National Regulatory
Research Institute

Briefing Paper

Going "Long" with Gas: Considerations for State Regulators

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The National Regulatory Research Institute

September 2010

10-13

Acknowledgments

The author wishes to thank William Gilmore of the North Carolina Utilities Commission, Robert Harding of the Minnesota Public Utilities Commission, Scott Hempling of NRRI, and Kenneth Zimmerman of the Oregon Public Utility Commission for their comments on an earlier draft of this paper. Any errors in the paper remain the responsibility of the author.

Online Access

The reader can find this paper on the Web at www.nrri.org/pubs/gas/NRRI_going_long_with_gas_sept10-13.pdf.

Executive Summary

One feature of the U.S. gas market is the predominance of short-term transactions for commodity gas and the short duration of pipeline contracts compared to twenty-five years ago. The primary force behind this transformation from the previous era of long-term contracts with rigid terms and conditions lies with simple economics: Retail gas and electricity consumers have had more choice in suppliers, and gas utilities have faced more uncertainty over future prices and their load requirements. As gas utilities, for example, downsized the bundled-sales-service side of their business, they invariably had less desire for long-term commitments. Overall, competitive pressures have made long-term commitments a more expensive proposition for utilities by increasing risk. One reason for the restructuring of the natural gas industry, in fact, was the high social cost associated with rigid long-term contractual arrangements that became more pronounced as the industry transitioned to a more liberalized structure.

Both utilities and gas suppliers recently have given more attention to the possibility of long-term contracting. This new attention relies on the presumption that the U.S. gas market will have ample supplies of natural gas over the next several decades, resulting in prices becoming more stable—and predictable—than those of the past ten years' experience. With these conditions, both buyers and sellers might be willing to make long-term commitments. The trading parties might find it easier to specify contractual terms, as there would likely be fewer contingencies (e.g., gas prices would less likely soar to extremely high levels). Thus, renegotiations would occur less often, thereby reducing the lower transaction costs associated with long-term contracting. It is unknown to what extent this reversal of recent trends will spread throughout the natural gas industry.

This briefing paper identifies different choices available to utilities in view of new market conditions. Two general categories of choice are market transactions and self-supply through vertical integration. In each of these categories, utilities can select gas purchases of varying durations. The paper then lists the benefits and costs of long-term contracting. It also discusses factors in determining the appropriate mix of different transaction types. When purchasing gas, most utilities use a portfolio approach, which involves purchases under different durations and other terms and conditions. Utilities might buy some gas in the spot market (days or months ahead) and some under contract for longer periods (e.g., six months or two years ahead). The utility might overlay these purchases (especially for spot gas) with financial derivatives to hedge the price.

This paper discusses the significance of regulators' making different commitments to long-term contracts: What obligations does a regulator have when it approves a long-term contract? Does approval mean guaranteed cost recovery by the utility? What are the problems with a regulator "over-committing" or "under-committing" to a long-term contract?

Finally, the paper lists questions that regulators can ask in a generic investigation of long-term contracting. Answers to these questions will allow regulators to make better decisions about the merits of long-term contracting relative to other institutional arrangements, such as spot purchases and financial hedging.

This paper makes several recommendations:

1. ***In evaluating long-term contracting, regulators should consider this option within the context of a portfolio in which a utility attempts to combine different options in meeting different objectives.*** Following this approach, regulators should encourage utilities to strike a balance between moderating risks and providing reliable service at the lowest possible price. Regulators should choose the utility gas purchasing strategy that best balances the objectives they assigned to gas purchasing.
2. ***Regulators should recognize transaction costs as an important factor in determining the preferred duration and other features of market transactions and self-supply through vertical integration.*** Transaction costs are those costs (excluding the price) that firms and consumers incur in consummating a trade. The cost of negotiating and monitoring a contract is an example of a transaction cost. Empirical and theoretical studies have shown the importance of transaction costs in determining the most efficient institutional arrangement for trading.
3. ***Long-term gas transactions have some advantages over spot purchases, but they have some disadvantages as well.*** Although long-term contracts can help to manage supply risk and price volatility, they might not reflect the prevailing economic value of natural gas and pipeline transportation under changed market conditions; that is, the contract price might deviate significantly from the market price.
4. ***Given the changed natural gas market over the past two years, regulators should give more consideration to the merits of long-term contracts.*** Other conditions also favor long-term contracting. One condition is when a supplier is willing to offer a discounted, or below-market, price to a utility that is willing to commit for several years. Another condition is a highly risky infrastructure development that requires a certain level of revenue assurance for financing that long-term contracting can bring.
5. ***Regulators should scrutinize any self-supply option, especially when an affiliate is the supplier, for possible self-dealing abuses.*** One major distinction between market transactions and self-supply is the self-dealing aspect of the latter, which can pose special problems that regulators need to prevent through oversight and other actions. The regulator, for example, might need to establish codes-of-conduct rules that explicitly prohibit self-dealing abuses by restricting certain interactions between a utility and an affiliate.
6. ***Regulators should consider bilateral physical contracting as a substitute for financial hedging.*** High wholesale gas-price volatility supports consideration of hedging by utilities, including hedging with financial derivatives. Customers can suffer non-trivial economic welfare losses when natural gas prices rise to unusually high levels. Relative to physical hedges, such as storage and bilateral physical contracts, financial derivatives can have lower transaction costs and higher liquidity.

7. ***Regulators should decide up front what commitment they want to make to long-term contracting.*** Regulators should recognize the inherent tension between regulatory commitment and a potential perverse-incentive problem: If the regulator both approves a contract and guarantees cost recovery, a "moral hazard" might result in which the utility would lack a strong incentive to appropriately and sufficiently monitor the contract in the best interest of its customers. On the other side, too little commitment can lead to regulatory opportunism and uncertainty of cost recovery. Regulators need to find the right balance.

