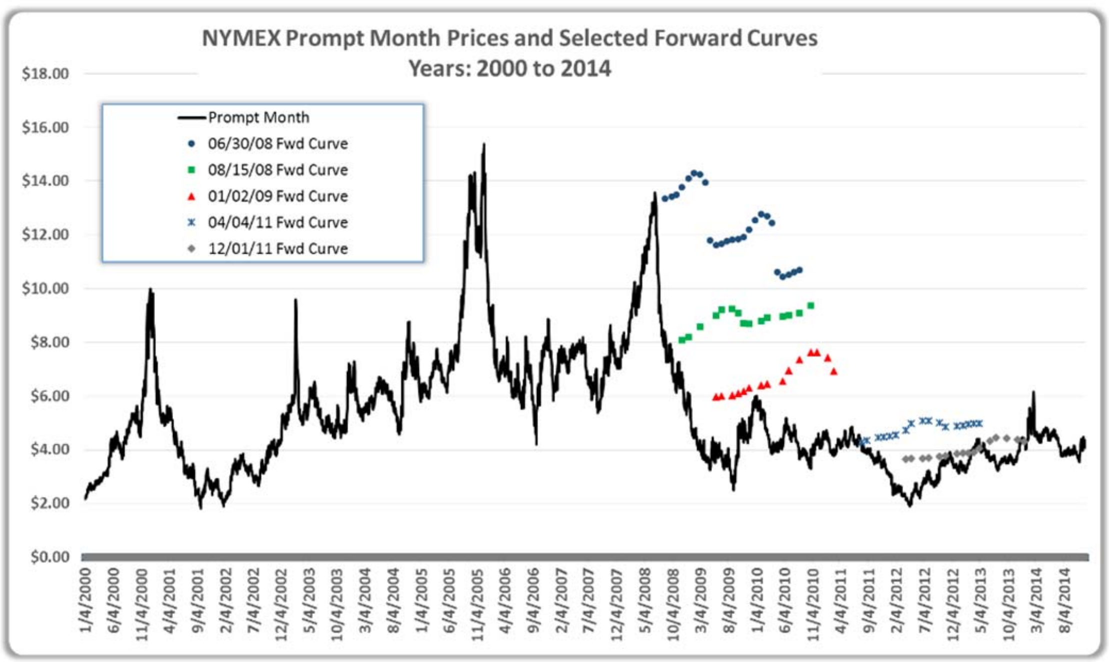
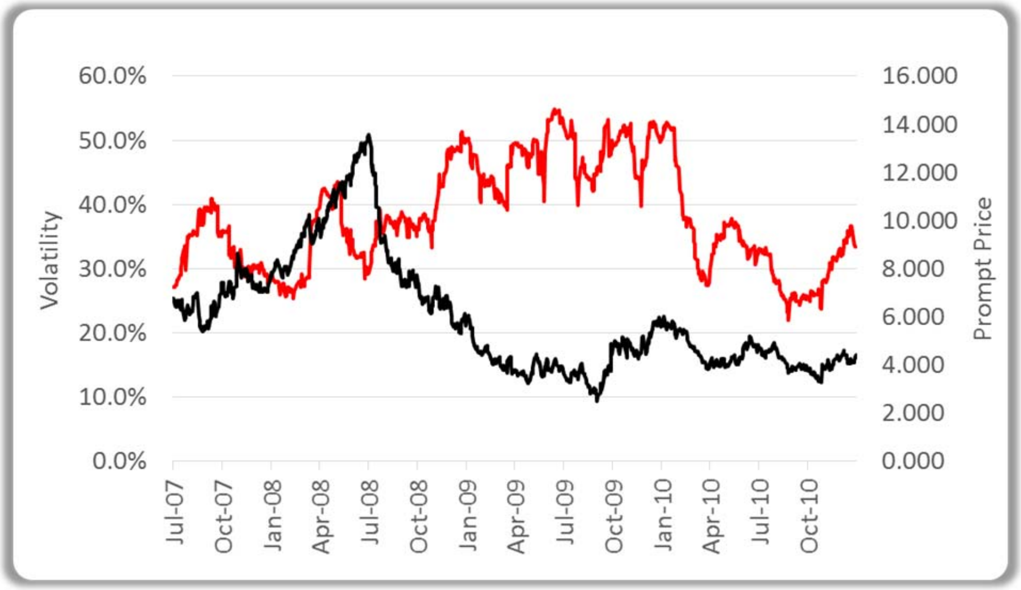


Table 8 will help confirm why risk-responsive programs would have performed better. Table 8 plots the average volatility (red) for the 12 nearest NYMEX contract months at any point in time from 2007 through 2011 along with the prompt-month prices (black). Consider that from 2009 onward, prices were falling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

Table 8: Measured Volatility, Average 12 Forward Months, from mid-2007 through 2010



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 was shown in Table 3. 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 unwound as the price collapse continued. More sophisticated strategies could have used options to navigate these conditions, but the use of put options does not produce as great an impact as simply offsetting hedges.

