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INCENTIVE REGULATION FOR LOCAL GAS DISTRIBUTION COMPANIES UNDER CHANGING INDUSTRY STRUCTURE

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EXECUTIVE SUMMARY

State regulators have been striving to develop responses to the emerging competitive environment in the gas industry. A major issue worth examining is whether current state regulation provides correct incentives to local gas distribution companies (LDCs) to efficiently utilize many opportunities offered by the new and rapidly changing gas market.

During the last decade, the Federal Energy Regulatory Commission (FERC) initiated a series of actions to promote competition in the gas wellhead market. The major milestones in this process have been authorization of off-system sales (sales by a pipeline outside its jurisdiction), blanket certification and special marketing programs, the introduction of open access interstate transportation through Order 436 and the recently issued Notice of Proposed Rulemaking (NOPR).

The study examines gas purchase opportunities currently available to the LDC, which have expanded significantly in the post-Order 436 era. These expanded opportunities also make the design of a purchase portfolio much more complex than in the pre-Order 436 era. This complexity is likely to grow further following the final implementation of the NOPR (also known as the "mega-NOPR").

The original goal of the study was to examine the role of state regulation in inducing efficient gas procurement by LDCs. During the course of the study, it was realized that a more comprehensive scope would better serve the goals of analysis given the interdependence of various costs incurred by the LDC and the generality of incentive mechanisms. However, improving the efficiency of gas procurement practices of LDCs has been retained as the primary focus of the study.

State regulation has been responding to the emerging competition in the gas industry by increasing the level of oversight and by introducing some incentive-based sharing schemes. Current regulation provides incentives that can avoid some of the inefficiencies inherent in a pure cost-plus contract. Commission scrutiny of utility

investments and expenditures, prudence reviews, management audits, and least-cost purchasing requirements provide clear incentives for cost minimization to an LDC.

The effectiveness of the current regulatory mechanisms may, however, be weakened by the fact that regulators have only limited access to information on utility effort and operating conditions. Regulatory alternatives that can at least partially overcome this limitation would potentially reduce the need for a strong oversight role for regulators. The options would also induce the utility to act to benefit both its stockholders and customers. The presence of this attribute in regulation is known as "incentive compatibility."

These regulatory options are divided into two broad *categories-incremental* and *nontraditional.* Incremental options retain, perhaps in a weakened form, the elements of scrutiny and oversight present in traditional regulation, but supplement them with market-based incentives to promote more efficient utility behavior. Nontraditional options significantly relax oversight requirements and rely heavily on market forces to achieve the same goals.

Incremental incentive options are presented in one generic scheme of cost-indexing having three elements: a benchmark cost, a sharing fraction, and a rate period.

Several methods are considered for estimating the benchmark cost in a cost-indexing scheme, including methods of estimating a benchmark price for spot gas and a benchmark price for contract gas, and of choosing a demand forecast. Estimates of each of these parameters can be combined to derive the benchmark cost.

Based on considerations of the scheme's effectiveness and the utility's financial viability, the sharing fraction should assign a larger fraction of gains and losses to ratepayers. There is no unique way to arrive at an optimal rate period and it is ultimately governed by administrative constraints.

Several nontraditional options are considered for implementation either alone or in combination, including price caps deregulation of the noncore market, and flexible rate-of-return pricing.

One proposal would impose price caps on firm transportation services and deregulate interruptible transportation and noncore gas sales. A second proposal suggests price caps on bundled sales to core customers, transportation to noncore customers, and deregulation of gas sales to the noncore market. It also proposes a three-year rate period and 75 percent to 80 percent sharing of all gains and losses by ratepayers. Another option is flexible rate-of-return pricing. A fourth option is deregulating the noncore gas sales market while the state commission still regulates the transportation service to this market. The potential for strategic behavior by utilities, changing cost and demand conditions, and uncertainty of utility responses are identified as significant concerns in implementing the proposed regulatory schemes.

Both current regulation and the proposed schemes have generally good incentives for promoting economic efficiency although the former may impose higher administrative costs. However, not all schemes promote all facets of economic efficiency equally well. Some (such as price caps and cost indexing) promote cost savings while others (such as deregulation of noncore sales market) reduce the potential for cross-subsidies and predatory pricing. Still others (such as prudence reviews) protects ratepayers from inefficient outcomes but do not necessarily promote efficient outcomes.

Most regulatory schemes are found to be generally equitable except price caps which have the potential for price discrimination against inelastic customers.

With few exceptions the proposed incentive-based schemes would generally tend to reduce the administrative burden and costs compared with current regulatory mechanisms. One exception may be price caps in which the effort normally spent on forging agreements on rate designs in traditional regulation may be shifted to forging agreements on such critical price-cap parameters as base price and productivity adjustment indices.

The study characterizes four broad strategies which public utility commissions (PUCs) can pursue for achieving least-cost objectives consistent with reliability requirements.

Strategy I: Status quo (cost-plus PGA, least-cost gas purchase/planning, prudence reviews.

Strategy II: “Best cost” gas purchase planning, contract preapproval, prudence reviews.

Strategy III: Cost-indexing of gas purchases, incentive-based PGA, symmetric treatment of different gas supplies.

Strategy IV: Deregulation of noncore gas supplies, price caps for other LDC services.

The study recommends no specific regulatory scheme, but provides an analytical framework that can be used to fashion regulation according to the needs and circumstances of individual PUCs. The new market environment warrants a reexamination of state regulation of LDCs. Regulators need to explore new options that would induce LDCs to make efficient and prudent choices in their gas purchase decisions. The conceptual approaches and analytical framework presented in the report are intended to assist regulators in that endeavor.

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FOREWORD

Developments at the federal level in restructuring the natural gas industry have induced a number of developments at the state level. In this tradition, this report examines existing incentives and the possible provision of new incentives to LDCs to efficiently utilize the opportunities offered by more competitive gas markets. Options available to regulators for various incentive arrangements are categorized and appraised in the context of implementability and consistency with both least-cost objectives and reliability requirements.

We believe this report will be helpful to commissions in framing their approach to incentive regulation for jurisdictional gas utilities.

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CHAPTER 1

INTRODUCTION AND BACKGROUND

During the last decade, the natural gas industry has undergone significant changes in market structure and regulatory regimes. The changes occurred as a result of a dynamic interplay between evolving market forces and regulatory actions initiated by the Federal Energy Regulatory Commission (FERC).[1] The FERC's actions were often a response to developments in the gas industry and sought to remove what were perceived as obstacles to greater competition in the wholesale gas market. A main objective of these actions was to systematically reduce the ability of interstate pipelines to exercise market power over the gas wholesale market, derived from their monopoly over interstate transportation of gas. Gradually, through a series of rulings and orders and resulting court battles between affected parties, a regulatory regime has emerged in which the interstate pipeline has progressively assumed the role of an open access contract carrier.[2] As a result, competitive markets for wholesale gas have emerged at the wellhead and have led to the development of spot markets and, more recently, a futures market.

These developments have widened options for gas procurement and transportation for local distribution companies (LDCs) and their customers. A growing number of public utility commissions (PUCs) which regulate the LDCs have responded to the new competitive environment by escalating their level of oversight to include closer scrutiny

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[1] Richard J. Pierce, Jr., "Reconstituting the Natural Gas Industry from Wellhead to Burnertip," *Energy Law Journal* (1988): 1-57. See also, Robert E. Burns, Daniel J. Duann and Peter A Nagler *State Gas Transportation Policies: An Evaluation of Approaches* (Columbus, OH: The National Regulatory Research Institute, 1989), 87 – 155.

[2] Traditionally, pipelines provided a bundled gas supply service which included both the procurement of gas and its transportation. Currently, most pipelines provide transportation of gas as a separate contractual service

of gas purchase contracts,[3] reforming gas transportation policies,[4] putting an increasing emphasis on "least-cost" plans,[5] and introducing certain incentive options.[6] LDCs themselves have been modifying their long-held operating practices to include more low-cost spot gas in their supply portfolios, interconnecting with pipelines other than those which historically have been providing transportation and providing open access transportation to end-users.

While acknowledging the merit of changes in regulatory oversight and LDC practices that already have taken place, it seems appropriate to examine whether current regulation provides the right incentives for LDCs to optimally utilize the many opportunities for gas procurement offered by the new market environment. It also seems appropriate to explore regulatory options within the traditional framework and other, more nontraditional ones to see whether they can better serve the goal of efficiency while maintaining reliable and equitable service to the ratepayers.

Overview of Evolution of the Gas Industry Toward a Competitive Structure

The movement toward deregulation of the natural gas industry started in the late 1970s when it was recognized that natural gas was artificially underpriced as a result of tight price control of wellhead gas by the FERC. This was causing severe shortages by inhibiting exploration and production. The Natural Gas Policy Act (NGPA) of 1978 removed or loosened some of the price controls from the sale of wellhead gas effective in 1985. The NGPA established categories of gas according to vintage, cost of production,

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[3] J. Stephen Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches* (Columbus, OH: The National Regulatory Research Institute, 1988), 117-51.

[4] Burns et al., *State Gas Transportation Policies.*

[5] C A Goldman and M. E. Hopkins, *Survey and Analysis of State Regulatory Activities on Least-Cost Planning for Gas Utilities* (Berkeley, CA: Lawrence Berkeley Laboratory and Washington, D.C.: National Association of Regulatory Utility Commissioners, 1991).

[6] Currently, Wyoming state status allow gas distributors up to a 10 percent incentive on reduction in gas costs.

location, and depth of production wells. It established maximum base prices for different categories of gas and monthly price escalators. It provided for price deregulation of certain categories of "new" and "high-cost" gas beginning in 1985. The NGPA was designed to promote aggressive exploration of gas previously inhibited by tight price controls, to send correct price signals to the buyers of gas, and at the same time to limit the potential for abuse of market power enjoyed by the interstate pipelines.

Between 1978 and 1985, FERC issued a series of orders and instituted a set of programs to implement the NGPA. The orders and programs were intended to open the market for wellhead gas to many sellers and buyers, extend the markets for gas beyond traditional geographic boundaries, and promote open access transportation on the interstate pipelines. Some of the orders were issued in response to concerns of adverse or inequitable effects on certain parties from a previous order or program and often followed a court battle.

The FERC attempted to balance two competing, if not conflicting, objectives in implementing the NGPA. First, it was trying to provide freer access to the wholesale gas market as well as expand the domain of this market beyond traditional geographical boundaries. Second, it was trying to mitigate any inequitable effect its actions may have had on any of the market participants. One of the equity issues it had to address was the problem of the large take-or-pay obligations that were beginning to plague pipelines.

The blanket certification program, issued through Order 234 in June 1982 was designed to extend the gas transportation provisions of the NGPA (as set forth in section 311 of the Act) to include more categories of gas and provide for automatic authorization of new transportation arrangements.[7]

In April 1983, the FERC issued its statement of policy on off-system sales that allowed interstate pipelines to sell gas to customers outside their traditional service

[7] Interstate Pipeline Certificates for Routine Transactions, Docket No. RM81-19-000, Order No. 234, 47 *Fed. Reg.* 24 (June 4, 1982), 254.

area.[8] Customers entitled to receive off-system gas included other interstate pipelines, intrastate pipelines, and LDCs. This was intended to prevent an interstate pipeline from using its revenues from its on-system customers to subsidize its off-system operations and gain a competitive advantage over other suppliers (such as intrastate pipelines) in its off-system market.

About the same time blanket certificate programs and off-system sales were being implemented, a third program was introduced to further open the market for wholesale gas. In these special marketing programs (SMPs), pipelines were allowed to release contractually dedicated gas for direct sales by producers and other suppliers. The released gas was then transported by the pipeline to other pipelines, LDCs, and end-users. In November 1983, the FERC approved several SMPs.[9]

The FERC actions until 1985, while designed to promote competition and freer access to wellhead gas and pipeline transportation, did not allow the full benefit of these programs to all customers. For example, in SMPs, the eligible purchasers were restricted to those who had not been served previously by the pipeline. This excluded captive pipeline customers, such as the LDCs. The blanket certificate programs allowed pipelines to lower their rates to fuel-switchable customers and charge monopoly prices to captive customers. Both SMPs and blanket certificates came under court challenge.[10] The Maryland Consumer's Counsel charged that they restricted access to transportation and allowed discriminatory pricing. In three cases, a U.S. Court of Appeals found SMPs to be invalid and vacated blanket certification programs and successor SMPs.

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[8] Off-System Sales, Docket No. PL83-2-000: Statement of Policy, 23 FERC pasg. 61,140 (1983).

[9] Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company, Docket No CP83-452-000; Findings and Order after Statutory Hearing Granting Interventions and Issuing Certificate of Public Convenience and Necessity, 25 FERC para. 61,220 (November 10, 1983).

[10] Maryland People’s Counsel v. FERC, 761 F.2d 768 (D.C. Cir. 1985); Maryland People’s Counsel v. FERC, 761 F.2d 780 (D.C. Cir. 1985); Maryland People’s Counsel v. FERC, 768 F.2d 1354 (D.C. Circ. 1985).

The court decisions on SMPs and blanket certification programs led the FERC to issue Order 436, which provided for voluntary (self-implementing) open access and nondiscriminatory transportation by interstate pipelines.[11] If a pipeline became an open access transporter, it had to agree to all specified contract demand (CD) reductions for existing sales customers. The customers could also *convert* contract demand for firm sales to firm transportation.[12]

While Order 436 removed some of the potential for discriminatory pricing by pipelines against captive customers present in blanket certification and special marketing programs, it failed to address all the concerns of various parties. Gas distributors feared that the contract demand reduction provisions of the order would force them to bear a greater share of the pipelines' capital costs as other, noncaptive customers exercised that option. Distributors mounted a court challenge in Associated Gas Distributors (AGD) v. FERC.[13] In its decision, the D.C. Court of Appeals upheld most of Order 436, but decided to remand the order back to FERC to deal with certain issues that needed further consideration. While the Court agreed with the CD *conversion* provisions of the order, it was not persuaded that CD *reduction* provisions were necessary to achieve FERC objectives. Another concern of the LDCs and their regulatory commissions was that Order 436 would lead to significant LDC bypass by noncaptive customers. The Court dismissed this assertion and agreed with FERC that captive customers could be protected from bypass by the PUCs changing rate designs that made LDC investors rather than ratepayers bear the resulting loss of revenue.

The contracts written between producers and pipelines generally contained take-or-pay clauses which required a pipeline to take or pay for a minimum volume of gas

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[11] Regulation of Natural Gas Pipelines after Partial Wellhead Deregulation; Docket No. RM85-1-000; Order No. 436A, 50 *Fed. Reg.* 52,217 (December 23, 1985).

[12] CD reduction refers to a reduction of contracted volume to be supplied accompanied by a corresponding reduction in payment (similar to a “cash refund” policy). CD conversion credits the payment to a transportation contract (similar to an “exchange only” policy).

[13] Associated Gas Distributors v. FERC, 824 F. 2d 981 (D.C. Cir. 1987).

from a producer regardless of the pipeline's requirements. The rationale for take-or-pay clauses was that producers often had to make large investments to explore for and develop gas wells in response to a pipeline's requirements as reflected in the contract demand; therefore a mechanism had to be in place to recover these costs even if the projected demand did not materialize. The contracts entered into by the pipelines with the producers were often long term with restrictive and costly take-or-pay clauses. The pipeline usually passed the take-or-pay obligations downstream to the LDCs in the form of minimum bill provisions (which mirrored take-or-pay clauses). However, the expected rise in gas prices did not materialize partly because of energy conservation efforts in the United States and partly as a result of the oil glut experienced in the early 1980s. This left the pipelines stranded with huge take-or-pay obligations which could not always be passed downstream to LDCs and other purchasers of gas who now had access to other sources of gas, often as a result of FERC actions.

While blanket certification programs, off-system sales, special marketing programs, and Order 436 were designed to provide freer access to the gas wholesale market as well as expand the market, most of these actions also attempted to mitigate the take-or-pay problem. The FERC statement of policy on off-system sales required pipelines to demonstrate significant take-or-pay liability as a condition for off-system sales. In special marketing programs, producers were required to discount prices and provide take-or-pay relief to pipelines in return for direct transportation of gas to third parties.

FERC Order 500, issued in 1987, while designed to address equity concerns articulated by LDCs in AGD v. FERC also attempted to further mitigate take-or-pay problems.[14] The order retained the option for an LDC to convert its contract demand (CD) to firm transportation but eliminated the CD reduction option. The order also required producers to extend take-or-pay relief to pipelines in exchange for

[14] Regulation of Natural Gas Pipelines after Partial Wellhead Deregulation; Docket No. RM87-34-000; Order No. 500, 50 *Fed. Reg.* 30,334 (August 14, 1987).

transportation (previously limited to off-system sales only). The order also allowed a pipeline providing such transportation to charge a fixed amount to its customers to recover its take-or-pay costs. The remaining take-or-pay costs were to be recovered through sales or transportation charges.

Order 500 also included provisions designed to prevent the recurrence of take-or-pay problems. The order introduced the Gas Inventory Charge (GIC), which is to be paid by pipeline customers to the pipeline of holding sufficient supplies of gas that the pipeline stands ready to deliver during peak demand periods. Unlike the minimum bill, the GIC is not a retrospective charge against past purchases by the pipeline. Rather, the GIC is a prospective charge to those customers who desire assured supplies in the future. The customer is allowed to make monthly nominations of the amount of gas desired and the pipeline is required to post the GIC schedules for various levels of nominations. Upon agreement between customers and pipelines, the gas supply contract will contain the chosen GIC. If the gas market in question is determined to be workably competitive, the GIC can be indexed to spot prices of gas. It thus has the label "market-based GIC." In the absence of workable competition, the GIC is cost-based.

Another issue closely related to the functioning of the wholesale gas market that has emerged with increasing importance during the post-NGPA period involves comparability of service between the transportation component embodied in pipeline sales and availability of transportation on an unbundled basis. Since the interstate pipelines enjoy a monopoly over transportation service, there was a concern that they might discriminate between purchasers who buy gas from the pipeline and those who buy from other sources. While FERC regulation precludes an open access pipeline from refusing to transport gas for any party, a potential exists for discrimination in the pricing, conditions of delivery, use of storage, and other service terms.

The FERC has been responding to the service comparability issue by facilitating an unbundling of different services, which include sales, transportation, and storage. On July 31, 1991, the FERC issued a Notice of Proposed Rulemaking (NOPR) which proposes to further unbundle services beyond what was anticipated in Order 436.[15]

The NOPR (which is also known as the "mega-NOPR") addresses a number of issues related primarily to service comparability and the presence of what are perceived to be obstacles to an efficiently operating national wellhead market. The issues discussed in the mega-NOPR include, among others, unbundling gas sales and transportation, pipeline rate design, allocation of pipeline capacity, pre-granted abandonment of pipeline sales and transportation services, scheduling of gas injections and deliveries, location of gas receipt, and delivery-point access to pipeline-owned storage. The mega-NOPR stresses the need to further unbundle sales and transportation services so that the wellhead market would become more competitive by changing the level of pipeline control over each of these elements of the gas supply system.

The mega-NOPR would change current pipeline rate design from the modified fixed variable (MFV) method, (which, according to the mega-NOPR, was more suitable in an era of bundled service) to the straight fixed variable (SFV) method.[16]

The mega-NOPR would require pipelines to develop separate tariffs for their sales, transportation, and storage services and to provide storage to other shippers on an open-access basis. The mega-NOPR also would replace capacity brokering (the practice of a customer selling off excess pipeline capacity rights to other customers) by a FERC-regulated capacity release and reallocation system.

The mega-NOPR would modify gas curtailment rules by recommending that sales customers be curtailed ahead of transportation customers in a gas supply or transportation shortage situation.

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[15] Pipeline Service Obligation and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations; Docket No. RM91-11-000 (July 31, 1991).

[16] A rate usually has two components. One reflects the fixed and the other the variable costs of service. In an SFV design, all the fixed costs are assigned to the fixed component. In an MFV design, a part of the fixed costs are assigned to the variable component. The MFV was introduced to encourage throughput and thus increase efficient utilization of the pipeline transportation capacity.

The provisions of the mega-NOPR may have mixed results for an LDC. Limiting bundled service to small customers may have an adverse effect on those LDCs wishing to retain the coordination and aggregation benefits available from a bundled service package, especially to meet peak and swing service demand. Complete unbundling of service may also impose additional transaction costs on LDCs, as they would be required to contract separately for sales gas, transportation, and storage. As a response, many LDCs may build their own storage to mitigate the uncertainties associated with contract storage.

The mega-NOPR also may have some benefits. If it achieves its stated purposes, it may reduce the prices of wellhead gas and thus provide gas to all customers at lower prices. Removing control over access to storage may further reduce the market power of pipelines and thereby make an LDCs gas purchase options available on more even terms.

A clearer perspective on the impact of the mega-NOPR will emerge only after the final rule has been issued and the industry as a whole has had time to assess its implications and develop responses. Some of the potential implications of the mega-NOPR on the purchase options of an LDC are discussed further in Chapter 2.

The developments in federal regulation and the evolution of market forces since the NGPA passes in 1978 has led to a radical restructuring of market relationships between gas producers, transporters, and consumers. Prior to 1978, the gas industry was configured as a vertically segmented system as represented by Figure 1-la. Gas was produced at the wellhead, transported by interstate pipelines to the city gate, and distributed by an LDC to the end-user. During the last decade, the vertically well-segmented structure has been radically transformed by the introduction of many new supply arrangements between traditional sellers and buyers and the infusion of new entrants into the gas market. The new market structure is represented by Figure 1-lb.

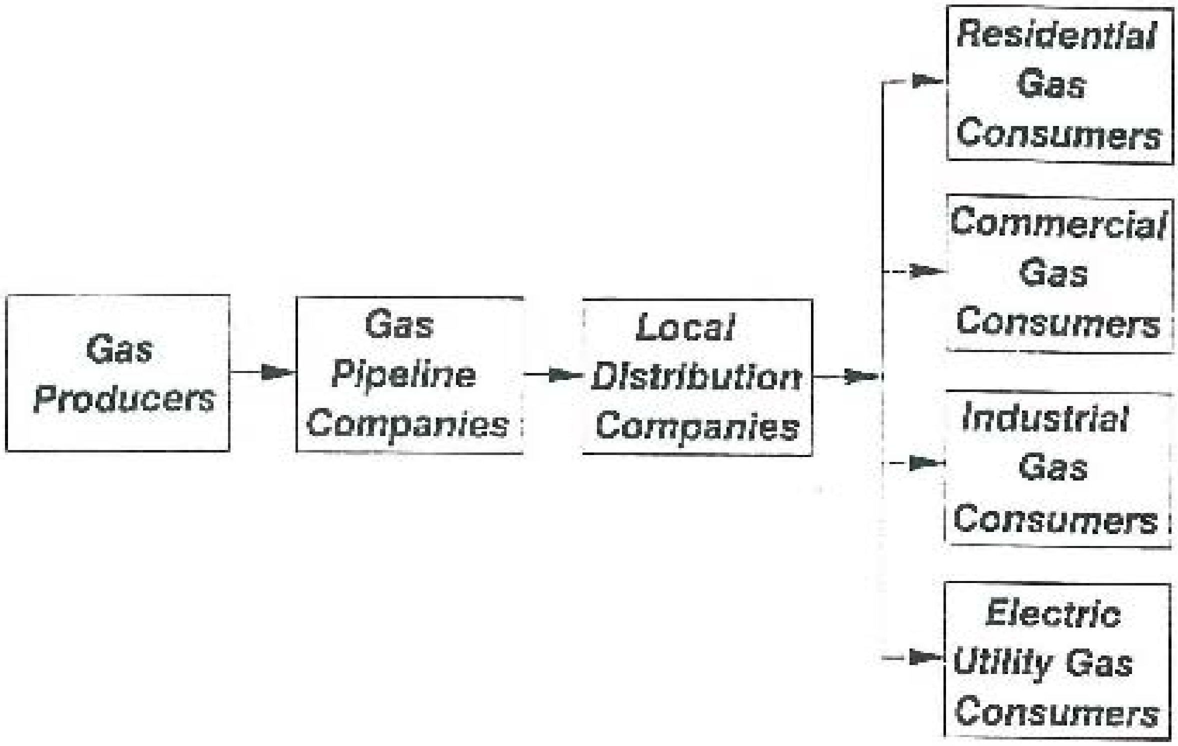

Fig. 1-1a. Traditional natural gas market structure (Source: Arthur Andersen & Co. and Cambridge Energy Research Associates, 1988).

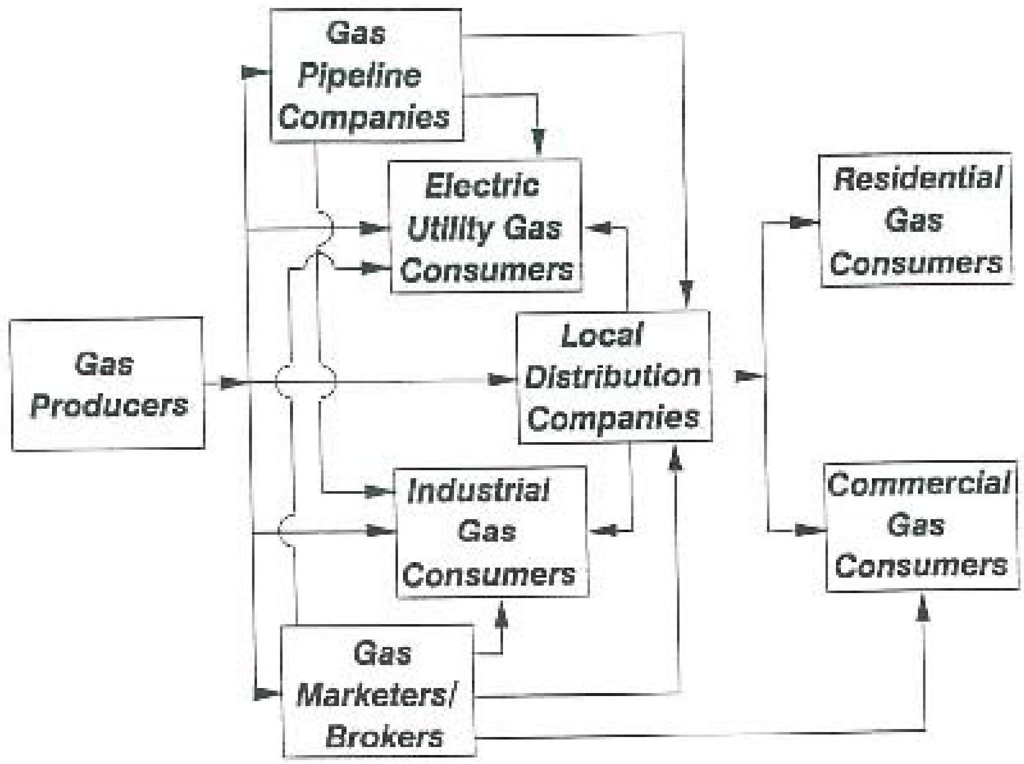

Fig. 1-1b. Current natural gas market structure (Source: Arthur Andersen & Co. and Cambridge Energy Research Associates, 1988).

