Natural Gas Hedging: Should Utilities and Regulators Change Their Approach?

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Online Access

The reader can find this paper on the Web at http://www.nrri.org/pubs/gas/NRRI_gas_hedging_May11-10.pdf.

Executive Summary

Why Regulators Should Revisit Hedging

Events since 2008 have raised questions about the future of hedging by gas utilities. Since the beginning of this century, utilities have hedged against the volatile price of natural gas to protect their customers from the effects of unexpected and severe price spikes. Projections of more stable gas prices for the immediate future seem likely to reduce the benefits of hedging at this time.

The large losses many utilities suffered from hedging with financial derivatives—in the range of hundreds of millions of dollars—are an additional reason state public utility commissions ("regulators") should revisit hedging. Regulators should expect utilities to realize small losses from hedging in most years because hedging is, after all, an insurance policy against severe price spikes, and insurance is not costless. The question regulators must now confront is this: Should the regulator play a more proactive role in reviewing a utility's hedging plan, overseeing the plan's design implementation, and reviewing utility applications for cost recovery if they do hedge?

It can be difficult for regulators to assess the benefits of hedging after the fact, because the benefit—protection against higher costs that perhaps did not materialize—cannot be determined with precision. If regulators have not been active in plan development and oversight, they are limited to determining, after the fact, whether a utility's large or prolonged losses reflect events that were outside the utility's control, or if some of these losses were avoidable and the result of imprudent utility actions. If regulators are limited to an after-the-fact review of utility hedging that suffered high losses, both utility and regulator should evaluate the program's costs and benefits—even if those benefits are inexact—to determine what might have been done differently and what can be gleaned to improve future practices.

Should a Utility Hedge at All?

The main reason for a utility *not* to hedge is if it appears that the price-protecting benefits from hedging will not justify its costs, such as during a period when relatively stable prices are expected, as many expect for the immediate future.

Regulators should require utilities to revisit the merits of hedging today. Is the problem of potential price spikes, which can be hard to predict, one facing only low-income households, or is it more broadly based? Neither utilities nor regulators have an understanding of what price customers would be willing to pay to avoid facing extremely high gas bills during high-use winter months. If the problem lies only with low-income households, the most efficient policy might be to have the utility not hedge and, instead, dedicate additional monies to low-income households when prices rise to intolerably high levels; but that may raise questions of inter-customer equity that are better handled by legislative bodies. Regulators should consider this option and other approaches to insulate customers from high natural gas prices.

The Need for Change

Regulators should be involved more than they have been, prospectively and retrospectively, in assessing the costs and benefits of utility hedging. They should require utilities to submit hedging plans prospectively to the regulator for review and to evaluate their hedging activities continuously. These reviews will enable utilities to respond in a more informed way to changing market dynamics that can shift the balance for or against hedging. Such review is especially useful in times like these, with new natural gas discoveries and drilling techniques that may provide ample gas supplies, with more stable prices, at least for several years. Until now, regulators have penalized utilities only infrequently for hedging practices that, in retrospect, were suboptimal and led to large losses that were passed on to customers. Utility and regulatory practice that might have sufficed for the past will not serve the public interest today.

Recommendations for Regulators

Regulators should be prepared to determine whether large hedging losses are the result of a faulty or poorly executed hedging plan, or if they reflect to some degree the built-in risks of hedging. Regulators should review hedging plans and strategies prior to their execution and require the utility to keep them informed throughout the execution of any hedging plan. To be fair to the utility and to safeguard the interests of its customers, thorough involvement by the regulator in reviewing a hedging plan, overseeing its execution, and determining appropriate cost recovery is the best approach.

Regulators should therefore: (1) evaluate prospectively a utility's proposed hedging plan and strategies and (2) determine whether the utility executed the hedging strategy prudently. Depending on the plan's level of detail, this second task might simply involve determining whether the utility complied with its plan. This recommendation offers a balanced regulatory policy by giving the utility predictability at the outset without forfeiting the regulator's duty to question whether any costs incurred in hedging were imprudent and unreasonable.

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I. What Is Hedging and Why Do It?

"Hedging" refers to an economic activity in which a party acts to protect against potential adverse price fluctuations in a market. Hedging instruments come in both physical and financial forms. Among the former are bilateral physical contracts with fixed prices and storage; included in the latter category are such financial instruments as futures contracts, options,[1] and swaps. Hedging with physical or financial assets is the principal means a natural gas utility has to mitigate the effect of sharply rising or falling natural gas prices on its customers. Portfolio diversification with respect to the timing of gas purchases—e.g., staggering of contracts over a specified period—is yet another hedging mechanism utilities may use to reduce the effects of volatile prices on their customers.[2]

Hedging is intended to reduce price risk to customers. If a hedging program is poorly administered, however, or properly administered but poorly planned, its cost can exceed the cost of doing nothing—i.e., paying market prices and not engaging in hedging. Hedging can also increase risk. It can add counterparty risk,[3] create collateral obligations,[4] and produce "regret," sometimes known as "buyer's remorse." Regret refers to a situation in which, after the fact, it is determined

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[1] "Put" and "call" options are common risk-management devices. As an example of the latter, a gas utility may establish a price-cap hedge by purchasing call options giving it the right—but not the obligation—at a defined future time to purchase gas at a predetermined price, called the "strike price" or "exercise price." A put option is the opposite: the right, but not the obligation, to sell the commodity at a preset price at some time in the future. Gas options are available in both the New York Mercantile Exchange (NYMEX) and the over-the-counter (OTC) market. OTC instruments may avoid the margin requirements associated with futures contracts. They also provide greater opportunities for tailoring contracts to the preferences of individual traders, but, as a result, are less liquid. OTC transactions require utilities to negotiate, execute, and administer bilateral contracts. Each of these activities requires a cost to the utility.

[2] Non-hedging devices that gas utilities sometimes use to moderate cost impacts of price variability on customers are predetermined fixed rates or flat-rate budget billing during the winter heating season. These devices smooth out costs but do not reduce them.

[3] The opposite party in a bilateral agreement or transaction is a counterparty. Counterparty risk is the risk associated with the financial stability of the opposite party to a transaction.

