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NATURAL GAS PRODUCER-DISTRIBUTOR CONTRACTS: STATE REGULATORY ISSUES AND APPROACHES

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EXECUTIVE SUMMARY

The natural gas transportation policy currently being fashioned at the Federal Energy Regulatory Commission (FERC) is changing the way in which gas is bought and sold in the U.S. and the way in which its cost is regulated by state public utility commissions. Local gas distribution companies are likely to have much greater freedom in contracting for gas than during any period in the history of the industry. Instead of relying mostly on its traditional interstate pipeline supplier(s), a distributor may have future opportunities to participate directly in the wellhead gas market and to arrange to transport the gas it buys through interstate pipelines that have decided to participate voluntarily in the federal gas transportation program under the FERC Orders 436 and 500. Consequently, state regulators are faced with the prospect of reviewing, understanding, and overseeing a distributor's contractual arrangements for gas supply to a much larger extent than was the case when a FERC-regulated pipeline was the distributor's principal supplier. This report examines several facets of the resulting effects on state regulatory policies, procedures, and oversight activities, recent changes in the federal transportation program, and quantitative models to determine an optimal portfolio of gas supply sources.

The FERC Order 500 is a recent change in the nation's gas transportation policy. It requires a producer to offer a pipeline credits against take-or-pay liability for gas that the producer wishes to transport through the pipeline company's facilities. The Order is an interim rule that should make it easier for pipelines to obtain relief from take-or-pay liabilities that might be made worse when a pipeline transports gas. In this way, the Order eases the tension that some pipelines have encountered in attempting to make the transition from the role of gas merchant to that of gas transporter.

State regulators must be aware that Order 500 allows a pipeline company to extract take-or-pay credits from a producer with regard to a set of contracts between the pipeline company and the producer in exchange for an agreement by the pipeline company to transport gas sold by the producer to some other customer under an entirely separate set of contracts. Because of the transition difficulties facing the gas industry, the D.C. Circuit Court has affirmed the Commission's interim crediting plan in Order 500, thereby approving this idea, which, in effect, uses one set of contracts to hold hostage another. It should be noted that both the Court and the Commission have expressed concerns over the privity of contracts. In their opinion, Order 500 does not constitute crass, governmental abrogation of contracts, in the context of the current transition and in light of the fact that government rules are required in order to transport gas in the first place.

It is difficult to know how the crediting mechanism will work in practice, which depends upon the interrelationships among contracts and physical links between producers and pipelines. The data request issued by the FERC in Order 500 should help industry analysts understand the Order's implications.

Two issues, in particular, could be studied further with the data. First, the Commission may wish to impose a limit to the crediting mechanism. In certain circumstances, the combined actions of many LDCs converting their contract demand to firm transportation services can effectively convert a producer's high-priced, take-or-pay gas into lower-priced gas to be sold in the spot market and transported by the pipeline. The conversion occurs because the crediting mechanism operates in terms of volumes. The dollar value of one million Mcf of take-or-pay obligations may be converted into the dollar equivalent of one and a half million Mcf of transportation gas, because of the difference in the two prices. There are several natural limits to this kind of conversion, but importantly, there is no limit to it in Order 500.

The producer's option to not transport at all establishes a limit to how much of his high-priced take-or-pay gas can be replaced by lower-priced transportation sales before he would choose to forego the transportation option, and instead hold the pipeline to its take-or-pay obligations. The action of some producers withholding their transportation gas might place upward pressure on spot prices in the short term. Other producers may find the choice to be unattractive and may be exposed to the risk that all or most of their take-or-pay obligations are effectively eliminated on a continuing basis by Order 500. Less extreme cases are more probable. Better data are needed to ascertain the extent of any such effects under Order 500, and also to assess the resulting economic efficiency. In some circumstances, a limit to the crediting formula (for example, a producer might offer credits for up to, say, 25 or 50 percent of its annual take-or-pay obligations with a pipeline) might improve both economic efficiency and horizontal equity among producers. Economic efficiency would be improved by the inclusion of such a limit if Order 500, as written without a limit, were to convert a larger fraction of the nation's long-term secure gas contracts into spot contracts than would be consistent with the optimal aggregate mix of long and short supplies. (This is an abstract, but nonetheless real, concept of efficiency that would be difficult to evaluate in practice.) Horizontal equity would be improved if some small set of producers is exposed, in the absence of a limit, to very large financial risk because of the effective elimination of their take-or-pay contractual provisions.

A second issue for possible further study is the interaction between Orders 451 and 500. Contracts terminated under the good-faith bargaining rule of Order 451 are not subject to the crediting requirement of Order 500. In Order 451, the Commission does not require a producer to repay the pipeline for any take-or-pay prepayments that might remain when a contract is terminated. The Commission's logic in Order 451 was that it did not want to interfere with the negotiation process. The clause exempting a producer from the crediting rule in Order 500 is consistent with its Order 451 negotiation rule. That is, if the Commission allowed transportation credit for gas released under the Order 451 good-faith negotiation rule, it would effectively eliminate the contract's take-or-pay prepayments. The Commission explicitly declined to do this in Order 451 and has decided that the transportation credit formula in Order 500 will not be allowed to do the same thing implicitly. A neutral policy, it could be argued, would allow such credits up to the accumulated amount of the prepayments, regardless of the identity of the transporting pipeline. Since Order 451 was adopted before the Court had given implicit approval of the idea of a crediting rule, the Commission may wish to address the issue again in fashioning a final rule.

To assess state commission actions and procedures regarding distributor-producer contracts, the NRRI conducted a survey of the commissions during the summer of 1987. Most commissions review the gas supply contracts of their jurisdictional distributors as part of a purchased gas adjustment process. Almost all states reserve the right to subject a distributor's purchasing practices to a prudence review, although few have actually conducted such an investigation. Many states have a requirement, sometimes mandated by statute, that a distributor must purchase a least-cost portfolio of supplies though the meaning of "least-cost" is necessarily imprecise. Reliability and dispatchability are examples of service quality differences that are difficult to measure in the same terms as price. Other than a prudence review or a least-cost requirement, most states do not have any other mechanism to create an incentive for a distributor to purchase gas efficiently. An example of such a mechanism, used in a few states, is a formula that would allow a distributor to keep a portion of the savings achieved by a reduction in supply costs.

Also in the summer of 1987, the NRRI collected a sample of long-term gas supply contracts between producers and distributors. The collection costs were high and the sample is relatively small, consisting of 28 contracts suitable for detailed quantitative analysis. The current transition period that the gas industry is experiencing is only partially completed, and that which we have observed has occurred while the market has been slack. Also, the sample is not necessarily representative (the distributors are mostly in the Midwest). Despite these limitations the sample is nonetheless suggestive. It shows that in a slack gas market, as currently exists, contract prices for gas are likely to be about 20 cents per Mcf, or about 9 percent, higher than spot prices. That differential tends to be smaller at higher levels of the spot and contract prices. These observations are consistent with the behavior of contract and spot prices in other markets.

Contractual terms appear to influence the initial price in a contract. The NRRI classifies the most important contractual clauses as affecting the buyer or seller's flexibility of adjusting either future prices or future quantities. The NRRI constructed an index to measure price adjustment flexibility and quantity adjustment flexibility by ranking the contracts according to the contractual terms in each contract that are relevant to each notion of flexibility. Price and quantity flexibility have an effect on the initial price in a contract because they represent types of risks borne by the buyer and seller as future circumstances change. These contractual risks vary for two reasons. A distributor may wish to have a range of contracts with adjustment terms from easy to difficult to correspond to the profile of risks associated with its demand conditions. Also, risk conditions can differ between distributors, and for that reason a particular distributor may adopt more rigid contract terms to compensate partially for local-specific risk. These two reasons give conflicting expectations about how quantity flexibility in a contract, for example, will affect the initial contract price. The first reason suggests that more rigid quantity terms should be associated with a lower contract price, while the second suggests rigid quantity specifications in a contract can partially offset local, high-risk conditions that result in higher prices. Consequently, identifying and estimating these separate effects require a particularly rich data set. The small sample collected by the NRRI, not surprisingly, is only partially successful in unraveling the relation between contract price and contract terms. Because of the geographical variation within the sample, the adjustment indices are mostly a proxy for supply security and therefore are estimated to increase the contract price. A richer data set is needed to disentangle the relationships further.

Data Envelopment Analysis is a promising technique for assessing the relative efficiency of regulated entities, or in this case, gas supply contracts. The use of the technique in this report is intended as an introduction of it to the state regulatory community. By using the DEA procedure, a staff member can find an efficiency index for each entity (production unit or a contract) in his sample, based upon the construction of a frontier that literally envelopes the sample, called the "best practice frontier." Comparisons of individual entities with the best practice frontier form the basis of the efficiency measurement. This idea can be used to examine a set of contracts and to identify those that appear to deserve additional scrutiny. In this way, a commission staff member could concentrate discussions with a distributor's gas supply manager on those contracts that are unusual in price or contractual terms.

Besides assessing the merits of individual contracts, commissions must be concerned also with the overall gas purchasing strategy of an LDC and the resulting portfolio of gas supplies. There are a number of quantitative techniques that commission staff members might use to assess a distributor's plan. Two promising techniques are the mean-variance analysis associated with financial portfolio theory and a two-stage linear programming formulation of the supply mix problem. Both techniques are amenable to computer solution using mathematical programming software packages that are commonly available.

Either of these types of models could form the basis of a screening process by which obviously inferior supply sources are identified and eliminated. Following the screening process, more detailed analysis of the portfolio selection problem could be conducted using an NRRI computer model, GASMIX. The model is a user-friendly program written in FORTRAN to run on a mainframe computer. It analyzes the supply mix problem of a distributor using a sophisticated combination of linear programming and simulation techniques.

Because of the complex and changing nature of the natural gas industry, it is not possible to anticipate now the variety of problems likely to confront state regulators in reviewing and overseeing a distributor's gas purchasing plan. This report deals with several important issues, including the implications of the FERC Order 500, the relation between long-term contract prices and spot prices and also between contract price and other contractual terms, the efficiency of individual contracts, and the nature of an optimal portfolio of gas supply sources. Additional issues will continue to emerge as this industry adjusts to its new configuration of competitive wellhead markets and regulated transportation services.

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FOREWORD

This report deals with gas supply contracts and the new context in which they take place; their intent and how their various elements may be technically analyzed in order to achieve appropriate levels of commission oversight. Two surveys were conducted by the NRRI to secure basic data--one involving review of actual gas contracts and one ascertaining existing state commission treatment of distributor-producer contracts. Several methods of quantitative analysis are offered for use in examining the phenomenon of direct purchases.

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CHAPTER 1

INTRODUCTION

The natural gas transportation program currently being fashioned at the Federal Energy Regulatory Commission (FERC) is changing the way in which gas is bought and sold, and the way in which its cost is regulated by state public utility commissions. Local gas distribution companies (LDCs) are likely to have much greater freedom in contracting for gas in the future than at any time in the history of the industry. Instead of relying mostly on its traditional interstate pipeline supplier(s), an LDC may have future opportunities to participate in the wellhead gas market directly and to a greater extent than in the past. The FERC transportation program under Orders 436 and 500 allows a supply manager of an LDC to arrange the transportation needed to move gas that he may wish to purchase from producers in distant fields. The federal gas transportation policy remains unsettled at this writing; nonetheless, the industry appears to be moving toward a structure where the interstate pipeline companies will provide significant transportation services in the future, as opposed to their merchant function of the past. State regulators, then, are faced with the prospect of reviewing, understanding, and overseeing an LDC's contractual arrangements for gas supply to a much greater extent than was the case when a FERC-regulated pipeline was the LDC's principal supplier. This report seeks to familiarize state commissioners and staff members with several aspects of the gas market in general and with gas supply contracts in particular.

State commission staff members may not be fully familiar with the regulatory oversight and management that will be needed to monitor direct gas purchases by local distributors. Heretofore, state commissions could rely on the FERC to review the appropriateness of interstate pipeline purchasing practices. Local distributors may buy some gas from local producers, but most often the bulk of a distributor's supplies currently comes from interstate pipelines that are under FERC jurisdiction. The FERC Order 436 may change this if many pipelines decide to accept the FERC offer of becoming nondiscriminatory carriers, and if local distributors decide to exercise their option to reduce their contract demand with pipelines. If such circumstances actually occur, state commissions need to be prepared for more detailed and extensive review of purchasing contracts.

Commissions must be prepared to monitor and track a distributor's gas costs. In many cases, cost tracking mechanisms are used already by commissions, and may need only minor modification. Monitoring the terms of the gas contract, however, is likely to be a new activity in most commissions. The issues are similar to those involved in overseeing the coal contracts of electric utilities. The monitoring of gas contracts can be approached in two ways. One is to audit or examine the utility's own purchasing practices. The second is to compare a distributor's contracts with those of other LDCs, possibly those within the commission's jurisdiction. Since the detailed regulation of direct gas purchases is relatively new to commissions, some may be interested in supplementing the audit function with some comparative analysis. Both approaches are addressed in this report.

Since the importance of an LDC's direct gas purchase contracts stems from the federal transportation policy, this report begins in chapter 2 with a discussion of the evolving industry structure and the recent FERC Order 500. The chapter contains a brief review of the federal transportation programs up to and including the FERC Order 436. The more recent FERC Order 500 is described in greater detail, including an analysis of some policy implications of the Order. This material should be interesting to state commissions because the issue has to do with regulatory treatment of take-or-pay terms in pipeline-producer contracts and also because the federal resolution of the issue will affect the transportation options available to an LDC.

To help focus the report on gas contracts, the third chapter describes the typical kinds of gas contracts used in the industry. An important distinction is made between spot market contracts and longer-term contracts. The chapter describes the typical clauses and terms in both types of contracts, and discusses what regulators might expect to be reasonable behavior of spot prices versus contract prices.

The NRRI conducted a survey of state commissions to ascertain their policies and procedures regarding a jurisdictional gas company's direct gas supply contracts. The results of that survey are summarized in chapter 4 and described in greater detail in appendix A. This chapter should be interesting to commissioners who would like to know the policy direction taken by other state commissions.

The NRRI also collected a sample of long-term gas supply contracts signed by distributors in Kentucky, Ohio, Michigan, and Mississippi. The sample is small, only 28 long-term contracts met all of our requirements. Nonetheless, its detail permits a sophisticated statistical analysis to be made of the relationship between the initial price of a long-term contract and such factors as the prevailing spot price and the presence or absence of contractual terms like a take-or-pay clause. The quantitative analysis is presented in chapters 5 and 6, and the sample itself is described in appendix B. Chapter 5 contains an analysis based on conventional statistical concepts like mean, standard deviation, and regression analysis. Chapter 6 reports on an analysis of the sample using a recently developed technique called Data Envelopment Analysis (DEA). The DEA technique can be used to identify those contracts that are efficient (in a particular sense) and those that are inefficient by comparison. The technique is quite general and could be used to study the relative efficiency of other aspects of public utility regulation, such as power plant productivity issues or inter-utility performance measurements. In part the NRRI is using this report to illustrate the use of DEA to the state regulatory community. It has not been included in previous NRRI performance measurement studies.[1] The Public Utility Regulatory Commission of Texas, however, has used the technique to assess the efficiency of electric cooperatives.[2] Since this is

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[1] See, for example, Luc Anselin and J. Stephen Henderson, A Decision Support System for Utility Performance Evaluation (Columbus, Ohio: The National Regulatory Research Institute, 1985).
[2] Dennis L. Thomas, Auditing the Efficiency of Regulated Companies: An Application of Data Envelopment Analysis to Electric Cooperatives (Austin, Texas: IC² Institute, The University of Texas, 1986).

the first occasion for use of DEA by the NRRI, a technical description of the technique is included as appendix C of this report, for more technically-oriented commission staff members.

Chapters 3 through 6 of the report, then, deal with issues regarding an individual contract--its typical construction, its price, the relation between its price and other factors, and its relative efficiency. Chapter 7 discusses the issue of combining such contracts into a supply portfolio so as to manage the risk now facing an LDC that decides to purchase a large fraction of its supply directly from producers. Two approaches are identified in the chapter--the mean-variance analysis associated with financial portfolio theory and a two-stage model of decision making under uncertainty. Both approaches are extensions of a previously developed gas supply model discussed in chapters 5 and 6 of the NRRI report Natural Gas Rate Design... (cited in footnote 1). That model, called GASMIX, has been modified for easier use on a main frame computer. A user's manual for GASMIX is in appendix D of this report. The model is available to commissions through the NRRI model dissemination program. Chapters 5, 6, and 7, as well as appendices C and D, discuss quantitative methods commissions could use to examine individual gas purchase contracts and portfolios of contracts. The material is presented in a descriptive manner for the most part; however, some technical details are also discussed.

This report deals with state commission concerns about gas supply contracts at several levels--from policy analysis of the federal transportation program and a description of state oversight procedures to technical modeling of an LDC's portfolio choice problem. The intent is to present the policy issues to state commissioners and staff members and to suggest analytical approaches to them that may be helpful in assessing the contracts and the supply plans of a distributor.

CHAPTER 2

NATURAL GAS TRANSPORTATION ISSUES

Prior to 1984, the major suppliers for virtually all local gas distribution companies outside of Texas, Louisiana, and Oklahoma were interstate pipeline companies. The pipeline companies purchased gas in gas fields in the southwestern U.S., Appalachia, and the Rocky Mountain region, transported it to distant consuming areas, and sold it. Most pipeline sales were made to local distribution companies (LDCs), who in turn resold the gas to industrial, commercial, and residential end-users. The pipeline companies acted as gas merchants, selling a combined or bundled product that consisted of the gas commodity itself and its transportation service. Since 1984 the role of the interstate pipeline companies has evolved away from merchandising toward the transportation of gas that is purchased directly by the LDCs or final users. The importance of direct gas purchase contracts between an LDC and a producer has emerged as a result of the Natural Gas Policy Act of 1978 (NGPA) and a series of regulatory initiatives on the part of the Federal Energy Regulatory Commission regarding gas transportation, and also as a result of court cases reviewing these initiatives. This chapter outlines the recent developments at the federal level as a way of providing a context for understanding the increasing importance of direct gas purchases in an LDC's future supply portfolio.

Overview of FERC Transportation Policy

As is widely recognized, the natural gas industry is undergoing a transition from a regulatory environment characterized by tight oversight and complex rules to one that will rely more on competitive forces, particularly at the wellhead. Traditionally, the FERC, and its predecessor the Federal Power Commission, were concerned with protecting consumers from high, monopoly gas prices, and with assuring that supply was adequate. The current focus on consumer protection remains substantially the same; however, the NGPA of 1978, and the FERC, under its Order 436 of October 1985, are shifting the social responsibility for supply reliability from the regulatory apparatus to the marketplace. The NGPA and the FERC transportation programs leading up to Order 436 have been reviewed in previous NRRI reports and do not require extensive discussion here.[1]

The NGPA eliminated the FERC control of natural gas wellhead prices for new gas and also eliminated the certification authority over sales between producers and pipelines. Formerly, a certificate was required to commence gas sales in interstate commerce, and in addition the sales could not be stopped without formal approval from the FERC to abandon the sales. New gas sales no longer require such a certificate and likewise can be stopped without a FERC hearing. In effect, the contract between the producer and the pipeline solely governs the relationship between a buyer and a seller of new gas. Likewise, a new contract between an LDC and a gas producer becomes the sole governing document regarding the sale of the gas. An LDC may need a transportation agreement with one or more pipelines in addition to the sales contract. These circumstances increase the importance of state commission understanding of the sales contract, particularly because some of the contracts in the future may substitute for pipeline system sales that had been subject to Federal regulatory review under the FERC certification and abandonment rules.

In addition to eliminating wellhead price controls on new gas, the NGPA established an interim set of price ceilings for all gas during the time -- between 1978 and 1985. The ceilings intentionally were set high for some categories of gas in order to create an incentive for producers to explore. The intent was to initiate a policy that relies on the marketplace for assured supply, instead of administrative rules. Following the gas

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[1]See J. Stephen Henderson, Jean-Michel Guldmann, et al., Natural Gas Rate Design and Transportation Policy under Deregulation and Market Uncertainty (Columbus, OH: National Regulatory Research Institute, NRRI 85-15, January, 1986), and J. Stephen Henderson (ed.), Natural Gas Industry Restructuring Issues (Columbus, Ohio: The National Regulatory Research Institute, NRRI 86-8, September 1986).

shortages of the late 1970s producers and pipelines responded enthusiastically with substantial amounts of new gas supplies contracted at or near the lawful ceiling price.

Partly because of the NGPA limits on price, and partly because the parties wished to prevent a recurrence of the then recent shortages, new gas contracts in the late 1970s and early 1980s contained unusually high take-or-pay requirements. Had the demand for natural gas continued to expand, such take-or-pay clauses would have been both justified and undoubtedly the subject of praise from today's regulators and market analysts. Unfortunately, a recession in the U.S. economy, a fall in world oil prices, and consumer conservation in reaction to higher prices combined to reduce the demand for natural gas substantially. The drop in sales was large enough to trigger many take-or-pay clauses, particularly in contracts that had been recently signed at high, incentive prices. After the fact, the agreed-upon take-or-pay levels can be seen as a business gamble that turned out badly. The industry today is still suffering through the aftermath of having signed such contracts.

The gas bubble, or excess supply deliverability, was a major feature on the economic landscape when the price of substantial amounts of new gas was deregulated on January 1, 1985 according to the NGPA timetable. At about the same time, a spot market for natural gas emerged. By 1986 the spot market was well developed and organized with independent marketers and brokers arranging a variety of gas deals. In general, spot prices have been falling from 1985 to the present (Autumn 1987), with the exception of the 1986-87 heating season.[2] More importantly, spot prices generally have been below the price of gas that the major pipeline companies have under contract. This creates an incentive for LDCs and other large buyers of gas to seek lower cost gas supplies in the spot market. Of course such gas must be transported from a producer's well to the buyer's premises or the LDC's city gate. As gas sales plummeted on individual pipelines due to the overall drop in demand, the pipeline company managers and the FERC perceived a need to fashion a transportation program. The pipelines wanted to

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[2] Based on spot price information provided by Mr. Paul Tasso, The Yankee Gas Co., Dublin, OH.

increase their throughput, and the federal regulators wanted a program to further develop a competitive market. Any gas transportation program must satisfy several requirements, however, that up to now have proven to be difficult obstacles.

There are three major constraints facing the FERC as it creates a gas transportation policy. First, any program must be voluntary because the Natural Gas Act specifically exempts the gas pipeline companies from being common carriers. A mandatory carriage program administered by the FERC can not be forged under current legal authority, in the opinion of most observers.[3] Second, any program must be nondiscriminatory and must make transportation services available to all users. This is a requirement imposed by Section 5 of the NGA, and more recently reiterated by the courts in Maryland People's Counsel v. FERC I.[4] Third, a gas transportation program must take into account the contractual reality facing the interstate pipeline companies, especially their take-or-pay obligations. The D.C. Circuit Court has made the importance of this third requirement clear in its opinion in Associated Gas Distributors v. FERC.[5]

Because of the difficulty in satisfying all three of these conditions, it is perhaps not surprising that the FERC has had several false starts in fashioning gas transportation programs in the last five years. A program of off-system pipeline sales was proposed by several pipelines in 1982-83 as a way to avoid take-or-pay obligations. The program mainly involved sales to other pipelines and eventually died because the decline in demand affected all pipelines and few, if any, needed to purchase gas to meet their obligations. Also, the price for off-system sales dictated by the FERC was too high and uncompetitive during a time of falling demand.

Following the off-system sales program, the FERC authorized special marketing programs (SMPs). The FERC issued a blanket certificate for the transportation and sale of a producer's surplus gas. The pipeline transported the gas on a temporary basis in exchange for take-or-pay relief.

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[3] See Henderson, Guldmann, Natural Gas Rate Design and Transportation Policy, pp. 66-77, for additional discussion.

[4] Maryland People's Counsel v. Federal Energy Regulatory Commission, 761 F.2d 768 (D.C. Cir. 1985).

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

The gas was typically sold to fuel-switching industrial users who would otherwise burn oil. The SMPs were used extensively, and were extended beyond the pipelines to producers and marketers. A SMP is inherently discriminatory, however, since the program arranges for a sale at favorable prices to a limited set of customers. This discrimination was deemed legally unacceptable by the D.C. Circuit Court in Maryland People's Counsel v. FERC I. During this time (1983-1985), the FERC also authorized certain blanket certificate programs that made self-implementing transportation available for all end-users. The court in Maryland People's Counsel v. FERC II[6] struck down the blanket certificates because, in reality, the programs had been used by the pipelines to serve fuel-switchable customers and exclude captive customers. To the extent that the certificates are used in such a discriminatory fashion, the court ruled they are illegal.

Instead of modifying these existing transportation programs in 1985 when the court found them discriminatory, the FERC issued Order 436. This order changes the nature of the gas transportation business in a fundamental way. The order has three major features: (a) voluntary, nondiscriminatory transportation on a self-implementing basis, (b) an option for an LDC to reduce or convert its contract demand with a pipeline, and (c) optional expedited certificates for new facilities.

There are two types of transportation service under Order 436. Section 311 of the Natural Gas Policy Act of 1978 (NGPA) authorizes a variety of sales and transportation arrangements among interstate pipelines, intrastate pipelines, and local distributors. Under Order 436, Section 311 transportation service by an interstate pipeline can be provided "on behalf of" an LDC or an intrastate pipeline. In general, section 311 service does not require FERC approval; however, the FERC regulates the prices and terms of 311 service. Order 436 specifies that any new transportation under section 311 authority must be nondiscriminatory. Most 311 transportation is currently performed under an interim waiver of the contract demand conversion and reduction provisions of Order 436. The Commission enforces the Order by hearing complaints on a case-by-case basis.

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[6] Maryland People's Counsel v. Federal Energy Regulatory Commission, 761 F.2d 780 (D.C. Cir. 1985).

The second kind of transportation service covered by Order 436 is an open-access blanket certificate under the provisions of Section 7 of the NGA. Such a blanket certificate is subject to the rate design provisions and contract demand reduction conditions of Order 436. Once issued, the blanket certificate allows for preapproved abandonment of service for individual transactions; this does not pertain to the abandonment of the certification itself. That is, a pipeline transporting gas under a section 7 blanket certificate must continue to provide nondiscriminatory open access until the FERC has approved the abandonment of the certificate. Section 311 service is less restrictive in this regard, since a pipeline could cease providing nondiscriminatory transportation services to all users without FERC approval. Partly for this reason and partly because of the interim waiver of the conversion provisions of Order 436, most transportation service today is sought and authorized under Section 311 of the NGPA.

On June 23, 1987, the D.C. Circuit Court vacated Order 436 and remanded it to the FERC for further consideration of the take-or-pay issue in particular.[7] In general, the court upheld the substance of Order 436 and its emphasis on nondiscriminatory transportation.

In Order 436, the Commission did not address the pipeline companies' take-or-pay problems, other than reaffirming its 1985 policy statement that take-or-pay settlements do not violate NGPA price ceilings and that buyout costs would be considered on a case-by-case basis. The Court ruled that the FERC must address the take-or-pay issue in greater detail, given that producer-pipeline contracts are a significant part of the problem that created the need for transportation programs and subsequently Order 436 in the first place. The Court agreed with the Commission's concern about governmental interference with private contracts, but noted that producer access to transportation under Order 436 is grounded in a government rule and hence, conditioning that access on take-or-pay relief is not the same as government abrogation of contracts.[8] The Court stated that the FERC reasoning was inadequate with regard to why the Commission had chosen not to take action on take-or-pay under Section 5 of the NGA.

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[7] Associated Gas Distributors v. FERC, <u>supra</u>.
[8] Ibid., pp. 1026-1027.

The Court also expressed concern over the contract demand (CD) reduction provision of Order 436. The Court reasoned that as firm sales customers reduced their contract demand, pipeline costs would shift among the remaining customers with unfavorable effects on prices. To the Court this seemed inconsistent with the Commission's consumer protection role under the NGA. The Court agreed with the Commission that conversion of contract demand to transportation services is necessary in order to promote a competitive market for gas. The need for a contract demand reduction was not as clear to the Court since access to a competing pipeline may not be necessary in order for an LDC to be able to buy competitively priced gas. That is, competition among pipelines may not be needed to foster a competitive wellhead market, if a pipeline provides transportation services.

In response to the Court's concerns, the FERC issued Order 500 on August 7, 1987. This is an interim rule. The Commission intends to collect data on take-or-pay obligations of the pipelines and received comments on the interim rule in October 1987. No date for a final rule has been set at this time.

In Order 500, the Commission retains the option for an LDC to convert its contract demand to firm transportation, but has eliminated the CD reduction option. The Order also provides that a producer must offer a pipeline credit against the pipeline's take-or-pay liability for gas that the pipeline transports for the producer. Such credit must be offered for all gas transported except for two categories of gas: "(1) gas presently not committed to the pipeline by contract but which the pipeline previously purchased under a contract which has been terminated, or (2) gas released from a contract containing a market-out clause that allows the pipeline to terminate the contract at its discretion."[9] The Commission added a second mechanism that pipelines may use to recover prudently incurred take-or-pay costs. The policy that such costs can be included in the sales commodity rates of any pipeline was continued. In addition, if a pipeline is a nondiscriminatory transporter of gas, it may charge its customers a fixed

[9] FERC Order 500, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Docket No. RM87-34, 52 Fed. Reg. 30334 (August 14, 1987).

amount for a portion of its take-or-pay costs. In particular, a pipeline that absorbs 25 to 50 percent of its buyout or buydown costs may recover an equal amount from customers in the form of a fixed or lump-sum payment. The remainder may be recovered in the commodity prices of both sales and transportation service. The intent is to improve the competitive edge of the nondiscriminatory transporters by placing a smaller burden on their commodity rates, thereby increasing the incentive for a pipeline to choose to become such a transporter to begin with.

The D.C. Circuit Court denied a rehearing of the AGD v. FERC decision on September 15, 1987. This action permitted Order 500 to become effective immediately.

The interim rule should substantially reduce a pipeline's take-or-pay exposure that might be created by its transportation activity. The conversion of contract demand to firm transportation, for example, should create about as many take-or-pay credits as it does liabilities in an ordinary one-on-one relation between a pipeline and a producer. If such a producer wants to have his gas transported by the pipeline, he must sign an affidavit offering to credit the volumes against the pipeline's take-or-pay liability associated with any contract between the producer and pipeline.

The Commission's final rule may or may not be revised and perhaps may incorporate comments submitted by interested parties. Although the rule is not yet final, and because this issue is important to state commissions, it is appropriate to present a brief analysis of the take-or-pay crediting features of Order 500.

Policy Implications of Order 500

The crediting mechanism of Order 500 has been superimposed by the Commission on an already complicated landscape of gas contractual arrangements. Gas that is sold to an interstate pipeline company for inclusion in its system supply to be ultimately resold to LDCs is called sales gas in the following analysis. Some of this gas has high contract prices, a legacy from the 1979-82 era when the NGPA price ceilings and memory of recent shortages combined to induce pipelines to pay a premium for secure supply sources. Some of the sales gas, however, has a low price, perhaps enforced by contract, perhaps enforced by the continuing price regulation of old gas by the FERC. Gas that is sold to an end-user or an LDC is called transportation gas here. The title to such gas is not held by the pipeline company; it merely transports the gas for others. The price of much of the transportation gas is likely to be intermediate between the high-priced sales gas and the low-priced sales gas. Much of the transportation gas is most likely purchased on the spot market.

For the purposes of this discussion, it is enough to distinguish these three types of gas: high-priced sales gas, low-priced sales gas, and transportation gas. All three types of gas may be handled, in varying proportions, by any single pipeline. Likewise, a single producer may own and be interested in selling gas in all three of these categories. Major producers, such as Exxon, certainly have at least some gas of each type. Smaller, independent producers may have gas in only one category. A single producer, also, may be connected to one or several pipelines, and it may have sales contracts with a subset of these or perhaps all of them.

The pipelines' take-or-pay problems addressed by Order 500 occur mainly within the class of high-priced sales gas. Ordinarily, a contract that has a take-or-pay clause has another clause that commits the gas to the buyer. It is not possible for the producer to sell the gas to another buyer in such a contract without the buyer's permission. That is, suppose a contract specifies a take-or-pay level of 70 for a gas well that annually can deliver 100 units of gas. Suppose further that the pipeline-buyer takes only 60 units in a year and thereby incurs a take-or-pay liability of 10 units, to be made up in the subsequent 5 years. Finally, suppose the producer successfully arranges to sell an additional 20 units to a different buyer. Since the incremental sale results in the producer selling 80 percent of the well's deliverability, most people's sense of fairness would require the producer to eliminate the pipeline's take-or-pay liability of 10 units, in such circumstances. That is, it makes no sense that the original buyer could be held responsible for 70 units when a total of 80 has been produced and sold, in fact. If such a thing could occur, it would be possible, in theory, for the producer to sell all remaining 40 units of production and still impose a 10 unit take-or-pay burden on the pipeline. This would overcommit the well's production capacity and literally allow some portion of its output to be sold twice, a seemingly unfair outcome.

Regardless of one's view about equity, such an outcome presumably would constitute a breach of contract if the reserves are dedicated to the pipeline. It is equally a breach of contract whether the pipeline-buyer transports the gas or whether some other pipeline performs the transporting service. Because of the commitment, then, such double payments to the producer cannot occur legally; the buyer can simply enforce his contractual rights. The pipeline-buyer can require the producer to grant take-or-pay relief as a precondition to any other sale of the gas, whether or not the pipeline itself provides the transportation service. If some other pipeline transports the gas, preventing the sale might be difficult because the identity of the gas is uncertain; nonetheless, the buyer can enforce his rights to the gas in court and prevent the sale, in theory, and most likely in practice.

The point of this discussion so far is that FERC Order 500 is not directed toward nor is it needed to solve any problem having to do with gas being transported from a specific well under a contract with a take-or-pay clause because such gas is typically committed to the pipeline by contract. Under the current rules, FERC authority is needed to transport the gas at all, but the buyer's contractual rights are sufficient to insure that proper crediting of take-or-pay liability occurs for gas under long-term, take-or-pay, committed reserves contracts. A FERC crediting mechanism is not needed in these rather simple circumstances.

The FERC Order 500 crediting rule is directed towards a more complicated set of transportation and sales arrangements. In particular, Order 500 permits a pipeline to require take-or-pay credits from a producer that owns both sales and transportation gas. That is, a single producer has some wells that are committed under long-term, take-or-pay contracts to a pipeline-buyer. The same producer has other gas wells that are not similarly committed to the pipeline, from which the producer wishes to sell gas on the spot market, for example, to an LDC or end-user. The pipeline-buyer may be in a position to act as pipeline-transporter for this second category of gas. The FERC Order 500 allows the pipeline-buyer to extract take-or-pay credits from the producer to apply to the first set of contracts in exchange for the pipeline company transporting other gas, in the second category, not associated with the pipeline by any contractual arrangement, except for possible transportation.

In ordinary economic times and circumstances, this is surely an odd idea. Suppose a coal producer owned two mines, the output of one is under a long-term take-or-pay obligation to electric utility A, and the output of the other is sold on the spot market to electric company B. Suppose that because the relation between utility A and the coal mine is long-term, the utility has invested in a railroad to transport the coal to its generators. This same railroad, for the sake of argument, is used to haul spot market coal from the second mine to utility B for some portion of the trip for which no alternative transportation is available. If reduced demand for electricity in A's territory causes a drop in its need for coal below its take-or-pay level, A might be tempted to refuse to transport coal along the other route unless the producer gave A take-or-pay credits for coal sold to B from the other mine. If A did such a thing, a court likely would find it to be an illegal restraint of trade. There is no contractual connection between the two activities and the only economic connection is monopoly ownership of an essential transportation facility.

The FERC has expressed concern about this issue and the need to respect the privity of contracts. The Court has echoed this concern, but suggested in AGD v. FERC that producer access to transportation is conditioned upon government intervention in the first place. In addition, these are not ordinary economic times. The Commission's transition that has encouraged transportation has exacerbated the take-or-pay problems caused by the previous recession and fall in world oil prices. Consequently, the Court said that conditioning access to transportation on take-or-pay relief may be appropriate in the circumstances. The Court affirmed the Commission's interim crediting plan, thereby approving the idea of using one set of contracts to hold hostage another.

It is difficult to know how the crediting mechanism will work in practice. It depends on the cross-connections among contracts and on the cross-connections between pipelines and producers. Partly for this reason, the FERC, in Order 500, has requested data from the industry regarding take-or-pay obligations. With these data the Commission should be able to revise Order 500 appropriately.

Some difficulties with the implementation of the crediting rule can be anticipated for particular configurations of the possible cross-connections. The importance of each is an empirical question that can be answered, at least in part, by the FERC data request. It seems appropriate to examine some of these problems by enumerating a few of the possible configurations.

Table 2-1 summarizes six possible configurations between a producer and the one or two pipelines connected to his wells. These are not intended to be exhaustive, only illustrative. In the following analysis, it is useful to discuss whether the crediting mechanism of Order 500 effectively changes the operation of a take-or-pay clause in favor of the producer or in favor of the pipeline. The intent of the discussion is to identify such changes in relation to the original contract, which both parties voluntarily signed. As such, fulfilling the contract as written can be thought of as neutral. Nothing more is intended by use of the word "neutral." In particular, no judgments about the social worthiness of pipelines and producers is implied. The point of view is that of the contract. Policymakers may be interested in knowing the effect of Order 500 in relation to the contract for reasons that have to do with broader judgments about social equity and economic efficiency--judgments that we leave to the policymakers.

The first possibility shown in the table is that a producer has only high-priced, take-or-pay gas wells and these are connected to a single pipeline. In this case, Order 500 provides no means of crediting and hence, no take-or-pay relief to the pipeline. In ordinary circumstances, this would be considered appropriate and neutral, favoring neither the pipeline nor the producer. In the current environment, however, such an outcome might be considered as an obstacle to the transition envisioned by the FERC and, accordingly, one that favors the producer. Such an interpretation makes sense, however, only because the industry is now aware that the take-or-pay contracts have turned out to be enormously burdensome after the fact. (The question mark following "producer" in table 2-1 signifies this uncertainty in claiming that the lack of take-or-pay credits favors the producer).

The second possibility listed in the table is that a producer may not have any contracts with a pipeline, but rather may own only transportation gas. In this case, like the first, there is no possible credit that can be given. Unlike the first, however, such an outcome is clearly neutral and appropriate.

TABLE 2-1

POSSIBLE ACTIONS UNDER THE ORDER 500 CREDITING RULE

Possibility	A Producer's Wells Are Connected to Pipeline A	B	Possible Actions	Source of Authority	Action Favors
1	H		No Credit	-	Producer?
2	T		No Credit	-	Neutral
3	H, T		H converted to T	LDC conversion	Pipeline
4	L, T		L converted to T	Order 451	Producer
5	H	T	No Credit	-	Producer?
6	L	T	L converted to T	Order 451	Producer

Note: H means high-priced, take-or-pay gas; T means transportation gas; and, L means low-priced take-or-pay gas.
Source: Authors' analysis.

A third possibility is that a producer has both high-priced, take-or-pay gas (H) and transportation gas (T), and in addition, his wells are connected to only a single pipeline. This is perhaps the best example of the circumstances towards which Order 500 is directed and in which the Order is likely to work best. The producer must offer the pipeline take-or-pay credits against gas sources H in exchange for the pipeline transporting gas sources T.

If the identities of the separate gas sources, H and T, do not change, the Order will work as intended. Any time an essentially homogeneous product like gas is sold at two different prices, however, there is an incentive for buyers to seek the lower price or for the seller to seek the higher. Such violations of the economist's "law of one price" tend to elicit a variety of creative ways for buyers and sellers to circumvent the artificial distinctions that have created the price difference. It is not possible to anticipate all of the methods pipelines, producers, LDCs, or end-users may discover, intentionally or not, that enable them to circumvent the intent of Order 500. Accordingly, the following is only an example of a possible outcome.

In the circumstances described by the third possibility in table 2-1, high-priced, take-or-pay gas can be converted, in effect, into transportation gas for the spot market. This could happen by the action of the LDC customers of the pipeline converting their contract demand into firm transportation under Order 500. This action may or may not be purposeful. There is no intent in this discussion to judge the actions of the participants as right or wrong, only to describe possibilities.

Under Order 500, an individual LDC has an incentive to convert contract demand to firm transportation if the spot price of the gas it can buy is lower than the price of the pipeline's system-sales gas. The LDC may choose to buy from a producer who is currently committed to the LDC's pipeline and who also has spot gas for sale. That particular LDC might choose, instead, a different producer who has no gas committed to the pipeline. Regardless of how producers and LDCs match up, the overall effect of the LDC's conversion actions is that a pipeline could reduce its annual takes of high-priced, take-or-pay system gas. If producers want to sell spot gas and have it transported, they must give the pipeline take-or-pay credits on a volumetric basis. This means that the producer will sell transportation gas at the spot price and credit the pipeline for sales gas at a higher price. This effectively converts the producer's high priced system supply sources into spot market supplies on a continuing basis, to the extent that this kind of conversion can happen.

There are several natural limits to how much of this kind of conversion can happen, but importantly there is no limit to it included in Order 500. One type of natural limit is that a producer always has the option under

Order 500 of not transporting any gas and instead holding the pipeline to its take-or-pay obligations under current system supply contracts. Whether a producer with both sales gas and transportation gas will choose to sell any of the latter depends on which action yields more profits. The producer's option to not transport at all provides a limit to how much of his sales gas can be converted to lower-priced transportation gas. Each producer can find his own limit quite readily. He knows system sales, Q_H, from high-priced contracts, and he knows the take-or-pay obligations under these contracts, Q_O. (Q_O is generally a fraction of Q_H). Suppose that the annual rate of system sales, Q_H, is less that Q_O, which corresponds to a situation where take-or-pay liabilities are accruing annually. The producer also knows the amount of transportation gas he would like to sell, Q_T. In order for the producer to break even under Order 500, it is most likely necessary for him to transport more gas than the shortfall of system sales from take-or-pay obligations, Q_O-Q_H. The reason is that the price for transportation gas, P_T, is likely to be less than the price of system sales, P_H. In particular, a producer must transport $(Q_O-Q_H)\ P_H/P_T$ in order to receive as much revenue from transporting gas as he would to its take-or-pay obligations.