Need for Reexamining State Regulatory Options

The opening of the wholesale gas market presents many procurement options for LDCs. They now can buy gas from producers through long-term contracts, from the spot market directly, through marketers, and from interstate pipelines. There exist variations in price, delivery terms, and reliability features among the different sources of gas, each of which is subject to uncertainties caused by the dynamics of a rapidly developing market. In the past, when the gas market operated as a vertically well-segmented system, the LDC could buy almost all of its gas services from an interstate pipeline as a bundled package at a FERC regulated price. At the time, gas supply planning and management were almost entirely devoted to predicting seasonal and long-term demand and taking good account of the related uncertainties. For an LDC, managing the supply of gas involved relatively few uncertainties. While there was still some uncertainty surrounding price, it did not present a significant problem to the LDC because cost-plus ratemaking passed on the risk of price variation to the ratepayers.

Over the last few years, as FERC continues its deregulatory thrust and various parties through intervention at the FERC and litigation at federal courts attempt to erode the pipeline's monopoly advantage, pipeline gas supplies are no longer the most preferred source of gas. Buyers now can acquire gas directly from producers at the wellhead or from the spot market either directly or through marketers, and arrange for transportation through an open access pipeline.

The new opportunities presented by the emerging market, however, are not without risks. Diversity of sources is an essential element in designing a supply portfolio of high reliability. The LDC knows less about the reliability of individual sources of gas and may lack expertise and resources to aggregate diverse sources. Also, an LDC has a smaller scale of operations and therefore needs a smaller portfolio of gas supplies than a pipeline. This limits its ability to diversity its portfolio relative to a pipeline. Because of the comparative disadvantages, the LDC may still have to depend on a pipeline or marketer for its gas aggregation and supply management needs. In today’s environment, the LDC needs to carefully balance the advantages of making full use of the wholesale gas market against the risk of sacrificing traditionally ensured supply reliability.

In the face of the emerging wholesale market and its related opportunities for minimizing gas procurement costs and the risks of compromising reliability, the outcome that can best serve the interests of the LDC as well as its customers is the following: the LDC operates efficiently in purchasing its inputs-the gas commodity as well as the reliability of its supply-and in pricing its output, the reliable delivery of the gas commodity. This means that the LDC pays not only the lowest possible cost for the gas commodity but the minimum cost for the required reliability. It also means that it prices the gas to different classes of customers to reflect the actual costs of serving the customers and does not underprice the gas in the competitive segment of the market and recover the resulting revenue shortfall by overpricing it in the regulated monopoly market. Such an outcome while highly desirable from the regulators' point of view, may be hard to achieve.

Given the environment emerging in the various segments of the gas supply market, a central question is whether the current forms of state regulation (including more recent ones such as scrutiny of gas purchase contracts, introduction of "least-cost" supply requirements, reform of transportation policies, and introduction of limited incentive sharing schemes) promote efficient LDC behavior and whether other regulatory alternatives should be explored.

Objectives and Organization of the Report

This report, guided by economic theory and based on somewhat limited empirical evidence that now is available, examines the efficacy of current forms of state regulation in achieving potential efficiencies presented by the emerging gas markets. It also explores regulatory options and strategies which may better achieve this goal.

The remaining chapters of the report are organized as follows. Chapter 2 provides the background and context for the discussion of regulatory reform and regulatory alternatives in the rest of the report. It describes how the traditional structure of the market has been transformed through the emergence of new market segments and introduction of intermarket competition and how these developments are related to the growing unbundling of gas supply services. Finally, it describes various options that have arisen for the LDC to procure gas and arrange for its supply as a result of the developments over the last decade and how the LDC can use these options to acquire least-cost supplies of gas while maintaining reliability of supply. Readers familiar with the post-NGPA changes in market structure and gas purchase opportunities for an LDC may wish to move directly to Chapter 3 without any loss of continuity.

Chapter 3 discusses the status of state regulation and whether current forms of regulation provide sufficient incentives for efficient LDC operation, vis-a-vis utilization of the new market opportunities, and whether there is a need to explore other regulatory options. Several options are discussed, some of which fall within the framework of traditional regulation and others which are more nontraditional. The relative ease or difficulty in implementing each regulatory option is discussed next. Chapter 4 evaluates each option and compares it to others according to its merit in achieving efficiency and equity and reducing regulatory costs. Chapter 5 summarizes the findings of the study and offers recommendations to state commissions for evaluating the need for regulatory reform, and if the need is recognized, in designing effective strategies for reform.

CHAPTER 2

THE EMERGING GAS MARKET AND GAS PURCHASE OPTIONS FOR LDCs

Segmentation of the Gas Supply Market

The traditional gas supply structure contained clearly defined market segments. Gas supply services include acquisition of gas from the wellhead, transportation over interstate pipelines to the city gate, and final delivery of the gas to the end-user's premises. Prior to the enactment of the NGPA, each of the services was typically provided by a single firm or group of firms specializing in providing that service. A typical gas wellhead market had several producers as sellers who differed only in their relative proximity to an interstate pipeline which was their only buyer. The pipeline bought the gas from the producers through long-term contracts. Next, the pipeline transported the gas to the city gate and delivered it to the LDC. The gas commodity and the interstate transportation were sold as a bundled package to the LDC. This city-gate market had the pipeline as the only seller and one or more LDCs as buyers. The LDC usually obtained this service through long-term contracts with pipelines. Finally, the LDC transported the gas over its distribution lines and delivered it to the premises of the end-use customer. Again, the gas delivered to the end user was a packaged product whose price included all the costs of acquisition from wellhead, interstate transportation, and local distribution.

Among the various gas services, interstate transportation and local distribution were regulated monopolies. The FERC regulated the price and other service terms of interstate transportation. A state PUC performed a similar function for the local gas distribution service. Wellhead gas, although not a monopoly, was also subject to price regulation by the FERC In the pre-NGPA era the natural gas market could be neatly characterized as consisting of wellhead, city gate, and end-use segments (Table 2-1).

TABLE 2-1

MARKET SEGMENTATION IN THE PRE-NGPA AND POST-NGPA PERIODS

	Pre-NGPA			Post-NGPA
Market Segments	Sellers	Buyers	Sellers	Buyers
Wellhead	Producers	Pipelines	Producers, marketers, pipelines	Pipelines, LDCs, end-use customers
City Gate	Pipelines	LDCs	Producers, marketers, LDCs, pipelines	LDCs, end-use customers
Distribution	Not separately provided	Not separately provided	LDCs, pipelines	End-use customers
End-Use	LDCs	End-use customers	Pipelines, LDCs	End-use customers
Spot	Not applicable	Not applicable	Producers, marketers	Pipelines, LDCs, end-use customers
Transportation	Not separately provided	Not separately provided	Pipelines	Producers, marketers, LDCs, end-use customers

Source: Authors' construct

Each downstream segment had a well-defined relationship with all of the upstream segments. All transactions that took place were essentially vertical, although the ownership structure itself was not vertically integrated.

Enactment of the NGPA and subsequent FERC actions (especially Order 436) to implement its provisions has led to a radical restructuring of the gas supply market. The heretofore well-defined and clearly segmented vertical structure has been transformed into a regime where competition (however imperfect) has replaced regulation in several of the market segments whose number has grown and whose boundaries have been blurred by the entry of new participants as well as old ones from other market segments. Also, the fact that each of the gas supply services now can be provided in an unbundled form (as well as bundled with others) makes it difficult to define market segments in a way that clearly conveys the market relationships and transactions.

The new market segmentation is also shown in Table 2-1. The gas acquisition market now consists of two separate markets. The first is characterized by the direct purchase contracts with producers as the sellers and pipelines, LDCs and end-users as buyers. The second, the so-called spot market, has the same buyers as the direct purchase market and marketers as the principal sellers. The marketers, however, may or may not own the gas that they sell (which they acquire from producers) and function as intermediaries whose primary role is to locate and aggregate supply sources for gas to be delivered to a diverse group of buyers.[1]

In that role, they also perform the important function of matching each buyer to an appropriate portfolio of supply sources and each supplier to an appropriate group of buyers. Neither the direct long-term purchase market nor the spot market is regulated and competition exists within each market and between markets. Another market has developed at the city gate (as a result of open access transportation by LDCs) where the LDC competes with producers, marketers, and pipelines as a seller, and with its noncore customers (large industrial and electric utility) as a buyer.

[1] For a more detailed discussion on the role of marketers and other market intermediaries, see the subsequent section on "Free Access Trends and the Rising Need for Information."

A concurrent and related development of the transformation of the gas supply structure is the unbundling of gas supply services. A gas buyer such as an industrial customer now can purchase gas from the spot market, arrange interstate transportation with a pipeline, and have the gas delivered to its premises by an LDC. Each of these services, namely gas procurement, interstate transportation, and local delivery can be arranged and contracted for separately. The buyer also has the option of purchasing a combination of two or more gas supply services as a bundled package offered by various sellers. Besides the primary services mentioned, markets have also developed for auxiliary services such as gathering and aggregation, storage, and brokering of pipeline capacity.

Another milestone in the chain of developments in the gas industry is the opening of the gas futures market at the New York Mercantile Exchange on April 30, 1990. Futures trading allows traders either to hedge their price risk or speculate for profit by exploiting price movements of a commodity or price differentials between commodities. Development of the spot market, the growing unbundling of services, and the opening of the futures market reflect the competitive thrust that has been propelling the gas industry in the post-NGPA era. A consequence of these developments is the growing role of information in facilitating transactions between market participants. The following sections first describe the important features of the spot market and the futures market. Next, they discuss the role of market intermediaries such as marketers in meeting the increasing need for information generated by the rapidly developing market forces.

Emergence of a Spot Market

One important result of open access transmission is the emergence and growth of spot markets for gas. Spot trading started in 1983 and has been growing rapidly every since Between 1983 and 1989 volumes traded on spot markets grew from less than 1 trillian cubic feet (Tcf) to about 12 Tcf, representing an increase from 5 percent to 75 percent of the total natural gas sales.[2]

The characteristics of a spot purchase are its short duration, fixed price and quantity, and the degree of supply "firmness" specified in the contract. A spot contract is usually good for a month, and no price or quantity adjustments are specified in the contract. More importantly, the commitment on the part of the seller to supply gas is on a "best-efforts" basis; that is, the seller will deliver gas to a specific point at a specific time only when the seller has the ability to do so. Also, the buyer itself (rather than the seller) needs to make arrangements for transportation, storage, and scheduling of gas after the gas has been delivered to a specific location.

Currently, there are several broad categories (by production area) of spot gas being traded in the United States.[3] The spot prices vary with delivery points, which may range from a producer's wellhead to a customer's burner tip. Spot prices generally vary with region. Table 2-2 shows pricing trends of spot gas in several regions of the United States. The regional variation in prices may depend on demand patterns, market access, fuel switchability of customers, and transportation priorities of gas pipelines.[4]

Within the same region, spot prices vary with season, being lowest in the summer and highest in the winter (Table 2-2). The annual variation in price has been relatively small for the past few years.

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[2] New York Mercantile Exchange, *NYMEX Natural Gas Futures Handbook*, (Washington, D.C.: NYMEX, February 28, 1990), C-6, C-7.

[3] They are the Texas-Westhaha, East-Houston-Katy, North-Texas Panhandle, South- Corpus Christi, Louisiana-Onshore South, Oklahoma, Alberta, and others.

[4] New York Mercantile Exchange, *NYMEX Energy in the News*, (Washington, D.C.: NYMEX, Fall 1990).

TABLE 2-2

REGIONAL SPOT PRICES

Pricing Point	June 1987	Dec. 1987	Mar. 1988	June 1988	Sept. 1988	Dec. 1988	Mar. 1989	June 1989	Sept. 1989	Dec. 1989	Mar. 1990	June 1990	July 1990	Aug. 1990	Sept. 1990
Wellhead															
Texas	1.35	1.72	1.52	1.30	1.66	1.91	1.40	1.55	1.39	1.89	1.31	1.35	1.37	1.31	1.42
Louisiana	1.39	1.77	1.67	1.37	1.66	2.19	1.45	1.62	1.46	2.05	1.44	1.41	1.37	1.33	1.42
Gulf of Mexico	1.37	1.70	1.68	1.31	1.61	2.05	1.48	1.58	1.43	1.98	1.39	1.35	1.32	1.25	1.42
Oklahoma	1.32	1.65	1.50	1.25	1.34	1.60	1.28	1.29	1.25	1.72	1.25	1.20	1.20	1.20	1.27
Rocky Mountains	1.31	1.42	1.37	1.05	1.18	1.56	1.19	1.10	1.02	1.41	1.02	1.03	1.05	1.03	1.10
Appalachia	1.71	1.97	2.11	1.77	1.81	2.22	1.97	1.97	1.83	2.42	2.07	1.84	1.80	1.60	1.75
Delivered to pipeline															
Texas	1.40	1.70	1.68	1.53	1.65	1.95	1.39	1.55	1.42	2.00	1.39	1.38	1.36	1.30	1.33
Louisiana	1.45	1.78	1.79	1.39	1.69	2.18	1.47	1.66	1.50	2.09	1.49	1.45	1.41	1.35	1.40
Oklahoma/Kansas	1.37	1.65	1.63	1.25	1.49	1.77	1.29	1.41	1.32	1.81	1.28	1.28	1.27	1.23	1.28
Rocky Mountains	1.33	1.37	1.44	1.17	1.29	1.53	1.29	1.34	1.19	1.68	1.19	1.12	1.16	1.12	1.17
Henry Hub	–	–	–	–	–	–	–	–	–	–	–	1.52	1.46	1.39	1.43
City gate															
California	1.79	1.99	1.90	1.64	2.20	2.11	1.88	2.04	2.06	2.53	1.97	2.08	2.08	2.06	2.04
West Great Lakes	1.81	2.16	2.27	1.79	1.96	2.56	1.96	1.95	1.79	2.46	1.86	1.78	1.83	1.67	1.72
East Great Lakes	2.04	2.38	2.30	1.77	2.15	2.75	2.21	2.24	2.00	2.70	2.16	2.06	1.88	1.88	1.91
New York/ New Jersey	2.01	1.99	2.26	1.88	2.17	2.77	2.15	2.19	2.03	2.45	1.85	1.89	1.90	1.85	1.86
New England	2.03	NA*	NA*	1.90	2.14	NA*	2.30	2.32	2.08	2.56	NA*	2.04	1.96	1.91	1.90
Burner tip															
Houston Ship Channel (large)	1.48	1.74	1.71	1.46	1.79	2.07	1.48	1.75	1.52	2.03	1.45	1.58	1.53	1.41	1.42
Houston Ship Channel (small)	1.52	1.76	1.73	1.47	1.79	2.09	1.52	1.76	1.54	2.07	1.51	1.61	1.54	1.44	1.45
Louisiana/Mississippi River	1.56	1.86	1.77	1.47	1.84	2.25	1.60	1.78	1.63	2.22	1.57	1.59	1.57	1.46	1.48
GSU Sabine plant	1.62	2.07	1.89	1.60	1.72	2.19	1.65	1.88	1.87	2.26	1.61	1.75	1.68	–	–
CLECO Rodemacher plant	1.72	2.14	2.01	2.01	2.05	2.06	1.99	2.18	1.84	2.26	1.77	2.13	2.12	–	–
SWEPCO Lieberman plant	2.44	2.73	2.78	2.78	2.58	NA*	2.54	1.74	1.60	2.33	NA*	1.68	1.54	–	–
LP&L Ninemile plant	1.45	1.12	1.39	1.57	1.69	1.49	1.51	1.71	1.41	1.63	1.09	1.48	1.53	–	–

Source: NYMEX Energy In the News.

* Utility sources reported that they purchased no 30-day spot gas in these months.

The Opening of a Gas Futures Market

The development of open access to both field markets and city-gate markets and a lengthy effort by the New York Mercantile Exchange (NYMEX) finally succeeded in opening a natural gas futures market on April 3, 1990.

A gas futures contract is a right to buy or sell a certain amount of gas at a prespecified price at a future date. In many ways, a futures contract resembles a forward contract.[5] However, a futures contract differs from other forward contracts (such as gas purchase contracts between LDCs and pipelines) in some important ways.

A common forward contract is a private agreement to deliver a commodity from a seller to a buyer of a specified quality and quantity at a specified future date at a specified or yet-to-be-determined price. A futures contract, on the other hand, is a transferable, legally binding agreement to make or take delivery of a specific amount of a commodity with standard minimum quality requirements during a specific month under terms and conditions established by the federally designated contract market where trading is conducted.[6] Therefore, a futures contract can be considered as a standardized form of a forward contract.

Besides the feature of standardization (in both the contract format and the trading mechanism) a futures contract has two other important features. One is that buyers and sellers of futures contracts rarely take physical possession of the underlying commodity. The other is that only a margin (a cash deposit that is usually a fixed percentage of the total value of the futures contract) is required to guarantee contract performance.

Currently there are many futures contracts (such as those for wheat, orange juice, crude oil, pork bellies, gold, and U.S. Treasury notes) being traded in various exchanges. The futures contract with the closest relationship to natural gas is crude oil futures being

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[5] Raymond M. Leuthold et al., *The Theory and Practice of Futures Markets* (Lexington, MA: D. C. Heath and Company, 1989), 394.

[6] Ibid.

traded in the New York Mercantile Exchange (NYMEX) and the London-based International Petroleum Exchange.

The size of a gas futures contract is 10,000 million Btu. The month of delivery can be any month of the year and the trading can start twelve months before the month of delivery. The delivery point is the Henry Hub (a gas processing plant) in Erath, Louisiana. There are no restrictions (except for typical credit and margin requirements) on participants in the gas futures market. A local distribution company, as well as other participants of the gas market such as producers, pipelines, and end users, can freely buy and sell gas futures contracts. Proof of adequate transportation arrangements to and from the Henry Hub for the delivery of gas must be demonstrated ten days before the month of delivery.

The gas futures market is expected to meet two important needs of the gas industry under the transformed environment. They are the need for a reliable mechanism to improve the flow of price information on current and expected natural gas prices to all domestic natural gas market participants and the need for a reliable mechanism to facilitate the management of price risk.[7]

The standardized futures contract, the public outcry system used at a futures exchange, and the published futures prices provide an inexpensive and readily accessible means to all potential sellers and buyers (both traders and nontraders in the futures exchange) for acquiring information on future price expectations of the market. This can make the cash market, where the physical commodity is actually traded, function more efficiently with the futures market acting as a source of reference prices.[8]

It is important here to underscore the relationship between spot markets and futures markets. A well functioning spot market adjusts prices primarily in response to *actual* demand and supply, while a futures market sets prices that reflect *expectations*

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[7] Energy Information Administration, *Annual Outlook for Oil and Gas 1990* (Washington, DC: Energy Information Administration, 1990).

[8] Leuthold et al., *The Theory and Practice of Futures Markets*, 4.

expectations about future demand and supply. The existence of a futures market is predicated on the belief that the spot market is reasonably well functioning; otherwise there would be no rationale for traders to participate in the futures market. At the same time, a futures market improves an otherwise well-functioning spot market even further by improving the flow of price information.

A futures market also improves the functioning of forward markets and other long-term contract markets. In the absence of a futures market or any other arrangement to inexpensively and publicly facilitate the exchange of price information, participants in contract markets obtain their price information through strategic bargaining in bilateral negotiations. One example of this practice is the inclusion of the most favored nation (MFN) and the market-out (MO) clauses in gas contracts. The MFN carries a guarantee that if the seller reduces its price for one buyer, it will do the same for all buyers. The MO stipulates that the seller will meet a competitor's price or release the buyer from its purchase commitments. Both MFN and MO clauses allow the seller to acquire information on prices being offered by its competitors and engage in what is known as "price signalling."[9] This can have the effect of inefficiently holding prices at a certain level while the sellers choose to compete on nonprice terms of contracts, a situation similar to that of an oligopoly.[10] A futures market removes this distortion by substituting a public and inexpensive means of exchanging price information for the less efficient bilateral arrangement. Thus, opening of the futures market will have the effect of making

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[9] William L. Baldwin, *Market Power, Competition, and Antitrust Policy* (Homewood, IL: Richard D. Irwin Inc., 1987), 409-410.

[10] Robert E. Burns, Mark Eifert, and Peter A. Nagler, *Current PGA and FAC Practices: Implications for Competitive Ratemaking* (Columbus, OH: The National Regulatory Research Institute, 1991), 215 217. See also E. I. du Pont de Nemours & Company v. Federal Trade Commission and Ethyl Corporation v. Federal Trade Commission, 729F 2d 128 137, 139 (1984).

the forward contract market work more efficiently.[11] It is also likely that the prices of forward and long-term contracts will be indexed to futures prices of gas.[12]

Perhaps the most important function of a futures market is price risk management. All sellers and buyers in a market face the risk of losses when the price of a commodity rises or falls beyond expectation. If the commodity is also traded in a futures market, each seller and buyer has the option to "lock in" current prices, purchase offsetting quantities in the physical and futures markets and thus "hedging" or eliminating the risk of losses from unexpected price movements. Other than hedging, traders also engage in speculation which can be defined as a trading activity designed to profit from price movements of a commodity in a futures market. Thus, a futures market allows hedgers, who are risk averse, to shift their price risk to speculators, who are risk takers. Hedgers and speculators both perform useful roles in a futures market and are essential for its efficient functioning.

Since its opening, producers, marketers, and large industrial customers have participated in the futures market. The lack of LDC participation may be explained by a perceived lack of significant price risk given the cost pass-through provisions of PGAs. Despite LDC nonparticipation, the futures market appears to be rapidly growing over time in both open interest and total volume traded.[13] Whether the gas futures market will continue to flourish to the benefit of the gas industry is hard to predict. In the past, there have been a few failures of futures markets. Of all the commodities introduced for trading on organized futures markets, 16 percent were withdrawn within the first year and 40 percent did not survive for six years. On average, trading in a commodity offered on the futures market lasts only about twelve years. Evidence also shows, however, that

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[11] For an analysis of the effect of the futures market on forward markets, see Edward H. Jennings, "The Use of Natural Gas Futures by Local Distribution Companies," *NRRI Quarterly Bulletin* (December 1991), 481-92.

[12] Energy Information Administration, *Annual Outlook*.

[13] Open interest represents total numbers of "long" and "short" positions held in the futures exchange. Total volume traded represents the number of contracts opened or closed during any given day. Open interest has grown to about 20,000 contracts and total volume traded to about 2,700 contracts in twenty-one months since the opening of the gas futures market on April 3, 1990.

markets in industrial materials (which includes natural gas) tend to have higher survival rates.[14]

Free Access Trends and the Rising Need for Information

As LDCs and producers need more specified information on the gas market, the role of gas marketers or other market intermediaries has substantially expanded. Since direct gas purchases are relatively new for most LDCs, several forms of market intermediaries who can provide procurement and transportation services or assume certain market risks for LDCs have emerged.

The emergence of various types of markets and merchants associated with the natural gas industry can mainly be viewed as a result of the huge increase in demand for market information. According to a famous proposition of Adam Smith, the division of labor is governed by the extent of the market.[15] This proposition predicts that the size of market demand for a certain commodity is the key factor determining the degree of division of labor. If the size of the demand is small, a high degree of specialization is not likely.

Although this proposition seems quite plausible and realistic, George Stigler refined it and provided a more scientific analysis.[16] Society may have many potential processes for producing a commodity. Stigler explains that processes subject to increasing returns tend to be performed by a single firm as the size of the market grows. On the other hand, he explains that processes subject to decreasing returns tend to be

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[14] David Wirick, "Establishment of The Natural Gas Futures Market: Regulatory Watershed or Non-Event?" *NRRI Quarterly Bulletin* (June 1991): 222. See also Dennis W. Carlton, "Futures Markets: Their Purpose, Their History, Their Growth, Their Successes and Failures," *The Journal of Futures Markets*, 4 no. 3 (1984): 256-59.

[15] Adam Smith, *An Inquiry into the Nature and Causes of the Wealth of Nations*, Book I (New York: Modern Library Edition, 1937), chapter 1.

[16] George J. Stigler, "The Division of Labor is Limited by the Extent of the Market," *Journal of Political Economy* (June 1951): 185-93.

spun off as the size of the market grows. More generally, in the case of a U-shaped average cost curve for a specific process, it will be spun off at the size where average cost is at its lowest level. This idea can be applied to the recent free-access trends in the natural gas industry. As deregulation allowed free access to the producers by LDCs (and vice versa), there has been a sharp upsurge in demand for information on producers' location, prices, reserves, close pipeline networks and their price and capacity, and so forth. This large demand now may allow more division of labor to handle information and distribute risk in the natural gas industry. Not surprisingly, diversified markets and specialization within this industry have developed in the form of spot markets, a futures market, and market intermediaries that were previously performed internally by pipelines. The growth of marketers and market intermediaries is a logical outcome of the evolving market structure and performs a useful function for the gas market.

The expanding demand for information now allows a spinoff from pipelines that specializes in gathering, processing, and distributing relevant information which, by its nature, requires substantial economies of scale. It may not have been profitable just a few years ago to specialize in natural gas industry information. After such an explosive increase in the demand for information, however, each information-handling firm could attain enough market share for profitable business.[17]

LDC Gas Purchase Options in a New Gas Market

As discussed before, unbundling gas services and unraveling the traditional three-tier gas industry structure have greatly expanded the gas purchase options available to the local distribution companies (LDCs). Under the changed gas industry structure the LDCs

[17] The reader may ask whether pipelines can monopolize such businesses because of economies of scale. However, the information supplied by pipelines may not be so credible to the customers as that of independent suppliers since pipelines are not objective third parties.