Q. Have you reviewed the other parties' testimony filed in this docket?

A. Yes I have.

Q. Would you like to address any of the issues raised regarding the risk-responsive methodology?

A. I would. I would like to address the perception of undue complexity. This seems to be the basis for numerous companies' contention that implementation would take two years.

Also TECO witness Bly expressed a concern with unwinding or offsetting hedges that should be addressed.

I would also like to address the comments of FPL witness Yupp regarding what he called “the exercise of a considerable amount of discretion” and his contention that the methodology would take the IOUs and Commission “into the realm of ‘outguessing’ the market,” and finally, his contention that the simulations somehow benefit from “hindsight” which will not be available to the IOUs.

Q. Please address the complexity issue first and the implications as to implementation.

A. I believe the perception of complexity has been fed in part by the simulations I ran that were vetted in the workshops. Understand that those simulations deal with about 750 weeks of risk metrics from year 2000, and for each weekly assessment they look at 36 forward monthly futures prices and the associated volatilities. The simulations were built in about a month’s time, and I have substantially revised the model for this testimony. In practice, an IOU would only be dealing with one week at a time, looking forward at thirty six months of known futures price quotes and the related volatilities. There are commercial software systems that do this.

I have implemented such systems over the course of months, not years. The implementation would consist of three tasks. Task 1 would enable the measurement of Value-at-Risk. Most IOUs probably already have a computer system that does this. In fact, a reading of their risk management policies indicates that most or all are already measuring a one-day VaR for control purposes. Task 2 would consist of the development of a risk-responsive strategy: This element can start slowly, and advance with experience. Within six months, a first strategy can be developed that includes low-level programmatic hedge accumulation and multi-tiered defensive triggers. Any reasonable spacing of those triggers will provide a material benefit compared to calendar-based accumulation that is blind to risk quantification. Task 3 would be the ongoing monitoring and execution. Probably all IOUs have a deal-capture system. If the IOU quantifies VaR for control purposes, some type of risk quantification module is attached to that system even if the risk module consists of Excel spreadsheets. If so, the only modification necessary would be the configuration of risk metrics and reports in a way that informs the strategy execution.

Witness Bly asserted that I recommended daily monitoring and that requirement would be an undue burden. In fact, I recommended weekly monitoring, not daily. Commercial risk systems typically produce reports daily, or even real-time in more intense applications, but I have recommended that weekly monitoring is fully adequate for the purpose of utility natural gas risk management.

Q. Please address the concern as to unwinding or offsetting hedges.

A. Swaps can be bought; they can also be sold. In fact every time a swap comes to maturity, the settlement effectively reverses or sells the hedge position. The hedge ratio is a tool to accomplish the risk management objectives. Once the objectives are defined as two-fold, i.e., mitigating costs and constraining hedge losses, that tool must be deployed in two directions or else the hedge-loss objective cannot be served.

There has been a perception among some that reversing a hedge position amounts to trading, but "trading" involves the pursuit of profits. In the case of risk-responsive hedging the motivation is to navigate volatile markets in order to produce acceptable outcomes for natural gas costs and to constrain the losses while doing so. Every utility begins with a 100% short position with respect to natural gas needs. As they accumulate hedges in response to one risk environment, why should that preclude necessary adjustments when that environment changes?

Q. Would you address your concerns with witness Yupp's testimony?

A. There were three topics there that I would like to address. The first goes to his contention that the risk-responsive approach requires the exercise of a considerable amount of discretion. The only discretion required is how to set the annual strategy, and that process is informed by the same risk metrics that will be monitored on a continuum. Once the strategy is set, hedge responses can simply follow the hedge decision protocols that were defined at the time of the strategy formulation. I find the setting of a metrics-based strategy to be vastly superior to whatever process has governed the judgments to hedge a target percentage every year regardless of risk conditions.

Secondly, his contention that the methodology would take the IOUs and Commission into the realm of "outguessing" the market is groundless. There is no requirement in the methodology to guess market direction or make any other market forecast, and there is no suggestion that the Commission needs to guess at anything. The risk metrics are grounded in known realities and the hedge responses are preplanned based on known risk metrics. The Commission's review of the plan execution is also grounded in known facts with no guessing required. The Commission will know the reality of the risk management strategy as filed and the reality of the known metrics as reported as well as the IOUs' responses to those metrics.