8. ***Regulators should consider conducting a generic investigation that asks several questions about the merits of long-term contracting and its appropriateness.*** As a policy matter, regulators should take a neutral position on long-term contracting. They should support long-term trading arrangements when they are an integral part of a utility's optimal gas procurement portfolio. While long-term contracting can serve a useful function, it should not be a requirement for utilities. Regulators should ask utilities and other stakeholders questions relating to: (a) alternate regulatory policies on long-term contracting, (b) economic considerations that regulators should take into account, and (c) specific price and non-price contract provisions.

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Gas utilities purchase gas to sell directly to retail customers while electric utilities purchase gas to fuel their gas-fired generating facilities. Both utility types have long-term obligations to serve. What kind of gas-purchase commitments should they make—short-term, medium-term, or long-term?

Part I of this briefing paper defines terms relevant to long-term contracting. **Part II** provides an overview of market conditions since 1985 that tended to favor spot and other short-term transactions. **Part III** discusses new market conditions that might make long-term contracting more economically attractive. **Part IV** identifies different choices available to utilities in view of new market conditions. **Part V** lists the benefits and costs of long-term contracting relative to alternative transactions. It also discusses factors in determining the appropriate mix of different transaction types. **Part VI** discusses alternative regulatory commitments to long-term contracts: What obligations does a regulator have, for example, when it approves a long-term contract? Does approval mean guaranteed cost recovery by the utility? What are the problems with a regulator "over-committing" or "under-committing" to a long-term contract? **Part VII** lists questions that regulators can ask in a generic investigation of long-term contracting.

I. Terminology: Definitions and Distinctions

While acknowledging that the duration of transactions is a continuum, this paper groups transactions into the discrete categories "long-term" and "spot." It uses these simplified categories for purposes of clarity, recognizing that the focus is on emphases rather than precise outcomes.

*"Long-term***"** can have different meanings. In the context of this paper, it refers to a multi-year period; one definition is that "long-term" has a minimum duration of three years. A long-term contract might call for a fixed amount of supply (thereby guaranteeing reliability) but with variable-price terms (e.g., tied to the first-of-the-month futures price adjusted for basis[1]). In this example, the parties make a long-term commitment to supply but not to price; the parties do commit, however, to a price based on some agreed-upon formula. Although long-term contracting exists for both upstream gas storage service and pipeline transportation, the focus of this paper is on commodity gas.[2]

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[1] "Basis" is the difference between (a) the quoted futures price for a specific delivery month and (b) the cash or spot price at the local market at any point in time. For storable commodities such as natural gas, the basis reflects both carrying charges and transportation costs.

[2] For a thorough discussion of long-term contracting in the natural gas market, *see* J.M. Petrash, "Long-Term Natural Gas Contracts: Dead, Dying, or Merely Resting?" *Energy Law Journal*, vol. 27, no. 2 (2006): 545-82.

A *bilateral physical contract* is an agreement between two parties for the sale and purchase of a commodity or service (e.g., natural gas or transportation service) with specific terms and conditions. The buyer under a bilateral physical contract expects to have gas supplied or delivered to its location of use. In contrast, a *financial (or futures) contract* is an agreement to buy or sell a specific amount of a commodity or financial instrument at a particular price on a stipulated future date. (See also the definition of *financial derivatives* below.) A futures contract allows the parties to manage price risk, and/or provides one party the opportunity to profit by selling the contract at a higher price than the price it paid for the contract (i.e., of speculating). A speculator in natural gas, for example, might purchase a futures contract today believing that at expiration in six months it will sell for a higher price, making a profit in the process.

Spot transactions involve the trading of a commodity for immediate or near-term use. For natural gas, these transactions involve sales within the following 30 days. A utility will use the spot market to buy natural gas for the next day or month. Well-developed day-ahead and monthly spot markets for natural gas have thrived since the early 1990s. The U.S. has several spot markets with a large number of sellers and buyers transacting natural gas and other services. A spot market usually has several pipeline interconnections. Spot transactions based on standardized North American Standards Board (NAESB) contracts provide individual buyers with much assurance of reliable supply.

Prices in these markets reflect short-term supply-and-demand movements as well as futures prices. Because gas is a commodity, spot prices can change quickly and fluctuate widely, with the timing of gas purchases having a large effect on a utility's actual annual average gas costs. The spot price of gas depends on several factors, including production cost, storage levels, economic conditions, weather, pipeline capacity, and random shocks (e.g., events in the Middle East affecting oil prices).

Spot transactions provide flexibility to the utility in the daily balancing of supply with demand. Gas utilities use spot purchases to supplement firm contracts during times of high demand or to displace gas having a higher cost. Spot markets also require repeated trading, which over time can drive up transaction costs.

Self-supply through vertical integration means that a utility purchases gas, transportation, or storage service through either one of its divisions or an affiliate. Self-supply can involve either short-term or long-term transactions. Self-supply avoids having the utility rely on market transactions, but it poses other problems for regulators (*see* Part IV.B below).

Financial derivatives are instruments that derive their value from an underlying cash market commodity, futures contract, or other financial derivative. They are traded on regulated exchange markets or over the counter. For example, futures contracts are derivatives of physical commodities, while options on futures are derivatives of futures contracts. Many gas and electric utilities use futures contracts, options, and other financial derivatives to hedge (i.e., reduce the price risk associated with) their physical gas purchases.[3] Since 2000, both utilities and state

[3] For an overview of gas hedging, see the NRRI report *Use of Hedging by Local Gas Distribution Companies: Basic Considerations and Regulatory Issues*, at http://nrri.org/pubs/gas/01-08.pdf.

regulators have recognized the importance of their local gas utilities' using financial derivatives to moderate price volatility for their customers. These derivatives reflect the natural outgrowth of the well-developed and volatile gas spot markets that stimulate hedging activities.