Are afforded a broad range of new alternatives in managing their gas supply portfolio.[18] Specifically, an LDC can enter into long-term purchase contracts with wellhead producers directly, buy gas in the spot market, or hire a gas marketer to secure and transport gas on its behalf. Additionally, an LDC can use storage and trading of gas futures contracts in combination with other gas purchase options to further control the price and supply risks associated with its gas supply portfolio.

LDC Gas Purchasing Objectives

The LDC has a franchise to supply gas to various customers in a designated jurisdictional service area. Under state regulation, the LDC is required to procure and deliver gas at the lowest cost achievable: the cost minimization objective. The LDC also has an obligation to serve which requires it to procure a sufficient quantity of gas and arrange adequate transportation to meet both the volumetric and peak-load requirements of customers: the supply reliability objective. The two objectives are not completely independent and there is typically a tradeoff between the two. The lowest-cost sources of gas (such as the spot market) are usually the least reliable. Pipeline contracts represent the most reliable source of gas but also tend to be the most expensive. Obviously, an LDC needs to design an optimal portfolio of supply sources and transportation arrangements to meet both the cost minimization and the supply reliability objectives. In meeting these objectives, the LDC has to account for certain factors related to demand, pricing, and supply constraints present in the gas market. Three such factors are the seasonality of gas demand, short-term and long-term fluctuations of gas prices in the wellhead market, and the reliability of gas supply arrangements. These factors carry with them uncertainties which impose risks on an LDC's earnings. An LDC supply management

[18] Detailed discussion of the various new gas procurement alternatives available to the local distribution companies can be found elsewhere. See Daniel J. Duann, Robert E. Burns, and Peter A. Nagler, *Direct Gas Purchases by Gas Distribution Companies: Supply Reliability and Cost Implications* (Columbus, OH: The National Regulatory Research Institute, 1989), 39-48 and J. Stephen Henderson ed., *Natural Gas Industry Restructuring Issues* (Columbus, OH: The National Regulatory Research Institute, 1986), 91-102.

strategy needs to incorporate measures to minimize these risks.

Factors Affecting Gas Purchase Options Selection

Because of the variety of demand profiles for gas facing a typical local distribution company and the volatility of price and supply in a competitive gas market, it would be unusual for a single gas procurement strategy to be uniformly applicable to all LDCs at any specific period of time. It also would be unlikely for most LDCs to rely upon only one gas purchase option to secure their gas supplies. For most LDCs, several purchase options would be used at the same time. Various studies have addressed the issue of constructing an optimal gas supply portfolio.[19] This section discusses three key factors in selecting various gas purchase options: seasonality of demand, price fluctuation, and reliability of supply.

These three factors are discussed in the context of plausible assumptions about the current, and likely future, gas market structure, and federal and state regulatory settings. Specifically, it is assumed that the local distribution companies are operating in a gas industry where the gas acquisition market is essentially unregulated, where the interstate transportation market is operated on an open-access basis with all major pipelines providing transportation service on demand if sufficient capacity is available, and where the state regulatory agencies generally allow the end-use customers to bypass the LDCs for procuring gas supplies. For the overall gas market, it is assumed that neither substantial supply surplus nor prolonged shortage are likely to occur in the foreseeable future.[20]

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[19] See, for example, J. Stephen Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches* (Columbus, OH: The National Regulatory Research Institute, 1988), 91-111.

[20] More discussion about the various projections of future gas market conditions can be found in Duann et al., *Direct Gas Purchases by Gas Distribution Companies*, 12-28.

Seasonality of Gas Demand

The seasonal variation in gas demand is significant. For example, 1990 gas consumption by end users (residential, commercial, industrial, and electric utilities) in the "warmest" month of the year (September) was 1,287 billion cubic feet (Bcf), about 60 percent of the consumption in the "coldest" month of the year (January).[21] This drastic variation in gas demand stems from the fact that gas is used as the primary energy source for heating in the winter months, particularly for residential customers. Though the large increase of gas demand in winter can be countered somewhat by the increased use of gas by electric utilities to generate electricity for air conditioning during the summer months, the seasonal variation is still quite significant. The seasonal patterns of gas consumption by end users for the past three years is shown in Figure 2-1.

On the other hand, the production of gas is relatively stable over the course of a one-year period, and the amount of gas that can be transported is generally fixed within the same timeframe. For example, the amount of gas production in September (1,361 Bcf) was about 86 percent of that in January (1,605 Bcf).[22] Consequently, withdrawals from storage fields and imports become two primary forms of balancing production and consumption. In the event that such adjustments are not sufficient, the market price of gas, in the absence of outside interference, will react to the balance of demand and supply.

Gas Price Fluctuation

The United States gas market for the last decade has shown significant price fluctuations. Over the past three years, however, the annual variations have been small relative to seasonal fluctuation of gas prices as shown in Figure 2-2.

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[21] Energy Information Administration, *Monthly Energy Review* (Washington, D.C.: Energy Information Administration, March 1991), 66.

[22] Ibid., 65.

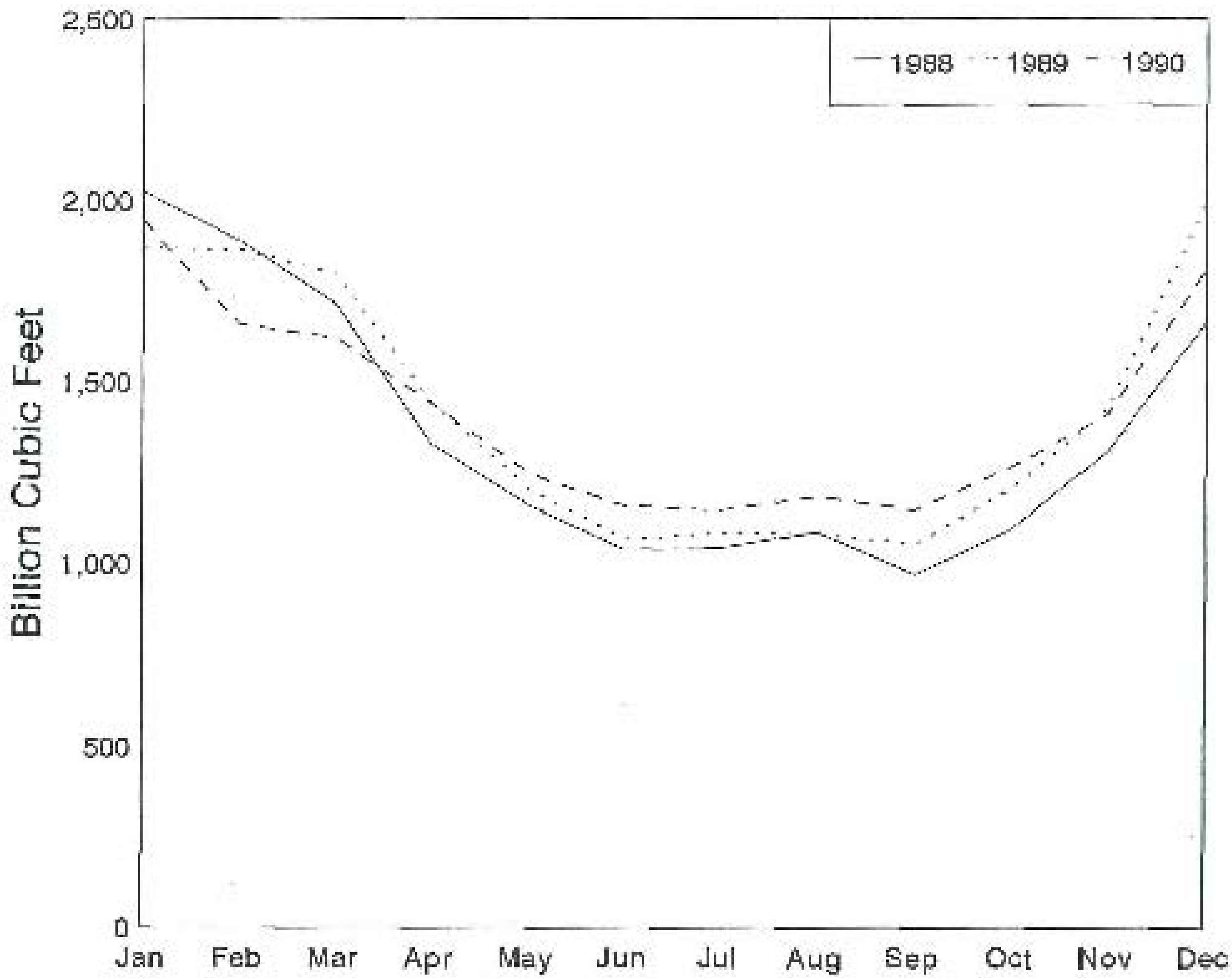
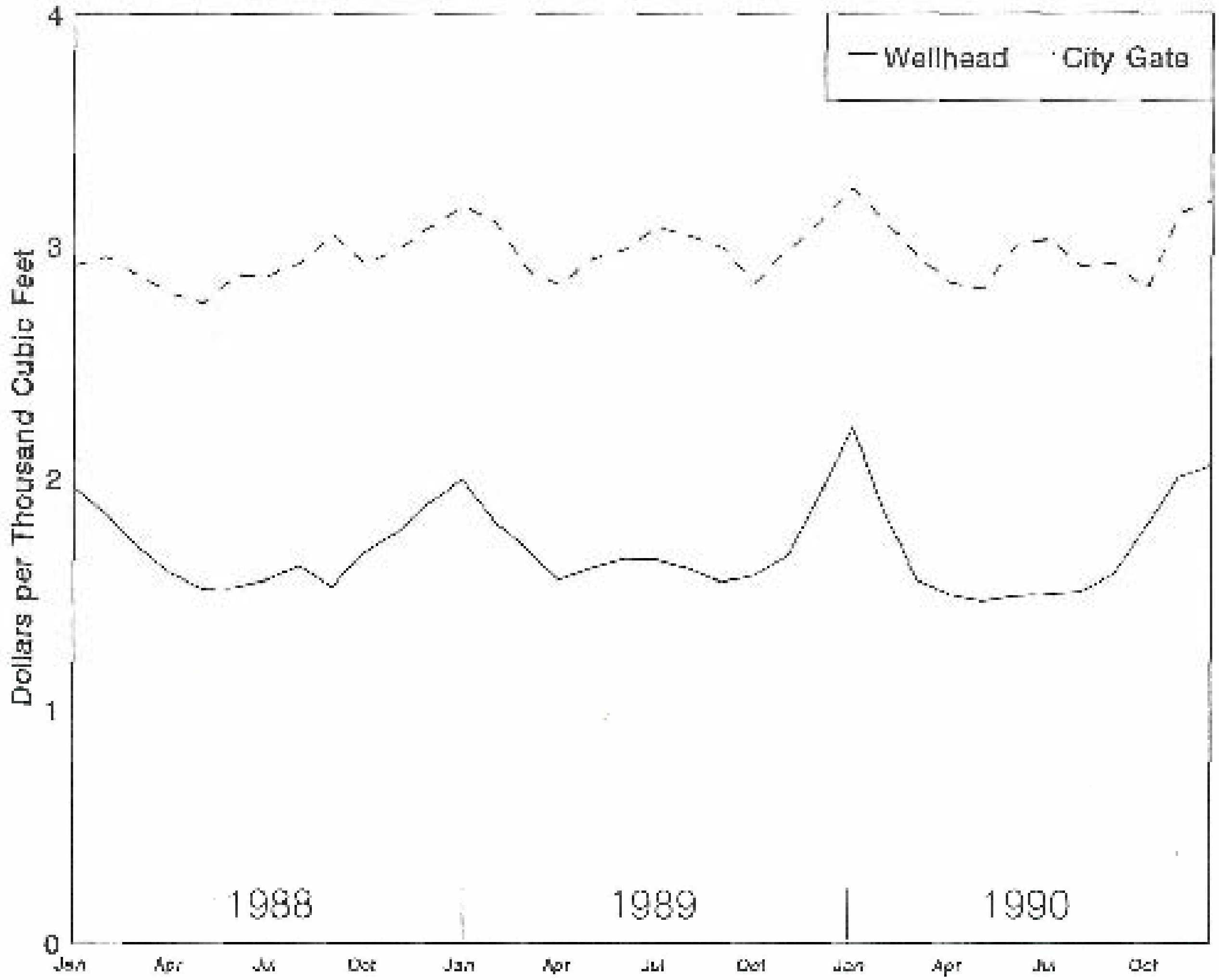


Fig. 2-1. Monthly natural gas consumption by end users from 1988 to 1990.

Fig. 2-2. Monthly average wellhead and city-gate prices of natural gas from 1988 to 1990.



As mentioned, seasonal gas price fluctuations can be attributed to the seasonality of demand that can result in significant demand/supply imbalance. Another source for the fluctuation in price during this particular period has been the change in the market structure and regulatory settings. At this time, it may be assumed that the competitive and deregulatory trends of the past decade will continue. Under this assumption about the future gas market structure and institutional setting, price fluctuations are likely to continue and can be drastic at certain periods of time. Another factor affecting the long-term fluctuation of gas prices is the movement of price of oil in the global market, which is governed by international political and economic forces. Finally, the Clean Air Act Amendments of 1990 may impact future prices of gas if it becomes, as expected by some, a significant part of the electric utility industry's compliance options as an alternative fuel to higher sulphur coal.

Reliability of Gas Supply

Under the current competitive market structure, an LDC can almost always secure the amount of gas required as long as it is willing to pay the market prices of gas supply and transportation capacity, no matter how high they are. Consequently, gas supply reliability must be defined in terms of the cost of buying reliability in comparison with other LDCs in similar situations. An absolute criterion of supply reliability may not be desirable or useful in planning a gas procurement strategy.

The supply reliability consequences of various gas purchase options can be analyzed in terms of a single gas procurement transaction as well as in the context of an overall supply portfolio. It is important to recognize that supply reliability is governed by both gas acquisition and transportation services. In other words, if sufficient transportation capacity cannot be secured to transport gas from the wellhead to the city gate, the supply reliability of the LDC will be affected even if it already secured the title to the required amount of gas. In fact, given the competitive nature of the current wellhead market, the provision of transportation service may well be the key to reliable gas service.

The recent mega-NOPR issued by FERC has raised new concerns about an LDC's supply reliability. Among the features of the mega-NOPR that may affect reliability are mandatory unbundling of sales and transportation services, exemption of pipelines from obligation to serve, and nondiscriminatory access to storage, receipt, and delivery points. Complete unbundling of sales and transportation services would prevent LDCs from utilizing the reliability advantage of a bundled service that provides assured supplies of gas to serve unanticipated swings of load. Exemption of pipelines from the obligation to serve reduces the ability of an LDC to ensure gas supplies to meet peak winter season demand. Nondiscriminatory access to receipt and delivery points and to storage removes the ability of the pipeline to coordinate gas supply according to the priorities of its customers. While the LDC may attempt to ensure supply reliability by purchasing separate services and rebundling them, it does not have the resources and experience previously available to a pipeline to do so. The LDC also can try to purchase packaged services from a marketer, but the marketer may not have the technical expertise, financial standing, or statutory obligation to serve to guarantee delivery of gas to meet swings of load and peak load needed by an LDC.

If the features of the mega-NOPR that may have potentially adverse impact on reliability are incorporated into the final rule, then the risks of supply reliability will shift from the pipeline to the LDC. This will make the design of an optimal portfolio of supply sources a much more complex task for LDCs than in the past. However, this may be a transitional problem which will pass as the industry responds to the mega-NOPR as mechanisms develop that provide reliability at market-based prices.

LDC Gas Purchase Options: Basic Features and Uses

Long-Term Contracts with Pipelines

A long term gas purchase contract with a pipeline company was the dominant form of gas procurement by the local distribution companies in the past. They covered a long period of time, typically twenty years or longer, and the buyer agreed to take a minimum amount of gas annually (minimum-take provision) and obligate itself to purchase or pay for a certain quantity of gas (take-or-pay provision). A long-term contract also was characterized by several price-adjustment provisions which allowed the price to be adjusted periodically to reflect significant changes, if any, that could occur in the gas market during the life of the contract.

Several explanations have been advanced for the prevalence of long-term pipeline contracts in the past. A gas pipeline can be better utilized at full capacity all the time than in an intermittent way. A long-term contract can assure a stable amount of gas being transported in the pipeline system most of the time, and make the pipeline transportation more efficient. Furthermore, the extremely low heat content of gas at normal pressure and temperature makes the pipeline the only viable alternative for transporting a large quantity of gas.

Long-term contracts can be designed to meet LDCs' seasonal demand, long-term price fluctuations, and supply reliability requirements. The seasonality of demand can be met by incorporating seasonal tariffs and separate rates for summer and winter months. Based on expectations of future prices, a long-term contract can "lock in" low prices or include market-out clauses to make prices more market sensitive. Finally a long-term contract with a pipeline probably provides the best reliability features. Because of its access to storage facilities, and its expertise in diversifying and aggregating supply sources, the pipeline may be best able to assure a secure supply of gas that matches an LDCs demand profile. Further, the need to economize transaction costs and control opportunistic behavior may have been important factors contributing to the prevalence of long-term contracts in the past. Long-term contracts, which guarantee the utilization of gas transportation facilities, were an essential form of obtaining financing for pipeline construction since such investments would have little value in alternative uses. Long-term contracts also were viewed as essential in mitigating the opportunities and incentives for what economists call contract “hold-up” by the parties involved. A contract “hold-up” means that one party may negate a gas purchase contract after transaction-specific investments have been made by another party.[23]

As a result of the changes in federal regulations, however, the interstate pipeline network has become widely available to wellhead producers, LDCs, and end users, the possibility of contract "hold-ups" in gas procurement may have diminished considerably.[24] Thus, the need for entering long-term contracts to minimize transaction costs and prevent opportunistic behavior in gas procurement may have been lessened.

Long-term pipeline contracts, in spite of recent developments that significantly eroded their advantages, may still play an important role as a mechanism for achieving a secure supply of gas. LDCs may still want to use such contracts to meet a significant part of their peak demand. This would be especially true of those LDCs that have limited access to storage or for which storage is a relatively expensive option.

Direct Purchase from Wellhead Producers

The local distribution company also can enter into long-term gas purchase contracts directly with wellhead producers. Such a contract shares many features with long-term contracts between LDCs and pipelines except that transportation has to be separately arranged. From the perspective of a local distribution company, however, purchasing gas directly from a wellhead producer is a more demanding endeavor. The

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[23] See John Harold Mulherin, *Vertical Integration and Long Term Contracts in the Natural Gas Industry* (Ph.D. Dissertation, University of California at Los Angeles, 1984) for a comprehensive analysis on this issue.

[24] Though a gas well or production field in most instances remains physically connected to the interstate gas delivery system through only one pipeline, a producer can sell to many entities besides its connecting pipelines. On the other hand, if a pipeline cannot secure gas from its connecting producers, it can access other producers through pipelines owned by others or use its underutilized pipeline capacity to transport gas for others.

LDC needs to take on several tasks that were undertaken previously by the pipeline company. The critical tasks in making direct purchases from wellhead producers are acquiring extensive knowledge and experience in locating a large number of potential suppliers, and securing transportation service for moving gas from the field to the city gate.[25] Additionally, an LDC also needs to schedule the delivery of gas it purchases directly and arrange backup service in case the purchased gas cannot be delivered as scheduled.

Spot Market Purchases

As discussed earlier, spot gas purchases were typically not used prior to the mid-1980s because of the small number of potential buyers and sellers resulting from restricted access to gas transportation facilities. With the trend toward open access firmly established, spot purchase has become a viable and important part of the gas procurement strategy for many LDCs and end users.[26] In combination with other options (such as storage) spot purchases allow an LDC to design a flexible strategy to meet seasonality of demand and price fluctuations.

Using Gas Marketers to Acquire Gas

The fourth option available to an LDC is procuring gas from marketers. Several forms of market intermediaries that provide procurement and transportation services or that assume certain market risks for LDCs have emerged with the increased popularity

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[25] As an alternative, an LDC can obtain this service from a gas marketer. See the following discuss on "Using Gas Marketers to Acquire Gas."

[26] The existence of a spot market usually requires that the underlying commodity is readily available from different suppliers with no significant quality difference, and with a relatively large number of buyers and sellers competing actively in the market. Gas is a commodity with generally uniform quality, and potentially large numbers of buyers and sellers abound if open access to pipeline facilities can be assured.

of direct purchases.[27]

A gas marketer can provide many services, including locating and qualifying suppliers; aggregating purchases from many buyers; arranging transportation, backup supplies, or transportation alternatives; and other services. If the gas marketer actually holds title to the gas to be purchased by an LDC (even for a brief period of time), it assumes the risks associated with insufficient transportation capacity, gas production shortfall, or drastic price changes for the eventual buyer-the local distribution company.

At first glance, a gas marketer performs several functions similar to those previously undertaken by the pipeline company. An important difference lies in the fact that an independent gas marketer generally owns neither the facilities used in transporting gas nor the gas being transported. Since it has no ownership interest in any particular gas supply source, a gas marketer has no conflict of interest in obtaining the "best" supply sources for an LDC. By contrast, a pipeline is likely to have some built-in incentives to sell gas from its own supply portfolio or use its facilities to transport gas. Some marketers, however, are not completely independent and are affiliated with other gas industry participants (such as producers, pipelines, and LDCs). In such a case, the marketer may have its own biases because of its affiliations. Further, marketers may not have the assets to guarantee contract performance. This and the fact that marketers do not own either production or transportation facilities may make them less reliable sources of gas supply than either pipelines or producers in times of supply and capacity shortages.

Gas Purchase Options and Business Risks of an LDC

The four purchase options identified above are used primarily to procure supplies of gas. An LDC, like any other business enterprise, however, needs to address various

[27] For example, it was estimated that the number of firms involved in gas marketing has increased from fifty-one in 1985 to around one hundred in 1988. Some of the largest marketers can handle transactions exceeding 100,000 Mcf each day.

business risks arising out of uncertainties in demand and supply conditions. These risks can have an adverse effect on its earnings and financial viability.

These risks are likely to grow as more competition replaces federal regulation at the gas wellhead market. State regulation of LDCs currently shifts these risks to the ratepayers. This study identifies some regulatory options that would transfer some of these risks to the LDC through use of incentive-based cost recovery mechanisms. This may require LDCs to develop and use risk management strategies.

The procurement options discussed earlier can be tailored to mitigate some business risks. Two other options, namely the increasing use of storage and the buying and selling of gas futures, afford additional potential for risk mitigation. These options can be combined with gas procurement options to design effective risk mitigation strategies.

A discussion of the business risks of an LDC and possible risk management approaches appears in the appendix. No attempt is made to design rigorous risk management strategies. The discussion is limited to identifying risk elements and conceptual approaches for risk mitigation.

Market Competitiveness and Choice of LDC Options

While cost and supply reliability are the two most important factors that govern an LDCs choice of purchase options, other important constraints limit the choice too. One such constraint is the degree of competitiveness in the wholesale gas market, which like most markets, affords different degrees of market power to different participants. The degree of market power depends, among other things, on differences in operating characteristics, whether and to what extent complementary operations are regulated, and the relative size of various participants.

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[28] Baldwin, *Market Power, Competition, and Antitrust Policy*, 107-119.

Structure of a market is defined by the number and relative sizes of buyers and sellers, the economic characteristics of the product, the production, cost and demand conditions, and the nature of distribution channels. Conduct is defined by activities pursued by firms to assure themselves a favorable position in the market. Activities include collusive price fixing, predatory pricing, price discrimination, tying arrangements, price leadership, pricing to limit or exclude entry, resale price maintenance, and agreements to divide markets or restrict output. Performance is defined by several criteria such as total resource costs to society, the allocation of resources in both production and consumption, and such equity considerations as wealth distribution. In examining a market, it is not necessary to use each and every criteria listed. Any given market may have or lack certain features that render some of these criteria irrelevant and make certain criteria more important than others.

To examine the degree of competitiveness in the wholesale gas market, certain factors may be considered critical. These are market share or concentration, ease of entry by new participants, options available to sellers to preempt other sellers' gas from being sold, ability to engage in price and nonprice discrimination among purchasers, and countervailing options available to parties subject to anticompetitive practices.

Market concentration is an important measure of market power. Several indices of market share are available. The most well known one is the Herfindahl-Hirshman Index (HHI) adopted by the U.S. Department of Justice as a standard for implementing antitrust policies in approving mergers.[29]

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[29] The HHI is a compound index that uses both the number of sellers in the market as well as their sizes. It is given by

$$HHI = \sum_{i=1}^{n} s_i^2$$

where s_i equals the percentage share or fraction of the market accounted for the ith firm. The reciprocal of the HHI equals the equivalent number of sellers of equal size. As an example, an HHI value of 0.125 is equivalent to eight sellers having equal market shares. HHI values close to one reflect high concentration (and market power) and values close to zero reflect low concentration.

In a recent study, the FERC computed the HHI at various spot markets in the United States (see Table 2-3). The table shows that the HHI are generally low indicating relatively low market concentrations. These data alone, however, do not necessarily indicate complete absence of market power in the wholesale gas market. In recent testimony before the FERC, the Illinois Commerce Commission contended that an estimate of HHI depends critically on the definition of product and geographic boundaries.[30] The HHI, if computed on the basis of spot sales alone during periods of slack demand, may indeed be low. If the product boundary, however, is confined to peak-load gas, the HHI would be significantly larger. One can reasonably contend that the market for short-term spot contracts is workably competitive while market dominance for contracts for peak load gas may exist.

It may be true that pipelines do dominate the market for peak-load contract gas. This dominance, however, cannot be attributed entirely to anticompetitive practices of the pipeline. The statutory obligation to serve imposed on the pipeline makes this supply source more attractive and reliable to all purchasers at times of greatest need. Other gas shippers have only a contractual obligation to serve which can be more easily abandoned than a statutory obligation. So, the primary reason for pipeline dominance in the market for peak load gas may be regulatory-induced rather than reflecting the exercise of market power.

