Hedging Under Scrutiny

Planning ahead in a low-cost gas market.

By Julie Ryan and Julie Lieberman

The new world of gas supply, brought about by shale development, the economic downturn, and expanded gas infrastructure, has caused regulatory stakeholders to challenge utility gas supply hedging programs.

Hedging, a common feature of utility risk management practices, serves as a tool to stabilize prices, protect customers from market volatility, and insure against unexpected price spikes. However, regulatory commissions and intervenors are challenging the merits of their utilities' hedging programs with increasing frequency, questioning whether the risk mitigation benefits of hedging have justified the associated costs, and whether customers are paying for insurance to manage a risk that might no longer exist.

Concerns raised by commission staff or other stakeholders relating to the cost of utility hedging programs has led to an emerging trend of greater commission and stakeholder involvement in assessing such programs' efficacy. Regulatory commissions are asking utilities to provide written justification of their hedging practices, applying pressure on utilities to work with stakeholders to resolve hedging differences through collaborative processes and to find common ground on the risk-reward spectrum. In some cases, risk management hedging programs have been suspended until there are visible increases in volatility and market prices.

Utilities that engage stakeholders in a dialogue now about their risk-management practices can ensure hedging remains a viable tool for limiting exposure to future price volatility.

> Care must be exercised when applying the least-cost principle to hedging, which presents trade-offs in risk, reward, and costs.

Costs Incurred and Avoided

This shift toward re-assessing hedging practices is relatively recent. In 2008, a survey conducted by the National Regulatory Research Institute (NRRI) indicated that most commissions in the U.S. either supported or were neutral to hedging.[1] This was reinforced in a follow-up survey the AGA conducted in 2009.[2] Among more than 100 respondents, over 90 percent said their commissions allowed financial hedging of commodity price risk. However, only a very small number of commissions required utilities to engage in financial hedging.

Push-back on utility hedging typically begins with intervenors. Ultimately, however, most administrative law judges and commissions generally support hedging. While intervenors often recommend disallowance of hedging costs, commissions generally accept that the goal of hedging is price stability and not "to beat the market." As a result, cost disallowance decisions by commissions have been rare.[3] But, in an environment where utility customers are experiencing across-the-board rate increases, it isn't surprising that commissions would encourage utilities to evaluate changes to their hedging programs.

Intervenors have tended to take a retrospective view when evaluating the efficacy of hedging programs. While it's tempting to look at historical hedging based on current information and perfect hindsight, the regulatory standard for what is reasonable and prudent must consider the availability of information and what was known at the time hedging decisions were made. This is the standard commissions have adopted when reviewing historical hedging costs.

Many stakeholders have focused on costs associated with hedging, but there has been less focus by all parties on avoided cost analysis. In several instances, success—or lack thereof—has been measured by comparing the hedged prices to spot market prices. The costs have included net premiums paid for call options, as well as the difference between the fixed price or option strike price and the spot market price. There is often a failure to see the cost of options as an insurance premium, as well as to consider a fixed price as a rate stabilization tool. Further, what's missing is more analysis of the potential avoided cost. Additional scenario analysis would demonstrate the risk of what could have occurred as well as estimate the potential price exposures avoided as a result of hedging.

Additionally, some stakeholders raise the concept of "least cost" in hedging program critiques. Care must be exercised when applying the least-cost »

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principle to hedging, which presents trade-offs in risk, reward, and costs, depending upon the hedging instrument. Using the analogy of insurance, it is possible to buy an inexpensive policy with a low premium, but this is usually accomplished by increasing the deductible, placing a cap on the total payout, or carving out conditions under which benefits aren't paid. Additionally, different hedging strategies yield different benefits, depending on market price direction. For example, if a utility is purchasing energy in a rising-price market, a fixed price purchase might be optimal as there is no option payment incurred and the coverage starts immediately. In a range-bound market, a costless collar might be the lowest cost of insurance, and in a declining market, a cap at a relatively high strike might be the most attractive form of hedge protection.

The Shale Gas Factor

A review of comments filed by commission staff and other stakeholders shows that shale gas development is repeatedly referred to as a "game changing" technology. Shale gas producers access prolific geological deposits of reserves for production at relatively low costs, which has led to significantly dampened price volatility and lower market prices.