Hedging refers to an economic activity in which a person or entity enters the market with the specific intent of protecting an existing or anticipated physical market exposure from unexpected or adverse price fluctuations. Hedges come in both physical and financial forms: Utilities can use storage or bilateral physical contracts with fixed prices as hedges; they can also purchase financial hedges, such as futures contracts, options, and swaps.

The *portfolio approach* (sometimes referred to as the "best cost" approach) to gas purchases has evolved from the past least-cost paradigm, partly because of wholesale price volatility and a more dynamic gas market. A least-cost strategy focuses on cost minimization, but in the process might compromise other objectives such as reliability and moderate price volatility. Diversification of gas supplies from different sources and under various market and self-supply transactions gives a utility more flexibility and protection from uncertain future events. In other words, the utility is able to adapt to unforeseen events with less disruption and at a lower cost. Diversification also allows a utility to better achieve different objectives, some of which are conflicting. A utility that buys all of its gas in the spot market, for example, might experience extreme price volatility that can harm customers. Most gas utilities apply the portfolio approach to their gas procurement activities.[4]

Transaction costs are those costs incurred by trading parties to find each other and then to negotiate, draft, monitor, and enforce contracts. As expressed by one noted economist:

> [T]here were costs of using the pricing mechanism. What the prices are have to be discovered. There are negotiations to be undertaken, contracts to be drawn up, inspections to be made, arrangements to be made to settle disputes, and so on. These costs have come to be known as *transaction costs*. Their existence implies that methods of coordination alternative to the market, which themselves are costly and in various ways imperfect, may nonetheless be preferable to relying on the pricing mechanism…[5]

[4] *See* American Gas Association, "LDC Supply Portfolio Management during the 2009-2010 Winter Heating Season," June 24, 2010.

[5] R.H. Coase, *Essays on Economics and Economists* (Chicago, IL: The University of Chicago Press, 1994), 7-8 (emphasis added).

II. Market Conditions Since 1985 Have Favored Spot Transactions

Prior to the 1980s, a conspicuous feature of the industry was contracts over long durations (e.g., over twenty years) at fixed prices, for both producer-pipeline transactions and pipeline-gas utility transactions. Starting around 1985, trading arrangements within the natural gas industry have become much more short-term and flexible, in both price and terms and conditions, compared to prior periods. We have observed this trend throughout the sector, from gas procurement, gas storage, and retail transactions to capacity contracting for pipeline services.

This trend is a result of a more open and restructured natural gas market, among other factors. This market includes buyers and sellers consummating trades with minimal transaction costs. Other factors favoring shorter-term contracts since the mid-1980s include a highly developed financial market for gas hedging, regulatory prudence reviews of natural gas purchasing practices, and the evolution of short-term electricity markets. The last factor stems from generators' finding it excessively risky to commit on a long-term basis to gas purchases when they do not have long-term commitments from electricity buyers.

Since FERC Order 636, the gas pipeline network has become substantially more interconnected between spatially distinct markets (meaning gas producers, pipelines, and storage operators have enlarged markets).[6] The increased number of producers and pipelines in regional markets has reduced the need for long-term contracts to support investments in gas supplies and pipeline capacity. This development has also increased a utility's ability to switch between producers and pipelines, thereby reducing its preferences for long-term price and reliability protections. With the more competitive market that has evolved in the natural gas industry, therefore, long-term transactions have become less appealing to utilities. Because of utilities' "obligation to serve" for core customers, however, firm and reliable supplies, transportation, and storage are still necessary.

The evolution of the U.S. gas market over most of the past two decades thus has weakened the economic rationale for long-term contracting of both commodity gas and pipeline transportation. In fact, a major impetus behind the restructuring of the natural gas industry was the high social cost associated with rigid long-term contractual arrangements, which became more evident as the industry transitioned to a more liberalized structure. Long-term contracts in the past twenty some years, incidentally, have had more flexible terms and conditions, including renegotiation provisions, than prior long-term contracts.

[6] The reader can access FERC Order 636 at http://www.ferc.gov/legal/maj-ord-reg.asp. Most relevant for our discussion here, the FERC ruling buttressed non-discriminatory access to interstate pipeline service by: (a) requiring pipelines to unbundle transportation from sales, (b) removing pipelines from the merchant function, and (c) requiring pipelines to provide open-access storage.

In sum, the primary force behind this broad reshaping of trading arrangements is simple economics: Retail gas and electricity consumers have had more choices of suppliers, and gas utilities have faced more uncertainty over future prices and their load requirements. As gas utilities, for example, downsized the bundled-sales-service side of their business, they invariably had less desire for long-term commitments. Overall, competitive pressures have made long-term commitments a more expensive proposition for utilities by increasing risk.

III. New Market Conditions: Shale Gas Might Favor a Larger Role for Long-Term Commitments

The current consensus is that shale gas will help to assure sufficient U.S. gas supplies over the next several decades, assuming gas prices do not fall too low and environmental opposition to hydraulic fracturing does not intensify.[7] There is also the question of how much it will cost to drill and produce shale gas beyond what we have developed so far. The experience up to now has been encouraging, but uncertainty remains. The most likely prospect is that we will extract large amounts of shale gas at a reasonable cost.[8] Another emerging development is the efforts of the natural gas industry to find new and additional uses for gas, particularly in the electric power and transportation sectors.