Furthermore, because of their monopoly over interstate transportation and related services, pipelines have opportunities to discriminate between shippers who buy gas from the pipeline and those who buy it from other sources. Pipelines are currently allowed to offer bundled services which include both gas procurement and transportation. These bundled service contracts may contain more favorable terms than what a purchaser could get if it were to buy its gas separately from a nonpipeline source and obtain transportation service from a pipeline. A pipeline also can deny access to storage, receipt, and delivery points to nonpipeline shippers. Part of these discrimination

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[30] Illinois Commerce Commission, Testimony presented before the Federal Energy Regulatory Commission in the *Matter of Natural Gas Pipeline Company of America*, Docket No. CP89-1281.

TABLE 2-3 MARKET CENTER

INFORMATION

Market Center	No. of Pipelines	Center Point	Radius (miles)	Production Deliverability (Bcf/d)	Peak Storage Deliverability (Bcf/d)[c]	HHI[d]
Blanco, NM	3	Blanco Gas Plant	120*	2.45		0.1774
Detroit, MI	6	Pipeline connection	65		3.30	
Erath, LA	28	Henry Gas Plant	50	19.15		0.0643
Guymon, OK	16	Pipeline connection	65	12.05	0.45	0.0327
Katy, TX	23	Katy Gas Plant	70	12.02	2.75	0.1691
Lebanon, OH	6	Pipeline connection	60			
Leidy, PA	6	Pipeline connection	30		5.10	
Midland/Waha, TX	15	Waha Gas Plant	70	5.29		0.0959
Monroe, LA	14	Pipeline connection	50	2.74	0.96	0.0938
Niagara, NY	6	Pipeline connection	50		0.41	
Opal, WY	12	Pipeline connection	110[b]	2.90	0.32	0.0811
Topock, AZ	5	Pipeline connection	10			
Tuscola, IL	5	Pipeline connection	45		0.10	

Source: Federal Energy Regulatory Commission, Office of Economic Policy, "Importance of Market Centers," OEP Discussion Paper (Washington, D.C: August 21, 1991).
• If new facilities **were** built to connect El Paso and Transwestem pipelines, the distance between the center point and the new interconnectin could be reduced to about 90 miles.
If a pipeline interconnectin near Rock Springs (rather than Opal) were the cetner point, the radius coudi be reduced to about 75 miles. [c] Total reserves divided by annual reserve to deliverability ratio divided by 365.
HHI for uncommitted and pipeline supplies.

practices, however, may be needed for the pipeline to manage and coordinate its transportation operation and may not necessarily reflect abuse of market power. However, there is clearly room for anticompetitive and exclusionary practices. In examining pipeline market power, one should examine what countervailing options are available to competitors.

A nonpipeline shipper or purchaser affected by a perceived or actual abuse of market power by a pipeline can file a complaint with the FERC and the appropriate court of law to seek adjudicatory and legal remedies. Seeking these remedies, however, may require significant effort and legal expenses comparable to the benefits to be achieved from securing a more evenly balanced treatment from a pipeline. The recent FERC initiative to mandate unbundling of all pipeline services is intended to remove these opportunities for anticompetitive behavior. As discussed earlier, a certain amount of bundling may be necessary to ensure proper management and coordination of transportation services and supply reliability. This advantage may have to be sacrificed if a fairly complete unbundling were to occur. The potential degradation of reliability is likely to have a more adverse affect on the LDC, which also has a statutory obligation to serve, than other purchasers of gas. This leads to the next important issue, the disparity among various customers of gas and its implications in a more competitive wholesale gas market.

In discussions of market power, it is not sufficient to address only the relative advantages of one seller over another without addressing the unevenness that may be present among various purchasers of gas. The LDC has a statutory obligation to serve, especially its core or "human needs" customers. This translates into a virtual (if not statutory) obligation to buy both the gas commodity and the transportation to meet the needs of these "captive" customers. Other gas purchasers such as large industrial customers do not have a corresponding obligation to buy either to meet a legal requirement or their own consumption needs. Many large industrial customers can switch to an alternate fuel such as oil if the price of gas becomes relatively expensive or if the supply of gas is interrupted for any reason For electric utilities, gas is used as a prime fuel to meet peak demand for electricity, which generally occurs during the summer (due to high air conditioning loads) when gas is available at a relatively low price in spot markets. Although they have an obligation to serve, electric utilities, like large industrial customers, also have the ability to switch quickly to alternate fuels. Thus noncore customers' demand for gas is highly elastic relative to the core customers. This introduces significant unevenness in buying power between the LDC and the large dual-fuel customers.

An aggressive "freeing" of the wholesale gas market, such as that undertaken by the FERC, without consideration of the disparity between various pipeline customers may not necessarily achieve the efficiency objectives of such an initiative and will probably introduce some inequities. When the potential for market abuse exists, as is claimed by the competitors of pipelines, the inelastic customer such as an LDC is likely to be more adversely affected than other buyers. If the opportunities for market abuse are removed and the market is rendered more "free," it is unlikely to improve the market position of the LDC as a buyer. Instead it may impose additional risks of lower supply reliability.

Besides unbundling sales and transportation services, the FERC (through the mega-NOPR) proposes a capacity reassignment program that would be an alternative to traditional capacity brokering and allow nondiscriminatory access to storage, and allow shippers flexibility in choosing receipt and delivery points. A pipeline's discretionary control over these elements of transportation service may be necessary to ensure reliable service to firm customers (which includes LDCs), even if the pipeline may be able to abuse its discretion for anticompetitive gains. Removing existing controls from the pipeline may merely transfer the opportunities for anticompetitive abuse to large producers, who may be able to strategically control the access to these facilities to extract noncompetitive rents from relatively inelastic customers.

The degree of competitiveness of the gas market and market power possessed by various sellers of gas has significant implications for an LDCs gas procurement options. While the market is workably competitive for spot gas purchased primarily to meet off-peak load, both the potential for anticompetitive abuse and critical need for reliability to exist in the market for gas during peak winter months. Therefore, to meet their service obligations during peak seasons, the LDC may be constrained to trade cost minimization for supply reliability, whether under the current regime or after the changes proposed to the mega-NOPR. State commissions have been sensitive to this constraint and will probably continue to be so in their oversight of the LDC purchasing practices. Given this fact, certain incentive issues surrounding an LDCs gas purchase options still need to be explored. They include: (a) whether LDCs have availed themselves of the opportunities in the post-Order 436 era to aggressively bargain for both spot gas and contract gas, (b) whether LDCs have been prudent in purchasing supply reliability at the lowest achievable premium or cost, and (c) whether current state regulation provide LDCs with the correct incentives to be efficient and prudent given both the flexibility of options in the emerging gas market and the persistence of certain market and regulatory constraints. The issues listed under (a) and (b) require empirical resolution. Issue (c), however, can be examined in the light of general economic and regulatory principles and this is what the remainder of the report attempts to do.

CHAPTER 3

REGULATORY OPTIONS

Basic Considerations

As mentioned, the evolution of the gas industry and regulatory regimes over the past decade has fundamentally changed the way LDCs now must conduct their business. They must account for new realities that have emerged on both the demand and the supply sides of their enterprise. They face a significantly competitive marketplace for procuring gas from a large number of suppliers, including interstate pipelines, producers, and marketers. Transportation, which traditionally has been bundled with gas sales, now can be separately arranged and contracted for to ensure delivery of the gas commodity. The opening up of the wholesale market, in which they are purchasers, and the retail market, in which they are sellers, present them with many new opportunities and confronts them with many new risks. While still a regulated monopoly, the LDC is now forced to act more like a competitive firm in the unregulated marketplace. It is, however, also bound by regulation to ensure reliable service to its customers-especially core customers-at the lowest achievable cost. The LDC now needs to balance the potential gains from the new opportunities against the potential losses from the related risks within the confines of regulatory and market constraints.

The changed market and regulatory environment faced by the LDC also changes the way its regulator, the state PUC, discharges its mission. While the PUC still must ensure that ratepayers receive reliable service at the lowest possible cost, it must be aware of the opportunities available to the LDC to achieve this and be sensitive to the risks and constraints that face the LDC. These observations lead to a set of principles that may best guide the regulation of LDCs

Because the utilities have access to better informatioiin than regulators, many believe that regulators should not attempt to take on the roles of managers for utilities. In the past, when the LDC had to deal with a predictable marketplace for its purchase and supply decisions, this principle was considered an essential tenet of regulation. In the changed market environment with its attendant uncertainties, it may have even more validity. The uncertainty also requires regulators to be more flexible in their oversight of the LDC operations. For example, if a gas purchasing plan made with the best available information turns out to be a bad performer over time due to unforeseeable circumstances, the regulator should not penalize the LDC for the outcome (unless, at the same time, the LDC is rewarded for a favorable outcome). Another way to deal with adverse unpredictable outcomes is to allow for them in the initial plan. An astute regulator presumably will do both: require accounting for uncertainties in the initial plan and be flexible in dealing with poor outcomes.

Regulators are aware that significant potential for conflict exists between utility goals and ratepayer interests and that they often need to strike a balance between them. This task has been made more complex by the new market environment and its attendant uncertainties. Ideally, the regulator would want the LDC to provide its services at the least possible cost while ensuring a minimum level of reliability. But the regulator usually does not have sufficient information to determine what the cost and reliability objectives ought to be and how best to achieve them. Attempting to acquire such information would turn the regulator into a manager, a role best avoided. The informational advantage of the LDC over the regulator allows it to strategically manipulate the regulatory system to its advantage. For example, an LDC if it is risk-averse may "buy" more reliability than it needs by biasing its portfolio toward firm contracts. In the absence of quantitative measures of reliability, it is— difficult for the regulator to detect this inefficiency and take corrective action. On the other hand, if the regulator emphasizes cost minimization, the LDC may opt for purchasing a relatively larger fraction of its gas from the spot market and sacrifice reliability standards. In either case, the regulator is at a disadvantage in deciding an optimal tradeoff between reliability and cost One way to deal with this problem is to design ‘incentive compatibility”, that is, to construct regulatory approaches that attempt to make ratepayer and LDC interests compatible.[1] The LDC, in pursuit of its profit-maximizing goal, is induced to some extent to act that also tends to minimize the revenue burden to the ratepayer. Needless to say, such approaches are difficult to construct and implement. In the past, traditional regulation devoted little attention to incentive compatibility presumably because the LDC, purchasing gas from a regulated pipeline and then delivering the gas to an essentially captive market, had little room for manipulating its procurement strategy to the detriment of its customers' interests. It had very little control over the cost of gas it purchased which it then passed on to its customers. In the changed market, approaches that achieve incentive compatibility should be explored. Such approaches may constitute "incentive regulation," which has gained significant currency in the academic community and less significant support among regulators; improvements to traditional regulation; and perhaps some combination of the two. Some of the regulatory options that attempt to achieve incentive compatibility are discussed in the following sections.

Current Regulation and Incentives

Current regulation, which is based on full recovery of all utility costs (including a return on investment) does contain incentives for cost minimization. Some argue the incentives are either very weak or flawed and therefore usually do not induce cost minimizing behavior of the LDC. The regulatory oversight practices include rate case proceedings, PGA hearings, prudence reviews, and least-cost purchasing requirements.

Rate case proceedings provide cost-minimizing incentives in two ways. The first incentive, the scrutiny exercised through the hearing procedure may force the utility to submit rate filings that do not, prima facie, appear to contain exorbitant costs components that can be easily detected. This incentive assures a utility plan is reasonably cost-efficient.

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1 Roger Sherman, *The Regulation of Monopoly* (New York: Cambridge University Press, 1989), 47 and 71 – 77.

The second incentive is provided by the time lag between rate hearings. Once over, rates remain in force until another rate hearing takes place. During the period between rate case proceedings, the utility can maximize its profits by keeping costs as low as possible.

The effectiveness of both incentives, however, can be seriously compromised by other factors. Usually, the regulatory commission and interveners do not have access to information on utility operations that is as detailed and accurate as the utility. Thus it is possible for the utility to deliberately inflate its cost projections as long as it stays below the "detection threshold" of the commission and interveners. This problem can be corrected only by more intrusive scrutiny, which could put the commission in the role of a manager-- a role the commission wishes to avoid since it imposes additional regulatory burdens and costs.

The other incentive, provided by the regulatory lag is weakened by the presence of the PGA (purchased gas adjustment) as an approved regulatory mechanism for cost recovery. A PGA allows the utility to adjust its rates automatically to reflect deviations from cost projections for gas purchases approved in a prior rate hearing. The PGA either requires no hearing or a less extensive hearing than a rate case. Since the utility can recover its costs as they are incurred rather waiting until the next rate case, there is little incentive to minimize costs. The rationale behind the PGA and its effectiveness (or lack of it) is discussed in the next section.

Purchased Gas Adjustments

The PGA was designed as a regulatory device to achieve two purposes. First, it was expected to promptly bring rates closer to actual costs without the burdensome procedure of a rate case. Second, it was intended to recover only those costs that are beyond the control of the utility management. For example, until recently the typical LDC had only one supplier of gas (namely the pipeline) which supplied gas at a price regulated by the FERC. The LDC had no control over the price of the gas commodity and the transportation provided by the pipeline. If either cost increased beyond what was projected in a prior rate case, it was argued that the LDC, since it had no control over such cost increases, should be allowed to recover the additional costs. Prompt recovery of such costs through a full rate hearing would mean undesirably frequent hearings, which are burdensome and costly to all parties involved. Delayed recovery through adjustments in the next full rate hearing would compromise the financial viability of the LDC. The PGA was thus designed to allow prompt recovery of unanticipated costs beyond the control of the LDC management.

The PGA, primarily a cost recovery mechanism, can have cost minimization incentives built into it. The PGA is usually subject to review by a commission and also may be subject to a reconciliation hearing. The commission can disallow either completely or partially the rate increases requested in a PGA. The threat of complete or partial disallowance of a PGA submission provides the utility with some incentive to keep its costs under control and to exercise prudence in making PGA submissions.

The incentives present in a PGA also suffer from the same weakness as a full rate case hearing. The weakness lies in the informational advantage of the utility over the regulator. An LDC can include in the PGA the costs that are within management control. It may be difficult for a state commission to detect discrepancies in a PGA submission given its limited access to the information on LDC operations.

Prudence Reviews

Prudence reviews are conducted to evaluate past utility decisions using standards of efficiency and may be conducted in conjunction with a rate proceeding or PGA hearing or as a separate proceeding. Prudence reviews concern both capital investments (such as capacity additions to an LDC pipeline network) and expenditures (such as gas purchases and transportation contracts). A prudence review is retrospective and, as traditionally practiced, judges actions on the basis of contemporaneous circumstances rather than outcomes. If a decision is found to have been imprudent, the related expenses may be disallowed and excluded from revenue requirements. Prudence reviews allow state regulator another means of monitoring the efficiency of utility actions. The potential threat of disallowance is expected to induce an LDC to make efficient investment and expenditure decisions.

As in rate case proceedings and PGAs, the informational asymmetry may limit the effectiveness of prudence reviews. Unlike rate case proceedings and PGAs, however, prudence reviews are more likely to penalize rather than favor an LDC. Although a prudence review usually excludes consideration of the outcome, the outcome may influence the review decision. Thus it may penalize a utility for unanticipated outcomes even if the decision itself was prudent, given the circumstances at the time the decision was taken. However unfair this may seem, such a practice arguably mimics a competitive market, penalizing bad outcomes.

It may be argued that prudence reviews somehow balance the consequences of PGAs and rate case proceedings that tend to favor a utility because of its informational advantage over the regulator. This makes regulation less of a pure cost-plus contract.[2]

Management Audits

Management audits are another way a state PUC can monitor utility expenses. The data gathered in a management audit can be used in future rate case proceedings and PGAs. If management audits are performed prospectively, they also can deter future inefficient operation and management.

Depending on the level of scrutiny, a management audit may be considered an undue intrusion by a state PUC into LDC management. The audit itself may add to the utility's cost of keeping records and the regulator's cost of oversight. Thus, while the management audit may be a good tool to gain information on the utility's operation and management that would have been unavailable in rate-case proceedings and PGAs,

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[2] Paul L. Joskow and Richard Schmalensee, “Incentive Regulation for Electric Utilities,” *Yale Journal on Regulation,* 4 no. 1 (Fall 1986): 1 – 14.

the additional cost and potential for intrusion into management prerogatives may make this option unattractive.

Least-Cost Purchasing

Many state commissions formally require LDCs to buy gas from least expensive sources consistent with providing reliable service. Other state commissions use least-cost requirements through review of gas supply plans and preapproval of gas purchase plans.[3] Least-cost purchasing requirements may also be used as standards in rate case proceedings, PGA hearings, and prudence reviews.

Least-cost purchasing requirements represent perhaps the most visible regulatory response to the post-NGPA development of competitive gas markets. The new flexibility of gas purchase options resulting from the FERC actions and the evolution of a competitive market caused state regulators to more closely scrutinize the gas purchase practices of LDCs and to set up standards by which the scrutiny is to be carried out.

Depending on the efficacy with which utility operating data and market information can be evaluated, least-cost purchasing requirements can be an effective tool in encouraging efficient purchase practices. Its effectiveness, by the same token, is limited by regulators' access to information. To meet the least-cost standard, the LDC often has to present volumes of data and computer-generated output which may be difficult to evaluate. Like the other regulatory devices discussed earlier, its effect on the efficiency of an LDCs gas purchase practices may be mixed.

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[3] C. A. Goldman and M. E. Hopkins, *Survey and Analysis of State Regulator Activities on Least-Cost Planning for Gas Utilities* (Berkeley, CA: Lawrence Berkele Laboratory and Washington, D.C.: National Association of Regulatory Utility Commissioners, 1991).

General Incentive Problems with Traditional Cost-Pius Regulation

The economics literature on regulation identifies several incentive problems with traditional cost-plus regulation. The problems may be generally classified under informational asymmetry, moral hazard, and adverse selection.[4]

Informational asymmetry refers to the fact that a utility generally has better access to information than a regulator. The regulator can only observe outcomes but has limited ability to observe utility actions and even less ability to observe factors that affect utility operations. The latter include consumer demand and costs of capital equipment and gas procurement. As discussed in earlier sections, such informational asymmetry can allow the utility to operate inefficiently without being detected by the regulator. As long as the utility can easily pass the costs it incurs on to the ratepayer, it has little incentive to bargain aggressively on procuring gas, employ potential technological improvements, or make management more efficient. Regardless of what regulatory procedure is adopted, as long as the procedure depends on the regulator's access to information, the regulator is at a disadvantage relative to the regulated utility.

Two consequences of informational asymmetry in combination with the risk-sharing attributes of traditional regulation are moral hazard and adverse selection. The facts that the utility's actions can only be observed imperfectly by the regulator and that the risks associated with the actions are shifted almost entirely to ratepayers through a cost-plus recovery arrangement, may induce the utility not to exercise the necessary diligence and prudence in its actions. This is known to economists as "moral hazard." Also, the regulatory arrangement may allow the utility to misrepresent its choices for actions or the merit of such choices. When the regulator approves the utility's actions based on misrepresented information, this may be construed as an adverse selection.

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[4] For definitions of informational asymmetry, moral hazard, and adverse selection, see Daniel F. Spulber, *Regulation and Markets* (Cambridge, MA: The MIT Press, 1989), 62-65. See also Joskow and Schmalensee, "Incentive Regulation for Electric Utilities," 16.

Informational asymmetry, moral hazard, and adverse selection are concepts initially developed to study the behavior of various parties in the insurance business and are idealizations that only imperfectly reflect real world conditions. By improving the quality of data gathering on its potential subscribers and the design of insurance contracts, an insurance company can at least partially mitigate the harm posed by the presence of these conditions. For example, the use of a deductible in an automobile insurance policy partially shifts the risk of an accident from the insurer to the insured and, in addition, provides an incentive to the insured to exercise adequate care (and thus counter moral hazard) in operating a vehicle. In public utility regulation, the requirement to submit detailed information in regulatory proceedings, the close scrutiny of utility operations, the risk of disallowances, and regulatory lag can mitigate to some extent the adverse effects of informational asymmetry on utility efficiency. They cannot be completely eliminated. Regulators would need to persistently pursue policies that address the presence of conditions that may allow inefficient behavior on the part of utilities. Informational asymmetry, moral hazard, and adverse selection are conceptual constructs that provide a powerful framework for studying utility behavior and help regulators develop incentive-compatible policies.

The Argument for Incentive Regulation

The problems of either weak or conflicting incentives for a utility to perform efficiently under traditional regulation underscore a need for exploring other regulatory options. The need has grown in the last decade as the wholesale and retail market for gas has become more competitive, transportation has become significantly unbundled from sales, and new opportunities have developed for both the LDC and its customers to procure gas from many different sources at competitive prices. Whether these opportunities reflect real and workable competitive conditions in the various unregulated gas service markets may be important in determining both the need for incentive regulation and its expected effectiveness. For example, if a pipeline can exercise market power over gas sales by exploiting its monopoly over gas transmission, it may limit the LDC's ability to shop "aggressively" for sales gas in the wellhead market. Chapter 2 examined these opportunities and concluded that the degree of competition that has evolved in various gas service markets makes it imperative that the LDC be provided incentives to bargain more aggressively for the cheapest source of gas while meeting reliability requirements.

Two basic approaches can be developed to address the problem of improving incentives for LDC cost minimization. The first approach uses an incremental strategy where the elements of scrutiny and oversight contained in traditional regulation are retained, but are supplemented with market-based incentives to promote more efficient utility operation. Such an approach may also require either weakening or strengthening of one or more traditional oversight procedures. The second approach uses more nontraditional options in which the regulator relaxes the oversight requirements significantly and relies heavily on market forces to induce efficient utility behavior. The first approach supplements incentive options to traditional regulation while the second essentially replaces it. Both approaches must address the problem of providing reliable and reasonably priced gas service to core customers, who are essentially captive and whose needs cannot be left entirely to the vagaries of the market place. The following sections examine the incremental options first. The nontraditional options are examined second.

Incentive Regulation: Incremental Options

To examine incremental options, it is helpful to study each element of cost incurred by an LDC in providing gas service. The total gas service cost can be divided into gas purchase, transportation, storage, and other non-gas costs. The LDC attempts to minimize its costs when given proper incentives. Within each category of costs are subcategories. For example, the gas costs consists of both the costs of long-term and other firm contracts with pipelines and producers, and spot purchases from markets. The LDC can attempt to minimize a given category or subcategory of gas costs. It should be recognized, however, that the various cost components may not be independent of each other. For example, a long-term contract may have a high demand rate and a low commodity rate, while a spot contract has no demand rate but a high commodity rate. It may not be economically optimal to minimize either long-term contract costs or spot-purchase costs individually. This is because the optimal mix depends on demand parameters such as peak demand and annual volume demand, and supply parameters such as the maximum delivery per day each firm supplier can guarantee and the total volume each spot supplier is able to deliver. Further, there exist tradeoffs between buying or leasing storage services and purchasing supply security through firm contracts.

Given the various dependencies, it may be too complex to construct an incentive design that incorporates all or most of these tradeoffs. It is especially difficult to achieve such a design in an incremental option because such an option, for its effectiveness, depends on accurate and reliable information on cost and demand data. Some of the information is subject to uncertainties and neither the utility nor the regulator can have any controllable access to it. There are other categories of information to which the utility has better access than the regulator. Both the uncertainty that characterizes certain categories of information (for example, future fuel prices and consumer demand) and the informational advantage enjoyed by the utility over the regulator render the design of a comprehensive incentive option based on traditional regulatory principles extremely difficult. A preferable approach may be to attempt incentive designs that incorporate the more important cost components when the goal is to strengthen the incentives already present in traditional regulation. Several such designs, under the generic scheme of cost indexing, are discussed next.

Gas Cost Indexing Schemes

Among the various components of an LDCs operating expenses, gas purchase costs have perhaps the most potential for efficiency improvements because of the flexibility of gas procurement options. Presumably, gas in most locations is bought and sold in a workably compettive wholesale market with many buyers and sellers. The cost of gas purchase can be minimized if the LDC engages in aggressive bargaining with pipelines, producers, and spot suppliers to obtain the lowest achievable prices and combines the various supply sources in an optimal portfolio. At the same time, the LDC also needs to ensure reliability of supply and price stability for which premiums may have to be paid. The LDC also can minimize these premiums through effective bargaining of the nonprice terms of its purchase contracts.

State commission oversight of the LDCs gas purchases varies from strict scrutiny of individual contracts and management audits to holding rate case and PGA hearings, which require relatively lower levels of scrutiny. It is generally difficult for a state commission to determine whether an LDC purchase portfolio is optimal. Usually, the LDC is required to submit its own analysis of its proposed portfolio and show that it is optimal. The state commission can review the methods and data used in the analysis and make a determination of their adequacy. Regardless of the level of scrutiny used by a state commission to oversee LDC purchase practices, the informational advantage of the LDC can influence the effectiveness of the oversight. Also, the higher the level of scrutiny, the more burdensome the reporting requirements and related regulatory and utility costs. As examined below, some incremental incentive options have the potential to reduce oversight requirements and related costs and yet achieve the objective of minimizing gas purchase costs while ensuring reliability requirements. The suggested option is designed to set base rates, but has broader applications that can be used to design PGAs.[5]

This option establishes a target cost and allocates rewards and penalties based on deviations from the target. Both the target cost (or a formula for updating the target cost) and the sharing fraction (the fraction of the reward or the penalty to be shared between the ratepayers and investors) are established ex ante. This provides the utility with an incentive to exceed the target by minimizing its gas costs. The sharing mechanism ensures that a part of the cost savings flows through to the ratepayer and that any losses suffered are not entirely borne by the ratepayer.

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[5] For a discussion of designing incentive-based PGAs, see Robert E. Burns, Mark Eifert, and Peter A. Nagler, *Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, December 1991).

The general method can be written as

$$C = C_t + g(C_a - C_t) , \tag{3-1}$$

where

- C_t: a target or benchmark for the gas purchase costs to be established ex-ante
- C_a: actual gas purchase costs
- C : gas purchase costs to be passed through to ratepayers
- g : fraction of deviation from the target cost to be passed through to the ratepayers (also known as the "sharing fraction").

There are three theoretical issues in designing an incentive scheme that uses this sharing mechanism. First, one needs to establish a method by which the target cost will be determined. Second, one needs to choose a sharing fraction. Third, one needs to decide the rate cycle or period in which the mechanism is operative. The choice of each of the three parameters can influence the effectiveness of the incentive option.