[4] When natural gas prices decline, the counterparty to the utility often requires collateral from the utility to compensate for the risk that the utility will not pay the transacted price and will instead purchase lower-priced gas from someone else. The collateral, referred to as a "margin call," could be cash or a letter of credit.

that the utility's costs for hedging were significantly greater than they would have been for not hedging or hedging in a different manner.[5]

A 2001 NRRI paper commented on what regulators should expect (and not expect) from hedging:

> [H]edging with financial derivatives may result in the gas utility locking in a price that turns out to be higher than the prevailing market price. Hedging also should not be expected to reduce the average price of gas purchases over time. Hedging, in its purest form, does not provide a means to reduce the expected price of gas for a utility. Rather, from the consumers' perspective its primary function is to stabilize prices. Generally, risk-averse consumers should be expected to pay extra for shouldering less risk, such as exposure to volatile prices.[6]

Gas utilities have hedged since the beginning of this century.[7] Pressures from regulators wishing to protect gas customers from volatile wholesale gas prices induced utilities' willingness to hedge. Utilities are also motivated to hedge for fear that, if they do not and circumstances later indicate that they should have done so, they could face cost disallowances. Benefits to the utility from hedging arguably can offset its risk, even under the threat of cost disallowance. One such benefit is elimination of imprudence risk from *not* hedging. Failure of a utility to hedge against a price spike that occurs could also undermine customer goodwill and reduce its competitiveness.

Utilities hedge in different ways.[8] The best plan for a utility and its customers depends on many factors, including the utility's hedging objectives, market conditions, the efficacy and availability of hedging tools available, the regulator's policy on hedging, and the costs and availability of physical and financial hedges.[9] These factors make it advisable for utilities, along

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[5] One example: Assume that a utility purchases a call option at $1 million without exercising it. Regret does not necessarily mean that the utility was imprudent—only that if it could do it over again, with the benefit of hindsight, it would not have made the decision it did.

[6] Kenneth W. Costello and John Cita, *Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues*, National Regulatory Research Institute 01-08, May 2001, at http://nrri.org/pubs/gas/01-08.pdf.

[7] Almost all regulators allow gas utilities to hedge with financial instruments; a much smaller number require them to do so. Regulators generally allow utilities to fully recover their hedging costs, subject to a prudence review. *See* American Gas Association, *AGA Rate Inquiry: Regulatory Hedging Policies*, Fall 2009.

[8] The author found it difficult to get detailed information on individual hedging plans, as they contain sensitive market information that is confidential. Much of the public information is only of a general nature.

[9] Physical hedges include stored gas, a diversified gas portfolio, and long-term fixed price contracts. Financial hedges include futures contracts, options, and bilateral over-the counter (OTC) financial instruments. The value of a financial instrument derives from a cash

with their regulators, to review their hedging plans periodically, especially after a change in market conditions or in light of other relevant new information.

market commodity, futures contract, or other financial instruments. Parties trade these instruments on regulated exchange markets or over-the-counter. For example, futures contracts are derivatives of physical commodities; options on futures are derivatives of futures contracts.

II. Components of a Hedging Plan

A hedging plan has three broad parts. (*See also* Table 1.) The first involves policy—determining the objectives and underlying principles to be pursued. The second encompasses plan design. The third involves plan execution and risk controls.

A. Policy

The most common hedging policy objective is to limit the price paid for natural gas during the winter heating season. Consumers might prefer what is called "catastrophic protection"—protection from the chances of extreme price spikes. Catastrophic protection is the least costly form of hedging and might be sufficient to satisfy the public interest.[10] Even if most customers are quite risk averse, regulators should not conclude that the utility should try to eliminate all price volatility because the transaction costs to do so might be unacceptably high. Except for some low- to middle-income customers, the financial pain threshold of most customers may not be greatly influenced by their monthly gas bill.

Below are elements regulators should require a utility hedging plan to address:

1. *Least-cost protection*. A utility should achieve the desired level of price stability at least cost.

2. *Hedging objectives*. Minimal, "catastrophic" protection against large price spikes, or a more comprehensive approach? The former approach tends to be much lower in cost than the latter.

3. *Senior management oversight*. Senior utility management should oversee and be responsible for all elements of and actions taken pursuant to a hedging plan.

4. *Mechanical or discretionary hedging?* The plan should address whether hedging is best managed through a systematic, mechanical approach, such as cost averaging of instruments; through a more discretionary approach; or through some combination of the two.

5. *Evaluation and documentation.* A utility hedging plan should evaluate the benefits and costs of all potential hedging strategies and should document all hedging decisions, including decisions not to hedge.

6. *Consultants.* A hedging plan should permit the utility to engage experts in natural gas markets if advice beyond that residing in the utility is required. The regulator should be informed in advance if the utility is contemplating such an arrangement.

7. *Reporting.* Utilities should report all hedging activities and costs to the regulator in a timely fashion.

[10] Such a policy would reveal a preference for a price-cap approach or the use of options.

B. Plan design

A central part of the plan is its design and the hedging strategies it anticipates. This would include determining whether and when to hedge, which hedging tools to apply in a given situation, price triggers for discretionary hedging, and the time horizon of hedging activity.

Since neither the regulator nor the utility knows the risk tolerances of the utility's customers, they should consider ways in which consumer views about risk tolerance might be solicited and considered as part of plan development. One approach would be to have an informal information gathering process, such as a workshop, in which representatives of customer groups could be informed about market conditions the utility may face and express their tolerance for price risk and their preferences for a particular approach.

C. Execution and risk control

With some understanding of customers' risk tolerance, utilities should set price triggers and other parameters to guide hedging decisions. They may choose among a number of financial instruments and physical hedges, such as storage and fixed-price, long-term physical contracts. Each has distinct features and costs. Some will be more compatible with the plan's policy objectives and principles than others.[11]

Plan execution and risk controls involve compliance with the plan, reporting to the regulator when gas market or other relevant circumstances change, and criteria for determining when and whether to respond to updated information.

[11] Transaction costs play a crucial role in determining the attractiveness of long-term physical contracts relative to financial instruments. Futures and options contracts have low transaction costs because they trade in a liquid, centralized exchange. It is much easier to buy or sell a futures contract when market conditions change than to renegotiate or terminate a bilateral physical or financial contract under the same conditions. Although physical and financial contracts may be interchangeable for strategic purposes, they are not perfect substitutes for one another.