Both utilities and gas suppliers recently have given more attention to the possibility of long-term contracting.[9] This new attention relies on the predictions that the U.S. gas market will have ample supplies of natural gas over the next several decades, resulting in prices becoming more stable—and predictable—than those of the past ten years. With a supply-abundant gas future and accompanying price stability and predictability, both buyers and sellers might be willing to make long-term commitments. The trading parties might find it easier to specify contractual terms because there would likely be fewer contingencies (e.g., gas prices would less likely soar to extremely high levels). Thus, renegotiations would occur less often, thereby reducing the lower transaction costs associated with long-term contracting.[10] It is unknown to what extent this reversal of recent trends will spread throughout the natural gas industry.

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[7] *See*, for example, U.S. Department of Energy and National Energy Technology Laboratory, *Modern Gas Shale Development in the United States: A Primer*, April 2009.

[8] *See*, for example, U.S. Energy Information Administration, *Annual Energy Outlook 2010*, May 2010.

[9] *See*, for example, B. Casselman and R. Smith, "Natural-Gas Producers Seek Long-Term Contracts," *Wall Street Journal*, December, at http://www.rigzone.com/news/article.asp?a_id=84813. Earlier this decade, studies by the National Petroleum (NPC), the Interstate Natural Gas Association of America (INGAA), and the Keystone Center supported long-term contracting in various functions of the natural gas sector.

[10] Part V.D discusses the effects of transaction costs on the institutional arrangement for gas purchases by a utility. A major cost component of contracting is renegotiating contracts in light of unforeseen events.

IV. Given These New Market Conditions, What Are a Utility's Choices?

For utilities looking to change their emphasis from spot-market purchases to long-term contracting, there are two main options: market transactions and self-supply. Whichever approach a utility chooses, portfolio analysis is necessary. This section discusses these options.

A. Market transactions

As explained in Part I, *long-term contracting* represents a transaction in which the seller and utility desire more certainty, over the next few or several years, in price and reliability than what spot-market transactions can offer. The parties also might want to customize other non-price terms to their unique needs. The parties' risk aversion, as well as market conditions, plays a large role in a contract's negotiated terms. These conditions include the predictability of the future, and the relative bargaining strength and the planning capability of each party. Evidence of risk aversion is the higher price that a buyer would be willing to pay to have more stability of price over time.

Contracting has several dimensions that are negotiated between the utility and seller, with the outcome largely dependent on market conditions—both physical and financial—and on other contract terms that provide value to either party. A firm contract that allows for flexibility in daily takes would generally be worth more to a utility than one without this flexibility. This flexibility will frequently increase the price to the buyer. If a buyer desires firm supply, the seller will often attach a reservation fee. This fee gives the buyer the right to reserve gas up to the maximum daily contract quantity. Long-term contracts also commonly have a market-based commodity price linked to price indices published in industry trade publications.

Similarly, a take-or-pay contract (i.e., a contract in which the utility would be obligated to pay a minimum amount irrespective of its actual use) will be more valuable to a seller. On the downside, contracting can produce uneconomic results, namely, a price above the prevailing spot market price, or excess gas supplies because of an unexpected downturn in demand, the costs of which customers might have to bear. Simply having a price that is above prevailing market prices, however, may not indicate an uneconomic or unwise choice, if there are other elements of the contract that allow it to work well within a portfolio or if simply unforeseen market developments emerge.

B. Self-supply through vertical integration

Self-supply through vertical integration involves a utility self-supplying its gas either within a division of the utility or through an affiliate. One example is an electric utility that supplies itself with natural gas from wells that it owns. Another example is a gas utility buying gas from a marketing affiliate. Transaction cost-based theories focus on how incomplete contracts, asset specificity, imperfect information, and incentives for opportunistic behavior make vertical integration economically attractive. One challenge for a firm undergoing vertical integration is to avoid substantially higher organizational costs from taking on new activities

internally.[11] For example, a firm might decide to produce the materials needed to make widgets. The firm's management, which now needs to involve itself with a new activity that requires additional acumen and knowledge, might then neglect its core activities.[12]

An affiliate relationship raises a fundamental question: Does this association produce real cost efficiencies, or is just a device by which to make captive customers bear the risks while shareholders receive the rewards? Assume that both the utility and the outside entity (e.g., an affiliated gas marketer) are under the control of the same parent company. Their resources are then internal to a single corporation. Why could not the parent company allocate the expertise and skills of the other entity to the utility? Would not this allocation eliminate the middleman in carrying out the designated functions? Could not the costs to the utility's customers be held down as a result?

One can legitimately ask: What is the real reason for an affiliate to provide services that the utility itself provides using the same resources of the parent company? The reason may simply be that the parent company expects to earn higher profits by allowing its unregulated affiliate to profit from providing services that the regulated utility had previously provided itself at less or no profit. This additional profit could come at the expense of the utility's customers. A benign explanation is that the unregulated affiliate is providing similar services to other utilities under the control of the same parent company. Economies of scale might, therefore, exist that would make this arrangement economically tenable and beneficial to all the utilities' customers.

Table 1 shows the different options for a utility in procuring natural gas. They include: (1) *market transactions* in the forms of spot purchases and long-term contracting, and (2) *self-supply* within a utility's division or through an affiliate, each with the possibility of spot purchases or long-term contracting. One major distinction between market transactions and self-supply is the self-dealing aspect of the latter, which can pose problems that the regulator needs to

[11] *See*, for example, O.E. Williamson, "Transaction-Cost Economics: The Governance of Contractual Relations," *Journal of Law and Economics*, vol. 22 (October 1985): 233-61.

