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NATURAL GAS RATE DESIGN AND TRANSPORTATION POLICY UNDER DEREGULATION AND MARKET UNCERTAINTY

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EXECUTIVE SUMMARY

The natural gas industry in the United States today, while not in crisis, stands at an important crossroad. The direction of its future evolution is not yet clear, but important changes in its organization seem likely. The industry is at the beginning of partial decontrol of wellhead prices, has suffered through two years of an unexpected drop in demand, is yielding to pressures to renegotiate supply contracts, has witnessed the emergence of a spot market, and is being exhorted to offer unbundled transportation, storage, and brokerage services on a nondiscriminatory basis. Although the major regulatory reforms are occurring at the federal level, state public utility commissions (PUCs) are active participants in the process, both separately and as part of the National Association of Regulatory Utility Commissioners. To assist the state PUCs in these matters, the National Regulatory Research Institute (NRRI) was asked by its Board of Directors to study natural gas design issues in the context of the greater market uncertainty that is likely to accompany the current reforms. This report addresses these rate design issues in particular and in addition discusses gas transportation policy, a topic that has gained considerable importance since the inception of this research.

The natural gas market is currently in a condition of disequilibrium. The recession of the U.S. economy in the early 1980s, the reduction in the world price of oil, competition from Canadian and Mexican imports, and the advent of a spot market have placed significant downward pressure on prices, which remain above market-clearing levels. Consequently, there are producers whose wells are not fully utilized and who would be willing to sell gas at a favorable price, but may not be able to arrange to have the gas transported to a potential end user. Since 1983 the Federal Energy Regulatory Commission (FERC) has issued a series of innovative rules and reforms intended to facilitate the interstate transportation of gas. The FERC Notice of Proposed Rulemaking (RM 85-1-000) and its Final Order 436 are the most recent policy developments. In the final order, interstate pipeline companies are given the option of accepting a self-implementing authority to transport gas for all users on a nondiscriminatory basis.

These current regulatory and market conditions are important matters as state commissioners begin to consider transportation programs and tariff structures that are appropriate to the new circumstances. In addition to current conditions, regulators may wish also to consider fundamental factors that govern the efficiency of long-term contractual arrangements. The large scale fixed investments that are very specialized and embedded in pipelines, combined with a fairly high degree of uncertainty and infrequency of transactions, suggest that complex, long-term contracts for gas supply are likely to remain an important part of an efficient gas market. The spot market is quite likely to endure, but its role is likely to be less important in the future after the market has regained its equilibrium. Contract carriage, on a nondiscriminatory basis, would facilitate this market adjustment process. Hence, the current need for transportation programs is mostly due to a disequilibrium in which cheap gas supplies cannot be brought to market. Once a transportation program is erected, the market transactions could take place, prices could be brought into equilibrium, and the original need for the transportation program would be much reduced. The eventual industry structure is likely to involve long-term contracts with the interstate pipeline companies maintaining a major role in the marketing and brokerage of gas. A small, but viable spot market and contract carriage business would be important elements of a competitively configured industry.

Besides transportation issues, state commissions are interested in rate designs, not only at the retail level, but also at the pipeline supplier level since these become the basis for retail prices. Pipeline rate structures strongly influence the competitive pressure on industrial rates, in particular, and in the extreme can create industrial customer interest in bypassing the local distributor in favor of a direct connection to an interstate pipeline supplier. Accordingly, the NRRI analysis includes an evaluation of fixed-variable rate designs (mostly important in the context of FERC oversight of interstate pipeline tariffs), as well as a quantitative study of retail prices based on an NRRI simulation model of a gas distributor. An important conclusion of this research is that natural gas pricing would be improved by unbundled, time-of-use rates for separate services such as the gas commodity itself, its transportation, and its storage. Such rates would be based on cost-of-service principles and would be available to all users on a nondiscriminatory basis. This industry has never adopted time-of-use pricing, despite a peak-responsiblity type of justification for the traditional centerpiece of pipeline rate structures--the demand charge.

Because fixed costs exist, some price discrimination may be warranted as a way to recover the revenue requirement and possibly as a way to improve the aggregate economic well-being of all customers. Such price disrimination has natural limits which, if violated, tend to induce a death spiral in any market where an attempt is made to recover an excessive amount of these fixed costs. In most cases, such limits do not constrain the regulator in practice, since the regulatory process most likely produces a compromise set of prices that falls within the extremes at which such instability would be induced. Nonetheless, there is a close relationship, not previously developed in the literature, between market instability, fixed cost recovery, and unrestricted monopoly pricing. Regulators may find this relationship helpful in evaluating such claims as "Preferential low prices for one customer group can actually reduce prices for the remaining customers also." The circumstances under which such no-loser price discrimination is possible are quite limited. Indeed, a price must exceed that which an unrestricted monopolist would charge (which turns out to be a price so high as to induce a death spiral) before reducing it has the favorable byproduct of also allowing the prices paid by others to be reduced, while keeping constant the regulated company's profits.

It is important to note that the argument concerning these limits to price discrimination is equally applicable to any of the unbundled services that might be offered by a gas distributor or pipeline. Hence, price discrimination is not an issue solely for full-service gas suppliers who can load the fixed costs of the embedded pipeline onto the single commodity price paid by users for a combination of services. It also pertains to companies that offer separate services at unbundled prices, each of which is limited by the maximum price at which instability occurs.

Three capacity conserving rate designs are potentially important in both pipeline and distributor tariffs: time-of-use rates, interruptible rates, and demand charges. For each of these, economic efficiency principles suggest pricing rules that have the effect of sharing capacity costs among all users. The Seaboard and United formulas are consistent with such a generally stated sharing idea. The fixed-variable type of rate design advocated by many pipelines and large industrial customers, by contrast, collects very little fixed costs from interruptible customers who do not pay the demand charge.

The principal virtue of currently configured demand charges is to reduce the financial risk of the pipeline company. Such risk reduction has merit. Nonetheless, little or no empirical evidence is available about the magnitude of this reduction, which needs to be compared to the risk which is shifted forward to distributors and from there shifted to captive retail customers by state commission pricing policies. Careful empirical study is needed to determine whether overall social risk is reduced by fixed-variable rate designs. This overall risk reduction benefit, in turn, needs to be compared with the economic efficiency gains that could be achieved with alternative capacity-conserving rate designs.

The presence of interruptible customers in a distributor's service area can be important to other, firm customers in times of greater uncertainty. Much of this advantage to firm users, however, is due to the reductions of minimum purchase penalties in pipeline-distributor contracts that are made possible by the addition of interruptible users. From the narrow focus of the gas distributor, such minimum purchase requirements are inherently inefficient as evidenced by the optimum, but clearly second-best, dispatching sequence in which the most expensive gas should be taken first, up to the specified minimums. This is a socially perverse order in which to use the nation's natural resources. This distortion to social well-being is justified only if such minimum purchase requirements reduce the financial risk of the pipeline company substantially. The resulting decline in the pipeline's cost of capital must be sufficiently large to offset the misallocation that is induced in the distributor's supply planning and dispatching processes before the conclusion can be drawn that minimum purchase requirements improve overall economic efficiency.

One regulatory option in times of greater uncertainty is to economize by reducing the quality of service. In this study, service reliability is the major indicator of service quality. A reduction in planned reliability, from a curtailment rate of 1 percent to that of 5 percent, can enable a distributor to significantly reduce maximum contract delivery rates. Hence, degrading service reliability is a viable alternate as a response to greater uncertainty. Whether such an action would be wise social policy has not been addressed in this analysis. The optimum provision of public utility capacity is a subtle matter that requires estimation of the value that consumers attach to high quality service. The purpose here is merely to note that the capacity savings associated with a reliability reduction are not trivial and could become part of a commission's regulatory deliberations as a way of dealing with the increased uncertainty facing the natural gas industry.

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FOREWORD

The facts of "deregulation and market uncertainty"--phrasing in the title of this study--are increasingly found throughout the transport and utility sectors. Surely these phenomena characterize the current state of the natural gas industry. This report is intended to help regulators as they consider transportation policies and tariff structures that are appropriate to the new circumstances.

I commend it to you in this light.

Douglas N. Jones
Director
Columbus, Ohio
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CHAPTER 1

INTRODUCTION

The natural gas industry in the United States is currently being reshaped by economic circumstances and regulatory reform. It is encountering new rules, new forms of competition, and more need for flexibility than ever before in its history. Long accepted contractual arrangements are yielding to pressures to renegotiate the terms of supply including price, length of contract, take-or-pay provisions, and transportation services. Industry spokesmen suggest that unbundling transportation, storage, brokerage and other services may be in the self interests of pipeline companies, both local and interstate. State public utilities commission (PUC) regulation of gas distribution companies is likely to be affected profoundly. Although the major regulatory reforms are now (and likely to be in the future) at the federal level, state commissions are active participants in this process both separately and as part of the National Association of Regulatory Utility Commissioners (NARUC). To assist the state PUCs in these matters, The National Regulatory Research Institute (NRRI) has been directed by its board to study and report on natural gas rate design issues in the context of the current reforms. This report is intended to address such rate design policies in general, including transportation rules and policies.

This research is reported in four, interrelated parts. The first is a review of the current status of the natural gas market which appears in chapter 2. Supply and demand conditions are summarized, along with a review of the trend of regulatory reform, particularly at the Federal Energy Regulatory Commission (FERC). At the time that the NRRI Board of Directors instituted this project, natural gas rate design during a period of wellhead price decontrol was the intended focus. Since then, market conditions and FERC rulemaking have placed gas transportation issues at the forefront of the policy agenda, both at the federal and state commission levels. This research project was not directed at these specific transportation issues. Nonetheless, these policy matters are sufficiently important to state commissions to be reported here in at least a preliminary fashion. The background to this discussion is in the second and third sections of chapter 2. The first of these describes the recent decisions and directions of the FERC. This begins with an analysis of the FERC minimum bill rule, which is important in the subsequent quantitative work in chapters 5 and 6, and ends with a summary of the recent Final Order 436.

The last section in chapter 2 addresses trends in gas regulation at the state commission level. The NRRI surveyed 16 states in early 1985 regarding interruptible rates, flexible pricing, special marketing programs, and gas-on-gas competition within each state's jurisdiction. The responses are summarized in chapter 2, and a more extensive analysis is contained in appendix C.

The second part of this research is a discussion and analysis of rate design issues in the natural gas industry today. This is not confined to state commission jurisdiction over retail rates. Included also is an analysis of fixed-variable rate designs which are important mostly in the context of the FERC oversight of interstate pipeline tariffs. State commissions are vitally interested in pipeline rate design, since such rates become the basis for retail prices. Also, pipeline rate designs strongly influence the competitive pressure on industrial rates, in particular, and in the extreme could become the source of industrial customer interest in bypassing the local distributor in favor of a direct connection to an interstate pipeline supplier. Various economic efficiency perspectives on fixed-variable rate designs are analyzed in chapter 3. The chapter concludes with a discussison of a relationship between price discrimination and market instability that is important to regulatory practice and which has not been developed in the literature to date.

The third part of this report is a discussion of the policy issues regarding the transportation of natural gas. Chapter 4 summarizes both long-and short-term considerations that may be of interest to state commissions. The long-term perspective is presented in the context of Oliver Williamson's framework for understanding the transaction costs of contracts. The major arguments for and against specific transportation proposals are analyzed within this framework.

The fourth part of this research is reported in chapters 5 and 6. The NRRI developed a computer simulation model to investigate natural gas rate design and supply mix questions in the context of demand uncertainty. The approach is to formulate a gas distributor's problem of choosing a least-cost mix of gas supplies as a chance-constrained program. The random nature of demand is made explicit by a Monte-Carlo simulation of the optimum dispatching sequence of the selected set of gas supply contracts. The average gas prices that emerge from the actual dispatching are compared to those used in the long-term, planning stage of selecting gas suppliers. The entire numerical procedure is repeated until an equilibrium is achieved between the long- and short-term optimization problems. This model design allows the analyst to study such matters as minimum purchase requirements and the curtailment of occasional excess demand, issues which are analytically intractable. A technical description of this optimization model is given in chapter 5.

The model has been used to study a variety of regulatory policies and demand conditions. The results of these numerical exercises are summarized in chapter 6. A brief summary of this research constitutes chapter 7.

CHAPTER 2

CURRENT STATUS OF THE NATURAL GAS MARKET

A variety of factors have combined in recent years to create fundamental changes in the operation of the national market for natural gas. Chief among these has been the partial decontrol of most wellhead prices, a reduction in the world price of oil, increased competition from Canadian and Mexican imports, the advent of a spot market in natural gas, and regulatory changes, particularly at the federal level, that encourage competition by facilitating contract carriage programs. Since this report deals with rate design issues under greater uncertainty, it is useful to frame the discussion in terms of current market conditions. These are briefly reviewed in the first section of this chapter. The second section contains a discussion of regulatory trends at the federal level that focuses on the most recent development, the FERC Notice of Proposed Rulemaking (RM 85-1-000) and the Final Order 436 issued on October 9, 1985. The third section of this chapter addresses regulatory trends at the state commission level.

Natural Gas Supply and Demand

Much of the current turmoil in the natural gas industry has to do with the changes in transportation programs. These transportation issues, which are discussed later in this chapter and analyzed in chapter 4, derive much of their importance from recent U.S. supply and demand conditions. The current disequilibrium in the national gas market serves as a backdrop against which rate design and transportation policy must be viewed. For this reason, a brief review of natural gas market conditions is a useful prelude to the remaining discussion.

This section summarizes a more in-depth review that interested readers can find in appendix A of this report.

The nationwide demand for natural gas declined in every year from 1980 to 1983, in large part due to the U.S. economic recession. Within this overall trend, two kinds of consumption patterns can be distinguished. First, the residential and commercial sectors can be combined and described as classes for which consumption peaked in 1979 and then gradually declined until 1983, although the decline was not steady. For each, demand dropped by about 9 percent during this time. Although demand of both sectors has recovered some since 1983, 1979 usage levels have not yet been reached. Part of this demand decline can be attributed to the recession and part to price-induced conservation. Demand in these sectors tends to be somewhat insensitive to price; however, the price increases during the early 1980s were large enough to induce a noticeable usage reduction, nonetheless.