Finally, witness Yupp contends that the simulations somehow benefit from "hindsight" which will not be available to the IOUs. This statement seems to misconstrue the nature of the simulations. In every weekly quantification of risk, the price and volatility values would be known by any market observer prior to the measurements being made. Those known values form the basis of decisions that would be made contemporaneously with no knowledge of future outcomes. No post facto knowledge is required to deploy the methodology in practice, and no post facto knowledge was utilized in the simulations.

Q. Finally, are you aware of any IOUs or other utilities using OTM call options as the sole instrument for hedging natural gas requirements?

A. No, I am not. In its response to Staff Interrogatory No. 3, FPL could not identify any company using call options in the fashion they recommend as the sole instrument for hedging. FPL identified a few firms that use call options, but not as an exclusive instrument. If the use of call options as a supplemental tool in a risk strategy were supportive of a call-option-only strategy, then the fact that some or all risk programs use some swaps would support nothing but swap-only programs. I would not recommend a call option only program for the reasons articulated above.

Part III - Regulation

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 variable metrics-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-cost-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 9, 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, risk metrics, could use a 20-workday holding period at 2 standard deviations.

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.

<u>Part IV – OTM Strategy</u>

Q. The utilities have proposed the use of call options, executed on a calendar schedule, as an alternative to your recommendations. Do you have a view on that proposal?

A. I do. Call options can, at times, be a viable tool in the risk manager's arsenal, but the blind execution of options on a calendar schedule is likely to be a poor solution for the risk management issues I discussed previously. My concerns span five topics: lack of risk responsiveness, the fallacy of the insurance argument, the volatile nature of options prices, a strong likelihood that human nature will defeat the strategy, and pragmatic concerns as to execution of call options.

Q. Please speak to the concern as to lack of risk responsiveness.

A. The IOUs seem to believe that the OTM strategy is "risk-responsive" when in fact they seem to steadfastly resist the measurement of risk. How can anyone respond to risk if they refuse to measure it? Call option expenditures are likely to range from at least 5% to 14% of the market cost of underlying gas volumes. In the last price peak, hedging the IOU-recommended 60% in this manner would have required more than $80 million for a 200 Bcf portfolio. Importantly, that assumes "normal" pricing which is unlikely to exist in stressful times. Assuming an IOU has expended $80 million for call options, I would ask how it might respond further should costs and risks continue to rise. Of course the question is moot since by not measuring risk, the need for more hedges would never be identified. There is no risk-responsive aspect to the IOU proposal. It simply replaces the prior calendar-based swap plan with a calendar-based options plan.

Q. Please explain what you mean by the fallacy of the insurance argument.

A. IOU witnesses have stated that "OTM will not result in settlement losses" as though the money invested in option premiums does not count when the options settle with no value. Those call option premiums are likely to equal hundreds of millions of dollars statewide, but somehow, by calling that cost "insurance" the IOUs render those dollars "costless."

The IOUs have recommended calls that are 15% out of the money and cover 60% of planned volumes. In other words, if natural gas futures were priced at $5.00 for any coming gas year, the options would expire worthless unless prices exceeded $5.75 and even then 40% of gas cost increases would be unmitigated. And, even if prices exceeded $5.75 in the example, the strategy would produce losses until prices exceeded $5.75 plus the options premium investments. The options would expire worthless far more than half the time and actual cost mitigation would be rarer still. Table 9 shows probabilities of one-year-tenor OTM options actually mitigating costs under various volatility assumptions. There would be no mitigation from OTM calls 70% to 80% of the time. In contrast, swaps fix price outcomes the day they are executed. Once again this table assumes normal pricing; that is, the implied volatility used to value the option is assumed to be equal to the observed volatility of the underlying gas futures contract. This assumption is also overly optimistic, so it represents unrealistic expectations as to how the strategy might play out.