It is possible that a producer might decide to transport no gas at all, instead of allowing FERC Order 500 effectively to convert the shortfall in his system sales contracts into transportation gas. Some producers, then, can be expected to withhold gas from the spot market, thereby placing upward pressure on spot prices.

The possibility of converting sales gas into transportation gas does not necessarily end at this point. Whether a producer chooses to participate in the transportation program depends on his transportation volumes in relation to the annual shortfall in his system supply contracts. That shortfall, Q_O-Q_H, is not necessarily fixed. If a pipeline reduces the system supply takes from a particular producer, Q_H is reduced. If a pipeline reduces Q_H too severely, the producer will not wish to transport any gas, because Q_T will be less than $(Q_O-Q_H)\ P_H/P_T$. A pipeline may not know Q_T precisely for a particular producer, but it certainly can estimate it. One way to estimate it is for a pipeline to reduce its takes of system gas until a producer decides to cease his participation in the transportation program. At that point, the pipeline has a good idea of the volumes of transportation gas, Q_T, a producer has for sale.

With a sensible estimate of Q_T,[10] it is possible to imagine a pipeline engaging in the following type of strategic behavior. It would behoove the pipeline to arrange its pattern of system supply reductions so as to minimize its take-or-pay exposure, as LDCs exercise their conversion options. The result could easily have large adverse effects on some producers and only minor effects on others.

In the extreme, it is at least theoretically possible that a producer with a large amount of transportation gas to sell (relative to system supply) could have his system supply contracts virtually eliminated. That is, a pipeline could reduce its annual takes from a producer's system supply wells to zero and completely eliminate its take-or-pay obligation through the transportation credits under Order 500 on a continuing basis.[11] All that is required for this to happen is that the producer's annual transportation volumes exceed $Q_O(P_H/P_T)$. This means, for example, that if the price of system contract gas is 50 percent higher than the spot price, and if the producer's transportation volumes are larger than 150 percent of its aggregate take-or-pay volumes, the producer will have greater revenues under Order 500 by transporting gas and offering credits, even if the pipeline shuts in all of his system supply wells year after year.

Less extreme results, of course, are more likely. It could happen that a particular producer might be exposed to the risk of losing only half of the take-or-pay contractual payments, because his potential transportation

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[10] The pipeline's calculus may be much more complex than simply requiring an estimate of Q_T. Expectations about take-or-pay buyouts, the future pattern of spot prices, and the future recovery of demand are all relevant. Nonetheless, a pipeline can estimate the critical Q_H that forces a producer out of the transportation market and then buy just a little more system supply. The remainder of the argument remains valid with this more complicated calculus.

[11] It is important to emphasize that such an outcome is at least theoretically possible year after year. That is, even if there was no prior accumulation of take-or-pay liabilities, the crediting mechanism of Order 500 could eliminate the annual take-or-pay obligations in some contracts. Such a possibility would be an isolated circumstance, most likely.

volumes are not as large. In any case producers with both sales and transportation gas could incur widely different adverse effects from the combination of the conversion and crediting features of Order 500. Note that the argument just presented is equally valid whether or not there is any previously incurred accumulation of take-or-pay liabilities. To the extent that such an accumulation exists, as it currently does, it may be possible for a pipeline to convert even larger amounts of high-priced sales gas into transportation gas on a temporary basis, until the accumulation has been reduced to zero. The conversion of $(Q_O-Q_H)\ P_H/P_T$, however, could be permanent under the Order.

The discussion so far of case 3 in table 2-1 has pointed out that rather large wealth transfers are possible under Order 500. The participants who lose in such circumstances will oppose the Order, and vice versa. These are important matters of fairness that the Commission must address.

The issue of fairness, however, is not the central focus of this analysis. More importantly, there is a question of whether a large scale conversion of system supply gas to transportation gas improves or detracts from overall economic efficiency and the nation's best allocation of its resources. The question is difficult to answer in the absence of facts. Thus, only a few preliminary and general observations about efficiency are possible now.

The conversion of sales gas to transportation gas, if it occurs, would lower consumer prices. As attractive as this is to consumers, efficiency is not thereby improved, per se. Efficiency will be promoted if the conversion moves the market closer to its efficient configuration, which means its optimal mix of long-term and spot contracts with prices for both types of contracts at their market clearing levels. It also means that gas is produced more or less in economic order, with gas from cheaper sources produced first.

Given the persistent surplus in gas deliverability over the past few years, it is apparent that market clearing prices are lower than those prevailing in the system supplies of most pipelines. From this perspective, the perhaps unintended result of Order 500 to convert sales gas to transportation gas by effectively eliminating or dramatically reducing annual take-or-pay obligations (as opposed to allowing pipelines merely to eliminate previously accumulated obligations) between at least some pipeline-producer combinations would seem to improve the efficiency of the gas market. In effect, the action allows average gas prices to fall towards the spot price, which may improve allocative efficiency from a narrow short-run perspective.[12]

Matters are not so clear from a long-term efficiency viewpoint. In the long run, it is important to know the optimal mix of volumes purchased under long-term contracts (for secure supply) versus those sold on the spot market. Undoubtedly, both would exist in a well-ordered market, and most likely spot prices would be observed as being less than new contract prices under ordinary economic conditions.[13] A way of thinking about this is to ask the hypothetical question, What would the current gas market look like if the economic recession and plunge in world oil prices had occurred 20 years after wellhead price deregulation had combined with an effective transportation program to make the gas market essentially competitive? A precise answer is, of course, unknowable. It would be sensible to expect, however, that the pipelines would have some secure gas supplies under take-or-pay contracts, that moderate amounts of take-or-pay liability would have accumulated, and that contract prices averaged over vintages would be higher than spot prices although the differential most likely would be smaller than we currently observe.

If an otherwise rational market that coincidentally happens to be experiencing a temporary excess supply would have the appearance just described, this suggests that contract prices ought not to be forced all the way down to spot prices via the crediting mechanism of Order 500. Long-term economic efficiency would not be served by such an outcome. This suggests

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[12] A good estimate of short-run marginal cost is the spot price. Lowering the average price in the direction of short-run marginal cost would improve short-run efficiency but not necessarily long-run efficiency.
[13] For a good discussion of contract versus spot price behavior in some representative and workably competitive markets see Natural Gas Procurement: Experience with Spot vs. Contract Pricing in Analogous Commodity Markets (Boston, MA: Charles River Associates Inc., CRA No. 154.00, November 1986). In most markets studied by CRA, the spot price was less than the contract price during slack to normal market conditions. In tight markets, the spot price tends to rise above contract price.

that some sort of limit might be adopted for the crediting mechanism. For example, the FERC might require that a producer offer a pipeline take-or-pay credits for transportation gas up to a limit of 40 percent (say) of the pipeline's take-or-pay liability in any year. This would mean that 60 percent of the take-or pay obligation would remain. So, for example, if the take-or-pay clause is written as 70 percent of deliverability, the maximum credits a producer would have to offer in order to have other gas transported would result in the producer receiving at least 42 percent (60 percent times 70 percent) of the potential revenue of a well at its contract price. This would be the producer's worst possible case. Depending on the conversion activity of the pipeline's LDC customers, and also on the producer's relative amounts of gas under contract versus those available from the spot market, the producer might receive somewhere between 42 and 70 percent of the potential revenue on a take-or-pay basis.

This analysis suggests that long-term economic efficiency could be promoted by limiting the crediting mechanism of Order 500 in some fashion, possibly as a fraction of the take-or-pay obligations between producer and pipeline. In addition, depending on the results of the FERC data request, there may be some strong equity arguments for such a limit. Horizontal equity among producers may be seriously damaged if some are subjected to much larger wealth transfers than others. Some may be exposed to the risk that all of their contract gas can be shut-in, and it would still be more profitable for them to transport gas and offer credits. Others may have a lower risk because their transportation volumes are relatively smaller, and hence, a pipeline can successfully shut-in only a portion of their contract gas. This inequity is reduced by the simple expedient of a limit to the crediting mechanism.

As a final comment in this lengthy discussion of the third possibility listed in table 2-1, it should be noted that neither the crediting mechanism in Order 500 nor the limitation just suggested would necessarily improve the economic ordering of takes from cheapest to most expensive wells. For multiple wells owned by a single producer, the wording of Order 500 does allow a pipeline to improve the economic ordering. Between producers connected to the same pipeline, however, there is no necessary improvement in the correct ordering of the aggregate set of wells. From an even broader perspective, there is no improvement over the set of wells connected to all of the pipelines because the crediting mechanism does not permit comparisons between wells served by different pipelines or owned by different producers. Within the context of a take-or-pay crediting formula, there is nothing that can be done to improve the economic ordering across producers or pipelines. The purpose of mentioning this is to point out that this type of short-run inefficiency (as opposed to the simpler variety in which price exceeds short-run marginal cost) must be tolerated within the context of Order 500.

Continuing in table 2-1, a fourth possibility is that a single producer has both low-priced, take-or-pay supplies and transportation gas available. Some of the low-priced supplies may be converted, in effect, into transportation gas by producers. In this case, one possible conversion mechanism could be the clause in Order 500 that exempts from the crediting mechanism gas previously purchased under a contract that has been terminated. This portion of Order 500 is closely related to the good faith negotiation procedures established by the Commission in Order 451.

In Order 451, the Commission set a single ceiling price for all jurisdictional gas that it regulates under the just and reasonable standard. The Order provides a multi-step negotiation process under which a producer can ask for a higher price for old gas and a pipeline can ask for a lower price for other, newer supplies under the same contract or other contracts containing old gas. If the parties cannot agree, the contract is terminated and service is abandoned. The Commission explicitly refused in Order 451 to rule on the disposition of any accrued take-or-pay liabilities associated with the terminated contract. The Commission stated that any ruling that it made regarding gas not taken, but already paid for, would hinder the negotiation process. Accordingly, a producer has no obligation to repay any part of the prepayments that might remain when a contract is terminated under the Order 451 negotiations. The exemption clause in Order 500 is consistent with the Commission view that it ought not to interfere in the good faith negotiation procedures. That is, if the Commission allowed transportation credits for gas released under the Order 451 negotiation rule, it would eliminate, in effect, the contract's take-or-pay obligations. The Commission explicitly declined to do this in Order 451 and has decided that the transportation credit formula in Order 500 will not be allowed to do the same thing implicitly.

In these circumstances, some producers may be able to effectively convert low-priced, take-or-pay gas into transportation gas. If the pipeline refuses to pay the ceiling price for old gas (which currently exceeds the spot price), the producer can terminate the contract, sell the gas on the spot market, have the gas transported by the same pipeline, and not incur any obligation to repay any prepayments that the pipeline previously made under the contract.

The importance of this conversion of low-priced, take-or-pay gas into transportation gas is difficult to assess. On the one hand, "the interaction of Orders 451 and 500 'creates a loophole big enough to drive the proverbial speeding truck through,' said (the) ANR and CIG (pipelines)."[14] On the other hand, Order 500 does not appear, on its face, to change the working of Order 451 in this regard. That is, the extent to which a producer may wish to take a chance and sell his low-price old gas on the spot market ought not to be much affected by Order 500, per se. Whatever incentives existed to do so under Order 451 are more or less the same in the presence of Order 500.

It is true that the lack of transportation credits favors the producer, as indicated in table 2-1. This is because the producer may keep any prepayments made by the pipeline. If Order 500 were modified to require transportation credits, a neutral policy would limit the credits to the prepayments. Without such a limit, transportation of gas released under the good faith negotiation rule might continue to generate take-or-pay credits far greater than the prepayments existing at the time the contract is terminated. Requiring transportation credits with such a limit, however, amounts to a policy of requiring producers to refund any prepayments to the pipeline, a policy specifically rejected by the Commission in Order 451.

The policy in Order 500 upholds the Commission's decision about take-or-pay in Order 451 and can be said to favor the producer to the extent of any prepayments. Allowing transportation credits up to the amount of the prepayment for gas previously sold under a contract that has since been terminated would appear to be a neutral policy. Allowing transportation

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[14] "Order 500 Isn't the Answer to Take or Pay, Pipelines Tell Court," Inside FERC, August 24, 1987, p. 5.

credits for such gas without limit goes beyond neutrality and would favor the pipelines, in some cases to a potentially large degree. Of the two non-neutral policies, the Commission has chosen the one that appears to have the smaller distortion, although better information is required to say for certain.

The fifth possibility in table 2-1 is that a single producer has high-priced, take-or-pay gas under contract with one pipeline, called pipeline A in the table, and has other transportation gas sources that can be delivered through the facilities of another pipeline company, B. In this case, the transportation of the gas through pipeline B generates no credits for the take-or-pay liabilities of pipeline A. In some limited sense, this policy could be said to favor the producer, but only to the extent that the take-or-pay contracts are onerous and have turned out to be unfortunate decisions after the fact. This possibility is similar to the first possibility in table 2-1 in which a producer has transportation gas. The foregoing analysis is based on an assumption that high-priced, take-or-pay gas is committed to pipeline A and cannot be sold as transportation gas to pipeline B. That is, the commitment prevents the producer from being paid twice for the same gas. If this assumption is false in particular contracts, the producer certainly has a large advantage. Such contracts do not seem likely to be commonplace; a fact subject to further study using the information requested by the Commission in Order 500.

A sixth possible configuration of a producer and pipelines in table 2-1 is that a single producer has low-priced, take-or-pay contracts with one pipeline and transportation gas that can flow over another pipeline. There is no difference between this case and the fourth possibility in the table. That is, the action of a producer terminating a low-priced contract under which prepayments have been made does not depend upon whether the producer has other suppliers or other connections with pipelines. The producer's incentive to convert the low-priced, take-or-pay contract into transportation gas is the same, since the original pipeline must provide transportation service under Order 451 in any case.

Summary

This rather extensive discussion of federal gas transportation policy, and the FERC Order 500 in particular, is intended to help state commissioners and staff members understand the difficulties that have been encountered at the federal level when dealing with contractual terms for the sale of natural gas. The same kinds of clauses and terms appear in natural gas contracts for direct sales made to local distributors. Familiarity with the federal problems and policies should assist state commissions in understanding the difficulties faced by local distribution companies in arranging transportation through interstate pipelines, in deciding on an appropriate policy concerning the transportation of gas for large end-users by jurisdictional LDCs, and in evaluating an LDC's direct gas purchase contracts.

The FERC has taken action in Order 500 to facilitate its transportation program by making it easier for the interstate pipeline companies to obtain relief from take-or-pay liabilities that otherwise might be made worse when a pipeline transports gas. The Order does not provide relief except through the transportation crediting mechanism and the passthrough of buyout or buydown costs. The Order, for this reason, cannot be interpreted as raw governmental abrogation of contracts. Also, for the same reason, the Order does not provide relief from all of a pipeline's take-or-pay obligations, some of which occurred because of the drop in gas demand. The Order eases the tension that some pipelines have encountered in attempting to make the transition from the role of gas merchant to that of transporter.

The discussion in this chapter has highlighted two areas in which the Order might be adjusted. First, the FERC might consider relaxing the restriction of allowing no credits for the transportation of gas previously purchased under contracts that are now terminated. A neutral policy, it could be argued, would allow such credits up to the accumulated amount of prepayments, regardless of the identity of the transporting pipeline. The restriction currently embodied in Order 500 is consistent with the intent of Order 451 with regard to take-or-pay; however, Order 451 was adopted before the Court had given implicit approval to the idea of a crediting rule, and hence may be an issue that the FERC will address again in fashioning a final rule.

Second, the FERC might consider imposing a limit to the crediting mechanism. In certain circumstances, it appears that the combined actions of many LDCs converting their contract demand to firm transportation may convert much and possibly all of some producers' high-priced, take-or-pay gas into lower-priced transportation gas on a continuing basis. A limit to the amount of credits a producer must offer would soften a rule that otherwise may be quite harsh on producers in some limited circumstances. More information is required to assess the importance of this issue--facts that may be forthcoming as a result of the FERC data request. Regardless of whether the FERC revises Order 500, it appears that the Commission has fashioned a transportation program that meets all three requirements imposed by law or by the courts: it is voluntary, nondiscriminatory, and it addresses take-or-pay contractual problems.

Apart from the federal transportation programs, state commissions may need to increase their familiarity with the gas market and the typical kinds of contracts for selling the commodity. The next chapter introduces the topic by describing typical contracts used in the industry.

CHAPTER 3

AN OVERVIEW OF DIRECT GAS PURCHASE CONTRACTS

State commissions are likely to be more closely involved in reading and evaluating wellhead gas contracts in the future than they have found to be necessary up to now. The federal transportation program discussed in the previous chapter will encourage more local distribution companies to seek out and obtain their own sources of gas as opposed to depending on their pipeline supplier for this service. The federal policy initiative also will cause state regulators to review their own transportation policies and their responses to bypass proposals. This report is directed towards the issues that arise from the regulatory function of overseeing the contracts. The purpose of this chapter is to give the reader a short introduction to the content and structure of gas sales contracts.[1] The following chapter reports the results of a National Regulatory Research Institute survey of state commission procedures regarding these contracts, while chapters 5 and 6 present two kinds of statistical analysis of contracts that commission staff members may find useful.

Types of Contracts

As part of this research project, the NRRI reviewed about 100 contracts for the purchase of natural gas between field producers and local distribution companies. The contracts were all signed, or in a few cases

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[1] The Natural Gas Staff Subcommittee of the National Association of Regulatory Utility Commissioners is, of course, especially interested in gas contracts. The Subcommittee conducted a workshop in Orlando, Florida in October 1987 on gas regulation that was intended to familiarize commission staff members with the operation and regulation of the gas market from wellhead to burner tip. Interested readers may wish to contact the subcommittee for further information. Its chairman is Harold A. Meyer, Wisconsin Public Service Commission, 4802 Sheboygan Avenue, Madison, WI 53707.

modified, in the period from 1985 to 1987. These are, therefore, new contracts. Of the contracts that were reviewed by the NRRI, 28 are suitable for the statistical analysis reported in chapters 5 and 6. The sample is not uniformly distributed across the country, consisting of contracts signed by Michigan, Ohio, Kentucky, and Mississippi distributors. Conversations with industry representatives, however, suggest that the contractual terms observed in the NRRI sample are representative. That is, the actual prices observed in the sample may have a distinct mid-western focus, but the contract terms governing how the price can be modified in the future, for example, are common to the industry.

There are two basic kinds of contracts now used to sell natural gas: spot purchase contracts and long-term contracts, where "long-term" means any duration of time longer than that found in a typical spot market contract--usually one month. This distinction between spot and long-term contracts is useful for a number of reasons. The spot market for natural gas is a relatively new institution that regulators have encountered only recently. Its existence is a marked departure from the previous pattern of pipeline merchants securing an LDC's gas needs with long-term supply commitments. Contractual terms across spot contracts are more or less the same, except, of course, for the actual price (which may not appear in the contract at all, but instead may be determined monthly according to a procedure described in the contract). In contrast, the nature of the terms and clauses in a long-term contract may serve to make future adjustments of the price very easy or very difficult. Likewise, clauses in long-term contracts can be written so as to allow substantial flexibility in day-to-day or month-to-month sales, or alternatively these can severely restrict future quantity adjustments. The effect of these restrictions on future action is to shift financial risk between the buyer and seller in subtle ways. Spot market contracts are for such a short duration that it is not usually possible to shift financial risk by any substantial degree. Spot market contract terms, then, mainly serve to protect both the buyer and seller against ordinary business risk, such as the requirement for legal title to the gas to pass from the seller to the buyer at the delivery point(s).

Another reason for distinguishing spot from long-term contract purchases is that both types of contracts coexist in many commodity markets in a variety of economic conditions. It is commonplace for new long-term contracts for coal supply to be signed during a month when substantial quantities of spot coal are sold. This happens when the market is slack and spot prices are below contract prices, and it also happens when the market is tight and spot prices are high relative to contract prices. This is true in a variety of markets.[2]

A typical pattern in the seven markets reviewed by Charles River Associates is that spot prices are below contract prices when the market is slack to normal. That is, over many years, the most common experience is that spot prices are below contract prices by 5 to 20 percent. When the market tightens significantly, spot prices can go above contract prices, usually for a short time. So spot prices tend to be more volatile than contract prices, and in a sense buying and selling on the spot market is the residual activity that serves to clear the market as a whole. Also, most typically, contract prices exceed spot prices by 5 to 20 percent, a premium that buyers are willing to pay for supply security and price certainty. Buyers in these markets tend to purchase 50 to 75 percent of their supplies through long-term contractual commitments even when there is a readily available spot market.

Now that a spot market in natural gas has emerged, a reasonable set of expectations about the overall gas market can be formed on the basis of experience elsewhere. Regulators can expect both spot and long-term contracts to coexist in the supply portfolio of their jurisdictional LDCs. In particular, it is not likely that an optimal portfolio would consist solely of spot gas, merely because the spot price is currently lower. Regulators can expect long-term secure supplies to command a price premium over spot sources in a normal to slack market. The premium might be 5 to 20 percent, although this expectation should become better focused as experience with a natural gas spot market grows and encompasses a wider variety of economic circumstances than the slack condition that has prevailed since the market was established in 1984-85.

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[2] Charles River Associates reviewed the contract and spot price behavior in several markets, including Appalachian coal, bulk ocean shipping, intrastate gas, and commodity markets such as copper, aluminum, nickel, and molybdenum. See Natural Gas Procurement: Experience with Spot vs. Contract Pricing in Analogous Commodity Markets (Boston, MA: Charles River Associates Inc., CRA. No. 154.00, November 1986).

These conclusions are quite general and thus are not likely to greatly assist a state regulatory body, except to rule out some rather extreme possible policy positions. For example, an extreme policy (not adopted by any commission to the authors' knowledge) would impute the spot price as the per unit cost of all of a distributor's gas sources. Since an optimal supply portfolio of a competitive firm would not consist solely of spot purchases, the policy would not be an appropriate imputation for a regulated gas company either. The truly important supply choices, instead, have to do with the optimal mix of spot and contract supplies to serve firm, captive customers, and the optimal mix for interruptible customers who may have alternative fuel choices. The optimal mix would be different, presumably, for the two types of customers. This issue is addressed later in this report in chapter 7.

The recognition that spot and long-term contract markets are going to coexist suggests that state commissions may wish to become familiar with sources of data regarding the spot market. Brokers like the Yankee Gas Company provide such prices to their clients routinely. Long-term contract price information is more difficult to obtain; however, a commission can use contracts under its own jurisdiction to form a basis for comparison, if one is needed.

Contractual Terms

A typical contract for the sale of natural gas contains a variety of articles or clauses. The purpose of this section is to describe these briefly and to indicate generally the importance of each. No attempt is made in this section to present a legal analysis. Rather, the emphasis is on the economic importance of the contract terms.

Standard Clauses

There are several types of clauses or articles encountered in almost all gas contracts that are standard and have well-understood meaning to industry participants. The contractual language may differ from contract to contract; however, the basic legal obligations are well known. These contract sections can be summarized very briefly as:

Definitions. An article containing a glossary.

Reservations. An article describing gas that the seller reserves to himself for personal or on-site use.

Delivery Point(s). An article describing the physical location(s) where the gas is to be delivered.

Quality. An article describing the physical characteristics of the gas and the allowable deviation, such as the minimum Btu content, maximum water vapor, maximum impurities, pressure, and so on.

Measurement. An article describing the method of measurement (dry or wet, which are ways of metering gas--the meter involves a dry or wet measuring technique, whereas the gas itself is dry), the responsibility of each party, and the recourse of each party if measurement errors occur.

Laws and Regulations. An article that states that both parties agree to abide by the laws and regulations of any commission having jurisdiction over matters such as prorationing, price ceilings, etc.

Warranty of Title. An article that states that the seller has legal title to the gas and that title passes to the buyer at the delivery point(s).

Force Majeure. An article that lists a set of events such as earthquakes or riots that constitute reasons why one or both parties may be unable to perform their contractual duties and for which neither is held responsible.

Billing and Payment. An article describing the details of the monthly billing cycle, such as when payments are due, to where a payment is sent, and so on.

Term

A natural gas contract will contain an article or paragraph that establishes the length of time over which the contract remains valid. A long-term arrangement may last for 20 years, although 3 to 5 year contracts with an option to renew the contract annually thereafter are commonly used today. Some "long-term" contracts may have a term of only 3 months. This is clearly a contract with a short duration and could be considered long-term only in relation to spot contracts that typically are for one month.

Quantity

A contract may have one or more articles dealing with the volumes of gas to be sold. If the seller's reserves are to be committed to the buyer, the contract includes a clause describing the geographical location of the lands covering the committed field. Such a commitment, of course, would not be part of a spot contract.

The contract may have an article dealing with the measurement of reserves. In it, a process for determining reserves is described, possibly including a requirement that the seller must provide whatever information the buyer may need in order to form an independent and confirming estimate of the reserves that the seller claims to have. Knowledge of the reserves is important mainly in contracts that contain take-or-pay obligations that are specified on the basis of a well's annual or daily deliverability, which is linked in the contract to the estimated reserves. That is, the buyer may be obligated to purchase or else pay the seller for a quantity of gas, whether taken or not, based on a well's deliverability that may be expressed as 1 MMcf per day for each 3.65 Bcf of gas reserves, for example. The ratio of reserves to daily deliverability results in a 10 year period in this example, by which time the parties plan to exhaust the well. The buyer's interest in accurately estimating reserves is due to his annual take-or-pay obligations that are based on deliverability, which is based, in turn, on the reserves.

In addition to the foregoing, a gas contract may specify a minimum take. This is intended to be a floor on the volume purchased by the buyer. This is different from take-or-pay in that the parties' intention is to move the gas and not simply to pay for it if it is not taken. There is usually some physical characteristic of the gas well that motivates such a requirement. Part of the reason may be to prevent drainage by well-owners on surrounding land. The risk of drainage can also be reduced by a clause stating that the buyer will obey any state prorationing rules.

The combined effect of all the contractual terms governing quantities is to make future adjustments in the delivered quantities easy or difficult. The quantity terms may be written to say that the seller provides gas or the buyer takes gas on a "best efforts" basis, in which case the parties have substantial freedom to adjust to future conditions. Alternatively, the quantity terms may require a 90 percent take-or-pay level, thereby severely restricting the possibility of future adjustments. The conclusion to this line of reasoning is that substantial insight about the importance of contract terms governing quantity is possible by viewing such terms as restrictions to future adjustments. As such, the quantity clauses determine, in part, the risks borne by each party. Long-term contracts with committed reserves and take-or-pay requirements reflect a bargain whereby the seller agrees to give up his right to seek alternative buyers in exchange for the buyer's promise to continue to take gas and not shut-in the wells. Secure supplies are obtained, in part, by the buyer giving up the option to reduce his purchases below some level.

In the sample of contracts obtained by the NRRI, it was the case that any contractual arrangement with a take-or-pay provision also had committed reserves. Some contracts had reserve commitments, however, and no take-or-pay requirement. Any contract that specified quantities are to be taken or delivered on a "best efforts" basis had no provision for committing reserves. All of these relationships conform to good business practice and make economically good sense.

Price

Clauses specifying price are written quite differently in spot versus long-term contracts. The price of spot purchases is expected by both parties to change monthly. The contract will set out the process to be used each month in determining price, and for that reason the contract may not include even the initial price, since the contractual process can be relied upon even in the first month. The price determination process may be that the buyer nominates his advertised price for gas and the seller can either accept or reject the offer. In other instances, the seller may post the price and the buyer can accept or reject. In any case, the contract specifies the procedure that the monthly bargaining will follow.

In long-term contracts, the price provisions can be more complicated because the parties are agreeing on a series of prices over time that will not be as flexible as spot prices. In some contracts, price is fixed for the term of the contract. In others, future adjustments are allowed. In these cases, the adjustment mechanism is described in detail. The mechanism may be a fixed escalator clause. It may link the contract price to the price of Number 6 fuel oil. Or it may link the contract price to some other gas price, such as the distributor's incremental price paid to his pipeline supplier(s), or a field price.

Quite complicated price adjustment clauses can be constructed by combining the above elements. For example, a contract may have a minimum price and a maximum price, and a separate, fixed escalator clause for each. (A fixed escalator clause is one that contains a formula for price increases based on a fixed, annual rate of increase.) Between the minimum and maximum price, the contract may specify that the price will be the lesser of the price of Number 6 fuel oil or a pipeline company's incremental price. If the fuel oil or other gas price persistently drops below the minimum, the buyer may be able to redetermine the price at the lower, alternative fuel price. Such a redetermination may free the seller to seek other bids, in which case the buyer typically has the right of first refusal. Accordingly, a redetermination of price outside of the range established by the minimum and maximum creates a risk that the buyer may lose a supplier. Such a redetermination, presumably, would not be undertaken lightly.

Market-out clauses are common features in long-term contracts today. This clause provides some recourse to the buyer if the buyer finds that he cannot resell the gas profitably. A contract may specify, for example, that acceptable evidence of the buyer's difficulties consists of a contract price higher than the incremental commodity cost of the LDC's traditional pipeline supplier. The buyer's recourse usually is to reduce the direct purchase contract price down to the pipeline's incremental price. If the buyer does this, the seller may have the contractual right to seek another buyer, however. Market-out clauses thus have some similarities to price redetermination features of a contract and to escalator clauses that link the contract price to an alternative gas price.

Some long-term contracts have periodic price redeterminations, possibly every 6 months or year. If the parties cannot agree on a price, the seller may be free to seek other buyers. In some cases when this happens, the contract is terminated, and in others, the contractual relationship persists, perhaps after a period of two years.

All of these contractual terms regarding price affect the risk each party bears by entering a contract now that may in the future turn out to be unfavorable. Typically, the buyer agrees to some inflexibility regarding future prices, thereby running the risk that the contract price may be unfavorable in comparison to the spot price prevailing at some future date, in exchange for a secure, long-term supply of gas.

CHAPTER 4

COMMISSION OVERSIGHT OF DIRECT GAS PURCHASES

This chapter describes state utility commission procedures to oversee LDC direct gas purchases from producers. The procedures are, in part, a response to current gas market conditions, federal regulation, and the LDC contracting practices discussed in previous chapters. The discussion in this chapter is based on a survey of state commission staff members conducted by the NRRI during the summer of 1987. Surveys were sent to thirty-seven commissions (in as many states). In the remaining thirteen states, direct gas purchases are either unregulated or infeasible. Responses were received from thirty commissions. The survey questionnaire and detailed responses are in appendix A.

The chapter is organized around two major topics: commission review of direct gas purchase contracts and commission incentives to promote efficient purchasing.

Commission Review of Direct Gas Purchase Contracts

Several questions in the NRRI survey dealt with the nature and scope of current commission review of direct gas purchase contracts. Topics covered included the occasions for a review, the types of information reviewed, other types of information that might be helpful, the possible need for revision of purchased gas adjustment procedures due to direct gas purchases, and the need to ensure confidentiality of contracts. The purpose of these questions was to determine what commissions are doing to monitor LDC purchases, what documents they examine, and what documents they might like to examine. The NRRI survey revealed a variety of ways that commissions are using or are planning to use to oversee the new gas purchasing opportunities facing local distributors.

Nature of the Review Process

Commissions review direct gas purchase in a variety of ways, including: review in a PGA proceeding, review in a general rate case, periodic review by commission staff or outside auditors, and preapproval of contracts by a commission. Some report having no review at all. Contracts that an LDC has with an affiliated gas producer typically are scrutinized more closely. The majority of the commissions surveyed review direct gas purchase contracts in some way. The review is usually part of a PGA proceeding, although general rate cases are sometimes used for this purpose. The Oregon and Tennessee Commissions are exceptions and review such contracts only in general rate cases.

The frequency of reviews varies with the commission, with annual and semiannual reviews being the common. The California Commission reviews contracts in PGA proceedings twice a year, although the Commission plans to change to annual reviews. In Connecticut, reviews are conducted monthly in PGA proceedings and every two years in general rate cases. The New Jersey Board reviews contracts annually in PGA proceedings and every three years in rate cases. The Delaware Commission reviews a contract in a PGA proceeding if the contract changes or if the issue arises for other reasons. Contracts are reviewed also in general rate cases if they have changed or are about to change in the near future. Some commissions, such as those in Kansas and Kentucky, review the contracts regularly in PGA proceedings and then again in rate cases only if necessary. In Iowa, contracts must be filed annually with the Board as part of PGA and annual review of gas procurement (ARG) filings. Information from the contracts is also used in the calculation of purchased gas adjustments, which are filed whenever a change of 0.5 cents per therm occurs, although not more frequently than every thirty days.

The Ohio Commission also reviews contracts in PGA proceedings. The frequency of the review is dependent on the number of customers that the company serves. Companies that have over 5,000 customers are reviewed annually, while smaller companies are reviewed biennially.

Some states have developed other types of proceedings in addition to or in lieu of PGA or rate case review of contracts. The Michigan Commission, for example, has replaced the PGA proceeding with an annual Gas Cost Recovery Proceeding. Under this proceeding, which is required by state law, a utility must file an annual gas cost recovery plan that is subject to formal hearings to determine its prudence and reasonableness. Direct purchase contracts are reviewed in these proceedings. In Iowa, the Board conducts annual review of gas procurement (ARG) proceedings (mentioned above) during which the utility must prove that it is taking all reasonable steps to minimize gas costs. Contracts are reviewed in these proceedings, which are in addition to PGA procedures.

Commission staff may review direct purchase contracts on some occasions other than during PGA proceedings or rate cases. In West Virginia, for example, the staff may review a contract in a complaint proceeding or if an affiliated transaction is involved. Some commissions require that the contracts be filed with them, and staff may examine the contracts at that time. The Ohio Commission staff may undertake a preliminary review of a contract at the request of the utility. The frequency of staff reviews varies with the commission and ranges from twice a year to every three years, or as warranted.

Although gas contracts typically are reviewed by commission staff members, a few commissions use outside auditors and a few preapprove the contracts. Two states reported the use of outside auditors. The Ohio Commission hires outside auditors to review contracts as part of the PGA proceedings. The New Jersey Board also has an annual review of contracts by outside auditors. The North Carolina Commission preapproves contracts in some special circumstances in which a filing is made. The West Virginia and Kentucky Commissions approve contracts involving affiliated transactions. In West Virginia, a hearing is held at which time the utility must prove that the terms and conditions of the contract are reasonable, that neither party is given an undue advantage, and that the contract does not adversely affect the public.

Several state commissions reported special procedures for dealing with contracts between an LDC and its affiliate. The Kentucky Commission monitors affiliated transactions through data requests. The New Mexico Commission must be notified when an affiliated transaction is undertaken and furnished with a copy of the contract.

The Oklahoma Commission has a procedure to determine if an affiliated transaction is an arm's-length agreement. In it, the Commission considers whether the contract price is comparable to a fair field price paid to other producers and whether the contract terms are likewise similar to those in contracts of other unaffiliated producers.

The Pennsylvania Commission, like the Kentucky Commission, subjects affiliated transactions to more intense scrutiny. The Delaware Commission reported one instance of an LDC purchasing from an affiliated producer. In that case, the gas price was midway between the pipeline's commodity rate and the most recent spot price, and consequently the price was considered reasonable.

Several commissions do not now conduct any type of review of direct gas purchase contracts; others are much more active in overseeing direct purchases. The New York and Kentucky Commissions, as examples, actively oversee direct gas purchase contracts. The New York Commission reviews contracts in PGA proceedings and in rate cases, requires contracts to be filed with the Commission, and provides for staff review and monitoring of contracts. The Kentucky Commission reviews contracts in quarterly PGA proceedings, and (if necessary) in rate cases, requires contracts to be filed with the Commission, provides for staff reviews as contracts are filed, and carefully examines contracts with affiliated producers. Most other commissions monitor such contracts less intently.

Types of Information Reviewed

Filing requirements that commissions may impose on jurisdictional LDCs include: the contract itself, price and volume information from each contract, and aggregated price and quantity information from all contracts. In addition to these, the California Commission requires any records, internal memos, and correspondence between the parties involved to be submitted. The Commission wants to understand what the utility knew at the time that it made the agreement. The Iowa Board requires that invoices be provided.

The Kansas Commission requires that an LDC provide a description of other alternatives for obtaining fuel and the reasons for selecting the alternative embodied in the contract. A justification for each price escalation invoked under the contract must also be furnished. The Ohio Commission requires an independent auditor or the Commission staff to review a contract, including an evaluation of its volume, price, and obligations such as minimum takes, take-or-pay, price escalators, and cost of transportation.

The Pennsylvania Commission allows an LDC to collectively report information about individual gas suppliers who provide less than 3 percent of the total system supply. In Minnesota and Utah, there are no set information requirements. In Utah, the Commission and the Division of Public Utilities (which is not the Commission's staff) determine the scope of an investigation in a case and then request the necessary information. Usually, summaries of contracts are reviewed.

The West Virginia Commission requires a contract to be submitted if the agreement is subject to FERC jurisdiction. If a contract is with a local producer, a summary of relevant items must be provided, such as name, quantity, price, county of production, producer name, well name and number, and NGPA classification. Some information must be broken down between projected and historical PGA periods. For the projected period, the LDC must furnish estimates of the total cost of purchased gas, the volume of gas purchased, sales, total supply available, and excess unaccounted-for gas. For the historical period, the LDC must submit the actual quantity and cost of purchased gas, the actual quantity and cost of all gas transferred to and withdrawn from storage, the total gas sold, a list of any offers to purchase gas issued by the utility, and a list of any offers to sell gas received by it.

Information That Might Be Helpful

As part of the NRRI survey, commissions were asked if there were any types of information not received currently that the commission might find useful in reviewing direct purchase contracts. Most respondents answered "no," or said that they were obtaining all of the information that they needed. Some stated that certain data might be helpful. Three commissions pointed out that it would be useful to know an LDC's reasons for turning down bids or offers of gas, for comparison with the accepted contracts. The Delaware, Minnesota, and West Virginia Commissions noted this possibility.

Other types of information that respondents mentioned included: any LDC legal analyses of contracts; survey data to use as a standard for evaluating LDC actions; an external, independent measure of the reliability of suppliers; an evaluation of the market that the LDC plans to serve with the gas supply; a description of the proposed delivery point of the gas into the LDC system, as well as the amount of other gas flowing into the system there and the capacity at that delivery point (to assess the LDC's ability to accept the gas); a synopsis of the LDC's least-cost strategy; and an explanation of how a contract fits into the overall LDC supply plan. These kinds of information reflect the regulators' desire to gain more insight into utility decision making, including why a particular option was chosen, why another option was not, and how the chosen alternative fits into an overall plan to provide reliable service at least cost.

Overall, then, most commissions appear to be receiving substantial amounts of information on direct gas purchase contracts. Although a minority of the commissions had suggestions about additional information, most perceived that the information currently received is adequate to oversee LDC direct gas purchases.

Need for Revision of PGA Procedures

Because direct gas purchases are a relatively new phenomenon, some commissions may need to change their established PGA procedures. The NRRI survey indicates that several commissions have made or plan changes. This is not surprising. The purchased gas adjustment procedure is the main means of commission oversight of direct gas purchase contracts, and commissions want to insure that the procedure continues to work effectively under changing circumstances. Nonetheless, most commissions plan no changes to their procedures, an indication that most believe their procedures (and access to information) are adequate to deal with changing circumstances.

Examples of revised procedures include the action of the Minnesota Commission to give utilities that make direct gas purchases a variance from existing PGA rules. The new PGA policy allows a utility to pass through the costs of the purchases.

The Ohio Commission plans to merge its review of LDC long-term forecasting with its purchased gas management and performance audit. This move is designed to enable the Commission to examine a utility's long-range gas purchasing strategy and to offer more prospective guidance. The change, however, is not due solely to direct purchase contracts.

The Oregon Commission is considering a shift to quarterly PGA reviews from its current semiannual PGA trackers. In part, the change is due to the effect of the FERC Order 436 on interstate pipelines.

The Virginia Commission has made some revisions in its PGA procedures on a case-by-case basis. The Commission intends to eliminate lags in the process that previously kept lower gas costs, such as spot purchases, from being passed through to ratepayers for up to twelve months after the purchases had occurred. The Commission also plans to initiate a generic proceeding covering gas purchasing and revisions to PGA procedures.

The South Carolina Commission has issued orders to begin annual hearings to examine the purchasing policies and procedures of LDCs. The Tennessee Commission is considering a modification to its PGA process that will allow all gas costs to be recovered through a balance account.

The West Virginia Commission adopted a rule providing for the historical and projected PGA reporting requirements described earlier. The Commission would like LDCs to contract more often with local producers for gas and to buy more spot market gas. As part of this overall policy, the Commission recently approved a rule requiring LDCs and intrastate pipelines to provide open access transportation.

The Wisconsin Commission currently does not review direct purchase contracts. In July 1987, however, the Commission initiated a generic purchasing, planning and prudence investigation. PGA modifications were considered as part of that proceeding.

Contract Confidentiality

Regulators protect the confidentiality of the contracts in a variety of ways. The documents are not required to be filed at some commissions, and they are part of the public record with guaranteed public access at others. Some commissions safeguard the contracts by prohibiting public access or by using special procedures such as confidentiality agreements. Others limit access to contracts only if the utilities make such requests. Most commissions have adopted procedures to guarantee confidentiality. Some use the procedures only if requested to do so by a utility and otherwise allow public access to contracts.

Three commissions (Connecticut, New Mexico, and Tennessee) have policies of unconditional public access. A fourth, the Washington Commission, provides "broad access of the public to anything at the Commission" but does not require contracts to be filed with it, as do the other three. Three commissions prohibit public disclosure of contracts. These are the California, Kansas, and North Carolina Commissions. The Oklahoma Commission does not disclose contracts to the public, and the Commission staff does not maintain files of contracts.

The Delaware, Nevada, Oklahoma, and Oregon Commissions review the contracts at the utility's offices. Confidentiality is assured because the contracts remain with the utility.

The staffs of the Delaware, California, and Utah Commissions, and of the New Jersey Board sign confidentiality agreements. As mentioned, the California Commission has a policy that contracts are not disclosed to the public. The Utah policy is to agree to a confidentiality statement in cases "where confidentiality is vital."

While many commissions employ confidentiality protection procedures if requested to do so by an LDC, the commission may not automatically honor the request. In Pennsylvania, for example, the administrative law judge hearing a case must decide whether or not to grant such a request. In other states, such as Iowa, Minnesota, New York, West Virginia, and Wyoming, requests for confidential treatment of contracts must be approved by the Commission.