A second consumption pattern is discernible for the industrial and electric utility sectors. The economic recession affected the users in these groups more severely. By 1983 the demand of each had declined by about 20 percent from the 1980 level. Users in these two groups are relatively sensitive to price and consequently, part of the usage drop can be explained by the price increases during this period.

Whether caused by the recession or retail price increases, however, the outcome was a significant reduction in gas demand in the early 1980s. The other half of the natural gas market, that is, supply, remained relatively stable during this same period. Wellhead prices, for the most part, were increasing or stable, which created sufficient drilling incentives that total reserves remained more or less constant. Consequently, the capacity to deliver gas from existing reserves exceeded demand causing some gas wells to be shut in. This excess deliverability is expected by the U.S. Department of Energy to last until the late 1980s or early 1990s.[1]

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[1]See appendix A for further discussion.

The importation of natural gas will be a major factor influencing U.S. markets both in the near term and for many years. Although Mexico and Algeria export natural gas to the U.S., Canada is, by far, our largest foreign supplier. Canadian gas is currently about 90 percent of all imports. The Canadian government changed its export policy in November 1984 to allow Canadian suppliers to compete more effectively in U.S. markets. Although the policy change at that time relaxed the rules, exporters still had to meet seven conditions (discussed in appendix A) before a negotiated contract would be accepted by the government. These were still restrictive, although less so than the preceding rules. These rules have been liberalized even further in October 1985. In particular, the previous pricing floor, which had been the Toronto city gate price, has been replaced by pricing benchmarks in the area adjacent to the export point. Also, a condition that had prevented Canadian suppliers from undercutting the price of alternative fuels has been dropped. Canadian gas is likely to become even more competitive in light of these new rules.

The prices that are likely to emerge from the interaction of supply and demand are routinely forecasted by the U.S. Department of Energy (DOE), DRI, Inc., and others. Some of these are reviewed in appendix A. DOE expects demand to expand in all energy markets in the near future. World demand for oil is likely to remain stable during the 1980s but expand in the 1990s, in the DOE view. The current deregulation of the natural gas industry is expected to make gas competitive with alternative fuels for the remainder of this century. Because of these predictions, DOE forecasts the price of natural gas to remain stable during the 1980s and then increase in response to rising oil prices.

Federal Regulatory Trends

Many factors contribute to the level of uncertainty in the natural gas industry. But, as with any market transition to a deregulated environment, much depends on the role played by the commissions involved.

The post-NGPA years have been a time of decisions and actions for the FERC as well as other commissions with jurisdiction over natural gas sales. If any one factor can be singled out as the most influential in determining the future state of the natural gas industry, it is the role played by the FERC. The actions taken by this federal agency during the coming months will affect the ease with which the transition process occurs. The path of deregulation in this industry will be influenced if not determined by decisions of the FERC. It is important for state commissions to monitor closely the steps taken by the FERC during the remaining phases of natural gas deregulation.

This section reviews some of the basic transitions that have occurred in the recent past, and the role the FERC has played in these processes. The discussion begins with recent changes to minimum bill regulations where the FERC has ruled, in essence, that variable costs must be eliminated from natural gas pipeline minimum bills. Next, the advent of special marketing programs and spot markets is briefly reviewed. The section concludes with a discussion of the recent FERC's Notice of Proposed Rulemaking, and the Final Rule 436 which will shape the natural gas market restructuring during the final phases of deregulation.

Minimum Bills

Minimum bills are used in gas purchase contracts between distribution companies and pipeline companies. A minimum bill generally consists of a demand charge and may also include a minimum commodity charge. A demand charge is the price paid by a distributor for its billing demand which is the maximum quantity of gas that a seller is obligated to deliver without curtailment or interruption. The demand charge covers a certain percentage of the fixed costs of the pipeline facilities as determined by the specific cost allocation method used by the FERC for rate design. Before 1952, a fixed-variable method was used that assigned all fixed costs to the demand charge. In 1952, the Seaboard formula was adopted which assigned 50 percent of the fixed costs to the demand charge. In 1973, the FERC began to use the United method which assigns only 25 percent of fixed costs to the demand charge.

A commodity charge is a price per unit of gas actually delivered and is intended to recover both the remaining fixed cost and all of the variable cost, including that of the purchased gas. If the minimum bill contains a minimum commodity charge, a specified percent of the billing demand must be purchased whether the gas is taken or not. The Zinder review of pipeline rates shows that in 1984 minimum commodity charges were based on take-or-pay fractions as high as 90 percent, although 75 percent was used most frequently.[2]

By recovering some part of fixed costs with commodity charges, the Seaboard and United formulas increase the financial risk of the pipelines. Minimum commodity bills are intended to reduce this risk. Pipeline companies typically advocate a minimum bill in that:

1. It protects pipelines from underrecovery of fixed costs because of the Seaboard and United methods of computing the commodity charge,

2. It protects full requirements customers from the cost burden caused by swings off the system by partial requirements customers, and

3. It protects all customers from take-or-pay costs incurred by the pipeline since a minimum commodity charge prevents the incurrence of take-or-pay payments by discouraging customer cut backs.[3]

However, minimum bills have adverse effects on the gas industry and the consumer. Minimum bills tend to prevent the transmission of market signals back from the burner tip to the wellhead. They also shield the pipelines from the risk of market loss. Under such conditions, pipeline companies may have less incentive to engage in hard bargaining with producers since much of the risk associated with

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[2] Rate Schedules of Natural Gas Pipelines (Washington, D.C.: W. Zinder & Associates, September 1984).

[3] Public Utilities Fortnightly, August 30, 1984, pp. 53-54.

producer-pipeline contracts is shifted to the distribution company, thereby inhibiting the development of market-based competition for the delivery of gas supplies and services.

The importance of minimum bills has changed as the natural gas market has evolved. Before the passage of the Natural Gas Policy Act (NGPA), the regulated price of gas exhibited little fluctuation, and hence, minimum bill provisions were of little importance. Moreover, during this time the regulated price of gas was low compared with alternative fuel prices, and the result was an excess demand for and shortage of natural gas. In such circumstances, distribution companies paid a low regulated city-gate price for gas and agreed to a relatively high minimum bill. During such periods of short supply of gas, pipeline companies were not concerned with swings off the system by partial requirements customers and any adverse effects of minimum bills were minor. Following the passage of the Natural Gas Policy Act in 1978, however, a variety of circumstances combined to create an excess supply of natural gas. In these circumstances, minimum bills were quite burdensome to some customers that could not use all contracted gas volumes. Moreover, they could not shop around for cheaper sources of gas under the binding minimum bill provisions.

Minimum bills have caused a number of disputes between pipelines and distribution companies in the early 1980s. In some cases, partial requirements customers have sought relief from minimum bill payments over the opposition of the pipeline companies, naturally enough. Until 1984, the FERC settled such disputes on a case-by-case basis. The Commission used one of three creative regulatory settlements.[4] One suspended minimum bill obligations and instead substituted interim monthly and interim annual provisions.[5] In addition, this settlement allowed a time period during which the distribution company could make

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[4]Ibid., pp. 51-52.

[5]See State of Michigan and Michigan Public Service Commission v. Trunkline Gas Co., Docket No. RP81-103-000, July 8, 1983. See also Michigan Consolidated Gas Co. v. Panhandle Eastern Pipeline Co., Docket No. RP83-84-000, February 17, 1984.

up any shortfall in purchases below the annual purchase obligation under the interim annual minimum bill. The second type of settlement waived all or a portion of the variable cost components of the minimum bill.[6] A third form of the settlement was specifically directed at the Tenneco Inc. special marketing program called Tenneflex. A pipeline transporting gas from a releasing pipeline to an end-user received a credit against its minimum bill for the quantity of gas transported, as would the local distribution company serving the end user. This effectively credited against the minimum bill requirement all variable costs (including purchased gas costs) associated with the quantity of gas transported.[7]

In the face of the pervasiveness and significance of minimum bill problems, the FERC issued a rule in May 1984 that eliminated variable costs from minimum bills.[8] The rule requires that purchased gas costs (including take-or-pay obligations) must be stated separately in all pipeline tariffs. The FERC also prohibited the recovery of gas costs for gas not taken on the effective date of the rule. The rule has the following effects on the natural gas industry:

1. The risk of market loss imposed on pipeline customers is shifted to the pipelines.

2. Pipeline customers, mostly partial requirement customers, are encouraged to pursue least-cost purchasing policies.

3. The potential for pipeline loss of load resulting from fuel switching by customers is diminished since a decrease in the gas costs due to the minimum bill rule, especially to industrial customers, allows the gas to be more competitive with low cost alternative fuels.[9]

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[6]See Texas Gas Transmission Corp., Docket No. RP82-137-000, July 12, 1983.

[7]See Tenneco Oil Co. et al., Docket No. CI83-269-001, January 16, 1984.

[8]FERC Order No. 380, Docket No. RM83-71-0000.

[9]See Robert W. Stewart, "Challenges Facing the Natural Gas Industry and Its Regulation," Public Utilities Fortnightly, September 27, 1984, p. 14.

Special Marketing Programs

From 1983 to 1985, Special Marketing Programs (SMPs) were used by pipelines and producers to improve the competitiveness of natural gas in overall energy markets. Most SMPs were characterized by several conditions:

- Gas was sold directly from the producer to final customers,
- The pipeline served as a transporter and coordinator, and
- The producer reduced the price below that in existing contracts and provided take-or-pay relief to the pipeline releasing the gas.

The SMPs were a direct result of high natural gas prices and the resulting loss of sales. Mentioned frequently in the literature was the fear of a "death spiral" where the load loss leads to an even higher price, leading to more load loss, and so on. The notion of such a death spiral is discussed more thoroughly in chapter 3.

Most SMPs were structured so that only large customers could take advantage of the opportunity to purchase low-cost gas. During this time, pipelines and distributors tried several other ways to compete with alternate fuel prices and thereby avoid the loss of large industrial sales, in particular. Contract carriage programs to transport gas purchased in a spot market by the end user are an example. Another is the action of distribution companies to tie gas prices for large industrial users to the price of alternate fuels. State commission responses differed. For example, the Michigan Commission ruled that such special gas rates for industrial customers with easily accessible substitutes for natural gas were not discriminatory.[10] On the other hand, the Pennsylvania Commission rejected such discount rates for industrial customers with ready substitutes because these rates were

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[10]See Southeastern Michigan Gas Company Case No. U-7652 and U-7653, November 1, 1984.

not in the public interest and could not be justified with a cost-of-service study.[11]

Although SMPs were supported by most industry analysts and groups such as INGAA, such programs accounted for at most only about 1.5 percent of total gas sales. The FERC established several guidelines for each SMP in an effort to make these programs consistent with the public interest. These had the effect of ensuring that the released gas was priced higher than the pipeline's weighted average cost of gas and also higher than the ceiling price of section 109 gas. The FERC mandated transportation rates that were based on fully allocated costs so as to protect system customers from paying more than their fair share of fixed costs. The FERC also placed restrictions on the type of end user eligible to participate in a SMP. These limitations were intended to control the amount of competition permitted between pipelines in so-called core markets, ostensibly to protect captive customers of a pipeline from bearing a larger fixed cost burden if a pipeline were to lose in such a competition.

The Special Marketing Programs represented a creative regulatory response to a persistent disequilibrium market condition. Prices were and are not sufficiently flexible to eliminate the current excess supply deliverability. SMPs are inherently discriminatory, however, as pointed out by the U.S. Court of Appeals on May 10, 1985. In the court's view, the FERC "has not adequately attended to the agency's prime constituency--the consumers whom the Natural Gas Act (NGA) was designed to protect."[12] This led to the most recent action taken by the FERC in proposing comprehensive changes in its regulations governing transportation of natural gas by pipelines. Since this action is going to affect the industry for years to come, the Commission rules are discussed next in detail.

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[11]See Pennsylvania Public Utility Commission v. Equitable Gas Co., R-822031 and R-822031C001, November 22, 1983.

[12]Maryland People's Counsel v. Federal Energy Regulatory Commission, United States Court of Appeals No. 84-1090, May 10, 1985.

FERC's Notice of Proposed Rulemaking

On December 24, 1984 and January 18, 1985 the FERC initiated a Notice of Inquiry about natural gas transportation, rate design, and risk in which it undertook a comprehensive review of and received extensive public comments about the state of the industry. As a result of this inquiry, and following the partial wellhead decontrol of natural gas which took place on January 1, 1985 as well as the aforementioned court decision, the FERC proposed a series of changes that will reform the Commission's regulation of interstate pipelines. On May 30, 1985 the FERC unanimously approved a Notice of Proposed Rulemaking (NOPR) (Docket No. RM85-1) that would implement policies in four specific areas.[13] The changes are in the form of revisions to parts 2, 154, 157, 161, and 284 of the Commission's Regulation pursuant to sections 4, 5, 7, and 16 of the Natural Gas Act, 501 of the Natural Gas Policy Act, and 402 and 403 of the Department of Energy Organization Act.

The NOPR has four basic parts. In three of them, dealing with transportation, optional certificates, and buy-outs of take-or-pay liabilities, the FERC uses its conditioning power to induce interstate pipelines to accept certain operating procedures. In each of these three parts, the new procedures have the effect of improving the competitiveness of the natural gas market, and each is conditional upon the pipeline accepting (voluntarily) particular rules of conduct. The fourth part is not voluntary and would impose a new billing system that is intended to save the benefits of low-priced old gas for existing, high priority customers.