Table 9: Option Gain or Loss Probabilities

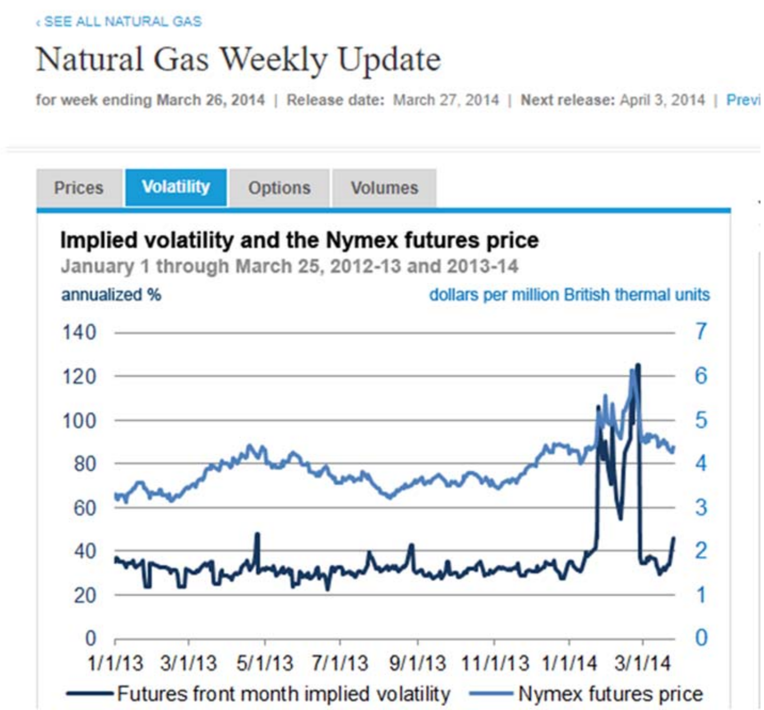
Assuming Implied Volatility Equals Observed Volatility

Price Index	Strike Index	Observed Volatility	Impled Volatility	Theoretical Call Value as % of Price	Probability of Worthless Expiry	Probability of Loss Incl. Premium	Probability of Net Gain
100	115	20%	20%	3.3%	75.8%	80.0%	20.0%
100	115	25%	25%	5.1%	71.2%	76.8%	23.2%
100	115	30%	30%	7.0%	67.9%	74.6%	25.4%
100	115	35%	35%	8.9%	65.5%	73.0%	27.0%
100	115	40%	40%	10.9%	63.7%	71.8%	28.2%
100	115	45%	45%	12.9%	62.2%	70.8%	29.2%
100	115	50%	50%	14.9%	61.0%	69.9%	30.1%

Q. Please explain what you mean by the volatile nature of options prices and your earlier references to "normal" pricing.

A. Options prices depend on various factors including the price of the underlying futures contract and the strike price, the time to expiration, and the "implied volatility" embedded in the options value. A simple example can explain implied volatility. A call option gives the buyer the right but not the obligation to buy gas at the strike price. So consider the value of an option where the futures price is $5.00/dekatherm (Dth) and the call option strike price will also be $5.00. But in one hypothetical environment the perceived range of gas prices at the option's expiration spans $4.00 to $7.00, but in another environment the perceived range spans $2.00 to $14.00. The second environment will produce far higher options values because the buyer could ignore the low potential prices (no obligation), yet exploit the very high ones. The "implied volatility" is far greater in the second environment and therefore options prices would be far greater as well.

<u>Table 10: EIA Graph of Implied Volatility, 2013 to Early 2014</u>



The trouble is that implied volatility reflects perceptions, and perceptions can vary wildly. I do not have a historical database of implied volatility, but consider the graphic in Table 10, published by the Energy Information Administration. It reflects implied volatility of natural gas options for a period of relative price stability from 2013 through early 2014. Note how, in early 2014 implied volatility spiked from about 30% to more than 100%. This effect is driven by transient perceptions.

Under early-2014 conditions, when implied volatility spiked by 70 percentage points, option prices would have spiked as well. Table 11 shows how options would trade at multiples of "normal" values if implied volatility spiked by 70 percentage points.

Table 11 Options Values under High Implied Volatility

Assuming a 70 Percentage Point Spike in IV

Price Index	Strike Index	Observed Volatility	Impled Volatility	Theoretical Call Value as % of Price	Call Value versus "normal"
100	115	20%	90%	31%	9.2 x normal
100	115	25%	95%	32%	6.4 x normal
100	115	30%	100%	34%	4.9 x normal
100	115	35%	105%	36%	4.1 x normal
100	115	40%	110%	38%	3.5 x normal
100	115	45%	115%	40%	3.1 x normal
100	115	50%	120%	42%	2.8 x normal

Consider how resolutely a company might follow a calendar-driven OTM strategy when options trade at these multiple of “normal” pricing. And consider how these multiples could expand in a truly stressful environment like 2008 if the above numbers reflect a relatively stable environment of 2014.