III. Rationale for Regulatory Action

The rationale for regulatory action is that utility hedging activity, unregulated, may deviate from the interests of the utility's customers and the public interest. Hedging has been an integral part of natural gas markets because both spot-market and forward prices have exhibited high and unpredictable volatility, which can inflict sharp price increases on utilities and their customers, with serious economic consequences.[12]

Utilities and regulators alike recognize the benefits of hedging in managing market price spikes.[13] Utility gas procurement attempts to balance the objectives of low cost and low volatility with high reliability in its gas procurement. Least-cost procurement involves acquiring a portfolio of resources that exhibits the lowest expected future cost, subject to a given level of reliability. Hedging, by contrast, involves action to reduce unexpected future costs in the commodity and is appropriate for regulatory oversight at all stages of the process, from hedging plan development to its execution.

Some regulators have at times questioned the value of hedging, as well as specific utilities' hedging practices that have produced undesirable results. These questions stem from two major sources: (1) Utility customers have had to pay much higher prices because of hedging, compared *ex post* to the cost of market prices and *not* hedging, as discussed below at Section IV; and (2) the expected future value of hedging has seemed to diminish in view of the dramatic development in shale gas that may result in less volatile prices. The natural gas industry has seen a dramatic turnaround in prices since 2008, with the prospect that shale gas may be able to supply the U.S. gas market adequately for decades at reasonable and more stable prices. This market shift should have caused gas utilities to reevaluate their hedging strategies as these developments have unfolded, but it is not clear that all companies have done so.[14]

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[12] *See, e.g.*, Frank C. Graves and Steven H. Levine, "Managing Natural Gas Price Volatility: Principles and Practices Across the Industry," paper prepared for the American Clean Skies Foundation, Nov. 2010, at http://www.cleanskies.org/pricestabilitytaskforce/papers/ManagingNGPriceVolatility.pdf; and Richard G. Smead, "Price Instability in the U.S. Natural Gas Industry: Historical Perspective and Overview," paper prepared for the Task Force on Natural Gas Market Stability, July 15, 2010, at http://www.cleanskies.org/pricestabilitytaskforce/papers/Intro2NA_NGMarkets.pdf.

[13] As stated by Avista Utilities in its natural gas integrated resource plan, the goal of natural gas procurement is "to provide reliable supply at stable and competitive prices in navigating a variety of market conditions." *See* http://www.avistautilities.com/inside/resources/irp/electric/Documents/2009%20Natural%20Gas%20IRP-FINAL.pdf.

[14] Since 2000, we have seen high price volatility resulting from moderate changes in market conditions, explained largely by the weak short-run response of both supply and demand for natural gas to price changes. With the additional natural gas supply expected, the market price should fluctuate less, especially to upward extremes.

Even in the absence of the above market changes, good regulatory practice should require periodic review of a utility's hedging plan every two or three years to determine if it is appropriate and up to date. If a utility has not changed its hedging plan in the past three years, the regulator should be concerned and should require development of an updated plan.

IV. Utility Experience with Hedging

Hedging has potentially serious economic consequences for the utility, its customers, and the economy of the utility's entire service area. Utilities typically hedge against potential large increases in natural gas prices to blunt the effects of such increases, but hedging activity can have either positive or negative consequences, as the hypothetical examples in Appendix 2 illustrate.

A. Recent hedging experience

Some utilities have suffered large losses[15] as a result of their hedging programs. One California utility had losses of almost $60 million during 2007-2008; another California company had losses of over $37 million during 2008-2009. One North Carolina utility sustained losses of over $156 million during the winter of 2008-2009.[16] Maryland utilities during 2008-2009 suffered losses in the tens of millions of dollars.[17] Two South Carolina utilities have had losses in the tens of millions of dollars since 2006. Starting in 2006, four Michigan utilities

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[15] Losses are essentially calculated as the difference between the hedged price and the prevailing market price times the amount of gas hedged.

[16] Most of these losses were from put options that the utility sold for a period over which wholesale gas prices unexpectedly fell. The utility had to compensate the buyer for the difference between the strike price and the market price. Put options have the problem of mitigating downside price volatility, which is harmful to utility customers. (On the positive side, put options help pay for call options, which can benefit customers.) *See* Testimony and Exhibit of James G. Hoard, in Docket No. G-9, Sub 569, September 23, 2009. *See also* the Order of the North Carolina Utilities Commission in the same docket, at http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=6AAAAA84001B&parm3=000131144. The commission commented that:

> The Commission is concerned that Piedmont's end of review period balance in the hedging account is $156,196,742. The purpose of hedging is to reduce volatility in the cost of natural gas borne by consumers. Costs in excess of $156 million are an exceptionally high price for this putative benefit. Piedmont's customers justifiably can ask whether the reduction in volatility they have experienced is worth this price (at 9).

The utility has modified its hedging plans over time. It has, for example, reduced its hedging volumes, shortened its hedging horizon from 24 months to 12 months, and shifted from futures contracts to OTC contracts. The utility made the latter change to reduce the margin requirements associated with NYMEX futures contracts.

[17] Losses have occurred in spite of colder-than-normal winter temperatures. Under this condition, the hedged price should have looked good relative to the market price, which would normally be expected to rise because of weather-driven demand.

accumulated huge losses of around $1.6 billion.[18] One Colorado utility incurred hedging costs of over $206 million from 1997 through 2008.[19] Finally, the Minnesota Public Utilities Commission has questioned specific utilities' hedging practices and whether they have been beneficial to customers.[20]

Large losses of the type recently seen have led to regulator concern about utility hedging practices.[21] In South Carolina, for example, utilities have reduced their hedging volumes, switched hedging alternatives (e.g., purchasing call options instead of futures contracts), and shortened the time horizon of hedges.[22] Other utilities have also revisited their hedging

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[18] *See* Frank J. Hollewa, *Testimony and Exhibits on Behalf of the Residential Ratepayer Consortium*, before the Michigan Public Service Commission, Case No. U-16146, April 21, 2010. No party, as far as the author knows, has contested the $1.6 billion figure. A major factor for these losses was the utilities' purchases of futures contracts at prices greater than the market price at the time of settlement. Hollewa contended that NYMEX prices consistently exhibited an upward bias compared with actual spot prices that transpired.

[19] These costs represent the utility's expenses for administering the hedging program, including fees, commissions, and computer software. Commission staff also found that, for the state's largest utility hedging, costs exceeded benefits for all years during the 2005-2008 period. Unexpectedly, losses occurred during the 2005-2006 winter heating season, when natural gas prices spiked. The evidence suggests two questions for the commission: (1) Do customers want hedging at high cost? and (2) What value do customers place on catastrophic price spikes? *See* rebuttal testimony of Scott England for a critique of the utility's hedging plan and an evaluation of the outcomes, before the Colorado Public Utilities Commission (Docket No. 08A-0956), Aug. 11, 2008.