While the emergence of shale gas production is generally well-known by intervenors and regulators, the broader market dynamics are less well understood. Equally important is the fact that new pipeline infrastructure has served to deliver shale gas supplies into what historically have been transportation-constrained end markets, thereby changing traditional basis-pricing relationships and further easing price volatility. Additionally, new LNG import facilities and expansions in natural gas storage capacity in recent years have contributed to expanded supply capacity. These supply and capacity additions have occurred at the same time that demand has declined. On the demand side, increasing energy efficiency measures and declining demand resulting from weak economic conditions have dampened consumption.

However, history repeatedly has shown that commodity market conditions are never stagnant, and that markets often correct as supply and demand factors re-balance. The recent 24 months of price declines have lulled many stakeholders into believing that low gas prices are now the norm, but market conditions will change at some point. The question is when, how quickly, and to what degree? If we have learned anything from the past, it is that we cannot predict the future with certainty. In the future, changing supply-demand factors might turn market prices in the other direction.

> **There are unique opportunities today for utilities to hedge more for the same cost, or to continue similar coverage at lower cost.**

Utilities will want to be prepared before a market shift occurs. On the supply front, there might be environmental regulation that slows shale gas production, additional compliance requirements that increase shale gas production costs, or technical factors that reduce the projected size of economical reserves. Natural gas demand might increase due to stymied nuclear plant development, rising coal plant operating costs, or closures of coal plants as a result of environmental compliance. New demand could result from economic recovery, LNG exports, or new natural gas and electric vehicle use. A combination of these factors could cause the North American gas supply-demand balance to materially shift, bringing about increases in market prices and volatility.

As market prices have dropped, many stakeholders are encouraging utilities to adapt their hedging practices to the current market supply and pricing paradigm. Some have suggested utility hedging be reduced until such time as gas market prices show some sign of rallying. Others are taking a more proactive stance, encouraging longer-dated hedging and new hedging program design.

Two commissions that recently have suspended hedging activities are the Public Utilities Commission of Nevada (December 2010), with respect to Nevada Power, and the British Columbia Utilities Commission (July 2011), in regard to FortisBC. The commissions didn't disallow previously executed hedge transactions, and they left existing hedges in place; the decisions applied to future hedging activity.

In its Dec. 16, 2010 order (Docket No. 10-09003), the Nevada PUC approved a stipulation that included the requirement that Nevada Power not proceed with any additional financial gas hedges. However, the utility was told it should continue reviewing natural gas hedging in light of prevailing market fundamentals and conditions.[4] More recently, on July 22, 2011, the British Columbia Utilities Commission rejected FortisBC's "Price Risk Management Plan." In the order, the Commission Panel wrote: "in light of the recent exploitation of shale gas, the likelihood for more stable natural gas prices is significantly greater and the risk of dramatically higher natural gas prices, excepting short periods of price disconnects, is significantly lower than it has been in many years."[5] Further, the panel suggested that hedging was not the best way to deal with the potential for price increases, but commented that if there were a change in market conditions, they would be willing to consider proposals to » mitigate price risks for customers. They concluded by saying that the performance of the utility's "Price Risk Management Plan" over the last 10 years did not convince them that continuation of the program was in the ratepayers' interest.

Measuring Prudence

Hedging programs are undergoing a greater degree of regulatory scrutiny. In some instances, hedging programs have been scrutinized and continued without modification, while in other cases, hedging programs have been targeted for additional review.