[12] A vertically integrated firm incurs costs when producing one of its inputs. These costs include contracting with employees and supervising them. Buying the input in the marketplace requires the firm to contract with sellers and monitor the quality of the product. These are the *transaction costs* of buying a product. Competitive pressure should cause firms to minimize their costs by selecting the cheaper alternative between buying and making the input.

prevent through oversight and other actions.[13] The regulator, for example, might need to establish codes-of-conduct rules that explicitly prohibit self-deal abuses by restricting certain actions.[14]

Table 1: Utility Options

Market Transactions	**Self-Supply**
Spot purchases	**Utility division** • **Spot purchase** • **Long-term contracting**
Long-term contracting	**Affiliate** • **Spot purchase** • **Long-term contracting**

C. Diversification: gas purchasing involves a portfolio

Portfolio-based approaches to gas purchases have evolved from the past least-cost paradigm, partly because of wholesale price volatility and a more dynamic gas market. Diversification gives a utility more flexibility and protection from uncertain future events. A portfolio of gas supplies accounts for:

1. The multi-objective nature of gas procurement (e.g., achieving the lowest cost for highly reliable service, with moderate price volatility);

2. Tradeoffs among objectives;

3. The value placed on diversity because of complementarities among the different gas supply sources and contractual arrangements (i.e., one source of gas supply having features that compensate for the deficiencies of other sources); and

[13] Problems of self-dealing can derive from several sources: the pricing of utility-affiliate transactions, cost-shifting, cross-subsidization, discriminatory regulated service from "essential facilities," mandatory tying of "essential facilities" service and unregulated service, and discriminatory release of information from a utility to unregulated entities.

[14] For a discussion of the questions surrounding codes-of-conduct rules, *see* K.W. Costello, "Do Codes of Conduct Achieve Their Objectives?" *The Electricity Journal*, vol. 13, no. 2 (March 2000): 55-66.

4. The dynamic and uncertain state of situations in which utilities today must purchase gas supply, transportation, and financial and physical hedges.

Even after accounting for all of these factors, utility management still has to make a series of collective judgment calls in selecting an "optimal" plan. Signing a long-term contract, for example, can give a utility more certainty about future prices and greater reliability; the downside is that the utility might forgo opportunities in the future to buy low-priced spot gas. A portfolio of gas supplies from different geographical sources can increase reliability by mitigating the effect of a single event disrupting transportation from one of the pipelines serving the utility. Financial hedging can reduce price volatility but increase the long-term price of gas to the utility.

A utility can assemble a diverse gas portfolio by: (a) interconnecting with multiple interstate pipelines, (b) accessing multiple supply basins and sources of supply, (c) purchasing gas supplies under different pricing rules or mechanisms, (d) balancing its portfolio, and (e) staggering gas purchases and financial price hedges. A gas utility can achieve diversity by buying gas from geographically dispersed sources using different pricing mechanisms: the first-of-month spot price, the daily spot price, a fixed price, or the NYMEX futures price. It also can achieve diversity by staggering its gas purchases and asset contracts (e.g., for transportation capacity) over different times of the year and month.

As a real-world example, the typical gas utility purchases physical gas from brokers, other middlemen, producers, and others. It might buy some gas in the spot market (a day or month ahead) and some under contract for longer periods (e.g., six months or two years). The utility might overlay these purchases (especially for spot gas) with financial derivatives to hedge the price.

D. Hedging with financial derivatives

Hedging is an economic activity in which an individual or group uses the market to protect an existing or anticipated physical market exposure from unexpected or adverse price fluctuations. One example of financial hedging is a utility purchasing gas futures contracts to cover future months' requirements and fix its purchase price.

Futures contracts and options are examples of financial derivatives. Utilities and other firms use derivatives to provide risk management. The derivatives or tools of risk management are referred to as derivatives because their financial value is completely derived from economic variables that have a more basic nature. For example, the value or price of natural gas futures and options depends upon the price of physical gas in the spot market. In general, the price of derivatives is highly correlated with the cash-market price of their underlying variables. Thus, when the spot price of gas increases or decreases, so too does the futures price of gas, and vice versa. The futures price normally corresponds to the spot price plus the storage cost, interest, and insurance cost from carrying the commodity forward to the delivery date of the futures contract. What this relationship means is that when a futures price increases, the current spot price also should increase. It is the correlation between the price of derivatives and the price of their underlying variable that makes price-risk management possible.

High price volatility supports consideration of hedging by utilities and other large consumers, including hedging with financial derivatives. Customers can suffer non-trivial economic welfare losses when natural gas prices rise to unusually high levels. This effect implies that a utility should hedge to prevent customers from paying extremely high prices, especially during high-demand periods. Relative to physical hedges, such as storage and bilateral physical contracts, financial derivatives can have lower transaction costs and higher liquidity.

V. Considerations for Regulators in Determining the Appropriate Mix of Transaction Types

Each option for purchasing gas has advantages and disadvantages. The economic question is whether regulators expect these benefits to outweigh the costs. As with any activity, the justification for the portfolio approach or diversification comes only after reviewing both the benefits and the costs.

A. Benefits of long-term contracting

Long-term contracting can help to:

1. Ensure reliability over time at a "reasonable price";[15]

2. Avoid the consequences of short-run demand or supply shocks that could sharply drive up the spot price of gas;

3. Give the utility flexibility to vary its daily or seasonal take of gas;

4. Reduce the transaction costs associated with repeated spot-market or other short-term exchanges;

5. Mitigate price risks (i.e., monetary losses from unexpected and undesirable price movements) when futures contracts or other financial derivatives are unavailable or too expensive; long-term contracts for physical gas are a substitute for financial derivatives in mitigating price risk;

6. Protect against price increases or supply constraints resulting from tight market conditions in the long term; tight conditions mean that small changes in demand or supply can have a large effect on price; and

7. Remove a potential barrier to new infrastructure development by service providers, such as gas producers or transporters; long-term contracts can assure revenues to the provider that it might require to receive financing for new infrastructure development.