Commission agreement to confidential treatment of documents may limit, but not entirely exclude, outside access to those documents. The Minnesota Commission, after ruling that information is to be considered a "trade secret" and not available to the public, nonetheless allows the information to be examined by state regulatory agencies and some other intervenors. The Ohio Commission generally does not keep copies of contracts on file and may, in gas cost recovery cases, issue protective orders limiting access to any information it does have. The Ohio Consumers' Counsel, in addition to Commission staff is permitted access to the documents.

Commission Incentives to Promote Efficient Purchasing

A state utility commission can provide incentives for an LDC to purchase gas efficiently through its purchased gas adjustment procedure, a least-cost purchasing requirement, or a prudence review. The strength of the incentives differs among these three policy options. A PGA provides the least incentive if it is used merely to pass through fuel costs. A commission may structure a PGA proceeding, however, in a way that promotes more efficient purchasing practices.

The other two options provide more incentives for least-cost purchasing because they include some sanctions. The sanctions are in the form of denial of cost recovery if purchases are deemed unnecessarily expensive. A distributor, in addition, may want to avoid the extra costs and potential embarrassment that could result from a prudence investigation, for instance, into its gas purchases.

PGA Procedure

Many commissions' PGA procedures do not have any features intended to create an incentive for efficient gas purchasing and supply planning. In some cases imprudent costs may be disallowed or there may be certain tariff features or other statutory requirements that create some incentives.

The disallowance of imprudent costs (or similar language) was mentioned by the survey respondents from Connecticut, Iowa, Kansas, New York, Ohio, and Pennsylvania. The Iowa rules require the Board to disallow costs in excess of those that would be incurred under prudent practices. This procedure is part of the Iowa Board's annual review of gas procurement practices (ARG).

Indiana law requires the Commission to grant increases in gas charges only if it finds (among other requirements) that the LDC "has made every reasonable effort to acquire long-term gas supplies so as to provide gas to its retail customers at the lowest gas cost reasonably possible...." In one case, the Indiana Commission decided, in a gas cost adjustment proceeding, that the LDC would not be allowed to recover a price for nonpipeline gas greater than the price of pipeline gas.

Incentives for efficient purchasing can be created by allowing an LDC to keep some fraction of revenues from cost reductions for itself or by placing LDC profits at risk. A Wyoming statute, for example, allows an LDC to keep ten percent of any reduction in the cost of gas. The other ninety percent is passed through to ratepayers.

The Oklahoma Commission has approved tariffs that allow LDCs to split transportation margins 75 percent to 25 percent with stockholders. A 90-10 split is approved for off-system gas sales. A Rhode Island Commission approved tariff splits margins from the sale of gas to interruptible customers between the LDC (25 percent) and firm customers (75 percent). This split is effective only after a target level of sales has been attained.

Examples of the second type of incentive include a tariff approved by the Oregon Commission that places an LDC at risk for 20 percent of the loss or gain between rate cases due to changes in the cost of gas for serving interruptible customers. The California Commission has recently divided natural gas customers into core and noncore sectors. Core customers receive traditional utility service. Noncore customers may receive, at the customer's option, transmission service or both transmission and gas supply procurement services from an LDC. Under this arrangement, part of the utility's profit is based on throughput. Service to noncore customers is riskier for the LDC with 1.5 percentage points of the return to equity (10 percent of profit) at risk under the plan.

Requirement of Least-Cost Purchasing

A requirement to pursue least-cost planning presumably provides some incentive for an LDC to purchase gas efficiently. Most commissions have some type of requirement that an LDC obtain gas at least cost. At some, such as those in California, Connecticut, and New Mexico, the issue is raised in PGA proceedings. In Mississippi, Kansas, and New York, rate filings provide the vehicle.

In some cases, a commission may have no formal requirement for least-cost purchasing, but still may consider the issue. The Delaware Commission, for example, has no formal requirement for an LDC to show that its direct gas purchases are part of an overall least-cost purchasing strategy, but such purchases are reviewed as part of a utility's annual and semiannual fuel filing for rate changes. The Oregon Commission has no specific written requirement for least-cost purchasing, but rates are always based on the lowest cost gas available. The Utah Commission reviews the efficiency of a utility's gas mix but has no specific least cost requirement.

In Indiana, a state statute (discussed in the previous section) requires each LDC to secure long-term gas supplies and provide service at the lowest cost possible.

Pennsylvania law requires an LDC, when initiating a rate case, to provide the Commission with information on "the utility's efforts to negotiate favorable contracts with gas suppliers and to renegotiate existing contracts with gas suppliers or take legal actions necessary to relieve the utility from existing contract terms which are or may be adverse to the interests of the utility's ratepayers." The LDC must also describe its efforts to obtain lower cost gas supplies both inside and outside of Pennsylvania. These efforts may include transportation agreements with pipelines or other LDCs.

New York law contains a requirement similar to the Indiana and Pennsylvania statutes. When applying for a rate increase, an LDC must describe all of its supply sources and any anticipated changes in those sources. The utility must also show that other reliable, lower-priced sources are not available. The statute requires an LDC to purchase gas from local producers if the cost of that gas is equal to or less than the utility's highest priced source of gas produced outside of New York. If the purchase of New York produced gas would be harmful to ratepayers, however, the LDC does not have to buy the gas.

Other statutory rules have been used to establish procedures for regular commission review of LDC gas procurement (above and beyond rate case or PGA review) with the intent of ensuring least-cost purchasing. The Nevada legislature, for example, recently enacted legislation (S.B. 449) requiring an LDC periodically to submit a plan to the Commission that projects the demand for gas, estimates the cost of meeting the projected demand, describes how the utility intends to minimize the cost, and estimates the cost, reliability and quantity of gas to be obtained from each supply source.

The Iowa Board conducts an annual review of gas procurement practices for each regulated LDC. Every utility annually must file a procurement plan that includes a summary of the legal and regulatory actions taken to minimize gas costs and a description of the supply sources selected with an evaluation of the reasonableness and prudence of the utility's supply decisions. Each LDC must also submit an annual gas requirement forecast along with a supply forecast. The supply forecast describes all suppliers and includes a supplier-mix options list and a list of planned supply contracts and arrangements. The supplier-mix options list includes projections of purchase costs for each mix option. The LDC has the burden of proving that it is taking all reasonable actions to minimize gas costs.

The Minnesota Commission requires an annual report from each LDC on its procurement policies. The report includes a summary of the utility's efforts to minimize gas costs. Periodic reports on least-cost plans and fuel procurement are also required by the Washington, Ohio, and Oklahoma Commissions.

In its review of fuel procurement, the Ohio Commission allows intervenors to challenge a utility's purchases by claiming that alternatives would have cost less. The Iowa Board also allows outside intervenors to participate in its ARG reviews.

Importantly, least-cost considerations must be balanced with concerns about supply reliability. The respondent from the Ohio Commission stated that, "the Commission attempts to balance the concept of least cost with an assessment of supply reliability, therefore the lowest cost gas is not always the optimal purchase."

Overall, commissions consider least-cost purchasing by an LDC to be a very important goal. That objective is embodied in statutes and commission orders and is raised in rate cases and PGA proceedings. Progress in meeting the goal is monitored in special hearings and through LDC reporting requirements. The goal of least-cost purchasing covers more than simply direct gas purchases. Nonetheless, direct gas purchases can be an important tool used by an LDC to meet a legal requirement of lowest gas costs (or some other commission or statutory goal such as the New York and West Virginia goal of buying gas from local producers).

Prudence Reviews

A third potential commission method for encouraging efficient gas purchasing is the prudence review (or the possibility of such a review). Some commissions do not undertake prudence reviews. Others include the prudence issue in rate cases or fuel adjustment proceedings instead of holding separate inquiries. Some of the prudence reviews are conducted in the context of a larger annual review of an LDC's procurement plans. The Iowa Board's ARG review is an example. The Michigan Commission reviews LDC gas cost recovery plans annually to determine if the plans are prudent and reasonable. The California Commission has found some small contracts to be imprudent when compared to alternatives.

The New York Commission has recently conducted two inquiries. In one case, involving Brooklyn Union Gas, the Commission issued a show cause order to the utility to justify gas purchases from an affiliate at a higher rate than other purchases. The contract was renegotiated at a lower price and the Commission rescinded the order. In another case, involving National Fuel Gas, a gas purchase contract was disallowed when a price escalation clause in it resulted in what the Commission considered to be uneconomic rates.

The Oklahoma Commission reviewed a nonrecoupable, take-or-pay settlement between an LDC and a producer. The Commission staff concluded that the settlement was prudent after considering whether the settlement's dollar amount was less than what the producer had initially claimed as the take-or-pay amount; whether the settlement mandated lesser quantities to be purchased from the producer; and whether the settlement provided for a lower price.

The West Virginia Commission undertakes prudence reviews to try to insure least cost purchasing. The Commission may impute a lower price to the gas supply. In a case involving Mountaineer Gas Company (also involving a contract between affiliated entities) the Commission reduced the purchase price from \$3.20 per decatherm (dth) to \$2.90 per dth to reflect a more market-oriented price.

The Ohio Commission examined some purchases by an LDC from an affiliated producer. The purchases were not found to be imprudent as the cost was as low or lower than other purchases and this source was curtailed when oversupplies occurred.

Thus, prudence reviews have been used, at least occasionally, by commissions to investigate gas purchasing strategies of LDCs. Affiliated transactions, in particular, are closely scrutinized in this way.

Risk Assessment

In reviewing a direct gas purchase contract a commission might compare the riskiness of long-term contracts containing requirements for minimum volumes to be purchased with shorter term contracts such as those for spot market gas. Most of the commissions surveyed by the NRRI indicate that they do not now assess such risk. In some cases, the issue has not yet risen, and in others, the commission has no guidelines for conducting such a review. The New York Commission considers risk in a general way but has no written guidelines or decisions. The Kentucky Commission plans to consider risk in upcoming reviews although it is not now being considered. The South Carolina Commission also plans to consider riskiness of contracts in future reviews.

Some survey responses described commission attempts to assess risk. The staff of the California Commission, for example, carefully reviews certain types of pricing terms. These include tying the price of gas to the rate of return on the producer's rate base or using the weighted average cost of gas of all long-run gas supplies. The security of the gas supply is currently not an issue.

The Michigan Commission considers supply reliability in its reviews. The Ohio Commission is also concerned about supply, particularly with the ability of an LDC to continue to provide firm service to captive customers.

The Utah Commission, in its review of the supply mix of an LDC, assesses the risk of long-term contracts with take-or-pay requirements versus spot market purchases. The Oklahoma Commission reviews LDC fuel supply models, including purchase requirements, projected fuel cost, and supply mix. The staff has found that LDC efforts to buy spot market gas have been impeded by various contractual requirements to purchase.

The West Virginia Commission considers the riskiness of an LDC buying gas from a local producer instead of from an interstate pipeline. The

Commission also considers the riskiness of long-term versus short-term contracts, but it has not established any minimum or optimum requirements.

Risk assessment is not commonly used by state commissions, although this is changing. As direct gas purchases become more common, supply risk may become an important issue for more commissions.

Other Aspects of Commission Oversight

A final part of the NRRI survey provided an opportunity for the respondents to offer any special insights about the topic of direct gas purchasing. In many cases, commissions are only beginning to explore this area and deferred comment.

The Utah respondent cautioned that procedures that work well in Utah might not work in other states. Utah's LDCs have access to a variety of gas sources, including some that are utility-owned.

The Oklahoma respondent described the Commission's review procedure for gas purchase contracts, noting that the staff first determines what the LDC fuel procurement practice is. Key contractual provisions are then reviewed to confirm the utility's policy.

The respondent from the Pennsylvania Commission noted that review of contracts between an LDC and an affiliated producer has "revealed some surprising results." He stated that "it is especially important to encourage non-affiliated producers to participate in the proceedings to uncover instances where potential gas supplies have not been utilized."

The West Virginia respondent discussed that commission's least cost purchasing policy. She stated that while the policy may have been hampered somewhat by implementation on a case-by-case basis, its existence and the fact that it can be brought up in rate cases may cause the distributors to comply with it. According to this respondent, local gas production has increased and LDCs have lowered their gas costs because of the policy.

Staff members from two commissions offered differing views on the trustworthiness of LDCs. One stated that LDCs generally act in good faith to keep gas costs as low as possible and to retain their interruptible industrial customers. Another discussed a problem that the commission encountered in dealing with distributors. In the past the commission gave prior approval to contracts. The staffer stated that in such circumstances an LDC might not share all of the relevant information with the commission. A utility might tell the commission enough about the proposal in order to obtain preapproval and later use that approval as evidence of prudence.

A different viewpoint on contract review was offered by the one commission respondent. He stated, "I do not believe that Commissions should be involved in that phase of utility management." This respondent also felt that the interstate pipeline is best equipped to furnish a reliable long-term supply of gas at least cost to customers who have few alternatives.

Conclusions

State utility commissions have responded to the new challenges posed by direct gas purchases mainly by the use of established practices and procedures (rate case and PGA reviews). In most cases, the commissions believe that their information sources are adequate to ensure effective oversight. Additional information, particularly regarding utility decisionmaking, would be useful to some commissions. The commissions have also set up procedures for dealing with the confidentiality question.

The main occasion for review of direct gas purchase contracts is the purchased gas adjustment proceeding. This proceeding has been structured, in some cases, to include an incentive for an LDC to purchase efficiently. Various issues, including lowest possible gas costs and prudence of purchases, are raised in PGA proceedings in addition to pass-through of gas costs. Some commissions also have used the PGA proceeding to pursue other goals, such as to promote the purchase of locally produced gas by an LDC. Separate proceedings, such as prudence and procurement reviews, have also been used by commissions, although these inquiries are sometimes incorporated into PGA hearings.

Most regulators believe that their efforts are sufficient to protect the interests of the ratepayers while allowing the LDCs to explore new opportunities to purchase gas. The new opportunities to participate in a more competitive gas market will offer challenges both to the gas distributors and to their regulators. To meet these challenges requires an understanding of how the gas market works now and how it can be expected to work in the future. An analysis of a sample of gas supply contracts is discussed in the next chapter in order to assess certain aspects of the current market.

CHAPTER 5

AN ANALYSIS OF SOME RECENT CONTRACTS

The nature of the natural gas market has changed dramatically over the last few years. The emergence of the spot market and the deregulation of new gas supplies have created a situation sufficiently novel that it is important to assess how the market is working. This chapter and the next give some preliminary observations about the market and its behavior. The results are preliminary for two reasons. First, the natural gas market has undertaken its transition only recently. The change is therefore only partially completed, and that which we have observed has occurred during a period when the market has been slack. A tight market may behave differently. Second, the sample of contracts collected by the NRRI is small, and because it is dominated by contracts in three states, it is not necessarily representative. The results are nonetheless suggestive and should be of interest.

Sample

The NRRI collected a sample of about 100 recent contracts for gas supply between producers and local gas distributors. Some of these were spot contracts and some were longer-term arrangements. From these a smaller sample of 28 long-term contracts was assembled that meet the following conditions: the contract was initially signed or else modified during the period from January 1985 to July 1987; information was available on all pertinent items including the contract's initial price and the presence or absence of a minimum-take clause, and so on; and a matching spot price was available from other sources. It is this sample that is analyzed in this chapter.

The cost of collecting the sample was quite high because the contracts are typically confidential. As mentioned earlier, some contracts are filed with the state commissions and are available to the public, and others are available only from the parties. The NRRI respects the confidentiality of the contracts in any case, and the names of the parties are not revealed in this report. The sample was obtained primarily through the state commissions of Kentucky and Michigan, and from the East Ohio Gas Company. A detailed listing of the sample appears in appendix B, including the initial price, a corresponding spot price, and a series of "dummy" variables indicating the presence or absence of various contract clauses. In all cases, the gas field is located in the same state as the distribution company. That is, gas distributors typically enter into long-term arrangements for supplies within their own states. All out-of-state contracts that we reviewed were for spot purchases. This may change in the future as distributors gain more familiarity with distant markets and the FERC Order 500 begins to open up the firm transportation market. But for now, distributors tend to make long-term contracts close by and to venture further afield only for spot purchases.

Part of the objective in collecting the sample is to determine whether and to what extent contractual terms themselves affect the contract price for gas. Is there a trade-off, for example, between take-or-pay obligations and the contract price? To detect any such relation requires first that the contractual terms be represented by some kind of quantifiable index. Eight types of contract clauses were recorded for each contract using the following set of definitions:

1. Time between price renegotiations (in months). This is either the initial term of the contract or a shorter period at the end of which the parties may renegotiate the price.

2. Fixed escalator (a specific rate of growth, like 5 percent per year) clause. Coded as 1 if the contract had such a provision; 0 otherwise.

3. Escalator clause tied to an alternate fuel, such as No. 6 fuel oil. Coded as 1 if the contract had such a provision; 0 otherwise.

4. Escalator clause tied to the price of some other source of natural gas. Coded as 1 if the contract had such a provision; 0 otherwise.

5. Sequence in which any revised prices are submitted. Coded as -1 if the buyer bids a price first, and the seller can accept or reject it; 1 if the seller asks a price first and the buyer can accept or reject it; and 0 if the process occurs simultaneously, or if a bilateral negotiation is specified.

6. Market-out clause. Coded as 1 if the contract has a clause stating that the buyer may revise a price, revise the quantities to be taken, or possibly terminate the contract if conditions make the gas unmarketable at the contract price; 0 otherwise.

7. Take-or-pay clause. Coded as the fraction of a well's deliverability that the buyer must take or pay for if not taken, if the contract contained such a clause; 0 otherwise.

8. Minimum take clause. Coded as a fraction of the deliverability.

All of the contracts contained all of the ordinary and usual clauses discussed in chapter 3, such as warranty and force majeure clauses, and accordingly, there is no need to include these as added dimensions in this analysis--there is no variance in the observed terms. Likewise, all long-term contracts in our sample contain a clause dedicating the reserves, and hence, there is no variation along this dimension in our sample. A detailed examination of approximately 30 spot contracts confirmed our expectations and revealed no substantive differences in their contractual terms. While the words and format used in a spot contract may vary among producers or distributors, the contracts were basically the same. Each contract specified a process by which quantity and price are determined each month. Supply by the seller and the amount of gas taken by the buyer are on a "best efforts" basis, and either party can terminate the contract from month to month. With no essential difference among contract clauses, there is, of course, no possibility of observing them having any influence on price. In effect, a spot purchase is a standard, homogeneous commodity, and only price matters.

Long-term contracts, however, are not homogeneous. The contractual terms expose the parties to varying degrees of financial risk and supply security--conditions that ought to be reflected in the initial price at the time a contract is signed. Part of the purpose of the subsequent analysis is to investigate this conjecture.

To accurately unravel the influence, if any, of contract terms on price requires that the analysis also account for overall natural gas market conditions. Given its homogeneous nature, a good indicator of this is the price of spot gas. That is, tightness or slack in the gas market should be observable as increases or decreases in the spot price. In addition, one can think of a competitive long-term market in gas as assigning a premium relative to the spot price that buyers must pay for secure supplies. Accordingly, each contract in the NRRI sample was matched with a corresponding spot price at the time the long-term contract was signed and at the distributor's location, meaning that the spot price includes transportation cost. The matching spot price information was obtained from a time series of quarterly purchased gas adjustment filings submitted by distributors to the Kentucky and Ohio Commissions and also from a monthly time series of spot prices provided by Yankee Gas Company, a natural gas broker. The matching is quite close and should be accurate for the purposes of this study. As is always the case in statistical studies, better data would improve matters. In this case, company-specific spot prices would have been preferred, instead of estimating these from quarterly PGA filings.

Simple Descriptive Statistics

Most of the sample, 16 of 28 long-term contracts, are from Kentucky. 7 are from Michigan, 4 are from Ohio, and 1 is from a Mississippi distributor. The contracts were signed in 1985, 86, and 87, with an average date of about July 1986. The average contract price is $2.45 per Mcf. The average of the corresponding spot prices is $2.25 per Mcf. (Recall that the spot price is a delivered price and includes 35 to 50 cents of transportation fees.) The average difference between the two prices is about 20 cents per Mcf. Accordingly, in the NRRI sample, distributors paid an average price premium of about 9 percent over spot for secure supplies. This is consistent with the findings of Charles River Associates, discussed in chapter 3, that contract premiums are between 5 and 20 percent typically. In our sample, the premium ranged from a modest 1 percent (for a contract that was written in terms similar to those in a spot contract) to about 24 percent. As the gas market tightens in the future, commissions can expect spot prices to rise relative to contract prices and the average premium should decline. In a tighter market, however, there may be more uncertainty and the range of observed price premiums may actually increase, causing a few larger premiums to be observed.

Because of the detailed nature of the data, it is possible to go beyond simple averages and to estimate relationships, that is, to analyze determinants of contract price and the average pricing premium just described. As an illustration of an interesting relation, a simple regression equation was estimated to predict contract price, P_c, as a linear function of spot price, P_s. (A more sophisticated statistical model is described in the following section.) The estimated equation is:

$$P_c = \underset{(2.887)}{.363} + \underset{(16.947)}{.929} P_s \tag{5-1}$$

where the numbers in parentheses below the estimated coefficients are t-ratios and prices are measured in dollars per Mcf. The R-square for the equation is .917, meaning that spot price explains a very large fraction, 91.7 percent, of the observed variation in contract prices. The equation is statistically significant at a very high level, although this is hardly surprising since spot and contract prices naturally move together.

Because the estimated coefficient of the spot price is less than unity in equation (5-1), the regression analysis implies that the contract price premium is not constant, but that it instead declines for larger values of the spot price. To illustrate this, equation (5-1) predicts a 20 percent price premium at the sample average spot price of \$2.25. This is the same as the simple average described before because a regression line always passes through the point of the sample means ($\bar{P}_c$ and $\bar{P}_s$, where the bar denotes the mean). The standard deviation of the spot price is about 50 cents in the sample. An interesting exercise is to calculate the predicted price premium at one standard deviation above and below the sample average. At one standard deviation below, or a spot price of \$1.75, the predicted price premium of contract over spot purchases is about 3.5 cents larger or about 23.5 cents. This is a 13.5 percent premium over the spot price. For a spot price which is a standard deviation larger than the mean, \$2.75, the predicted premium is about 3.5 cents smaller, or about 16.5 cents. This is a 6 percent premium over the spot market. The regression analysis, then, is consistent with the expectation that contract price premiums can be expected to be smaller when the spot price itself is higher, most likely reflecting tighter market conditions.

A Statistical Model of Contract Price

The simple regression analysis in the previous section suggests that 92 percent of the variation in contract prices is explainable by spot prices. While those results are interesting, and certainly useful to commissions, they are nonetheless not surprising. The purpose of this section is to go beyond the market conditions represented by the spot price and determine whether terms and conditions contained in the contract itself affect the agreed-upon price. In particular, the objective is to discover what, if any, influence the eight contractual dimensions listed in the first section of this chapter have on the contract price. The answer to this rather simple question turns out to be more complicated than might be supposed. It is described in two steps. The first, discussed in the next subsection, is to estimate a hedonic price equation, which turns out to be flawed because of colinearity. The second, intended to overcome the colinearity difficulties, is to estimate a structural model, which turns out to be flawed because of simultaneity problems. In the end, it is clear that the sample provides some strong reasons to believe that contractual terms and conditions have important influences on the contract price, yet the information is not good enough to provide precise, reliable estimates of the effects of specific contract clauses. Still, the importance of supply security and financial riskiness can be discerned in the relationships between contractual terms and the contract price.

A Hedonic Price Model

A hedonic price equation or model is one in which the presence or absence of contract terms is used in a multiple regression to explain (or predict) the contract price. The idea is that the item in question, in this case a contract, has a variety of dimensions that affect its quality. High quality items are likely to sell at higher prices than those with a lower quality. (A good example, not related to public utility regulation, is to statistically estimate the price of a house as a function of its size, number of bathrooms, whether it is air conditioned, has a garage, and so on.) So a natural gas contract with a particular set of contract terms will fetch a different market price than one with a different set of terms.

To estimate the hedonic price equation for the NRRI sample of 28 contracts, a multiple regression model was estimated that has the linear form:

$$P_c = a_o + a_1 P_s + a_2 N + a_3 F + a_4 A + a_5 G + a_6 S + a_7 M + a_8 T + a_9 K + \epsilon \quad (5\text{-}2)$$

where P_c is contract price,

a_i are parameters to be statistically estimated for i = 0 to 9,

P_s is spot price,

N is time between price negotiations,

F indicates a fixed escalator clause,

A indicates an alternate fuel escalator clause,

G indicates another gas escalator clause,

S indicates whether the buyer or seller or neither initiates the price renegotiation process,

M indicates a market-out clause,

T indicates a take-or-pay clause,

K indicates a minimum-take clause, and

ϵ is an error term.

A detailed description of the variables in equation (5-2) is in the first section of this chapter. The statistical results are reported in table 5-1.

The R^2 for the hedonic equation explaining the contract price is .9786. The addition of the eight variables measuring contractual terms has increased the R^2 by .062 over that of the simple equation containing only the spot price. This increment to R^2 is highly statistically significant; the corresponding F statistic is $F^8_{18} = 8.892$, which is significant at the

TABLE 5-1

HEDONIC PRICE MODEL OF GAS CONTRACTS

Dependent Variable:	Initial Contract Price
Sample Size :	28
R^2 :	.9786

Independent Variable[a]	Estimated Coefficient	Standard Error	(Probability > |t|) Significance Level[b]
Intercept	.2556	.1301	.066
Spot Price	.9739	.05883	.0001
Time to Neg.	.00102	.000439	.036
Fixed Escalator	.3484	.1249	.013
Alter. Fuel Escalator	.0733	.1877	.701
Other Gas Escalator	-.1516	.084	.089
Price Sequence	-.1117	.0506	.041
Market-Out	-.1585	.0716	.0407
Take-or-Pay	.8504	.4433	.072
Minimum-Take	-.0365	.1218	.768
Michigan	-.761	.3030	.022

Notes:

a. The independent variables and the coding are described in the first section of this chapter.

b. The significance level is the probability of being wrong in concluding that the actual effect of a variable in a larger population is as observed in this sample.

Source: Authors' calculations.

.001 level. As a group, contract terms clearly exert an influence on the contract price.

Unraveling the separate influence of each of the eight contract dimensions is difficult in this particular sample because of severe colinearity. The symptom of this colinearity, as reported in table 5-1, is that some coefficients of individual contract terms are estimated unreliably and have large standard errors. As an example of the colinearity, all of the contracts with take-or-pay clauses in the NRRI sample are from Michigan, which tend to have high spot prices (because the state is furthest from the spot market and hence has high transportation fees) and coincidentally tend to include escalator clauses tied to both alternative fuels and other sources of gas. Accordingly, the take-or-pay variable is correlated with spot price and the price escalator variables. This is why the take-or-pay variable has an estimated coefficient of .8504 in table 5-1. This appears to mean that the inclusion of a 100 percent take-or-pay clause would add about 85 cents to the contract price. Alternatively, an additional 10 percentage points of take-or-pay (from 70 to 80 percent, for example) seemingly adds 8.5 cents to the contract price. One would expect the relation to be negative, and not positive as is the case. The positive coefficient comes about because the take-or-pay variable is a good indicator of contracts for secure supplies, particularly in Michigan, and not because the clause itself causes the buyer and seller to agree to a higher price.

The conventional wisdom is that take-or-pay provisions in a contract ought to act as a substitute for price, because the increased financial security of the seller under higher take-or-pay levels should induce the seller to agree to a lower price. The difficulty is that the sample has significant contract price differences that are associated with differences in geographical location. The equation includes a variable that indicates whether or not the contract was written in Michigan to control for this geographical effect. The coefficient of the Michigan variable is -.761, however, which is negative and implausibly large in absolute magnitude. The difficulty can be traced, once again, to colinearity problems that create difficulties in separating geographical effects from those due to supply security.

Because of the rather severe colinearity problems the coefficients in table 5-1 have not been estimated reliably. Some seem quite sensible, others appear to be biased. The coefficient of the variable measuring the time between price renegotiations (in months) is estimated to be .00102, which means that longer-term contracts have higher prices--presumably because of the additional security of supply. Adding 5 years to the time before price can be renegotiated is estimated to add about 6.1 cents to the contract, which seems plausible. The presence of a price escalator based on some other gas price is estimated to reduce the initial price by 11.1 cents, and yet the presence of an escalator clause tied to the price of an alternate fuel has a positive 7.3 cents effect on the contract price, an amount which is statistically insignificant. It seems doubtful that the escalator based on some other gas price would be statistically significant but the escalator based on alternate fuel would be insignificant. Because of the mixed results, some sensible and others not, it is worthwhile to use a somewhat more sophisticated approach to the estimation, as reported next.

A Structural Model

The source of the problem just discussed is that a sample of 28 observations does not contain enough information to successfully estimate the independent effects of 8 contractual dimensions. There is a variety of ways to reduce the number of variables, including the simple expedient of omitting one or more. The statistical method of principal component analysis can be a useful way, also. Instead of either of these, a structural approach was adopted, whereby a reduced number of variables was created, each based upon economic principles and similarity of purpose served in the contract.

A detailed examination of the contracts reveals that most of the terms and conditions (of those eight that vary from contract to contract) can be classified as serving one of two purposes: the clause affects the future flexibility of price adjustments or else it affects the future flexibility of quantity adjustments. At the time a contract is signed, the price that will prevail at some date in the future can be anticipated to be easily adjusted if the contract contains a clause that bases the price on the price of an alternate fuel (No. 6 fuel oil) or upon the price of gas from some other source (the incremental price of an LDC's pipeline supplier is typical). Likewise, price is easily adjusted in the future if a market-out clause is included. Longer times between price renegotiations serve to make future price less flexible; that is, future adjustments of it are more difficult. The variable that measures whether the buyer or seller initiates the price change does not have an obvious, a priori effect on future price flexibility, although it could be argued that contracts with seller initiation have more future potential for adjustment since the producer side of the wellhead market may be more competitive. That is, there are many more producers than LDCs and pipelines. In any case, it is an empirical issue best left to statistical analysis.

When a contract is signed, the parties can anticipate that the future quantities or takes may be adjusted easily or with difficulty, depending on certain contract terms. A high take-or-pay fraction restricts the buyer's ability to adjust quantities, possibly severely. Likewise, a minimum-take clause limits a buyer's flexibility, although not as severely in most of the contracts in the NRRI sample. A market-out clause increases the possibilities for future adjustment, by creating conditions under which the parties must reach a mutual agreement or else be released (at least temporarily) from the contract.

The preceding discussion suggests that a large number of contract dimensions could be reduced down to two indices of adjustment difficulty: one for price and the other for quantity. In any such reduction of dimensionality, some information is likely to be lost. In suffering such a loss, the analyst hopes to reduce the colinearity problems and thereby more accurately estimate the effects of a smaller number of variables.

For this study, the two adjustment indices were developed judgmentally, although a more formal statistical technique like principal components could be used. The judgmental procedure for each index had two steps. First, the entire sample of contracts was rank ordered according to the difficulty of adjusting prices (and separately, quantities). The ordering was based upon the judgment of two NRRI analysts who directly compared all possible pairs of contracts. After the sample was completely sorted (there were some ties, so the ordering was not strictly complete), the contracts were assigned an index number from 1 to 4, with 1 indicating easy adjustment and 4 indicating difficult adjustment. The index is intended to represent an interval scale and includes tenths of an integer, such as 1.2 or 3.8. This procedure, first sorting and then rating on the scale from 1 to 4, was conducted separately for the price flexibility and quantity flexibility dimensions of the contracts. These two adjustment indices should capture most of the information conveyed to the parties by the eight contractual dimensions.

The statistical model containing the two adjustment indices is described in table 5-2. The model has three equations. The first predicts the contract price based upon the spot price, the two indices, and a dummy variable indicating whether a contract is from Michigan. The other two equations are used to predict the two adjustment indices. The equations contain variables reflecting contract provisions expected to influence the difficulty of adjustment, as well as the contract price. The presence of contract price in these two equations is intended to reflect simultaneity in the joint determination of the contract price and the contract's provisions for future adjustment. This is to say that not only might future price flexibility affect the parties' agreement about the initial price, but in addition, a high initial price may be a reason for a buyer to want flexible terms included in the contract. Cause and effect may go both from contract terms to price and from price back to contract terms. The model specification in table 5-2 is intended to allow for this type of simultaneous interaction.

The structural model was estimated using ordinary least squares, two-stage least squares, and three-stage least squares. The latter two methods are intended to compensate for simultaneity bias that might otherwise affect OLS. The 2SLS and 3SLS results were quite similar and since 3SLS estimators should be more efficient, only these are reported in table 5-3. The table shows the estimated coefficients using OLS and 3SLS. Beneath each estimated coefficient is its significance level, shown as a probability with smaller values indicating greater statistical significance.

The estimates of the coefficients change very little in comparing the OLS to the 3SLS results. Both sets of estimates indicate that price adjustment is an important determinant of contract price, but that quantity adjustment difficulty has little effect. The estimated effect is that contracts with terms that make price adjustment difficult are likely to have higher initial prices. Difficulty in adjusting quantities is estimated to have a small negative, but statistically insignificant, effect on the contract price. In addition, the analysis suggests that contracts in Michigan are likely to have contract prices about 25 cents higher than the rest of the sample.

To understand these results, it is important to recognize that price and quantity adjustment terms affect the riskiness of a contract as perceived by both parties. Higher values of I_q and I_p mean that a contract is less adjustable and consequently more certain. An increased degree of certainty, less riskiness, should reduce costs from the producer's viewpoint and thereby encourage a greater supply of gas at a given contract price.

TABLE 5-2

A STRUCTURAL MODEL OF CONTRACT PRICE

The model is

$$P_c = b_1\ I_p + b_2\ I_q + a_1\ P_s + a_2\ H + a_3\ F + \epsilon_1$$

$$I_p = \qquad b_3\ I_q + b_4\ P_c + a_3\ N + a_4\ A$$

$$+ a_5\ G\ + a_6\ S\ + a_7\ M + \epsilon_2$$

$$I_q = b_5 I_p \qquad b_6\ P_c + a_8\ T + a_9\ K + a_{10}\ M\ + \epsilon_3$$

where P_c is contract price,

I_p is the index measuring the difficulty of price adjustment,

I_q is the index measuring the difficulty of quantity adjustment,

P_s is spot price,

H indicates that a contract is from Michigan,

F indicates a fixed escalator clause,

N is time between price renegotiations,

A indicates an alternate fuel escalator clause,

G indicates another gas escalator clause,

S indicates whether the buyer (-1) or seller (1) or neither (0) initiates the price renegotiation process,

M indicates a market-out clause,

T is the take-or-pay fraction,

K indicates a minimum-take clause,

a_i are parameters of exogenous variables,

b_i are parameters of endogenous variables, and

ϵ_i are error terms.

Source: Authors' calculations.

TABLE 5-3

ESTIMATED COEFFICIENTS OF THE STRUCTURAL MODEL*

	Estimation Technique					
	Ordinary Least Squares			3 Stage Least Squares		
	Equation			Equation		
Variable	P_c	I_p	I_q	P_c	I_p	I_q
P_c		.300 (.19)	-.094 (.36)		.241 (.31)	-.104 (.34)
I_p	.105 (.04)		.192 (.05)	.124 (.06)		.144 (.27)
I_q	-.019 (.66)	.406 (.02)		-.027 (.60)	.323 (.06)	
P_s	.918 (.0001)			.923 (.0001)		
H	.252 (.01)			.264 (.01)		
F		-.0076 (.98)			-.089 (.80)	
N		.0032 (.08)			.0038 (.05)	
A		.111 (.84)			.380 (.53)	
b		-1.17 (.0004)			-1.167 (.0005)	
S		-.716 (.0009)			-.731 (.0008)	
M		-.994 (.0012)	-.553 (.0001)		-1.089 (.0007)	-.575 (.0001)

(continued on the next page)

TABLE 5-3 (continued)

ESTIMATED COEFFICIENTS OF THE STRUCTURAL MODEL*

	Estimation Technique					
	Ordinary Least Squares			3 Stage Least Squares		
	Equation			Equation		
Variable	P_c	I_p	I_q	P_c	I_p	I_q
T			1.273 (.0001)			1.239 (.0001)
K			1.800 (.0001)			1.974 (.0001)
Intercept	.128 (.35)	1.248 (.07)	1.413 (.001)	.084 (.59)	1.547 (.03)	1.547 (.0031)
R^2	.961	.810	.974		(System R^2 = .953)	

*Numbers in parentheses are the significance levels or the probability of being wrong in concluding that an independent or structural variable has an effect on the dependent variable. (Lower numbers indicate greater statistical significance.)

Source: Authors' calculations.

From the buyer's perspective, more certainty about the contract (because I_q or I_p is high and the contract is inflexible) should reduce the need for contract supplies and allow demand to be shifted in favor of spot sources. More inflexible contracts should make the contract market less attractive and the spot market more attractive. Hence, higher values of I_q or I_p should encourage more supply and discourage demand of long-term contracts and should lead to lower contract prices. All other things held constant, this perspective suggests that I_p and contract price ought to be negatively related, the opposite of what was observed in the NRRI sample.

Other things, however, are not constant, and in particular uncertainty most likely varies between LDC territories for a variety of reasons not observable in the contracts. An exogenous difference in uncertainty from one service territory to another can be offset by a judicious adjustment of contract terms. From the above discussion, greater uncertainty of an exogenous nature would tend by itself to increase prices in the contract market and could be partially offset by adjusting the contract terms so as to reduce uncertainty, which would be observed as a higher value of I_p in our sample. Consequently, the observed positive relation between I_p and contract price could be due to geographical differences in the ways of writing contracts that have been adopted to cope with local conditions of uncertainty.

In effect, the locational differences in risk seem to make the index of price inflexibility a measure of supply security. Contracts with relatively inflexible pricing terms tend to be contracts that the parties intend to be enduring, long-term, and consequently secure. More secure contracts, in turn, tend to have higher contract prices. This is consistent with the observation that contract prices typically exceed spot prices--security is a valuable aspect of a contract.

Hence, there are two conflicting relationships that confound the analysis of contract terms and prices. First, within a local gas production area, contract terms that create inflexibility in future adjustments to price or quantity could be expected to substitute for contract price, and accordingly the relation between contract price and the indices of inflexibility ought to be negative. On the other hand, contracts in different production areas partly reflect local conditions of risk. Riskier areas are likely to have higher contract prices and also more inflexible contract terms as a partial offset to the higher level of exogenous risk.

These conflicting tendencies are observed in the NRRI sample of contracts. The contracts from Michigan especially appear to reflect local conditions that have resulted in high prices and rather restrictive, inflexible contract terms. As such, the variable that indicates whether a contract is from Michigan mostly identifies an area where local risk conditions differ from the remainder of the sample. This is borne out by additional analysis. If the Michigan variable is omitted from the contract price equation, the variable measuring quantity adjustment, I_q, is then estimated to be positive (a sign change) and is statistically significant. In effect, I_q becomes the variable that identifies local conditions of high risk when the Michigan variable is omitted.

The structural model includes the possibility that contract price will feed back upon and affect the price and quantity adjustment conditions in a contract. Neither effect is statistically significant in table 5-3. Contract price has a small positive effect on pricing inflexibility, suggesting that the parties like to "lock in" a price if there is reason to agree to a high price to begin with. This may be due to the influence of supply security considerations. Contract price has a small negative effect on the inflexibility of quantity adjustment terms. This may be compensatory in nature; that is, high prices are more agreeable if quantities can be adjusted in the future.

The model also suggests that contracts with inflexible quantity terms are likely to have inflexible pricing terms also. Conditions of risk that require the parties to restrict future quantity adjustments tend to need limits on price flexibility in addition. In table 5-3, the 3SLS structural coefficient for this effect is .323, statistically significant at the .06 level. Likewise, inflexible pricing terms appear to influence the quantity adjustment conditions. This coefficient is estimated to be .144 by 3SLS, but it is not significant.

The complicated nature of the structural relationships among contract price, quantity flexibility, and price flexibility in table 5-3 makes it difficult for the reader to unravel the implied influence that particular clauses have on the contract price. To help understand the model, the effects of each of the eight contractual dimensions on contract price is given in table 5-4. These are reduced-form effects, meaning that the simultaneity among the three equations has been sorted out to find the direct effect of a contract clause, as well as all indirect effects that may operate through various equations. For purposes of comparison, table 5-4 shows the reduced-form effects estimated using three statistical models: a direct estimate of the reduced form (previously reported in table 5-1); OLS estimates of the structural model; and, 3SLS estimates of the structural model. It is clear that the structural model is an improvement over the reduced-form model, which is plagued by colinearity that causes the Michigan and take-or-pay coefficients to be large and opposite in sign.

The lessons from the structural model are more or less the same regardless of the estimation technique used. There are three contract clauses that have an important influence on contract price. The inclusion

TABLE 5-4

ESTIMATED REDUCED-FORM EFFECTS OF CONTRACT TERMS ON INITIAL CONTRACT PRICES

Exogenous Variable		Reduced-form Model (OLS)	Structural Model OLS	Structural Model 3SLS
Spot Price	P_s	.974	.974	.951
Negotiation Time	N	.001	.00036	.00049
Alternate Fuel	A	.0733	.0126	.0494
Other Gas Price	G	-.152	-.132	-.152
Price Sequence	S	-.112	-.081	-.0952
Market-Out	M	-.159	-.127	-.150
Take-or-Pay	T	.850	.034	.018
Minimum-Take	K	-.036	.051	.029
Fixed Escalator	F	.348	-.0009	-.0116
Michigan	H	-.761	.260	.272

Source: Authors' calculations.

of a price adjustment clause linked to some other price of gas is estimated to reduce the contract price by about 15 cents. Similarly, a market-out clause is estimated to reduce contract price by about 15 cents. Lastly, if the future course of price negotiations is one in which the buyer announces a price and the seller can take it or leave it, the initial contract price is estimated to be about 8 to 10 cents higher.[1]

All three of these effects are understandable in the context of the existing surplus condition in the natural gas market. A market-out clause

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[1] The coding of the price sequence variable is -1 if the buyer initiates the process, 0 if the process is described as simultaneous bargaining, and 1 if the seller initiates the process.

and an adjustment clause based on some other gas price are useful tools that a buyer can use during a surplus to induce a seller to reduce the initial contract price. In effect, these devices convey to the seller the fact that the LDC has difficulty in marketing high-priced gas and is willing to accept only low, competitive prices. The seller is willing to agree to the lower contract price partly because of the current surplus, and partly because the contract price can rise when the current surplus disappears. It also makes sense that contract prices are higher when the buyer initiates the renegotiation process, if one also considers the current surplus. During a surplus, seller initiation of the process or simultaneous negotiation is likely to reflect the producer's urgency in trying to sell a commodity in a glut market. A buyer's advertised price may lag behind the downturns in the market. This suggests that an LDC may want to avoid advertised prices during a surplus and instead bargain separately with producers who have difficulty in moving their gas.