The transportation portion of the NOPR creates a new blanket-certificate program. Pipelines that accept the self-implementing authority under section 7 of the Natural Gas Act and section 311 of the Natural Gas Policy Act must provide transportation services to all

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[13]Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, Docket No. RM 85-1-000, May 30, 1985.

users on a nondiscriminatory basis. In addition, pipelines accepting this role of contract carrier must charge volumetric rates that are based on representative volumes. This effectively imposes the risk of any losses on the pipeline if its management decides to lower rates for competitive or other reasons. Customers would be able to contract for firm transportation services or for interruptible carriage. Customers currently buying gas from the pipeline would be able to convert sales entitlements to transportation entitlements at the rate of 25 percent per year for the next four years. The volumetric prices would be based upon fully allocated costs during the peak period, while off-peak rates would be based on variable costs. Those pipelines that choose not to accept these conditions may continue to use the traditional section 7 procedures.

The second conditional part of the NOPR would allow pipelines to buy out their take-or-pay liabilities and amortize these over five years. Rate base treatment would not be given to these liabilities and the FERC suggested treatment would allow only a return of and not on capital. The precise details of the buy-out have not been settled, and the FERC has requested comments on the appropriate take-or-pay percentage to use in this matter. Pipelines that take advantage of this procedure, however, must accept the nondiscriminatory carriage feature.

A third part of the NOPR, also illustrating the FERC use of its conditioning power, would provide expedited treatment of a pipeline's application for a new or expanded service certificate. This optional certificate would be available to those pipelines willing to accept the risks associated with such new facilities by charging volumetric rates.

The final provision is neither conditional nor voluntary and preserves the benefits of low-priced old gas for existing customers. Gas costs would no longer be rolled in. Rather, the FERC proposes to substitute a three-part pricing structure. The first block would encompass old, price regulated gas and would be allocated to existing customers on the basis of their three-year average consumption during

1982 to 1984. All other gas costs would be recovered in the second block. After four years, the pipeline could set this price at an unregulated, market clearing rate providing it has accepted the nondiscriminatory carriage role. The third block would recover capital costs. The precise nature of the pricing for this block is, as yet, uncertain. It appears that the FERC intends to recover these costs with demand or customer charges, although the NOPR refers only to a non-gas rate structure.

The new FERC emphasis on competition, in part, seems to include the view that if a few pipelines accept the self-implementing transportation authority and thereby achieve a competitive edge, other pipelines will be encouraged, if not forced, to also begin to market unbundled transportation services. The industry would be converted to one that emphasizes the carriage role, if the FERC vision is correct. Successfully transforming the industry in this way, which relies on the voluntary adoption of competitive carriage by the industry, would allow the FERC to achieve its goal of increasing competition without the FERC having to impose politically sensitive policies such as mandatory carriage. The strategy is interesting and is certainly different from that adopted by the courts and the FCC in the case of the telephone industry.

The Final Order

On October 9, 1985 the FERC issued its final order (Order 436) regarding the NOPR (RM85-1). The final order implements the nondiscriminatory carriage portions of the NOPR (with some modifications), delays the block-billing mechanism, and completely drops the take-or-pay buyout provision. The changes in the final rule reflected the comments that the Commission had received during the NOPR process. Acknowledging this, FERC Chairman Raymond O'Connor said "We do read this stuff. We are giving serious, objective consideration to it."[14]

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[14]"FERC's Flexibility on Final-Rule Provisions May Be Key to Its Success," Inside FERC, October 14, 1985, p. 1.

The block billing mechanism had been the subject of much comment, both to the FERC and to the Congress. After lengthy testimony by many pipeline and producer spokesmen, Senator Don Nickles (R-Oklahoma), of the Senate Energy and Natural Resources Committee, was prepared to introduce an amendment to a pending budget bill that would have delayed block billing. Producers are worried that the FERC billing scheme would force all high priced gas contracts down to a market clearing level, while at the same time it would keep all old, regulated gas prices low. In their view, fairness would be served by allowing old gas prices to rise to the market clearing level if unregulated prices are to be forced down to such a level.

This line of reasoning is an example of the contention that almost inevitably follows public regulation of the profits associated with an increasing cost industry. Such profits are distinct from the monopoly profits associated with the exercise of monopoly power whereby production is withheld from a market in order to force price up. OPEC's control of world oil prices, now eroding, is an example of monopoly power. The profits accruing to a producer in an increasing cost industry have an entirely different source. Such an industry is characterized by the fact that producers have differing unit costs.

In the case of natural gas, some wells are less expensive than others, either because the real cost of recovering the gas is fortuitously cheap or because the reserve was discovered at a time when historical recovery costs were low. The current, marginal cost at the wellhead is associated with the most expensive, marginal well. Economically efficient prices are those that are based on current, marginal cost. If such wellhead prices prevail throughout the natural gas market, low cost producers would enjoy a windfall gain. It is these economic rents, or pure economic profits, which are in contention. These rents, however, are not the result of any opportunistic behavior on the part of producers, whereas the exercise of monopoly power involves such socially inefficient behavior. Economic efficiency offers no guide on which party should be deemed socially worthy and receive the rents in an increasing cost industry. The purpose here is merely to note that as long as the identity of the recipient is uncertain, rent-seeking behavior in public forums, such as witnessed in the Senate Energy and Natural Resources Committee, is likely to remain a common occurrence.

The FERC is accepting additional comments on the block-billing mechanism. If the mechanism survives this new round of scrutiny, it would become effective on July 1, 1986.

The FERC decision to abandon the rebuttable presumption of prudence for limited buyouts of take-or-pay obligations reflected fears that any percentage stated by the FERC to be a safe harbor would have become a floor. Pipelines argued that producers would point to the FERC benchmark as an important negotiating strategy, whereas the pipelines might be more successful in reducing the take-or-pay fraction without such a benchmark. Under its final rule, the FERC review of prudence will be conducted on a case-by-case basis.

The most important part of the final rule is the transportation program, which offers an optional blanket certificate to provide carriage on a non-discriminatory basis. The transportation authority under the certificate is voluntary and self implementing. It covers firm service, as well as interruptible service. Pipelines must use unbundled, volumetric rates, differentiated by peak and off-peak periods as well as geographical areas, to ration capacity and encourage full asset utilization. A major change from the NOPR is that customers may reserve firm transportation capacity by paying a reservation charge. As in the NOPR, customers of pipelines accepting the blanket certificate may reduce entitlements by 25 percent annually for four years. The transportation authority does not depend upon distributors granting similar open access to their system or on producers granting take-or-pay relief, both of which had been suggested in comments.

As this report is written, it is not yet clear whether pipeline companies will accept the blanket certificate or not. Most have not declared their ultimate intentions. Open access advocates are exploring ways to place Congressional and Justice Department pressure on pipeline companies to embrace non-discriminatory transportation.[15]

State Commission Regulatory Trends

In early 1985 a survey of selected state commissions was conducted by the NRRI requesting information regarding pricing policies and regulatory practices for major natural gas distributors. A letter, a copy of which appears in appendix B, was mailed to nineteen state commissions. Of these, sixteen responded either by letter or through follow-up phone calls. The sixteen states providing information were California, Florida, Illinois, Kentucky, Louisiana, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Texas, Washington, West Virginia, and Wisconsin. The NRRI survey requested information about interruptible rates, flexible pricing, Special Marketing Programs, and gas-on-gas competition within each state's jurisdiction. This section summarizes the responses. A more complete description is in appendix C.

At about the same time that the NRRI survey was mailed, the NARUC Staff Subcommitte on Gas surveyed its members regarding intrastate carriage of natural gas. Fifteen states were included in the subcommittee's report, of which eleven were states that were also surveyed by NRRI. In one area, intrastate carriage, the two surveys were similar in that the NRRI question about special marketing programs within a state's jurisdiction generally requires some form of intrastate carriage. Hence, the two surveys reinforce one another on this particular issue, and complement one another more generally since the NRRI survey was more extensive. Interested readers may wish to obtain the subcommittee's results to supplement the information reported here.[16]

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[15]"Producers Seek Probe of Pipelines; House, Senate Resolutions Offered," Inside FERC, November 11, 1985, p. 1.

[16]1985 Report of the Committee on Gas (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1985), pp. 31-32.

Most state commissions reported that distributors in their states used interruptible rates. Most commonly, the interruptible tariff is fashioned so that customers that volunteer to be interrupted pay a smaller fraction of the distributor's margin than firm customers. In some cases, state commissions reported that this lower price was based on cost-of-service principles, while others said that interruptible customers do not pay the demand component of the pipeline tariff. The economic efficiency of such interruptible rates is discussed in the next chapter.

Flexible pricing is used in many states, although several commissions reported that such a policy is not used in their states. Included in this latter group are Florida, Kentucky, Missouri and Texas. In the case of Kentucky, a flexible pricing rule exists but has never become effective because the flexible pricing formula has always yielded a price higher than the regular tariff which is a ceiling price in the rule.

In most states, flexible pricing formulas are linked to some benchmark price of an alternate fuel. The price of low sulphur, number 6 fuel oil is the benchmark in California and Illinois, for example. The benchmark in Wisconsin, North Carolina, and Pennsylvania is based upon the industrial customer's own circumstances. In effect, the distributor and industrial user negotiate a price that allows the customer to remain on the gas system. In such cases, the customer is typically required to document the ability to switch fuel suppliers and to verify the price at which the customer can purchase the alternate fuel.

The survey respondents reported a wide range of activity regarding intrastate carriage of gas and Special Marketing Programs. Several states had no intrastate carriage program at the time of the survey. These included California, Florida, New Jersey, New York, Texas, and Wisconsin. Since then, California and New York have begun to investigate intrastate carriage programs, and more state commissions are likely to consider such programs in light of the U.S. Court of Appeals decision, the FERC NOPR, and the final order.

Of those commissions reporting intrastate transportation tariffs, two approaches were evident from the survey responses. Kentucky and Missouri permitted carriage of SMP gas only if such gas were displacing an alternate form of energy. Carriage was not permitted if the gas being transported displaced the distributor's firm sales. This restriction was not reported by most states, however, which typically allowed any SMP gas to be transported.

Most state commissions that have approved intrastate carriage programs have based the transportation fee on some version of the distributor's margin. This margin is typically calculated as the customer's general service rates less the cost of the distributor's system supply. This type of methodology is used in California, Illinois, and New York among others. In practice, this method can be applied in a variety of ways. In California, the marginal cost of gas is subtracted from the general services rate. Because of Southern California Gas Company's sequencing policy, its marginal cost of gas is lower than its average cost which results in an unusually large transportation rate. Most other states and companies subtract the average cost of system gas supply. An alternative to this method is to base transportation prices on a cost-of-service study of the unbundled set of services offered by a local distributor. Such cost studies are likely to become more common if interstate carriage becomes more widespread, as seems likely.

Direct competition between pipelines is unusual outside of the major gas producing states of Texas and Louisiana where pipelines compete openly for industrial load. Apart from these, only the Illinois, New York, Pennsylvania, and Ohio Commissions reported any gas-on-gas competition. In Illinois and New York, several distributors are partial requirements customers of more than one pipeline, and the respective commissions encourage the distributors to purchase the least cost gas. In Ohio, the self-help gas program has been working effectively since the mid-1970s to provide a small amount of competition to the major pipelines. In addition, one distributor in Ohio has chosen to connect with a second pipeline in order to reduce gas costs. The Pennsylvania competition has taken the form of neighboring distributors competing for the same industrial load. The Commission decides such territorial disputes separately and has no generic rules.

Summary

The current condition of excess deliverability in the natural gas market means that there are opportunities to find producers with wells that are either shut in or are not producing to capacity and who would be willing to accept a price lower than the prevailing price. The FERC final order may open up the competition for such producers to distribution companies and large industrial users. Whether such competition will materialize depends on the voluntary acceptance of non-discriminatory carriage by the interstate pipeline companies. If the interstate companies move toward a larger carriage role, state commissions need to be prepared with complementary carriage programs and rates for local distributors. Many have such programs already; many have not yet had the need to address the issue of carriage. Some issues regarding a distribution company's transportation tariff are discussed in chapter 4, following an analysis in chapter 3 of natural gas rate design issues from several different economic efficiency perspectives.

CHAPTER 3

PERSPECTIVES ON FIXED AND VARIABLE COST RECOVERY

The design of natural gas rate structures must balance a variety of factors: the risk of revenue recovery by producers, pipelines and distributors; the relative cost of serving firm versus interruptible users; the competitive pressures from alternative fuel supplies; and equitable, nondiscriminatory treatment of all customers. A variety of federal and state regulatory practices, policies, and rate designs have evolved in the past 50 years that have attempted to balance these forces, with varying degrees of success depending on the status of gas supply and demand. Federal policies, in particular, are currently changing in fundamental ways. Most gas has been freed of wellhead price controls, and the Federal Energy Regulatory Commission is about to propose new rules for the interstate pipeline industry. State commissions are faced with adapting retail gas rates to the new transportation and billing rules at the federal level. The purpose of this chapter is to outline the rate design issues that state PUCs are likely to encounter in these circumstances. The chapter has five sections beginning with a short policy discussion of current fixed-variable rate designs, especially for interstate pipelines, and ending with a discussion of the limits to price discrimination.

Toward An Evaluation of Fixed-Variable Rates

Two-part tariffs, consisting of a demand charge for a customer's own maximum demand (in units of maximum mcf per day) and a commodity charge for each mcf used, have been the most common rate structure used by gas utilities. This has been particularly true for the FERC regulated rates of the interstate pipelines, and to a lesser extent, for state regulated distribution utilities. Time-of-use (TOU) rates have never been a standard feature of natural gas pricing policy, despite the strong seasonal nature of gas demand. The FERC Notice of Proposed Rulemaking and the final rule contain features of a TOU rate structure for transportation, but these are not fully developed as yet. The fact that gas storage is used to balance the load between seasons does not eliminate, by itself, any differences in the marginal supply cost between seasons.[1] To the extent that marginal cost differences do exist, these are most likely to be a reflection of the limited pipeline capacity to transport gas during high demand periods. The cost of the gas itself does not vary seasonally. Since the commodity cost of the gas is more than half of most retail rates, it might be that time-of-use pricing would create only a small seasonal differential. For this reason, it may be true that TOU gas rates would have little practical value. Whether this is true or not, however, much of the contention regarding gas rate design has to do with recovery of fixed costs, meaning the capital cost of the pipelines owned by distributors and interstate transporters. Economic efficiency suggests the recovery of such costs on the basis of seasonal usage, with all users charged the same transportation fee for gas delivered at the same time. In addition, users who are willing to be interrupted would be charged a lower price during those times when such interruptions were likely. The purpose of calling the reader's attention to TOU transportation rates at this juncture is merely as a reminder that one measure of the usefulness of rules of thumb such as "Interruptible customers should pay no demand costs" is how well they mimic TOU cost patterns.