In spring 2009, the Colorado Public Utilities Commission commented on testimony filed by commission staff, which criticized gas hedging by Xcel's subsidiary, Public Service Company of Colorado. The staff had conducted a quantitative analysis to determine that during the period following Hurricane Katrina (2005-2006), the utility's hedges were close to breaking even, *i.e.*, the premium paid for hedging nearly equaled the benefits it provided over spot market prices. But a break-even analysis of the hedging costs compared to spot market prices for the period 2005 to 2008 illustrated that the utility only regained approximately one third of every dollar spent on hedging. Ultimately, in its order, the commission supported the administrative law judge's position that the utility's hedging program should not be suspended. In his recommended decision, the judge wrote, "Preapproved elements of the [hedging] plan avoid hindsight evaluation of each program. Simply stated, [the plan] is to be evaluated based upon information available at the time, not in terms of whether the plan 'beat the market.' To the extent Public Service implements such a plan, as approved, the associated hedging costs should not be subject to disallowance in any subsequent gas cost prudence review proceedings."[6]

In another example, a commission decided to open a utility's hedging program to further review. In May 2011, in response to PacifiCorp's rate filing for Rocky Mountain Power, the Utah Industrial Energy Consumers filed direct testimony asking the Utah Public Service Commission to disallow $19.7 million in revenue requirements related to what the group called "imprudent hedging practices" by the utility. Rocky Mountain Power's hedging program layered-in hedges 48 months into the future, hedging nearly 100 percent of its open commodity price risk. In the industrial group's testimony, it commented that the utility's hedging program wasn't adjusted to account for changes in market conditions and the expanding supply of natural gas through shale gas production.[7] Hence, the industrial group suggested the utility was imprudent to hedge such a large percentage of its open positions and should have reduced its fixed-price hedges, to leave open one-third of its portfolio to spot market pricing.

Gas market conditions will change at some point. The question is when, how quickly, and to what degree?

In July 2011, a stipulation was filed with the Utah PSC where the parties agreed to a collaborative process to review possible changes to the company's hedging practices. As part of the stipulation, it was agreed that the utility's past hedges wouldn't be disallowed, but that the utility would implement any changes that result from the collaborative process or commission order. Issues addressed in the collaborative process included: a new maximum hedge volume percentage limit or range; risk tolerance bands based on time-to-expiry value-at-risk (TEVaR) or value-at-risk (VaR) limits; position limits; a process for review of hedging transactions outside of accepted guidelines, including natural gas reserves or storage; liquidity, transparency, and other risks of different hedging tools such as financial swaps, fixed-price physical forward contracts, and options; a semi-annual confidential report on hedging status; and coordination and implementation issues relating to the inclusion of financial swap transactions in Rocky Mountain Power's energy balancing account.[8] The stipulation was approved in a commission order on Sept. 13, 2011, and PacifiCorp and the other stakeholders were expected to complete discussions by January 2012.

In February 2011, the South Carolina Office of Regulatory Staff (ORS) requested suspension of the hedging programs of South Carolina Electric and Gas (SCE&G) and Piedmont Natural Gas. The ORS commented that the hedging costs incurred by the utilities might be appropriate for markets where there is significant price volatility, but were not appropriate for more stable natural gas market conditions. According to the ORS, SCE&G's hedging program cost customers more than $50 million since 2006, and Piedmont's program cost over $37 million since 2002.[9] This request for suspension was later withdrawn in July 2011, and it was determined that the utilities and the ORS would address the prudence of the hedging activities in each of the companies' respective annual purchased gas adjustment (PGA) proceedings.[10]

In SCE&G's PGA proceeding, the ORS evaluated the company's hedging program and affirmed its previous recommendation that the hedging program should be suspended. SCE&G agreed to immediately suspend all hedging until the commission directs it to recommence. The agreement anticipates that changing market conditions—*e.g.*, environmental restrictions on shale gas production—could warrant a resumption of hedging.[11] Conversely, Piedmont's hedging program was approved in its PGA proceeding with the removal of its previously established minimum hedging requirement of 22.5 percent. Although Piedmont's gas purchasing and hedging activities were deemed to be prudent, there was disagreement on whether gas purchasing and hedging activities, pursuant to a commission-approved hedging program, should be subject to an after-the-fact prudence determination. The commission requested an *ex-parte* briefing on the issue of how to measure prudency in hedging programs.[12]