The remaining contractual conditions in table 5-4 are estimated to influence the initial contract price only modestly. The coefficient of the time-between-price-negotiations variable, .00049, implies that extending this period by 5 years adds about 3 cents to the contract price, which is quite small but in the expected direction. Including a price adjustment clause based on No. 6 fuel oil appears to add about 5 cents to the contract price, perhaps because the parties anticipate that world oil prices will decline in the future, a plausible prediction during the 1985-87 time period. The inclusion of a take-or-pay clause is estimated to add about 2 cents to the contract price, despite the negative direct effect that the quantity adjustment index has on the contract price. The indirect effect operating through the separate price adjustment equation is positive and outweighs the negative, direct effect. In any case, the net result is quite small, both for the take-or-pay and minimum-take provisions. The overall positive influence of both kinds of contract terms, although small, reflects the geographical richness of the NRRI sample in the sense of identifying those contracts with high supply security. The last contract effect in table 5-4 suggests that including an escalator clause with fixed growth rates has a negligible and negative effect on the contract price. Most contracts in the NRRI sample that had such a provision also included a market-based pricing mechanism. The latter is much more likely to be important to the parties during surplus conditions. If the market tightens up in the future, fixed price escalators may become more important and may exert a stronger negative influence on the initial price. (If price were truly anticipated by the parties to be pushed up in a fixed way, the negotiated initial price could be expected to be lower in compensation.)

Summary

A quantitative analysis of 28 long-term natural gas supply contracts between a distribution company and a gas producer shows that market conditions, as measured by a corresponding spot price, are the most important determinant of a contract's initial price. Contract terms play an important, but secondary, role. In addition, contract terms cannot be thought of as merely exogenous influences upon the contract price. Locational differences in risk, as well as the contract price itself, exert subtle, but real, influences on the contract terms. As a preliminary analysis of gas contract prices and terms, this study has succeeded in identifying some of these subtle effects and how they work in a market surplus. As mentioned previously, the reader should be cautioned that the study period, in addition to reflecting a surplus, also represents a transition time for the industry. The relationships described in this chapter are worth additional study when the market is more stable.

The approach adopted in this chapter is based upon classical statistical analysis. State commissions may also be interested in a newly developed approach called Data Envelopment Analysis. This method is designed to study the relative efficiency of a set of production units or, in our case, gas contracts. It is not well equipped to study relationships, as was the objective in this chapter, but rather is useful in pointing out contracts that appear to be particularly good or bad.

CHAPTER 6

AN EFFICIENCY FRONTIER OF CONTRACT PRICE AND OTHER CONTRACTUAL TERMS

The previous chapter discusses the relationships among contract price, spot price and other characteristics of a gas contract. The relationships posited there and the estimates of the parameters obtained are based on the average properties of the sample of contracts. The emphasis is on identifying underlying trends and the strength of the relationships based on statistical properties of the data. In this chapter the focus shifts from the analysis of the aggregate properties of the contracts to the analysis of individual contracts. In the statistical analysis of chapter 5 the average tendencies in the data are important, whereas the analysis that follows is based on the extreme properties of the contracts. That is, contracts are compared to a set of "best" contracts--those that are identified as having the best performance. The technique used for the analysis in this chapter is called Data Envelopment Analysis (DEA).

Data Envelopment Analysis can be useful to state commissions in a variety of contexts, not simply in a study of gas contracts. As mentioned in chapter 1, the Texas Commission has used the technique in its study of the efficiency of electric cooperatives.[1] Virtually any issue relating to productivity or efficiency can be addressed using DEA. The use of DEA to analyze gas contracts in this report is intended to introduce the technique to state commissions that may be unfamilar with it and to supplement the ordinary statistical analysis of the contracts reported in chapter 5 with a detailed consideration of those contracts that can be considered efficient. The technique is first described using a simple example and then is used to

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[1] Dennis L. Thomas, Auditing the Efficiency of Regulated Companies: An Application of Data Envelopment Analysis to Electric Cooperatives (Austin, TX: IC[2] Institute, The University of Texas, 1986).

illustrate how it may be helpful in analyzing the performance of individual contracts.

Background

Data Envelopment Analysis has recently emerged as a technique for obtaining the relative efficiency of processes that produce outputs from inputs. DEA yields an index of performance which provides, on a scale of zero to one, an indication of the performance of the input-output process. Describing each of the units of analysis as a decision making unit (DMU) which is engaged in obtaining the maximum set of outputs from a set of inputs, the index provides a measure of each DMU's performance relative to what is observed to be the best performance among the units being studied. Thus, the measure obtained here is a multidimensional measure of relative performance.

In the present context, the unit of analysis is a gas contract which is to be evaluated on the basis of criteria used to determine the relative attractiveness of the contracts. The criteria used here are the same as those in ordinary least squares analysis of the previous chapter. The data used in this analysis consist of 28 contracts, including the contract price, the spot price, and the two adjustment flexibility indices described in chapter 5. Based on the analysis in that chapter, the indices of price and quantity adjustment difficulty are interpreted here as measures of supply security. A different sample or different circumstances could require that this interpretation be reversed. Each index ranges from 1 to 4 where 4 is the maximum and 1 is the least security, from the buyer's point of view, for either price or quantity. The buyer is thought to desire maximum price and quantity security for a given contract price. The difference between the contract price and the prevailing spot price may be interpreted as the premium the buyer pays for the security of a contract. From a buyer's point of view, the preferred contract is one which has the smallest premium. Thus, for a given contract price, a buyer would want to maximize the scores on the security indices and the spot price.[2] See appendix B for a complete listing of the data for the 28 contracts.

Given these criteria for evaluating the performance of a contract, DEA attempts to identify the best contract or set of contracts. In the case of multiple "best" contracts, they are best in the sense of being Pareto-superior (or dominant) to all other contracts. In the data space, the surface defined by connecting these Pareto-superior data points is the best-practice frontier made up of contracts that exhibit the best observed performance. This best-practice frontier literally envelopes the data and hence the name, Data Envelopment Analysis. The DEA index of performance (or in the context of inputs and outputs, of efficiency) is obtained in terms of distance from the best practice frontier. Appendix C provides a more detailed treatment of the DEA index. The following example helps to clarify the idea and illustrates the creation of the index.

A Preliminary Example

For the purposes of this illustration, suppose that the data consist of only three pieces of information for five contracts. The information is the contract price and the adjustment difficulty indices for price and quantity. The hypothetical data are shown in table 6-1 and are plotted in figure 6-1. The two axes denote the adjustment difficulty indices for price and quantity respectively, and the numbers in the graph are the contract price associated with each combination of the price and quantity index of adjustment difficulty.

The next step in the process is to obtain the surface that envelopes these data, that is, to identify the surface on which lie the extreme points representing the maximum security (in the sense of least price flexibility

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[2] Note that the direction of this interpretation is based on the findings reported in chapter 5. A larger sample of contracts from a single distributor may reflect different risk considerations than the NRRI sample used here. For a single distributor it is possible that higher values of the quantity adjustment index (more difficulty of adjustment), would be associated with lower initial contract prices, perhaps because of high take-or-pay requirements. In that case, the DEA analyst would need to reverse the treatment of the adjustment indices from that used in this chapter.

TABLE 6-1

HYPOTHETICAL GAS CONTRACT DATA

Contract	Price	Adjustment Index Price	Adjustment Index Quantity
A	2	4	2
B	2	2	4
C	1.5	1	1
D	1.5	2	1
E	2	0.5	2

Source: Authors' calculations.

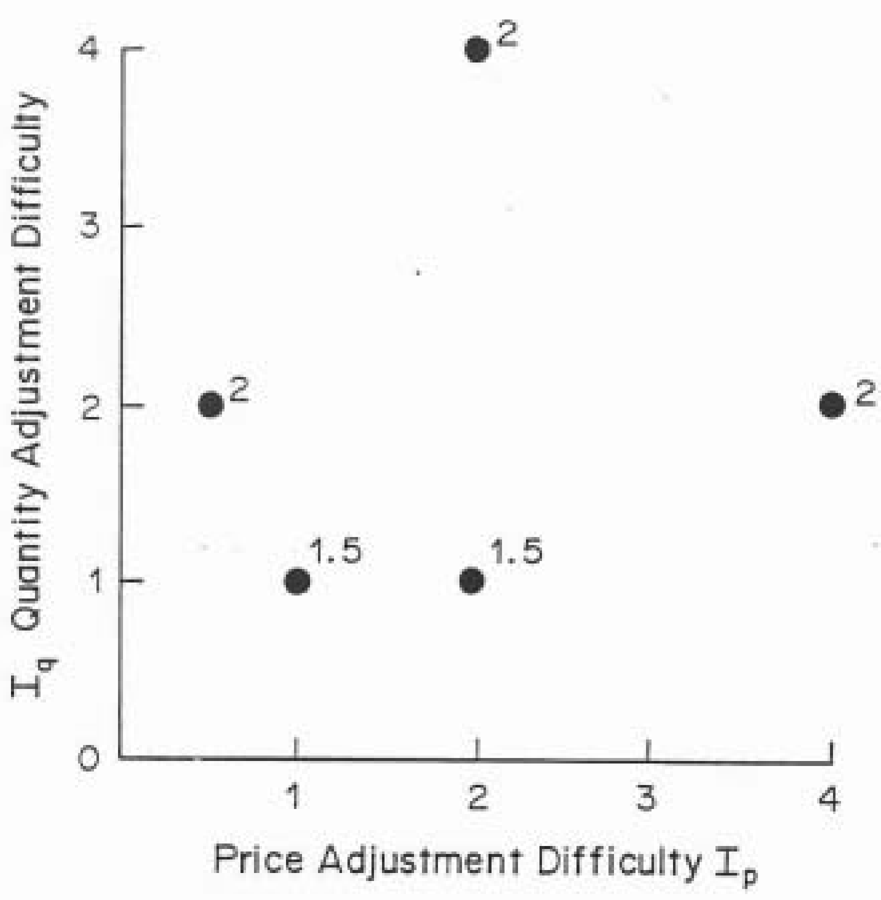

Fig. 6-1 Plot of adjustment indices

or least quantity flexibility) for the minimum price. This task is simplified by dividing each security index by price, which yields the data in table 6-2 and the corresponding figure 6-2.

The best practice frontier is obtained by connecting the extreme data points A and B and extending the lines parallel to the corresponding axes as shown in figure 6-2. Points A and B are said to exhibit the "best practice," that is, the most price security and quantity security per unit of price. The points C, D and E are off the frontier and therefore are not efficient. This is because the portion of the frontier between points A and B can be thought of as linear combinations of the two points or, as a portfolio consisting of the two contracts. The point C' represents a particular mixture or combination of the efficient contracts A and B that dominates the actual contract C. Accordingly, the frontier does not include contract C.

An equiproportional increase in both price and quantity security move the inefficient points E, C, and D along a ray from the origin to E', C', and A respectively. The measure of inefficiency is the ratio of the distance of the point from the origin to the distance from the origin to the

TABLE 6-2

HYPOTHETICAL DATA IN TERMS OF PRICE

Contract	Security Index Per Unit Price Price	 Quantity
A	2	1
B	1	2
C	0.66	0.66
D	1.33	0.66
E	0.25	1

Source: Authors' calculations.

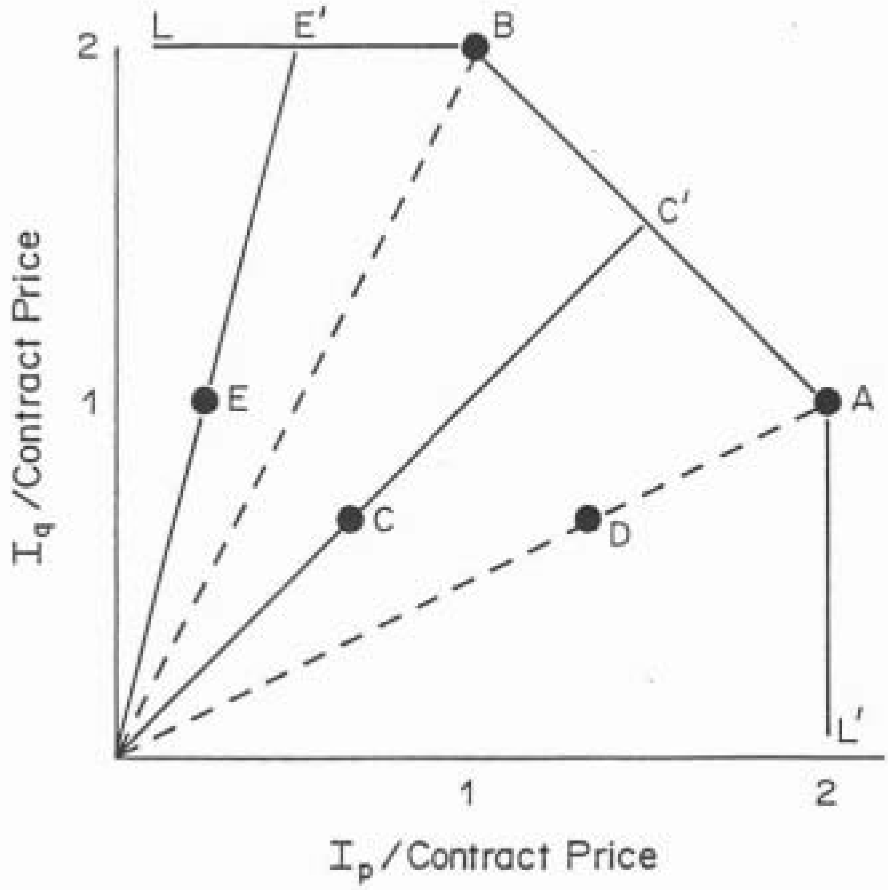

Fig. 6-2 Security indices per unit of price

frontier along the ray. Thus the inefficiency scores for E, C, and D are OE/OE', OC/OE', and OD/OA', respectively.

It should be noted that while E' is on the frontier, it is not truly efficient. It is still possible to move from E' along the efficient surface to B, thus increasing the price security per unit of price without changing the quantity security per unit of price. Thus, while LL' defines the "efficient" or best practice frontier, all sections of the contour are not truly efficient. Any points lying on the section AB of the frontier are Pareto-superior to all other data points. Along the section AB, the slope of the line is a measure of the tradeoff between the two indices of contract security and is similar to the concept of a marginal rate of substitution.

The contracts on sections of the frontier parallel to the axes are not truly efficient in the sense that it is possible to increase one of the security indices by a move along the frontier towards A or B with changing the other index. For instance, the move from E' to B does not require a tradeoff between the two security indices. The move from E' to B results in an increase in price security without a loss in the quantity security index. Points on the frontier where such moves are feasible, that is, no tradeoff is necessary, are termed Pareto-Koopmans efficient, whereas the points on those sections of the frontier corresponding to AB are termed Pareto-efficient.

Thus, Data Envelopment Analysis yields a "best-practice frontier," which is a piece-wise linear surface connecting the extreme data points that are Pareto-superior to all other data points. The points on the frontier denote the best observed practice. In particular, the frontier represents the best practice attained in the data set and is not an indicator of performance that is optimal in the sense of being representative of a theoretically determined level of performance.

In summary, the DEA index is a measure of relative performance based on distance from the best practice frontier. Points on the frontier have a score of unity while those off the frontier have scores proportional to their distance from the frontier.

DEA provides additional information that may be useful to regulators in discussions with a distributor's gas supply manager about the circumstances and reasons underlying a particular contract's seemingly poor performance. For each data point off the frontier, the analysis identifies the set of frontier points against which it is compared to obtain its performance score. Thus, the analysis identifies a set of contracts on the frontier that are most similar to a particular, inefficient contract in terms of the criteria used in the analysis. This may help to focus discussions about why this particular contract is different from a few others that are apparently superior. Factors not included in the formal analysis would be relevant in such discussions.

Analysis of the Gas Contracts

As shown in the preceding examples, DEA produces an index or measure of performance relative to the best observed performance. An initial illustration of using DEA to analyze the NRRI sample of gas contracts is the construction of an index analogous to the regression equation (5-1) in chapter 5. Recall that the equation is an estimate of the relationship between contract price and spot price, on average.

A similar exercise using DEA produces a simple index based on the ratio of the spot price to the contract price. The value of the ratio is less than one because all the spot prices are less than the contract prices. The closest to unity is one of the Ohio contracts (labeled as EE in appendix B) for which there is only a one cent difference between the contract price ($1.88) and the spot price ($1.87). In this instance, the premium paid for the security of the contract is minimal. If the contracts are ordered by the score on this ratio, then this Ohio contract is the "best" in the sense that it has the minimal premium for contract security. DEA assigns a value of unity to this contract and all other ratios of spot price to contract price are adjusted relative to it. This Ohio contract is considered to be the "best observed practice" and the scores for all other contracts are calculated with respect to it. In its simplest form, a DEA index is a ratio of two numbers where the "best" ratio has a value of unity and the rest are values relative to this best value.

Table 6-3 provides a listing of the spot and contract prices and the corresponding DEA scores in the column labeled efficiency index, DEA-I. The lowest value is .81 for Contract W, which has a relatively large difference between the spot and contract prices.

The analysis of chapter 5 reveals a very strong relationship between spot and contract prices. Despite this, the difference between the two prices, has a wide range, as shown by the DEA-I index. The price difference is as low as one penny for contract EE, and, in addition, there are other contracts for which the premium is under five cents. However, there are few low premiums and the majority of the contracts are clustered around an index value of 0.93.

In general, the variations in the price differential (between spot and contract price) can be explained by the terms of the contract. A richer DEA

TABLE 6-3

DEA-I INDEX BASED ON SPOT PRICE

Contract	Spot Price	Contract Price	Efficiency Index DEA-I
A	1.85	2.00	0.93
B	1.85	2.00	0.93
C	2.94	3.14	0.94
D	3.20	3.26	0.99
F	1.86	2.00	0.93
G	1.80	2.00	0.90
H	1.80	2.00	0.90
I	1.74	2.00	0.87
J	1.90	2.00	0.95
K	3.14	3.25	0.97
L	1.98	2.25	0.88
M	1.98	2.03	0.98
O	2.59	2.70	0.96
P	2.39	2.45	0.98
Q	2.39	2.50	0.96
S	2.39	2.50	0.96
T	1.62	1.85	0.88
U	2.79	3.00	0.93
V	2.12	2.40	0.89
W	2.01	2.50	0.81
X	2.64	3.00	0.88
Y	2.94	3.01	0.98
Z	2.30	2.80	0.82
AA	2.05	2.40	0.86
BB	2.08	2.50	0.84
CC	2.88	3.00	0.96
DD	1.87	2.25	0.83
EE	1.87	1.88	1.00

Source: Authors' calculations.

index may be obtained by incorporating additional information about the contracts into the index. The indices of price and quantity security developed in chapter 5 contain information that helps explain these price premiums. The hedonic price model of chapter 5 identifies the importance of various factors in explaining variations in the contract price. The DEA method uses the same information somewhat differently in that it obtains a score of relative performance of these contracts with respect to these factors. For instance, a DEA index that incorporates the deminsions of price and quantity security measures the performance of each contract in terms of the amount of security bought for a unit of price.

To construct this richer DEA index, divide each security measure by the contract price. Next, plot the data and extreme points in the direction of maximum security per unit of price. The best performance or practice frontier is found by connecting the extreme points in a piecewise linear fashion. The index, in this instance, is simply the ratio of the distances along the ray from the origin to the data point and to the frontier.

Figure 6-3 represents a scatter of the contracts in two dimensions where the horizontal axis denotes the price security index divided by the contract price and the vertical axis represents the quantity index divided by the contract price. (The data are listed in appendix B where the contracts are identified by the letters A to Z, and then AA to EE.)

The contracts, T and DD, one from Mississippi and the other from Ohio, define the best practice frontier. They partition the data into three groups as shown in figure 6-3. Each group has a reference contract on the frontier. DD represents group 1; DD and T jointly represent group 2; and T represents group 3. The contracts within each of the three groups are said to belong to the same comparison group in the sense that they share the same "tradeoff" rate between the two adjustment flexibility indices. The tradeoff rate is the slope of the section of the frontier corresponding to the reference contracts. The slope of the line T-DD can be interpreted as the marginal rate of substitution between the price and quantity indices of adjustment flexibility.

Note that true tradeoff rates exist only for those sections of the frontier that are bounded by actual data points. It is not feasible to find a tradeoff rate for either section of the frontier that extends from T or DD and is parallel to the corresponding axis.

DEA-II in table 6-4 is the DEA index of relative performance of the contracts when compared on the basis of price and quantity indices normalized by the price of the contracts.

In comparing DEA-I with DEA-II, the most obvious difference is in the identity of the efficient contract. EE was the best contract in DEA-I by virtue of the fact that only a penny was paid as contract premium over the spot price. The indices differ not only in the score assigned to each contract but also in their relative ranking. The worst contract on DEA-II

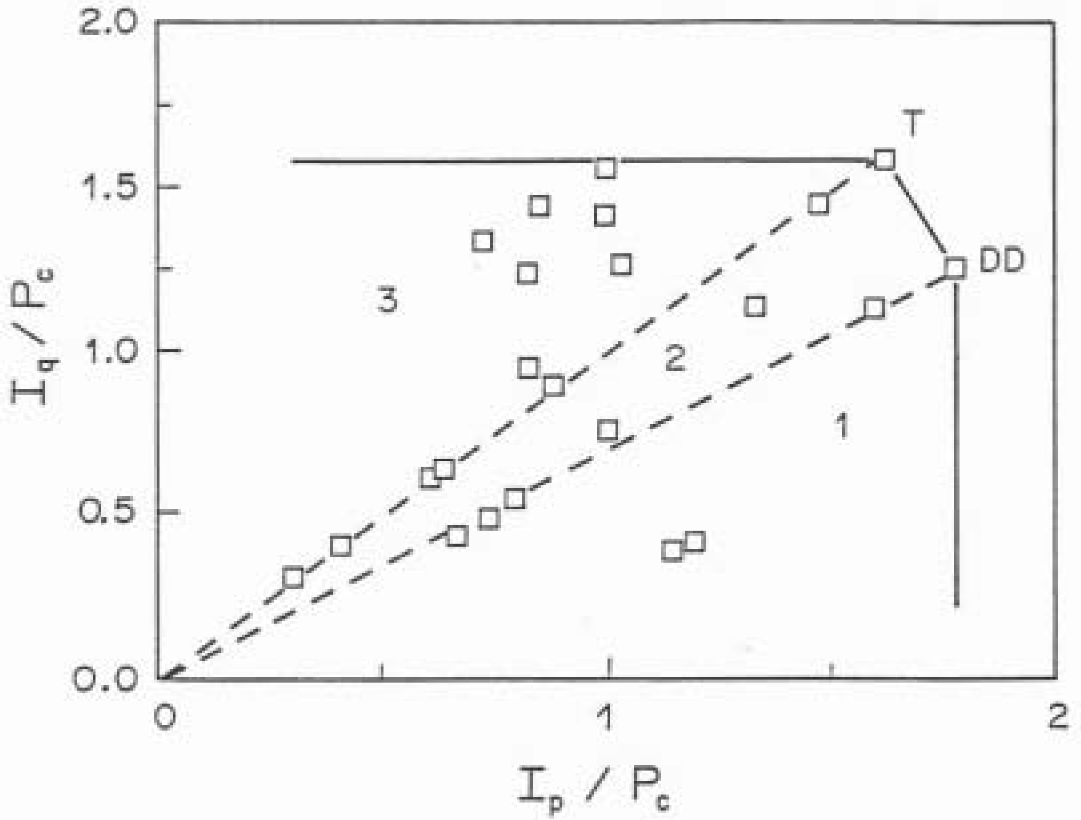

Fig. 6-3 Gas contract sample: security per unit of price

is P with a score of 0.26 while the worst in DEA-I is W with a score of 0.81. The differences in the scores, ranking, and range of the two indices suggest that the information contained in the two DEA indices is not redundant. In other words, DEA-I and DEA-II contain useful and, to some extent, mutually exclusive information.

The analysis is further extended to incorporate both the spot price and the security index information. In adding this third dimension to the previous index, the ability to graphically observe the relative positions of the contracts is lost. While the visual aid is lost, it is still possible to partition the data into groups of comparable contracts and to identify the reference contracts on the frontier.

TABLE 6-4

A COMPARISON OF DEA-II AND DEA-III INDICES

Contract	DEA-II	Group	DEA-III	Group
A	0.57	2	0.94	1
B	0.57	2	0.94	1
C	0.41	3	0.94	5
D	0.39	3	0.99	5
F	0.57	2	0.94	1
G	0.57	2	0.91	1
H	0.57	2	0.91	1
I	0.57	2	0.88	1
J	0.57	2	0.96	1
K	0.39	3	0.97	5
L	0.79	2	0.90	3
M	0.91	3	1.00	-
O	0.42	1	0.96	6
P	0.26	3	0.98	6
Q	0.67	1	0.97	1
S	0.67	1	0.97	1
T	1.00	-	1.00	-
U	0.79	3	0.95	5
V	0.80	3	0.90	5
W	0.89	3	0.90	4
X	0.79	3	0.90	5
Y	0.85	3	0.99	5
Z	0.91	3	0.92	4
AA	0.98	3	0.98	2
BB	0.90	3	0.95	3
CC	0.59	1	0.97	5
DD	1.00	-	1.00	-
EE	0.45	3	1.00	-

Source: Authors' calculations.

The new model is that the contract price depends not only on the indices of price and quantity adjustment flexibility but also on the current spot price. As discussed before, a buyer wishes to minimize the contract price while attempting to maximize both price and quantity security. The spot price is incorporated into the analysis as another factor that the buyer wishes to maximize for a given contract price. The argument for this interpretation is that a buyer wishes to minimize the difference between the spot and the contract price. In a long-term contract, a buyer purchases a certain degree of security and is therefore willing to pay more than the spot price, but prefers to keep the premium as low as possible.

In table 6-4, DEA-III is the column of new scores, which include spot prices in the analysis. Note that some apparent "inefficiencies" in contracts as measured by DEA-II disappear with the incorporation of the spot prices. Also, the variability of DEA-III is less than DEA-II. Table 6-5 provides some summary statistics about the three indices.

By increasing the number of dimensions along which the contracts are evaluated, the criteria for judging the contracts have been increased, which allows the contracts more room to show good performance. The score for a contract on either index DEA-I or DEA-II serves as a lower bound for the DEA-III score. That is, a contract must obtain at least as good a score on a composite index as its best score on either of the simpler indices. It immediately follows that all the contracts on the frontier for either the DEA-I or DEA-II index must necessarily be on the frontier for the DEA-III index. This is illustrated in table 6-5 where the minimum value of DEA-III is .88 which is higher than either of the previous DEA index values.

TABLE 6-5

SUMMARY STATISTICS FOR THREE DEA INDICES

	Mean	Standard Deviation	Minimum
DEA-I	0.92	0.05	0.81
DEA-II	0.67	0.21	0.26
DEA-III	0.95	0.04	0.88

Source: Authors' calculations.

Also, the average of the DEA-III scores has risen and the dispersion in the scores is reduced.

In addition to T, DD and EE, which were on the frontier for the first two indices, M is also on the DEA-III frontier. These four contracts serve as benchmarks against which all other contracts are compared. As suggested by figure 6-3, rays from the origin to these points in three dimensional space partition the data into six comparison groups, as identified in the extreme right hand column of table 6-4. The efficient, reference contracts for each group are listed in table 6-6. Note that groups 1 and 5 have the same reference contracts but their orientations in the multidimensional space are different and hence they form two separate groups.

The notion of reference points on the frontier and the definition of a comparison group having a common set of reference points on the frontier can be useful. First, the data can be partitioned into groups that are similar and therefore comparable. Second, each contract off the frontier can be associated with one or more contracts on the frontier thereby providing examples of contracts with similar characteristics that are performing better. Such information could be used to focus discussions with a distributor's gas supply manager about seemingly inferior contracts.

The presence of one particular contract in several reference sets, such as point M in table 6-6, serves as a warning that it may be an "efficient" outlier. The likelihood of it being an outlier is greater if the average score for the whole data set is low and there are very few data points that are close to the frontier (that is, with scores above 0.9). Sensitivity analysis can be conducted by systematically removing efficient data points from the sample and monitoring the changes in the scores or the number of points on the frontier. Ideally, one would like as many points as possible on the frontier. A frontier consisting of several efficient points would be unlikely to contain an efficient outlier.

In this analysis of the gas contracts, removing contract M from the analysis does produce a richer frontier, which has six instead of three data points making up the best practice frontier. The effect of its exclusion on the scores, however, is small since they are already fairly high--the points are close to the frontier anyway. Also, in a data set as small as this one, it is best not to remove a data point unless it is fairly clear that it distorts the frontier considerably.

The discussion so far has focussed on the frontier and comparisons with the frontier. Equally useful information can be gained by examining the most distant points from the frontier. Such points are ones that need the most improvement and also have the greatest potential for improvement with small changes in their operation or in this context, in the terms of the contract. For instance, contract I, with a score of 0.88, is below the mean

TABLE 6-6

REFERENCE CONTRACTS FOR DEA-III INDEX

Comparison Group	Number in Group	Reference Contract
1	9	M, EE
2	1	T
3	2	M, DD
4	2	M, T
5	8	M, EE
6	2	EE

Source: Authors' calculations.

and therefore worthy of targeting for additional investigation in order to identify the sources of its apparently poor performance. The distributor may be able to identify factors not considered in the formal DEA study that explain the findings.

Summary

In this chapter we have introduced and described Data Envelopment Analysis as an intuitively appealing tool for studying relative performance. The idea is based on the relatively simple notion of identifying an efficient set of points and then using their characteristics as a benchmark for comparing and evaluating all other data. Used this way, DEA can be a powerful diagnostic tool.

The explicit identification of best performance and the linking of each data point with at least one point (usually several) on the frontier provides useful information to the regulator in discharging his oversight responsibilities. The robustness of the results, while not based on any statistical criterion of stability, can be investigated by systematically excluding frontier data points.

Since the purpose of this chapter is to illustrate, the analysis has been restricted to a limited number of dimensions. The mathematical formulation, however, does not place any bounds (within reasonable limits) on the number of dimensions or criteria used in the evaluation. The formulation allows for the simultaneous maximization of several criteria (for example, security) and the minimization of others (for example, spot price) ,thus allowing for a truly multi-objective analysis of performance. In a broader context, Data Envelopment Analysis facilitates the monitoring of the performance of an individual contract. This can be particularly useful in tracking the performance over time of specific gas distributors.

CHAPTER 7

OPTIMAL CONTRACT PORTFOLIO SELECTION METHODOLOGIES

The previous two chapters examined the relative efficiency of individual contracts. Supposing that a "best" contract could be identified, would an optimal supply portfolio consist solely of that contract? The answer is clearly no and this chapter deals with problems and issues that arise when a distributor tries to diversify supply risk by purchasing a mixture of supplies. The mixture would consist of contracts that are on or near the frontier described in the previous chapter. Determining the proportions in which each contract would be held in an optimal portfolio is the subject of this chapter.

The opportunity now facing many distributors of being able to select their own supply portfolios carries both rewards and risks. Conflicting portfolio criteria and factors must be considered, including short-term and long-term costs, price stability, supply reliability for sensitive core-customers, and long-term gas availability. Portfolio decisions are made in the face of high uncertainty about future developments in the gas market.

The purpose of this chapter is to provide an in-depth analysis of the characteristics of today's gas supply options for an LDC in terms of relevant supply planning criteria, and to propose two quantitative methodologies that can be used in establishing a supply portfolio. Illustrated by numerical applications, these methodologies involve the application of (1) financial portfolio theory, and (2) multi-stage linear programming under uncertainty.

A third quantitative method is embodied in a new, user friendly NRRI computer model called GASMIX. It is described in appendix D, the second half of which is a user's manual for the model. The model is written in FORTRAN for use on a mainframe computer, and it is available from the NRRI as part of its model dissemination program. Either of the methods described in this chapter could be used to screen a large number of potential suppliers and to reduce the number of them down to the point where the GASMIX model could be used for more detailed analysis.

Gas Supply Characteristics and Planning Criteria

LDCs have traditionally bought most of their gas from interstate pipelines under long-term contracts (10-20 years) that include both commodity charges and minimum bills. The latter involve demand charges applied to contract demand and, often, also commodity charges applied to minimum takes. The contract demand is the peak daily deliverability purchased by a distributor from a pipeline, and the minimum take is generally defined as a fraction of the contract demand. In the past, minimum take requirements prevented LDCs from taking full advantage of the post-NGPA gas surplus and of attractively priced spot market opportunities. Two decisions by the Federal Energy Regulatory Commission (FERC) modified this situation. In 1984, FERC Order 380 removed variable costs from minimum bills and eliminated minimum take obligations from most pipeline-LDC contracts. Substituting spot purchases for regular pipeline purchases became in many instances economically feasible despite (lowered) minimum bills. Then in 1985, as discussed in chapter 2, the FERC Order 436 provided interstate pipelines the option to become contract carriers, and allowed LDC to convert contract demand to firm transportation, thus further allowing an LDCs to purchase gas directly from both close-by and far-away producers and to transport that gas via the pipelines. These two decisions led to the development of the natural gas spot market and to the direct purchase of gas from producers (or brokers). In 1986 for the first time, pipeline companies transported more gas than they sold (25 major pipelines surveyed transported 6.612 Tcf in 1986, or 50.1 percent of total throughput, with sales dropping from 9.382 Tcf in 1985 to 6.578 Tcf in 1986).[1]

In addition to continuing existing contracts with traditional pipeline suppliers, some LDCs now have the option of establishing new contracts with these and other pipelines, as well as with producers. More LDCs can be expected to have such options in the future. The new contracts may display significant variability in several ways:

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[1] Inside FERC, Special Report, April 20, 1987.

- contract duration: from one month (typical spot) to one-to-three years (direct purchases from producers) to 20 years (pipeline purchases);
- contract flexibility: presence or absence of minimum bills and minimum takes (on a daily, monthly, and/or annual basis), and market-out (contract termination) clauses;
- contract costs: levels of commodity and demand (if any) charges and price escalation and renegotiation (if any) provisions;
- contract reliability: is peak deliverability guaranteed, or can supply be interrupted at any time?
- transportation availability for direct purchases from producers: firm or interruptible transportation, and at what cost?

Clearly, LDCs are currently taking strong advantage of available cheaper supplies on the spot market, often at the urging of their state regulatory commissions, which have stepped up audits of purchasing practices. For instance, the East Ohio Gas Company (EOGC), which serves northeastern Ohio, has shifted from a pre-1980 supply pattern involving 90 percent of the purchases from two pipelines (75 percent from Consolidated Gas Company and 15 percent from Panhandle Pipeline Company) and 10 percent from local Ohio gas producers, to a 1985-1986 pattern involving the following shares: Consolidated (54 percent), Panhandle (8 percent), local Ohio producers (23 percent), and spot purchases from Southwest producers (15 percent). The spot supplies enabled EOGC to achieve a $20 million savings in purchase costs (EOGC's average cost of gas decreased from its 1983 peak of $4.07 per Mcf to $3.86 per Mcf in 1985-1986). EOGC has three types of supply contracts with intrastate producers: (1) life-of-well (all production is sold to EOGC for the productive life of the well); (2) 3-year fixed term (similar to life-of-well, but the agreement can be terminated after three years); and (3) limited 90-day term. In all these purchase agreements, the price is fixed for the term of the contract (for instance, on October 1, 1985 the price offered was $3.00 per Mcf for the life-of-well and $2.75 per Mcf for the 3-year fixed price contracts). Contracts with other spot market producers (or brokers) also are quite variable in terms of length (from 1 month to 15 years in duration), price adjustment procedures, contract extension, and other factors. Many of these contracts are on a best-effort basis, and the possibility of supply interruption is often included in the agreements.

While these new supply opportunities offer great savings potential for LDCs, they also carry significant risks. Reliance on short-term agreements may render the LDC vulnerable to both price shocks and gas shortages if, at some future time, the current "bubble" disappears and long-term arrangements are difficult to obtain. Short-term savings may then be outweighed by long-term cost increases, and reliable supply to core customers (residential, commercial, and small industrial who have no fuel switching capability) may be compromised. On the other hand, too cautious an approach, relying on long-term pipeline supplies only, may not be reasonable and can deny ratepayers significant opportunities for rate decreases. Thus, an LDC must weigh the costs, risks, and benefits of various possible gas supplies to choose an appropriate portfolio. A fundamental aspect of this choice is the respective roles and shares of spot gas versus pipeline supply. In designing its supply portfolio, an LDC must consider current supply opportunities, the various possible developments that may take place in the future (for example, changes in the price of oil) and the implications for future supply opportunities, the size of the present and likely future markets, the sharing among core and noncore (switchable) customers, and the conflicting goals of cost minimization, supply reliability, and price stability.

Quantitative methods can help to design contract portfolios that account for the above factors and trade-offs. In the following sections, two design approaches are examined and numerical illustrations are given. Each method has advantages as well as shortcomings, which are fully discussed. One method may be more appropriate than the other in particular circumstances. Neither solves the portfolio problem, but the discussion of the two methods should go a long way in helping commission staff members to understand the problems facing an LDC supply planner in delineating appropriate options and strategies.

The Financial Portfolio Theory Approach

Some insight into how one can select a portfolio of gas contracts can be gained by using a technique for selecting a portfolio of financial securities. The financial portfolio choice problem is related to how to distribute, in an optimal fashion, a given budget among N securities the rates of return of which are uncertain. Harry Markowitz's seminal contribution[2] to solving this problem was to find an efficient frontier showing the minimum portfolio risk (measured as the variance of return) obtainable for a given level of return. This approach, most appropriate for risk-averse investors, provides an explicit role for diversification. It has been viewed as a major breakthrough in modern finance theory and has spawned a considerable body of literature.[3]

The basic decision variable of the problem, x_i, is the holding share of security i. The rate of return r_i on security i is a random variable with mean μ_i and variance σ_i^2. The covariance of the rates of return r_i and r_j is denoted σ_{ij}. The basic Markowitz model minimizes the variance of the total return on all securities subject to a minimal expected return, R, and to a budget constraint (the securities shares must sum to unity):

$$\text{Min} \quad V = \sum_{i=1}^{N} \sigma_i^2 x_i^2 + 2 \sum_{i=1}^{N} \sum_{j=i+1}^{N} \sigma_{ij} x_i x_j \tag{7-1}$$

subject to

$$\sum_{i=1}^{N} \mu_i x_i \geq R \qquad \text{(minimum expected return)} \tag{7-2}$$

$$\sum_{i=1}^{N} x_i = 1 \qquad \text{(budget constraint)} \tag{7-3}$$

Successive solutions of this problem for various values of R establish the mean-variance frontier. The problem is a standard quadratic program for which efficient computer codes are available. It is generally assumed that the rates of return are jointly normally distributed, so that the total return is also normally (and hence symmetrically) distributed. The variance V is a measure of the dispersion of the aggregate return for any one portfolio, denoted by $x = (x_1, \ldots, x_i, \ldots, x_N)$.

The above model has been extended in several ways. One stream of studies is related to the empirical estimation of the covariances. Indeed,

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[2] H. Markowitz, "Portfolio Selection," Journal of Finance, 12 (1952), 77-91.

[3] See, for instance, H. Levy and M. Sarnat, Portfolio and Investment Selection: Theory and Practice (Englewood Cliff, NJ: Prentice-Hall, 1984).

for large numbers of securities, this estimation is impractical (1000 securities would require the estimation of about 500,000 covariances). To facilitate the application of the general model, Sharpe[4] has introduced "index" models, which assume that the securities' rates of return can be expressed in terms of some market indices or factors (leading to the diagonalization of the covariance matrix.) The basic model has also been extended to include transaction costs. Indeed, most applications of portfolio optimization involve the revision of an existing portfolio as expectations change and dividends have to be reinvested. These revisions entail both sales and purchase costs (brokerage commissions, taxes, etc.), which should be accounted for. An alternative approach is to set an upper limit to portfolio turnover.[5] Finally, another approach worth mentioning involves the maximization of the expected return subject to a chance constraint requiring that the actual return be greater than some lower bound with a stipulated probability.[6]

Portfolio Models for Gas Supply Contracts Selection

Consider an LDC that may purchase gas from N different suppliers ($i=1 \rightarrow N$), the first N-1 of which provide gas under firm contracts, and the last one, N, represents the spot market. Each contract is characterized by a specific price structure and flexibility (e.g., minimum take). Variation in contract duration, however, cannot be considered. That is, the financial portfolio model cannot be adopted to a study of contract length. The model discussed in the next section is suitable for such matters. For the financial portfolio model of this section, it is assumed that all contracts have the same duration, covering a period of T years, and that the selected portfolio cannot be modified during this period. It is also assumed that the total annual gas demand does not change during the period. On the other

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[4] W. F. Sharpe, "A Simplified Model for Portfolio Analysis," Management Science, 9 (1963): 277-293, 1963.
[5] A. F. Perold, "Large-Scale Portfolio Optimization," Management Science, 30 (1984): 1143-1160.
[6] N. H. Agnew, R. A. Agnew, J. Rasmussen, and K. R. Smith, "An Application of Chance Constrained Programming to Portfolio Selection in a Casualty Insurance Firm," Management Science, 15 (1969): B512-B520.

hand, the commodity cost of gas under contract i during year t may vary, depending upon the price of oil and other factors at that and other times. Assume that all the relevant possibilities for future developments can be enumerated, and let C_{is} be the vector of gas commodity prices for contract i under scenario s:

$$C_{is} = (C_{is1}, \ldots, C_{ist}, \ldots, C_{isT}) \tag{7-4}$$

where C_{ist} is the estimated commodity price of gas under contract i at period t if scenario s turns out to be the actual "state of the world."