The two-part tariffs actually approved by the FERC have drifted, since 1950, towards a larger recovery of demand costs in the commodity charge portion of the user's bill. In the 1950s, pipelines typically used a fixed-variable formula in which all variable costs were

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[1]For a discussion of this point see Graham Pyatt, "Marginal Costs, Prices and Storage," <u>The Economic Journal</u>, December 1978, pp. 749-762.

recovered in the commodity charge and all fixed costs in the demand charge. The conventional practice was that "firm" customers paid the demand charge, while interruptible users did not. Large, industrial customers who were directly connected to the interstate pipeline generally benefitted from a substantial discount by agreeing to take gas service on an interruptible basis. Local distributors were "firm" customers of the pipeline company and paid the FERC approved demand charge. The subsequent recovery of such demand charges from the distributor's residential and industrial customers was and is regulated by the state commission. The state-approved industrial price might include some allocation of the pipeline's demand charge; however, the state's pricing policies may be limited if some of the distributor's industrial customers can plausibly threaten to bypass the distributor and connect directly to the interstate pipeline. Hence, the FERC approved demand charge influences industrial retail pricing beyond the very substantial, direct industrial level.

Partly in recognition of these pricing effects, the FERC (then the Federal Power Commission) adopted the Seaboard formula in the 1960s which effectively narrowed the difference between the prices paid by firm and interruptible customers. The gap was narrowed further in 1973 when the United method was adopted. Recently, pipelines and their industrial customers have argued, with modest success, for a return to rate design principles that place more of the fixed costs in the demand charge. The FERC staff has presented a modified fixed-variable rate design in a recent case. Although it was not accepted, the Administrative Law Judge adopted the Seaboard method which moves in the direction of unloading the commodity charge. The current pressure to revert to a modified fixed-variable structure has been characterized as a "desperate attempt to help utilities retain and recover price-sensitive industrial load."[2] Hence the link between the industrial pricing

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[2]Arlon R. Tussing and Connie C. Barlow, "The Fixed-Variable Paradigm," ARTA Energy Insights, April 1984, p. 3.

policy of paying only the commodity charge and the FERC non-TOU method of recovering fixed costs results in pressure to reallocate such fixed costs in times of severe price competition from alternate fuels.

A fixed-variable rate design has been advocated by several commentators in recent years. Tussing and Barlow have summarized these arguments as having three major strands.[3] The first is that interruptible customers would be charged a minimum of zero of the fixed costs and more than this only when market conditions allowed. Such a fixed cost allocation is appropriate because these customers have not "reserved" capacity, but rather are willing to be interrupted. Second, because nonfirm users typically have multi-fuel burning capability, they can quickly drop out of the gas market when supplies are tight which will help to dampen wild fluctuations in spot market prices. Third, since such rates correspond to the incurrence of costs, the financial risk to the pipeline's investors is reduced. These views are commonly advanced by many industry commentators to support fixed-variable rate designs.

The difficulty in evaluating the fixed-variable rate proposal is that, like many other regulated pricing structures, the final form of the tariff has little to do with the arguments used to justify it in the first place. The argument that certain customers are interruptible, are not responsible for the cost of capacity, and therefore, should pay none of or only a small fraction of the demand charge when market conditions allow it, is based on two interrelated ideas: (1) capacity costs are associated with peak demand and (2) interruptible service is qualitatively inferior to firm service. The second idea is discussed in the next section where various models of interruption are reviewed.

The first idea, that peak demand causes the need for capacity, is the basis of TOU pricing in the economics literature. In practice, TOU demand patterns of firm versus interruptible customers are compared, possibly in a formal cost-of-service study, and the assertion is made

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[3]Ibid.

that firm customers are responsible for the peak and hence should pay all or most of the demand costs. The prices that emerge from the typical version of such an exercise are the same in peak and off-peak periods for a given customer class. Differences in the non-TOU prices between firm and interruptible customers are asserted to correctly allocate fixed costs. Such an argument would be more persuasive, however, if the rate design reflected the TOU cost differences that motivated the assertion in the first place. Indeed, the objective of studying and discerning TOU cost patterns is to design corresponding pricing patterns, at least from the viewpoint of promoting economic efficiency. To use such a study to fashion rates that do not vary over time may promote social equity in the view of many regulators, but most if not all of the efficiency virtue is simply lost.

Most peak-load pricing models have advanced beyond the stage where all capacity costs are collected, in effect, only from peak users. Even in the case of the simplest possible circumstances in which only peak users pay for capacity, however, it seems clear that large industrial customers, otherwise interruptible, usually would take gas during the winter heating season and thus would pay for part of capacity during that time under a TOU pricing policy. The nonseasonal nature of their demand undoubtedly would result in a lower, year-round, average price for these users, but it seems unlikely that they would pay no portion of the fixed costs, as suggested in the fixed-variable rate designs.

The purpose of dwelling on the TOU nature of gas rate designs is to illustrate the complexity of the issues. If the policy discussion must be confined to rate designs that have two parts, each of which does not vary over time but does vary between customer classes, then the fixed-variable proposal deserves serious consideration. The FERC Seaboard formula, however, is also likely to receive high marks in the context of such second-best pricing options. The FERC is currently proposing new rules that are likely to change fundamentally the way the pipeline industry provides transportation services. This is a good occasion to expand the policy discussion of rate designs to include the possibility of time-differentiated transportation fees as the FERC has done in at least a tentative way. If a pipeline's load factor is so high that transportation costs do not vary between seasons, for example, then interruptible customers have no basis for their claim to escape demand charges since the responsibility for the peak would be spread evenly over the year in such a case. In any case, empirical studies of the time pattern of transportation cost-of-service would be a good supplement to the FERC recent Notice of Proposed Rulemaking (NOPR).[4]

A second, purported virtue of a fixed-variable rate structure is that "... because multi-fuel consumers can painlessly drop out of a supply-constricted market, their presence at the margin assures firm users that spot prices ... are unlikely to undergo wild fluctuations."[5] The conclusion is that an industrial customer's positive contribution to the overall stability of the system is a reason for adopting a fixed-variable tariff. In other words, price discounts are appropriate for those customers whose market participation tends to dampen price swings. The effect would be to price discriminate in favor of the most price-sensitive consumers.

While it is true that all consumers benefit from the actions of the most price-sensitive customers, the idea to reward them for such service is unique. The authors know of no other suggestion that price discounts for such a reason be given to those customers who are on the margin of any market. The same argument could be advanced for any market, even those that are unregulated. Customers that receive any consumers' surplus in any market are presumably pleased that others value the product less, shop carefully, and buy only when the price is favorable. Such actions serve to hold down prices to the benefit of all. We ordinarily do not wish to give price discounts for such

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[4]Federal Energy Regulatory Commission, Notice of Proposed Rulemaking, RM85-1-000 (Washington, D.C.: Federal Energy Regulatory Commission, May 30, 1985), or see 50 Fed. Reg. 24130 (1985).

[5]Tussing and Barlow, "The Fixed-Variable Paradigm," p. 4.

service, however. In addition, the stabilizing effect of marginal consumers does not increase because of a price discount which only serves to shift the market's margin to another group of consumers with a lower willingness to pay. Stated differently, the externality in this case is purely pecuniary and does not have any real economic content. The stabilizing influence of marginal consumers is correctly transmitted to the market by the fluctuating price signals themselves. There is no need to create average pricing differentials to reward such marginal customers. Indeed, the attempt to do so is self defeating since another group of marginal customers would crop up claiming the need for a reward for their social service of price stabilization.

The third strand of the argument in favor of fixed-variable rate designs is that financial risk of the pipeline is reduced by rate designs that have a large demand charge. This view is commonly advocated by the pipeline companies. The argument has merit. Demand charges, in the short term, are similar to lump-sum payments that are collected by the pipelines. Because such payments are relatively insensitive to random changes in demand, the pipeline's financial returns are stabilized. This ultimately should have a favorable effect on the utility's cost of capital since investors would value such a risk reduction.

There are two difficulties encountered in attempting to evaluate this risk reduction argument. First, the empirical evidence supporting the favorable cost-of-capital effects is quite sparse, if not nonexistent. While it seems clear that risk is reduced, it is important to have an estimate of the magnitude of the corresponding reduction in cost. Second, it is not clear that overall social risk is reduced by pipeline demand charges. The risk is shifted, at least in part and perhaps mostly, to the customers of the pipeline who must pay the demand charge regardless of the volume taken. Hence, local distribution companies and captive residential and commercial customers bear the financial risk that the FERC shifts downstream from the pipelines. Overall social risk may or may not be reduced by such a policy. The resolution of this issue requires empirical evidence about the effect of demand charges on the pipeline's cost of capital, on the distributor's cost of capital, and on the value of any risk that state regulators pass on to captive retail customers.

With this introductory view of natural gas rate designs, the three following sections address three specific issues: the design of interruptible rates, the economic efficiency of demand charges, and the limits of price discrimination. The reader should bear in mind that any or all of the rate designs associated with these issues could be used in conjunction with a TOU pricing policy.

Interruptible Rates

The basic regulatory policy upon which current interruptible rates policy is based can be described as a cost allocation exercise that separates fixed and variable costs and then recovers some fraction (possibly zero) of the demand costs with a demand charge that interruptible customers do not pay. Like all allocations of fixed cost, this process is inherently arbitrary to some degree. The academic literature contains several formulations of interruptible pricing that serve as a benchmark against which current practice can be compared. Most of these models are formulated for an electric utility; however, they are applicable to gas companies as well.

A variety of models describing optimal pricing of interruptible service have appeared in the literature. The model of Marchand is perhaps the earliest.[6] In it, he specifies that customers pay for both energy and maximum power, and can be interrupted whenever a shortage of generating capacity occurs. Neither the maximum power price or the interruption scheme correspond to actual U.S. utility practices. The maximum power is a contracted quantity, to be made available to the

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[6]M.G. Marchand, "Pricing Power Supplied on an Interruptible Basis," European Economic Review, 1974, pp. 263-274.

customer with a particular probability. If the event on which the probability is described actually occurs, the customer is limited to the contracted maximum power and pays for it, regardless of whether he uses that amount or less. In contrast, typical demand charges in the U.S. electricity industry are based on billing demand, which is the customer's own, actual, maximum usage. Most retail natural gas demand charges are similarly based on actual maximum. It is true that natural gas distributors typically pay for contracted maximum volumes; however, the actual demand charge differs from that described by Marchand in this case also. The distributor's demand charge is paid with 100 percent probability. That envisioned by Marchand is contingent upon the events themselves and so a customer pays for various levels of the demand charge with separate probabilities.

The interruption scheme employed by Marchand is likewise unusual. In his model, whether a customer is interrupted depends upon the customer's actual use at the time a particular contingency materializes. The interruption takes the following form: the utility reduces each customer's maximum allowable demand according to a pre-arranged contracted sequence. The sequence of maximum demand levels is selected separately by each customer; however, the probabilities of the events under which these maximums can be taken is the same for all customers. In Marchand's scheme, customers do not buy a position on the rationing list, such as first to be curtailed, last to be curtailed, etc. Rather, each customer agrees to have his or her own maximum demand restricted under certain contingencies. If such a customer happened to be using very little electricity at the time of the maximum demand restriction, no personal curtailment would occur. Hence, the list and order of customers actually interrupted would change from instant to instant. Each customer's demand is random. Each combination of customer demands actually realized that yields the same system demand (and consequently the same event that defines the curtailment scheme) will result in a different set of customers being interrupted. This type of contingency-dependent order of interruption stands in sharp contrast to the more commonly used contract in which a customer agrees to be interrupted in a pre-arranged sequence, if required by system conditions, irrespective of his needs at the time of curtailment.

Ostensibly, Marchand's model is one in which customers sometimes are interrupted and sometimes are not. Marchand himself, however, notes that his rationing rule has the effect of always using generating plant at full capacity. Aggregate demand, then, is never less than capacity and the need for interruption is continuous. This is consistent only with a capacity choice set equal to the smallest possible realization of demand. An indication of how difficult Marchand's model is to interpret is Hamlen and Jen's characterization of it as one in which the customer is guaranteed the maximum level purchased, thereby requiring capacity equal to the aggregate of all maximum demands in customer contracts.[7] With such installed plant, aggregate demand would be almost continuously less than capacity, except for the unlikely occasion when everyone simultaneously wanted to use his own maximum limit. Hence, Marchand's own characterization is one in which capacity is always fully used, while Hamlen and Jen interpret it as one where capacity is almost never fully used. These two views can be reconciled only in the case of nonstochastic demand, a condition that would make the entire exercise uninteresting.

Panzar and Sibley[8], and Dansby[9] modified the Marchand model by including the technological idea of automatic fuses to limit a customer's maximum usage. In the Panzar and Sibley treatment, the total system capacity is equal to the sum of maximum fuse levels

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[7]W.A. Hamlen, Jr. and F. Jen, "An Alternative Model of Interruptible Service Pricing and Rationing," Southern Economic Journal, April 1983, pp. 1108-21.

[8]J. Panzar, and V. Sibley, "Public Utility Pricing Under Risk: The Case of Self-Rationing," The American Economic Review, December 1978, pp. 888-95.