Strategic Adaptation

In some jurisdictions, regulators are modifying the hedging program horizon and limiting discretionary actions. In Delaware, Delmarva Power has a programmatic hedging program with periodic hedging at pre-determined intervals. In 2009, the utility reduced the tenor and the total volume of hedging. More recently, in response to Delmarva Power's "Gas Cost Rate" filing, a consultant for the commission staff proposed two alternative hedging strategies to enhance flexibility in the hedging framework and to provide a greater smoothing effect on gas price spikes. The consultant recommended either lengthening the "hedging interval" beyond 18 months to take advantage of lower volatility in outer months; or implementing dollar cost averaging,[13] with fixed dollars allocated for hedges rather than fixed volumes, so that hedging volumes would increase in low-priced market environments and would decrease in higher-priced market environments. The consultant stated that dollar cost averaging results in lower gas costs when compared to a less-flexible, programmatic hedging strategy.[14] Although no changes were made to Delmarva Power's gas hedging program, the company agreed to review and discuss the staff consultant's recommendations for modification.[15]

In Michigan, intervenors in the Consumers Energy rate case proposed a range of changes to reduce the volume and tenor of hedging under the utility's fixed-price hedging program to address concerns that the utility was over-hedging with fixed-price purchases. In that proceeding, intervenors urged the commission to eliminate the "tiered" strategy, which provided for programmatic purchases of fixed price supply in accordance with monthly hedge targets, and suggested modifications to the company's "quartile" strategy, which it had employed in tandem with the tiered strategy, using historical pricing to determine the amount of forward market hedging. All parties proposed a reduction in annual hedging caps. The ALJ decision supported the company's proposed plan, but indicated that certain accelerated purchases under the tiered strategy would require justification by market conditions to be deemed prudent.[16] At this writing, a final decision in this proceeding was pending.

In California, parties to the electric utilities' procurement plan filings are discussing moving from fixed caps on hedging, as determined by the consumer rate tolerance (CRT) of 1 cent per kilowatt hour, to a restructured CRT that represents a percentage of the individual utility's system average rate. By moving to a percentage of the system average rate, the percent hedged under the CRT would remain constant and wouldn't fluctuate with rate changes.[17]

Locking-In for the Long-Term

The Public Utility Commission of Oregon approved a $250 million investment in reserves by its gas utility, Northwest Natural. The utility entered an agreement with Encana Oil & Gas (USA) to develop physical gas reserves expected to supply a portion of the utility customers' requirements over a period of about 30 years, with 8 to 10 percent of Northwest Natural's average annual requirements supplied through the arrangement. The Commission approved the utility's plan in April 2011, allowing the utility to recover the costs of gas produced and delivered, plus a rate-base return on investment through its annual PGA mechanism.[18]

In Colorado, the *Clean Air - Clean Jobs Act* of 2010 (HB 10-1365), included a legislative provision to facilitate fuel-switching from coal to natural gas, while protecting ratepayers from volatility in prices. The provision provides regulatory certainty that utilities will be allowed full cost recovery, without risk of future disallowance, for commission-approved, long-term gas contracts—of between three and 20 years in duration—entered into pursuant to the act.[19] To that end, Public Service Company of Colorado and Anadarko entered a 10-year, fixed-price gas supply agreement, subject to annual price escalations, that is projected to result in savings to ratepayers of approximately $97 million, when compared to forecast gas costs without the contract.[20]

Black Hills Energy of Colorado has incorporated a long-term hedging strategy into its "Gas Mitigation Plan." The plan provides for hedging between 50 and 70 percent of its gas requirements under normal conditions, with the remaining gas requirements purchased in the monthly or daily spot market. Of the hedged volumes, half are comprised of fixed-price swaps phased in over three separate terms: three years, five years, and seven years. The long-term hedges, once fully phased-in, will represent approximately half of the company's normal annual volume requirements. Another 20 percent of the gas supply requirements are hedged using call options in a short-term hedging strategy for the upcoming year.[21]

Successful design and implementation of a hedge plan hinges on stakeholder collaboration and support.

Commissions will continue to review their utilities' hedging plans in a critical light, and it will be necessary for utilities to work in collaboration with stakeholders to consider adaptations to hedging plans that respond to new market conditions and that protect customers in the event of rising gas and power prices.

Window of Opportunity

Hedging objectives are an important part of the dialogue between commissions and utilities, and avoided costs need to be considered in developing a hedging program. "Hedging" can mean different things to different parties. Therefore, an important first step is to obtain broad consensus about the objectives of the utility's hedging program. By way of simple example, one objective could be that hedging is intended to protect customers against price spikes during certain high usage seasons, while another objective might be to protect customers against rising price trends that could occur over an extended period of time.