The evolution of price C_{ist} depends upon the price escalation and renegotiation clauses included in the contract (e.g., gas prices may be pegged to oil prices or other economic indicators). Assuming unit sales, the present value of the total commodity cost under contract i and scenario s is:

$$T_{is} = \sum_{t=1}^{T} \frac{1}{(1+r)^t} C_{ist} \tag{7-5}$$

where r is the discount rate.

A probability p_s can be assigned to each scenario s and the cost T_{is} is then a random variable, with mean μ_i and variance σ_i^2 estimated as follows:

$$\mu_i = \sum_{s=1}^{S} p_s T_{is} \tag{7-6}$$

$$\sigma_i^2 = \sum_{s=1}^{S} p_s (T_{is} - \mu_i)^2 . \tag{7-7}$$

Define C_i as the random variable that takes on values of T_{is} according to the probability distribution p_s. As such, it is the commodity cost of contract i--a random variable with a mean and variance given by equations (7-6) and (7-7). The costs C_i and C_j of two different contracts i and j are not independent, and, in some cases, strong covariations may be present due to similar contract clauses regarding price escalations. Let σ_{ij} be the covariance between C_i and C_j. We have:

$$\sigma_{ij} = \sum_{s=1}^{S} p_s \, (T_{is} - \mu_i) \, (T_{js} - \mu_i) \quad . \tag{7-8}$$

The decision variable x_i is the share of the total demand (assumed equal to one) to be supplied by contract i. The expected value, E(C), and variance, V(C), of the total supply cost are then:

$$E(C) = \sum_{i=1}^{N} \mu_i \, x_i \tag{7-9}$$

$$V(C) = \sum_{i=1}^{N} \sigma_i^2 \, x^2 + 2 \sum_{i=1}^{N} \sum_{j=i+1}^{N} \sigma_{ij} \, x_i \, x_j \quad . \tag{7-10}$$

An LDC may want to minimize economic risk as measured by V(C) subject to not exceeding a maximum value, $\hat{C}$, for its expected supply cost, and thus to solve the following problem:

$$\text{Min} \quad V(C) \tag{7-11}$$

$$\text{s.t.} \quad E(C) \le \hat{C} \tag{7-12}$$

$$\sum_{i=1}^{N} x_i = 1 \quad . \tag{7-13}$$

Alternatively, the LDC may want to minimize the expected supply cost subject to not exceeding a maximum risk, $\hat{V}$, in terms of cost variations, with:

$$\text{Min} \quad E(C) \tag{7-14}$$

$$\text{s.t.} \quad V(C) \le \bar{V} \tag{7-15}$$

$$\sum_{i=1}^{N} x_i = 1 \quad . \tag{7-16}$$

The numerical applications described in the next subsection are based on the above equivalent formulations of the mean-variance frontier. Before describing these examples, note that the above models can be easily expanded to account for peak demands and demand contracts, minimum takes, and their related costs. Let P be the peak daily demand of core customers, and let I be the set of contracts that provide for a contract demand. Let Y_i be the contract demand for contract i, and t_i be the minimum take expressed as a percentage of the maximum take. The following constraints can then be added to the above models:

$$\sum_{i \in I} Y_i \geq fP \text{ (guaranteed peak deliverability)} \qquad (7\text{-}17)$$

$$365\, t_i Y_i \leq x_i \leq 365\, Y_i \text{ (the actual annual take under contract i is bounded by maximum and minimum takes, } i \in I.) \qquad (7\text{-}18)$$

where f is a fraction selected by the analyst so as to guarantee 100 percent reliability for that part of core customer peak demand.

Contract demand charges C_i^D are associated with the contract demands, Y_i. These charges are random variables, in the same way as the commodity charges C_i. The decision variable vector then includes both variables $x_i (1 \rightarrow N)$ and $Y_i (i \epsilon I)$, and the total cost T is:

$$T = \sum_{i=1}^{N} C_i\, x_i + \sum_{i \epsilon I} C_i^D\, Y_i \qquad (7\text{-}19)$$

Once the expected values, $E(C_i^D)$, and the covariances, $Cov(C_i, C_j^D)$ and $Cov(C_i^D, C_j^D)$, are estimated, the mean-variance models (7-11) - (7-13) and (7-14) - (7-16) can be extended in a straightforward manner to include demand charges.

In summary, the above methodology accounts for both short-term and long-term gas procurement costs, the economic risks involved in potential gas price swings, and the need to assure a reliable supply to core customers. Contracts with different levels of flexibility (e.g., minimum take percentages) can be considered in this framework. A major drawback of the approach is its inability to account for varying contract lengths. A multiperiod modeling methodology integrating this factor is presented in the next section. These portfolio models are likely to provide a first approximation of appropriate strategies that might be further refined using other models. The following subsection describes an application of the portfolio model approach.

Application

Consider an LDC that can purchase gas from three sources: two sources providing gas under firm contract ($i=1,2$), and a spot supplier ($i=3$). Only commodity costs are considered in this application. Their means, standard deviations, and variances are presented in table 7-1.

In table 7-1, the spot supplier's mean price is significantly lower than the other two prices, but its high variance illustrates the well-known volatility of spot prices. The two firm contracts are characterized by a trade-off between mean price and dispersion (i.e., contract 1 has a higher mean price but a smaller price variance than contract 2). To complete the formulation of the model, the price covariances must be estimated. Let ρ_{ij} be the correlation coefficient between C_i and C_j. Then the covariance σ_{ij} is:

$$\sigma_{ij} = \rho_{ij}\, \sigma_i\, \sigma_j \; . \tag{7-20}$$

We assume that $\rho_{12} = 0.8$, $\rho_{13} = 0.6$, and $\rho_{23} = 0.7$. It follows that $\sigma_{12} = 0.3$, $\sigma_{13} = 0.45$, and $\sigma_{23} = 0.7875$. Denote the maximum expected supply cost as $\bar{C}$, and constrain each supplier's share not to exceed 75 percent, so as to avoid excessive reliance on any one supplier. The portfolio model that minimizes cost variance subject to not exceeding a maximum expected cost is then written as follows:

$$\text{Min} \quad V = 0.25\, x_1^2 + 0.5625\, x_2^2 + 2.25\, x_3^2 + 0.6\, x_1x_2 + 0.9\, x_1x_3 + 1.575\, x_2x_3 \tag{7-21}$$

s.t.

$$3.5\, x_1 + 3\, x_2 + 2\, x_3 \le \bar{C} \tag{7-22}$$

$$x_1 + x_2 + x_3 = 1 \tag{7-23}$$

$$x_1 \le 0.75 \tag{7-24}$$

$$x_2 \le 0.75 \tag{7-25}$$

$$x_3 \le 0.75 \tag{7-26}$$

TABLE 7-1

CONTRACT COST CHARACTERISTICS

Supplier	Mean μ_i (\$/Mcf)	Standard Deviation σ_i	Variance σ_i^2
1	3.50	0.50	0.2500
2	3.00	0.75	0.5625
3	2.00	1.50	2.2500

Source: Authors' calculations.

where x_1, x_2, and x_3 are the unknown shares of the three contracts. The above model has been solved using the quadratic programming option of the computer package LINDO[7] available on an IBM 4341 computer. A parametric sensitivity analysis has been performed over the maximum expected cost $\tilde{C}$. The results are presented in table 7-2.

The results in table 7-2 clearly show the progressive shift of the portfolio from reliance on the firm contract 1 to reliance on spot gas when the maximum expected cost decreases from \$3.375 per Mcf to \$2.250 per Mcf, with a concomitant increase in the variance V. The optimal solution at $\tilde{C}$ = 3.375 remains the same for $\tilde{C} > 3.375$, and the same is true for the solution at $\tilde{C} = 2.250$ and for $\tilde{C} < 2.250$. The trade-off between expected cost and variance is illustrated in figure 7-1.

The curve AB in figure 7-1 represents the set of efficient trade-offs between the mean and variance of the contract portfolio cost. No point below the curve is attainable, and all the points above it represent inferior solutions. The final portfolio choice along the curve AB will obviously depend upon the relative weights placed by the LDC's supply planners on expected costs and cost variance.

An alternative approach is to compute a measure of riskiness for each point along the frontier. Suppose we are interested in the level of cost of

[7] Linus Schrage, Linear, Integer, and Quadratic Programming with LINDO - User's Manual (Palo Alto, CA: The Scientific Press, 1984).

TABLE 7-2

SOLUTIONS OF THE CONTRACT PORTFOLIO QUADRATIC PROGRAM

Maximum Expected Cost $\tilde{C}$ (\$/Mcf)	Contract Shares			Variance V	Standard Deviation σ
	x_1	x_2	x_3		
3.375	0.750	0.250	0.000	0.2883	0.5369
3.250	0.640	0.290	0.070	0.3444	0.5868
3.000	0.336	0.496	0.168	0.5121	0.7156
2.750	0.031	0.703	0.266	0.7519	0.8671
2.500	0.000	0.500	0.500	1.0969	1.0473
2.250	0.000	0.250	0.750	1.5961	1.2634

Source: Authors' calculations.

each portfolio in the upper 5 percent of its probability distribution, a worst-case type of analysis. Call this α percentile point of the probability distribution $U(\alpha)$, where $\alpha = .05$ if a 5 percent risk level is acceptable. If total cost is normally distributed, then

$$U(\alpha) = \tilde{C} + z_{\alpha}(V)^{1/2}. \qquad (7\text{-}27)$$

For $\alpha = .05$, $z_{\alpha} = 1.64$, and $U(\alpha)$ has a minimum of \$4.172 per Mcf at for $\tilde{C} = 2.75$. Accordingly, the portfolio in table 7-2 associated with $\tilde{C} = 2.75$ has the smallest risk, in the sense that it has the smallest extreme values of cost.

A Two-Stage Linear Programming under Uncertainty Approach

The so-called two-stage linear program under uncertainty applies to problems where the decision-maker must select "here-and-now" values for one set of decision variables, then observes the actual values of some random variables (the random event), and finally selects the values of the

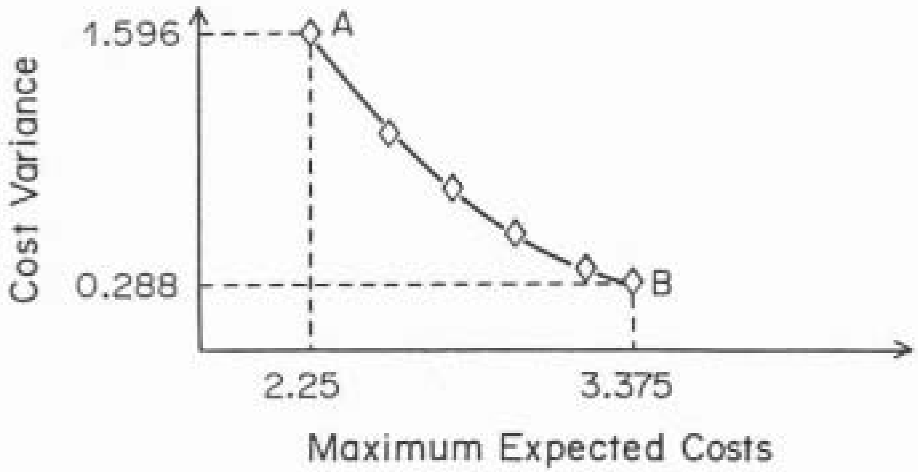

Fig. 7-1 Mean-variance efficient frontier

remaining decision variables in such a way that optimal corrective action is taken. The approach has also been labeled stochastic programming with recourse. The standard mathematical form of the problem is:[8]

$$\min_{x} Z(x) = cx + E_{\xi}\{\min_{y} gy|x\} \tag{7-28}$$

$$\text{s.t.} \quad Ax = b \tag{7-29}$$

$$Tx + My = \xi \tag{7-30}$$

$$x \geq o \tag{7-31}$$

$$y \geq o \ . \tag{7-32}$$

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[8] R. J. B. Wets, "Programming under Uncertainty: The Equivalent Convex Program," J. SIAM Appl. Math. 14 (1966): 89-105.

The vector x represents first-stage variables while y is a vector of second-stage ones. The vector c represents costs associated with the first stage, and g is the second stage cost vector. Once $x = \hat{x}$ is selected, a vector of random events $\xi = \hat{\xi}$ is observed, and then y is selected to minimize gy while respecting the constraint $My = \hat{\xi} - T\hat{x}$. Clearly, the second-stage decisions y are taken when no uncertainties are left in the problem. A feasible solution to (7-28) - (7-31) is a vector x that satisfies the first-stage constraints (7-29), as well as the second-stage constraints (7-30) for any values assumed by the random variables ξ.

To simplify the above problem, consider the case of finite distributions for the random variables g_s and ξ_s. The index s ranges from 1 to S and corresponds to a specific state of the world or scenario s, which occurs with probability p_s (with $\sum_s p_s = 1$). Let y_s be the values of the second-stage variables if event s takes place. The model is then:

$$\min_x Z = cx + \sum_{s=1}^{S} p_s g_s y_s \tag{7-33}$$

$$\text{s.t.} \quad Ax = b \tag{7-34}$$

$$Tx + My_1 = \xi_1 \tag{7-35}$$

$$Tx + My_2 = \xi_2 \tag{7-36}$$

$$Tx + My_S = \xi_S \tag{7-37}$$

The optimal values for the vectors y_s represent optimal <u>decision rules</u> or <u>strategies</u> that indicate the best choice of the second-stage variables <u>for each possible outcome of the uncertain event</u>. The fact that one must determine rules for future actions is what distinguishes this approach from ordinary dynamic optimization where all future actions are determined initially and are not open to modifications.

The typical objective function for a problem of this sort is an expected value (cost, benefit, and so on), but it could conceivably be extended to include the variance of gy. Such an extension, however, would destroy the linear structure of the model. Most applications of this model involve only two stages, although multistage problems can also be formulated under this approach.[9] The number of possible sets of values for the random elements is likely to be very large, however, and the resultant linear programming problem would be difficult to solve.

A Two-Stage Linear Model for Gas Contract Strategies

Consider a gas LDC that may contract for its supply with three suppliers (or supplier groups): (1) a supplier providing gas under firm contract that covers the initial and next periods considered; (2) a supplier providing gas under firm contract covering one period; and (3) a spot supplier. Contracting with supplier 1 implies that a contract demand Y_1 is selected that applies to both periods, with corresponding minimum and maximum take constraints. This is the basic decision that must be taken now and will constrain future decisions.

We assume that the contracts' cost structures and gas demand levels are known with certainty for the first period. The following are defined for the first period:

<u>Parameters</u>

D_1 = total annual gas demand

D_{1c} = total annual gas demand of core customers

L_{1c} = daily load factor of core customers

P_{1c} = peak daily gas demand of core customers ($P_{1c} = D_{1c}/365\ L_{1c}$)

C_{i1} = gas commodity cost under contract i (= 1→3)

C_{i1}^{D} = gas demand cost under contract i (= 1→2)

t_{i1} = minimum percentage take under contract i (= 1→2) (we assume that this parameter is constant for contract 1 in both periods, and we denote it t_1).

[9] H. M. Wagner, <u>Principles of Operations Research</u>, 2nd edition (London: Prentice/Hall International, 1975), Chapter 16.

Variables

Y_1 - peak deliverability under contract 1 (applies to both periods)

Y_{21} - peak deliverability under contract 2

x_{i1} - actual annual take under contract i.

The total supply cost during period 1 is:

$$T_1 = \sum_{i=1}^{3} C_{i1} x_{i1} + 12 C^D_{11} Y_1 + 12 C^D_{21} Y_{21} \quad . \tag{7-38}$$

The demand balancing and supply constraints for period 1 are then:

$$\sum_{i=1}^{3} x_{i1} = D_1 \text{ (annual gas demand)} \tag{7-39}$$

$$Y_1 + Y_{21} \geq P_{1c} \quad \text{(peak deliverability to core customers)} \tag{7-40}$$

$$365\ t_1\ Y_1 \leq x_{11} \leq 365\ t_1 \quad \text{(minimum and maximum takes constraints for contract 1)} \tag{7-41}$$

$$365\ t_{21}\ Y_{21} \leq x_{21} \leq 365\ Y_{21} \quad \text{(minimum and maximum takes constraints for contract 2)} \tag{7-42}$$

We next consider S ($s=1 \rightarrow S$) possible scenarios or "states of the world" for the second period (stage), each characterized by a probability p_s. Each scenario s is characterized by specific values of the demand (D_{2s}, P_{2cs}) and cost (C_{i2s}, C^D_{i2s}, t_{i2s}) parameters. The second-stage decision variables are then:

Y_{22s} - peak deliverability under contract 2 if scenario s is the actual outcome, and

x_{i2s} - actual annual take under contract i if scenario s is the actual outcome.

The expected cost for the second-stage decisions is:

$$E(T_2) = \sum_{s=1}^{S} p_s \left[\sum_{i=1}^{3} c_{i2s}\, x_{i2s} + 12\, c^{D}_{12s}\, Y_1 + 12\, c^{D}_{22s}\, Y_{22s} \right] \tag{7-43}$$

and the second-stage constraints are:

$$\sum_{i=1}^{3} x_{12s} = T_{2s} \quad (s=1 \to S) \quad \text{(annual gas demand)} \tag{7-44}$$

$$Y_1 + Y_{22s} \geq P_{2cs} \quad (s=1 \to S) \quad \text{(peak deliverability)} \tag{7-45}$$

$$365\, t_1 Y_1 \leq x_{12s} \leq 365\, Y_1 \quad (s=1 \to S) \quad \text{(maximum and minimum takes for contract 1)} \tag{7-46}$$

$$365\, t_{22s} Y_{22s} \leq x_{22s} \leq 365\, Y_{22s} \quad (s=1 \to S) \quad \text{(maximum and minimum takes for contract 2)} \tag{7-47}$$

The overall model involves finding the values of the decision variables $(x_{i1}, x_{i2s}, Y_1, Y_{21}, Y_{22s})$ that minimize the total expected cost

$$E(T) = T_1 + E(T_2), \tag{7-48}$$

subject to constraints (7-39) - (7-42) and (7-44) - (7-47). The following section describes an application of this model.

Application

Assume that the total annual demand and peak demand of core customers do not change from the first to the second stage, whatever the scenario. This simplification enables us to focus on the role of the cost parameters in the determination and structure of the decision rules. We normalize the annual demand (that is, we set it equal to 1) and assume that core customers make up 80 percent of the total annual demand and have a load factor of 50 percent. The peak daily demand (P_c) of the core customers is then equal to 0.00438. The values of the cost parameters are presented in table 7-3 in the hypothetical case of three scenarios for the second stage.

Scenario 1 may be viewed as a continuation of the current gas surplus situation, with a decline in the spot market price. Scenarios 2 and 3 represent tightening supply conditions, and therefore increasing commodity and demand charges. Scenario 3 represents the tightest market, where spot gas is available only at prices above firm contract prices. Long-term contract 1 is assumed to include price escalation clauses, hence its varying commodity and demand charges. The minimum takes are equal to 60 percent (relatively inflexible) for contract 1 and 30 percent (very flexible) for contract 2, in both periods. Two sets of scenario probabilities have been analyzed:

Case A: $p_1 = 0.4 \quad p_2 = 0.4 \quad p_3 = 0.2$

Case B: $p_1 = 0.2 \quad p_2 = 0.3 \quad p_3 = 0.5$

The future suggested by Case A represents a continuation of present trends or mild tightening of the supply situation. Case B, on the other hand, suggests an overall strong tightening of supply conditions.

The model, which has 17 variables and 24 constraints, has been solved for both Cases A and B, and the results are presented in table 7-4. The total expected cost E(T) (see equation 7-48) is equal to \$6.916 in Case A and to \$7.469 in Case B.

For the probabilities given in Case A, both firm contracts are used in similar magnitudes to guarantee peak deliverability. The annual purchase shares are the same both in the first stage and under scenarios 1 and 2 in the second stage (44 percent for contract 1, 26 percent for contract 2, and 30 percent for contract 3). If scenario 3 materializes, however, spot purchases are completely eliminated and replaced by additional purchases under contract 1. In Case B, complete reliance is placed on contract 1, which is not surprising in view of the strong likelihood of significant price increases for contracts 2 and 3. Contract 2 is never chosen; instead, peak deliverability to core customers is wholly guaranteed by contract 1. About 4 percent of the total annual gas demand is purchased from the spot supplier (contract 3) in the first stage and under scenarios 1 and 2 in the second stage. In all these three situations, it is clear (see table 7-3) that spot supplies are cheaper than supplies under contract 1, but the

TABLE 7-3

COST PARAMETERS FOR THE TWO-STAGE GAS CONTRACT LP MODEL

Supplier Contract	First-Stage Values	Second-Stage Values Scenario 1	Scenario 2	Scenario 3
	Commodity Cost ($/MCf)			
1	3.0	3.0	3.5	4.5
2	3.0	3.5	4.5	5.5
3	2.0	1.5	3.0	6.5
	Demand Cost ($/Maximum daily Mcf)			
1	5.0	5.0	6.5	8.0
2	8.0	8.0	8.5	11.0
	Minimum Take (%)			
1	60	60	60	60
2	30	30	30	30

Source: Authors' Calculations.

minimum take constraint of this contract is binding at the take level of 0.959, and it is therefore impossible to decrease takes under contract 1 in order to increase those from the spot supplier. Under scenario 3, however, this situation no longer holds because the spot price ($6.5 per Mcf) is higher than the contract 1 price ($4.5 per Mcf), and thus contract 1 provides for the whole gas demand.

The above examples clearly illustrate the potential of the approach, provided that the contracting problem can be structured as a multistage decision-making and information flow problem. Linear programs involving several thousands of variables and constraints can be solved routinely with powerful algorithms and computer codes available on most mainframe

TABLE 7-4

OPTIMAL SOLUTIONS OF THE TWO-STAGE LP MODEL

Supplier Contract	Case A First Stage	Case A Second Stage Scenario 1	Case A Second Stage Scenario 2	Case A Second Stage Scenario 3	Case B First Stage	Case B Second Stage Scenario 1	Case B Second Stage Scenario 2	Case B Second Stage Scenario 3
	Annual Purchases ($D_i = 1$)							
1	0.446	0.446	0.446	0.743	0.959	0.959	0.959	1.000
2	0.257	0.257	0.257	0.257	0.000	0.000	0.000	0.000
3	0.297	0.297	0.297	0.000	0.041	0.041	0.041	0.000
	Demand Contract ($P_i = 0.00438$)							
1	0.00204	0.00204	0.00204	0.00204	0.00438	0.00438	0.00438	0.00438
2	0.00234	0.00234	0.00234	0.00234	0.00000	0.00000	0.00000	0.00000

Source: Authors' calculations

computers. Extending the model presented in this section to include many more contracting options over more than two periods should not present special technical difficulties. It is more difficult to delineate all feasible multistage scenarios and forecast their characteristics (gas demands, prices, etc.).

Summary

Two quantitative methodologies, one based on financial portfolio analysis and the other on multistage linear programming, have been proposed as ways to analyze and solve the complex supply planning problems currently faced by gas LDCs. These methodologies account for the uncertainty that characterizes both future gas demands and future gas costs, and for the trade-offs that exist between short-term and long-term supply costs, supply reliability for core customers, and price stability. They do not aim to replace the judgment of the decision-maker, but rather to inform it. Viewed in this way they should be helpful to both LDC gas supply planners and to the staffs of the state regulatory commissions, who audit LDC purchasing practices to make sure they achieve the various goals and constraints described above. The methods discussed in this chapter account for future price risk, a phenomenon that greatly complicates the planning of an optimal supply portfolio. This chapter has dealt with some aspects of the regulated firm in a rather simplified way. Examples are the regulated cost allocation process and the time profile of demand by customer groups. The NRRI model GASMIX, described in appendix D, contains a more detailed representation of the cost allocation process and the time profiles of demand, but does not deal explicitly with the risk of future price changes. Interested commission staff members may wish to use a combination of the three methods to study the gas purchasing strategies of jurisdictional distributors.

CHAPTER 8

CONCLUSIONS

The material covered in this report is wide ranging and directed at a variety of problems that are likely to emerge in the new environment surrounding state regulation of natural gas distribution. Some portions of the report are intended for policy analysts, while others are examples of quantitative and technical approaches that can help commission staff members more fully assess and deal with the emerging importance of a distributor's gas supply contracts. The report has covered recent developments in the federal transportation program for gas; the fundamental nature of a typical gas supply contract; the practices and procedures used by state commissions in overseeing such contracts; the emerging relationship between contract price and spot price and the influence of contractual terms on the contract price; the notion of an efficient contract in comparison to others; and the need to select an optimal portfolio of contracts.

At the federal level, Order 500 requires producers to offer take-or-pay credits to pipelines for gas a producer wishes to transport. Because of the complicated array of contracts, some regulated by the FERC, some not, the Order is necessarily imperfect. The Order relieves the take-or-pay pressure that otherwise tends to prevent a pipeline from accepting Order 436 status and thereby becoming a voluntary, nondiscriminatory transporter of gas. Because commission approval and rules are needed for transportation to occur in the first place, the Order does not constitute crass governmental abrogation of contracts. There is a risk that the combined actions of several LDCs in converting their contract demand to firm transportation may convert much, possibly all, of a particular producer's high-priced, take-or-pay gas into lower-priced gas. For this reason, the FERC might consider imposing a limit to the crediting rule.

The NRRI survey of state commission practices and procedures shows that most commissions review a distributor's gas supply contracts as part of their purchased gas adjustment process. Almost all states reserve the right to subject a distributor's purchasing practices to a prudence review, although few have actually conducted such an investigation. Many states have a requirement, sometimes mandated by statute, that a distributor must purchase a least-cost portfolio of supplies, although the meaning of "least-cost" is necessarily imprecise. Other than a prudence review or a least-cost requirement, most states do not have any mechanisms to create an incentive for a distributor to purchase gas efficiently. An example of such a mechanism, used by a few states, would be a formula that would allow a distributor to keep a portion of the savings achieved by a reduction in its supply costs.

The NRRI sample of distributor-producer contracts suggests that in a slack gas market, as currently exists, contract prices for gas are likely to be about 20 cents per Mcf or about 9 percent higher than spot prices. That differential tends to be smaller at higher levels of contract and spot prices. These observations are consistent with the behavior of contract and spot prices in other markets. Contractual terms appear to influence a contract's initial price.

The NRRI classifies the most important contractual clauses as affecting either the difficulty of adjusting future prices or of adjusting future quantities. The indices of price and quantity adjustment difficulty have an effect on the initial price in a contract because they represent types of risks borne by the buyer and seller as future circumstances change. These contractual risks vary for two reasons. A distributor may wish to have a range of contracts with adjustment terms from easy to difficult to correspond to the profile of risks associated with its demand conditions. In addition, risk conditions can differ between distributors, and for that reason a distributor may adopt more rigid contract terms to compensate partially for local-specific risk. These two reasons give conflicting expectations about how quantity rigidity in a contract (for example) will affect the initial contract price. The first reason suggests more rigid quantity terms should be associated with a lower contract price, while the second suggests rigid quantity specifications in a contract can partially offset local, high-risk conditions that result in higher prices. Consequently, identifying and estimating these separate effects require a particularly rich data set. The sample collected by the NRRI consists of only 28 long-term contracts and, not surprisingly, is only partially successful in unraveling the relation between contract price and contract terms. Because of the geographical variation within the sample the adjustment indices are mostly a proxy for supply security and therefore are estimated to increase the contract price. A richer data set is needed to disentangle the relationships further.

Data Envelopment Analysis is a promising technique for assessing the relative efficiency of regulated entities or, in this case, gas supply contracts. By using the DEA procedure a staff member can find an efficiency index for each entity (production unit or a contract) in his sample, based upon the construction of a frontier that literally envelops the sample, called the best practice frontier. Comparisons of individual entities with the best practice frontier form the basis of the efficiency measurement. This idea can be used to examine a set of contracts and to identify those that appear to deserve additional scrutiny. In this way, a commission staff member could concentrate discussions with a distributor's gas supply manager on those contracts that are unusual in price or contractual terms.

Besides assessing the merits of individual contracts, commissions must be concerned also with the overall gas purchasing strategy of an LDC and the resulting portfolio of gas supplies. There are a number of quantitative techniques that commission staff members might use to assess a distributor's plan. Two promising techniques are the mean-variance analysis associated with financial portfolio theory and a two-stage linear programming formulation of the supply mix problem. Both techniques are amenable to computer solution using mathematical programming software packages that are commonly available.

Either of these types of models could form the basis of a screening process by which obviously inferior supply sources are identified and eliminated. Following the screening process, a more detailed analysis of the portfolio selection problem could be conducted using an NRRI computer model, GASMIX, described in appendix D. The GASMIX model is numerically intensive and somewhat expensive to run. For this reason it is not suitable for analyzing more than 10 or so supply sources.

Because of the complex and changing nature of the natural gas industry, it is not possible to anticipate now the variety of problems likely to confront state regulators in reviewing and overseeing a distributor's gas purchasing plan. This report has dealt with several important issues, including the implications of the FERC Order 500, the relation between long-term contract prices and spot prices and also between contract price and other contractual terms, the efficiency of individual contracts, and the nature of an optimal portfolio of gas supply sources. Additional issues will emerge as this industry adjusts to its new configuration of competitive wellhead markets and regulated transportation services.

APPENDIX A

QUESTIONS AND RESPONSES FROM NRRI SURVEY OF COMMISSION PROCEDURES

In order to develop current information on state utility commission oversight of direct gas purchases, the NRRI surveyed 37 state commissions during the summer of 1987. In the remaining 13 states, direct gas purchases are either currently infeasible, unregulated, or otherwise not an issue. The results of the survey are discussed in chapter 4. This appendix contains the survey instrument and the responses of the 30 Commissions that replied.

The responses are presented in this appendix separately for each question of the survey. The answers are arranged alphabetically by state for each question. Apart from some minor editing, each response reported here is quoted directly from the survey form.

THE NATIONAL REGULATORY RESEARCH INSTITUTE

Survey on
Commission Oversight of Direct Gas Purchases

June 1987

At the request of the NRRI Board, the NRRI is gathering information about current and planned state commission procedures for oversight of direct gas purchases by local distribution companies (LDCs) from producers. Since the oversight of direct gas purchases is a relatively new activity, commissions may be interested in learning about what other commissions are doing. In addition to a description of current or planned methods, we would also like to know what kinds of information that your Commission does not already receive but would find useful. Please include any Commission orders, notices, rules or opinions that are relevant to the topic. These might include a description of the Commission's method for adjusting rates for changes in gas acquisition costs or any Commission least cost purchasing rule.

The survey may be answered in one of two ways, at your option. Answers can be written on the survey form itself and returned to us, or we can telephone you and rely on our notes of the conversation. In any case, we will call in about two weeks to see which is convenient for you. If written comments are provided, please return this survey by July 15, 1987 to:

J. Stephen Henderson
Senior Institute Economist, NRRI
1080 Carmack Road
Columbus, OH 43210-1002
Phone (614) 292-9404

Name of person filling out this form:

Phone:

Title:

QUESTION

1. What is the general nature of the process used by your Commission to review direct gas purchase contracts between a local distribution company under your jurisdiction and a gas producer? Select as many of the following as needed, by writing yes or no to the left of the statement.

______ a. Such contracts are not reviewed by the Commission. If not, by any other agency? Name of Agency: ____________.

______ b. Such contracts are reviewed as a part of a purchased gas adjustment proceeding. Frequency (e.g. quarterly): __________.

______ c. Such contracts are reviewed as a part of a general rate case. Frequency: __________.

______ d. Such contracts are reviewed periodically by commission staff members. Frequency: __________.

______ e. Such contracts are reviewed periodically by outside auditors. Frequency: __________.

______ f. Such contracts are approved in advance by the Commission. If so, describe the approval process briefly.

______ g. Are your procedures different if the producer is affiliated with the distributor, and if so, how?

ANSWERS

California: Contracts are reviewed as part of a purchased gas adjustment proceeding. This review is done semiannually although the Commission is going to change to an annual review. Contracts are reviewed occasionally by Commission staff members, as warranted. Contracts are not reviewed by outside auditors.

Connecticut: Contracts are reviewed monthly as part of a purchased gas adjustment proceeding. Contracts are reviewed as part of a general rate case every two years. Contracts are reviewed by Commission staff when entered into.

Delaware: Contracts are reviewed as part of a purchased gas adjustment proceeding if the contracts change or the issue arises from other reasons. Contracts are reviewed as a part of a general rate case if the contracts change or are about to change in the near future. Contracts are not reviewed periodically by Commission staff or outside auditors, and are not approved in advance by the Commission. Procedures do differ if the producer is affiliated with the distributor. This has occurred in one instance. The LDC is pricing the gas at the midpoint between the TRANSCO CD commodity rate and the most recent spot gas purchase rate.

Indiana: Contracts are not reviewed by the Commission or by any other agency.

Iowa: Contracts are reviewed as part of a purchased gas adjustment proceeding. Information from the contracts is used in the calculations of the PGAs which are filed with the Board whenever a change of 0.5 cents per Ccf or therm occurs, but are not required more frequently than every thirty days. The contracts themselves will be required concurrently with the annual PGA filing and with the annual review of gas procurement (ARG) filings. Contracts have not yet been reviewed as part of a general rate case. The Board intends to review contracts in the context of annual PGA and ARG filings, but that would not preclude review during a subsequent general rate case. Contracts are not reviewed periodically by Commission staff. The contracts have not yet been received, for the most part. Contracts are not reviewed by outside auditors and are not approved in advance by the Board. Board procedures do not differ if the producer is affiliated with the distributor. The Board is not aware that any of its jurisdictional distributors are affiliated with any of their suppliers.

Kansas: Contracts are reviewed as part of a purchased gas adjustment proceeding. Contracts are also reviewed as part of a general rate case as needed, and they are reviewed by Commission staff on intake. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. Commission procedures do not differ if the producer is affiliated with the distributor.

Kentucky: Contracts are reviewed quarterly in purchased gas adjustment proceedings. Information is provided on request. Contracts are reviewed, if necessary, as part of general rate cases as cases are filed. Contracts are reviewed periodically by Commission staff as contracts come in. It is a newly instituted (1986) practice of the Commission to require that contracts be filed by the LDCs with the Commission. Contracts are not reviewed periodically by outside auditors and are not approved in advance by the Commission. Procedures do differ if the producer is affiliated with the distributor. In those cases, contracts are more carefully scrutinized, usually in a PGA case. Data requests are often used to monitor activities as closely as possible.

Louisiana: Contracts are not reviewed by the Commission.

Michigan: Contracts are reviewed annually as part of a gas cost recovery proceeding which has replaced the purchased gas adjustment. Contracts are reviewed annually by Commission staff. Contracts are not reviewed as part of a general rate case. They are not reviewed by outside auditors and are not approved in advance by the Commission. Commission procedures do not differ if the producer is affiliated with the distributor.

Minnesota: Contracts are reviewed by the Department of Public Service and may be reviewed by the Commission. Contracts are reviewed annually as part of a purchased gas adjustment proceeding. While the Commission has not yet decided a case in which a utility made direct gas purchases, contracts will be reviewed as part of a rate case whenever a rate case involving direct purchases is filed. Contracts are not reviewed periodically by Commission staff or outside auditors and are not approved in advance by the Commission.

Mississippi: Contracts are reviewed as part of a purchased gas adjustment proceeding. Contracts are also reviewed as part of a general rate case and annually by Commission staff members. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. Commission procedures do not differ if the producer is affiliated with the distributor.

Nevada: Contracts are reviewed annually in purchased gas adjustment proceedings. Contracts and invoices are reviewed to verify the prices used. This is done annually but a PGA can be filed at any time. Contracts are not reviewed in general rate cases. General rate cases usually do not consider the purchased gas cost. Contracts are not reviewed periodically by Commission staff and are not approved in advance by the Commission. Procedures do not differ if the producer is affiliated with the distributor.

New Jersey: Contracts are reviewed annually in purchased gas adjustment proceedings. Contracts are also reviewed every three years in general rate cases. Contracts are reviewed by Commission staff (BPU auditors) in three year intervals. Contracts are also reviewed annually by outside auditors. Contracts are not approved in advance by the Board and Board procedures do not differ if the producer is affiliated with the distributor.

New Mexico: Contracts are reviewed biannually as part of a purchased gas adjustment proceeding. Contracts are not reviewed as part of a general rate case, are not reviewed by outside auditors, and are not approved in advance by the Commission. Procedures do differ if the producer is affiliated with the distributor. Notification of an affiliated transaction must be provided along with a copy of the contract.

New York: Contracts are reviewed as part of a purchased gas adjustment proceeding. Gas adjustments are filed monthly and monitored by staff, including contracts and purchases. There are no prescribed proceedings. Contracts are reviewed as a part of a general rate case. All rate filings require the submission of evidence on gas purchase practices, and review by staff. All contracts for purchase of gas are required to be filed with the Commission. Approval is not required but all contracts are subject to staff review and reporting to the Commission if questioned. Contracts are not reviewed periodically by outside auditors and are not approved in advance by the Commission. Procedures do not differ if the producer is affiliated with the distributor.

North Carolina: Contracts are reviewed semiannually as part of a purchased gas adjustment proceeding. Contracts are not reviewed as part of a general rate case. Contracts are reviewed periodically by Commission staff but not by outside auditors. Under some special circumstances it may be desirable to have the Commission approve the contract in advance. (A filing must be made.) Procedures do not differ if the producer is affiliated with the distributor.

Ohio: Contracts are reviewed as part of a purchased gas adjustment proceeding. This is done annually for companies with over 5,000 customers and biennially for smaller companies. Contracts are not reviewed as part of a general rate case. Contracts are reviewed periodically by Commission staff members, who may give preliminary reviews of contracts at the request of the companies. Contracts are reviewed by outside auditors as part of the purchased gas adjustment proceeding. Contracts are not approved in advance by the Commission and procedures do not differ if the producer is affiliated with the distributor.

Oklahoma: Contracts are reviewed as part of a purchased gas adjustment proceeding and as part of general rate cases. Contracts are reviewed by Commission staff every six months. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. Procedures do differ if the producer is affiliated with the distributor. The Commission procedure is to determine if the transaction was an "arm-length" agreement. In performing this task the following issues must be considered, weighed, and evaluated.

A. Is the affiliated purchase price comparable to the "Fair Field Price" paid to other producers?
B. Is the contract purchase requirement comparable to other producers in the gas field?

Oregon: Contracts are reviewed annually in general rate cases.

Pennsylvania: Contracts are reviewed annually in purchased gas adjustment proceedings. Contracts are also reviewed as part of general rate cases whenever general rate increases are filed. Contracts are reviewed by Commission staff in the course of PGA and rate case proceedings. Contracts are not reviewed by outside auditors and are not approved in advance by the Commission. Procedures do differ if the producer is affiliated with the distributor. Gas purchased from affiliated interests is subject to more intense scrutiny.

Rhode Island: Contracts are not reviewed by the Commission. Contracts might possibly be reviewed in semiannual purchased gas adjustment proceedings or in general rate cases. Contracts are not reviewed by Commission staff or outside auditors and are not approved in advance by the Commission. Procedures do not differ if the producer is affiliated with the distributor.

South Carolina: Contracts are reviewed annually in purchased gas adjustment proceedings. Contracts are reviewed in general rate cases whenever such cases are filed. Contracts are reviewed by Commission staff with variable frequency. Contracts are not approved in advance by the Commission and procedures do not differ if the producer is affiliated with the distributor.

South Dakota: Contracts are not reviewed by the Commission.

Tennessee: Contracts are reviewed in general rate cases every 18-30 months.

Utah: In some cases contracts may be made a part of a case record and are reviewed by the Public Service Commission. Generally the Commission directs the Division of Public Utilities to review such contracts as part of a general review in rate cases. The Division is not the Commission's staff but on occasions provides similar service.

Virginia: Contracts are reviewed monthly in purchased gas adjustment proceedings. The specific provisions of the contracts are not reviewed. The spot prices paid and the transportation arrangements for the contracts are monitored on an ongoing basis. Contracts are not reviewed as part of general rate cases and are not reviewed periodically by Commisson staff or outside auditors. Contracts are not approved in advance by the Commission and procedures do not differ if the producer is affiliated with the distributor.

Washington: Contracts are not reviewed in purchased gas adjustment proceedings or in general rate cases. Contracts are not reviewed periodically by Commission staff or outside auditors. The Commission cannot, by statute, approve a contract. Procedures do differ if the producer is affiliated with the distributor. This involves the statute regulating affiliated transactions.

West Virginia: Contracts are reviewed in purchased gas adjustment proceedings annually if a rate increase is sought. The utility must prove that dependable lower priced supplies of natural gas are not readily available from other sources, that contracts between the utility and its suppliers are negotiated at arm's length and that such contracts are not detrimental to the utility's customers or the utility itself. Contracts are not reviewed as part of general rate cases. Contracts are reviewed periodically by Commission staff usually in the context of the purchased gas adjustment proceedings but sometimes in complaint proceedings or affiliated transaction proceedings. Contracts are not reviewed periodically by outside auditors and are not, unless for an affiliated transaction, approved in advance by the Commission. The approval process for affiliated transactions often entails a hearing in which the company must prove that the terms and conditions are reasonable, neither party is given an undue advantage and the contracts do not adversely affect the public.

Wisconsin: Contracts are not reviewed by the Commission. Contracts are not reviewed in purchased gas adjustment proceedings or in general rate cases. Contracts are not reviewed periodically by Commission staff or by outside auditors. Contracts are not approved in advance by the Commission.

Wyoming: Contracts are reviewed periodically by Commission staff. See response to question #3.

Question

2. What kind of information must a distributor provide the Commission as part of the review process? Write yes or no to the left of the statement.

_____ a. The contract itself.

_____ b. Price and/or volume information for each contract.

_____ c. Aggregate price and/or volume information for all contracts.

_____ d. Other. Describe briefly.

ANSWERS

California: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided. In addition, any records, internal memos, and correspondence between parties must be furnished. The Commission wants to try to understand what the utility knew at the time.

Connecticut: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

Delaware: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

Indiana: N/A

Iowa: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided. Invoices must also be provided.