[15] "Reasonable price" refers to the perception of the price at the time when parties signed a contract; but this price, after the fact, could turn out to be excessive because of unexpected market conditions driving future spot prices down. The buyer might expect future prices to be higher then what the market consensus predicts. She might, therefore, feel that a contract whose price correlates to the market consensus of future prices is a bargain. When a contract ties future prices to a market index, price forecasts become irrelevant.

B. Costs of long-term contracting

The costs of long-term contracting include:

1. Negotiation costs;

2. Monitoring costs;

3. The costs, time, and effort associated with contract renegotiation or renewal (if necessary);

4. Counterparty risk (i.e., the risk associated with the financial stability of the non-utility party to the contract); and

5. Changes in market conditions making contract terms and conditions economically undesirable during the course of the contract. This cost depends on: (a) the flexibility that the utility has to vary its daily and seasonal take of gas and (b) price determination (e.g., fixed price or price tied to a designated market price index).

Although long-term contracts can reduce supply and price risks over time, they might not reflect the prevailing economic value of natural gas and pipeline transportation under changed market conditions; that is, the contract price might deviate significantly from the market price. If the deviation is substantial, one of the parties would have an incentive to either renegotiate or terminate the contract.

C. Importance of regulatory objectives

Gas procurement objectives include reliability, security, price stability, and reasonable prices. The utility should recognize the objectives that it wants to achieve, while taking into account the contractual, purchasing, and operational constraints. An important consideration in designating an objective is the well-being of retail customers. The pursuit of price stability should require evidence showing that customers place a value on less volatile and more predictable prices. High service reliability, as another example, should require a benefit-cost calculation showing that a lower level of reliability would increase the expected level of service-disruption costs to both customers and society as a whole more than it would reduce customers' gas bills.

A major objective of a utility's procurement strategy is to ensure the adequacy of future gas supplies by identifying required new supply resources. Some of these objectives conflict; advancing one objective can impede others. In such instances, the utility will need to make trade-offs that best promote customer welfare and the public interest.

D. The influence of transaction costs

1. Long-term contracting

Transaction costs are those costs (excluding the price) that firms and consumers incur in consummating a trade. The cost of negotiating and monitoring a contract is an example of a transaction cost. Empirical and theoretical studies have shown the importance of transaction costs in determining the most efficient institutional arrangement for trading.

According to transaction cost theory, which category of trading arrangement—spot, long-term contracting, or vertical integration—is consummated, as well as which is most efficient, depends on the conditions surrounding a transaction. For example, when asset specificity, sunk costs, and a high degree of complexity (e.g., the buyer requires a product to have exact specifications of a high technical nature) characterize a trade, vertical integration can turn out to be the efficient alternative. As the contractual process becomes highly complex, a firm might decide that producing a required input internally rather than purchasing it in the marketplace avoids the high transaction costs associated with contracting. On the other hand, firms become less vertically integrated as the cost of using the marketplace to purchase a good or service decreases.

As an illustration of support for long-term contracting, assume that a factory designs its assembly line to produce *customized* widgets for a single customer. The factory manager would likely require a long-term contract with provisions that protect the factory's financial interest in the event that the customer decides either not to buy at all or only to continue buying if the factory offers a low price. The economic reason for a long-term contract lies with the factory's expending large sums of dollars to design its assembly line specifically to produce the kinds of widgets that the customer desires. Alternative uses of the assembly line to produce widgets for other customers would have much lower value. Such *relationship-specific investments* usually require contracts of a long duration. The implication is that the potential for opportunism in the absence of a long-term contract could lead to underinvestment. This example is most applicable to the natural gas sector when a customer (e.g., gas utility or electricity generator) requires a new pipeline or lateral off a main line. Here, the pipeline owner might demand a long-term contract with explicit terms and conditions to compensate for its vulnerability from serving only a single customer. The customer might exploit her advantage by threatening not to transport gas over the pipeline unless given a lower price or other more favorable conditions.

Two factors—incomplete contracts (i.e., contracts that do not account for all contingencies) and imperfect information—can lead to high transaction costs when market conditions change from those anticipated at the signing of the contract. *Asset specificity* refers to a characteristic of an investment that has an alternative value much lower than its value in its original use. This condition makes investments vulnerable to "hold up" or "opportunism" by the buyer. A seller might receive lower revenues because the buyer threatens to terminate a contract if not offered a lower price or other more favorable terms and conditions. The seller might agree to a lower price, if only because other buyers would assign less value to the product. One classic example of asset specificity is a coal mine that is located next to an electric generating facility.

The mine has really only one buyer, so it would likely require a commitment from the utility to purchase its coal over several years.[16]

2. Duration of contracts

In regard to the optimal time duration of a contract, two opposing forces come into play. The first, favoring longer-term contracts, derives from the cost of negotiating terms of trade on a period-by-period basis (for example, annually, or even more frequently, as in a spot transaction) which could accumulate to a large amount over time. The second, making longer-term contracts less appealing, relates to the risk of being constrained under an inflexible arrangement over a longer period of time. Inflexibility has a potentially high cost in a volatile market. It can lead to the utility overpaying for gas (relative to changing market prices) or being required to take gas that it does not need. It explains why, in a market where price and supply are difficult to predict, parties are reluctant to sign a long-term contract with rigid terms and conditions.