One benefit arising from the increased focus on utility hedging is that regulators and stakeholders have grown increasingly sophisticated about commodity markets and hedging, and some might support more complex programs in the future. However, the more discretionary a program design, the more critical decisional documentation and transparent processes become. Further, there must be rigor and consistency in how hedging is adjusted in different market price environments. It will be important in the design and approval stage that the hedging program has clear triggers for when hedging decisions will be executed. During the implementation stage, it will be important for utilities to document information that was known to them at the time hedges were transacted to demonstrate that reasonable actions were taken, consistent with the program design.

It is somewhat ironic that in today's market, as the price of hedging has declined, stakeholder support for hedging has waned. The low-price and low market-volatility environment introduces opportunities to execute hedges at historically attractive price levels. If utilities were to abstain from hedging until volatility increased and market prices rose, the cost of hedging would increase to the point where hedging could be deemed by regulators to be too costly for ratepayers.

In jurisdictions where intervenors and perhaps regulators might be reluctant to support an expansive hedging program at current lower market prices, utilities should use a collaborative process to garner support. The first objectives would be to improve stakeholders' understanding of the supply-demand market fundamentals that have contributed to current lower prices, and to explain future trends and events that could move market prices upward. A better understanding of market drivers and how prices could potentially change will help stakeholders appreciate the utility's need to be ready with hedging strategies to protect customers from rising wholesale market prices.

The second objective would be to engage stakeholders in a dialogue about how the utility's current hedging program was developed, and to listen to stakeholders' concerns. Working collaboratively, it is possible for all the parties to bring a fresh perspective to the hedging program and consider how it might be adapted under varied market conditions. Such efforts will yield the greatest benefit for utilities and their customers if they happen before supply-demand conditions materially change market prices, and the current window of opportunity closes.

Endnotes:

1. National Regulatory Research Institute, *NRRI Services: Survey on State Commission and Local Gas Distribution Company Actions in Addressing High Natural Gas Prices*, (July 3, 2008).
2. Bruce McDowell, *AGA Rate Inquiry: Regulatory Hedging Policies*, American Gas Association, (Fall 2009).
3. In a recent commission order (Docket No. UE 228), the Public Utility Commission of Oregon penalized Portland General Electric (PGE) for failure in 2007 to document the reasons for executing 2012 gas hedges. In its decision, the Commission noted its 2002 order (in Docket No. UE 139) in which the commission disallowed costs associated with certain of PGE's forward power purchases citing the company's failure to provide evidence regarding price trends or internal company market analyses that might have supported the reasonableness of the company's decisions. In its decision in UE 228, the commission reduced the utility's 2012 net variable power costs forecast by $2.6 million "to ensure management's future compliance" with commission orders. The penalty was calculated as the monetary equivalent of a one-year, 10-basis-point reduction in PGE's authorized return on equity. Public Utility Commission of Oregon, Docket No. UE 228, *2012 Annual Power Cost Update Tariff*, (Nov. 2, 2011).
4. Public Utilities Commission of Nevada, Docket No. 10-09003, *Application of NV Power Co d/b/a NV Energy for Approval of its Energy Supply Plan Update for 2011-2012*, Order (Dec. 16, 2010) and Stipulation (Nov. 9, 2010). Note, in September 2011, Nevada Power submitted a proposal to engage in new hedging, using out-of-the-money call options in its filing to the Public Utilities Commission of Nevada, *Application of Nevada Power Company d/b/a NV Energy for Approval of its Energy Supply Plan Update for 2012*, Docket No. 11-09003, (Sept. 1, 2011). However, in its draft order in the same docket, dated Dec. 14, 2011, the commission rejected NV Energy's hedging proposal and ordered NV Energy to continue the existing commission-approved hedging strategy described in the stipulation that the commission approved in Docket No. 10-09003 on Nov. 9, 2010, without exception.
5. British Columbia Utilities Commission, Order Number 6-120-11, *Application by Terasen Gas Inc. and Terasen Gas (Vancouver Island) Inc. (collectively Terasen Gas) (now FortisBC Energy Inc. and FortisBC Energy (Vancouver) Inc.) for Approval of the Price Risk Management Plan Effective April 2011-October 2014*, (July 12, 2011).
6. Public Utilities Commission of the State of Colorado, Docket No. 08A-095G, *In the Matter of the Application of Public Service Company of Colorado for Authorization to Continue in Effect, On a Permanent Basis, Its Monthly Gas Cost Adjustment Tariffs, With Modifications to provide For Symmetrical Interest on Deferred Balanced of Over- And Under-Recovered Gas Costs, and to Extend For an Additional Four-Year Period the Current Procedures for Seeking and Obtaining Authorization to Implement Annual Gas Price Volatility Mitigation Plans for Its Gas Sales Customers*, (March 2, 2009).
7. Public Service Commission of Utah, Docket No. 10-035-124, Direct Testimony of J. Robert Malko, Utah Industrial Energy Consumers, *In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, (May 26, 2011).
8. Public Service Commission of Utah, *Rocky Mountain Power Settlement Stipulation, (July 28, 2011) and report and order, Rocky Mountain Power 2011 General Rate Case*, Docket Nos. 10-035-124, 09-035-15, 10-035-14, 11-035-46 and 11-035-47, (Sept. 13, 2011).
9. South Carolina Office of Regulatory Staff, *Letter Re.: Request for Suspension of SCE&G and Piedmont Gas Hedging Programs*, Docket No. 2011-82-G, (Feb. 24, 2011).
10. Public Service Commission of South Carolina, Commission Directive, Docket No. 2011-82-G, Order 2011-402, (July 13, 2011).
11. Public Service Commission of South Carolina, Settlement Agreement, *IN RE: Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies of South Carolina Electric & Gas Company*, Docket No. 2011-5-G, (Nov. 2, 2011).
12. Public Service Commission of South Carolina, Order Ruling On Purchased Gas Adjustment And Gas Purchasing Policies, *IN RE.: Annual Review of Purchased Gas Adjustment and Gas Purchasing Policies of Piedmont Natural Gas*, Docket No. 2011-4-G – Order No. 2011-580, (Aug. 17, 2011).
13. Dollar cost averaging is the technique of hedging a fixed dollar amount of a particular commodity on a regular schedule, regardless of the contract price. More contracts are purchased when prices are low, and fewer contracts are purchased when prices are high.
14. Public Service Commission of Delaware, PSC Docket No. 010-295F, Direct Testimony of Richard W. Lelash on behalf of the Staff of the Delaware Public Service Commission, *In the Matter of the Application of Delmarva Power & Light Company for Approval of Modifications to Its Gas Cost Rates*, (Feb. 10, 2011).
15. Public Service Commission of Delaware, Order No. 8061, *In the Matter of the Application of Delmarva Power & Light Company for Approval of Modifications to Its Gas Cost Rates* (Filed Aug. 31, 2010), PSC Docket No. 010-295F, (Oct. 18, 2011).
16. Michigan Public Service Commission, Case No. U-16485, Notice of Proposal for Decision, ALJ Sharon L. Feldman, *In the Matter of the Application of Consumers Energy Company for Approval of a Gas Cost Recovery Plan and Authorization of Gas Cost Recovery Factors For the 12-Month Period April 2011- March 2012*, (Sept. 12, 2011).
17. California Public Utilities Commission, Rulemaking 10-05-006, *Proposed Decision Approving Modified Bundled Procurement Plans*, Proposed Decision of ALJ Peter Allen, (Nov. 10, 2011).
18. Northwest Natural, Securities and Exchange Commission, 10-Q filing (First Quarter 2011).
19. See Colorado General Assembly H.B. 10-1365, Section 40-3.2-206. Part 4 (signed into law April 19, 2010).
20. *Statement of Position of Public Service Company of Colorado*, in Docket No. 10M-245E, at 72, (Nov. 29, 2010)
21. Direct Testimony of Trent Cozad, Docket No. 11A-580E before the Colorado Public Utility Commission *(Re: Gas Mitigation Plan)*, pp.3-7.