Kansas: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided. A utility must also provide, under the provisions of the policy order, Docket No. 106, 850-U, a description of other alternatives for obtaining fuel and the reasons for selecting the alternative embodied in the contract, and a justification for each price escalation invoked under the contract.

Kentucky: The contract itself must be provided. Beginning in September 1987, the Commission will implement a formal review process for class A LDCs. More extensive information will be required at that time.

Louisiana: Price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

Michigan: The contract itself, or price and/or volume information for each contract and aggregate price and/or volume information for all contracts must be provided.

Minnesota: Commission rules do not specify the information required to be filed. In the most recent automatic adjustment reports, the utilities making direct gas purchases filed the contract provisions but did not reveal the name of the producer.

Mississippi: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

Nevada: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

New Jersey: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

New Mexico: The contract itself (sometimes), price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

New York: The contract itself, and price and/or volume information for each contract (in monthly GAC filings) must be provided.

North Carolina: The contract itself must be provided.

Ohio: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts (used for calculating the GCR rate each quarter) must be provided. Other kinds of information provided include independent auditor and/or Commission staff review of the actual contract considering volume, price, and any obligations such as minimum takes, take or pay, price escalators, the cost of transporting the volumes, reliability, etc.

Oklahoma: The contract itself, and price and/or volume information for each contract must be provided.

Oregon: Price and/or volume information for each contract must be provided.

Pennsylvania: Price and/or volume information for each contract must be provided. The contract itself does not have to be provided, but it can be obtained during the proceedings. Individual gas suppliers whose volumes are less than 3 percent of the total system supply can be reported collectively.

Rhode Island: N/A.

South Carolina: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

South Dakota: N/A.

Tennessee: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

Utah: There is no set requirement for contract information nor is there an automatic review of all contracts in each case. The Commission and Division determine the scope of investigation in each case and request the information necessary. Sometimes all contracts are reviewed, sometimes a sample is taken, usually summaries only are reviewed.

Virginia: Price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided. The contract itself does not have to be provided.

Washington: N/A.

West Virginia: The contract itself must be submitted if it is subject to FERC jurisdiction. If the supply contract is with a local producer, only a list of relevant terms (name, quantity, price, price escalator, term, county of production and certain producer information: producer name, well name and number, API identification number, date drilling commenced, NGPA classification, date NGPA determination received, contract date, contract expiration date, price adjustment, contract quantities, price in $/MMbtu and Mcf) must be submitted. If the supply contract is affiliated, the contract must be filed. Price and/or volume information for each contract and aggregate price and/or volume information for all contracts must be provided. Other information that must be provided includes:

For Projected PGA Period (November Yr. 1 - October Yr. 2)
- estimated amount of total purchased gas costs
- estimated volume of gas purchased
- estimated sales
- estimated total supply available
- estimated excess unaccounted for gas

For Historic PGA Period (July Yr. 1 - June Yr. 2)
- actual quantity and cost of purchased gas
- actual quantity and cost of all gas transferred to and withdrawn from storage
- actual net settlement cost of exchange gas
- actual cost of gas shrinkage
- total gas sold in Mcf
- list of offers to purchase gas issued by the utility including terms offered, response and terms of resulting contracts
- list of offers to sell gas received by utility, including terms, response and terms of resulting contracts
- list of sources investigated
- indication of which contracts contain take-or-pay provisions, indefinite price escalators and/or most favored nation clauses; if these clauses exist, utility must show clauses do not require it to buy more than a reasonable amount of gas at a greater than reasonable price
- utility must show it has let out bids for the purchase of a substantial quantity of natural gas

Wisconsin: No formal review yet. In July 1987, the Commission was to start a generic purchasing, planning and prudence review investigation.

Wyoming: The contract itself, price and/or volume information for each contract, and aggregate price and/or volume information for all contracts must be provided.

QUESTION

3. What procedures, if any, has your Commission adopted to protect the confidentiality of the contracts? Is the information on file at the Commission? Subject to public disclosure? Under what conditions?

ANSWERS

California: No disclosure. Staff must sign a confidentiality agreement.

Connecticut: Public information.

Delaware: If a review of these type contracts is conducted by Commission staff, the review takes place at the utility. This procedure eliminates the need for confidentiality treatment since the contracts do not leave the utility offices. Staff has, however, had to sign confidentiality statements that would ensure the information would not be disclosed to outside parties.

Indiana: N/A.

Iowa: The Board has not adopted any procedures to protect the confidentiality of contracts between distributors and their suppliers, specifically. If, at the time of filing these contracts, the distributor wishes to request that all or a portion of a contract or contracts be held confidential, it may file a Request for Confidentiality pursuant to Iowa Administrative Code 199--1.9.

Kansas: In accord with Docket Number 106, 850-U:

A. Contracts are deemed proprietary information;
B. Contracts are kept in secured files at the Commission; and,
C. Contracts are not subject to public disclosure.

Kentucky: Contracts are kept on file here at the Commission. While only 1 LDC has requested confidentiality, we require that any outside party interested in reviewing contracts must come to the Commission's offices to do so. We do not send them out in the mail.

Louisiana: Commission does not review the contracts and, therefore, the protection of the confidentiality of the contracts is not a problem.

Michigan: Information is on file.

Minnesota: The Commission has developed trade secret procedures. If a utility so requests, and the Commission agrees, information considered "trade secret" is not subject to public disclosure but is available to state regulatory agencies and possibly other intervenors.

Mississippi: Public record--unless the utility requests that the material be treated as proprietary and/or confidential.

Nevada: The review generally occurs during an on site audit. Individual contracts usually are not identified in formal exhibits or testimony. Only prices and quantities appear in exhibits.

New Jersey: Contracts are supplied under protective agreement.

New Mexico: None. All information filed is open to the public.

New York: All contracts are filed with the Commission as public documents unless confidential protection is requested and specifically granted by the Commission. To date, direct gas purchase contracts have been in the short term spot market with no requested confidential treatment.

North Carolina: Contracts are not available to the public, summary data only in published documents.

Ohio: Generally, the contracts are not filed with the Commission. Due to the sensitivity of price competition among utilities, not all information regarding a contract is necessarily made public. In GCR cases, this information may be subject to protective orders which limit access to these documents. The Commission staff and Office of Consumers' Counsel are permitted access.

Oklahoma: The review process of gas purchase contracts is usually conducted in the field. The contracts with gas producers are confidential and not subject to disclosure. Because of confidentiality of gas purchase contracts, staff does not maintain gas purchase contract files.

Oregon: We don't keep contracts on file, but we have access to the contracts at the utility company. Generally speaking, company revenue and expense data may be released to the public once it is six months out of date.

Pennsylvania: LDCs can request confidential treatment of contract information required to be filed with the Commission. The Administrative Law Judge assigned to the case will decide whether such a request will be granted.

Rhode Island: N/A.

South Carolina: No procedures have been adopted by the Commission. The contracts are not on file with the Commission.

South Dakota: N/A.

Tennessee: Information is on file at the Commission subject to public disclosure.

Utah: Where confidentiality is vital, an oath of confidentiality is signed by the examiners and such information is not made part of the public record.

Virginia: None. The Commission has not addressed this issue since the filing of direct purchase contracts is not required at this time.

Washington: Don't know. We have very broad access of the public to anything at the Commission.

West Virginia: Only affiliated contracts must be filed; however, as indicated above, the relevant terms of all other contracts must be listed. This is all public record. If the utility desires a protective order to protect sensitive information from disclosure it must seek such an order with justification for the issuance of such an order from the Commission. The Commission follows the West Virginia Rules of Civil Procedure, Rule 26 governing discovery and the West Virginia Freedom of Information Act.

Wisconsin: N/A.

Wyoming: The contracts are filed with the Commission. The Commission accepts the contracts for filing only. Unless requested by the utility, the contracts are available to the public during normal business hours. The Commission acts individually on the confidentiality of contract requests made by utilities.

Question

4. Is there any type of information regarding direct gas purchase contracts that you do not now receive that you believe would be helpful to the Commission in its review? Describe briefly.

Answers

California: Legal analysis of contracts that has been done by the utility. (e.g. interpretations of "best efforts," and "marketability.")

Connecticut: Survey-type information as a standard for evaluating LDC action.

Delaware: Reasons why LDCs have rejected bids from alternate sources.

Indiana: N/A.

Iowa: None that we can think of.

Kansas: Two types of information would be helpful:
1. Synopses of least-cost strategy methodologies, and
2. Statements regarding the contract as part of the overall supply plan.

Kentucky: Because our formal review process has not yet been implemented, I have no answer at this time.

Louisiana: No.

Michigan: No.

Minnesota: Copies of the contracts. Contracts offered to the utility but not accepted by the utility and the reason for the rejection.

Mississippi: No.

Nevada: No. If additional information is required, the auditor would make a formal request.

New Jersey: No.

New Mexico: No.

New York: No.

North Carolina: No.

Ohio: If these were an external/independent measure of the reliability of the supplies/supplier it would increase our ability to properly judge these contracts.

Oklahoma: Presently staff reviews the entire file and finds no additional information is required at this time.

Oregon: No.

Pennsylvania: No--we can get anything we want.

Rhode Island: N/A.

South Carolina: No.

South Dakota: N/A.

Tennessee: None known.

Utah: The Commission has been able to obtain the information it deemed necessary.

Virginia: N/A.

Washington: Market that the LDC plans to serve with the supply.

West Virginia: Yes, particularly on offers or supply sources not accepted by the utility. It would be helpful to know the proposed delivery point into the utility's system as well as other takes and capacity restrictions at that point in order to determine the physical constraints, if any, on the utility's ability to actually accept that gas throughout the year.

Wisconsin: N/A.

Wyoming: Not applicable.

QUESTION

5. Have any purchased gas adjustment procedures used by your Commission been modified because of the increasing importance of direct gas contracts? Do you anticipate any such change? Describe briefly.

ANSWERS

California: No.

Connecticut: No.

Delaware: PGA requirements have not been modified by the Commission due to direct gas contracts. We do not anticipate any changes in the near future.

Indiana: No change anticipated.

Iowa: Yes. A rulemaking was commenced in October 1986 and the new rules are now in effect.

Kansas: At present, the Commission is considering the benefits, costs, and requirements of developing the contracts into a computer database.

Kentucky: In cases of affiliated entities, increased scrutiny and information requests concerning purchasing contracts have become the rule. Otherwise, only increased interest in gas sources used.

Louisiana: No. No change is anticipated.

Michigan: No.

Minnesota: Utilities making direct gas purchases have received variances from existing purchased gas adjustment rules to pass through the cost of such purchases through the PGA. In addition, the Commission has initiated a rulemaking docket in which it will revise the existing rules to include procedures for direct gas purchases.

Mississippi: None.

Nevada: No.

New Jersey: No.

New Mexico: Not at the present time. Take or pay issues may arise in the future.

New York: No.

North Carolina: Proposals now before Commission.

Ohio: Not exactly. Our purchased gas management/performance audit is expected to be enhanced next year by merging our long-term forecasting review with it. This merger will enable us to look at the long-range strategy of a company's purchasing and facilitate more prospective guidance. However, this change is not solely due to direct gas contracts.

Oklahoma: The purchased gas adjustment clause is determined by actual fuel cost purchased by the utility less fuel level rolled in. As the utility companies purchase gas from new sources, the fuel cost recovery will be adjusted by the incremental difference. Since the Commission approved Purchased Gas Adjustment, clauses are adaptive to current purchases. There will be no reason to anticipate any rulemaking in regards to direct gas contract purchases.

Oregon: We may go from semiannual PGA trackers to quarterly purchased gas adjustment trackers due to FERC proposal in RM 86-14 for interstate pipelines.

Pennsylvania: Our current regulations became effective in 1985 and no changes are anticipated at this time.

Rhode Island: No.

South Carolina: The Commission recently issued Orders providing for annual hearings to address the Company's purchasing policies and procedures.

South Dakota: N/A.

Tennessee: A proposed PGA modification would ensure that all gas costs are recovered through a "Balance Account."

Utah: There have been no recent modifications of procedures. A "pass-through" procedure and the use of a "gas balancing account" were implemented earlier with the passing of the NGPA.

Virginia: Certain case-by-case revisions in PGA provisions have been made to eliminate lags inherent in the historic PGA mechanisms. These lags prevented ratepayers from seeing the full impact of lower gas costs attributable to spot purchases until twelve months after the purchase took place. The Commission intends to conduct a generic proceeding to develop policies governing gas purchasing practices and to address any necessary modification to the PGA mechanism.

Washington: No.

West Virginia: Yes. Rule 43 requiring the bid procedures and the detailed contract and offer information set forth in answer to item 2 above was adopted in 1983 as an effort to induce local distribution utilities to enter into more local producer contracts as well as more spot gas contracts. The Commission also recently enacted a rule requiring open access transportation by local distributors and intrastate pipelines. No additional changes are anticipated.

Wisconsin: No modifications. However, PGAs are now being submitted on almost a monthly basis. We will also investigate PGA process and policy in the July '87 generic investigation.

Wyoming: No.

QUESTION

6. Is there any requirement for a distributor to show that its direct gas purchases or lack thereof are an effective part of an overall least-cost gas purchasing policy? Describe briefly.

ANSWERS

California: Yes, in the PGA process, they must minimize cost subject to constraints, i.e. take or pay, minimum take provisions, alternative supply prices. These are the bases of a prudence review.

Connecticut: Implicitly in PGA monthly proceedings.

Delaware: There is no formal requirement for an LDC to show that its direct gas purchases are an effective part of an overall least-cost gas purchasing policy. Overall gas purchases are reviewed as part of the utility's annual and semiannual fuel filing for rate changes.

Indiana: The Indiana Code, I.C. 8-1-2-42 (g)(3)(A), requires gas utilities to make every reasonable effort to acquire long-term gas supplies to provide service at the lowest gas cost reasonably possible.

Iowa: Yes. See Iowa Administrative Code 199--19.11 and other new rules especially IAC 199--19.11 (3)-(5).

Kansas: The Commission currently evaluates the issues of overall least-cost gas purchasing policies in terms of rate case proceedings. Also, see Docket Number 106,850-U, page 24.

Kentucky: In a rate case that could become an issue now when it hasn't in the past. In our purchase review beginning this Fall, we will be looking for least-cost purchases consistent with supply reliability.

Louisiana: No.

Michigan: Yes. State law (1982 PA 304) requires that utility gas cost plans be reasonable and prudent.

Minnesota: Utilities must file an annual report. This report is reviewed at a separate Commission meeting. The report is part of the Commission rules. The part dealing with planning is 7825.2800 which says "All public utilities shall file annually on September 1 of each year the procurement policies for selecting sources of fuel and energy purchased ... and a summary of actions taken to minimize cost."

Mississippi: Yes - mostly during rate hearings.

Nevada: Yes. New statute. The Commission has not made any regulations yet.

New Jersey: LDCs are encouraged to purchase whenever they can.

New Mexico: Yes. Every two years a gas utility must justify its continuance of purchased gas adjustments, and as such, must show that it is making a reasonable attempt towards a least-cost gas purchasing policy.

New York: Least cost reliable purchasing practices are required and supporting evidence must be submitted with all major rate filings. This would include direct gas purchases.

North Carolina: No, but the Public Staff could raise the issue.

Ohio: Yes. As a part of the management/performance audit of gas procurement, the volume and price of each supply source is evaluated and parties may challenge the company's purchases based on alternatives that would have represented least cost. The Commission attempts to balance the concept of least cost with an assessment of supply reliability, therefore the lowest cost gas is not always the optimal purchase.

Oklahoma: Currently there isn't any requirement for a least-cost gas purchasing policy. The Commission performs fuel audits every six months and monitors their fuel procurement practices.

Oregon: No specific written requirement. However rates have always been set based on using the lowest cost gas available.

Pennsylvania: Yes. State law requires the Commission to examine whether a least cost gas procurement policy is being followed.

Rhode Island: No.

South Carolina: No.

South Dakota: N/A.

Tennessee: No.

Utah: There is no specific requirement to justify the inclusion or exclusion of direct gas purchases as part of a "least-cost" purchasing policy. The gas "mix" of each utility, especially the major gas company, is reviewed in each case for its efficiency.

Virginia: Not at this time. The generic proceeding described above could result in such a requirement.

Washington: Yes. We have specifically required by rulemaking that LDCs submit to the Commission on an annual basis their least cost acquisition plans.

West Virginia: Yes. See response to item 1b above. However, in practice, the Commission interprets least cost purchasing with many qualifications; for example, considering take-or-pay and minimum bill requirements, considering whether the wells from which the gas supply is offered have in fact been drilled, etc.

Wisconsin: N/A.

Wyoming: Yes, the utility has the burden of proof of supporting any of its cost. The utilities are required to provide the most reliable "least" cost of service to their consumers. This also includes gas contracts.

QUESTION

7. Are prices or other terms of direct gas contracts subject to prudence or prudence type review? If so, briefly describe the circumstances and results of a recent review, if any.

ANSWERS

California: Yes. Some small contracts have been found imprudent, compared to alternatives.

Connecticut: Yes. All to date have been in lieu of higher priced gas.

Delaware: This Commission does not conduct prudence audits. If prudence matters evolve, they are evaluated as part of either a fuel or rate case application.

Indiana: To date, the Indiana Commission has only denied the recovery of one utility's non-pipeline gas costs because the price of the gas including transportation charges exceeded the utility's average pipeline supplier's rate. This was done through the gas cost adjustment procedure. We didn't actually review any contracts.

Iowa: Yes. Same response as #6.

Kansas: The Kansas Corporation Commission does not undertake formal prudency review proceedings. Rather, the net effect of price strategies and the impact of contract terms are considered in terms of rates as appropriate to rate case hearings.

Kentucky: Prices are reviewed in PGAs. Any unusually high prices are subject to investigation.

Louisiana: No.

Michigan: State law (1982 PA 304) requires each utility to file an annual gas cost recovery plan which is subject to formal hearings to determine if the plan is reasonable and prudent.

Minnesota: 1. Gas costs are subject to review in the annual automatic adjustment reports review. The Commission could initiate an investigation if it finds prudence of direct gas contracts to be an issue. 2. Gas costs are subject to review in general rate cases. If the Commission finds rate case gas costs to be imprudent, it could disallow a portion of the costs.
To date, the Commission has not taken these steps.

Mississippi: Yes, during rate hearings to determine the competitive price.

Nevada: Yes, as are any utility expenses. We do not know of any special reviews.

New Jersey: Yes, as a part of rate case proceedings.

New Mexico: Yes.

New York: Brooklyn Union Gas - Commission issued show cause order to BUG to justify purchases from FRI (an affiliate) at a higher unit rate than other purchases. Order rescinded when contract renegotiated bringing prices in line. National Fuel Gas--In rate proceeding contract for purchases from Paragon was disallowed and contract disapproved when price escalation clause in contract resulted in uneconomic rate.

North Carolina: Could be (see #6).

Ohio: Yes, as a part of (6) above. In one case last year, a company's purchases from an affiliate producer were scrutinized. No finding of imprudence was made since the cost was as low or lower than other purchases and this source was curtailed first when oversupplies occurred.

Oklahoma: Staff recently reviewed a non-recoupable take or pay settlement which an Oklahoma utility company paid to a gas producer. In performing this task, staff reviewed the following areas:

A. Is the settlement agreement dollar amount less than what the producer initially claimed as the take or pay amount?
B. Does the settlement require less purchase quantity from the producer?
C. Does the settlement agreement provide a lower price?

Staff concluded the settlement was prudent and recoverable from ratepayers.

Oregon: These issues are considered in general rate case reviews. The distributor may be left at risk for gas cost savings that he doesn't achieve.

Pennsylvania: Yes ... all sources of gas are examined for prudency and costs can be disallowed if found to be imprudently incurred; that is, not recovered from ratepayers.

Rhode Island: No.

South Carolina: The Commission recently issued Orders providing for annual hearings and the prudency issue will be addressed in the hearings.

South Dakota: N/A.

Tennessee: Yes. Subject to review but none have been made recently.

Utah: Prudence is a major concern in all reviews. Nothing noteworthy has resulted from the most recent reviews.

Virginia: Not at this time.

Washington: No.

West Virginia: Yes--to the extent the terms represent least cost purchasing; if not, the Commission may impute a cheaper available priced supply. The Commission exercises more control over affiliated transactions because of the requirement for prior review. In a recent non-affiliated transaction, the Commission refused to impute a cheaper priced supply because of the FERC minimum bill rule and the fact that local wells had not yet been drilled. (Equitable Gas Company, Case Nos. 83-375-G-30C and 84-499-G-30C). In a recent affiliated case, the Commission repriced affiliated purchases from $3.20/dth to $2.90/dth to reflect more market oriented prices (Mountaineer Gas Company, Case No. 86-250-G-PC).

Wisconsin: See #5 & #2.

Wyoming: Only if they become contested issues during a general rate filing, pass-on, balancing account adjustment or Commission ordered investigation.

QUESTION

8. Does the Commission include in its review any assessment of the riskiness of a distributor's contracts? This might take the form, for example, of a comparison of the riskiness of long-term contracts, perhaps containing a requirement for a minimum volume to be purchased, versus that of shorter term contracts, such as those for spot market gas.

ANSWERS

California: Yes. Especially pricing terms. Ex: 1) structured with price formula that tied price of gas to the rate of return on the producer's rate base (like public utility regulation); 2) weighted average cost of gas of all long-run gas supplies. (Note: The California Commission is suspicious of those sorts of terms.) Supply security is not much of an issue.

Connecticut: Gas companies use firm contracts for guaranteed supply. Direct purchases are purchases in lieu of firm supplies.

Delaware: This issue has not occurred at this time.

Indiana: Not yet.

Iowa: The only specific guidelines are those that can be interpreted from the enclosed rules.

Kansas: Not at the present time.

Kentucky: Not at this time. Risk will be a factor considered in upcoming reviews.

Louisiana: No.

Michigan: Supply reliability is one of the factors considered by the Commission.

Minnesota: There are no specific provisions for the review.

Mississippi: No.

Nevada: No, there are no specific standards established.

New Jersey: Yes.

New Mexico: Yes.

New York: Yes, in a general way, but there have been no written guidelines or decisions on the issue.

North Carolina: Yes.

Ohio: Yes, see Ohio's answer to question 6 above. The concern about risk has to do with the company's ability to continue to provide firm supplies to its captive markets. With the long-term interstate pipeline contracts still in place, however, direct purchases currently function as short term price optimizers. This is expected to change as the industry stabilizes.

Oklahoma: Staff reviews the utility companies' fuel supply models for fuel supply purchase requirements, projected fuel cost, and supplier mix. Upon review of the utilities' fuel supply models, staff has noticed that their contractual purchase requirements have frustrated their efforts to purchase spot market gas.

Oregon: No.

Pennsylvania: Risk, or service reliability, has not been a factor as yet.

Rhode Island: N/A.

South Carolina: The Commission recently issued Orders providing for annual hearings and this issue will be addressed in the hearings.

South Dakota: N/A.

Tennessee: No.

Utah: Risk of long-term contracts with "take or pay" requirements versus spot market purchases is an important part of the review of gas "mix."

Virginia: Not at this time.

Washington: No.

West Virginia: Yes. The Commission considered the riskiness of local producer contracts versus interstate pipeline supply in Equitable Gas Company's 1983 and 1984 purchased gas proceedings. The Commission also considers long-term versus short-term contract riskiness, but no minimum or optimum requirements have been required by the Commission. One local distributor purchased 62 percent of its supply in the spot market in the 1986-1987 purchased gas period.

Wisconsin: N/A.

Wyoming: No.

QUESTION

9. Does the purchased gas adjustment procedure used by the Commission contain any specific features intended to create an incentive for efficient gas purchasing and supply planning? Describe briefly any feature that creates such an incentive or disincentive, in your opinion.

ANSWERS

California: Not really. Under restructuring, part of the utility's profit will be based on throughput:

1) Core--traditional utility service
2) Non-Core--customer responsible for arranging transportation and must find a supply (can opt for utility to find gas). No prudence review. $1\frac{1}{2}$ percent return on equity (10 percent of profit) is at risk under this plan (for the utility).

Connecticut: Possible disallowance of imprudently incurred costs.

Delaware: No, the PGA clause does not contain this type of feature.

Indiana: In order for the utility to recover its purchased gas costs it must show that it has met the requirements of Indiana Code 8-1-2-42 (g)(3)(A).

Iowa: The ARG rules (IAC 199--19.11) require that the Board "disallow any purchased gas costs in excess of costs incurred under responsible and prudent policies and practices." IAC 199--19.11(5).

Kansas: Under Docket Number 106, 850-U, the Commission may disallow pass through of the costs of gas incurred from a contract deemed imprudent.

Kentucky: No.

Louisiana: No.

Michigan: Yes. See answer 7.

Minnesota: There are no specific provisions in the current rule.

Mississippi: No.

Nevada: No.

New Mexico: No.

New Jersey: Yes. All over-recoveries are subject to interest at the LDC's overall rate of return.

New York: No prescribed features. Incentive is possible penalty for inefficient purchasing after review.

North Carolina: Not at this time.

Ohio: No specific incentives are part of the procedure. However, the company has the burden of proof to demonstrate its purchases provided least cost consistent with reliability of supply. The Commission has the ability to deny recovery of costs which have been judged imprudent.

Oklahoma: The Commission has approved tariffs with the provisions of a 75%-25% split of transportation margins with stockholders, and 90%-10% split off system gas sales. The Commission has approved these tariffs as an incentive to market their expensive gas supplies off system. As a result of the tariffs the utility company's cost of fuel has lowered and their exposure to take or pay claim lawsuits is substantially reduced.

Oregon: We have a tariff mechanism that puts the distributor at risk for 20% of the loss or gain between general rate cases in cost of gas for serving the interruptible market.

Pennsylvania: Yes ... the incentive to follow a least cost gas procurement policy is that otherwise the LDC won't be allowed to recover the cost from ratepayers.

Rhode Island: Yes. Margins from the sale of gas to interruptible customers are "shared" with the company after a "target level" of sales is reached. The target level would be set in a general rate proceeding. The sharing is 75% to firm customers and 25% to the company. This tariff is in effect for only 1 of 4 regulated gas distribution companies.

South Carolina: No.

South Dakota: No.

Tennessee: No.

Utah: There is no particular feature that creates incentives or disincentives to efficient planning. The existence of a review procedure is an incentive for efficient planning in itself.

Virginia: No. Virginia's purchased gas adjustment presently assures full recovery of all gas costs through deferred accounting. One incentive to promote efficient gas purchasing may be to partially eliminate deferred accounting for certain gas costs (i.e. the demand cost of gas).

Washington: No.

West Virginia: The requirements for a bidding procedure and for investigation of all possible supply sources should create an incentive for efficient gas purchasing and supply planning. However, implementation of these requirements by this Commission has weakened the effectiveness of the rule. For example, the requirement to purchase the cheapest readily available source of supply has been weakened by the Commission's apparent requirement that wells be actually drilled to constitute "readily available" supply for repricing purposes. Additionally, the requirement that the proof of least cost purchasing be submitted only in cases where rates are increasing has weakened the effectiveness of the rule in a period such as the current time where excess supply exists and prices are declining.

Wisconsin: N/A.

Wyoming: Yes, Wyoming State Statutes allow gas distributors up to a 10% incentive on reduction in gas costs.

QUESTION

10. Do you have any insights about regulatory review of direct gas purchase contracts that you would like to share with other Commissions? A policy or procedure that has worked well, for instance.

ANSWERS

California: PUC in the past gave prior approval to contracts. Comment: Utilities do not share all info. Utilities should reveal all facts and so on. (e.g. Buyout presentation seemed biased.) Idea is that utilities tell PUC enough to get preapproval and later use that approval as evidence of prudence. But, in reality, not all the facts or issues are presented.

Connecticut: No.

Delaware: We currently do not have a specific policy or procedure that deals with direct gas purchase contracts. However, we would be interested in receiving information from other Commissions to see how they have handled this situation.

Indiana: No.

Iowa: None that we can think of. As indicated in the cover letter, Iowa distributors have not been involved in non-traditional gas purchases long enough for a complete, representative review process to occur. The distributors began making non-traditional purchases, for the most part, last fall, and the 1987 ARG's will be due August 1, so we anticipate the review of the majority of non-traditional contracts to take place during the 1987 proceedings.

Kansas: N/A.

Kentucky: Not at this time. Perhaps after our review has been in place for a year or two.

Louisiana: No.

Michigan: No.

Minnesota: No; we are still reviewing possible procedures for regulatory review for the revision of existing rules and therefore are looking for additional information and procedures that have worked well in other jurisdictions.

Mississippi: No.

Nevada: N/A.

New Jersey: N/A.

New Mexico: N/A.

New York: No.

North Carolina: No.

Ohio: No.

Oklahoma: Staff's procedure for regulatory review of gas purchase contracts is to generically determine what the company's fuel procurement practice is. Once this step is performed, review of the key contractual provisions of gas purchase contracts for confirming the utility's policy is done.

Oregon: Nothing specific. Our utilities have generally acted in good faith to keep gas costs as low as possible in order to retain their interruptible industrial load.

Pennsylvania: The review of gas purchase contracts with affiliated producers has revealed some surprising results. It is especially important to encourage non-affiliated producers to participate in the proceedings to uncover instances where potential gas supplies have not been utilized.

Rhode Island: N/A.

South Carolina: No.

South Dakota: The Commission has not yet specified any policy with regard to direct purchase contracts, but the matter has been a topic for discussion and further attention.

Tennessee: No.

Utah: Utah's major gas distributor and to a lesser extent its other distributor enjoy an accessibility to a variety of gas sources including some utility owned sources. Procedures that work well in Utah might not work as well in other states.

Virginia: N/A.

Washington: No. I do not believe that Commissions should be involved in that phase of utility management. In the State of Washington we have broad statutory language governing the ability of the Commission to set rates. If the utility is not providing service at rates that are fair, just, and reasonable, the Commission may investigate. I believe this applies to the review of gas purchase contracts. Finally I do strongly believe that the interstate pipeline is best equipped to assure an adequate long term reliable supply at least cost to the customer base that has the least alternatives.

West Virginia: Although the West Virginia Commission's least cost gas purchasing policy has been somewhat weakened through implementation on a case-by-case basis, the fact that the policy exists and can be used against utilities in rate cases has a political impact in that utilities feel that they must show good faith compliance. As a result, local production has increased and the local utilities have consequently lowered their gas costs by obtaining cheaper sources of supply in their supply mix.

Wisconsin: Not yet.

Wyoming: N/A.

APPENDIX B

SURVEY OF DIRECT GAS PURCHASE CONTRACTS

The NRRI collected a sample of direct gas purchase contracts between local distributors and producers. The sample forms the basis of the discussion and description of contracts in chapter 3 and the quantitative analysis of the contract prices and terms in chapters 5 and 6. The survey form and the data set are described in this appendix. A copy of the survey is presented so the reader can understand more fully the information used to build the data set. A copy of the data set with explanations about the various contract variables is presented also.

The Survey

The NRRI sent a survey to state commissions in June 1987 to collect information on direct gas purchase contracts. The survey requested information on prices, price adjustment mechanisms, transportation arrangements, gas quality and quantity, contract duration, terms of termination, and overall contract flexibility. A copy of the survey is included at the end of this appendix. In all, information on about 100 contracts was obtained. In most cases the contract itself was made available to the NRRI. Some commissions chose to reply on the survey form.

The Data Set

The data set contains information on long-term contracts only, that is, contracts longer than one month. There are 28 such contracts, each contract constituting one observation in the data set. This is the largest sample that could be fashioned for which all information was available, including a corresponding spot price and all contract terms. The contracts are described by the following fourteen variables: state, contract date, contract price, spot price, fixed price adjustor, alternate fuel price adjustor, market index price adjustor, time between renegotiations, negotiation sequence, market-out clause, take-or-pay clause, minimum-take clause, price difficulty index, and quantity difficulty index. A copy of the data set is listed in table B-1.

The variable "state" refers to the location of the buyer. The data set contains contract information from Kentucky, Ohio, Michigan, and Mississippi. The contract date is when the contract became effective. The contracts cover the period from February 1985 to June 1987 with nine contracts becoming effective in 1985, ten becoming effective in 1986, and nine becoming effective in 1987.

The contract price and spot price are delivered prices per Mcf, that is, they include transportation costs. Contract prices averaged $2.45 per Mcf, ranging from $1.85 to $3.26 per Mcf. Spot prices averaged $2.25 per Mcf, ranging from $1.62 to $3.20 per Mcf. The average difference between contract and spot prices is 20 cents per Mcf.

The variables indicating the presence or absence of a fixed price escalator clause, an alternate fuel price escalator clause, and an escalator based on some other gas price identify various mechanisms used to reset price throughout a contract's life. The variable is coded as 1 if the pricing mechanism is used, 0 otherwise. A contract has a fixed price escalator if the price is fixed from inception or if it has an escalator clause specified as a fixed percentage. If price is directly tied to an alternative fuel price, the contract is recorded as having an alternate fuel price escalator. When a price paid for another source of natural gas is used to adjust price, then the contract is recorded as having a gas price escalator. In the sample, seventeen contracts do not specify how prices are reset but simply state that prices are renegotiated at periodic intervals. Seven contracts use two or all three pricing mechanisms to adjust delivered prices throughout the contract's life.

The take-or-pay clause and minimum-take clause variables describe volume conditions placed in contracts. Both variables are fractions from 0 to 1. A value of 0 means that a contract has a 0 percent take-or-pay or minimum-take level, whereas a value of 1 implies a 100 percent take-or-pay or minimum-take clause. Seven contracts have a take-or-pay clause, and fourteen contracts have a minimum-take clause. All contracts having a take-or-pay clause have a minimum-take clause.

The variables "time-between-renegotiations", "negotiation sequence", and "market-out clause" reflect the ability of the buyer and seller to adjust price when future market conditions change. The time between renegotiations is recorded in months. Thirteen of the twenty-eight contracts renegotiated or readjusted price at least once every six months. The variable "negotiation sequence" has three values depending on which party initiates the process. The value -1 appears if it is the buyer, the value 1 appears if it is the seller, and the value 0 appears if both parties initiate the process or if a preagreed pricing mechanism is employed. In twelve contracts the buyer initiates the price redetermination process, in fifteen contracts both parties initiate the process, and in one the seller initiates the negotiating process. The variable "market-out clause" has the value 1 if the buyer can refuse unmarketable gas and the value 0 if otherwise. The market-out clause appears in thirteen contracts.

Two variables are used to measure the difficulty of changing price and volumes taken throughout the life of the contract. The values assigned to these variables are based upon contractual terms that affect future flexibility of prices and volumes. The index measuring price adjustment difficulty depends on the time between renegotiations, the negotiation sequence, and the various pricing mechanisms. The quantity adjustment difficulty index depends on the take-or-pay clause, the minimum-take clause, and the market-out clause. Both indices take on values between 1 and 4 with the value 1 implying little difficulty in adjusting price or volumes taken, and the value 4 implying great difficulty in making adjustments. Twenty-one contracts have a price difficulty index between 1 and 2.5 whereas sixteen contracts have a quantity difficulty index in this range. There are thirteen contracts having both indices below 2.5 indicating relative ease of adjusting both price and volumes taken.

TABLE B-1

DATA SET OF DIRECT GAS PURCHASE CONTRACTS

State	Identifier	Contract Date	Contract Price (Mcf)	Spot Price (Mcf)	Fixed Escal.	Alt. Fuel Escal.	Gas Price Escal.	Time Between Negotiation	Negotiation Sequence	Market Out Clause	Take-or-Pay Clause	Minimum Take Clause	Price Difficulty Index	Quant. Difficulty Index
KY	D	Feb. 85	3.26	3.20	0	0	1	6	0	0	0	0	2.0	1.5
KY	K	Mar. 85	3.25	3.14	0	0	1	1	0	0	0	0	2.0	1.5
KY	C	Aug. 85	3.14	2.94	0	0	0	6	-1	1	0	0	2.0	1.0
KY	S	Sep. 85	2.50	2.39	0	0	0	12	0	0	0	0	3.0	1.5
KY	Q	Nov. 85	2.50	2.39	0	0	0	12	0	0	0	.33	3.0	2.5
KY	O	Nov. 85	2.70	2.59	0	0	1	6	-1	0	0	0	2.0	1.3
KY	P	Jan. 86	2.45	2.39	0	0	0	1	1	0	0	0	1.0	1.5
KY	J	Aug. 86	2.00	1.90	0	0	0	6	-1	1	0	0	2.0	1.0
KY	F	Oct. 86	2.00	1.86	0	0	0	6	-1	1	0	0	2.0	1.0
KY	L	Feb. 87	2.25	1.98	0	0	0	12	0	0	0	.25	3.0	2.5
KY	M	Feb. 87	2.03	1.98	0	0	0	12	0	0	0	.50	3.0	2.8
KY	A	May 87	2.00	1.85	0	0	0	6	-1	1	0	0	2.0	1.0
KY	B	May 87	2.00	1.85	0	0	0	6	-1	1	0	0	2.0	1.0
KY	G	May 87	2.00	1.80	0	0	0	6	-1	1	0	0	2.0	1.0
KY	H	May 87	2.00	1.80	0	0	0	6	-1	1	0	0	2.0	1.0
KY	I	June 87	2.00	1.74	0	0	0	6	-1	1	0	0	2.0	1.0
MI	U	Oct. 85	3.00	2.74	1	1	1	12	0	0	.68	.60	2.5	3.3
MI	X	Nov. 85	3.00	2.59	1	1	1	108	0	0	.90	.60	2.5	3.7
MI	Y	Jan. 86	3.01	2.89	0	1	1	12	0	1	1.00	1.00	2.2	4.0
MI	V	May 86	2.40	2.07	1	0	1	240	0	0	.54	.20	2.5	3.0
MI	Z	July 86	2.80	2.25	1	1	1	12	0	1	1.00	1.00	2.4	4.0
MI	W	Apr. 87	2.50	1.96	1	1	1	69	0	0	.85	.50	2.5	3.5
MI	AA	May 87	2.40	2.00	1	1	1	84	0	1	.90	.60	2.4	3.7
MS	T	Oct. 86	1.85	1.62	0	0	0	12	0	0	0	.50	3.0	2.8
OH	CC	July 85	3.00	2.88	0	0	1	180	0	0	0	.50	2.5	2.8
OH	BB	May 86	2.50	2.08	0	0	0	180	0	0	0	.50	4.0	2.8
OH	DD	Oct. 86	2.25	1.87	0	0	0	36	0	0	0	.50	3.5	2.8
OH	EE	Oct. 86	1.88	1.87	0	0	0	3	0	0	0	0	1.5	1.0

Source: The NRRI Survey

THE NATIONAL REGULATORY RESEARCH INSTITUTE

DATA REQUEST FOR

DIRECT GAS PURCHASE CONTRACTS AND PRICES

The NRRI is collecting a sample of direct gas purchase contracts between local gas distributors and producers that were entered into between July 1985 and June 1987, and the prices (possibly month to month) that have prevailed since each contract's inception. The data will be used in a quantitative analysis to determine whether and to what extent the gas market assigns a price premium for various contractual provisions.

We recognize that the contracts may be proprietary in some state jurisdictions and may be part of the public record in others. Our sample shall be proprietary, in any case, and will not be shared with others without permission. In addition, we do not need the supplier's name, but only his general location. Anonymity can be assured for any contract by omitting the supplier's name.

We would like to have, for each jurisdictional distributor that has such contracts,

a) Five or more representative spot market contracts and the associated price history (as available) from July 1985 to June 1987, and

b) Five or more representative longer-term contracts and the associated price history (as available) from July 1985 to June 1987.

We request the data be provided in one of two ways, at your option:

a) You could send a copy of the actual contract, (possibly with the supplier's name omitted and other, more general location information substituted, such as the state or country of the gas well) and include a separate price history sheet attached to each contract. A worksheet to record the prices is included. Please copy this worksheet as needed.

or b) You could fill out the enclosed contract description form that can be used to describe the general nature and specific provisions of a single contract, and include a separate price history sheet attached to the description of each contract.

PRICE HISTORY WORKSHEET

(Data Request for Direct Gas Purchase Contracts)

Name of local distribution company:

Identification of contract:

Unit in which price is expressed:
(Mcf, dth, MMBtu, etc.)

Commodity Price:

1985:	July____	Aug____	Sept____
	Oct_____	Nov____	Dec_____
1986:	Jan_____	Feb____	March___
	April___	May____	June____
	July____	Aug____	Sept____
	Oct_____	Nov____	Dec_____
1987:	Jan_____	Feb____	Mar_____
	April___	May____	June____

Describe any contractual payments other than the commodity price, which might take the form, for example, of a fixed fee paid to a producer for his maximum daily delivery rate:

CONTRACT DESCRIPTION FORM

(Data Request For Direct Gas Purchase Contracts)

(Please use the following codes, if needed: N.A. Not applicable; N.K. Not known by respondent; N.Av. Not available; N.S.P. No such provision in contract.)

A. Name of local distribution company:
Name of person for further contact:
Phone:

Identification of contract:

Location of supplier (county, state):

Date contract was effective:

Duration of contract (including any provision for extension):

Delivery Point:

B. Transportation.

1. Arranged by Buyer? Yes ____ No ____
2. Arranged by Seller? Yes ____ No ____
3. Transportation fee up to delivery point:
    a. None ________
    b. Included in commodity price? Yes ____ No ____
    c. Buyer/Seller ________ pays a separate fee of ________ per Mcf/MMBtu/dth.

4. Interconnection lines up to delivery point:
   Owned by seller or buyer or third party? ________

5. Third party transportation is used? Yes _____ No _____

   a. Transportation fee is (if available) ________

   b. Volumes can be curtailed due to a shortage of transportation capacity? Yes _____ No _____

6. Seller retains processing rights after delivery to buyer?
   Yes___ No ___

C. Quality of gas.

1. Minimum Btu content:____________________
2. Pressure specifications:_______________
3. Temperature specifications:____________
4. Maximum Sulphur:_______________________
5. Maximum water vapor:___________________
6. Maximum carbon dioxide:________________
7. Specific Gravity:______________________
8. Other (specify):____

   ____

D. Gas quantity or volume.

1. Reserves are dedicated? Yes ____ No ____
   or, "all gas for life of well"? Yes ____ No ____

2. Minimum takes are specified? Yes ____ No ____
   If so, these are expressed as (give the amount):

   Minimum Monthly Volume? ____________________

   A percentage of the
   Average Volume? ________________________
   Maximum daily volume? _________________

   A minimum number of days during
   which gas is to be taken? _____________

   Other? ______________________________________

3. Maximum takes are specified? Yes ____ No ____
   If so, these are expressed as (give the amount):

   Maximum daily quantity? ______________________

   Some multiple of the average take? ___________

   Other? ____

4. Supply is interruptible? Yes ____ No ____

   If so, required notice is ____________

   Notice is given by:
   Buyer ____ Seller ____ Either ____

Gas quantity (cont.)