[9]R.E. Dansby, "Multi-Period Pricing with Stochastic Demand," Journal of Econometrics, January 1979, pp. 223-37.

purchased by all customers. Such a system is inefficient to the extent that any excess system capacity cannot be used to serve a customer on those occasions when his own fuse level is exceeded. Dansby envisions a case whereby the utility can activate the fuses, which means that only system-wide excess demand will trigger the interruptions. While this improves the utilization of plant, it is still inefficient since all fuses are triggered. Since some customers will be using less than their fuse levels when such a system event occurs, triggering all fuses necessarily means that excess capacity will exist afterwards.

The use of capacity is improved in the interruptible service model of Tschirhart and Jen.[10] In it customer groups are arranged in priority order, with different prices paid for varying degrees of reliability. The highest priority is assigned to a group that can be best described as the residential class. It is the only group with stochastic demand, and it is interrupted last. All other groups have non-random demand and are interrupted in priority sequence in a continuous manner in accordance with the continuous excess of demand above capacity. Tschirhart and Jen show that if demand is itself not dependent upon reliability then the price paid per unit (which is the only form of payment for service since customers' bills have no fixed component) increases as the reliability of service also increases. Customers that are to be interrupted first pay the lowest price, while the residential sector pays the highest. This ordering is not necessarily maintained if demand depends upon reliability. The reason has to do with the sensitivity of customers to the interruption probability. Customers that are highly sensitive to interruption may be given a favorable place on the priority list, and if they happen to be quite sensitive to price, the price may also be set low.

The concept of reliability used by Tschirhart and Jen has a single dimension--the probability of interruption. The model formulated by

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[10] J. Tschirhart and F. Jen, "Behavior of a Monopoly Offering Interruptible Service," The Bell Journal of Economics and Management Science, Spring 1979, pp. 244-57.

Hamlen and Jen distinguishes between the probability of the curtailment and its extent. They describe their curtailment scheme as a "limiter" method. A limiter is a complex fuse, which when activated allows a customer to draw some pre-set fraction of his own demand. All limiters are simultaneously activated in Hamlen-Jen's model when demand exceeds capacity. When that event occurs, all consumers are restricted to a pre-set fraction of the desired demand.

This concept of a limiter-type of curtailment, itself, has several limitations. It does not solve the capacity utilization problem of the fuse system, which is that after the fuses or limiters are activated, the demand being served is likely to be strictly less than capacity. No interconsumer allocations are possible because of the prefixed nature of the limiters. Second, the concept is more applicable to electricity than to natural gas. It is likely to be difficult to partially restrict gas flows and may even be dangerous in some applications. For example, gas burning appliances could not be allowed to draw more than the limited quantity since to do so would tend to reduce the gas pressure in the feeder line between the limiter and the appliance. Third, since usage is limited by a pre-set fraction, some customers might thwart the effectiveness of the limiters by creating the appearance of a large demand in order to receive more. In the electricity example, if the technology of creating a limiter is available, there is nothing to prevent the customer from reversing such a technology on his own premises. That is, installation of a "delimiter" on the customer's side of the junction to the central power station could be used to increase a particular customer's allocations. For example, suppose a customer wished to draw 100 kilowatts but was limited to 2/3 of his current desired demand. If he attempts to draw 100 kW, he will receive 66 2/3 kW. But if he creates the appearance of desiring 150 kW, he can obtain 100 kW, and avoid all curtailment. This type of strategic behavior on the part of customers is possible because of the prefixed fractional nature of the limiter concept. A limiter that specifies the absolute level of maximum demand could not be manipulated in this fashion. Hamlen and Jen do not address this strategic consideration, but rather presume honest revelation of desired demand.

At their current stage of development, the pricing guidance from these models is somewhat imprecise. The Hamlen-Jen model is the most general and its pricing implications warrant a brief summary. Welfare maximizing prices cannot be characterized in general, but Hamlen and Jen are able to provide a few insights about interruptible pricing. Firm or noninterruptible customers pay a price equal to variable plus capacity costs, as expected. If the set of optimal prices yields inadequate revenue, then the price paid by firm customers must be increased above the level of variable plus capacity costs. Hamlen and Jen distinguish two categories of interruptible customers, those that are partially interrupted and those that are completely interrupted. In both cases, the socially optimal price can be only vaguely characterized as being less than the sum of variable plus capacity costs. There is no indication, for example, that the price for even the completely interruptible customers consists solely of variable costs, as the fixed-variable rate structure would imply. The Hamlen and Jen results suggest only that nonfirm consumers pay some fraction of the capacity cost, a policy not inconsistent with the FERC traditional Seaboard formula, for example.

Economic Efficiency and Demand Charges

The discussion thus far of natural gas demand charges has touched on two aspects of economic efficiency: time-of-use and interruptible service pricing. The conclusions have been that (1) currently configured demand charges do not have the TOU characteristics used to justify, in part, fixed-variable rate designs in which large industrial customers pay little, if any, fixed cost, (2) a TOU transportation fee would result, most likely, in large industrial customers paying for some part of capacity costs, and (3) the reduced quality of service represented by a willingness to be interrupted has a socially optimal price which includes less than 100 percent of capacity costs, but most likely more than zero percent. The idea of a reservation price based upon capacity costs has some validity, but there is no theoretical justification for supposing that consumers wishing to reserve capacity should pay for 100 percent of it. Consequently, neither the TOU nor quality of services arguments support the fixed-variable rate structure that allows large industrial users to pay for only variable costs.

There is a third economic efficiency issue regarding demand charges that merits a brief review. Suppose, for a moment, that all pipeline customers pay the demand charge. This allows us to abstract from the ancillary issue that interruptible users do not pay the demand charge and hence avoid the need to justify price discrimination between large industrial and other users. Demand charges encourage individual users to manage their own peak loads, which reflects favorably, to some extent, upon the system's peak demand. The question to be addressed in this section is whether a socially optimal demand charge, designed to account for any such favorable system peak-demand effects, would have a fixed-variable nature, or would optimal demand charges recover less than 100 percent of demand costs?

The issue has been addressed by Marchand[11] and Henderson[12] using the electricity industry as an example. The Henderson formulation, in particular, is equally applicable to natural gas pipeline regulation and forms the basis of the discussion here. In times of excess supply, such as the gas market is currently experiencing, peak demand is not pressing upon pipeline capacity, except possibly in isolated regions. During such times, pipeline capacity is truly fixed, in the economic

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[11] Marchand, "Pricing Power Supplied on an Interruptible Basis," pp. 263-274.

[12] J. Stephen Henderson, "The Economics of Electricity Demand Charges," The Energy Journal, Special Electricity Issue, December 1983, pp. 127-139.

sense of the word, and there is no economic efficiency justification for recovering any of the capacity costs in rates. The regulatory practice of recovering these economically fixed costs gives rise to important equity and fairness considerations which are discussed in the next section. There are no economic efficiency issues, however, to guide cost recovery when costs are actually fixed. Hence, the question of designing demand charges so as to correctly convey price signals regarding capital costs does not arise until peak demand begins to cause a need for more transportation capacity. It is to these circumstances, apparently several years in the future, that this discussion is directed.

The key to understanding the nature of an optimal demand charge is to envision the set of factors that influence the demand for capacity, that is, the system peak-period demand. The demand for capacity would depend, in general, on both the billing demand and the volume of gas consumed by all customers during the peak period. The peak period might be a month or the entire heating season, for example, if the expense of time-of-day meters is to be avoided. However the peak period is defined, the important feature is to specify that system peak demand depends on both billing demand and volume. The effect of each of these (for each customer group) on the system peak becomes a matter to be estimated empirically. Optimal pricing depends on the reaction of the system peak to each of these components of demand. An optimal commodity charge for a customer group would include variable costs plus that fraction of capacity costs represented by the responsiveness of the system peak demand to that customer group's volume taken during the peak period. The optimal demand charge would recover the fraction of capacity costs given by the corresponding reaction of the system peak to the group's billing demand. More specifically, Henderson shows that the fraction of capacity costs recovered by an optimal peak commodity charge for any group is the elasticity of the system peak with respect to that group's own peak consumption. Likewise, the fraction of capacity costs recovered with an optimal demand charge for any group is the elasticity of the system peak with respect to that group's billing demand during the peak period. An estimate of the responsiveness of the system peak with respect to the various demand components for which customers are actually billed provides a direct, straightforward way of sorting out how much of demand cost to allocate to the demand charge versus the commodity charge.

The fixed-variable rate structure that allocates all demand costs to the demand charge would be correct only if the system peak is completely unresponsive to changes in the volume of gas taken during the peak period, which seems highly unlikely. Stated differently, the optimal demand charge would include 100 percent of all demand costs only if a one percent reduction in a customer's own billing demand resulted in an equal one percent reduction in the customer's demand at the time of the system peak. Ordinarily, a reduction of a customer's own peak demand does not result in a corresponding reduction of the customer's portion of the system's load. Part of the effect is lost or diluted because the customer's own peak does not necessarily correspond perfectly to that of the system. The elasticity of the system peak with respect to a customer group's billing demand correctly accounts for this dilution, in the sense that it measures the marginal effects that demand charges have on the system peak given that these are transmitted through a customer's adjustment of his own billing demand.[13] If it is true that such dilution typically occurs (a question that requires empirical estimation and verification), less than 100 percent of demand costs would be optimally recovered with demand charges. Compromise formulas such as the FERC Seaboard method are consistent with this conclusion, whereas the relatively more extreme type of fixed-variable tariff would result in demand charges that are too high if billing demand effects on the system peak are partially dissipated as expected.

Hence, if peak demand were large enough to justify a capacity expansion, economic efficiency would be promoted by demand charges that were based on less than 100 percent of capacity costs, with the actual

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[13]Interested readers may wish to refer to Henderson, "The Economics of Electricity Demand Charges," pp. 133-135 for the analytical details that support this conclusion.

percent based on the degree of dilution between a customer's own billing demand and that of the system peak. If demand is relatively slack in comparison to available capacity, the pipeline cost is truly fixed, and its recovery has no direct implications for economic efficiency. Which group pays, however, becomes an important social equity issue. The fair allocation of fixed costs between customer groups raises the question of price discrimination, a topic addressed in the next section.

Flexible Pricing, Price Ceilings and Floors, and the Possibility of a "Death Spiral"

The purpose of this section is to explore the issues surrounding the recovery of capital cost, when such cost is truly fixed.[14] TOU pricing, interruptible rates, and optimal demand charges are pricing policies that can have no effect on capacity decisions unless peak demand is pressing upon and thereby creating a need for capacity. When demand is slack, regulators may wish to maintain such policies for purposes of continuity; however, there is no instantaneous need for such capacity-modifying pricing. Despite this, fixed costs must be recovered nonetheless. In such circumstances, a public utility commission may be able to improve overall social welfare by allowing the utility to engage in price discrimination. The existence of fixed costs usually means that prices must exceed marginal costs and hence some social well-being must be sacrificed in order for the utility to break even. Pricing policies such as the inverse-elasticity rule are intended to minimize this sacrifice.[15]

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[14]This section draws heavily upon J. Stephen Henderson, "Price Discrimination Limits in Relation to the 'Death Spiral,'" The Energy Journal, forthcoming.

[15]A good discussion of inverse-elasticity rules or Ramsey pricing appears in William J. Baumol, "Reasonable Rules for Rate Regulation: Plausible Policies for an Imperfect World," in Prices: Issues in Theory, Practices, and Public Policy, eds., Almarin Phillips and Oliver E. Williamson, (Philadelphia: Univ. of Pennsylvania Press, 1967), pp. 122-123.

An aggregated view of social justice must be taken, however, in order to conclude that inverse-elasticity rules improve economic well-being. Some welfare of inelastic users who are charged a relatively high price is implicitly exchanged for a proportionally smaller mark-up over marginal cost for the elastic consumer. In other words, it must be true that in order to maintain constant profits, a price reduction for one service necessitates a price increase for some other service in at least some small region near the Ramsey pricing point or inverse-elasticity rule. Hence, price discrimination, in general, cannot benefit all customers. Regulators usually are faced with substantive choices that require a price increase for one group or service in order to give preferential treatment to another. Some public utility economists have examined special conditions under which it is claimed that such a trade-off is not needed. For example, reducing a favored group's price has such a propitious effect on the sharing of fixed costs that all other prices can be reduced also. Such a circumstance, if it existed, would be the regulatory equivalent of a free lunch.

This section delineates the nature of these special conditions and argues that such conditions are not likely to be common. The topic is closely related to the limits of price discrimination and also to the prices at which market instability is induced. The connection between these ideas has not appeared in the literature before and was developed as part of this research.

No-Loser Price Discrimination

The importance of the no-loser price discrimination was recently emphasized by Federal Energy Regulatory Commissioner Stalon in remarks to the National Conference of Regulatory Attorneys that included the statement,

> For a long time defenders of price discrimination have relied heavily on an elementary economic theorem that demonstrates that a regulated firm with monopoly power and with unexploited economies of scale...can discriminate in price and make those customers who are discriminated against better off than they would be without such discrimination.[16]

Commissioner Stalon went on to propose that this elementary economic theorem be used to establish price ceilings. A commission, for example, might direct that a utility establish a set of nondiscriminatory prices which would yield the overall revenue requirement and which would allow the utility to lower the price to all customers in a particular class if the prices of other classes could be either lowered also or at least held constant. Such a price ceiling naturally is attractive to regulators since there is a set of lower prices for all groups that covers the revenue requirement. The idea of using such a no-loser price discrimination criterion to establish price ceilings has been discussed by Merrill Roberts in the context of railroad rates.[17]

Variations of this no-loser price discrimination standard have been discussed by several public utility economists. The traditional example of an unviable utility made feasible by second-degree price discrimination[18] is extended by Kahn to third-degree discrimination, with one customer class having very elastic demand.[19] Howe and

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[16]Charles G. Stalon, "Finding New Objectives for Natural Gas Pipeline Regulation," remarks to the National Conference of Regulatory Attorneys, Hartford, CT, May 13, 1985, Mimeo.

[17]Merrill J. Roberts, "Railroad Maximum Rate and Discrimination Control," Transportation Journal, Spring 1983, pp. 23-33.