[20] In a 2008 order the Minnesota Commission said the following:

> The OES [Office of Energy Security] recommended that the companies should continue to consider whether it would be more economic to self insure against catastrophic high prices than to engage in hedging strategies. The OES also recommended that the companies work to ensure that they have an optimal hedging policy and an established method of evaluating the trade-off between lower price volatility and higher costs. The Commission finds that the OES's recommendation is reasonable and will direct the companies to work to ensure that they have an optimal hedging policy and an established method of evaluating the trade-off between lower price volatility and higher costs and will require them to do so. (*Order for Docket No. E, G-999/AA-07-1130, et al*, Dec. 8, 2008)

[21] One question this paper did not address systematically was whether utilities with large losses tend to stick with same hedging strategy year after year without consideration of costs.

[22] In February of 2011, the South Carolina Office of Regulatory Staff (ORS) requested a suspension of the hedging programs of South Carolina Electric & Gas (SCE&G) and Piedmont Natural Gas Company (PNG). ORS contended that:

strategies, largely in response to unexpectedly large hedging costs. It seems likely that not enough utilities have revisited their hedging plans and strategies, in part because their regulators have not questioned them.

These examples are but a sample of the losses that utilities and their customers have sustained in hedging. The dollar amounts are not insignificant.[23] In most instances, they represent *net losses*, in that they account for hedging benefits that might have occurred during the relevant period. This paper did not, however, examine whether utilities with large losses faced special conditions. Did they, for example, hedge a higher percentage of their winter load than other utilities? Were large losses more likely to occur when a utility hedged far in advance of the winter, or waited to hedge until the month before the flow of physical gas? Regulators should require utilities with large losses to address these questions.

These losses could have resulted from inflexible hedging, faulty hedging plans, or failure to account for extreme unexpected events. Regulatory review can help determine whether the utility needs to change its hedging strategy, incrementally or radically, to achieve a more favorable outcome.

B. Are utilities over-hedged today?

Dramatic change in the natural gas sector through development of shale gas has changed the economics of hedging. These events offer the prospect that abundant shale gas will supply the U.S. gas market for some unknown period of years, at reasonable and fairly stable cost. Advances in technology in the form of horizontal drilling and hydraulic fracturing ("fracking")

> ORS does not believe that the market conditions which led to the institution of the gas hedging programs, to mitigate the impact to customers of significant and unanticipated swings in the cost of natural gas to SCE&G and PNG's customers, still exist. Recent developments in domestic gas production and the correlating reduction in volatility in natural gas prices have eliminated much of the unpredictability which previously existed in the natural gas market. ORS does not, however, believe that a permanent elimination of these hedging programs is warranted as environmental concerns regarding shale gas production may eventually result in federally mandated restrictions on domestic production. Should such restrictions occur, the natural gas market may again be subject to price fluctuations caused by weather or an interruption in foreign supply. For that reason we believe that a suspension, as opposed to a permanent termination, of the SCE&G and PNG hedging programs is the prudent action at this time. (*See* ORS Request, at 2.)

[23] Large losses in absolute dollars do not measure the effect on the cost of each therm or Mcf sold to a utility's customers. As suggested by one reviewer, a utility could show the effect of hedging losses by developing a chart that graphs losses from swaps, futures, and financial instruments on a per-unit basis. For example, the utility could divide the annual hedge losses by the volumes hedged. It should show these losses over a multiyear period to better convey the effects of various market prices and weather conditions on the losses.

have led this change. The effect of shale gas on the U.S. and worldwide energy markets is likely to be dramatic. With an abundance of domestic natural gas, the U.S. would be able to rely much less on foreign sources, such as liquefied natural gas.

The Federal Energy Regulatory Commission's *State of the Market Reports 2009* stated: "The United States is closer than ever before to being a single natural gas market with congestion limited to a few markets for a few periods during the year."[24] The report added that pipeline capacity expansions had mitigated price volatility for gas delivered to the market. This is yet another factor that may tend to stabilize prices and lower the benefits of hedging.

Some level of hedging may still be justified, however, given the possibility that instability in the Middle East will reduce oil supplies and that increased oil prices will exert upward price pressure on natural gas, or that environmental concerns over "fracking" will substantially limit the supplies of shale-based natural gas. Natural gas consumption in electric power plants also seems likely to increase dramatically, especially since prospects for new nuclear plants in the U.S. suffered a serious setback as a result of the Fukushima Dai-ichi nuclear plant disaster. Indeed, one can conceive a scenario in which wholesale natural gas prices could go above $6-$8, even for a sustained period. If shale gas deliverability does decline, for environmental or other reasons, price speculation could jump sharply and destabilize the market. Such developments in either supply or demand could push natural gas prices well above current projections. So could a so-called "black swan."[25]

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[24] *See* Fed. Energy Reg. Commn, *State of the Markets Report 2009*, Item no: A-3, Apr. 15, 2010, at 13.

[25] A "black swan" is a highly improbable event with three distinct characteristics: It is unpredictable; it has a substantial effect; and, after the fact, analysts make the event seem less random and more predictable than it was. Policymakers should pay heed to Mark Twain's advice: "It ain't what you don't know that gets you into trouble. It's what you know for sure that just ain't so."

V. How Can Regulators Facilitate Sound Utility Hedging Decisions?

Hedging is a complex and costly activity that warrants thorough regulatory involvement from beginning to end.[26] (*See* Table 2). To ensure that the public and consumers' interests are well served and that the utility is treated fairly, the regulator should engage the hedging at three stages.

First, it should require the utility to submit a hedging plan and be thoroughly involved in its review and any revisions, if necessary. The plan should contain specific policy, design, and execution and risk control elements, all as set forth in Section II above.

Second, after plan adoption the regulator should require the utility to report to the regulator any significant changes it anticipates in gas markets, near- or long-term, along with any amendments to the hedging plan the utility believes to be appropriate.

Third, when the utility applies for cost recovery of its claimed hedging expenses, the regulator should conduct a thorough review of the utility's decisions and actions to determine (1) if they were consistent with the plan and its elements as enumerated in Section II.A. above, and any plan amendments adopted; (2) if they were consistent with the guidelines set forth immediately below in subsection A; (3) if there was information of which the utility was aware or should have been aware during the plan's implementation that it failed to disclose or act upon, and (4) if the utility acted prudently in executing the plan and its applicable strategies.