5. Volumes are adjusted within contract period? Yes____ No____

If so, allowable frequency is ____________________________

The process for determining the next period's volume can be described as:

Buyer gives notice, seller accepts or rejects? _______

Seller gives notice, buyer accepts or rejects? ________

Buyer and seller confer simultaneously?_______

All volumes are on a "best efforts" basis?______

E. Price of gas

(Please show actual prices on the price history worksheet. This section describes contractual features governing the price.)

1. Price is fixed for duration of contract? Yes_____ No_____

2. If the price is adjusted within the contract period, it is governed by:

a. An escalation clause? Yes_____ No_____

If so, the index is______________________________

____

b. A renegotiation clause? Yes_____ No_____

If so, the frequency (e.g. monthly) is___________

____

c. A cost recovery clause? Yes_____ No_____
If so, which of the producer's cost components are included?

____

____

____

d. Other?____

____

3. The process for redetermining the price can be described as:

a. Buyer gives notice of new price, seller can accept or reject? Yes_____ No_____

b. Seller gives notice of new price, buyer can accept or reject? Yes_____ No_____

c. Buyer and seller negotiate bilaterally? Yes_____ No_____

d. Other____

____

e. The notice procedure used by buyer or seller applies to:
This contract only? Yes_____ No_____

All interested parties? Yes_____ No_____

Other?______________________________

F. Contract termination features.

1. Contract contains a force majeure clause? Yes_____ No_____

2. Contract contains a so-called "economic" force majeure clause which is invoked under adverse market conditions? Yes_____ No_____

3. Contract contains a "market out" clause? Yes_____ No_____

4. Contract can be terminated with__________(days, months) notice given by buyer_____, seller_____, or either party_____?

5. Other?____

____

APPENDIX C

A TECHNICAL INTRODUCTION TO DATA ENVELOPMENT ANALYSIS

There are a variety of techniques that can be used to gauge the performance of production units. Many of these, including total factor productivity indices, cost function estimation, and subjective techniques like the analytical hierarchy process, have been examined and reported on in prior NRRI publications.[1] This appendix presents a technical outline of a method for measuring efficiency that belongs to a different class from those heretofore presented in NRRI reports. The general idea in this class, as mentioned in chapter 6, is to estimate an efficiency frontier. Such an approach is likely to have multiple applications in public utility regulation, and for this reason this appendix is intended to provide a rigorous introduction for those state commission staff members who may wish to explore the method further.

Background

Data Envelopment Analysis emerged from economics and operations research in an attempt to bridge the gap between the theoretical notion of a production function and its empirical estimation. For any process that has outputs or outcomes resulting from some inputs, the production function defines the optimal relationship between these inputs and the outputs or outcomes. Efficiency or effectiveness of a particular process is measured

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[1] See, for example, L. Anselin and J. S. Henderson, A Decision Support System for Utility Performance Evaluation (Columbus, OH: National Regulatory Research Institute, 84-15, April 1985).

in terms of its distance from this production function. A variety of efficiency measures exists. The most basic is <u>technical</u> efficiency. A process is said to be technically efficient if it produces the maximal output as determined by the production function for its given set of inputs. When the prices of the inputs are known then a technically efficient process is said to exhibit <u>allocative</u> efficiency if it produces a given output at least cost. A process exhibits <u>scale</u> efficiency if its scale or size of operation is optimal in the sense that reducing or increasing its size makes the process less efficient.

We limit the discussion to the measurement of technical efficiency in what follows. A simplified graphical description is used to clarify concepts.

Consider a number of units with the same process producing one output from two inputs. The shaded area in figure C-1 represents the scatter of these units in a two dimensional representation where input per unit of output is measured along the axes. There are a number of functional forms (Cobb-Douglas, CES, trans-log) that can be used to approximate the input-output process. Their parameters can be estimated by fitting the function

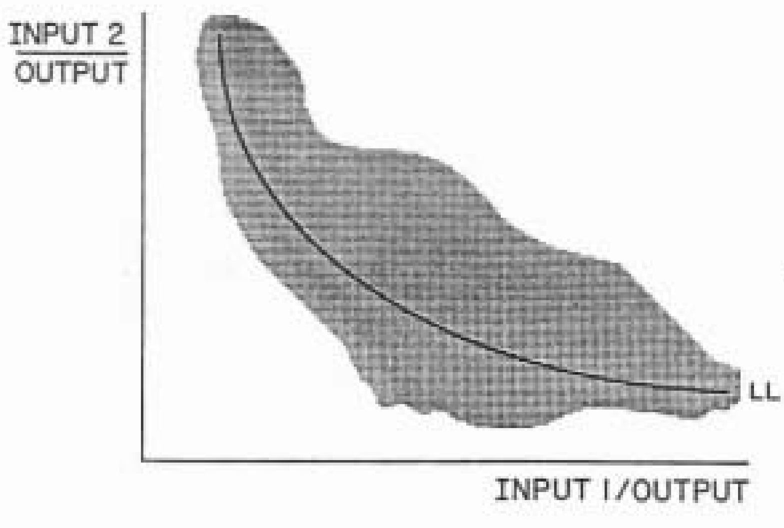

Fig. C-1 Hypothetical input-output data

to the data in the scatter diagram. The usual approach is to obtain the "best fit" to the data by minimizing the sum of the squared error (ordinary least squares) of the data points from the fitted curve. Such a procedure yields a line through the data cloud similar to LL. This line is obtained under the assumption that the deviations of the data points from the curve result from random error; hence, points are on both sides of the curve. Such a function cannot be readily used for obtaining measures of efficiency since some of the data, on one side of the line or the other, exhibit super-efficiency. Since each point represents output per unit of input, the efficient units are those that are closest to the bottom left hand corner in figure 1.

To overcome the problem of super-efficient points, DEA identifies a production-possibility frontier. This frontier is obtained by identifying all the extreme points closest to the axes joining them.

Point B in figure C-2 is more efficient than D by virtue of the fact that it requires less of both input 1 and input 2 to produce unit output than does D. It is not clear, however, whether C is more efficient than A. DEA solves this problem by defining all the extreme points closest to the axes as efficient. The efficient frontier, then, is obtained by connecting all the extreme points. Thus, QABCQ' forms the production frontier. Efficiency is measured in terms of distance from this frontier. Farrell provided this analysis three decades ago.[2] An index of efficiency can be based on distance along a ray from the origin. That is, the efficiency of D can be expressed as the ratio of the distance of the frontier from the origin to the distance of the point D along a ray from the origin. The efficiency of D, then, is

$$\frac{OD'}{OD}$$

where OD denotes the distance from the origin to the point D. It immediately follows that any point on the frontier has an efficiency score of unity. Farrell's measure of efficiency, therefore, ranges from almost

[2] Farrell, M. J., "The Measurement of Productive Efficiency," <u>Journal of the Royal Statistical Society</u>, A 120, part 3, (1957): 253-281.

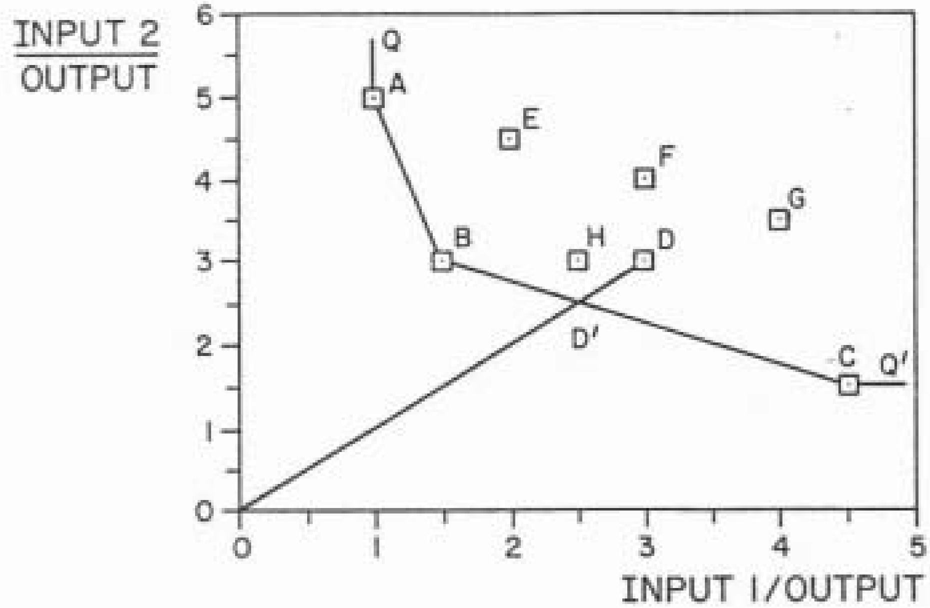

Fig. C-2 An input-output efficiency frontier

zero to unity, where unity denotes efficient performance.

The piecewise linear representation of the production frontier, QABCQ', together with its mathematical programming formulation was first proposed by Charnes, Cooper, and Rhodes.[3] We present next a more formal formulation of the DEA problem.

Mathematical Programming Formulation

Several variants of linear programming formulations exist for measuring Farrell's index of efficiency. The following implementation from Schinnar for the single-output multiple input production process corresponds to the graphical description in figure C-2.[4] The linear program for estimating the

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[3] Charnes, A., W. W. Cooper, and E. Rhodes, "Measuring the Efficiency of Decision Making Units," Eurpean Journal of Operational Research, 84 (August 1976): 655-676.
[4] Schinnar, A. P., "An Algorithm of Measuring Relative Efficiency," Fels Discussion Paper No. 144, University of Pennsylvania (August 1980).

relative efficiency, ρ, of a productive unit a_o given a set of units $a_1, \ldots, a_n$, which includes a_o, is

$$\begin{array}{lll} \text{minimize} & \rho & \text{(C-1)} \\ \text{such that:} & -A\mu + \rho a_o \geq 0 & \text{(C-2)} \\ & e\mu = 1 & \text{(C-3)} \\ & \mu \geq 0,\ \rho \text{ unrestricted} & \text{(C-4)} \end{array}$$

where

- A is a mxn matrix with columns corresponding to n production units and rows corresponding to m inputs. The columns of A form the points in the input space. A typical element a_{ij} denotes the amount of factor input i (or x_{ij}) per unit of output of unit j (or y_j) or $a_{ij} = x_{ij}/y_j$;
- a_o is a mx1 column of A corresponding to a production unit whose efficiency we seek to measure;
- μ is a nx1 vector defined by the unit simplex $e\mu = 1$, $\mu \geq 0$ where $e = (1,1,\ldots,1)$; and
- ρ is a scalar called "Farrell's index of efficiency." ρ is unrestricted but assumed positive.

Solution

The DEA index of efficiency can be obtained graphically when the process under consideration has a single output and two inputs or when there are two outputs and a single input.

We use the data in table C-1 for illustrative purposes. Figure C-2 represents a scatter plot of the data and QABCQ' is the best practice frontier. The points A, B, and C are efficient. The efficiency of D is OD'/OD. D is the point (3,3). Some simple coordinate geometry will show that D' is the point (2.5, 2.5) and that the efficiency score for D is 0.83.

A similar analysis in the output space yields figure C-3 where the axes represent output per unit of input. The measure of efficiency is the reciprocal of that in the input space. Hence, the efficiency score for S is OS/OS'. Note that this analysis in the output space corresponds to the examples provided in chapter 6.

TABLE C-1

ILLUSTRATIVE DATA

	INPUT PER UNIT OF OUTPUT	
Contract	1	2
A	1	5
B	1.5	3
C	4.5	1.5
D	3	3
E	2	4.5
F	3	4
G	4	3.5
H	2.5	3

Source: Authors' calculations.

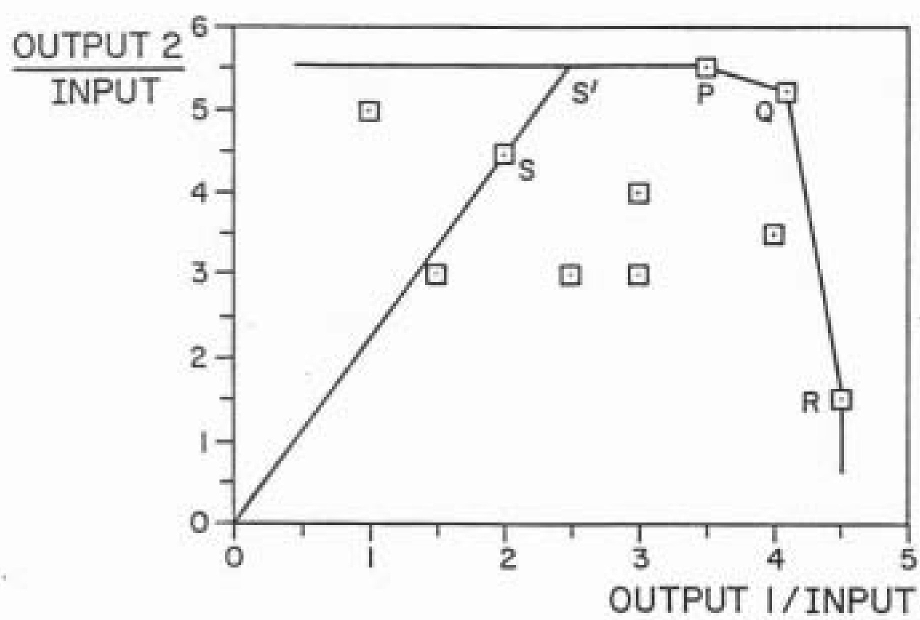

Fig. C-3 An output-input efficiency frontier

Figures C-2 and C-3 are useful only when the inputs and outputs can be represented in a two dimensional plane. A more general formulation, which simultaneously accommodates multiple inputs and multiple outputs, may be written as

$$\begin{array}{llr} \text{minimize} & z & \text{(C-5)} \\ \text{such that:} & -Y\lambda + zy_o \geq 0 & \text{(C-6)} \\ & X\lambda \leq x_o & \text{(C-7)} \\ & \lambda \geq 0 & \text{(C-8)} \end{array}$$

where

- Y is a r x n matrix with columns corresponding to n production units and rows corresponding to r outputs;
- X is a m x n matrix with columns corresponding to n production units and rows corresponding to m inputs;
- y_o is a r x 1 vector of outputs for the unit being evaluated;
- x_o is a m x 1 vector of inputs for the unit being evaluated;
- λ is a n x 1 vector of positive scalars;
- z is the reciprocal of Farrell's index of efficiency.

A computer algorithm is needed to calculate the efficiency indices when there are many production units. The basic task is to solve the mathematical program (C-5) - (C-8), once for each unit to be evaluated. Efficient algorithms that exploit the geometry of the data space have been developed. These do not necessarily require solving as many mathematical programs as there are data points.

Some of the essential features and capabilities of Data Envelopment Analysis are briefly summarized, below. The context of the following summary is that of public services being provided through a number of centers that are to be compared.

Best practice or frontier analysis - Estimates of performance (efficiency or effectiveness) are based on an extremal principle of converting input resources into outcome indicators. Performance is determined relative to the best pattern of service delivery or contract characteristics found in practice rather than based on a theoretical construct.

Comparison - Performance appraisal is a relative concept based on comparison of the operations of comparable contracts or centers. Specifically, for each center, the index of efficiency is a measure of the service output level that a center can attain with its given resources.

Effectiveness - The performance appraisal measurement distinguishes between effectiveness, efficiency, and productivity. Effectiveness is a reference to outcomes achieved relative to a set of standards which are usually taken to reflect minimal levels of practice. The DEA approach defines goals as the combination of best outcomes shown to be practically attainable, and measures program effectiveness of each center relative to the best practice of performance.

Efficiency and Productivity - are two reciprocal concepts: input efficiency shows what reduction in resources or inputs could still provide the same level of service outcomes, while output productivity measures the potential improvement of outcomes (or output indicators) that has been shown to be practically attainable with no more resources that are presently in use.

Multiple outputs and multiple inputs - The DEA method uses information on program outcomes (outputs) achieved and program resources (inputs) used, and allows for simultaneous incorporation of a multiplicity of such measures. The number of input and output measures is limited only by the number of observations used in the comparative analysis. Practical experience suggests that the ratio of measures (variables) to observations should not exceed 1 to 10.

Controls - Using production or contract characteristics as controls in the analysis, it is possible to identify the portion of inefficiency attributable to the economic conditions and the portion attributable to managerial inefficiency. In this manner, improvements in performance under the control of program managers can be distinguised from those that are not at their discretion.

Comparison groups and case studies - The DEA methodology uses the technology as it is reflected in the mix of inputs used and the combination of outputs achieved, in order to partition the entire set of observations (centers) into comparison groups. A comparison group thus consists of a subset of centers or contracts having similar characteristics (technology) and outputs. The centers or contracts within each comparison group are divided into efficient and inefficient units to guide follow-up evaluations of non-measurable factors that might help understand or improve the service quality.

Contract specific analysis and structural analysis - An important feature of the method is that, in addition to data being center-specific or contract-specific, the results of the analysis are also provided in terms of each specific center. Unlike statistical (e.g., econometric) techniques where the analysis is based on the means and variance of the complete data base and the results reflect the aggregate features of the sample, the DEA method yields a wealth of information pertinent to each observation (center) as well as structural (aggregate) results on the performance of the entire program.

Longitudinal monitoring of performance improvement - The methodology is well suited for processing longitudinal information about a contract's performance in order to monitor progress in performance improvement. The use of longitudinal information enables continuous monitoring of the effects of various remedial policies on the performance of service centers, thereby providing immediate feedback that is invaluable for improving the management of service delivery.

Contract models and choice of variables - The methodology does not pose any restriction on the choice of variables, which is left to the analyst. It should be noted, however, that any subset of input and output indicators also constitutes a model or description of contract performance. It is advisable, therefore, that alternative representations of the process be explored in an analysis of performance, as it is possible that the evaluation of a contract may depend on the set of variables used.

Units of analysis and observations - In assembling the needed data for analysis we distinguish between units of measurement and units of analysis. A unit of measurement is an "observation" in the data-collection effort. It is largely determined by the availability, reliability and level of aggregation in which data are found. A unit of analysis is a service delivery unit or a gas distributor whose performance is to be measured. The distinction between a unit of analysis and an observation gives the analysis added flexibility. Multiple observations on the contract from a single distributor allows performanced to be tracked over time, for example.

Commensurate dimensions of measures - Unlike benefit-cost analysis, outcome and inputs dimensions need not be the same in DEA. Data need not be converted into "monetary terms; instead, DEA can accommodate a variety of different quantities (hours, tons, frequencies, as well as dollars). The measurement is performed in a multi-dimensional space of inputs and outputs used in their disaggregate form. Aggregation can be done after the analysis has been completed and the tradeoff rates between the variables are available.

Other Methods - Table C-2 provides a brief comparison of regression, benefit-cost, and the data envelopment analysis techniques. The intent is not to portray these methods as competitors; in fact, they are complementery in several ways. The "best practice" approach, because of its formulation based on "frontier analysis," is most suitable for comparative performance appraisal. Benefit-cost is especially suitable for in-depth studies of few competing alternative new services, while the regression technique and its related methods is useful for hypothesis testing and selection of variables.

TABLE C-2

COMPARISON OF THREE METHODS USED FOR PERFORMANCE APPRAISAL

Method:	Benefit-Cost Analysis	Regression/Econometric Methods	Data Envelopment Analysis
Purpose:	Comparison among few alternative programs	Estimation of parameters of average service production functions, and hypothesis testing	Evaluate relative performance of a multiplicity of similar service units Estimate parameters of production frontiers
Technique:	Microeconomic analysis of marginal and average cost curves--does not require computer algorithms	Statistical analysis and curve fitting based on central tendencies--requires computer algorithms	Data envelopment by means of mathematical programming methods--requires computer algorithms
Data:	Limited observations on each variable (multiple measures of inputs and outputs, but requires aggregation)	Requires many observations on each variable (usually, single output, multiple inputs, and explanatory characteristics)	Requires many observations on each variable (multiple inputs, multiple outputs, and explanatory characteristics)
Results:	Apply to each of the few cases (observations) involved	Structural, apply to the entire observation set--not applicable to individual observations	Applicable to each individual observation in the data base as well as to entire set
Critical Assumptions:	Requires data be dimensionally commensurate as well as assumption about social welfare functions	Requires parametric specifications of the production function (a testable hypothesis)--all deviations from this function are due to random error	No outliers in data base--all deviations from best practice frontier are due to inefficiency
Performance:	A ratio score based on an aggregation of benefits and costs	Measure of marginal productivity, i.e., not of present level but of the addition of new resources	Measures of input efficiency and output productivity; measures of total efficiency as well as marginal contribution of each variable

Source: Authors' analysis.

APPENDIX D

GASMIX: A GAS DISTRIBUTION MODEL OF OPTIMAL SUPPLY MIX, SERVICE RELIABILITY, AND INTERRUPTIBLE RATE DESIGN

This appendix describes the GASMIX computer model. The description consists of two parts. The first part, which has been reproduced with minor modifications from a previous NRRI report, presents the theoretical background and methodology for the model.[1] The second part presents the operating procedure for implementing the model. It also includes the results of a sample run. A case study using the model is in the report cited in footnote 1.

Theoretical Background and Methodology

The rapidly changing energy scene and the competitive pressures from alternative fuel supplies are likely to produce a growing market for interruptible service to customers with multiple fuel-burning capability. Attracting and retaining such customers may lead to improved cost recovery for the distribution utility as well as to improved service reliability for firm customers. However, there is much variability in the structure of currently applied interruptible rates, and the theoretical and methodological issues relating to the appropriate cost allocation among firm and interruptible customers are still unresolved. The purpose of this appendix is to present a modeling methodology for selecting an optimal gas supply portfolio that includes firm and interruptible rates at the distribution level, with a particular emphasis on (1) alternative cost

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[1] J. Stephen Henderson, Jean-Michel Guldmann, Ross C. Hemphill and Kyubang Lee, Natural Gas Rate Design and Transportation Policy under Deregulation and Uncertainty, (Columbus, Ohio: The National Regulatory Research Institute, 1986, pp. 85-106).

allocation procedures, and (2) the role of weather randomness in the optimal determination of the supply mix and the reliability of service to firm customers. The proposed model is cast as a partial equilibrium pricing model, involving the optimization of supply mix, the Monte-Carlo simulation of gas purchases and usage by firm and interruptible customers, and a financial and pricing analysis that computes new rates in order to meet the revenue requirement. This sequence of calculations is repeated until equilibrium rates are achieved under the selected policies.

An overview of this model is presented first. Its detailed structure is described next. The description includes the principal features of a gas demand, a supply cost minimization, a Monte-Carlo dispatching simulation and a rate design submodel.

Overview of the Model

The GASMIX model can be used to analyze the effects of alternative reliability and cost allocation policies on firm and interruptible retail rates. The model finds an equilibrium rate for each end-use sector which is, in effect, the intersection of that sector's demand and the corresponding regulated supply curve. The resulting regulated rates are functions of the quantities demanded, the service reliability, and the cost allocation procedure selected. A general flow diagram of the model is presented in figure D-1.

Exogenous data, assumptions, and policies are the basic inputs to the model and include (1) parameters (e.g., elasticities) that characterize the structure of the firm and interruptible gas demand curves; (2) parameters that characterize the set of potential suppliers of gas to the distribution utility (e.g., demand charges, commodity rates, and minimum bills); (3) parameters that specify the utility's operations, economics, and finances (e.g., rate base, allowed rate of return, non-supply operating costs); and (4) parameters that determine the selected reliability and cost allocation policies (e.g., acceptable curtailment rate for firm customers, share of fixed costs allocated to interruptible customers.)

Initial end-use rates are selected arbitrarily and are inputs to the formulation of the firm and interruptible gas demand curves, which then depend only upon the random degree-day variables. These random demand

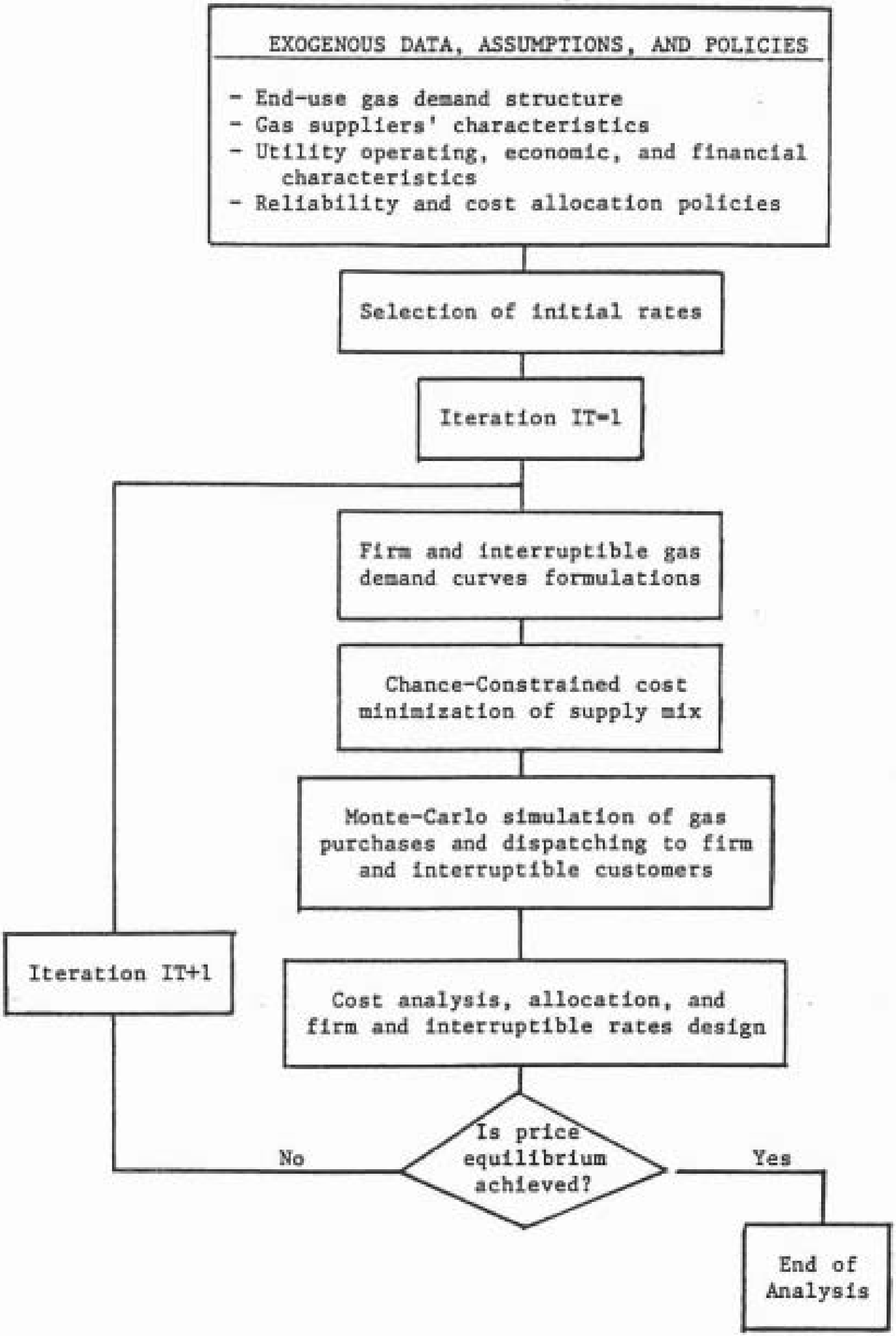

Figure D-1. General Flow Diagram of GASMIX functions are next used in the formulation of a chance constrained, supply-mix cost minimization submodel, which explicitly incorporates the selected service reliability for firm customers. Given a set of potential suppliers, each with its rates and other supply conditions, the submodel selects the least-cost subset of these suppliers, accounting for demand charges, and commodity charges as well as for any penalties related to minimum bill conditions, subject to satisfying the gas demand of firm customers with a given probability (i.e. reliability). The outputs of this cost minimization submodel are essentially the demand contracts with each selected supplier. These contracts, which specify the maximum daily amount of gas that may be purchased from each supplier, are inputs to the Monte-Carlo simulation submodel, where the process of gas purchasing and dispatching to customers is simulated over a large number of years. The weather component of monthly demands is selected randomly from a set of numbers that are distributed normally with a specified mean and variance. The outputs of this simulation including the expected (that is, average) values of the purchases from each supplier and of the corresponding costs, are inputs to the cost analysis submodel, where all costs are allocated among the various end-use sectors according to the preselected cost allocation policy. The end product of this analysis is a set of new firm and interruptible rates that would recover the expected revenue requirement. These new rates are then inputs to the next cycle of calculations, starting with the formulation of new demand curves. This cycle of calculations stops when equilibrium rates are obtained, that is, when rates do not change from one iteration to the next.

Structure of the Interruptible Rate Design Model

This section contains a technical description of the rate design model. It is divided into four subsections that correspond to the four modules shown in figure D-1.

End-Use Gas Demand Structure

Gas end-users can be divided into two broad groups--firm and interruptible customers. Firm customers require continuous gas provision and may be curtailed only under exceptional circumstances, for example, a pipeline breakdown or extremely cold weather. They are customarily grouped into three more and less homogeneous sectors--residential, commercial, and industrial. Interruptible customers are generally large industrial or commercial concerns with dual fuel-burning capability. The subscript s is an index, from 1 to S, of the firm customer sectors, whereas I is a subscript denoting the interruptible customer sector. The year is subdivided into M homogeneous subperiods denoting by the index m. The gas demand of each sector during each subperiod is a function of that sector's size (e.g., number of customers), the prices of gas and alternative competing fuels, and weather conditions which have a random component. The heating degree-day variable best expresses the effect of weather on gas demand. The general formulation of the demand functions for period m is assumed to be:

$$D_{sm} = D_{sm} (P_{sm}, P_{om}, X_m) \quad s=1 \rightarrow S , \tag{D-1}$$

$$D_{Im} = D_{Im} (P_{Im}, P_{om}, X_m, R_m) , \tag{D-2}$$

where:

D_{sm} = gas demand by firm sector s during period m,

D_{Im} = gas demand by the interruptible sector during period m,

P_{sm} = price of gas to sector s during period m,

P_{Im} = price of gas to interruptible customers during period m,

P_{om} = price of the alternative fuel (e.g., oil) during period m,

X_m = number of heating degree-days during period m, and

R_m = supply reliability (or interruptibility) to interruptible customers during period m.

<u>Chance-Constrained Cost Minimization of Supply Mix</u>

The supply mix problem is basically that of optimally selecting the gas suppliers and the corresponding demand contracts in such a way as to provide gas to all customers at least cost, where cost includes all commodity and demand charges and any penalties due to minimum bills. If gas demands were known in advance and were stable from year to year, the supply mix problem would be reduced to a simple linear program very easy to solve. However, demands are stochastic, and the determination of the optimal contracts as well as purchasing patterns has to be made under uncertainty conditions, leading to the formulation of a chance-constrained programming model. The determination of the least-cost purchase mix is further complicated by the possibility of gas storage, which the distributor may operate directly or rent from other companies. Gas can be injected into storage during off-peak summer months and withdrawn during winter, enabling the utility to contract for a lesser maximum delivery rate, and hence to reduce demand charges. Storage is part of the least-cost supply mix if its cost is smaller than the decrease in demand charges.

In the following discussion, it is first assumed that end-use demands are known with certainty, from which is obtained a deterministic version of the optimal supply mix model. Demand randomness is next introduced, leading to the formulation of a chance-constrained programming model.

The Deterministic Model

It is assumed that the utility can purchase gas from N suppliers denoted by the index i. For purposes of describing the model, these suppliers are called pipelines since the following set of parameters are generally positive numbers when the supply source is an interstate pipeline. Other sources, however, such as a spot market or a distributor's own production, can be incorporated into the model by specifying some parameters to be zero, for example.

The variables and their definitions are:

S_{im} = gas purchases from pipeline i during period m,

D_i = maximum daily deliveries from pipeline i (demand contract), and

T_{im} = maximum of the actual purchase and of the minimum take from pipeline i during period m.

The parameters are:

N_m = number of days in period m,

t_i = minimum percent take from pipeline i,

D_i^{max} = maximum demand contract with pipeline i,

C_i^C = commodity rate of pipeline i, and

C_i^D = demand rate of pipeline i.

The total firm demand during period m is defined by:

$$D_m^F = \sum_{s=1}^{S} D_{sm} \tag{D-3}$$

Let the storage flows be defined as follows:

SI_m = storage injection during period m, and

SW_m = storage withdrawal during period m.

Periodic storage injections and withdrawals, together with storage capacity, can be viewed as decision variables.[2] In the present model, however, these are treated as exogenous parameters, that is, the existing storage capacity cannot be expended and the injection-withdrawal schedule is predetermined and is to be adhered to, whatever the pattern of gas demands.

The constraints of the deterministic model are related to the maximum periodic purchases, to the endogenous determination of the variables T_{im}, and to the balance between supply and demand (while accounting for storage flows), with

$$S_{im} - N_m D_i \leq 0 \qquad i=1 \to N,\ m=1 \to M\ , \tag{D-4}$$

$$\left.\begin{aligned} T_{im} - S_{im} &\geq 0 \qquad i=1 \to N,\ m=1 \to M\ , \\ T_{im} - t_i N_m D_i &\geq 0 \qquad i=1 \to N,\ m=1 \to M\ , \end{aligned}\right. \tag{D-5}$$

$$\sum_{i=1}^{N} S_{im} = D_m^F + SI_m - SW_m\ . \tag{D-6}$$

The total cost of gas purchases is then

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[2] See, for instance, J.M. Guldmann, "Supply, Storage and Service Reliability Decisions by Gas Distribution Utilities: A Chance-Constrained Approach," Management Science, August 29, 1983, pp. 884-906.

$$C = \sum_{i=1}^{N} M\, C_i^D D_i + \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c T_{im} . \qquad \text{(D-7)}$$

The deterministic model is the linear program consisting of the objective function (D-7) and constraints (D-4) to (D-6). This model selects the values of the variables D_i, S_{im}, (and T_{im}) that minimize the total purchase cost C subject to the constraints.

The Chance-Constrained Model

The linear program presented in the previous section is essentially an ex-post optimization model, where the end-use gas demands are assumed to be known. In actuality, however, gas demand depends upon weather, which is not known in advance. Despite this uncertainty, decisions must be made during each period about levels of gas purchases from the different suppliers and allocations among the various end-use sectors, including the need for emergency curtailment. In addition, the demand contracts must be fixed before the annual cycle of operations starts. The basic problem is then to determine the demand contracts and to devise operating rules, which recognize the random character of gas requirements and which are, in some economic sense, optimal.

One approach is to solve the deterministic model for a large number of randomly generated gas patterns and to infer some rules and principles from the results. Chance-constrained programming (CCP) is an alternative, less cumbersome approach.[3] One major advantage of CCP is the possibility of introducing reliability constraints explicitly. Another is that optimal decision and management rules can be derived in some cases. The deterministic model just presented can be transformed into a chance-constrained one as follows.

The price of gas and the price of the alternative fuel are exogenous to the optimal supply mix model. Consequently, the aggregate firm demand D_m^F

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[3] See, for instance, A. Charnes, and W.W. Cooper, "Deterministic Equivalents for Optimizing and Satisfying Under Chance Constraints," Operations Research, 11, 1963, pp. 18-39.

only depends upon the random degree-day variable X_m, as does the aggregate gas supply S_m^T, with

$$S_m^T = \sum_{i=1}^{N} S_{im} - D_m^F (X_m) + SI_m - SW_m \ , \qquad \text{(D-8)}$$

or

$$S_m^T = S_m^T (X_m). \qquad \text{(D-9)}$$

Given X_m, and hence S_m^T, the individual purchases S_{im} can be determined if the optimal values of the contracts D_i are known, along with the minimum required purchases $N_m t_i D_i$. The optimal values of S_{im}, then, are the natural outputs of an economic dispatch analysis. The least-cost dispatching of gas purchases is similar to that in traditional electricity dispatching with the exception of the treatment of minimum purchase obligations. With this constraint, the least-cost sequence is to take gas in the order of most expensive gas first until minimum purchase requirements are fulfilled and then in the order of least expensive gas first, afterwards. Because of the minimum purchase requirement constraints the sequencing, the dispatch rule is optimal only in a second-best sense. In a general form then

$$S_{im} = F_{im} ({S^T}_m, \bar{D}, \bar{C}^c, \bar{t}), \qquad \text{(D-10)}$$

where $\bar{D}$, $\bar{C}^c$, $\bar{t}$ are the vectors of the variables D_i and the parameters C_i^c and t_i. As the latter are taken as given, it follows that

$$S_{im} = F_{im} (S_m^T, \bar{D}) = F_{im} (X_m, \bar{D}). \qquad \text{(D-11)}$$

The variable S_{im} depends upon the random variable X_m, and hence is a random function of $\bar{D}$, and has a probability density function $P_{im}(S_{im})$. Let P_{im}^{min} be the probability that the supply S_{im} takes on a value less than or equal to the minimum take $N_m t_i D_i$, with

$$P_{im}^{min} = \int_0^{N_m t_i D_i} P_{im} (v) \ dv. \qquad \text{(D-12)}$$

The total expected cost of supply is the sum of (1) the demand charge, (2) the penalty associated with purchases below the specified minimum, and (3) the usual commodity charge for purchases above the minimum, or

$$E(C) = \sum_{i=1}^{N} 12\, C_i^D\, D_i + \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, N_m\, t_i\, D_i\, P_{im}^{min} + \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c \int_{N_m t_i D_i}^{\infty} S_{im}\, P(S_{im})\, dS_{im} \, . \tag{D-13}$$

Minimizing the expected cost is the usual criterion when dealing with cost minimization under uncertainty. Fundamentally, the expected cost (D-13) is a function of the demand contract variables $\hat{D}$. These may have upper bounds related to the physical and other characteristics of the pipelines, and the optimization problem can be reformulated as

$$\text{minimize } E[C(\hat{D})] \tag{D-14}$$

$$\text{subject to: } \hat{D} \le \hat{D}^{max} \, . \tag{D-15}$$

However, the above problem cannot be solved as such because the supply functions F_{im} and the probability functions P_{im} cannot be represented in closed form. As an alternative, the functions F_{im} can be approximated as linear functions of the necessary aggregate supplies S_m^T, with

$$S_{im} = a_{im}\, S_m^T \, . \tag{D-16}$$

The coefficients a_{im} are decision variables to be determined endogenously to the model, with of course the constraint that

$$\sum_{i=1}^{N} a_{im} = 1 \, . \tag{D-17}$$

Equation (D-16) is a first-order approximation of the true function F_{im} which can be interpreted as a Taylor series expansion truncated at the first-order level. In a nonstochastic framework, the maximum supply constraint for each supplier and period would require that

$$a_{im}\, S_m^T \leq N_m D_i \ . \tag{D-18}$$

S_m^T is a random variable, however, and hence constraint (D-18) is likely to be violated under at least some circumstances. The frequency of such constraint violations may be explicitly incorporated into the model by transforming (D-18) into the chance constraint

$$\Pr(a_{im} S_m^T - N_m D_i \leq 0) \geq 1-\alpha_{im} \ , \tag{D-19}$$

where α_{im} is the probability measure of the extent to which constraint violations are permitted. As such, the α_{im} is the reliability level for pipeline service i in month m which is a parameter to be selected as an input to the overall modeling analysis.

In practice, a chance constraint must be transformed into a nonstochastic equivalent one. In the above case, consider the random variable

$$V = a_{im} S_m^T - N_m D_i \ . \tag{D-20}$$

Its expected value and standard deviation are

$$E(V) = a_{im} E(S_m^T) - N_m D_i \ , \text{ and} \tag{D-21}$$

$$\sigma(V) = a_{im}\, \sigma(S_m^T) \ . \tag{D-22}$$

The variable V is normally distributed, as is demonstrated later. Let $z_{\alpha_{im}}$ be the value of the standardized normal variable z so that

$$\Pr(z \leq z_{\alpha_{im}}) = 1-\alpha_{im} \ . \tag{D-23}$$

As $z=(V-E(V))/\sigma(V)$, it can be shown that constraint (D-19) is equivalent to the deterministic constraint

$$a_{im}\,[E(S_m^T) + z_{\alpha_{im}}\,\sigma(S_m^T)] - N_m D_i \le 0\ . \tag{D-24}$$

Constraint (D-24) is linear, with unknowns a_{im} and D_i. As the storage flows SI_m and SW_m are deterministic parameters, we have

$$E(S_m^T) = E(D_m^F) + SI_m - SW_m\ , \tag{D-25}$$

$$\sigma(S_m^T) = \sigma(D_m^F)\ . \tag{D-26}$$

In addition to the above constraints related to the violations of individual demand contracts, it is necessary to consider the aggregate supply capacity constraint

$$\Pr(S_m^T \le N_m \sum_{i=1}^{N} D_i) \ge 1-\beta_m\ , \tag{D-27}$$

where β_m is a parameter representing the monthly, overall system supply reliability level for firm customers. The deterministic equivalent of (D-27) is

$$N_m \sum_{i=1}^{N} D_i \ge E(S_m^T) + z_{\beta_m}\sigma(S_m^T)\ , \tag{D-28}$$

or

$$N_m \sum_{i=1}^{N} D_i \ge E(D_m^F) + z_{\beta_m}\sigma(D_m^F) + SI_m - SW_m\ . \tag{D-29}$$

Chance constraint (D-27) is redundant and superseded by chance constraints (D-19), if, and only if,

$$\prod_{i=1}^{N} (1-\alpha_{im}) \ge (1-\beta_m)\ . \tag{D-30}$$

This possible redundance thus depends upon the selection of the policy parameters α_{im} and β_m.