3. Attractiveness of financial derivatives relative to physical contracts

Transaction costs also play a crucial role in determining the attractiveness of long-term physical contracts relative to financial derivatives. Futures and options contracts have low transactions costs because of their trading in a centralized exchange, namely, the New York Mercantile Exchange (NYMEX).[17] It is much easier to sell a futures contract under changed conditions, for example, than to renegotiate or terminate a bilateral physical or financial contract under the same conditions. The futures market is a liquid market[18] with a large number of willing buyers and sellers. Futures contracts settle daily based on their current value in the marketplace. Renegotiating a bilateral physical contract, on the other hand, can lead to high costs for the parties. Although a bilateral physical contract has this liability, compared to a standardized futures contract it has the benefit of customizing terms and conditions to the specific needs of the negotiating parties.

E. Conditions favorable to long-term contracting

One condition is the need for revenue assurance in financing new infrastructure. A utility hoping to purchase capacity from a new regional natural-gas pipeline, for example, might have to commit to a long-term arrangement that gives investors guaranteed revenues. What we have found across a wide spectrum of industries is that long-term contracting becomes the predominant form of governance for large investments with limited alternative use. Under this

[16] *See,* for example, P.L. Joskow, "Contract Duration and Relationship Specific Investments: Empirical Evidence from Coal Markets," *American Economic Review*, vol. 77, no. 1 (March 1987): 168-85.

[17] Some financial derivatives trade over the counter, which can have high transaction costs but allows parties to structure a contract to reflect their individual needs.

[18] A market is liquid when selling and buying occur with minimal effect on price.

specific condition, a long-term contract becomes necessary to protect the financial interest of investors by mitigating intolerable risk.[19]

Second, favorable pricing by the seller can offer the utility discounts in return for a long-term commitment. This condition can occur when the seller is more risk-averse than the utility by placing a higher value on price stability. What price a utility should pay for gas under contract, and its relationship to the spot price, depends on the relative price-risk aversion of the seller and buyer. If a buyer exhibits more risk aversion than a seller, for example, the buyer would tend to pay more then the spot price to reduce price uncertainty. A buyer operating in a non-liquid spot market might also pay a premium for contracted gas to protect against possible regional supply shortages.

Another condition making long-term contracting more attractive is an underdeveloped or dysfunctional spot, futures, and other financial derivatives market. When spot markets are immature and illiquid, and financial derivatives are unavailable, long-term contracts to hedge price and supply become more attractive. Almost all industry observers believe that these conditions do not hold in this country. They would argue that the U.S. has well-functioning spot markets and an active financial-derivative market for natural gas.

Finally, low transaction costs make long-term contracting more appealing. If parties can agree on a contract that is simple in structure and easy to monitor and renegotiate, contracting becomes more attractive.

F. The tradeoffs involved

The bottom line for regulators is whether longer-term contracts are economical and beneficial to a utility and its customers. These contracts can reduce risk to a utility and its customers from a guarantee of price that is either fixed or moves in line with market conditions.[20] On the other hand, long-term commitments under inflexible and rigid provisions can pose a large risk to customers by being "out of market." That is, the contract can result in a price that deviates from prevailing market prices. A contract price at $7 per thousand cubic feet (Mcf), for example, means that customers are paying more than if the utility instead bought spot gas at the market price of $5.

Regulators should evaluate long-term contracts within the confines of a portfolio approach (discussed in Part IV.C above) or some other framework that accounts for the special circumstances faced by each utility. Following this practice, regulators would encourage utilities to strike a balance between moderating risks and providing reliable service at the lowest possible cost. The risks would be managed in accordance with corporate and regulatory objectives. A

[19] But the requirement of large investments does not necessarily call for long-term contracting. Those industries making large investments under competitive conditions, for example in oil refineries, petrochemical facilities, and automobile plants, do so without any prior guarantees of capacity utilization or long-term sales.

[20] S*ee*, for example, American Gas Association, "LDC Supply Portfolio Management during the 2009-2010 Winter Heating Season."

portfolio approach, which utilities have increasingly applied in recent years largely because of the high volatility in wholesale gas prices, would consider alternative transactions on the basis of a combination of different factors, including cost, risk, and reliability. A portfolio approach takes into account both short-term and long-term transactions of gas supplies and transportation and, in general, the balancing of objectives over different time horizons. Within the confines of a portfolio approach, a prudent long-term strategy can encompass long-term contracts for gas supplies, pipeline and storage services, and spot purchases.

In sum, long-term contracting can represent a prudent way to develop an appropriate balance between cost, risk, and reliability. The optimal mix of long-term contracting within a portfolio would likely vary by gas utility because of the unique conditions facing each utility. For example, a situation for which long-term contracting might be attractive occurs when a region's pipeline capacity becomes so restricted that a utility must prudently guarantee adequate future capacity by making a long-term commitment to new capacity.

VI. Proper Regulatory Commitment to Long-Term Contracting

A. Regulatory guidelines

A major factor affecting the inclination of a utility to sign a long-term contract is the presence and nature of regulatory guidelines. Guidelines can act as "safe harbor" rules or guiding principles that reduce uncertainty for the utility and mitigate hindsight reviews. By increasing the certainty of cost recovery, a utility might more willingly sign long-term contracts. This willingness will produce a positive outcome only if in the absence of guidelines the utility would not consider long-term contracts when they are in the public interest.