A. Guidelines for hedging

Before considering the merits of a utility hedging plan or taking up any application for cost recovery under such a plan, regulators should establish and publish guidelines—"rules of the road" for hedging—for its review of a proposed hedging strategy, of hedging results, and of utility management performance. These guidelines will help regulators and utilities alike ensure that under any hedging activity utility customers will not be asked to pay for costs that are imprudently incurred. Such an approach, with the regulator involved at all stages, should assure both the utility and its customers that any hedging plan and its execution will be consistent with public policy goals and with a "no surprises" approach to cost recovery.

The following are suggested regulatory guidelines for hedging activities. In some respects they echo or restate the elements of a hedging plan described in Section II.A:

1. **A utility should hedge at a level and cost consistent with customers' willingness to pay for stable prices.** Determining that value is inherently imprecise, but will require the attention of both the utility and the regulator.

[26] Regulators should avoid micromanagement, not least because they lack the expertise to direct a utility strategy.

2. **A utility should structure its hedging strategy and actions commensurate with the hedging plan's objectives.** If the objective is to protect residential customers during the winter heating season from extremely high gas prices, the utility should hedge its gas supplies for only those months and with alternatives that specify a price cap, such as a call option.

3. **A utility should evaluate all available hedging alternatives.** A utility should not have a preconceived notion of preferred alternatives without first evaluating each in terms of its ability to achieve the predefined objectives at the lowest possible cost.

4. **A utility should document its hedging strategy, including its decisionmaking process and internal policies.** This information is essential for regulators to evaluate a hedging strategy, both prospectively and retrospectively. The regulator should require the utility to demonstrate the merits of its proposed hedging plan and show that it is based on sound data and analysis.

5. **A utility's hedging strategy should accommodate changed market conditions and updated information.** Smart hedging involves a utility's assessing the market and making informed decisions. A utility "placing a bet and letting it ride" no matter what would be inconsistent with this approach. Some analysts believe that utilities should not try to "beat the market"[27] but instead should use a more mechanical approach if they lack the expertise to play the market more aggressively.

6. **A utility should report to the regulator all of its hedging activities and costs.** Regulators should require reporting of all relevant activities prior to monitoring and evaluating utility hedging activities.

7. **A utility should allow only qualified utility personnel or outside contractors[28] to carry out its hedging activities.** Managers should have sufficient flexibility to make specific decisions, and senior utility management should oversee all utility decisions.

This "guideline" approach is meant to provide sufficient direction to the utility such that the regulator's preapproval of a hedging plan—an action the utility might prefer—would be unnecessary. By defining hedging plan elements and guidelines while avoiding plan pre-approval, the regulator retains greater latitude to take appropriate action if it determines later that the utility acted imprudently. This approach seems appropriate, since the regulator typically lacks market and other information the utility may possess. This approach falls somewhere between the poles of (a) regulatory preapproval of a utility's hedging plan, and (b) offering no upfront guidance to the utility. Preapproval of a hedging plan by the regulator may have the

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[27] Trying to "beat the market" might involve the utility's buying large amounts of financial instruments at one time instead of spreading purchases over a longer period.

[28] With an outside contractor, the utility should make sure that the hedging strategy and activities are in the interest of the utility and its customers, rather than solely in the contractor's interest.

negative effect of inducing the utility to adhere too strictly to the letter of a hedging plan as a means to avoid later cost disallowances while avoiding prudent actions—e.g., a proposed departure from the plan to take advantage of a market shift—that would benefit customers. The "no guidance" approach simply leaves the utility at sea and likely to act too conservatively.

B. Balancing price risk and the cost of hedging

Hedging should produce benefits that exceed costs—not in any given year but over a multiyear period, taking account of the value of risk protection the hedge affords. Just as with home or auto insurance, in which almost every year's premium payments exceed the dollar value of any claims, the risk-shifting element of hedging has its own transaction costs. Regulators should determine initially whether a hedging plan should go beyond catastrophic protection.

The primary focus of most hedging plans is price spikes that can cause painfully high gas bills during the winter months. Such a concern, however, might overlook the downside risk that can also affect customers' gas bills. Downside risk imposes costs on utility customers from hedged or locked-in prices that are higher than the cash or spot market price. Part IV, above, presents real-world examples showing that this risk is large.

Regulators should also explore whether utilities consider downside risk when they design their hedging plans. Do they, for example, specify a tolerance for downside risk, as they do for upside risk? Doing so when there appears to be a reasonable possibility of softening prices could avoid regret and buyer's remorse.

C. Plan review

1. The policy element

The regulator should emphasize the importance of its review of the hedging plan, continuing oversight of the plan and its execution. The regulator should, where possible, establish benchmarks[29] for the utility's performance under the plan. A regulator's careful prospective review of a hedging plan has these benefits:

> *It internalizes the goal—appropriate risk management, as understood by assessing customer desires—as an essential part of the process.* Assessing how much, how, and when to hedge and how to hedge affects customers' welfare.

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[29] A benchmark is a standard that regulators can impose on utilities to indicate reasonable or prudent performance. It may represent a price point or a bandwidth of prices.

[29] For one idea on how regulators could establish a benchmark for hedging, *see* Michael Gettings, Prudence Standards for Utility Hedging, NARUC Winter Committee Meetings, Feb. 15, 2010, at http://www.narucmeetings.org/Presentations/Prudence%20StandardsNARUC%202010%20Winter%20Mtg.pdf%20Gettings.pdf.

It narrows the scope and incidence of after-the-fact prudence reviews and reduces opportunities for second guessing. Hedging is highly susceptible to second guessing by all parties. It is difficult to establish a benchmark to delineate the boundary between prudent and imprudent hedging. By focusing on establishing a sound process rather than trying to determine the elusive benefits of hedging,[30] regulators can reduce uncertainty for all parties.

It avoids placing the utility in a dilemma—no hedging versus hedging with no regulatory guidance. Without prior approval, the utility faces the predicament of "damned if we do, damned if we don't."[31] Boxing a utility into such a corner would be unfair to the utility and potentially costly to customers.

Regulatory review at the time of the utility's application for cost recovery should complement the earlier plan review by focusing on whether (1) the utility executed the hedging plan properly and (2) any large losses were the result of poor execution by the utility.