Further approximations to the basic model (D-14) - (D-15) must yet be made to render it computationally tractable. Indeed, the commodity charge and minimum bill penalty components of the expected cost E(C) in equation (D-13) cannot be used as such. Instead, they must be replaced by the expected commodity cost computed over the whole supply range and a penalty associated with the difference between the minimum purchase and the average supply. The expected commodity cost is

$$
\begin{aligned}
E(C_1) &= \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c \int_{-\infty}^{+\infty} S_{im}\, P(S_{im})\, dS_{im} \\
&= \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, E(S_{im}) = \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, a_{im}\, E(S_m^T) \;.
\end{aligned}
\tag{D-31}
$$

In order to introduce the penalty component into the objective function, it is first necessary to add the following constraints:

$$N_m t_i D_i - a_{im} E(S_m^t) = x_{im}^+ - x_{im}^- \quad \text{for } i=1 \to N,\ m=1 \to M, \tag{D-32}$$

$$x_{im}^+ \geq 0 \;,$$

$$x_{im}^- \geq 0 \;.$$

where x_{im}^+ and x_{im}^- are nonnegative variables to be chosen in the optimization. Any expected penalty is associated with the excess variable x_{im}^+ only (that is, whenever $a_{im}E(S_m^T) \leq N_m t_i D_i$) and is defined as

$$P_N = \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, x_{im}^+ \;. \tag{D-33}$$

The expected supply cost is finally approximated as

$$E(C) = \sum_{i=1}^{N} M\, C_i^D\, D_i + \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, [a_{im}\, E(S_m^T + x_{im}^+] \;. \tag{D-34}$$

E(C) is linear in the unknowns D_i, a_{im}, and x_{im}^+. The CCP is thus reduced to a linear program with the objective function (D-34) and the constraints (D-24), (D-29), (D-32), (D-15) and (D-17).

Monte-Carlo Simulation of Gas Purchases and Dispatching

In the CCP supply mix analysis, optimal demand contracts have been determined while approximating the exact dispatch functions (F_{im}) and the penalties associated with minimum purchase obligations. The purposes of the Monte-Carlo simulation submodel are (1) to account for the implications of the true dispatching and penalties, and (2) to introduce the role of interruptible customers into the analysis. One very important consequence of the latter is to reduce or eliminate the minimum purchase penalties that are more likely to occur if a distributor has only firm customers. Second, interruptible customers may pay for some fixed costs (the demand charges are examples), the burden of which would otherwise be solely borne by firm customers. The interruptible customer class share of fixed costs is a policy parameter in this model.

The Monte-Carlo simulation approach is appropriate because of the random character of gas demands. The monthly simulation is repeated over several years, and key policy outputs are then averaged to find expected values. A sequence of computer-generated random numbers is used to compute a sequence of random heating degree-day variables X_m, from which the firm supplies and interruptible demands, D_{sm} and D_{Im}, may be found. Next, total firm supplies are computed according to equation (D-8). The other inputs to the simulation are the demand contracts D_i, the suppliers' commodity rates, and minimum purchase percentages. The following steps describe the remaining analysis for each month of the simulation period:

Step 1. The total firm supplies S_m^T are compared to the aggregate of the maximum and minimum purchases, D_{Tm}^{max} and D_{Tm}^{min}, which are defined as:

$$D_{Tm}^{max} = \sum_{i=1}^{N} D_i N_m \quad , \qquad \text{(D-35)}$$

$$D_{Tm}^{min} = \sum_{i=1}^{N} D_i N_m t_i \quad . \qquad \text{(D-36)}$$

If $S_m^T > D_{Tm}^{max}$, the available supplies are insufficient and curtailments are necessary. In this case, step 2 is next. If $S_m^T < D_{Tm}^{min}$, firm customers are unable to use the minimumaggregate purchase requirement, and if the slack cannot be used by interruptible customers, minimum bill penalties must be paid. Inthis case, step 3 is next. If $D_{Tm}^{min} < S_m^T < D_{Tm}^{max}$, no penalties areassessed, and there is still gas available for interruptible customers. Go to step 4 for this allocation.

Step 2. Customers are curtailed up to their demands (D_{sm}) in the following order: industrial, commercial, and residential. Let (D_{sm}^a) be the actual gas provided to sector s during period m. For descriptive purposes later, the amount and rate of the curtailments can be computed as

$$Cur_{sm} = D_{sm} - D_{sm}^a \quad . \tag{D-37}$$

$$Pcur_{sm} = Cur_{sm}/D_{sm} \quad . \tag{D-38}$$

In this situation, no gas is available for interruptible customers, and $D_{Im}^a = 0$. Gas purchases S_{im} can be subdivided into four components which are

S_{im}^1 = amount of gas purchased for firm customers below the minimum take ($t_i N_m D_i$),

S_{im}^2 = amount of gas purchased for firm customers above the minimum take and below the maximum take ($N_m D_i$),

S_{im}^3 = amount of gas purchased for interruptible customers below the minimum take, and

S_{im}^4 = amount of gas purchased for interruptible customers above the minimum take and below the maximum one.

It must be true that

$$S_{im} = S_{im}^1 + S_{im}^2 + S_{im}^3 + S_{im}^4 \quad . \tag{D-39}$$

In the present case, these components are

$$S^1_{im} = t_i N_m D_i \qquad i=1 \to N \quad , \qquad \text{(D-40)}$$

$$S^2_{im} = (1-t_i) N_m D_i \qquad i=1 \to N \quad , \qquad \text{(D-41)}$$

$$S^3_{im} = S^4_{im} = 0 \qquad i=1 \to N \quad . \qquad \text{(D-42)}$$

Supply costs are computed next in step 5.

<u>Step 3</u>. All firm customers are provided their requirements. Suppliers are ranked in decreasing commodity rate (C^c_i) order. Assume that the minimum purchase requirements of the first N_1 suppliers are necessary to provide firm customers' needs. Then

$$S^1_{im} = t_i N_m D_i \qquad i=1 \to N_1 - 1 \ , \qquad \text{(D-43)}$$

$$S^1_{im} = S^T_m - \sum_{j=1}^{N_1-1} t_j N_m D_j \qquad i=N_1 \ , \qquad \text{(D-44)}$$

$$S^1_{im} = 0 \qquad i > N_1 \ , \qquad \text{(D-45)}$$

and

$$S^2_{im} = 0 \qquad i=1 \to N \ . \qquad \text{(D-46)}$$

Next, interruptible demand, D_{Im}, is fulfilled up to the minimum purchase requirements in the same order. For instance, if

$$D_{Im} > t_i N_m D_i - S^1_{im} \text{ for } i=N_1 \text{ , then}$$

$$S^3_{im} = t_i N_m D_i - S^1_{im} \qquad i=N_1 \ , \qquad \text{(D-47)}$$

and the remaining interruptible demand is satisfied up to the minimum purchase requirements of the remaining suppliers. Thus

$$S^3_{im} \le t_i N_m D_i \qquad i > N_1 \ . \qquad \text{(D-48)}$$

If all minimum purchase requirements are fulfilled, (i.e., $S^3_{im} = t_i N_m D_i$, $i > N_1$), then the remaining interruptible demand is satisfied with available gas supplies above the minimum and below the maximum purchases. This allocation, however, is in increasing commodity rate order. Assume that the first N_2 suppliers are to be used. Then

$$S^4_{im} = (1-t_i)N_m D_i \qquad i=1 \rightarrow N_2-1 \ , \tag{D-49}$$

$$S^4_{im} = D_{Im} - \sum_{j=1}^{N_2-1} (1-t_j)N_m D_j \qquad i=N_2 \ , \tag{D-50}$$

$$S^4_{im} = 0 \qquad i > N_2 \quad . \tag{D-51}$$

Supply costs are computed next in step 5.

Step 4. All firm customers are provided their requirements. All minimum requirements are purchased for firm customers, hence

$$S^I_{im} = t_i N_m D_i \qquad i=1 \rightarrow N \quad , \tag{D-52}$$

$$S^3_{im} = 0 \qquad i=1 \rightarrow N \quad . \tag{D-53}$$

The remaining firm requirements are allocated next to suppliers in increasing commodity price order. When all firm requirements are allocated, interruptible demand is allocated to any unused supplies in the same priority order. Supply costs are computed next in step 5.

Step 5. Compute the commodity charges, associated with the actual supplies S^k_{im} as

$$C^k_m = \sum_{i=1}^{N} C^c_i \, S^k_{im} \quad . \tag{D-54}$$

The actual penalties, if any, for violating any minimum purchase requirements are

$$C^{pen}_m = \sum_{i=1}^{N} C^c_i \, \text{Max} \, (0, \, t_i N_m D_i - S^1_{im} - S^3_{im}) \ . \tag{D-55}$$

After the above steps are repeated for the M periods of the current year and for the NY years of the simulation, various average values are computed. The average curtailment volumes and rates are policy evaluation criteria that are used after a price equilibrium is achieved. The average purchase costs and actual gas dispatching are used in the rate design submodel described in the next section.

Firm and Interruptible Gas Rates Design

The rate design submodel replicates, in a very simplified fashion, the calculations that are performed prior to rate case proceedings when the utility requests a change in its retail prices in order to achieve an appropriate rate of return on the net value of its plant in service (or ratebase).

Most costs belong to one of two categories: peak-related (PR) and non-peak-related (NPR) costs. PR costs include operating and plant costs related to storage, transmission, and distribution in part, as well as the corresponding depreciation costs. Demand charges are also part of PR costs. NPR costs include (1) operating costs related to customer accounts, customer services, sales, and distribution in part, (2) plant costs related to distribution, and (3) depreciation costs. Commodity charges, including any minimum bill payments, are included in this category. A third cost category includes costs related to administrative activities, to taxes, and to the general plant. This is a hybrid category, the allocation of which depends upon the allocation of PR and NPR costs.

The first step in the cost allocation process is to compute the costs to be charged to interruptible customers, which include

(1) the commodity cost of actual purchases by interruptible customers, and

(2) a share, called Sh_I, of all other costs of service (COS), including all demand charges, but excluding the commodity cost of purchases by firm customers. The total amount of cost allocated to interruptible customers is

$$CT_I = \sum_{m=1}^{M} (\bar{C}_m^3 + \bar{C}_m^4) + Sh_I\ (COS)\ , \qquad (D\text{-}56)$$

where a bar over a variable denotes its average value from the Monte-Carlo simulation. The total average annual gas sales to interruptible customers are

$$D^a_{IT} = \sum_{m=1}^{M} \bar{D}^a_{Im} . \qquad (D\text{-}57)$$

The ex-post average price that recovers CT_I is then

$$P_I = CT_I / D^a_{IT} . \qquad (D\text{-}58)$$

Note that the interruptible rate is constant across all M periods. The interruptible customers' share of fixed costs (COS) is a basic policy parameter. If this share is zero, then interruptible customers pay only the commodity cost of the gas specifically purchased for them, and none of the remaining fixed and variable costs.

Once CT_I has been determined, the remaining costs must be allocated among the firm customers, PR and NPR allocation factors are computed as follows. Let p be the peak period for aggregate firm sales. Then the peak-related allocation factors are

$$FP_s = D_{sp} / \left(\sum_{s=1}^{S} \bar{D}^a_{sp} \right) \qquad s=1 \rightarrow S . \qquad (D\text{-}59)$$

The non-peak related allocation factors, based on average annual sales, are

$$FY_s = \left(\sum_{m=1}^{M} \bar{D}^a_{sm} \right) / \left(\sum_{s=1}^{S} \sum_{m=1}^{M} \bar{D}^a_{sm} \right) \qquad s=1 \rightarrow S . \qquad (D\text{-}60)$$

Let CAL_s be the costs allocated to firm sector s by applying the allocation factors FP_s and FY_s to PR and NPR costs, respectively. The allocation factors for the hybrid cost category are then

$$FH_s = CAL_s / \left(\sum_{s=1}^{S} CAL_s \right) \quad s=1 \rightarrow S . \qquad (D\text{-}61)$$

The factors are used to allocate hybrid costs. The total costs allocated to sector s is denoted CAL^T_s. The ex-post average prices guaranteeing cost recovery are then

$$P_s = CAL_s^T / (\sum_{m=1}^{M} \bar{D}_{sm}^a) \qquad s=1 \rightarrow S \ . \tag{D-62}$$

Note that, as for interruptible rates, prices paid by firm customers are constant across the M periods. The end-use rates P_s and P_I are next compared to the same rates as obtained at the end of the previous cycle of calculations. If the absolute value of each of the differences is less than some pre-determined threshold ϵ, price equilibrium is considered to be achieved, and the calculations are terminated. Otherwise, these prices are used to begin a next cycle of calculations, starting with the formulation of new gas demand curves.

In essence, the NRRI model determines the least-cost supply mix and dispatching order of these supplies for a natural gas distributor under conditions of demand uncertainty and reliability constraints. The optimization technique employed is chance-constrained programming. The novel feature of the model is the equilibrium determination of average supply costs in a Monte-Carlo simulation that includes minimum purchase requirements and the associated dispatching to meet random realizations of demand.

Operating Procedure

GASMIX has been developed and tested on the IBM 3081 computer system at The Ohio State University. GASMIX consists of a single Fortran Source Program, an input data file, an output data file, and an associated set of JCL (Job Control Language) statements. The operation of GASMIX requires the following steps.

Step 1. Prepare an input data set.
Step 2. Store the data in a computer compatible format on a disk file.
Step 3. Run the program.

Each step in the above procedure is discussed in more detail below.

Prepare an Input Data Set

The data required to run GASMIX can be classified into following groups:

- o Utility Data
- o Suppliers' Data
- o Market Demand Data
- o Storage Data
- o Computational and Other Parameters

The data may be collected from distributors, suppliers and state commissions. Annual reports submitted by utilities to state commissions and FERC also serve as excellent sources of data. Individual items of data are discussed in the next section.

Store the Data in a Computer-Compatible Format on a Disk File

Once data collection is completed, it must be converted to a format consistent with Fortran data entry requirements. The following is a general description of the input data file used by GASMIX. The general format for the file is shown in table D-1.

The first ten lines are reserved for descriptive information that identifies the file. The information may include the name of the utility, the study period, the scenario being tested, etc. It is recommended that the first and the last lines among these ten be kept blank for ease of reading. These ten lines are ignored by the program and have been provided to aid the user.

After the first ten lines, the data are arranged in five blocks, each block representing one group of data (e.g., market demand data). Within each block, the first three lines are reserved for identifying the data group. The first and the third of these lines are kept blank for ease of reading.

TABLE D-1

GENERAL FORMAT FOR INPUT DATA FILE OF GASMIX

```
C    blank line
C          -
C          -
C          -
C          -
C    8 lines of descriptive information on the utility, study year,
     scenario, etc.
C          -
C          -
C          -
C          -
C    blank line
C    blank line
C    identifying information on first block of data <(e.g., utility data)
C    blank line
C    descriptive identifiers for data items (e.g., storage O&M, trans  O&M,
     etc.
C    blank line
     numeric data for the above data items
           -
           -
           -
           -
C    blank line
C    descriptive identifiers for data items
C    blank line
     numeric data for the above data items
           -
           -
           -
           -
     continue until all data items in the first block (group) of data is
     exhausted
     repeat for the remaining blocks of data
```

Source: Authors' analysis.

Next, there is a similar group of three lines containing descriptive identifiers for one or more data items. This is followed by actual numeric data. These may be more than one line of such numeric data. This set of data is continued until all the items on the descriptive data identifier line are exhausted. This is again followed by the next set of data identifiers and corresponding numeric data. This format continues until the next block of data is reached. Each block of data has the same general format as the preceding block. The bottom of the data file is reached when all the items in all the blocks of data have been entered.

The format for all floating point numeric data is 4F15.4 and for all integer numeric data is 4I5. This allows for a maximum of 4 items of data to be entered on each data line. All data entered between successive comment lines constitutes one row of data. One row may contain more than one line of data. Explanation of data items (elements) on each row follows.

Row 1	Element 1	Interruptibles share of cost of service (fraction)
	Element 2	Customer share of distribution costs (fraction)
	Element 3	The rate of return for the distribution utility (fraction)
Row 2	Element 1	Operations and maintenance costs for storage (dollars)
	Element 2	Operations and maintenance costs for transmission (dollars)
	Element 3	Operations and maintenance costs for distribution (dollars)
Row 3	Element 1	Customer accounts expenses (dollars)
	Element 2	Customer service and information expenses (dollars)
	Element 3	Sales Expenses (dollars)
Row 4	Element 1	Administrative and general expenses (dollars)
	Element 2	Depreciation expenses (dollars)
Row 5	Element 1	Storage plant in service (dollars)
	Element 2	Transmission plant in service (dollars)
	Element 3	Distribution plant in service (dollars)
Row 6	Element 1	General plant (dollars)
	Element 2	Ratio of net/gross plant in service (fraction)

Row 7	Element 1	Income taxes (dollars)
	Element 2	Other taxes (dollars)
Row 8	Element 1	Number of suppliers, N_s
	Element 2	Number of periods, N_m, in a year. Usually one period is a month although periods of other duration can be chosen.
Row 9	Elements 1-N_s	Commodity charges for each of the N_s suppliers (dollars/MMcf). MMcf stands for million cubic feet.
Row 10	Elements 1-N_s	Demand charges for each supplier (dollars/MMcf)
Row 11	Elements 1-N_s	Take-or-pay share of the demand contract for each supplier (fraction)
Row 12	Elements 1-N_s	Maximum contractible demand from each supplier (MMcf)
Row 13	Elements 1-N_m	Number of days in each period for N_m periods
Row 14	Elements 1-4	Base load coefficient (MMcf) for each customer class. The four classes of customers are residential, commercial, industrial, and interruptible.
Row 15	Elements 1-4	Heating load coefficient for each customer class (MMcf/deg.day)
Row 16	Elements 1-4	Reference level average prices for each customer class (dollars/MMcf)
Row 17	Elements 1-4	Demand elasticity for each customer class
Row 18	Elements 1-N_m	Degree-days in each period for N_m periods
Row 19	Elements 1-N_m	Standard deviation of degree-days in each period for N_m periods
Row 20	Element 1	Total annual delivery to or withdrawal from storage (MMcf). Deliveries are considered positive and withdrawals are considered negative.
Row 21	Elements 1-N_m	Delivery or withdrawal during each period for N_m periods (MMcf)
Row 22	Element 1	Convergence criterion, ϵ, (dollars/MMcf). This is compared to the gas prices of different classes of customers (i.e., residential, commercial, and industrial) at the end of each iteration.
Row 23	Element 1	Numbers of reliability levels, N_r (integer)
Row 24	Elements 1-N_r	Reliability values for each of the N_r levels (fraction).

TABLE D-2

STANDARD NORMAL DISTRIBUTION FUNCTIONS

(Z-VALUES) FOR SELECTED RELIABILITY VALUES

Reliability	Z-Value
0.80	0.8418
0.81	0.8778
0.82	0.9154
0.83	0.9542
0.84	0.9946
0.85	1.0365
0.86	1.0805
0.87	1.1264
0.88	1.1750
0.89	1.2263
0.90	1.2817
0.91	1.3406
0.92	1.4053
0.93	1.4757
0.94	1.5550
0.95	1.6450
0.96	1.7511
0.97	1.8814
0.98	2.0540
0.99	2.3267
1.00	3.9000

Source: Authors' calculations.

Row 25	Elements 1-N_r	Z-values for each of the reliability values. A Z-value is a standard normal distribution function corresponding to a reliability. See table D-2 for more information.
Row 26	Elements 1-N_m	Selected system reliability for each of the N_m periods.
Row 27	Elements 1-$N_m N_s$	Selected reliability for each of the N_s suppliers during each of the N_m periods. The first N_m values are for the first supplier. The next N_m values are for the second supplier. This is repeated until all the suppliers are exhausted.

Row 28	Element 1	Maximum number of iterations in search of equilibrium
	Element 2	Number of Monte-Carlo simulation years.
	Element 3	Seed for the random number generator. It should be a number between 1 and 9999.
Row 29	Element 1	Run option as follows: 1: print input but do not run the program 2: print input and run the program 3: do not print input but run the program
	Element 2	Output option as follows: 1: print the solution on printer but do not store any output on a disk file 2: print the solution on printer and store output on a disk file

Run the Program

A series of Job Control Language (JCL) statements is needed to execute the program, an example of which is listed in table D-3. It should be noted that (after the user prefix TS3026) GAS.FORT is the Fortran source program, INPUT.DATA is the input data file, and OUTFL.DATA is the output file. These file names are optional and can be changed for different runs. In addition, the output file (OUTFL.DATA in this example) should be deleted if its name is being reused for a run. The procedure FORTVCG on the IBM 3081 computer system at The Ohio State University stands for compile and execute using the FORTRAN-77 compiler. A similar or identical procedure should be available at other mainframe computer installations.

When the program is executed, the input data and the final solution are printed. In addition, the solutions at each iteration and intermediate results on cost minimization and dispatching simulation are also stored on the output file which can be examined later. The user can optionally suppress the printing of input data and part of output results with a specification on the input data file as explained earlier.

TABLE D-3

JCL FOR GASMIX

```
// JOB
// REGION=1024K,TIME=(0,50)
/*JOBPARM LINES=6000
//GASMIX EXEC FORTVCG,TIME.GO=(0,50),PARM='NOSOURCE,NOMAP'
//FORT.SYSIN DD DSN=TS3026.GAS.FORT,DISP=SHR
//GO.SYSIN DD *
//GO.FT10F001 DD DSN=TS3026.INPUT.DATA,DISP=SHR
//GO.FT12F001 DD DSN=TS3026.OUTFL.DATA,DISP=(NEW,CATLG),
// UNIT=USER80,SPACE=(TRK,(5,1)),
// DCB=(RECFM=FB,LRECL=132,BLKSIZE=6600)
//
```

Source: Authors' analysis.

Sample Run

A sample run of the program follows. The input data used for the run are shown in table D-4 and resides on a disk file named INPUT.DATA. The output consists of two parts. Part of the output is printed on a printer and another is stored on a disk file named OUTFL.DATA. The printer output consists of input data and the final solution. The disk file stores the solution at each iteration as well as significant intermediate results. Most of the input data have been explained in previous sections. A few of the input data items may require further explanation, which follows.

Notes on Specific Input Data Items

In the following sample run, the demand functions D_{sm} and D_{Im} (see equation D-1) have been assumed to have the following forms.

$$D_{sm} = (A_s + B_s DD_m)\ (P_s/P_{rs})^{EL_s} \qquad \text{(D-63)}$$

$$D_{Im} = (A_I + B_I DD_m)\ (P_I/P_{rI})^{EL_s} \qquad \text{(D-64)}$$

where A_s : Base load coefficient (MMcf) for customer sector s (Row 14, elements 1-3)

B_s : Heating load coefficient (MMcf)/deg-day) for customer sector s (Row 14, elements 1-3)

DD_m: Degree-days in period m (Row 18)

P_s : Price of gas (dollars/MMcf) for customer sector s (calculated)

P_{rs}: Reference level price (dollars/MMcf) for customer sector s (Row 16, elements 1-3)

A_I : Base load coefficient (MMcf) for interruptible customers (Row 14, element 4)

B_I : Heating load coefficient (MMcf/deg-day) for interruptible customers (Row 14, element 4). The interruptible demand is assumed to be independent of weather and therefore B_I is set equal to zero.

P_I : Price of gas (dollars/MMcf) for interruptible customers (calculated)

P_{rI}: Reference level price (dollars/MMcf) for interruptible customers (Row 16, element 4)

EL_s: Demand elasticity for customer sector s

EL_I: Demand elasticity for interruptible customers

A sample printout of the program follows. In this run, output option 1 has been chosen (table D-4, row 29) which prints the solution on the printer but does not store any output on a disk file.

TABLE D-4

INPUT DATA FILE FOR GASMIX

```
(
((C********1********2********3********4********5**3*******6
(
(                          ABC GAS COMPANY
(
(                          TEST DATA
(                          THREE SUPPLIER CASE
(
((C********1********2********3********4********5**3*******6
(
(
((C---- ---- ---- ---- ----UTILITY DATA--- ---- ---- ---- ----
(
( INTERPT SHR OF COS, CUSTMR SHR OF DISTR CST, RATE OF RETURN
(
(1      0.00          0.44          0.1224
(
( STORAGE O AND M, TRANS O AND M, DISTR O AND M
(
(2  12000000.0       3000000.0      35000000.0
(
( CUSTMR ACC EXPNS, CUSTMR SERV AND INFO EXPNS, SALES EXPNS
(
(3   40000000.0      7000000.0      3000000.0
(
( ADMIN AND GEN EXPNS, DEPRECIATION EXPNS
(
(4   49000000.0      22000000.0
(
( STORAGE PLANT INS, TRANS PLANT INS, DISTR PLANT INS
(
(5   64000000.0    129000000.0    480000000.0
(
( GENERAL PLANT, RATIO OF NET/GROSS PLANT INS
(
(6   26000000.0          0.60
(
( INCOME TAXES, OTHER TAXES
(
(7   45000000.0     96000000.0
(
((C---- ---- ---- ---- --SUPPLIERS' DATA-- ---- ---- ---- ----
(
( NUMBER OF SUPPLIERS, NUMBER OF PERIODS(MONTHS) IN A YEAR
(
(8    3   12
(
( COMMODITY CHARGES FOR SUPPLIERS
(
(9      3950.0          3800.0          3000.0
(
( DEMAND CHARGES FOR SUPPLIERS
(
10      1500.0          3500.0              0.0
(
( TAKE-OR-PAY SHARE OF THE DEMAND CONTRACT FOR SUPPLIERS
(
11       0.40           0.50           0.0
(
( MAXIMUM CONTRACTIBLE DEMAND FROM SUPPLIERS
(
12      1200.0          1200.0          100.0
```

TABLE D-4 (continued)

INPUT DATA FILE FOR GASMIX

```
C
C NUMBER OF DAYS IN EACH PERIOD (REAL NUMBER)
C
13        30.0           30.0           30.0           30.0
          30.0           30.0           30.0           30.0
          30.0           30.0           30.0           30.0
C
CC---- ---- ---- ---- ---MARKET DEMAND DATA--- ---- ---- ----
C
C BASE LOAD COEFFECIENTS
C
14    2534.41        887.09        3283.82        2500.0
C
C HEATING LOAD COEFFECIENTS
C
15     17.463         7.038         3.839          0.0
C
C REFERENCE LEVEL AVERAGE PRICES
C
16    5410.94       4977.54        4520.18        4000.0
C
C DEMAND ELASTICITIES
C
17      -0.22         -0.32         -0.64          -1.5
C
C DEGREE DAYS IN EACH PERIOD
C
18      506.6         248.2          50.5           11.0
         18.9         120.5         371.6          712.6
       1071.6        1207.7        1046.3          892.5
C
C STANDARD DEVIATION OF DEGREE DAYS IN EACH PERIOD
C
19       90.5          88.3          28.8            9.4
         14.1          42.1          91.1           85.6
        145.8         129.5         115.2          125.4
C
CC---- ---- ---- ---- ----STORAGE DATA--- ---- ---- ---- ----
C
C TOTAL ANNUAL DELIVERY/WITHDRAWAL (MMCF)
C
20    62000.0
C
C STORAGE FLOW DURING EACH PERIOD
C
21   8556.0         9796.0         9424.0          9300.0
     9238.0         8742.0         6944.0        -11036.0
   -12400.0       -17856.0        -9300.0        -11438.0
C
CC---- ---- ---COMPUTATIONAL AND OTHER PARAMETERS-- ---- ----
C
C CONVERGENCE CRITERION
C
22      10.0
```

TABLE D-4 (continued)

INPUT DATA FILE FOR GASMIX

```
C
C NUMBER OF RELIABILITY LEVELS
C
23     5
C
C RELIABILITY VALUES
C
24       0.99                0.98                0.97                0.96
         0.95
C
C Z-VALUES
C
25       2.3267              2.054               1.8814              1.7511
         1.6450
C
C SELECTED SYSTEM RELIABILITY LEVELS
C
26       1     1     1     1
         1     1     1     1
         1     1     1     1
C
C SELECTED SUPPLIER RELIABILTY LEVELS
C
27       1     1     1     1
         1     1     1     1
         1     1     1     1
         1     1     1     1
         1     1     1     1
         1     1     1     1
         1     1     1     1
         1     1     1     1
         1     1     1     1
         1     1     1     1
         1     1     1     1
C
C NO OF ITERATIONS, NO OF SIMUL YEARS, SEED FOR RANDOM NO GENERATOR
C
28     40   500 1000
C
C RUN OPTION, OUTPUT OPTION
C
29     2     1
```

Source: Authors' analysis.

****************** I N P U T   D A T A ******************

UTILITY DATA

INTERRUPTIBLES SHARE OF COST OF SERVICE =	0.000000
CUSTOMER SHARE OF DISTRIBUTION COSTS =	0.440000
RATE OF RETURN =	0.123400
OPER AND MAINT STORAGE COSTS (MILLION $) =	12.000000
OPER AND MAINT TRANSMISSION COSTS (MILLION $) =	3.000000
OPER AND MAINT DISTRIBUTION COSTS (MILLION $) =	35.000000
CUSTOMER ACCOUNTS EXPENSES (MILLION $) =	40.000000
CUSTOMER SERV AND INFO EXPENSES (MILLION $) =	7.000000
SALES EXPENSES (MILLION $) =	3.000000
ADMINISTRATIVE AND GENERAL EXPENSES (MILLION $) =	49.000000
DEPRECIATION EXPENSES (MILLION $) =	22.000000
STORAGE PLANT IN SERVICE (MILLION $) =	64.000000
TRANSMISSION PLANT IN SERVICE (MILLION $) =	129.000000
DISTRIBUTION PLANT IN SERVICE (MILLION $) =	480.000000
GENERAL PLANT IN SERVICE (MILLION $) =	26.000000
RATIO OF NET/GROSS PLANT IN SERVICE =	0.600000
INCOME TAXES (MILLION $) =	45.000000
OTHER TAXES (MILLION $) =	96.000000

****
SUPPLIER DATA
****

>>>>>>>>>>>>>>>>>> NO OF SUPPLIERS = 3

>>>>>>>>> NO OF PERIODS IN A YEAR = 12

SUPPLIER	COMMODITY CHARGE ($/MMCF)	DEMAND CHARGE ($/MMCF)
1	3950.00	1500.00
2	3000.00	3500.00
3	3000.00	0.00

SUPPLIER	TAKE OR PAY SHARE OF THE DEMAND CONTRACT
1	0.4000
2	0.5000
3	0.0000

SUPPLIER	MAXIMUM CONTRACTIBLE DEMAND (MMCF)
1	1200.00
2	1200.00
3	100.00

PERIOD	NUMBER OF DAYS
1	30.0
2	30.0
3	30.0
4	30.0
5	30.0
6	30.0
7	30.0
8	30.0
9	30.0
10	30.0
11	30.0
12	30.0

****
MARKET DEMAND DATA
****

CUSTOMER CLASS	BASE LOAD COEFFICIENT (MMCF)	HEATING LOAD COEFFICIENT (MMCF/DEG-DAY)
RESIDENTIAL	2534.4100	17.4630
COMMERCIAL	887.0900	7.0380
INDUSTRIAL	3283.8200	3.8390
INTERRUPTIBLE	2500.0000	0.0000

CUSTOMER CLASS	REFERENCE AVERAGE PRICE ($/MMCF)	DEMAND ELASTICITY
RESIDENTIAL	4977.54	-0.2200
COMMERCIAL	4977.54	-0.3200
INDUSTRIAL	4520.18	-0.6400
INTERRUPTIBLE	4000.00	-1.5000

PERIOD	DEGREE-DAYS	STD OF DEG- DAYS
1	506.6000	90.5000
2	248.2000	88.3000
3	50.5000	28.8000
4	11.0000	9.4000
5	18.9000	14.1000
6	120.5000	42.1000
7	371.6000	91.1000
8	712.6000	85.6000
9	1071.6000	145.8000
10	1207.7000	129.5000
11	1046.3000	115.2000
12	892.5000	125.4000

STORAGE DATA

>>TOTAL ANNUAL DELIVERY/WITHDRAWAL (MMCF) = 62000.0000

PERIOD	DELIVERY(+)/WITHDRAWAL(-) (MMCF)
1	8556.0000
2	9796.0000
3	9424.0000
4	9300.0000
5	9238.0000
6	8742.0000
7	6944.0000
8	-11036.0000
9	-12400.0000
10	-17856.0000
11	-9300.0000
12	-11408.0000

COMPUTATIONAL AND OTHER PARAMETERS

>>>>>>>>>CONVERGENCE CRITERION = 10.00 $/MMCF

>>>>>NO OF RELIABILITY LEVELS = 5

LEVEL	RELIABILITY	Z-VALUE
1	0.9900	2.3267
2	0.9800	2.0540
3	0.9700	1.8814
4	0.9600	1.7511
5	0.9500	1.6450

PERIOD	SELECTED SYSTEM RELIABILITY LEVEL
1	1
2	1
3	1
4	1
5	1
6	1
7	1
8	1
9	1
1Ø	1
11	1
12	1

SUPPLIER	SELECTED RELIABILITY LEVELS FOR 12 PERIODS											
1	1	1	1	1	1	1	1	1	1	1	1	1
2	1	1	1	1	1	1	1	1	1	1	1	1
3	1	1	1	1	1	1	1	1	1	1	1	1

```
>>>>>>>>>>>>>MAX NO OF ITERATIONS =    4Ø
>>>>>>>>>>>NO OF SIMULATION YEARS =   5ØØ
>>>>SEED FOR RANDOM NO GENERATOR =  1ØØØ

>>>>>JRUN = 2 : PRINT INPUT AND RUN PROGRAM

>>>>>JOUT = 1 : OUTPUT RESULTS ON PRINTER ONLY
```

++++++++++++++++++++++ OUTPUT RESULTS+++++++++++++++++++++++

ITERATION NUMBER 3

****

AGGREGATE PERIODIC LOADS

****

PERIOD	LOAD (MMCF)	STD OF LOAD (MMCF)
1	20522.945	2522.384
2	13320.911	2461.067
3	7810.686	802.703
4	6709.756	261.993
5	6929.942	392.990
6	9761.701	1173.396
7	16760.272	2639.107
8	26264.504	2385.813
9	36270.426	4063.686
10	40063.757	3609.378
11	35565.273	3210.814
12	31278.614	3495.105

OPTIMAL SOLUTION CHARACTERISTICS

DISPATCH SHARING PARAMETERS

SUPPLIER	SHARES IN 12 PERIODS			
1	0.41373	0.28964	0.33558	0.36125
	0.35772	0.31256	0.30809	0.37979
	0.38519	0.33055	0.39267	0.29106
2	0.50043	0.60635	0.50737	0.54619
	0.54085	0.54615	0.59060	0.57422
	0.52479	0.57143	0.51841	0.60181
3	0.08584	0.10401	0.15705	0.09255
	0.10143	0.14128	0.10131	0.04600
	0.09002	0.09802	0.08893	0.10713

DEMAND CONTRACTS

SUPPLIER	DEMAND CONTRACT (MMCF/DAY)
1	481.963
2	582.963
3	100.000

MINIMUM COST ANALYSIS

>>>>>OBJECTIVE FUNCTION (TOTAL COST) = 980.891799 MILLION $

SUPPLIER	DEMAND CHARGE (MILLION $)	COMMODITY CHARGE (MILLION $)
1	8.675339	345.940214
2	24.484428	526.085584
3	0.000000	75.706233

SUPPLIER	DEMAND CHARGE (PERCENT)	COMMODITY CHARGE (PERCENT)
1	2.45	97.55
2	4.45	95.55
3	0.00	100.00

MONTE CARLO SIMULATION RESULTS

DIFFERENT CATEGORIES OF GAS PURCHASES

SUPPLIER	MINIMUM REQUIREMENT PURCHASES BY FIRM CUSTOMERS FOR 12 PERIODS (MMCF)					
1	5784.	5784.	5784.	5784.	5784.	5784.
	5784.	5784.	5784.	5784.	5784.	5784.
2	8744.	8744.	8744.	8744.	8744.	8744.
	8744.	8092.	8739.	8705.	8744.	8654.
3	0.	0.	0.	0.	0.	0.
	0.	0.	0.	0.	0.	0.

SUPPLIER	PURCHASES IN EXCESS OF MINIMUMS BY FIRM CUSTOMERS FOR 12 PERIODS (MMCF)					
1	2778.	90.	0.	0.	0.	0.
	201.	0.	645.	204.	1288.	78.
2	8578.	5520.	196.	0.	0.	1103.
	5933.	216.	5749.	4608.	7410.	2916.
3	3000.	2991.	2537.	1518.	1671.	2864.
	2997.	1076.	2925.	2823.	2998.	2533.

SUPPLIER	MIN REQ PURCHASES BY INTERRUPTIBLE CUSTOMERS FOR 12 PERIODS (MMCF)					
1	0.	0.	0.	0.	0.	0.
	0.	0.	0.	0.	0.	0.
2	0.	0.	0.	0.	0.	0.
	0.	591.	6.	39.	0.	89.
3	0.	0.	0.	0.	0.	0.
	0.	0.	0.	0.	0.	0.

SUPPLIER	PURCHASES IN EXCESS OF MINIMUMS BY INTERRUPTIBLE CUSTOMERS FOR 12 PERIODS (MMCF)					
1	2541.	647.	0.	0.	0.	0.
	903.	2.	1130.	685.	1780.	293.
2	155.	2138.	2334.	1316.	1469.	2662.
	1891.	958.	1582.	1939.	970.	2053.
3	0.	9.	463.	1482.	1329.	136.
	3.	1248.	67.	132.	2.	363.

PERIOD	COSTS OF FOUR CATEGORIES OF PURCHASES (MILLION $)			
1	56.073927	52.570307	0.000000	10.625838
2	56.073927	30.302288	0.000000	10.709837
3	56.073927	8.353820	0.000000	10.261188
4	56.073927	4.553236	0.000000	9.446136
5	56.073927	5.013604	0.000000	9.568901
6	56.073927	12.782848	0.000000	10.523160
7	56.073927	32.329607	0.000000	10.764795
8	53.593327	4.048278	2.244210	7.389667
9	56.052496	33.170492	0.021431	10.676014
10	55.923728	26.783292	0.148792	10.470715
11	56.073927	42.242055	0.000000	10.724661
12	55.730788	18.987500	0.336649	10.048416

PERIOD	PENALTY FOR VIOLATING MIN PURCHASE REQ (MILLION $)
1	0.000000
2	0.000000
3	0.000000
4	0.000000
5	0.000000
6	0.000000
7	0.000000
8	0.236389
9	0.000000
10	0.001407
11	0.000000
12	0.006490

GAS SUPPLY CURTAILMENTS

CUSTOMER CLASS	GAS SUPPLY CURTAILMENTS (FRACTION) FOR 12 PERIODS					
RESIDENTIAL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
COMMERCIAL	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
INDUSTRIAL	0.0018	0.0000	0.0000	0.0000	0.0000	0.0000
	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

CUSTOMER CLASS	GAS SUPPLY CURTAILMENTS (MMCF) FOR 12 PERIODS			
RESIDENTIAL	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0
COMMERCIAL	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0
INDUSTRIAL	10.2	0.0	0.0	0.0
	0.0	0.0	0.0	0.0
	0.0	0.0	0.2	0.0

ALLOCATION OF COSTS

>>>>TOTAL DEMAND CHARGE= 33.159768 MILLION $

CUSTOMER CLASS	COMMODITY COST (MILLION $)
TOTAL FIRM	941.273366
INTERRUPTIBLE	123.960411

COST ITEM	PEAK-RELATED	NON PEAK-RELATED
PLANT COST (MILLION $)	34.191672	17.562288
O & M COST (MILLION $)	34.600000	114.400000
DEPRECIATION (MILLION $)	14.534478	7.465522

CUSTOMER CLASS	TOTAL SALES IN 12 PERIODS (MMCF)			
RESIDENTIAL	11288.1	6889.7	3439.3	2754.6
	2889.8	4642.4	9013.2	14970.0
	21272.3	23618.5	20822.2	18215.5
COMMERCIAL	4300.1	2573.5	1219.0	950.2
	1003.3	1691.3	3407.0	5745.4
	8219.4	9140.5	8042.8	7019.5
INDUSTRIAL	4740.0	3869.2	3178.1	3041.0
	3068.1	3419.1	4294.5	5487.7
	6750.0	7219.9	6659.7	6137.7
INTERRUPTIBLE	2696.0	2794.8	2797.9	2797.9
	2797.9	2797.9	2797.9	2797.9
	2784.7	2795.4	2782.4	2797.7

CUSTOMER CLASS	ANNUAL SALES VOLUME (MMCF)
RESIDENTIAL	139815.6
COMMERCIAL	53311.9
INDUSTRIAL	57865.0
INTERRUPTIBLE	33408.2

>>>>TOTAL FIRM ANNUAL SALES (MMCF) = 250992.5

>>>>>>>>>>>>>>>>>ANNUAL PEAK (MMCF) = 39970.9

CUSTOMER CLASS	COST ALLOCATION FACTOR BASED ON ANNUAL SALES	ANNUAL PEAK
RESIDENTIAL	0.557	0.591
COMMERCIAL	0.212	0.229
INDUSTRIAL	0.231	0.181

>>COST ALLOCATED TO INTERRUPTIBLE CUSTOMERS = 123.960411 MILLION $

>>CAP COST ALLOC TO FIRM CUSTOMERS >SALES-BASED= 116.485917 MILLION $
>PEAK-BASED = 88.502770 MILLION $

CUSTOMER CLASS	ALLOCATED COST INCL ENERGY COST (MILLION $)
RESIDENTIAL	642.454617
COMMERCIAL	245.361549
INDUSTRIAL	258.445887

CUSTOMER CLASS	ALLOC COST INCL TAX, ADMN & GEN EXPNS (MILLION $)
RESIDENTIAL	750.024372
COMMERCIAL	286.443800
INDUSTRIAL	301.718922

GAS PRICES

CUSTOMER CLASS	PRICE CHANGE FROM LAST ITERATION ($/MMCF)
RESIDENTIAL	2.45
COMMERCIAL	2.44
INDUSTRIAL	2.59
INTERRUPTIBLE	0.32

CUSTOMER CLASS	PRICE AT CURRENT ITERATION ($/MMCF)
RESIDENTIAL	5364.38
COMMERCIAL	5372.98
INDUSTRIAL	5214.19
INTERRUPTIBLE	3710.48