[18]See Charles F. Phillips, Jr., The Regulation of Public Utilities (Arlington, VA: Public Utility Reports, Inc., 1984), pp. 386-387.

[19]Alfred E. Kahn, The Economics of Regulation: Principles and Institution, vol. 1: Economic Principles (New York, NY: John Wiley & Sons, Inc., 1970), pp. 137-150.

Rasmussen, and James Koch use a similar illustration whereby third-degree price discrimination allows an essential firm to survive.[20] During recent years, a common assertion has been that lowering the price of natural gas for large industrial customers will prevent them from leaving their local distributor, thereby continuing to pay at least part of the fixed-cost burden that would otherwise fall on captive residential and commercial customers. Hence, a no-loser price discrimination argument has been used to support industrial price reductions. The importance of demand elasticity to this assertion is explored in a report by the National Regulatory Research Institute.[21]

All of these issues can be best understood in the context of a simple diagrammatic analysis that shows the locus of prices for two groups that yield constant profits. The formal properties of such a diagram are set out in appendix D. Suppose there is a public utility with several customer groups or services. If declining block rate structures are used, all inframarginal revenue in excess of marginal price is simply aggregated and combined with fixed cost.[22] The focus, here, is on the single price charged to any two customer groups or services, holding constant all other prices.

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[20]See Keith M. Howe and Eugene F. Rasmussen, Public Utility Economics and Finance (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1982), pp. 196-199. Additional discussion is in James V. Koch, Industrial Organization and Prices (Englewood Cliffs, NJ: Prentice-Hall, Inc., 1974), pp. 317-319.

[21]See Kevin A. Kelly, J. Stephen Henderson, Jean-Michel Guldmann, et al., State Regulatory Options for Dealing with Natural Gas Wellhead Price Deregulation (Columbus, OH: National Regulatory Research Institute, 83-7, 1983), pp. 204-209.

[22]Caution is needed here. The appropriate price is that upon which customer demand depends. In the short term, the marginal or tail block price may be the primary determinant of usage. In the longer term, particularly for customers considering leaving the local utility altogether, the average price may be more appropriate since investment decisions are at stake and total cost and benefits are being compared. The qualitative nature of the analysis presented in this paper, however, is unaffected by this distinction.

The locus of all possible price combinations that yield zero profits is shown in figure 3-1. The axes of the diagram are price levels for any two groups, say 1 and 2. The marginal costs of servicing each of the two customer groups are shown as dashed lines. For the diagram to be illustrative of a public utility, it must be the case that the zero-profit locus lies to the northeast of the marginal cost point, labeled E in figure 3-1. That is, the socially efficient pricing point, E, must yield negative profits due either to fixed costs in the short-term or long-term decreasing costs. Otherwise, the fundamental natural monopoly characteristic would be missing.

The most important feature of figure 3-1 is the location of points A, B, C, and D. The prices, P^M_i, are the profit-maximizing single prices that would be chosen by an unregulated monopolist. At points A and D, the zero-profits schedule is vertical, and at points B and C it is horizontal. It must be the case that points A and D are at the level of the unregulated monopolist's price for market 1 and similarly for B and C with respect to market 2. This geometry follows from some straightforward analysis in appendix D.

The point π^M is the unregulated monopolist's profit that would be associated with the combination of monopoly prices in both markets. The $\pi = K$ locus is associated with some positive profits, less than the unregulated level. Clearly, as prices are jointly increased from the origin to π^M, profits will increase. Beyond π^M, however, additional price increases actually yield less profit. The reason, as explained in all public utility economics texts, is that at such prices, demand is sufficiently elastic that further price increases result in a revenue reduction which is even larger than the cost saving. Stated differently, P^M_i is the price that yields the greatest revenue in excess of marginal cost and hence the greatest contribution to fixed costs.

In simple terms, a public utility commission's job to limit monopoly profits, say to zero, is to choose among points along the zero-profit locus. Of these, the only sensible choices, in the authors' view, are those between A and B. That is, the regulator's job

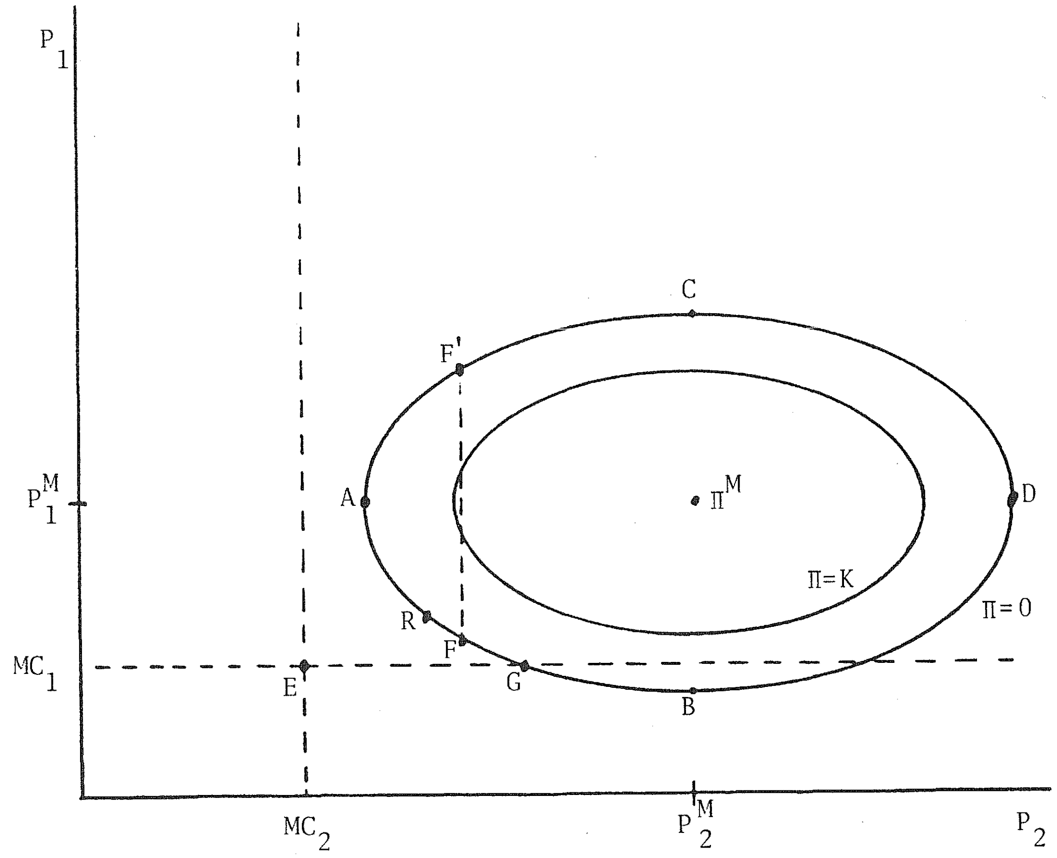

Fig. 3-1. Constant-profit schedules

of limiting monopoly profits, when translated to a particular market, means restricting monopoly power in each, separately. In this view, P_i^M are price ceilings. Any regulator allowing a price in excess of P_i^M could be considered negligent in his oversight, particularly from the perspective of the particular market charged more under regulation than by an unfettered monopolist. Imprecise estimates of the P_i^M naturally obscure whether these are ever exceeded in practice, however.

Apart from the regulatory obligation to prevent monopoly abuses, pricing points outside of the A-B segment, such as F' in figure 3-1, are plainly inferior to some subset of points along A-B. The point F, for example, consists of the same zero profits for the monopolist, the same price for group 2, and a lower price for group 1. Economic efficiency is enhanced since at least one party has been made better off, without hurting any other party. In this case, all social equity considerations in addition to economic efficiency are promoted if the regulator were to choose point F instead of F'. Indeed, all points between A and F that yield zero profits are superior to F' in all respects. Consequently, regulators should never consciously choose a pricing point where any single price is in excess of the unregulated monopoly price. Conversely, all choices along the A-B segment are substantive and involve improving the welfare of one customer group or service at the expense of another. Although the wisdom of Solomon is needed when selecting the best pricing point out of these, it is precisely this type of judgment that the regulator must have. Day-to-day cost allocation decisions in rate cases are much more likely to involve choosing among points along the A-B segment than those in the backward bending segments. Public utility regulators usually do not have the opportunity of making everyone better off.

Noting a few additional characteristics of the diagram facilitates the remaining discussion. The shape of a constant-profit locus is approximately that of an ellipse. (If the demand curve is linear, it is exactly an ellipse.) The line is negatively sloped throughout, although it may not be convex for the entire range between A and B. The ellipsoidal shape is elongated in the direction of the market with the less elastic demand. In figure 3-1, for example, market 2 has the less elastic demand. If social welfare is measured by the aggregate of consumer surplus, then Ramsey pricing, or the inverse-elasticity rule, is best and would be at a point such as R in figure 3-1. Each price at R is above marginal cost, this distance being inversely proportional to the demand elasticity.

Although Ramsey pricing is assuredly above marginal cost for all markets, the regulator's substantive choice set, A-B, may extend below marginal cost. Figure 3-1 shows a segment from G to B where the price in market 1 can be below its marginal cost and yet the revenue requirement can be covered by charging a high enough price in market 2. Whether such a range exists in reality depends on the price elasticity in the other market. Market 2, for example, having very inelastic demand would allow virtually any amount of revenue to be extracted from it, which would permit the market 1 price to be very low.

The question of whether marginal cost should be a price floor is naturally raised by the existence of segment G-B. Kahn asserts that marginal cost "...would have to be the bottom limit, as far as economic considerations prevail..."[23] The reason is that some other service or group suffers if one group is favored with a price below marginal cost. That is, a movement from point G to B, which favors group 1 with a price less than marginal cost, results in a higher price for group 2. The difficulty is that the same can be said of a movement from any point in the A-G segment, such as point R, towards point G. It is not clear how a movement from G to B can be prohibited on these grounds while allowing a movement from R to G. The same type of difficult, social judgment is involved in both cases. In principle, the choices are quite similar.

In practice, however, it may be the case that the position of points A and B are more difficult to estimate than the position of point G. Points A and B depend on demand elasticities, possibly in an extreme range of customer usage that has not been observed historically. By contrast, point G mainly depends on marginal cost, and may be easy, by comparison, to estimate. Interested parties may argue, for instance, that load will be lost if price is not reduced close to marginal cost. This is similar to a claim that point A is near point B,

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[23] See Kahn, Economic Principles, p. 144.

and since the location of point A is not easily verified such a claim is difficult to refute. Such an argument can be carried below marginal cost, however, only at the risk of consumer intervention from the other side whose lawyers and economists also can estimate the location of point G and argue persuasively that below such a price, economic harm to their clients ensues. Hence, the marginal cost pricing floor may be based more on political considerations than on economic reasoning.

Some commentators have suggested an entirely different type of price floor, one equal to the point where marginal cost equals marginal revenue, at least for elastic services.[24] Figure 3-1 makes clear that this requires P_1^M at point A to be a pricing floor. Such a price is at one extreme of the A-B range, and would, if adopted, eliminate virtually all of a commission's judgment and discretion. In addition, such a policy is at the threshold of being unstable, as discussed in the next section.

The graphical framework can also be used to analyze the concept of no-loser price discrimination. Figure 3-2 illustrates the idea of deriving price ceilings from such a notion. The suggestion made by Roberts and endorsed by Commissioner Stalon is to find an equi-proportional mark-up of prices that allows no-loser price discrimination and also yields zero profits for the utility. In figure 3-1, equi-proportional mark-ups over marginal cost are located along a straight line from the origin that passes through the point of marginal costs, E. A no-loser price discrimination point must lie along this line and must be on the zero-profit locus, but not in the segment from point A to B. Hence, the straight line must intersect the zero-profit ellipse outside the range of substantive choices. In figure 3-2, the point F' satifies these conditions. The prices associated with point F' are to become ceilings, in this concept.

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[24]These are discussed in Kahn, but the idea is not suggested by him. Ibid., pp. 145-146.

This concept of price ceilings has several drawbacks. First, point F' may not exist, in that the proportionality line may not intersect the zero-profit locus at all. (The line may lie above the ellipse everywhere.) Second, supposing the line does cross the zero-profit schedule, figure 3-2 shows that the intersection is much more likely to be in the A to B range than outside of it. If so, the resulting prices could not be the basis of no-loser price discrimination, since the pricing choices along the A-B segment involve substantive tradeoffs between groups 1 and 2. Consequently, the Roberts-Stalon concept of price ceilings is not generally applicable because its conditions may not, and indeed seem unlikely to, be fulfilled.

A more serious drawback, however, is that the resulting price ceilings do not seem very useful even if point F' exists, as it does in figure 3-2. The ceilings corresponding to F' are P_1^C and P_2^C, which includes all prices from F to F'. The range from A to F' is a set of prices dominated by others along the A to B segment and should not be chosen by regulators in normal circumstances. The remaining set of pricing alternatives are merely those from A to F. The choices from F to B are excluded by this rule. The elimination of this set of substantive options seems unwarranted in that it is not based on any well-founded judgment. In practice, the Roberts-Stalon rule, if it exists, seems likely to result in feasible price ranges near point A, as drawn in figure 3-2, which means that the favored customers are those with inelastic demand. If this is the desired outcome, a simple declaration of such a goal would be superior to a proposed set of price ceilings that sometimes do not exist and arbitrarily restrict the regulator's set of pricing alternatives when they do.