Q. Please address your concern as to the likelihood of human nature defeating the strategy.

A. Earlier I described how human nature can be self-defeating when decisions are not metrics-based. This same effect will apply to the OTM strategy. Since the OTM hedge ratio will be a matter of judgment, there will be a tendency to lower the ratio when prior-year options expired worthless. Similarly, if options expenditures were $50 million in one year, but appear to be growing to $100 million in the next, the tendency will be to lower the coverage ratio in order to reduce the necessary expenditures. With no risk metrics to guide the annual “strategy” decisions, how could appropriate judgments be made?

Further, as I understand it, the OTM strategy contemplates buying call options on a calendar schedule over the course of each year. How will companies respond when they have budgeted $40 million for OTM options expenditures and implied volatilities rise during the year requiring the true expenditures to be double that budget? Keep in mind the rise in implied volatility will typically coincide with increasing perceptions of risk, and that is not when hedge volumes should be reduced.

In contrast, the swaps used in the risk responsive strategy illustration require no premiums; they are simply executed at prevailing forward prices in response to the measured risk.

Q. Please speak to the pragmatic concerns associated with call options as proposed in the OTM strategy.

A. Options do not trade with nearly the liquidity of swaps, and their liquidity diminishes substantially with tenor and as the strike price moves further out of the money. Since the IOU strategy would use one-year tenor and 15% out of the money strikes, it could find difficulty soliciting competitive bids and the bid-ask spreads could be very large.

The Chicago Mercantile Exchange quote page for August 2018 options as of July 14, 2017 shows all traded volumes as zero, and since there were no transactions, the quotes were theoretical. Even reputable quote providers will fill in gaps with theoretical values when no transactions have occurred. Most options transactions take place between counterparties rather than on an exchange, so liquidity will be somewhat better than zero, but not even close to the liquidity of swaps. I do not yet know if the IOUs used theoretical quotes to assess the OTM strategy, but unless they found a source maintaining a database of actual transactions, I suspect that is the case.

So, if exchange-traded options for natural gas (one-year forward and 15% out of the money) exhibit very little liquidity, options would likely be bought over the counter with financially strong counterparties. If all of the IOUs follow the same strategy, they will be competing with each other for counterparty quotes. With no exchange-traded price transparency, the large counterparties who maintain energy desks will extract large premiums once they see all the Florida IOUs coming to market for the same one-year, 15% OTM options every month.

And there is one more consideration that can be very important. Risk management is primarily aimed at mitigating peak price periods when market stresses are greatest. It is a very real consideration that with little to no price transparency, no viable exchange-traded market, and no experience trying to place such options in stressed markets, that it could become impossible to execute the OTM strategy when it is most needed.

In contrast, the risk-responsive strategy that I have recommended uses swaps with occasional put options if desired. Swaps benefit from price transparency and all of the IOUs would not be using the same risk parameters to drive their hedge execution. The VaR metrics and the customized tolerances will create natural diversity in market transactions. That diversity combined with the price transparency will facilitate competitive hedge values. Further, the strategy relies on the same swap transactions that IOUs have deployed for years or even decades.

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 DE, FL, MI, NJ, NY, PA, WA, etc. Topics have included:

- In the risk domain: strategy formulation, economics and risk of long term commitments, regulatory policy, company 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

2017 Q-1 Report

			Holding Period	Confidence			Holding Period	Confidence	Current Gas Year
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													

2017 Q-1 Report

Plus One Gas Year

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 One Gas Year, Annual													
Projected Supply Needs:													
Hedge Ratio:													
Unhedged Ratio:													
$/MMBtu, Annual													
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Mark to Market													
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$000s, Annual													
Portfolio Value													
Mark to Market													
Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													

2017 Q-1 Report

Plus Two Gas Year

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													
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$000s, Annual													
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Cost VaR													
MtM VaR													
Cost Outlier													
MtM Outlier													

Action Boundaries

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.

Confidence Level

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.

Contingent Strategy

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

Cost Outlier

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.

Cost VaR

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

Defensive Hedging

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

Dual Tolerances

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.

Holding Period

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.

<u>Market VaR</u>

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

<u>Mark to Market</u> ("MtM")

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

<u>MtM Outlier</u>

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.

<u>MtM VaR</u>

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

<u>Programmatic Hedging</u>

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.

<u>Prompt Month</u>

The first month for which futures contracts trade.

<u>Risk-Responsive Hedge Strategy</u>

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.

<u>Targeted-Volume Hedge Strategy</u>

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

<u>Value-at-Risk</u> ("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: Analysis of IOUs' hedging practices.	DOCKET NO. 20170057-EI DATED: August 10, 2017

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 by electronic mail to the following on this 10th day of August, 2017.

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