2. The design element

This determination is a deeper, second-level evaluation of strategies and decisions a utility might be expected to make with regard to hedging (*See* Table 1). The regulator should be apprised of the various physical and financial tools the utility proposes to consider, with particular reference to the plan's objectives—i.e., whether its aim is geared primarily to catastrophic protection or a more aggressive strategy.

The regulator should develop a systematic approach for monitoring and evaluating hedging strategies during plan development and as the utility implements the plan. This approach will require that the utility keep the regulator informed of market changes and any proposed change in plan objectives or strategies.

Regulators should view large hedging losses during a hedging plan's implementation as a "red flag" requiring immediate attention.[32]

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[30] How does a regulator define the threshold between prudent and imprudent hedging? It is difficult, if not impossible, to estimate the benefit from hedging, as the benefit—protection against a result that did not happen—cannot be mathematically calculated. The peace of mind achieved when customers know that they will not pay above the defined capped level during the winter heating season cannot be ascertained in any quantifiable way.

[31] As discussed elsewhere in this paper, regulators have been reluctant to penalize utilities for large hedging losses. But just the threat of an adverse regulatory decision can affect a utility's willingness to hedge and how it hedges.

[32] For example, the regulator could require the utility to compare its per-unit gas prices on a hedged basis to a hypothetical unhedged price based on a first-of-the-month index or some other spot price. A large variance could represent a "red flag." The reader can view an illustration of this comparison in Energy Information Administration, *Impact of Higher Natural*

3. Execution and risk control

What risk-control elements were included in the plan and its strategies? Is hedging producing the desired price stability at least cost? If not, have risk control elements been implemented?

The questions the regulator must decide are whether the utility was prudent in executing the plan in deciding when and whether to hedge, and whether the hedging tools and risk control elements employed were appropriate. In reaching these judgments, the regulator should not focus exclusively on whether the cost of hedging appears excessive in relation to market prices, but rather on whether the utility's action were consistent with (a) the plan, as it may have been amended, (b) information the utility knew or reasonably should have known during implementation, and (c) the plan and strategies being executed in a least-cost manner.

To extend the possibility of symmetry—and, some would argue, fairness—to the utility, whose hedging costs are at risk of disallowance, it has been suggested that regulators consider rewarding utilities for extraordinary hedging performance that benefits customers through lower rates. The author's view is that utilities would not readily be tempted by such an opportunity; electric utilities have not sought to realize financial incentives based on their energy-efficiency achievements, seeing this tactic as fraught with difficulty. Seeking a performance bonus for hedging success would likely be even more challenging.

Whether utilities should use discretionary hedging or a more formulaic approach (e.g., dollar cost averaging with price triggers[33]) is also not clear. A flexible plan might specify soft caps and floors on hedging volumes, price triggers, staggered hedges, a short time horizon for hedges, and a diverse portfolio of hedging tools. When the utility faces new market conditions and updated information, a flexible plan can help it avoid large losses and improve outcomes (e.g., achieving a given level of price risk at lower cost). As one regulator has observed, "It is wrong to stick with a model when reasonableness and common sense suggest that the model's signals are in error."[34]

Gas Prices on Local Distribution Companies and Residential Customers 22 (July 2007, Box 6), at http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2007/ngpristudy/ngpristudy.pdf.

[33] "Dollar cost averaging" helps diversify the risk from hedging by evenly spreading out hedging purchases rather than purchasing hedges at a single point in time. One illustration is when a utility decides in March to hedge 50% of its winter heat season purchases by buying hedges in equal amounts between March and November. Some analysts regard "dollar cost averaging" as an overly mechanical approach to hedging that is nonresponsive to changed market conditions.

[34] *See Order of the North Carolina Utilities Commission, Docket No. G-9, Sub 569*, at http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=6AAAAA84001B&parm3=000131144, at 10.

In a market as potentially volatile as natural gas, it seems too limiting to require a utility to propose a hedging strategy at the outset and stick with it no matter what. The responsibilities of the utility and the regulator should permit adaptation when circumstances warrant. This does not mean that the utility should be empowered to make aggressive moves such as a speculator would, but that it may be prudent to change strategy, after conferring with the regulator, when circumstances warrant.

D. Considerations with respect to cost recovery

Regulators should exercise caution in judging the outcome of hedging merely on the basis of its cost. Early and continuing involvement in reviewing the hedging plan and keeping abreast of its implementation and any changes in the market or the plan will put the regulator in the best position to determine the appropriateness of cost recovery.

Because a utility receives no direct benefits from hedging, the regulator should allow it to recover all its prudently incurred costs. Regulators might find it tempting to disallow recovery of some hedging costs when losses are high, but unless evidence points to imprudent utility actions or its failure to timely inform the regulator of changed market condition or a deviation from its hedging plan, full recovery seems justified. "Just and reasonable" rates require such action.

VI. Conclusion

Hedging of natural gas prices presents unique problems for regulators by its very nature, as it is intended to protect the public interest in maintaining relatively stable prices for a commodity in a volatile market whose performance cannot be anticipated

In some instances, regulators have not been as active as they might in reviewing and even prescribing elements of a hedging plan. The result has been that when a utility applies for recovery of costs in implementing a hedging plan, the regulator may lack a solid basis for approving or partially rejecting the application because a prudence review cannot be grounded simply on judging the result *ex post* in the absence of a standard for performance. Even with the benefit of hindsight, where the cost of the hedging program far exceeded the market cost of gas had no hedging been undertaken, regulators have felt that they lacked a sound basis for a disallowance and so allowed full cost recovery. More active attention throughout the process can avoid such a trap.

This paper recommends that regulators become involved in the hedging process from the outset. Through involvement in every aspect of plan development—from determining the objective of a hedging plan and utility customers' tolerance for price risk; to the elements of a hedging plan, including tools and strategies available to the utility; to the flexibility of plan implementation; to plan updating indicated by changing market conditions—the regulator establishes benchmarks for utility performance that protect the utility customer while being fair to the utility. Such early and thorough involvement by the regulator can help narrow the issues and take the guessing and risk out of prudence reviews when the utility applies for recovery of hedging costs.

Finally, in addition to the proactive involvement in hedging-plan development this paper recommends, regulators should, as often as every two to three years, review a utility's hedging activities. If the results of the review reveal a problem with the hedging plan, the regulator should direct the utility to update the plan.