The Possibility of a Death Spiral

Thus far, the argument presented in this section has been that the limits of price discrimination are established by the same phenomenon

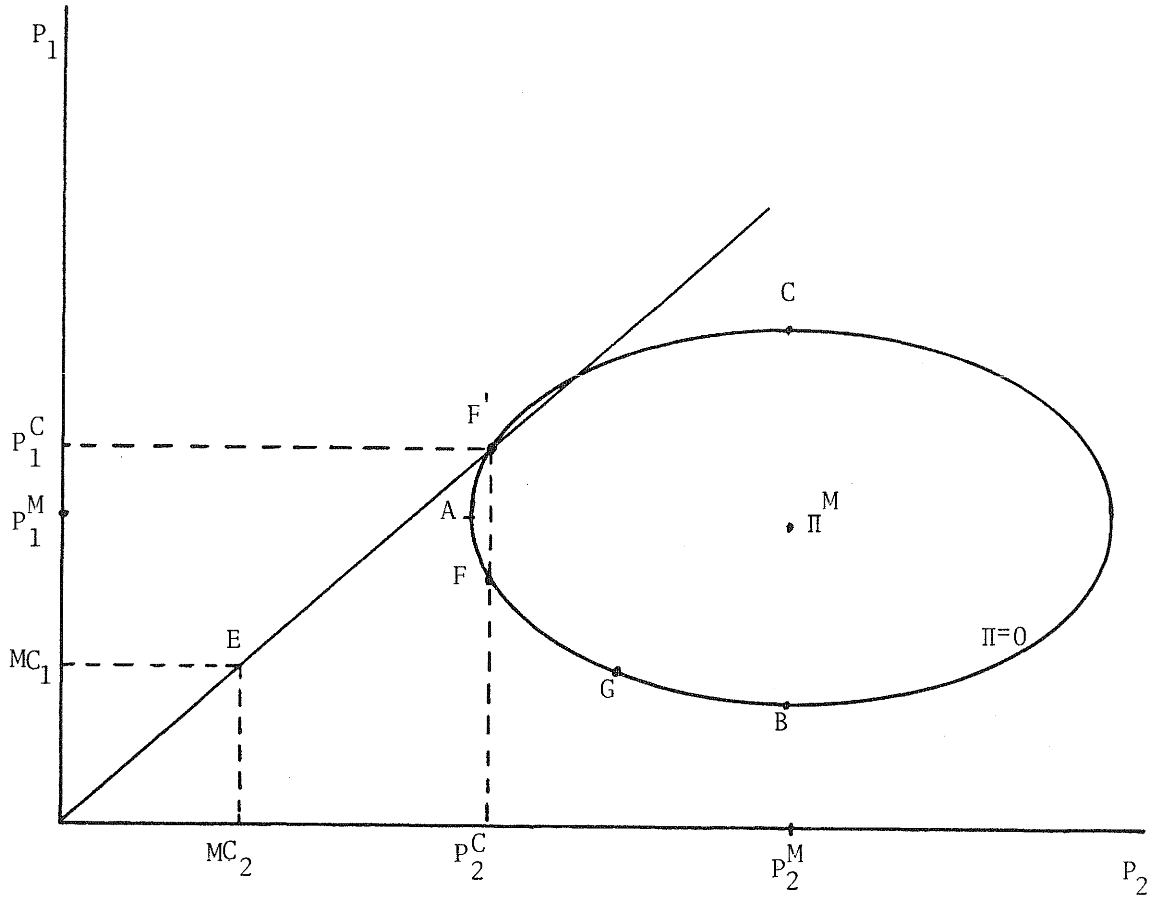

Fig. 3-2. No-loser price discrimination and price ceilings

that even an unregulated monopolist must respect--the sensitivity of market demand to price. Within this very wide range, shown as segment A to B in figures 3-1 and 3-2, the regulator can improve the well-being of one group only at the expense of another. The job of restricting monopoly power naturally creates a set of substantive pricing choices among which regulators must choose. The concept of no-loser price discrimination does not add any useful tool to the regulatory arsenal of a commission that has estimated the position of pricing points A and B.

A possibly more important reason for understanding and estimating the pricing limits of points A and B is that beyond these limits profit regulation is inherently unstable. At prices above the unregulated monopolistic level, demand becomes sufficiently elastic that any price increase serves only to induce "...a self-perpetuating collapse in demand, accompanied (and driven) by ever-increasing rates."[25] This is popularly known as a "death spiral", since any service subject to such a vicious cycle would not be viable. Either the price of such a service must be reduced below the monopoly level or the service will suffer a total collapse of demand. If all services of a public utility were in such a position, the utility itself would fail.

That death spirals are a possibility is not news. Several commentators, notably Arlon Tussing, have suggested that some natural gas markets are perilously close to such a position.[26] The purpose of this section is to support the claim that a death spiral is triggered when regulatory cost allocation results in prices above the monopoly level. Indeed, a necessary and sufficient condition for this type of self-perpetuating instability in a regulated market is that the price exceeds the monopoly level. This close link between these two ideas has not been developed in the literature. The technical details establishing this proposition are in appendix D. An intuitive explanation is graphically presented in this section.

It is not the case that a commission that inadvertently sets a price above the monopoly level must necessarily induce an irreversible death spiral. The simple, even obvious, remedy is to reduce such a price below the monopoly level, into the stable region. The discussion of the phenomenon for the purposes of this paper, however, requires that the regulatory policy from which the unstable price emerged has a certain degree of permanence. In particular, in keeping with the type

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[25]Arlon R. Tussing, "The Price-Elasticity of Residential Gas Demand," ARTA Energy Insights, December 1983, p. 6.

[26]Ibid.

of cost allocation associated with traditional cost-of-service studies, suppose that a commission assigns a particular fraction of fixed costs that are to be recovered by a particular service or customer class.

The typical regulatory pricing rule can be approximated as the sum of two components: variable (or marginal) costs and the allocated fixed costs that are spread over the sales of each service or in each customer class. If the allocation of fixed costs remains the same, the price of the service can decline as sales increase. The regulatory allocation results in a pricing formula that slopes downward when depicted on a graph of price and quantity. Such a formula is shown in figure 3-3. The figure also contains a demand schedule for the service. Under ordinary circumstances, the demand curve is steeper than the regulatory pricing schedule. In such circumstances, the market is stable. If, for some reason, the market were not in equilibrium, say at sales volume Q_O, the commission's cost allocation policy would result in the price P_O. At such a price, demand would be at point A, and sales would increase. At the next rate case, the same cost allocation would reduce the service's price because of the increased sales volume and in turn demand would increase to point B. The adjustment process would continue until the stable equilibrium is reached at point Z.

The unstable market occurs when the demand curve is flatter than the regulated pricing schedule. This is depicted in figure 3-4. Beginning, as before, at some arbitrary point other than Z, the process of recalculating prices so as to recover the same amount of fixed costs results in ever higher rates and an eventual collapse of demand.

The conditions that determine whether the regulated market is stable or not are straightforward, and proven in appendix D. Two numbers must be compared. First, for each service, find its fixed cost allocation as a fraction of total customer bills, where the aggregate billing covers variable costs, as well as the allocated fixed costs. Second, estimate the reciprocal of the service's demand elasticity. The market is stable if and only if the fixed cost fraction of customers' bills is smaller than the inverse of the demand elasticity.

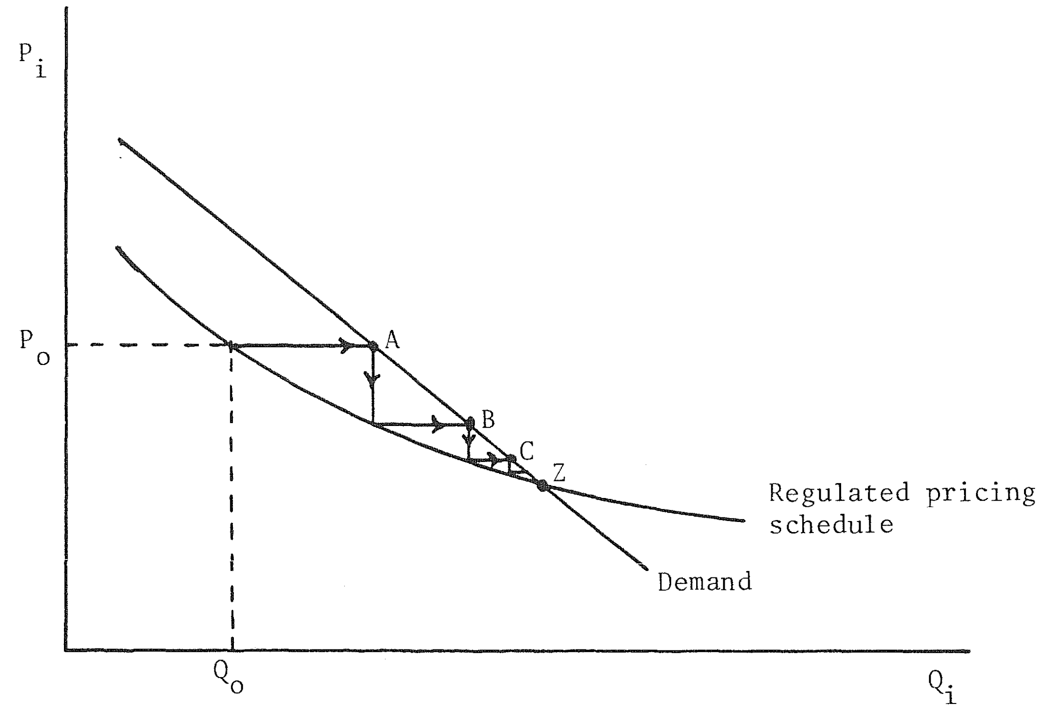

Fig. 3-3. Stable regulatory cost allocation

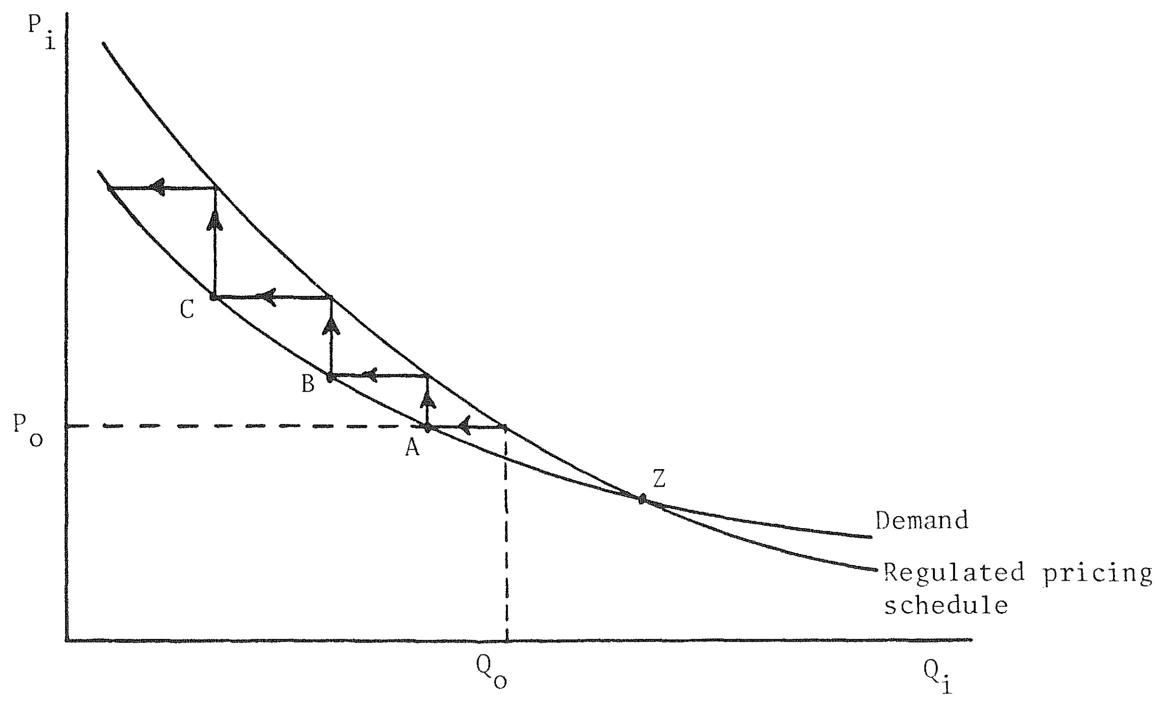

Fig. 3-4. Unstable regulatory cost allocation

This means that profit regulation induces instability into a market by attempting to recover a large fraction of fixed costs in relation to the demand elasticity. Markets with inelastic demand, therefore, are always stable in this sense because the inverse of such an elasticity is larger than unity and therefore not a fraction. Industries with no fixed cost, likewise, would not suffer a death spiral. Such an industry might wither to nothing because variable costs become higher than any buyer's willingness to pay, but not because of an increasingly futile attempt to recover fixed costs from an ever declining sales volume.

To illustrate the magnitudes necessary to induce instability, suppose the industrial sector as a group has a demand elasticity of -2.0. The reciprocal of this (in absolute magnitude) is .50. Any attempt to recover more than 50 percent of fixed costs in customer bills would result in a death spiral. That is, 50 percent or less of the bills must be fixed cost in order for the equilibrium to be stable. It is not 50 percent of the utility's fixed cost that is used as the benchmark. It is 50 percent of the users' bills. If the elasticity is quite high, say -3, then no more than 33 percent of the bills could be fixed cost. The elasticity would have to be enormously high, say -5.0, in order to prevent a 20 percent fixed cost recovery. Plausible estimates of industrial sector elasticities are -1.5 to -2.0, suggesting fixed cost portions of this sector's bills would have to be 50 to 66 percent before inducing stability. Consequently, a death spiral does not seem very likely for an entire sector, consisting of many customers. Individual industrial customers may be on the verge of switching fuels and consequently may have very large demand elasticities. If, in order to maintain this particular customer's load, the price paid by all industrial users in a class must be reduced, the prices paid by all remaining customer classes would have to be increased if the aggregate industrial class elasticity fulfills the stability requirements.

This stability condition is easily and directly related to the price charged by an unregulated monopolist. The fraction of fixed costs in customer bills is just another way of expressing the percentage deviation of price above marginal cost. The monopoly price level, where marginal cost equals marginal revenue, is characterized by the equality of this percentage deviation with the inverse elasticity of demand. Under a regulated cost allocation that remains the same, then, a death spiral is associated with prices that exceed those of an unregulated monopolist.