Regulatory guidelines can include criteria for acceptable long-term contracts, commission procedures for reviewing and evaluating long-term contracts, articulation of the role that long-term contracting can play in a utility's gas portfolio plan, and the conditions under which the regulator would tend to favor long-term contracting and allow recovery of the costs associated with a contract. Guidelines have the effect of reducing the risk to the utility from signing a long-term contract.[21]

As an example of reducing regulatory risk, a commission can articulate in guidelines that it would not apply hindsight to determine cost recovery for long-term contracts. It can express that it will not subject specific utility actions to prudence reviews that focus on outcomes rather than the utility's decisionmaking process. One method of doing so is for the regulator to pre-approve long-term contracts.[22]

B. Conflict between regulatory commitment and good incentives

Regulators should recognize the inherent tension between regulatory commitment and a potential perverse-incentive problem. If the regulator both approves a contract and guarantees cost recovery, a "moral hazard" might result in which the utility would lack a strong incentive to appropriately and sufficiently monitor the contract in the best interest of its customers. A "moral hazard" outcome is difficult to detect because regulators observe a utility's performance, which does not reveal how well management did or how prudent management would have performed. Regulators can expect a utility always to defend its actions, even when it knows that it performed imprudently.

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[21] Some commissions, like North Carolina's, have limited or no authority to establish guidelines or give its preapproval to a long-term contract.

[22] For a more detailed discussion of pre-approval mechanisms, *see* S. Hempling and S. Strauss, *Pre-Approval Commitments: When and Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?* NRRI 08-12, November 2008, at http://nrri.org/pubs/electricity/nrri_preapproval_commitments_08-12.pdf.

On the other side, too little commitment can lead to regulatory opportunism and uncertainty of cost recovery.[23] Regulators need to find the right balance. They should avoid second-guessing and taking a short-term perspective when evaluating long-term contracts. Because long-term contracts are by their very nature multi-period, they should be evaluated accordingly. The fact that they could be judged as less-than-optimal within a limited term should not reduce their overall value from a long-term perspective.

[23] One example of opportunism is when the regulator disallows some costs *only* because the contract price turned out to be higher than the prevailing market price.

VII. Questions for a Commission's Pre-Contract Investigation

A. General inquiry into the role of long-term contracting

Commissions should consider conducting a generic investigation on the merits of long-term contracting and its appropriateness in managing long-term price and volume risks within the confines of a utility's portfolio strategy. Long-term contracts should be evaluated along with other transactional arrangements on the basis of advancing various objectives, some of which might conflict, and balance these objectives in a prudent fashion.

As a policy matter, regulators should take a neutral position on long-term contracting. They should support long-term trading arrangements when they are an integral part of a utility's optimal gas procurement portfolio. While long-term contracting can serve a useful function, it should not be a requirement for utilities. Utilities face increased pressure to achieve a targeted level of reliability at competitive prices, which might involve little or no reliance on long-term contracting for gas procurement.

B. Categories of questions to ask stakeholders

Public utility commissions can ask utilities and other stakeholders several questions that will allow for better decisionmaking about the merits of long-term contracting relative to other institutional arrangements:[24]

Regulatory policy

1. Has regulation hindered utilities from signing long-term contracts for natural gas? If so, is this a problem that warrants a commission's attention?

2. Have a commission's actions, for example, led to an increase in the potential liabilities of contractual transactions, inducing an excess of shorter-term transactions?

3. Does the commission have a policy or guidelines on long-term contracting?

    a. Would utilities sign long-term contracts only when commissions pre-approve contracts or, at the minimum, establish firm guidelines for cost recovery?

    b. How much certainty should commissions give utilities over approval of utility actions and the costs associated with those actions? What are the implications of commission preapproval of a contract for cost recovery?

4. What should be the regulatory policy on long-term contracting? Should commissions encourage (discourage) long-term contracting?

[24] Many of these questions came from members of the NARUC Staff Subcommittee on Gas, who responded to a June 29, 2010 inquiry from the author.

5. How should commissions evaluate long-term contracts relative to short-term ones?

6. How do a commission's practices and policies (including authorization of the use of gas cost-recovery mechanisms) affect incentives for different commercial arrangements such as spot purchases and long-term contracting?

7. Should long-term contracts be competitively bid? If so, how should the utility structure and execute the bidding?

8. What oversight should a commission maintain over the life of the contract? Should a commission not concern itself with a contract once it is initially approved?

Economic consideration

1. What non-regulatory uncertainties do utilities face in signing long-term contracts? Do gas utilities with "customer choice" options and "supplier of last resort" obligations for small customers face higher risks in signing long-term contracts?

2. What factors have most contributed to the trend over the past thirty years of shorter-term natural gas transactions? Do current conditions support a reversal of this trend and longer-term transactions?

3. What is the role of long-term contracts in a utility's gas portfolio strategy? Can long-term contracts complement other kinds of commercial transactions that form a utility's portfolio?

4. What are the risks (and benefits) for a utility in signing a long-term contract for natural gas?

5. How necessary are long-term contracts for underwriting the cost of new infrastructure and guaranteeing a market for the supplier or service provider?

6. What risks do utility customers bear under a long-term contract?

7. What special concerns exist with a long-term contract between a utility and an affiliate?

Contract provisions

1. What are the different price and non-price terms and conditions in a typical contractual arrangement? For example, do or should contracts have a regulatory out clause or a release clause?

2. What factors affect the appropriate duration of a contract?

3. On what basis does (or should) the contracted price change (increase or decrease) over time? How was the base price or price term determined? Is it transparent?

4. How is the risk premium under a long-term contract determined?

    a. Should contract prices be lower or higher than the expected market price?

    b. Should buyers receive a discount from future market prices (e.g., a fixed percentage below the prevailing NYMEX futures price)?