Table 1: Elements of a Utility Hedging Plan and Its Broad Components

Policy Phase	Plan Design Phase	Plan Execution Phase
Determine objective of hedging Determine first principles and guidelines for hedging Determine customer price-risk tolerance (upside and downside) Determine goal in protecting against price risk Determine whether hedging is appropriate, given market information Determine criteria for changing hedging strategy Determine degree of utility discretion in hedging tactics Determine internal reporting requirements	Take account of seasonal nature of hedges Determine whether to set hard or soft targets for hedging volumes Determine budgeted amount for hedging Choose specific hedging instruments Determine price triggers for hedging volumes and timing Determine use of price forecasts and their distributions Determine (and periodically revisit) predefined formulas or models driving utility actions Determine time horizons of hedges Determine timing, amount and strategy of hedges Assess downward price flexibility Document all actions	Oversee market conditions and hedging positions Accommodate to changed market conditions and updated information Consider and continuously review compliance with plan; inform regulator if plan should be amended Report to regulator all hedging activities, costs, and results Document hedging activities for utility and regulatory review Interpret hedging results Conduct general oversight of hedging

Table 2: Eight Regulatory Functions Related to Hedging

Regulatory Action	Rationale
Establish regulatory principles for hedging	▪ Articulates regulator's goals and general criteria for hedging
Set hedging guidelines or standards	▪ Identifies acceptable utility actions compatible with principles
Review filed utility hedging plans	▪ Evaluate proposed utility actions relative to its principles and guidelines
Approve, reject, or modify proposed utility hedging plans	▪ Ensures that the approved plan is consistent with principles and guidelines
Review hedging results	▪ Allows a commission to understand and evaluate utility actions
Question hedging performance	▪ Identifies factors affecting hedging results
Evaluate prudence of utility management	▪ Determines utility recovery of hedging costs
Make other decisions based on review of utility hedging activities	▪ Improves future regulatory actions

Appendix 1: Questions Regulators Should Ask Utilities

Regulators should question utilities with respect to hedging under the four categories below.

Rationale for Hedging

1. What market conditions support hedging?
2. How have new developments in domestic gas-supply conditions since around 2008 affected the benefits of hedging?
3. How can utilities identify benefits from hedging? To what extent are they quantifiable?
4. If utilities are unable to precisely measure the benefits from hedging, or even know if customers place any value on less volatile prices, how can they justify hedging?
5. How does hedging compare to other utility alternatives to stabilize gas prices and bills?
6. What are the costs associated with different hedging tools?
7. What are potential losses for utilities from hedging activities?
8. What cost-benefit criteria determine whether the utility should hedge?

Design of a Hedging Plan

1. How is hedging integrated into the gas procurement process?
2. What role should price expectations play?
3. How much discretion should a plan allow a utility in executing the plan?
4. What are the time horizons of individual hedges?
5. Are hedges staggered over a predefined period?
6. What budget did the utility set for its hedging activities?
7. What hedging tools did the utility consider?
8. What criteria were used to select the hedging tools?
9. Does the plan include hard or soft targets for hedging volumes?

10. Does the plan include price triggers for determining hedging volumes and timing?

11. How were price forecasts developed and used in developing the plan?

12. How does the plan account for customers tolerance for both upside and downside price risk? How were estimates of customer-risk tolerance developed (e.g., quantitatively, market research, focus group, management opinion, inference from outside sources, or information from other jurisdictions and other utilities)?

13. What models or other quantitative tools assisted in developing the plan?

14. How should regulators judge benefits and costs in a post-review?

Execution of the Plan

1. How active is the utility in changing its positions on hedges and taking other appropriate actions following new market conditions and information?

2. Did the utility document all of its actions, and, if so, how?

3. Did the utility demonstrate how it complied with its plan?

4. Did the utility report on all of its costs and outcomes?

Review of Hedging Outcomes

1. If hedging losses occurred, what caused them?

2. How do the losses of the utility compare to those of other utilities in the state or in neighboring states?

3. What measured benefits did customers receive from hedging?

4. What is the value of both the tangible and intangible benefits customers received from hedging?

5. What prices would customers have paid if the utility had not hedged? (Include any assumptions used in developing the estimate of prices that would be paid without hedging.)

6. How will the outcomes affect the utility's future hedging activities?

Appendix 2: General Benefits and Costs of Hedging

Potential Benefits to Customers

A gas utility may purchase a futures contract to set a price cap on the gas it buys for some future period. Typically it would purchase futures contracts to cover future requirements and to lock in a future price. When the month for which the utility requires physical gas approaches, it will sell its futures contract and purchase physical gas. As the two transactions occur almost simultaneously, their prices cancel each other (with a "basis" adjustment to account for the difference in the spot price at the Henry Hub and the local delivery point). The result is that customers pay the original price of the futures contract for the physical gas they purchase from the utility.

As one example, assume that in February a utility purchases gas futures contracts that mature the following November at a price of $5/MMBtu. When November approaches and the utility needs to buy physical gas, the spot price is $6. But the utility is able to sell its November futures contract also at $6. As the two transactions occur at almost identical times, their prices cancel each other (with a basis adjustment). The result is that customers pay the original price of the futures contract ($5) for the physical gas they purchase from the utility.[35] In this example, customers benefit by $1 per MMBtu from hedging: if the utility did not hedge, it would have had to pay $6 instead of $5 for hedging or locking in a price at that level.

Assume that a utility purchases a swap[36] from a gas trader to lock in a fixed price of $6.[37] The utility would continue to pay the trader for physical gas at the market price—say, $7. Under the swap arrangement, the trader would pay the utility the $1 difference between the market price and the locked-in price. This example again illustrates the benefit to the utility and its customers from hedging.

A third example involves a costless collar, in which a utility pays no more than a specified maximum price and the seller receives at least a specified minimum price. No other

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[35] A utility holds a futures contract strictly to establish the hedge. It does not hold the contract because it wants to perform under it—that is, it does not plan to take delivery of the gas. Because it holds the futures contract only for hedging purposes, it must offset that contract before it expires. (One exception is when the utility needs gas at Henry Hub.) The utility must act upon all futures contracts that are actually held at the time of expiration.

[36] A "swap" is a custom-tailored, individually negotiated transaction designed to manage financial risk over some specified period. Swaps can involve two counterparties, or a third party. The third-party writer of the swap, typically a bank or brokerage house, may assume the risk itself, or manage its own market exposure on a central exchange.