Establishing a Benchmark Cost

There are several ways of establishing a benchmark cost. The most obvious is to let the LDC forecast gas cost. This has the advantage of ensuring that the LDC has no persuasive reason to contest the established benchmark cost on technical grounds later in a rate hearing. The main disadvantage is that the LDC will have an automatic bias to overestimate the benchmark. The disadvantage can be alleviated somewhat by commission review and a full hearing where the method and data used to arrive at the forecast can be challenged and scrutinized. This part of the regulatory proceeding would be quite similar to a rate hearing that uses a future test year. To establish a benchmark cost that is relatively free from the utility's own biases, the regulator would have to obtain independent estimates of several parameters. They are benchmark prices of spot and firm contracts, a target mix of gas supply sources and a demand forecast. The process and methods of estimating a benchmark cost are shown in Figure 3-1.

Spot Prices

Three different methods may be suggested to establish a benchmark price for spot contracts based on actual spot prices, a forecast of future spot prices, and futures prices. Among the three, actual spot prices is the simplest method to implement as it requires no complex estimation procedure and is not subject to controversy. The method based on a forecast of future prices is perhaps the most difficult to implement given the complexity of forecasting techniques and the uncertainty and controversy surrounding the results of forecasts. However, a benchmark price based on a forecast rather than actual spot prices may offer more flexibility to an LDC in designing and implementing a gas supply portfolio. A benchmark price of spot gas based on a forecast rather than actual price would result in a broader "dead band" in the benchmark cost. This would allow the LDC greater flexibility in its gas purchase decisions. Finally, a method based on futures prices offers a compromise between the other two methods. It avoids the difficulty of developing a forecast while providing a reasonable prediction of future prices of gas based on the expectations of market participants. However, the method still may be more controversial than the use of actual spot prices.

The method based on actual spot prices requires no further explanation. The methods based on the forecasts of future spot prices and on the futures prices are discussed next.

The current average price and a price escalator can be used to establish future spot prices. Three different average prices can be used as the base price. It can be the average of the spot contracts on a given LDCs portfolio, that of all the LDCs under the commission’s jurisdiction, or the regional average price. Each measure of the average has advantages and disadvantages. The LDC-specific base price takes into account size and supply characteristic limitations. For example, a small LDC is unlikely to get quantity discounts on spot gas that are available to larger LDC’s.

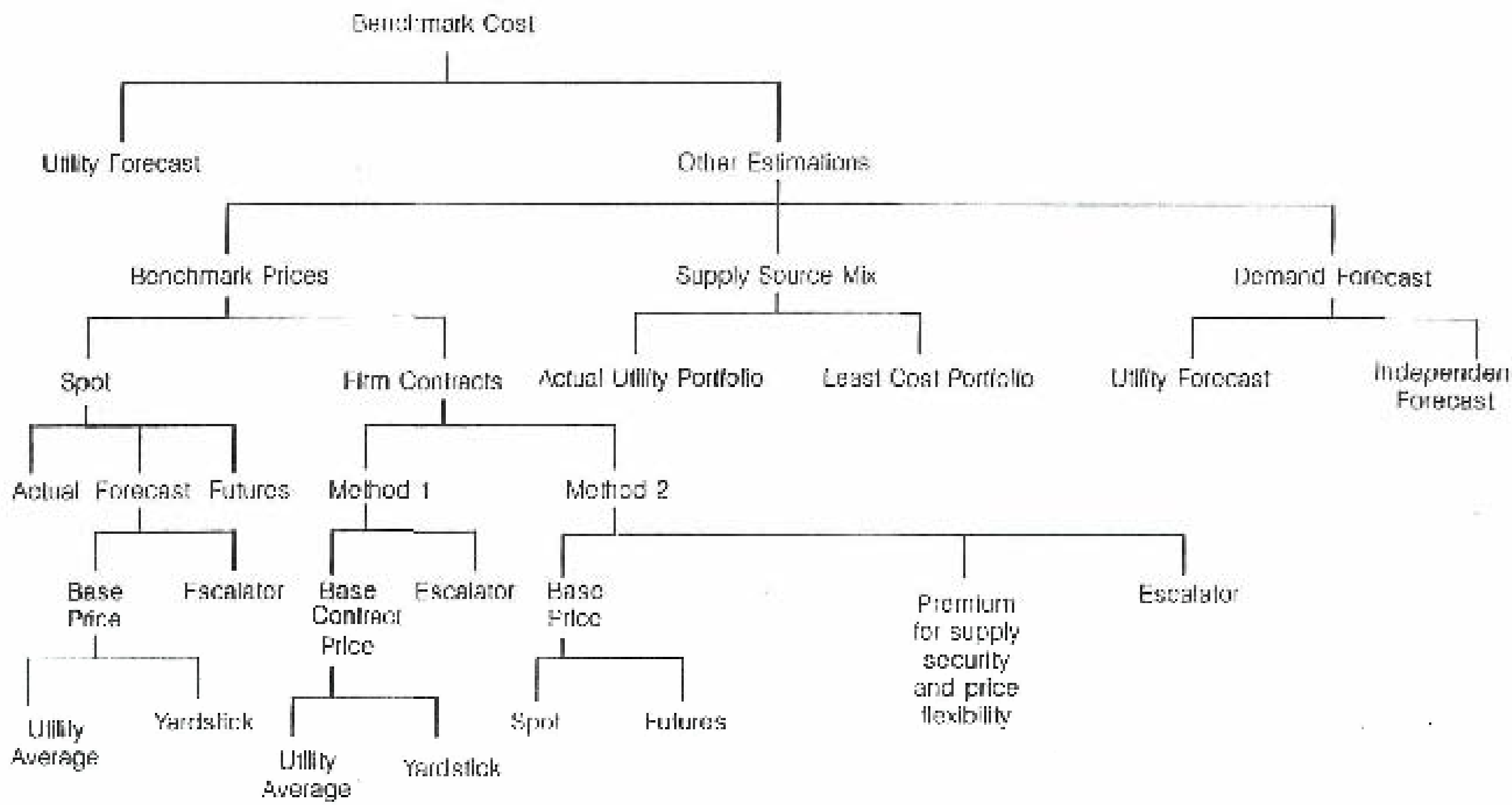

Fig. 3-1. Various methods of estimating the benchmark cost in a gas cost-indexing scheme.

Tying the base price to the purchase prices of LDCs with diverse size characteristics would unduly penalize relatively smaller LDCs and reward larger LDCs. If the LDCs are roughly similar in size and other supply characteristics, however, the yardstick approach proposed here may be useful. The yardstick approach can be further extended to include all LDCs in a given region if the prior criteria of similar size and operation generally hold. The larger the domain used to develop an average spot price, the more diverse the benchmark base price from the LDCs own purchase price and, thus, the stronger the incentive to minimize costs. Besides the base price, a price escalator is needed. It can either be the consumer price index (CPI) or a factor that reflects the actual change in average spot prices over time.

A third way to establish a benchmark price would be to use futures prices of gas. Futures markets, when they are efficient, perform a price discovery function. While at this time it is too early to judge whether the gas futures market is operating efficiently, it appears there are no known market barriers that potentially can prevent it from doing so. A benchmark based on the futures market has the advantage of not requiring extensive analysis either by the utility or the state commission to estimate it.

One concern is often expressed against using the futures price as an index for spot price. It is the so-called convergence problem: the fact that futures prices at maturity do not converge to spot prices. The convergence problem is suspected to be caused by the fact that there is a six-day lag between the closure of a futures contract and its maturity date. The lag is an unavoidable administrative necessity. The convergence problem can be addressed by doing a trending analysis of futures and spot prices and establishing an average lag parameter for each month. The parameter then can be used to adjust futures prices to monthly benchmark prices. A simpler method would be to use the running average of futures prices in two consecutive months as the monthly benchmark price.

Contract Prices

Two general methods may be suggested to develop a benchmark contract price. The first method would use either a spot price or a futures price as the base price, derive an estimate of the premium for supply security and price flexibility to be added to the base price, and apply a price escalator to the sum to establish the benchmark contract price. The second method would estimate a base contract price (which already includes the premium) based on either the utility average or a yardstick contract price to be adjusted over time by a price escalator to establish a benchmark price. These methods are explained in more detail in the following sections.

The price of gas in a long-term contract can be assumed to depend on several variables. One key variable is the spot price of gas and others relate to the nonprice terms of the contract, including contract clauses that specify price escalators, minimum take, take-or-pay, market-out, and price renegotiation provisions. Henderson and others found that the contract price depends most strongly on spot prices.[6] The dependence of the contract price on the nonprice terms was somewhat ambiguous, including the counterintuitive result that the presence of take-or-pay actually increased the contract price. The authors explained that the discrepancies may be due to the collinearity that may exist among the variables. They proposed a method based on data envelopment analysis (DEA) in which the number of independent variables was reduced to three. They are the spot price and two indices indicating relative flexibility of price and quantity adjustments. Using DEA, one can identify the optimal contracts as a function of the three variables.

While the DEA was proposed to evaluate contracts, it also suggests ways in which one can estimate benchmark prices for contracts. For example, a state commission can perform a DEA analysis of past contracts of LDCs in its jurisdiction, establish a benchmark contract with "average" or "high" flexibility of price and quantity adjustments, and obtain the corresponding difference between the spot and the benchmark contract prices as the benchmark premium. Future benchmark price for contract gas can now be developed as the spot price with an adjustment for inflation, and premiums for supply security and price flexibility. For the base price, futures instead of spot prices also can be used. To ensure that reliability of supply is not compromised, a commission can require

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[6] J. Stephen Henderson et al., *Natural Gas Producer-Distributor Contracts: State Regulatory Issues and Approaches* (Columbus, OH: The National Regulatory Research Institute, January 1988).

that quantity adjustment and guaranteed supply provisions of each contract at the minimum satisfy those of the benchmark contract. The reliability requirement can further be strengthened by choosing a benchmark contract with the highest quantity adjustment provisions.

Another method to establish a benchmark contract price is similar to that suggested earlier for a benchmark spot price. This method would use the average of firm contracts in an LDCs portfolio or that of all the LDCs under a state commission's jurisdiction. In deciding between an LDC-specific or a yardstick base price, all the considerations already discussed for benchmark spot price apply. If the LDCs under a commission's jurisdiction are comparable in size and supply characteristics, a yardstick approach would be preferred. Otherwise, an LDC-specific base price would be more appropriate. As in the previous methods, the benchmark price can be estimated by adjusting the base price by a price escalator to account for changes in price over time.

Target Supply Source Mix

Besides benchmark prices for spot and firm contracts, a target supply source mix is needed to estimate the benchmark cost. The specified mix can be the same as the gas supply portfolio used in the last rate period or an optimal portfolio independently estimated by the commission. The simplest design of the indexing scheme would use one average price for all spot gas and another average price for all firm contract gas. However, spot and firm contracts can be divided into groups and benchmark prices can be estimated for each member of a group using methods suggested.

Demand Forecasts

The last item needed to estimate a benchmark cost is a demand forecast. Again, the utility ma be allowed to make its own forecase. This has the problem that the utility may have a bias to overforecast demand. However, demand forecasts (unlike price forecasts) may be easier to evaluate because they depend more exclusively on the economic factors obtaining in an LDCs service area and less on regional, national, or international factors. An LDC is unlikely to make a forecast that is blatantly inaccurate as it can be verified against historical trends. If there are concerns about using the LDCs own forecast, the state commission can use an independent forecast.

Development of a "Dead Band"

The analysis underlying price and demand predictions will also provide estimates of errors that can then be used to develop an error range for the benchmark cost. The error range can be used as a basis to develop a "dead band" for the incentive plan. The dead band may be broader than the error range. The dead band is needed to account for uncertainties associated with estimating the benchmark cost. If the purchased gas costs fall within the band, no rewards or penalties are given; if costs go above the range, the utility shares the losses with ratepayers; if costs fall below the band, the utility shares the gains with the ratepayers.

Choosing a Sharing Fraction

The effectiveness of an incentive plan also depends on how the sharing fraction is chosen. If a utility is assigned a higher fraction of gains and losses (that is, a lower value for "g" in equation (3-1)), risk is shifted away from the ratepayer to the utility. This provides a stronger incentive for the LDC to minimize costs but affords fewer benefits to the ratepayer resulting from the efficiency improvement. The primary objective of incentive regulation is to minimize rates and revenues through minimization of utility costs. If minimization of utility costs does not translate into significant reduction of both revenue requirements and rates to the customers, the original purpose of incentive regulation has been defeated. As an extreme example, if the utility were made entirely responsible for all gains and losses, the incentive plan has served no reasonable purpose since the customers have not gained anything. The opposing alternative is to assign a higher sharing fraction (a higher "g") of risk to ratepayers. This would provide a significantly larger potential for gain by customers from efficiency improvements but, at the same time, would weaken the incentive of the utility to make such improvements. If minimizing ratepayer rates is assumed to be the primary purpose of incentive regulation, obviously there is a tradeoff between choosing a larger and a smaller sharing fraction.

Another important purpose generally held to be true of all regulation is keeping the utility financially viable, a goal that needs to be preserved in the long-term interest in the availability of utility services. Placing a large part of utility earnings at risk jeopardizes the financial viability of the utility and thus argues against such an option. So the tradeoff between larger and smaller sharing fractions is not limited to finding which option maximizes consumer welfare but also includes the issue of the utility's financial viability. Overall, a larger sharing fraction of risk imposed on ratepayers (>0.5) may be the preferred option. The optimal fraction is difficult to establish precisely. Fractions such as 0.9 and 0.8 seem reasonable and have been used in some incentive options already in practice.[7]

Establishing a Rate Period

As mentioned earlier, the rate period is an important parameter in inducing efficient utility behavior. The fact that all costs cannot be immediately recovered forces the utility to minimize its costs until the rate-adjustment period. But a rate period which is too long may put the utility's financial viability at risk or allow the utility to make windfall profits if the price and cost fluctuations are persistently out of alignment with cost recovery. Regulatory lag also may distort price signals and lead to inefficient

[7] The New York Public Service Commission allows electric utilities to retain 20 percent of the difference between projected and actual fuel and purchased power costs. Currently, Wyoming state statutes allow gas distributors up to 10 percent on reduction in gas costs.

consumption and investment decisions.[8] Ultimately, the regulatory lag may be governed by administrative constraints. There is no known and generally acceptable method to design an optimal rate period.

Nontraditional Options

Price Caps

Background

Criticisms of rate-of-return (ROR) regulation bring to the forefront such institutional arrangements as price-cap regulation. Generically, price-cap regulation refers to a mechanism whereby prices for specified utility services are permitted to change without a formal rate review. Price changes are constrained by indices reflecting cost changes for some economic unit more broadly based than an individual utility. Utility services falling under price-cap regulation can include all services, specific unbundled services, or services to particular groups of customers.

Although price caps for the telecommunications industry have received the most attention, they recently are being considered for the electric and natural gas industries.[9] A major reason is that both industries are undergoing significant changes toward greater reliance on market forces. Supporters of price-cap regulation argue that the rigidity of ROR regulation makes it ill-suited to cope with the fundamental changes taking place. Specifically, they point to the incompatibility between ROR regulation and its application to industries where competitive conditions have penetrated some markets.

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[8] Burns et al., *Current PGA and FAC Practices*, 206-211.

[9] For examples of how price-cap regulation can be applied to the energy industries, see Benjamin J. Ewers, Jr. and William D. Musolf, "Competitive Regulation: A New View of an Old Idea," *Public Utilities Fortnightly* (April 15, 1991): 32-35; Mark Newton Lowry, "The Case for Indexed Price Caps for U.S. Electric Utilities," *The Electricity Journal* (October 1991): 30-37; and Thomas P. Lyon and Michael A. Toman, "Designing Price Caps for Gas Distribution Systems," *Journal of Regulatory Economics*, 3 no. 1 (June 1991): 175-92.

Proponents argue that price-cap regulation has the ability to improve both pricing and productive efficiency. Pricing efficiency improves whenever firms have more flexibility to change their prices in line with market conditions. For example, an LDC could more easily serve customers at a cost lower than competing suppliers when it can change prices as low as its marginal costs. Large inefficiencies can exist when, under competitive conditions in some of its markets, a regulated firm is unable to vary its price to retain existing customers or attract new ones.

Price caps also are supposed to improve the incentive of a firm to control its operating costs and to innovate new production techniques. By severing the link between the price that a firm can charge and its actual costs, price caps allow a firm to profit permanently, or at least for a longer period of time than under ROR regulation, from efforts to reduce costs.

A last alleged benefit of price caps is that they reduce administrative costs both to regulators and stakeholders in the regulatory process. One perception is that price caps would spread out the number of rate reviews over time, with the different stakeholders expending less resources as a consequence.

Whether price-cap regulation of LDCs would yield these benefits is not certain. Before addressing this issue, one must know how price caps would be applied. For example, how would initial prices be set and price adjustments made? What services would be covered, and how often should formal rate reviews be conducted?

Candidates for initial prices include current prices and what economists call stand-alone prices.[10] Current prices have the advantage of previously passing rate-case scrutiny as being acceptable in terms of equity and allowing the firm a reasonable opportunity to be financially viable. Stand-alone prices, theoretically, are more appealing but are based on hypothetical conditions susceptible to rebuttal at rate proceedings.

Under a typical price-cap regime, annual price changes would represent the difference between a selected price index and productivity index. Both indices (for example, the Consumer Price Index and total factor productivity) in theory

[10] A stand-alone price can represent the lowest-cost alternative to a customer of getting services from other than the LDC.

should not reflect cost movements for an individual firm, but instead reflect cost movements for the industry as a whole.[11] The rationale is that a firm should earn surplus profits whenever its costs increase by less than the costs for the average firm in the industry; this is essentially how competitive firms are able to earn above-normal profits. Some analysts advocate omitting a productivity offset during the initial period of a price-cap regime. That is, a firm would keep all productivity increases until the beginning of the next rate review. In addition to giving a firm maximum incentive for productivity growth, a zero offset has the advantage of reducing the scope of rate reviews. Such an offset can be more justified for an industry such as gas distribution where the technology will likely change little over the next several years.

Choosing the services to be covered by price caps is important in affecting efficiency and equity outcomes. At one extreme, when all services are subject to price caps, pricing-efficiency objectives may be best achieved (assuming no cross-subsidization of competitive services by monopoly services), but at the same time, price discrimination potentially would be most pronounced. Under certain circumstances, price caps over time would converge to Ramsey prices.[12] For many situations a preferable procedure at least on equity grounds would be to apply a price cap to monopoly services only. So-called core customers would be protected from having to pay higher prices because of revenue "shortages" earned by firms in more competitive markets. Shortages can arise because of more competitors and from predatory practices (where the regulated firm would lower prices for competitive services below cost and

[11] Changing prices on the basis of costs and sales forecasts for an individual LDC, in contrast, means that it would earn surplus profits for any reason that causes sales to be higher than predicted or costs to be lower than predicted.

[12] See Ingo Vogelsang, *Price Cap Regulation of Telecommunications Services: A Long-Run Approach*, Rand Note N-2704-MF (Santa Monica, CA: The Rand Corporation, February 1988). Ramsey prices attempt to maximize consumer welfare by setting prices for different services and classes of customers inversely proportional to the respective price elasticities of demand. Ramsey prices would discriminate against core customers by allowing an LDC to earn higher profit margins on services provided to core customers.

charge higher prices for core services).[13] If the objective of regulators is to give a firm maximum pricing flexibility in competitive markets while protecting customers in other markets, restricting price caps to core markets seems the best approach. For LDCs, this means that only residential and other core customers would fall under price caps. Because these customers have little opportunity to switch to competitive alternatives, LDCs would have no incentive to charge less than the determined cap. Noncore customers could still be protected by regulation of gas transportation services. As noted later in this report, a good argument can be made for deregulating gas sales to noncore customers.[14]

The frequency of formal rate reviews under price caps affects the incentive of a firm to carry out cost-reducing activities. For example, if formal rate reviews occur any time a firm earns below or above a prespecified rate of return, the firm would have similar incentives to control costs as under ROR regulation. At one extreme, all price changes could be subject to the price-cap formula with no subsequent rate review. This arrangement coincides most closely with the concept of pure price-cap regulation, where the firm would have maximum incentives to control its costs; it imposes risks on regulators, however, in that the firm conceivably could earn exorbitant profits or encounter financial disaster. Historically, regulators have tried to prevent either outcome as part of their objective to serve the public interest.[15] It seems highly likely then that the long-term reliability of any price-cap regime requires that some element of ROR regulation be retained as a safety valve.

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[13] This assumes that core prices were previously below the level where the firm maximizes its profits.

[14] As discussed later, the argument centers on whether services that possess no natural monopoly characteristics should fall under price regulation, especially when consumers can switch to other suppliers or services at low transaction costs.

[15] Preventing these outcomes is consistent with the so-called social contract, whereby it appears that major goals of regulators include preventing a firm from earning "exorbitant" profits when times are favorable and from suffering large financial losses when times are unfavorable.

Observations

Before illustrating price-cap regulation of LDCs, some general observations should be made. First, the effect of price caps on improving the production efficiency (that is, the cost-saving activities) of LDCs in the long term may be small compared to, for example, the telecommunications firms. Opportunities for LDCs to use new technologies are constrained by their availability and the maturity of current technologies.[16] While price caps may have an effect on accelerating technological improvements, their greatest potential seems to lie with enhancing pricing and operating efficiencies. Under price caps, LDCs would be able to offer noncore customers prices for particular services that are in line with market conditions and the unique situations of individual customers.[17] Price caps also can provide LDCs with the correct incentive to purchase different sources of gas supplies. For example, LDCs would have an incentive to purchase the cost-minimizing mix of contract and spot-market gas supplies, subject to the constraints of regulatory and market service obligations.

Second, contrary to the arguments of advocates, price caps may not reduce the administrative costs associated with rate case filings. One argument for price caps centers on the presumption that because they would require fewer rate cases, regulators' budgets and the costs expended by regulated firms and intervenors to justify and rebut proposed rate changes would fall. While fewer rate cases over time may occur, it does not necessarily follow that groups would spend less money to draw regulators to their positions. Since the stakes would be the same, the different stakeholders (regulated firms, consumers, other intervenors, and commission staff) would be expected to expend about the same amount of effort in making their arguments before regulators. While arguments over cost of service and rate design would lessen (although even under price

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[16] This does not imply that LDC's will not adopt new technologies, but only that if they do, productivity improvements, at most, would be moderate.

[17] Price caps, for example, would lead to more contracting of services between the LDC and individual customers. An advanced stage of flexible pricing occurs when contracts increasingly replace tariffs as the dominant pricing mechanism.

caps they cannot be completely avoided), parties would debate new issues such as "trueing up" profits and what productivity offsets should be.[18]

Third, price caps, as well as other nontraditional regulatory procedures, should be premised on evidence of current inefficiencies in the distribution of natural gas. State regulators have recognized that a status-quo posture may maintain inefficiencies in an industry where radical and dynamic changes are taking place.[19] Regulators have responded in various ways over the last several years to these changes, allowing LDCs more flexibility in rate designs, especially to noncore customers.[20] Most states now require LDCs to offer transportation service to noncore customers.[21] Realizing that LDCs have more options and that the Federal Energy Regulatory Commission (FERC) has less authority, state regulators have assumed a more active role in overseeing gas purchases by LDCs. For example, they have resorted increasingly to advance review-approval of LDCs gas procurement plans under the name of "best-cost" planning. Regulators generally have favored a cooperative environment where LDC management

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[18] For example, if cost-of-service rates are calculated at the time of a formal rate review, stakeholders would debate how common costs should be allocated to different classes of customers and services. For evidence of higher administrative costs under the price-cap regime instituted by the Federal Communications Commission for the American Telephone and Telegraph long-distance rates, see Raymond W. Lawton, "The Impact of Price Caps on the Direct Cost of Regulation," *NRRI Quarterly Bulletin*, 12 no. 3 (September 1991): 345-56.

[19] These inefficiencies supposedly stem from pricing inflexibility and the lack of strong incentives for LDCs to operate and plan for their system in a least-cost fashion. For a discussion of current inefficiencies in the gas distribution industry, see Lyon and Toman,"Designing Price Caps," 175-92.

[20] One reason for more flexible rates design is the threat of bypass. Bypass has threatened LDCs in thirty-eight states. Most companies have successfully coped with bypass threats by offering unbundled transportation service.

[21] Robert E. Burns, Daniel J. Duann, and Peter A. Nagler, *State Gas Transportation Policies: An Evaluation of Approaches* (Columbus, OH: The National Regulatory Research Institute, 1989).

is given wide discretion, but also is made more responsible for its decisions and actual outcomes of its plans.[22]

Whether these recent actions by state regulators reflect steps in the right direction and satisfactory responses can be debated. In line with price-cap advocates, state regulators have acknowledged that "business-as-usual" represents an inadvisable alternative. Where the two groups may disagree lies with what steps should now be taken given that changes in the modus operandi are inevitable. Whether price caps or other proposals would improve the state of affairs in accommodating the forces of competitors in the natural gas industry constitutes a fundamental question.

Lastly, a pure price-cap regime, where future price ceilings are unaffected by profits earned in earlier periods, would unlikely be practical. No matter how well structured, a price-cap formula will likely produce profits during some periods unacceptable to regulators. If, for example, the firm earns surplus profits, regulators, as well as consumers, will inevitably petition for changes in the formula (for example, by incorporating a larger productivity offset). Any revision in the price-cap formula would redirect a firm's incentive to control costs toward that given to firms under rate-of-return regulation. The threat of such change would, therefore, mitigate the effectiveness of price-cap regulation as a socially desirable regulatory mechanism.[23]

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[22] See, for example, Interstate Natural Gas Association of America, *State Prudence Policies: Regulating the Gas Purchasing Practices of Local Distribution Companies* Research Report 8811 (Washington DC: Interstate Natural Gas Association of America, December, 1988).

[23] For evidence of retrospectivce price-gap revisions resulting from unacceptable profits, see Raymond W. Lawton, “Factors Affecting the Continuation of Price Indexing Systems for Regulated Utilities: An Examination of Four Historical Instances of Indexing,” *NRRI Quarterly Bulletin*, 12 no. 1 (March 1991): 5 – 31.

The Lyon-Toman Proposal

Lyon and Toman propose a price-cap regime for LDCs.[24] Under their proposal an LDC would unbundle transportation costs from the other costs incurred by an LDC to serve retail customers. Price caps would apply to firm transportation services, with commodity charges (variable operating costs) and demand charges (capital, maintenance, depreciation, and return on investment) each constrained by price ceilings. Interruptible transportation service would be deregulated, with a share of profits earned redistributed to customers at the next rate review.

The authors propose to constrain, initially, an LDCs total revenues at the cost-of-service level. Cost-of-service revenues supposedly satisfy current equity principles and an LDCs financial needs. Between five-year rate reviews a specified price index would impose limits on changes in overall rates. The price index combines the Consumer Price Index, an index reflecting the average change in financial costs for the gas distribution industry, and an index reflecting changes in variable transportation costs. The proposal excludes a productivity offset; the authors reason that actual productivity growth would be small and a zero offset would provide an LDC with the maximum incentive to operate efficiently its existing distribution system.

The proposal attempts to handle the "trueing-up" problem by redistributing a share of surplus profits earned in prior periods: the recalibrated required revenues for the start of the next period (measured as the revenues received by the LDC in the most recent period) would be adjusted downward by a prespecified share of the surplus profits earned by the LDC since the last rate review.[25] Arguably, the outcome would correspond to

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[24] Lyon and Toman, "Designing Price Caps," 175-92. The authors argue that price caps are simple to implement and they should improve both pricing and productive efficiencies for LDCs.

[25] The mechanism follows what can be called a modified Vogelsang-Finsinger (V-F) mechanism, whereby revenue constraints determined at the time of a rate review are adjusted downward to account for surplus profits that the firm may have earned since the last rate review. The modified V-F mechanisms also was proposed in Lorenzo Brown, Michael A. Einhorn, and Ingo Vogelsang, *Incentive Regulation: A Research Proposal*, prepared for the Office of Economic Policy, Federal Energy Regulatory Commission, 89-3 (Washington, D.C.: Federal Energy Regulatory Commission, November, 1989).

what is called retroactive ratemaking. To illustrate, assume that an LDC earned $10 million of surplus profits (discounted to the date of the last rate review) and its regulator stipulated that 80 percent of surplus profits are to be returned to customers; customers would receive lower rates until the next rate review that correspond to an $8 million "loss" in revenues for the LDC. Under this profit-sharing mechanism, according to the authors, an LDC would have an incentive to control costs because of regulatory lag and permanent retention of a share of the profits; at the same time, customers would share in the benefits of cost-saving activities by the LDC.

The authors offer different options for an LDC to recover its gas supply costs. They propose not to incorporate gas-supply functions into the price-cap formula. For noncore markets they recommend deregulation, arguing that customers have opportunities to purchase gas and substitutable energy supplies from various sources (which assumes that the LDC provides equal transportation access to natural gas purchased from third parties).

The authors present different regulatory options for the cost recovery of gas supplies to core markets. As they recognize, the objective is to give LDCs an incentive to purchase least-cost gas supplies. Although the authors consider cost indexing as the most promising, none of their four proposals is highly recommended. (The four include prudence review, deregulation, use of a future test year, and cost indexing.)

Other Illustrations

A Price-Cap Example

An alternative price-cap mechanism would dichotomize an LDCs market into core and noncore components.[26] Price ceiling would fall on transportation services as noncore customers and bundled services to core customers. It is assumed that LDCs would

[26] It should be noted that the price-cap example is presented here for illustrative purposes only and does not reflect a recommendation by the authors.

continue to have market power in the provision of these services. (Table 3-1 lists the major features of the price-cap example.) Gas supplies to noncore customers would be deregulated, with the LDC allowed to compete only through an unregulated subsidiary.

Under this mechanism an LDC would have the flexibility to vary its price for different transportation services to noncore customers and different bundled services to core customers. Core customers would be protected from revenue losses that an LDC may experience with competition in its noncore market. Under current regulation, when an LDC is required by market pressures to sell services at low cost to noncore customers, it could attempt to compensate for the "low" revenues by increasing prices to core customers. As a significant benefit, the price-cap mechanism would sever the linkage between core and noncore customers. This mitigates against possible predatory pricing and forms of price discrimination that could severely hurt core customers. By definition, core customers cannot easily switch gas suppliers or forms of energy; thus, it may be argued that price elasticities of demand for core customers would fall within a narrow range. Price discrimination should therefore not constitute a major problem, as LDCs would infrequently find it profitable to charge lower prices to some core customers and higher ones to others for the same services.

A three-year rate review is premised on the price-cap formula incorporating a zero productivity offset.[27] A defense for a zero offset is that productivity indexes for LDCs have been rarely, if at all, measured. As a further argument, as stated above, it is expected that productivity growth for LDCs will be small in the foreseeable future.

With a zero productivity offset the LDC would retain the benefits of any productivity gains until the next rate review. At that time, a determination would be made on sharing the surplus profits earned since the last rate review between

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[27] A nonzero productivity offset implies that some portion of productivity gains will benefit consumers between the current rate review and the subsequent one. Thus, a longer interval between rate reviews can be required to produce the same benefits to customers in present-value terms when there exists no productivity offset.

TABLE 3-1

PRICE-CAP EXAMPLE

Dichotomy of Markets

Core Market:	Price ceiling on bundled services
Noncore Market:	Deregulation of gas supplies
	Price ceiling on firm transportation services

Features

1. 3-year rate review
2. Price adjustment between rate reviews on basis of constructed cost indexes
3. Ex ante sharing of actual profits
4. Base prices equal to current prices

Source: Authors' construct.

shareholders and ratepayers. In setting the sharing parameter, regulators would need to consider the conflict between achieving efficiency and equity objectives.

At one extreme, maximizing an LDCs incentive to control costs would require that all surplus profit be retained permanently by the LDC. Such a sharing arrangement, however, would mean that ratepayers receive no benefits (in addition to the fact that prices would be inefficient since they would be above marginal costs). At the other extreme, when an LDC has to reallocate all the gains from cost savings to ratepayers, it would have a weak incentive to engage in productivity and other activities that reduce its costs.[28] Many regulatory sharing arrangements for electric utilities allocate most of the benefits to ratepayers, where a 75 percent to 80 percent reallocation to ratepayers is not uncommon.[29] Returning a high share to ratepayers would still give LDCs incentive to control costs, since they would keep all gains until the next rate review and a portion of the gains permanently.

Price adjustments between rate reviews would be based on commission-determined cost indices. In principle, cost indices should reflect changes in average cost for the gas distribution industry. To the extent an LDCs average cost rises at a lower rate than the industry as a whole, the LDC should benefit by earning above-normal profits. In competitive industries when a firm performs better than other firms in the industry, it realizes economic profits at least until the other firms catch up. The price adjustment for bundled services (for example, gas supplies-transportation) should reflect increases in the average cost of separate services weighted by their cost share relative to total costs.

Under the example, base prices would be set equal to current prices. Current prices have previously satisfied regulatory objectives such as equity and maintenance of a firm's financial viability. Another candidate for base prices, stand-alone prices,

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[28] Its incentive would depend on the response of customers to lower process, which in turn rests on the availability and prices of substitutes for services provided by the LDC.

[29] See, for example, National Economic Research Association (NERA), *Comments of National Economic Research Associates, Inc.*, FERC Docket No. RM-85-17-000, Phase I, August 9, 1985.

would arouse controversy since it is founded on hypothetical conditions rather than on a firm's actual costs.

Flexible Rate-of-Return Pricing

One variant of price-cap regulation, which can be labeled "flexible rate-of-return pricing," involves allowing LDCs to retain permanently all profits within some specified "dead band" range. Profits outside the range would trigger a change in price that would either benefit or harm ratepayers. Several telecommunications firms and one LDC (Michigan Consolidated Gas Company) are subject currently to this regulatory regime.[30]

As an illustration of how this mechanism would work, assume that the "dead band" range is specified as an 11 percent to 14 percent rate of return on equity (with the mean, 12.5 percent, representing the firm's cost of capital); and that a sharing arrangement allocates rates of return outside this range to ratepayers and shareholders on an 80 percent to 20 percent basis. This means that 80 percent of excess (deficient) rates of return outside the "dead band" range would be allocated to ratepayers in the form of lower (higher) prices.

This incentive mechanism gives a firm maximum incentive to control costs when the actual rate of return remains within the dead band range (assuming that the firm permanently keeps all the profits from "dead band" performance); the firm would still have an incentive to control costs when the rate of return falls outside this range, since the firm would retain permanently a share of incremental profits. The firm also would share in the losses realized when it, for example, fails to control its costs and suffers a decline

[30] The pricing mechanism for Michigan Consolidated Gas Company was adopted in case no. U-9475, April 12, 1990 under the name "Performance Incentive Provision."

in its rate of return to below the dead band range as a consequence.[31]

Key components of the flexible rate-of-return pricing mechanism include the dead band region and the sharing parameter. The dead band region should be sufficiently wide if the objective is to give a firm maximum incentive to control its costs over some range of profits; a narrow region would give the firm less incentive since some of the surplus profits would be shared with ratepayers.[32] On the other hand, a wide region may produce outcomes that conflict with the equity criterion that ratepayers should receive a "fair share" of the benefits from a more efficient firm.

The sharing parameter would allocate "abnormal" profits between shareholders and ratepayers. The specified sharing arrangement has implications for achieving both efficiency and equity objectives. For example, allowing the firm to retain more of the abnormal profits would intensify its incentive to control costs but simultaneously it would also deprive ratepayers of some of the benefits. The conflict between achieving efficiency and equity objectives complicates the regulator's decision. As a policy matter, regulators should balance the interests of ratepayers and shareholders when specifying a sharing parameter.

One feature of flexible rate-of-return pricing is its simplicity in design and implementation, requiring less information than price-cap regulation, since questions relating to the "correct" price index and productivity offset would not have to be addressed. Further, no change in accounting procedures would be required.

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[31] The mechanism can be described as a variant of the sliding-rule system, which generically allows a regulated firm to retain permanently some fraction of profits earned incrementally or decrementally to the profit targeted at the last rate review. See Harry M. Trebing, "Towards an Incentive System of Regulation," *Public Utilities Fortnightly* (July 18, 1963): 22-27. Under a sliding-rule system no "dead band" region exists, as the firm and ratepayers share profits deviating from the targeted level no matter the actual profits earned. Also, the same mechanism is used in incremental cost indexing schemes discussed earlier.

[32] As an illustration, assume that the “dead band” region is 12 percent to 12.5 percent rate of return on equity. The chances are good that the firm would earn a return either above (or below) the “dead band” region, in which case the firm would have to share the incremental gains (or loss) with ratepayers.

Transition costs to this type of regime would be small compared to price-cap regulation.

On the negative side, flexible rate-of-return pricing would not improve pricing efficiency. Some analysts may argue that the mechanism also would not noticeably improve firms' incentives to control costs over what they face with regulatory lag under traditional regulation. As with practically all incentive mechanisms, flexible rate-of-return pricing would be susceptible to "gaming" by firms. For example, a firm may allow its costs to increase in the short run with the expectation of receiving more generous price increases in a subsequent period. Finally, the dead-band region would need to be readjusted periodically as financial conditions change.

In sum, flexible rate-of-return pricing attempts to balance the interests of shareholders and ratepayers in distributing the benefits of cost-saving activities. Unlike price-cap regulation, it does so in a way that avoids the entanglements of an after-the-fact "trueing up" process.

Deregulating the Noncore Market

State regulators may wish to consider deregulating gas supplies purchased by noncore customers. "Noncore customers" are defined here as those customers who can, with minimal cost, switch from purchasing LDC gas supplies to those of other suppliers, which can be natural gas or other forms of energy that are close substitutes to natural gas. Noncore customers, for example, would include interruptible and transportation customers. Over time it is expected that more LDC customers will be placed in the "noncore" category as the cost of switching suppliers is reduced. Threats to bypass the LDCs gas supplies by purchasing gas supplies as well as other forms of energy from other sources typify the actions of noncore customers in recent years.

The simple argument for deregulating gas supplies to noncore customers centers on the question, Why regulate a commodity where buyers have choices of different suppliers? The fact that gas purchasing cannot be considered a natural monopoly activity bolsters the argument that it should not be regulated. (A case can be made, however, that scale economies may exist in the supply of backup service.)

Of course, the same contention can apply to core customers, with the exception that core customers by definition incur high transaction costs when playing the market.

Deregulating noncore gas supplies would be contingent upon several factors. First, the LDC has in place a gas transportation policy that allows equal access of all gas supplies at reasonable prices. In the absence of such a policy, few customers would be truly noncore. The LDC could, therefore, use its monopoly power to discriminate against these customers. The fact that transportation service has natural monopoly characteristics means that some type of regulation would still be required. Most likely, state regulators would continue to regulate transportation services. Since these services would be sold to customers with high price elasticities of demand, regulators may want to consider allowing LDCs some flexibility in setting transportation rates. Rigid, cost-of-service rates may induce noncore customers to otherwise choose higher-cost energy suppliers.

A second condition for deregulation entails customers having a sufficient number of suppliers from which to choose. In some localities customers may have few choices even in the presence of an LDCs transportation policy. Under such a situation, deregulation would only serve to transfer wealth from customers to an LDC. Rather than determining whether the market for gas supplies is workably competitive, regulators may want to require customers to determine whether they want to be placed in the noncore group not subject to regulation.[33] This approach has the advantage of placing the burden on those who would be directly affected by the decision on whether or not they want their gas supplies to be regulated. By making the decision to elect noncore status voluntary, customers who do elect apparently believe that they would be better off. Of course, they may regret the decision later, but that is a consequence they should bear since they alone receive the benefits of a favorable outcome. Noncore customers who elect not to have their gas supplies deregulated would continue to be regulated in accordance with current

[33] In testing for whether certain markets are workably competitive, regulators may want to institute price-cap regulation on a temporary basis and observe actual prices in relation to the price ceilings. For a discussion on how temporary price caps can assist in assessing the competitiveness of markets, see Kenneth Rose, "Price-Cap Regulation: Some Implementation Issues," *NRRI Quarterly Bulletin*, 12 no. 4 (December 1991): 499-500.

current regulatory practices.

Deregulating gas supplies also means that LDCs should have no obligation to provide gas supplies to noncore customers. (A customer, however, may have a standby arrangement with the LDC to supply gas as an insurance against interruptions and other events. The price of the standby service may be subject to cost-of-service regulation when such service exhibits scale economies.) For reasons founded on both equity and economic-efficiency considerations, deregulated noncore customers should be liberated from regulatory restrictions and regulatory protections alike.

Finally, deregulation involves a different role for LDCs supplying gas to noncore customers. It can be argued that LDCs should have the right to sell gas supplies to noncore customers but only through an unregulated subsidiary.[34] LDCs may be the "best-cost" supplier of natural gas, but, unless they are placed on an equal footing with other suppliers, their sales may reflect more market power and regulatory favor factors than greater efficiency relative to competitors. For example, an LDC may rely on its core market to help fund below-cost prices to the competitive noncore market, thereby placing it at an unfair advantage with its competitors.

By requiring an LDC to form a subsidiary if it wants to sell gas in the noncore market, core customers as well as competing suppliers receive protections from possible abuse by LDCs. Whatever price the LDC subsidiary wants to sell gas supplies at in the noncore market should not affect the price of bundled gas to core customers. Further, in the absence of cross-subsidies from core customers, the LDC subsidiary would lack the incentive to price its gas below cost, thereby protecting other suppliers from possible anticompetitive actions by the LDC. Instead it would have a strong incentive to supply the "best-cost" gas so it can compete successfully with other suppliers. Such an incentive benefits both noncore customers and society, as the market test would provide

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[36] For example, see Arlon R. Tusing, *Profiled Direct Testimony on Behalf of the Montana Power Company* before the Montana Public Service Commission, filed January 1990; and Arlon R. Tusing, *Comments of Arlon R. Tusing and Associates, Inc. on Procurement Pursuant to D87-10-043,* before the Public Utilities Commission of the State of California, March 31, 1988. Regulators would still have to determine the treatment of common costs and their allocation to prevent costs subsidies.

the sufficient criterion for determining whether an LDC subsidiary is supplying "best-cost" gas supplies.

Regulators obviously would want to know what effect deregulating noncore gas supplies would have on core customers. Under deregulation an LDCs revenue requirements would exclude the costs of gas supplies to noncore customers. In addition, the LDC would receive less revenues since it is now selling only transportation service (in some cases also standby service) to the noncore market. Assuming that the LDC was selling gas supplies to noncore customers at cost, core customers should be indifferent to whether gas supplies to noncore customers are discontinued.

Three reasons exist, however, for why core customers may benefit. First, an LDC would purchase gas solely on the basis of the demand requirements of core customers (that is, customers who elect *not* to play the market). Since the demand for gas by core customers is more predictable and arguably less volatile, in the absence of a service obligation to noncore customers, an LDC could lower its gas costs to serve core customers by "buying" less flexibility in its contracts with different gas suppliers. The load swings of noncore customers impose an additional uncertainty for LDCs in their gas planning and procurement activities that currently may not be reflected in the allocation of costs to different customers.[35]

Second, as discussed above, deregulation prevents the possibility of LDCs funding their activities in noncore markets where competitive conditions exist by increasing their rates to core customers. As long as prevailing rates to core customers are below the profit-maximizing level, an LDC may have an incentive to cross-subsidize its more competitive markets at the expense of core customers.

Finally, the outcomes of deregulation can act as a benchmark to be used by regulators to determine whether an LDC is paying excessive sums for gas supplies purchased to serve core customers. For example, regulators can apply the average cost of gas purchases to noncore customers as a benchmark, with an adjustment made for

[35] On the other hand, it can be argued that core customers typically have a greater seasonal saving and thus a single purchased gas adjustment clause would benefit core customers.

differences in gas supply reliability. Regulators can use the benchmark as a "red flag," indicating whether further regulatory action seems warranted.

Implementing Incentive Regulation

The previous discussion points to a wide array of options available to state regulators. Each option has its strengths and weaknesses in promoting objectives that regulators have long held to be important. Each option should be considered as one component of an overall strategy sanctioned by regulators.[36] The strategy should be founded on a prior assessment of the mechanisms currently in place to achieve specified regulatory objectives (see Figure 3-2).

States currently apply different mechanisms to induce LDCs to achieve certain objectives when planning for and purchasing gas supplies. The more frequently used ones include prudence reviews, "best-cost" planning guidelines, management audits, and preapproval of individual contracts.[37] All of these alternatives require regulators to acquire considerable information and have rather tight control over an LDCs operations. Less frequently have state regulators given LDCs explicit incentives to operate and plan for their systems more efficiently.[38]

Incentive-based regulation, in theory, avoids the burden on regulation to become second managers or acquire vast amounts of information. By creating an environment of incentive compatibility, regulators need not worry (at least as much) about the actions of LDCs since, by definition, what is best for the shareholders is best for their customers. Theorizing such an environment and creating one to work in the real world represents two

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[36] A recent report by the NARUC Staff Gas Subcommittee recognizes that the effects of different regulatory options (what the report calls "methods of oversight") can overlap (see NARUC Staff Gas Subcommittee, *Considerations for Evaluating Local Distribution Company Gas Purchasing Choices,* Report to the National Association of Regulatory Utility Commissioners Gas Committee February 1991)

[37] See Daniel J. Duann, Robert E. Burns, and Peter A. Nagler, *Direct Gas Purchases by Gas Distribution Companies: Supply Reliability and Cost Implications* (Columbus, OH: The National Regulatory Research Institute, 1989).

[38] See, ibid.

Regulatory Objectives

$\downarrow$

Current Mechanisms

$\downarrow$

Identified Weaknesses

$\downarrow$

Proposals for Change

$\downarrow$

Selected Proposals

$\downarrow$

Strategy

Source: Authors' construct.

Fig. 3-2. Sequential process in designing a regulatory strategy.

entirely different challenges.[39] Incentive systems may be developed and made workable, however, so that regulators could redirect their efforts away from those demanding substantial resources (for regulators as well as for consumer intervenors, LDCs, and other stakeholders in the regulatory process). For example, incentive systems can help displace prudence reviews and advance planning reviews, each of which can occupy a significant amount of regulators' time.

The rationale for incentives hinges on four major assumptions. First, LDCs always have better information than regulators on how to operate and plan for their system. This implies either that regulators will rubber stamp decisions by LDC management in deference to its superior access to information or regulators will make decisions based on poorer information about what actions LDCs should take both from a retrospective and prospective viewpoint.[40] For each event economic efficiency may suffer: regulation would resemble either a cost-plus contract or regulators would make decisions that LDC management is more qualified to make.

Second, actions which are in the best interest of LDCs may not be in the interest of customers or shareholders. Although an LDC can be pressured to form a gas procurement plan that is acceptable to all parties, how it will carry out the plan probably depends importantly on pecuniary incentives. Without strong incentives, an LDC may be languid in following a commission-approved plan in a manner that best serves the interests of customers.

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[39] For problems in applying incentive systems, see Joskow and Schmalensee, "Incentive Regulation for Electric Utilities," 1-49; and Leland L. Johnson, *Incentives to Improve Electric Utility Performance: Opportunities and Problems,* Rand Report R-3245-RC (Santa Monica, CA: The Rand Corporation, March 1985).

[40] Regulators in recent years have tended to increase their oversight of, and involvement in the gas procurement practices of LDCs While less frequently rubber stamping LDC's proposed activities, regulators seem reluctant to act as an additional layer of management. For example, most state regulators do not preapprove contracts between LDCs and their gas suppliers. One reason may be that for many regulators preapproval connotes a managerial responsibility that

Third, giving LDCs correct incentives implies that regulators reward them for exceptionally good performance. Otherwise, an LDC would have a strong incentive only to avoid bad outcomes that may trigger penalties imposed by its regulators.[41] Regulators more frequently penalize LDCs for bad performance than reward them for good performance. In fact, few cases exist where LDCs are rewarded explicitly for outstanding performance.[42]

The fourth assumption is that incentives represent a more effective approach for achieving certain objectives than other regulatory options. For example, incentives are assumed preferable to regulatory planning and hindsight reviews.

While incentive systems have theoretical appeal, they are not immune from problems when applied to real-world situations. Three reasons for this include strategic behavior by regulated firms, access to imperfect information by regulators, and changing cost and demand conditions. "Gaming" by the firm, while promoting the interests of management and shareholders, may jeopardize its customers. For example, in attempting to maximize the rewards associated with a (distorted) incentive system, a firm may allow its revenue requirements, and thereby its rates, to increase. Designing a system that is "incentive compatible" represents a most challenging task for regulators.

The information problem causes regulators to be uncertain about how firms would respond to new incentives. Examining the effects of incentives after the fact requires a counterfactual exercise in assessing how a firm's management would have acted without the new incentives. This makes it difficult for regulators to verify the effects of new incentives, as well as predict how proposed incentives will affect ratepayers.

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[41] Consequently, LDCs would tend to place emphasis on low probability, highly unsatisfactory outcomes. As such, they may be willing to pay a high price to mitigate against risk exposure.

[42] One exception occurs in South Dakota where the Commission has incorporated a provision in one of the PGAs that allows only 90 percent recovery of any increase in purchased gas costs and 90 percent pass-through of any decrease.

Changing cost and demand conditions requires regulators to reassess periodically a current incentive system. As discussed below, the theoretical literature suggests that optimal incentives depend on the degree of uncertainties over future costs and demand and the symmetry of information held by the firms and their regulators.[43] For example, price-cap incentives tend to be more desirable from the perspective of consumers when future uncertainties are minimal and information is symmetric.

Problems of Designing Optimal Incentives

The theoretical literature on incentives shows clearly the difficulty of designing an optimal system.[44] The source of this problem stems from what economists call the "principal-agent" problem: regulators playing the role of principal and firms acting as the agents may have conflicting objectives. As an often-used example, the firm may want to maximize profits while its regulator has another objective such as maximizing consumer welfare. Because the firm may find it costly to satisfy the regulator's objective, it may take actions incompatible with this objective. Regulators face the problem of not knowing whether the actual performance of the firm, which they are able to observe, mirrors the best efforts of management to promote regulatory objectives. In the extreme, the lack of information available to regulators places regulation in the category of a cost-plus contract. The key to designing incentives revolves around having the firm taking

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[43] For example, see Jean-Jacques Laffont and Jean Tirole, "Using Cost Observation to Regulate Firms," *Journal of Political Economy*, 94 no. 1 (1986): 614-64; and Richard Schmalensee, "Good Regulatory Regimes," *Rand Journal of Economics*, 20 (Autumn 1989): 417-36.

[44] See, for example, a discussion of the problems in designing optimal incentives in Joskow and Schmalensee, "Incentive Regulation for Electric Utilities," 16-21; Richard Schmalensee, *The Control of Natural Monopolies* (Lexington, MA: D. C. Heath, 1979); Laffont and Tirole, "Using Cost Observations to Regulate Firms," 614-41; Schmalensee, "Good Regulatory Regimes," 417-36; and David Sappington, "Strategic Firm Under a Dynamic Regulatory Adjustment Process," *Bell Journal of Economics*, 1 no. 1 (Spring 1980): 360-72.

actions that are in its own self-interest as well as satisfying the regulator's objective.

The problem of regulators designing perfect incentives is indeed difficult.[45] Even the theoretical literature, which attempts to design perfect incentives, makes assumptions that deviate from reality. For example, the theories do not account explicitly for the possibilities of regulators changing the incentive rules at some indeterminate future date and for firms engaging in strategic behavior. Periodic review, for example, can result in regulators taking away some of the past profits that a firm assumed it could keep permanently. All in all, the literature at best provides regulators with some insights on what types of incentives are more defensible under specific conditions. For example, concerns over the incentives provided by cost-plus-type regulation (the consumers assume all risks and receive all the benefits from a firm's successful cost-saving activities) to a firm should vary with such factors as the degree of uncertainty surrounding future costs and the ability of firms to engage in cost-reducing activities. If, for example, the regulator's objective is to maximize consumer welfare, applying price-cap-type incentives in a highly uncertain and unstable environment may be ill-advised: higher price ceilings would have to be set to maintain a firm's profitability, the firm's profits may fall outside a predetermined reasonable range, and fixed prices would tend to deviate further from costs.