[37] No fee exchanges hands because each party reduces its risk. In the example, the seller (buyer) knows that it won't receive (pay) less (more) than $6.

money changes hands, as each party values the contract at the same level.[38] Assume that a utility wants the guarantee of paying a price between $5 and $6; this range assures that it pays no more than $6 but will never pay below $5. The utility in effect purchases a $6 cap and sells a $5 floor, "collaring" its payment. If the premiums paid and received are equal, the transaction becomes what the market calls a "costless collar." As in the other examples, the utility benefits when the market price is above the locked-in ceiling price—in this example, the price cap of $6.

Potential Losses to Customers

Hedging also carries the risk that a utility and therefore its customers will pay above-market prices. An example is when a utility purchases a futures contract in the summer to hedge for the following winter at a price higher than the actual winter market price.[39] Another example is when a utility sells a put option and the buyer exercises it when the market price turns out to be lower than the strike price.

With the facts of this example, the three positive outcomes in the previous section can easily cause the utility and its customers to be worse off because of hedging. Assume that the

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[38] One description of a collar is as follows:

> A collar is a financial instrument wherein the Company [utility] sells a put and uses the value received for selling the put to purchase a call option. The sale of the put guarantees the floor or lowest price the Company will be paying for its supply and the purchase of the call establishes a ceiling or maximum price that the Company will pay for its supply. The goal of the collar is to use the proceeds from the sale of the put to reduce the cost for hedging positions and/or improve the maximum price position provided by the call option. This type of financial instrument generally sets the maximum and minimum price for the Company's gas supply cost. (*Testimony and Exhibit of James G. Hoard*, in Docket No. G-9, Sub 569, September 23, 2009, 5.)

[39] Futures prices reflect market-consensus estimates that emerge from the trading activity of many parties. As expressed by one source, "The futures market . . . distills the diverse views of market participants into a single price . . . [These] participants buy or sell a futures contract at the price they believe the commodity will sell for on the delivery date." (United States Government Accountability Office, *Energy Derivatives: Preliminary Views on Energy Derivatives Trading and CFTC Oversight (GAO-07-1095T)*, July 12, 2007, 4.) One interpretation of futures prices at contract maturity being higher than the cash or market price is that events had taken place in the interim to reduce cash or market price below what was expected when the utility purchased the futures contract.

market price is $4. In buying a futures contract for $5, the utility loses $1[40]; in the swap example, the utility loses $2; in the collar example, the utility loses $1.[41]

Hedging frequently produces losses. Regulators should not expect losses, however, to be large for almost all years. Regulators should also not expect hedging to lower a utility's purchased gas costs over a multiyear period. Instead, hedging would tend to cause customers to pay higher prices over the long term and in most years, but at the benefit of protecting customers against extremely high prices. Good hedging strategies balance price risk with the risk of hedging itself. The latter includes "regret," in which after the fact the utility and its customers realize they would have been better off without hedging. Hedging also introduces other new risks like counterparty risk and collateral obligations.

Overall, a good hedging strategy should produce gains roughly equal to losses in the long term, with expected losses somewhat higher to account for transaction costs and the costs associated with shifting price risk to other market players.[42] But regulators should not expect hedging to result in substantially higher costs over a multiyear period.

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[40] A high frequency of these losses might suggest that futures prices have an upward bias that would consistently cause the final settlement price to fall below the purchase price.

[41] In the swap example, the utility guarantees the gas trader a price of $6, so when the market price is $4, the utility owes the trader an additional $2. In the collar example, the trader receives a minimum price of $5, so the utility owes the trader an additional $1.

[42] The "long term" here refers to at least five years and as long as ten to fifteen years. In that time, for example, the utility could experience several years of small losses and a year or two of large gains.

Appendix 3: Reading Materials on Hedging

1. Dennis W. Carlton, "Futures Markets: Their Purpose, Their History, Their Successes and Failures," *Journal of Futures Markets* 1 (1984): 237-71. This paper discusses the economic role of futures markets and how they have operated in the U.S. Throughout their history, futures markets have encountered problems, but for the most part they have served markets well in providing liquidity and reducing transaction costs for risk-management activities, especially in commodity markets.

2. Kenneth W. Costello and John Cita, *Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues*, The National Regulatory Research Institute 01-08, May 2001, at http://nrri.org/pubs/gas/01-08.pdf. This report examines the basic issues associated with hedging, including questions that state public utility commissions should address. The report provides guidelines that state commissions can refer to in reviewing utilities' hedging activities.

3. Kenneth A. Froot, David S. Scharfstein, and Jeremy Stein, "A Framework for Risk Management," *Harvard Business Review*, November-December 1994: 91-102. This paper discusses, applying modern finance theory, why firms hedge. Specifically, it argues that firms use hedging as a risk-management tool to stabilize internal cash flow. Hedging, for example, allows a firm to better align its demand for funds with the internal supply of funds. With available internal funds available, a firm is in a better position to finance value-enhancing investments without the costs of outside financing.

4. Mike Gettings," A Prescription for Regulatory Agreements Regarding Energy Commodity Price Risk Mitigation," July 18, 2008, at http://nrri.org/pubs/gas/PACE_Final_Regulatory_Paper_9-9-08.pdf. This paper addresses some of the most complex issues that have emerged from the several years of experience with financial hedging by gas and electric utilities. These issues include the influence of regulatory polices and practices on utility hedging activities, the value of more price stability to consumers, and regulatory incentives that would optimize utility hedging from the perspective of customers.

5. Frank C. Graves and Steven H. Levine, "Managing Natural Gas Price Volatility: Principles and Practices Across the Industry," paper prepared for the American Clean Skies Foundation, November 2010, at http://www.cleanskies.org/pricestabilitytaskforce/papers/ManagingNGPriceVolatility.pdf. This paper reviews a number of tools and techniques for managing natural gas price volatility. It also discusses how different market participants in the natural gas industry use these techniques. The paper includes case studies of hedging programs, highlighting their different purposes

6. NYMEX/CME website on natural gas derivatives, at http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html. NYMEX is the world's largest physical commodity futures exchange and the preeminent trading forum for energy and metals. NYMEX first offered gas futures contracts in April 1990. Options on gas futures contracts began trading in 1992. NYMEX is both regulated and self-regulating. The Commodities Futures Trading Commission (CFTC) is responsible for overseeing futures markets.