The literature on optimal incentives offers several insights:

1. In almost all circumstances cost sharing would be preferable to either cost-plus or price-cap regulation. Cost sharing allows some adjustment of prices to changes in costs, in addition to lessening the likelihood of a firm earning excessive profits from having more information than regulators and from favorable events.
2. Designing an optimal incentive system is made more complicated when considering dynamic effects and strategic behavior by firms. Strategic behavior may make the firm

[45] Ibid., Joskow and Schmalensee, "Incentive Regulation for Electric Utilities."

3. Optimal incentives depend on such factors as the availability of information to regulators, the degree of uncertainty surrounding the firm's costs and demand, and the rate of technological change in the regulated industry. For example, less stable and more uncertain conditions within a regulated industry, assuming other things remain constant, would support a shift toward cost-plus regulation.
4. Price caps tend to be less defensible in maximizing consumer welfare when the firm faces increasingly uncertain cost and demand conditions and the degree of technological change and competition are minimal. This implies that while price caps surpass other regulatory systems in providing incentives for cost control, they may rarely maximize consumer interests.
5. As regulators possess more information on the efforts of firms and the ability of firms to reduce costs, price-cap-type regulation becomes more defensible. In the extreme case where regulators possess as much information as firms, a fixed price (that is, a target price) can be set for a designated period that reflects the regulator's perception of an efficiently managed firm.
6. Providing stronger incentives for cost reductions may come at the expense of a decline in pricing efficiency. The logic of this statement stems from the fact that inducing a firm to produce more efficiently may require that regulators set prices above costs. The loss in consumer welfare from setting above-cost prices directly relates to the price elasticity of demand.[46]

[45] See, Schmalensee, "Good Regulatory Regimes," 417-36.

7. Optimal incentives are expected to change over time as well as vary among regulated firms.4[7] For example, improved prospects for technological innovations within a specific industry would tend to favor a move toward price-cap regulation. Since firms in the industry would have more opportunity to reduce their costs, price-cap-type regulation would give them more incentive to do so. Thus large benefits may result. The question that should be asked now is: How does the literature on optimal incentives apply to LDCs? The first point to make is that state regulation of LDCs, as currently practiced, lies within the spectrum bounded by cost-plus regulation and price caps. Once prices are approved by regulators, firms have an incentive to control their costs since profits would increase accordingly. Like price-cap regulation, every dollar that a firm saves translates into an immediate and equal increase in profits. But when cost reductions turn into lower prices at a later time, regulation resembles a cost-plus contract. For example, when past cost savings are built into future rates, the regulated firm loses the benefits from cost savings to consumers.

Speculating what direction optimal incentives have taken for LDCs over the last several years first requires knowing how conditions facing regulators and the industry have changed. Since 1985 the LDC industry has changed dramatically in various ways. First, LDCs are encountering unprecedented competition where they must compete aggressively with producers, marketers, and pipelines to retain their market share. The threat of bypass has affected LDCs throughout the United States. Competition increases the uncertainty of future demand for the services of individual LDCs. Notwithstanding the increased competition, LDCs still possess market power over core customers. Regulators still face the challenge of assuring that LDCs do not recover excessive costs

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[47] Joskow and Schmalensee, "Incentive Regulation for Electric Utilities," conclude that:

> [N]o single incentive scheme will be optimal in all circumstances and that the appropriate incentive scheme for any particular firm may change dramatically over time as economic conditions and the commission's information change.

from their customers. Second, LDCs face increased pressure from both consumers and regulators on the pricing and costing of unbundled services. Third, state regulators have acquired more information on gas procurement and other activities of LDCs. Whether this increased availability of information to regulators has kept pace with the increased information possessed by LDCs is difficult to say. Also, it is unclear that regulators currently can better distinguish between bad and good management practices by LDCs than prior to five or six years ago. Although regulators now have more information, the information requirements for evaluating an LDCs performance have increased as well. Finally, LDCs face more choices in the purchasing of natural gas supplies. They have greater opportunities to control then-costs by aggressively searching for the best-cost gas supplies. Predicting future costs, especially for gas purchases, has become more difficult as LDCs recently have steered away from long-term contracts and instead have shifted their preferences for purchasing their gas needs in the spot market.

Taken together, these changes have provided no clear direction for optimal incentives over the last several years. It is also unclear, at this time, whether incentives should correspond closer to cost-plus- or price-cap-type regulation. Changes in the prospects for supply side technological innovations in the LDC industry essentially have stayed the same. Therefore, technological factors have not played a role in affecting the direction of optimal incentives over the last several years. The fact that technological conditions in the LDC industry are expected to slowly change in the foreseeable future means that the benefits from technological improvements, which may be induced by price-cap-type regulation, would likely be insignificant.

Increased uncertainty over cost and demand, according to the theoretical literature, tends to shift optimal incentives away from a price-cap system. As stated earlier, setting a fixed-price target in an uncertain environment poses three potential problems: prices deviating far from costs, the firm earning unreasonably high or low profits and consumers receiving a small share of the gains from costsharing activities by the firm. On the other hand, since competition has increased in the LDC industry, price-cap-type regulation (assuming other things remain constant) may be the preferred regulatory system. This system would lead to more pricing flexibility, which is particularly crucial from an efficiency perspective when a firm faces competition in some of its markets. Studies show that allowing firms much pricing flexibility when they face varying degrees of competition in different markets would produce Ramsey-type prices.[48] Consumers who have the least opportunities to switch to different suppliers, however, will suffer discriminatory prices.

In sum, some doubt exists over the direction of change in optimal incentives since the mid-1980s, when the LDC industry started to undergo dramatic changes. At this point no conclusion can be reached on whether the incentives provided by state regulators to LDCs should favor a cost-plus or price-cap contract. It can be argued, however, that in view of the inherent problems associated with each type of regulatory contract and the fact that prevailing conditions in the LDC industry do not support either contract that some form of cost-sharing mechanism, would seem most appropriate.

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[48] See, for example, Vogelsang, *Price Cap Regulation of Telecommunications Services*.

CHAPTER 4

EVALUATING REGULATORY OPTIONS

Criteria for Evaluation

Identifying and conducting the most effective regulatory actions including incentive systems involves first of all, agreeing on the major regulatory objectives. While regulators have adhered to many, four seem to stand out: promoting economic efficiency, avoiding unfair or unequitable outcomes, controlling administrative costs, and achieving risk incidence compatible with specified efficiency and equity goals. Economic efficiency is improved any time firms have a stronger incentive to operate and plan in a least-cost manner. Pricing in line with actual market conditions also would tend to improve economic efficiency.

Equity, a more elusive concept, tends to exist whenever the rights of all groups are not violated. For example, equity standards may not be violated even when price discrimination burdens one or more groups. As long as the magnitude of price discrimination does not impose significant costs on any group, tolerable equity outcomes can continue to hold.

Controlling administrative costs has the benefit of requiring the different parties to expend less resources in articulating their positions before the PUC-- whether they actually do so depends on the frequency and scale of major proceedings that are expected under different incentive systems. For example, at one extreme lies deregulation with its zero, or close to zero, administrative costs; at the other extreme lie options such as prudence reviews or integrated resource planning, each of which requires utilities, intervenors, and commissions to expend substantial resources in regulatory proceedings.

The major objective of regulatory incentives considered in this report revolves around their effectiveness in motivating LDC management to purchase least-cost gas supplies gives the demand requirements of retail customers. Economic theory predicts that regulated firms would be less inclined to pursue a cost-minimizing strategy than unregulated firms. The incentive of LDCs to control their purchased gas costs is weakened particularly by their ability to shift costs to core markets by the cost-plus tendencies of rate-of-return regulation. This implies that an LDC may not avail itself of all opportunities to purchase what can be considered "best-cost" gas supplies when any of these conditions exists. ("Best cost" refers to the condition whereby an LDC purchases a predetermined reliable portfolio of gas supplies at the lowest attainable cost.)

Achieving best-cost objectives means that an LDC aggressively searches for the best deals and purchases the correct mix of gas supplies to meet customers' demands for natural gas. Regulators can employ two general approaches to promote this objective. First, they can require an LDC to have in place an acceptable process for procuring future gas supplies. Regulators, for example, can establish guidelines to steer LDC management actions in a way that is compatible with maximizing consumers' interest. This before-the-fact oversight function probably would need to be supplemented by an after-the-fact review to help assure that an LDC has carried out its commission-approved plan in a prudent and reasonable fashion.

As an alternative, regulators can design an effective incentive system whereby an LDC would be motivated to maximize the interest of consumers. If such a system were to exist, regulators would need to carry out minimal oversight. Since LDCs attempt to serve their shareholders through higher profits, an ideal incentive system would allow LDCs to receive financial gains from exceptionally good performance. Consistent with good economics, LDCs should be responsible for exceptionally bad performance as well. As envisioned here, exceptional performance (good or bad) extends beyond the question of whether an LDC made prudent or imprudent decisions; it encompasses only the outcomes of particular actions by LDC management. Consequently, outcomes depend not only on management decisions but also on market conditions, weather, luck, and anything else that affects the product of events.

Choosing a particular incentive system or strategy may involve trading off different regulatory objectives. As an example, price-cap regulations may give firms more incentive to control costs, but it allows them to tilt their rate structures that discriminates against residential and other core customers.[1] As another example, integrated resource planning may promote due process and better investment decisions by an LDC, but reduce economic efficiency by diminishing the roles of competition and prices in allocating an LDCs capital to different types of investments.[2] Integrated resource planning may also shift more of the risks associated with an LDCs investments to customers. This would be true if approving a plan means that all expenditures made to carry it out would be recovered promptly from customers without an after-the-fact review.

The incentive strategy ultimately decided upon by a commission should reflect both the regulators' perceptions of the reasons for less than satisfactory performance by LDCs and the weights implicitly assigned to different regulatory objectives. If, for example, regulators believe that informational problems greatly limit their ability to oversee LDCs purchasing activities, they should consider seriously an incentive-based system such as price caps that would require minimal regulatory reviews. As another example, regulators may believe that LDCs will abuse their PGAs at a cost to consumers, no matter how vigilantly oversight is carried out. Under such a condition, a regulator may opt for abolishing PGAs even at the risk of increasing a firm's cost of capital and the frequency of formal rate proceedings.[3]

The fact that state regulators have relied more on prudence reviews than on formula-based incentive systems, perhaps shows their concern over the uncertainties of incentives to benefit consumers. Incentive systems, for example, can generate windfall gains to regulated firms while yielding little or no benefits to consumers. That may

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[1] As stated earlier, this is especially true when price caps apply to both core and noncore services.

[2] This would be more true when integrated resource planning parallels the tenets of centralized planning, where regulators would have tighter control over an LDCs planning process and would dictate nonmarket-based prescriptions for planning actions.

[3] Although most analysts would agree that abolishing PGAs or other cost-plus automatic adjustment clauses would increase a firm’s financial risk, some evidence exists to the contrary (see Joseph Golec, “The Financial Effects of Fuel Adjustment Clauses on Electric Utilities,” *Journal of Business*, 63 no. 2 (April 1990); 165 – 86).

explain partially why few states give LDCs explicit incentives to hold purchased gas costs; many states, instead, may consider the threat of after-the-fact investigations a more effective and equitable form of incentive.

Besides being more compatible with conventional rate-of-return regulation, the threat of prudence investigations more directly links a commission's actions to benefits that consumers may perceive. While incentive systems appear attractive from a theoretical perspective, their benefits to consumers are difficult to verify. For example, most current incentive systems for electric utilities are designed to reduce fuel costs.[4] In achieving this objective a utility may incur higher nonfuel costs, which may benefit the utility but not its customers. The utility's total revenue requirements may increase, with consumers ultimately paying higher prices.

Comparison of Regulatory Systems

Table 4-1 provides a summary of the different incentive systems discussed in this report. It contains for each system the expected effects on economic efficiency, equity, administrative costs, and risk incidence. For many of the systems, achieving one objective involves trading off one or more of the others. For example, while contract preapproval may improve the process for, and results of, gas procurement planning, ratepayers may face greater risk. Preapproval may signal (although not necessarily) that the burden of bad outcomes and bad contract executions will fall on ratepayers.

The fact that no incentive system produces perfect results limits regulators' choices to those that may produce an undesirable outcome. Regulators must weigh these effects along with desirable ones to decide, on net, which systems are preferable.

Table 4-2 lists the strengths and weaknesses of the different incentive systems. As stated, each system has its own problems, which must be considered along with its favorable attributes. No recommendation should be implied except to say that regulators must ultimately decide

[4] See Paul L. Joskow and Richard Schmalensee, “Incentive Regulation for Electric Utilities,” *Yale Journal of Regulation,* 4 no. 1 (Fall 1986): 1 – 49.

TABLE 4-1

SUMMARY OF DIFFERENT REGULATORY OPTIONS

System	Economic Efficiency	Equity	Administrative Costs	Risk Incidence
Deregulation of Gas Supplies to Noncore Markets	• Promotes gas purchasing efficiencies in noncore market • Diminishes possibility of predatory pricing • Provides benchmark to assess prices of core-market gas supplies	• Protects core markets from revenue losses in noncore market	• Reduces scope of rate proceedings	• Shifts risk of gas purchasing to LDC subsidiary • Imposes risk on consumers electing deregulated gas service
Price Caps	• Promotes flexible pricing • Promotes cost-saving activities	• Promotes price discrimination against core customers	• Reduces frequency of rate review but not necessarily costs for stakeholders	• Shifts risks to LDC
Flexible Rate-of-Return Pricing	• Promotes cost-saving activities	• Ex Ante sharing of abnormal profits	• Prevents need for "trueing up" abnormal profits in formal rate review	• Shared risk for abnormal profits between ratepayers and shareholders

TABLE 4-1--Continued

System	Economic Efficiency	Equity	Administrative Costs	Risk Incidence
"Best Cost" Gas Purchase Planning	• Improves LDC's planning/investment decisions • Forces LDC to look at all supply side options	• Allows parties due process in challenging LDC's planning decisions • Has no effect unless preapproval standard applies	• Increases informational costs to all parties • Reduces need for prudence review of planning decision	• Shifts risk to ratepayers under preapproval
Cost-indexing of Gas Purchases	• Improves gas-purchasing efficiencies	• Protects ratepayers from poor performance by LDC	• Decreases scope of reconciliation proceedings • Reduces need for prudence reviews	• Shifts risk to LDC
Incentive-Based PGAs	• Improves gas-purchasing efficiencies	• Protects ratepayers from poor performance by LDC	• Decreases scope of reconciliation proceedings • Reduces need for prudence reviews	• Shifts risk to LDC

TABLE 4-1--Continued

System	Economic Efficiency	Equity	Administrative Costs	Risk Incidence
Prudence Reviews	• Improves incentive of LDC to avoid bad decisions/outcomes	• Depends on rules at time of decision	• Increases informational costs to all parties	• Shifts risk of bad decisions/outcomes to LDC
Oversight of Gas Purchasing Transactions	• Improves gas-contracting decisions especially when self-dealing occurs	• Burdens ratepayers with bad outcomes (assuming preapproval standard)	• Reduces prudence reviews • Increases scrutiny of LDC's gas purchasing activities	• Shifts risk of bad outcomes to ratepayers (assuming preapproval standard) • Reduces risk of self-dealing abuse

Source: Authors' construct.

TABLE 4-2

STRENGTHS/WEAKNESSES OF DIFFERENT REGULATORY SYSTEMS

System	Strengths	Weaknesses
Deregulation of Gas Supplies to Noncore Market	• Reduces possibility of cross-subsidization and price discrimination • Gives LDC subsidiary strong incentive to purchase "best-cost" gas supplies • Provides benchmark for assessing reasonableness of gas supply costs to core market	• Places noncore customers at risk when gas supply market is noncompetitive
Price Caps	• Accommodates market conditions via flexible pricing • Increases incentives for cost-saving activities	•Creates greater opportunities for price discrimination • Allows LDC to make unlimited profits for extended period
Flexible Rate-of-Return Pricing	• Requires less transition cost (e.g., relative to price caps) • Allows ratepayers and shareholders to share in benefits of cost-saving activities • Provides LDC with strong incentives to reduce costs	• Creates problem of determining correct "dead band" region and sharing parameter

TABLE 4-2--Continued

System	Strengths	Weaknesses
"Best-Cost" Gas Purchase Planning	• Allows parties due process in questioning LDC's proposed plans • Places different sources of gas supplies on equal footing for planning purposes	• Requires high informational costs • Offers no explicit incentive for good performance
Cost-Indexing of Gas Purchases	• Diminishes inefficiencies from cost-plus nature of traditional regulation • Diminishes scope of reconciliation hearings	• Increases risk to LDC • Creates problem for PUCs of whether cost targets reflect expected/acceptable performance
Incentive-Based PGAs	• Diminishes inefficiencies from cost-plus nature of conventional PGAs • Diminishes scope of reconciliation hearings	• Increases risk to LDC • Creates problem for PUCs of whether cost targets reflect expected/acceptable performance

TABLE 4-2--Continued

System	Strengths	Weaknesses
Prudence Reviews	• Allows PUCs opportunity to disallow recovery of unreasonable costs • Induces better LDC performance due to threat of cost disallowance	• Creates asymmetric incentives (avoid bad decision/outcome only) • Requires large informational costs
Oversight of Gas Purchasing Transactions	• Helps PUCs to increase vigilance of contracts involving affiliated parties • Provides better assurance of reasonable costs for poorly performing LDCs	• Places PUCs in role of second manager and thereby shifts risks to ratepayers (assuming preapproval standard) • Requires large informational costs • Limits flexibility of LDC in adapting to changed conditions

Source: Authors' construct.

which system or group of systems best fits a particular situation. Even within one state, regulators may judge correctly that what is the best strategy for one LDC is not the same for another. For example, one LDC may have a past history of gas procurement problems. For such an LDC, regulators may want to oversee its activities more closely by requiring the filing of "best-cost" gas purchase plans on a periodic basis, the submittal of any proposed gas procurement contract for review, and by requiring a prudence review of all its gas procurement activities. Such an iron-handed strategy hinges on the perception that a particular LDC has management problems that demand scrutiny, and possibly intervention, by outsiders. For another LDC in the same state, regulators may have a more favorable perception warranting a less iron-handed strategy.[5]

Table 4-3 lists four conceivable regulatory strategies for achieving "best-cost" objectives. Each attempts to combine different regulatory procedures to produce complimentary outcomes. Strategy I represents what PUCs typically do currently to regulate and oversee gas supply costs. This strategy reflects the fact that PUCs have taken a more active role in recent years but one that does not place them in the position of second managers. PUCs have exercised more widely their legal rights in overseeing LDCs' gas purchasing practices. Another observation of the status quo strategy is that PUCs have not widely used explicit incentive systems. As discussed earlier, the reason may involve the practical problem of applying a regulatory incentive system that visibly produces benefits to retail customers. Strategic behavior by regulated firms, lack of adequate information by PUCs, and changing demand and supply conditions (as discussed earlier) make it difficult, if not almost impossible, for regulators to assign a high value to

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[5] The main idea presented in this paragraph corresponds to the recommendation of the NARUC Staff Gas Subcommittee in its recent report, *Considerations for Evaluating Local Distribution Company Gas Purchasing Choices.* That report concludes that:

> To make appropriate choices, an LDC should carefully analyze its customers' needs and investigate the options available to best satisfy those needs. Both the customers and the supply and capacity options available to each LDC will differ. Thus, no single service strategy will be appropriate for all LDCs (p. 23).

TABLE 4-3 REGULATORY

STRATEGIES

Strategy I:	Status quo ("best-cost" gas planning, prudence reviews, traditional PGA)
Strategy II:	Oversight of gas-purchasing transactions, "best-cost" gas planning, prudence reviews, no PGA
Strategy III:	Cost-indexing of gas purchases, incentive-based PGA, symmetric treatment of different gas supplies
Strategy IV:	Deregulation of noncore gas supplies, price caps for other LDC services (including core)

Source: Authors' construct.

PUCs to design an incentive system that assures benefits to customers. As a general rule, PUCs currently prefer to punish firms for bad performance and not to reward firms for something that they should be doing anyway.

Strategy II reflects a firm posture, whereby a PUC would conduct more intensive and ongoing oversight of LDCs than under Strategy I. Little faith is placed in either incentive systems and cost-plus mechanisms, or LDC management to make the correct decisions. The emphasis is on punishing an LDC for making mistakes.

Strategy III relies heavily upon incentive-based procedures. It presumes that if faced with the right incentives, LDC management without iron-handed regulatory section incentive systems relative to other options as a mechanism to achieve "best-cost" objectives.

The last strategy, Strategy IV, reflects the position that "business as usual" no longer represents a viable regulatory response to a changed natural gas industry. Strategy IV takes a nontraditional approach by presuming that either deregulation of markets, where consumers have several choices, or flexible regulation constitutes the only choices for achieving socially desirable outcomes.

CHAPTER 5

CONCLUDING COMMENTARY

This report has attempted to offer insights pertaining to the future direction of state regulation of local gas distribution companies as it is confronted by a rapidly changing natural gas market with vastly widened gas procurement opportunities. The underlying goal has been to investigate whether state regulation, which has been responding to the competitive trends in the natural gas market primarily by increasing the level of oversight, should explore other options, some of which may require more reliance on market forces than present under traditional regulation. The investigation was predicated on the observation that traditional regulation because of its cost-plus nature (even when accompanied by a strong oversight regime) may not provide correct incentives to an LDC to make the most efficient and prudent gas procurement decisions.

The study has discussed the many opportunities for procuring gas offered by the rapidly emerging competitive environment in the industry, accentuated by FERC regulation. The new quasiregulated regime not only creates many new opportunities to manage the acquisition and supply of gas but imposes new risks on the LDC. First and foremost, it shifts the risk of inadequate supply reliability from the interstate pipeline to the LDC. The tasks of finding diverse supply sources, aggregating supplies, and coordinating deliveries no longer will remain with the pipeline. The LDC must take responsibility for these tasks, which are critical to ensuring the reliability of supply. While market intermediaries will assume some of these tasks, they are likely to be less effective than pipelines. As a result, the LDC needs to be more active than was required in an era of regulated pipeline supplies in ensuring least-cost procurement and reliable supply.

The study has examined the incentives provided for LDCs under traditional regulation. It has conclulded that while traditional regulation gives LDCs some incentives to manage their systems efficiently, they may be inadequate in today's marketplace to induce an LDC to bargain aggressively for price and nonprice terms of their gas purchases and for procuring gas from an optimal mix of supply sources.

The study has examined whether current regulation, which differs from its more traditional form by introducing strong oversight in many states, provides the LDC with the right incentives to apply the requisite diligence and prudence to optimally avail itself of the opportunities offered by the vastly changed gas market. In particular, LDCs may not be taking full advantage of the newly opened gas futures market because of an absence of regulatory guidance on the use of this option as a risk management tool.

The study examined nontraditional options for regulating the LDCs' gas purchasing practices. These options embody what is known as "incentive compatibility," a feature that would induce a regulated firm to make efficient procurement and pricing decisions. Such an approach to regulation was initiated in the telecommunications sector of public utility regulation and more recently in the electric sector. Evidence from these regulatory experiments does not conclusively and unequivocally favor "incentive regulation" over traditional regulation.[1] The lack of conclusive evidence reflects the inherent complexity of designing and evaluating incentive schemes in industries characterized by a mix of regulation and competition. The study found that nontraditional "incentive-based" regulatory options also have merits and flaws. One feature usually present in such regulatory options is the possibility of windfall profits and losses during times of economic instability, such as high inflation and deep recession.

The study also found that a move to "incentive compatible" regulatory options may be inhibited by regulators' legitimate concern about how well this relatively new and

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[1] A recent study on the incentive regulation of electric utilities found that incentive schemes focused on specific categories or determinants of cost do not significantly improve efficiency. Another study on telephone utilities found that states with ROR regulation had generally higher tariffs than those with price-cap regulation. See Sanford V. Berg and Jinook Jeong, "An Evaluation of Incentive Regulation for Electric Utilities," *Journal of Regulatory Economics,* 3 no. 1 (March 1991): 45 – 55 and Alan D. Mathios and Robert P. Rogers, "The Impact of Alternative Forms of State Regulation of AT&T on Direct-Dial, Long-Distance Telephone Rates," *RAND Journal of Economics,* 20 no. 3 (Autumn 1989): 457 – 55.

untried approach may work. This study does not attempt to resolve that concern conclusively. It merely suggests that such approaches be explored and that continuing the status quo is not the recommended approach.

Based on the observations of the study, certain approaches and options are recommended as follows.

Gas Purchase Options

State commissions should carefully consider the effect of current regulation on an LDCs choices of options. If a state commission puts a disproportionate emphasis on cost minimization, an LDC may prefer to purchase a disproportionate amount of its supply from the least reliable sources in the spot and forward markets. On the other hand, if reliability is given priority, the LDC may be tempted to contract for highly reliable and relatively expensive sources of gas. In other words, the LDC may purchase more reliability than needed and at a higher cost than would be justifiable.

To address the problem of the trade off between cost minimization and reliability, state commission must articulate a policy that encourages an LDC to actively seek least-cost supplies to meet annual volumetric needs, and to actively seek an optimal mix of resources to achieve reliability objectives. A general theme of the proposed incentive-based mechanisms is to induce the LDC to accomplish this tradeoff without intrusive scrutiny and oversight by the PUC. Storage, GICs in the long-term contracts with pipelines, and building a diverse portfolio of suppliers all contribute toward maintaining a reliable supply of gas.

Regulators also may wish to explore the use of futures markets as a price and earning risk-mitigation tool by LDCs. Futures trading allows an LDC to mitigate its business risks at a relatively small transaction cost. It also offers an opportunity to weaken the role of PGAs as a cost recovery mechanism and to shift an LDCs earnings risk from customers to speculators in the futures market.

Regulatory Options

The study does not recommend any specific regulatory option. Instead it presents an analytical decision framework and a range of incentive-based approaches which can be used to examine regulatory options and develop regulatory policy responsive to the market environment. It presents a number of options which involve various degrees of dependence on commission oversight and market forces. The study also identifies strengths and weaknesses of various regulatory options and compares them on chosen criteria of economic efficiency, equity, and regulatory costs. The analytical framework developed in the study and the comparative assessment of various options can be used to choose policies that best suit the needs of individual commissions and the LDCs they regulate. It has been observed earlier and underscored here that the same policy or option may not apply equally well in each state, to each LDC in a given state or even to a particular LDC at all times.

While the above may suggest an ad hoc and case-specific determination of policy, this is not the intended recommendation. Highly individualized and case-specific regulation can be abused by utilities to rationalize inefficient behavior. What is recommended is sensitivity to differences among states, LDCs, and to changes occurring over time while striving to develop policies that have incentive standards sufficiently independent from an LDCs own estimate and incurrence of costs. Such standards may range from the iron-handed posture of least-cost purchase requirements to the laissez faire approach of price caps. Independence from an LDCs own costs in developing standards is essential if regulation hopes to achieve least-cost objectives.

APPENDIX

BUSINESS RISKS OF AN LDC AND RISK-MANAGEMENT OPTIONS

A firm is usually exposed to a number of business risks broadly classified into three groups: price risk, supply risk, and demand risk.

Price risk includes those associated with fluctuations in the price of a commodity and may result in a loss of earnings. A firm may purchase a commodity it expects to sell at a certain price in the future. It also may make a future sales commitment of a commodity at a prespecified price that it plans to procure in the future. In the first case, if the price of the commodity is lower than expected at the time of sale, the firm may suffer a loss. In the second case, if the price is higher than expected at the time of procurement, it may have to forego projected earnings.

Supply risk occurs when a firm fails to acquire a commodity (or an input needed to produce a commodity) and thereby is unable to meet its demand and realize its projected revenues. The earnings loss can occur either in the form of foregone revenues or higher prices paid to procure the commodity from other supply sources.

A firm faces a demand risk because of the uncertainty associated with the demand of its product. The realized demand may be lower than the projected demand, or it can be higher. In the first case, a loss of revenues will occur because either a smaller quantity is sold or the price is lowered to maintain the projected sales volume. In the second case, a shortage of the commodity occurs. This may not present a serious problem for an unregulated firm which can usually raise the price and may realize a higher revenue and profit. A regulated firm, such as an LDC, is not automatically allowed to raise its rates in response to a shortage. Also, the LDC has an obligation to serve and therefore may be penalized for not meeting this obligation.

An LDC usually faces all of the risks outlined above. Mitigating these risks, however, may be possible by using supply management options and recourse to regulatory relief mechanisms such as purchased gas adjustments (PGAs).

The LDC faces a price risk due to seasonal and long-term fluctuations of gas prices. For example, if the LDC purchases gas on a long-term contract at a certain price, the price is "locked in" and cannot be changed even if the market price of gas declines. On the other hand, if the LDC plans to buy a certain amount of gas on the spot market at a future date and the price unexpectedly rises, the LDC faces the prospect of a revenue loss. The gas then may have to be sold at regulated rates that may be below the actual purchase price.

As discussed earlier, an LDC needs to secure a reliable supply of gas. The LDC faces a supply risk when a supplier fails to deliver committed volumes. The uncertainty associated with the reliability of supply sources and transportation arrangements imposes a risk on the LDC. It may suffer a loss of revenue both from the lower volumes sold and the penalties it may be subjected to for failing to meet its service obligations.

The LDC also faces a demand risk because actual demand may fall short of supply (surplus) or exceed projected demand (shortage). A surplus may occur if space-heating customers consume less gas during an unusually warm winter or dual-fuel customers unexpectedly switch to an alternative fuel whose price declines relative to gas. A shortage may occur if an unusually cold winter increases gas consumption by space-heating customers or a decline of gas prices relative to an alternate fuel causes consumers to switch to gas.

Risk Management Options of an LDC

Several options are available to mitigate an LDCs business risks. They include both purchase and sale strategies and the use of regulatory mechanisms.

Regulation provides the best protection to the LDC against price risk. Whenever gas prices rise above expected levels, the LDC can recover the resulting loss through the PGA When prices fall below predicted levels the PGA adjusts prices downward. IN spite of the relief available for price risk mitigations through regulatory mechanisms, it may still be in the interest of an LDC to develop other risk-management strategies for a number of reasons.

PGAs may not always result in complete cost pass-throughs and the rate relief may be delayed. PGAs allow a state commission and intervenors to scrutinize an LDCs expenditures. Furthermore, both the continued existence and the particular forms of the PGA may be open to future regulatory reform. Currently some states do not have PGAs.[1] Therefore, while an LDC will probably continue to use the PGA as a price-risk-mitigation option, it still may wish to pursue other risk management options.

Price risk can be mitigated by tailoring contracting and purchasing practices to meet specific risks. Long-term price risks can be mitigated either by designing long-term contracts that "lock in" low prices available in times of supply surpluses or that incorporate market-sensitive pricing terms (such as market-out clauses) in times of supply shortages. Short-term price risk can be mitigated by using regulatory mechanisms such as the PGA. Risk due to seasonal price fluctuations can also be managed by purchasing gas at low prices during the summer and storing it, thus reducing the volume of expensive gas purchased during the winter.

Supply risk can be managed by diversifying the supply portfolio, purchasing peak-load gas from proven suppliers, using storage, and contracting for firm transportation. Mitigating such risks generally comes at a price, however.

Demand risk is relatively more difficult to manage. A supply shortage (caused by excessive demand) can be prevented by using a conservative estimate of peak and volumetric demand and assuring sufficient supply through the use of firm supply contracts, storage, and firm transportation contracts. The higher the reliability sought, however, the higher the cost to the LDC and its customers. A supply surplus caused by low demand presents a different kind of problem for an LDC. If it is caused by customers switching to an alternate fuel, the LDC may have to recover the resulting revenue loss from remaining customers. If the decline stems from unexpected changes in weather (such as an unusually warm winter), rates may have to be raised for all customers This may result in a loss of customers having dual-fuel capability, which

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[1] Robert E. Burns, Mark Eifert and Peter A. Naylor, *Current PGA and EAC Practices: Implications for Ratemaking in Competitive Markets* (Columbus, OH: The National Regulatory Research Institute, 1991).

again may lead to an increase in rates for core customers only. Other options available in a supply surplus situation include holding excess gas in storage and reducing deliveries from upstream suppliers to the extent that such actions are feasible.

Gas Storage

Because of the highly seasonal nature of demand for gas and the limitations on gas production and transportation capacities, storing gas in depleted gas and oil wells and other reservoirs has been used often by producers and pipelines to balance the input and outflow of gas. In the past, the use of storage by local distribution companies has been less prevalent and generally on a smaller scale than pipelines.[2] As LDCs take on more of the aggregation and coordination tasks previously performed by pipelines, use of storage by LDCs is likely to increase.

Most gas storage technologies are well developed with reliable operational and cost information. Technologies include underground reservoirs made of porous rock or sand formations found in depleted gas, oil, and coal fields and in aquifers (water-saturated rock formations). Mined caverns in hard rock formations, above-ground storage tanks, and pipelines also can be used for storing gas.

According to data compiled by the American Gas Association, there are 395 underground storage sites located in twenty-seven states with a total capacity of 7,737,197 million cubic feet (MMcf), and a maximum daily sendout of 46,503 MMcf.[3] Among various gas storage alternatives, underground reservoirs that use depleted gas and oil fields are generally superior in terms of their overall effect on gas availability and cost.[4]

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[2] See Daniel J. Duann, Peter A. Nagler, Mohammad Harunuzzaman, and Iyyuni Govindarajan *Gas Storage: Strategy Regulation and Some Competitive Implications* (Columbus, OH: The National Regulatory Research Instittue, 1990), 48 – 52.

[3] American Gas Association, *1990 Gas Facts* (Arlington, VA: The American Gas Association, 1990), 51.

[4] Duann et al., *Gas Storage*, 13 – 52.

If suitable geological formations and transportation pipelines can be located, a local distribution company can develop and operate its own storage facilities. In certain areas of the country where winter demand for gas is high (such as New England), the LDCs also can build above-ground tanks to store gas. Above-ground storage is rather costly and the quantity of gas that can be stored is limited. In many instances an LDC pays a fee to use or reserve storage capacity provided by other entities, primarily pipelines and producers. Many state public service commissions have recognized the importance of storage as a gas supply management tool and have specified methods for setting storage fees and for allocating the benefits of storage among ratepayers, LDCs, and storage providers.[5]

The primary rationale for using gas storage is to shift gas acquisition and transportation operations from peak to nonpeak periods. An LDC can purchase low-priced gas in summer, hold it in storage for winter use and thus reduce its purchase of high-priced winter gas. Storage also can reduce the demand-related charges associated with firm transportation and sales contracts, and possibly avoid the congestion of certain transportation routes during peak demand periods.

Storage provides an excellent tool to manage an LDCs price risks. Storage not only provides a means of managing the *normal* price fluctuations between summer and winter, it can also be used to mitigate the risks of *unusual* price variations (for example, because of unusually cold or warm winters) between the seasons.

Storage is also a good tool for mitigating supply and demand risks. Besides providing reserve capacity to meet normal swings of demand, it also allows an LDC to meet unusually high demand (for example, because of an unusually cold winter) and unanticipated supply emergencies (for example, nondelivery of gas by a contract supplier).

The usefulness of gas storage to a particular local distribution company, however, may be site specific. The LDC may not simply have access to economical storage capacity. Also greater use of storage, even if it frees some transportation capacity

[5] A review of current state and federal regulations of gas storage can be found in ibid., 83 – 149.

through certain routes, may increase the demand for transportation through other routes from and to the storage site.

Buying and Selling Gas Futures

Of the three broad categories of business risks faced by an LDC, two-price risk and demand risk-can be mitigated through futures trading. Since the futures market is highly organized and the contract itself is standardized, little effort is required on the part of an LDC to ascertain the capability, reliability, credit, or idiosyncrasies of the potential sellers. Furthermore, only a relatively small amount of money is involved in buying and selling gas future contracts. So, buying and selling in the futures market can be a relatively easy and economical tool, in combination with other purchase alternatives, for managing an LDCs supply portfolio and business risks.

Two kinds of price risks need to be considered in the context of futures trading. First, an LDC may hold title to an inventory of gas for later sale (that is, hold a "long" position in the cash market). Even if the LDC does not physically hold the gas, a firm one-year or a multi-year contract with a price escalator puts it in the same position. If the market price of gas falls relative to the contract price prior to delivery, the LDC will be incurring a higher cost than other buyers. Second, an LDC purchase plan may include spot purchases to be made at a certain future period (that is, a "short" position) based on its expectations about future prices. If the price, however, rises above the expected price, the LDC still may have to buy the gas. The LDC now faces a loss because it still has to sell the gas at a regulated rate which may be below market price.

The most important source of demand risk is the possibility that the load projections made by an LDC may not materialize. This can happen either due to a loss of spaceheating load (in an unusually warm winter) or industrial load (caused by, among other things, adverse market conditions for a manufactured commodity that uses gas). Another source of demand risk is the dual-fuel capability of certain customers. Residual fuel oil is a substitute for gas. When the price of oil falls relative to gas prices, customers with dual-fuel capability can switch to the alternate fuel, the result being a significant loss of revenues to the LDC.

Futures Trading Strategies to Mitigate Price and Demand Risks

There are many strategies available to mitigate price and demand risks.[6] The basic strategy consists of taking a position in the futures market that is equal and opposite to that in the physical (cash) market. A "long" position in the cash market can be matched by a "short" position (a "short" hedge) in the futures market and vice versa (a "long" hedge).[7]

A short hedge is illustrated as follows. Assume that an LDC has a firm contract which stipulates taking delivery of 10,000 MMBtu of gas at $2.00/MMBtu five months from now. The current date is December 1, 1991 and the delivery date is May 1, 1992. The May futures contract price is $2.00/MMbtu. The long position in the cash market can be offset by taking a short position in the futures market (that is, by selling 10,000 MMBtu worth of May futures contracts). Now assume that on May 1, 1992, the market price of gas is $1.90/MMBtu as is the May 1, 1992 price of future contracts. The LDC closes its short position by buying a futures contract at $1.90/MMBtu. The LDC has suffered a $1,000 loss in value of its inventory, but it also has gained $1,000 on its futures

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[6] The following discussion is not intended to provide a comprehensive overview of the uses of futures trading by an LDC. For detailed overviews, see Edward H. Jennings, "The Use of Natural Gas Futures by Local Distribution Companies," *NRRI Quarterly Bulletin* (December 1991): 481-92;" J. A. Rosenkranz, "Should Gas Distributors Trade Futures?" *Public Utilities Fortnightly* (May 1, 1991): 31-34; and J. W. Trace, "Hedging LDC Price Risk in the Futures Market," *Public Utilities Fortnightly* (October 25, 1990): 31-36. For a general introduction to the subject, see David Wirick, "Establishment of the Natural Gas Futures Market: Regulatory Watershed or Non-Event?" *NRRI Quarterly Bulletin* (June 1991): 217-27.

[7] A "long" position represents the possession or the obligation to take delivery of a certain commodity. A “short” position represents the obligation to deliver a certain commodity. In the physicals or case market, the possession of or the execution of sales contracts to deliver the commodity constitutes a “short” position. IN the futures market, the purchase of a futures contract constitutes a “long” position while the sale of a futures contract constitutes a “short” position.

contract. The loss in value on its firm contract is exactly offset by the gain on the futures contract.

Now let us examine what would happen if the market and futures price were $2.10/MMBtu on May 1, 1992. In this case, the LDC would gain $1,000 on its inventory, but would lose $1,000 on its futures contract.

In both cases, the short hedge has the effect of making the long-term contract sensitive to gas price market movements. Similarly, one can construct an illustration of a long hedge. The net effect of a long hedge is just the opposite of a short hedge. It allows a buyer to "lock in" a certain price which makes it indifferent to future movements of market prices. This can be done either by a futures contract or any other form of forward contract.

It is important to discuss how an LDC may choose one of the two hedging strategies under any given circumstance. Clearly, it would depend on an LDCs inventory of long-term contracts and on its perception of whether the pricing terms of the contracts were favorable or unfavorable relative to its expectations of future market prices of gas. If an LDC is bound by a large number of long-term contracts to buy relatively expensive gas and it expects future prices of gas to be generally lower, it would likely opt for the short hedge. On the other hand, if an LDC does not hold a significant number of long-term contracts and it expects future spot prices of gas to be generally higher than what is offered on futures contracts, the long hedge would be the strategy of choice. Clearly, if an LDC engages in hedging in the futures market to mitigate its price risk, it has to adjust its hedging strategy in response to changes in the gas market and switch from one strategy to the other as needed.

These are examples of intertemporal hedging of price risk caused by movements of gas prices over time. The LDC faces another kind of risk arising out of fluctuations of demand imposed by the non-firm segment of its customer base who have the option of switching to an alternate fuel. This risk can be mitigated by a strategy known as intercommodity hedging[8] For an LDC this strategy would consist of taking equal and opposite positions in the futures market for gas and oil. For example, an LDC could take

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[8] Rosenkranz, "Should Gas Distributors Trade Futures?" 31 – 34. See also Trace, "Hedging LDC Price Risk in the Futures Market," 31 – 36.

take a long position (buy futures) for gas and a short position (sell futures) for oil. If gas prices increased relative to oil prices, the LDC would make a profit selling gas futures, buying oil futures or both to close out its futures contracts. This should offset any loss of revenues it suffers as a result of decreased gas demand caused by the increase in gas prices. If the opposite happens, that is, if gas prices decrease relative to oil prices, the LDC will suffer a loss on its futures contracts. But the loss will be offset by a probable gain in its revenues due to increased sales of gas.

Risks and Limitations of Gas Futures Trading

Futures trading is not without risks. The examples described above assume a well-functioning futures market. This assumption may not hold at all times. Ideally, futures prices reflect rational expectations of market participants based on available information. While a well-functioning spot market adjusts prices in response to *actual* demand and supply, a futures market reflects *expectations* about future demand and supply. If the futures market also is well-functioning, the two processes should converge. A futures market, however, cannot perform any better than the best predictive ability of the various forecasting tools used by the market participants. Needless to say, forecasts can be wrong, sometimes quite significantly. This is especially true if certain perceived triggering events are grossly misinterpreted. For example, in August 1990, speculation about skyrocketing oil prices in the aftermath of the Iraqi invasion of Kuwait sent gas futures prices soaring while spot prices held steady. After several weeks, spot prices showed little movement which eventually brought futures prices down.[9] Even when a futures market is working well, hedging opportunities available to individual traders may be limited.[10]

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[9] New York Mercantile Exchange, *NYMEX Energy in the News* (Washington, D.C.: NYMEX, Fall 1990).

[10] For an excellent discussion of the role of futures see Jennings, "The Use of Natural Gas Futures."

The LDC is not in the same position as other traders in the futures market either with respect to its price risks or the effectiveness of hedging strategies. The LDC is obligated to sell gas at regulated rates to an essentially fixed group of customers while another trader, such as a marketer, is free to sell gas at negotiated prices to a diverse group of customers. For this reason, the marketer can use hedging opportunities much more effectively than an LDC. In the short hedge example discussed earlier, the LDC effectively converts its firm contract into a market-sensitive spot contract. When the market price is below the long-term contract price, the LDC makes a net cash gain of $1,000. When the market price is above the long-term contract price, it suffers a net cash loss of $1,000. The offsetting loss in the first case (market price below contract price) and the offsetting gain in the second case (market price above contract price) cannot be realized in cash because the LDC is not free to resell its inventory in the wholesale market. A marketer, however, is not so constrained. In the first case, the marketer can either sell its inventory, which would exactly offset its gain of $1,000, or hold onto its inventory and retain its $1,000 profit. In the second case, it has the option of selling its inventory and making a profit of $1,000, which would exactly offset its loss of $1,000 in the futures market. It can also opt to sustain a $1,000 cash loss by holding on to its inventory. Thus compared to a marketer, the hedging benefits are limited for an LDC. Intertemporal hedging allows the LDC to make its purchase prices market sensitive when market prices are expected to be lower than contract prices, and "lock in" current low futures prices if future market prices are expected to be higher. Thus, the hedging benefits to be reaped from futures trading depend strongly on an LDCs ability to predict future prices in the gas market. A marketer is less susceptible to the risks of futures trading and price movements in the market primarily because it is an unregulated entity.

There are other limitations on the benefits an LDC can achieve through hedging Futures markets allow buyers to hedge their price risk only for the next eleven months and therefore are of no value if a longer-term hedge is sought. Forward contracts, such as long-term purchase contracts, are the only options to hedge price risks beyond one year. Another limitation pointed out by Jennings is the fact that the LDC can only hedge a long-term contract if the price of gas in the contract exactly matches that of a futures contract.[11]

Finally, while futures trading can be used to manage price risk, it provides very little protection from what is known as basis risk. *Price risk* refers to the exposure of participants in gas markets to the risk that natural gas *prices* will vary from their expected future values. *Basis risk,* on the other hand refers to the exposure of the market participants to the risk that *price spreads* (seasonal and regional) will vary from their expected values.[12]

Regulatory Treatment of Futures Trading

Perhaps the most significant reason for the lack of interest on the part of LDCs to participate in the futures market lies with regulatory practices. Most state PUCs allow LDCs to recover their gas costs through purchased gas adjustments (PGAs) when gas prices deviate from those used to set base rates. This essentially eliminates all price risk to an LDC caused by intertemporal (unexpected) price movements and therefore removes all incentives for participation in futures markets. PGAs, however, do not remove demand risks imposed by dual-fuel customers and LDCs still may gain by engaging in intercommodity hedging. Also, LDCs in certain states do not have PGAs and these could mitigate their supply related price risks through intertemporal hedging.[13] Therefore, certain incentives still remain for LDCs to engage in futures trading. Yet, there has been very little LDC participation in futures trading presumably because of a lack of recognition of its potential benefits and the uncertainty of regulatory treatment of gains and losses.

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[11] Ibid.

[12] For a more detailed explanation of price and basis risks, see Energy Information Administration, *Annual Outlook for Oil and Gas 1990* (Washington, D.C.: Energy Information Administration, 1990), 71-73.

[13] Michigan and Vermont currently do not have PGAs. See Burns et al., *Current PGA and FAC Practices*, 14.

Regulators may harbor an ambivalent attitude toward futures trading because of its association with speculation. This may reflect concerns that forces other than demand and supply can sometimes determine prices in futures markets. These are legitimate concerns. But it needs to be acknowledged that speculation performs a useful function by shifting risks away from hedgers to speculators, an essential task for efficient functioning of the futures market.[14] The regulator may also be concerned with the possibility of an LDC engaging in imprudent or inappropriate trading which may amount to "gambling with ratepayers' money."

Given the potential benefits of futures trading for an LDC and the possible skepticism of regulators about its value, one needs to address how these conflicting realities can be reconciled. A rational approach would be to develop guidelines on what trading activities are to be permitted, what part of the LDCs purchase portfolio will be allowed to be hedged, and how potential gains and losses from trading will be shared between ratepayers and shareholders. Clearly, an LDC should not be allowed to speculate and the distinction between hedging and speculation needs to be set.

The Financial Accounting Standards Board (FASB) provides guidelines on how to distinguish between speculation and hedging.[15] These can be adopted by state commissions. Next, the state regulator may provide general guidelines based on current market conditions and best available forecasts about the future on which trades have the best potential for price-risk mitigation. As discussed, in times of relatively low market prices (such as now) and no foreseeable change in the immediate future, it is best to hedge preexisting and relatively expensive firm contracts (the short hedge). This affords two benefits. The effective prices (contract price minus potential gains from futures trading) at which gas is purchased can be brought closer to relatively low market prices. At the same time, the reliability advantages of firm contracts are maintained which would otherwise not be available if the contracts were abandoned and replaced by spot purchases. On the other hand, if current market prices are low but expected to rise in the

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[14] Jennings, "The Use of Natural Gas Futures."

[15] Financial Accounting Standards Board, *Original Pronouncements* (Irwin, Homewood, IL, 1990), 777-92.

immediate future, it is best to "lock in" current prices either through futures contracts or other forward contracts. In the latter case, a forward contract may be superior to a futures contract in the sense that it has very little delivery risk. Finally, a state regulator has to decide how to allocate the gains and losses from futures trading. This decision is no different from that in which the regulator decides how to apportion cost overruns or underruns from an investment that was judged previously to have been prudent, or how to allocate above-normal profits or losses in a given rate period. This is a broad and generic issue that should be resolved according to regulators' preferred risk-sharing philosophy.

Later chapters address in some detail how different risk-sharing principles offer differing incentives for cost minimization. A few observations, however, are in order. The regulator has a range of options between the extremes of allocating the entire risk of futures trading either to the investors or the ratepayers. Allocating all risk to investors would tend to make the utility a more prudent trader, but also would deprive the ratepayers from any resulting benefits. Allocating all risk to ratepayers gives little incentive for the LDC to be prudent but offers the possibility that the ratepayer will benefit when certain trades result in gains. The optimal sharing mechanism presumably lies somewhere between the two extremes. The sharing scheme is not the only means of enforcing prudent trading, however. Trading guidelines set ex ante and prudence reviews conducted ex post can also help enforce the regulator's prudency goals. The regulator can design a policy which combines regulatory guidelines, incentive sharing and prudence reviews to ensure prudent trading and maximize its benefits to the ratepayer.

One final important issue that needs to be addressed. If regulators were to choose futures trading as an appropriate activity for an LDC to mitigate its price risk, should PGAs be retained? The PGA mitigates an LDCs price risk by shifting it to the ratepayers. Futures trading offers an opportunity to shift this risk either in part or in whole to the LDC Since the LDC may be allowed to engage in trading only as a hedger, it can shift most of the risk to the speculator. This argues for eliminating PGAs once a determination has been made that futures trading is an appropriate and effective instrument for mitigating price risks for LDCs. Making this determination, however, is far from straightforward.

Certain criteria can be set up to help evaluate the relative merits of PGAs and futures as instruments for price risk mitigation. The first set of criteria would be used to evaluate the functioning of the gas futures market and the potential effectiveness of hedging as a risk mitigation tool. The second set of criteria would be used to evaluate the historical performance of PGAs as an instrument for cost efficiency. The two criteria do not have any exact correspondence because the two instruments serve slightly different ends. PGAs were designed primarily to adjust rates promptly to changes in purchase prices of gas. Futures trading may allow the utility greater control over purchase prices and reduce the need to adjust rates. In effect, PGAs provide a back-end adjustment to changes in gas purchase prices while futures trading may allow the same adjustment to be made at the front end.

The other major difference between PGAs and futures trading may be termed as experiential. PGAs have been in use for some time, and utilities as well as regulators have significant experience in designing procedures and implementing PGAs. Regulators also have considerable knowledge of how best to use PGAs to promote efficient utility operations and possible limitations of using PGAs. Utilities also have considerable expertise in gathering data and preparing presentations for PGA submissions. Futures trading would be a new activity for LDCs and would require new oversight tools for regulators. Futures trading requires specialization and significant expertise in predicting market trends which any LDC is unlikely to have at the present time. If an LDC chooses and is authorized to engage in futures trading, it may have to invest in expert personnel, information processing, and other resources to equip itself for this activity. The PUC may have to make similar investments to prepare itself for appropriate oversight activities.

Several approaches can be suggested for making a determination of whether PGAs or futures trading is preferable for price-risk mitigation from a regulator's perspective. First, a state commission should evaluate its PGGGA and determine whether it has worked well in the past. If it has, it can examine whether allowing the LDC to engage in futures trading is going to improve its efficiency significantly. To do this comparison, all potential costs (including the cost of doing the study) and benefits (savings) associated with PGAs and futures trading need to be studied and quantified if possible. A state PUC can perform such a study itself or ask the LDC to do so. If the study indicates that there are significant benefits to participating in futures trading, then the commission can develop guidelines and take other steps necessary to authorize and oversee the LDCs trading activities.

Another possible approach is to permit futures trading for a small part of the LDCs total gas purchase requirements and eliminate the PGA for this part of the gas costs. Preferably, this component of the gas costs would come from noncore supply requirements, and intercommodity hedging rather than intertemporal hedging would be used. As the LDC gains expertise in futures trading and commissions gain more confidence in the operation of the futures market, it would be possible to expand the volume of gas futures traded.

The two approaches suggested here are not mutually exclusive. Some evaluation of the potential costs and benefits may have to be made even if a gradualist approach to futures trading is adopted. In conclusion, the futures market offers a new and significant opportunity to an LDC to optimally manage its purchase portfolio. It certainly deserves to be explored.