Because all methods of allocating fixed costs are arbitrary to some extent, a commission can avoid the death spiral by the simple expedient of reducing the fixed cost allocation in such a threatened market. In terms of figures 3-1 and 3-2, the required reduction must result in prices in the A-to-B portion of the zero-profit locus. This range is the stable set of pricing alternatives. A point such as F' in figure 3-2, for example, could not be maintained, even if the regulator were willing to charge a price higher than the monopoly level in a particular market.

There is, then, a close correspondence between the limits of third-degree price discrimination and the stability of regulated markets. Commissions that are willing to charge prices that are even higher than those of an unregulated market would find such a policy to be unviable. The resulting instability would force such a commission to reallocate fixed costs so as to reduce all prices below the monopoly level. No-loser price discrimination is possible only by initially exceeding the monopoly price level in at least one market. The inherent instability of such a price would force the regulator to reallocate fixed costs. In such circumstances, it is not clear whether we would wish to credit the magnanimity of the regulator with the resulting improvement to the well-being of all customers, when market instability would necessitate the same result.

Flexible Pricing

Competitive pressures from alternate fuels have caused several commissions to approve flexible pricing tariffs that pipelines and distributors can offer to their multi-fuel customers. The commission typically approves a zone of reasonableness by setting price floors and ceilings within which the utility is allowed to exercise its discretion. This allows the utility's management to react to market conditions more rapidly than would be possible if regulatory approval were required. In establishing these pricing zones, commissions may wish to consider the inherent stability (or lack thereof) of prices that approach monopolistic limits as described in this section.

For example, the notion of using the monopoly price as a floor in the elastic market, as reported by Kahn (see footnote 24), results in a pricing policy on the edge of the instability region (point A in figure 3-2). Likewise, the no-loser price discrimination formulation of price ceilings also yields a set of feasible prices that are close to the extremes of the stable region.[27] Pricing policies near the extremes of the stable A-B region are somewhat risky in that changing demand or cost conditions may render them unstable.

Prudent regulators may wish to choose pricing policies near the center of the stable region, in anticipation that economic conditions can change more rapidly than the capacity of commission regulation to adjust. The Ramsey pricing rule is naturally robust in this regard. It is located in the center of the stable region, in accordance with the relative demand elasticities. Commissions interested in establishing plausible price ceilings and floors might consider the following type of rule: beginning at the Ramsey point, R in figure 3-1, estimate the pricing point midway between it and each of the two pricing limits, A and B. The associated high and low prices for each market could be candidate ceilings and floors. Such prices would tend to be robust

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[27] If, as seems unlikely, the no-loser price discrimination rule should favor the elastic demand, the set of feasible prices would be near the other extreme, or point B in figure 3-2.

since they are in the center of the stable region and therefore are less vulnerable to economic shocks. Such a range could be widened or narrowed to account for other limits, such as marginal cost.

Setting the zone of reasonableness of a flexible pricing policy in the center of the stability region has several advantages. It allows the utility some flexibility in its competition with alternate fuels. Since changes in alternate fuel prices naturally change the monopoly pricing limits, points A and B in figures 3-1 and 3-2, there is always a risk that market conditions might change severely enough that a previously approved zone of reasonableness would suddenly be in the instability region beyond points A or B. Selecting the zone to be near the center of the stable region is a way of minimizing this risk.

Summary

This chapter examines a variety of natural gas rate design issues. This industry has never adopted time-of-use pricing, despite a peak-responsibility type of justification for the traditional centerpiece of gas rate structures--the demand charge. The current FERC initiative in the area of gas transportation policy provides a convenient setting in which to consider TOU transportation fees. A seasonal variation in transport prices is likely to capture most of the social benefits of such a policy, a change that would not require any additional metering. The current pricing practice is usually justified on the basis of the load-balancing virtue of customers whose demand is more or less constant over the year. Despite this, the resulting prices do not vary during the year, with the consequence that most of the social benefit of time-differentiated prices is simply lost.

The principle virtue of the pipeline's demand charge, as currently configured, is to reduce the financial risk of the enterprise. While there is no disputing that risk is reduced, the magnitude (about which we know very little) needs to be compared to the risk which is shifted forward to distributors and from there shifted to captive retail customers by state commission rate designs. It is by no means obvious without some careful empirical work that overall social risk is reduced by the pipeline's current rate design.

Three capacity conserving rate designs were reviewed in this chapter: TOU rates, interruptible rates, and optimal demand charges. In each case, economic efficiency principles suggest pricing rules that have the effect of sharing the capacity costs among all users. The Seaboard and United formulas are consistent with such a generally stated sharing idea. The fixed-variable type of rate design advocated by many pipelines and large industrial customers, by contrast, collects very little of the fixed costs from interruptible customers--none in extreme versions of this design. All three economically efficient rate designs need serious consideration in the design of natural gas rate structures. Any efficiency benefits associated with these need to be compared, in turn, with the net social benefits of the financial risk-reduction associated with currently-used demand charges.

Adding to the complexity of the overall problem of gas rate design, regulators must worry about the limits of price discrimination between customer groups and whether the attempt to collect an excessive amount of fixed costs, particularly from consumers that are quite sensitive to price, will destabilize such a market. Price discrimination limits and market instability of this sort are closely related ideas, an observation that has not been developed heretofore in the public utility economics literature. If prices are set so that all markets are stable, no-loser price discrimination is not possible. That is, if markets are stable (not undergoing a death spiral) it is not possible for a commission to reallocate fixed costs so as to reduce one group's price and simultaneously hold constant or reduce prices of all other groups if company profits are to be maintained. If a market is unstable in this sense, a condition that some multifuel boiler markets may have approached or even reached in recent years, then reducing such a market's share of fixed cost indeed can restore stability with no other customer class being made worse off. Such opportunities to satisfy all parties, however, are unusual. The common circumstance encountered in a rate case is that fixed cost reallocation will benefit one group to the detriment of another.

Compared to the quite sophisticated cost-of-service studies that are routinely presented in electricity rate cases, rate design and cost studies in the natural gas industry have remained virtually unchanged in the past 40 years. Shifts in the allocation of demand costs first toward and more recently away from the commodity charge have been the only innovation considered. The FERC Notice of Proposed Rulemaking is a good occasion for considering innovative gas rate designs, as well as transportation policy.

CHAPTER 4

THE TRANSPORTATION OF NATURAL GAS

The design of natural gas rate structures, particularly as regulated by the Federal Energy Regulatory Commission (FERC), reflects the historical role played by the interstate pipelines as merchant carriers. In this role a pipeline company purchases most gas that travels in its system and resells the commodity at a price that recovers the cost of both the transportation service and the purchase price of the gas. The transportation of gas owned by others, although increasing in importance in recent years, remains a minor part of the business. Such contract carriage is voluntary currently, and would remain so under the FERC Notice of Proposed Rulemaking (NOPR).[1] Alternative institutional arrangements include mandatory contract carriage and common carriage. Both arrangements place an obligation on a pipeline to transport gas owned by others. The distinction between the two has to do with the rights of customers if the pipeline capacity is insufficient. As common carriers, pipelines would reduce the transportation of all users more or less proportionally in order to accept a new customer. Most proposals that would mandate the carriage of gas for others, on the other hand, allow the pipeline to accept or reject transportation requests on the basis of available capacity.[2] Few observers are recommending common carrier status; mandatory carriage is frequently espoused, however, and is contrasted to the FERC voluntary program in

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[1]The NOPR (RM 85-1-000) is described in chapter 2 of this report.

[2]For a good discussion of this point, see Jeremiah D. Lambert and Jay D. Pedelty, "Mandatory Contract Carriage: The Changing Role of Pipelines in Competitive Natural Gas Markets," Public Utilities Fortnightly, February 7, 1985, pp. 26-33.

this chapter. The chapter begins with an overview of carriage in the gas industry. The factors that fundamentally influence the choice of institutional arrangements are outlined in the following section. The final section presents the arguments in favor of and against mandatory carriage in light of the FERC recent initiative.

Historical Overview of Carriage

In recent years, the pressure for access to transportation services has come from consumers (mostly large industrial users), producers and a few regulatory bodies, notably the Illinois Commerce Commission among state commissions. Consumers have been seeking gas supplies that are priced lower than those available from the traditional supplier, usually an interstate pipeline. Producers whose wells have been shut in perceive that their marketing would be improved if they could lower price and contact a wider range of customers than their traditional pipeline buyer. Regulators frequently have wished to facilitate such trades, particularly when it would benefit a local distributor's captive residential and commercial users. Mandatory carriage is a commonly espoused way of reducing gas prices in such circumstances, by requiring that interstate pipelines provide transportation services to move the gas between producer and consumer. Pipelines are perceived, for the most part, as unwilling participants in such arrangements.

The pressure for natural gas carriage has not always been of this nature. Within Texas and Louisiana, intrastate pipelines have a long history of carrying gas owned by others. Indeed, industrial gas sales are sufficiently competitive in Louisiana that the state commission chooses not to regulate them at all. Interest in carriage depends in part on the prices offered by traditional suppliers. Customers who are fortunate enough to be served by pipelines with low gas costs have little need to press for carriage since the opportunity to find a better price is quite limited. Oklahoma Natural Gas and Natural Gas

Pipeline Company, as examples, offer some of the lowest prices in the industry.[3]

Interest in carriage programs also depends on the character of the regulation. State commissions such as those in Illinois, Ohio, Kentucky and Iowa encourage local gas distributors to provide transportation services with the result that such programs work well, with little controversy. In Tennessee, the Commission has no general policy, mostly because there is no general interest in such services. The California PUC, until recently, has not encouraged contract carriage. This is due, in part, to the Commission's extensive control over pricing by customer priority categories and the gas sequencing practices of the two major gas utilities, Southern California Gas Company and Pacific Gas and Electric Company. The Commission sees that its control over industrial prices in particular (which are tied to high-priced distillate oil and thus are higher than cost-based rates) is likely to erode if it authorizes direct sales by allowing contract carriage. Recently, however, the California PUC has developed an order that would set up an intrastate carriage program so that local producers can serve the state's enhanced-oil-recovery market. The Commission apparently is sensitive to interstate pipeline proposals that have been filed at the FERC to serve this market.[4]

In the 1950s, several interstate pipelines were proposed to the Federal Power Commission (FPC) for the purposes of contract carriage. The Houston Corporation pipeline from south Texas to Miami was constructed primarily to serve as a contract carrier for gas that two large Florida electric companies had directly purchased from Louisiana and Texas producers. The motivation of the end users, in this case,

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[3]As reported by Connie Barlow "Carriage of Customer-Owned Gas," ARTA Energy Insights, September, 1984.

[4]As reported in Inside FERC, (Washington, D.C.: McGraw Hill, September 2, 1985).

was to avoid the wellhead price regulation as imposed by the Supreme Court in 1954. That decision applied to "sales for resale" under the Natural Gas Act of 1938. The combination of end users purchasing directly from producers (which only large industrial users or electric utilities found possible), and the pipeline acting as contract carrier allowed the FPC-administered wellhead prices to be circumvented. Although the FPC approved the Houston Corporation proposal, the Commission declined to issue certificates that had been requested for several similar pipeline projects at about the same time. According to Barlow, "The commissioners worried that proliferation of new pipelines under such contractual arrangements ultimately would reduce the amount of gas available to residential customers, who necessarily depend on local distributors."[5] By 1959, the FPC had formulated its Transco policy, which denied transportation services for nonjurisdictional gas sales, that is, sales for which the price was not regulated by the FPC. In effect, the Commission decided to protect the nation's gas supplies from being used by customers who were willing to pay more than the low, FPC-administered price. When actual gas shortages materialized in the 1970s, the FPC authorized self-help programs, off-system sales, and a few joint-venture, contract-carriage pipelines which allowed limited access to higher-cost gas. By contrast, the blanket transportation certificates and Special Marketing Programs of the post-NGPA era facilitate access to lower-cost gas during a time of gas surplus.

From this brief review of contract carriage, it is clear that the interest in this institution depends on the condition of the gas market and the perception by the FERC of its role in administering the NGA and NGPA. The forces that shape long-term contractual arrangements, such as gas carriage, are quite subtle and understood only imperfectly. It is, perhaps, not surprising that long-term, complex contracts to deliver gas purchased directly by end-users is sometimes encouraged and other times discouraged by government regulation. Regulatory

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[5]Connie Barlow, "Carriage of Customer-Owned Gas," p. 3.

policy in this area has been influenced by market conditions, which suggests that the FERC and state commissions may wish to find a basis for formulating a long-term policy about carriage. Such a policy would not necessarily be unchanging, indeed the need for a flexible policy seems clear; however, it would be grounded on enduring principles. The academic literature regarding the foundation of contractual arrangements is not sufficiently well-developed to provide the definitive regulatory structure of an optimal carriage policy; nonetheless, recent contributions by Williamson, in particular, are worth reviewing in this context.

Influences on Long-Term Contractual Relations

There is a danger, possibly minor, that public utility regulators may formulate policy regarding contract carriage on the basis of the strength of current political factions. The purpose of this section is to outline some fundamental economic considerations that govern long-term contracts so that commissioners can include these in their deliberations, as well as current political reality.

The academic literature on the topic of contractual arrangements has focused on transaction costs. This literature is extensive;[6] this section draws mainly upon the work of Williamson, which has been applied to electricity transportation (i.e., transmission) by Joskow

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[6]Transaction costs are important in R.H. Coase, "The Nature of the Firm," Econometrica, 4, 1937; R.H. Coase, "The Problem of Social Cost" Journal of Law and Economics, January 1960; Victor P. Goldberg, "Regulation and Administered Contracts," Bell Journal of Economics, 7, 1976; and Benjamin Klein, Robert G. Crawford and Armen A. Alchian, "Vertical Integration, Appropriable Rents, and the Competitive Contracting Process," Journal of Law and Economics, 21, 1978.

and Schmalensee.[7] When applied to competitive markets, the theory of transaction-cost economics suggests that efficient institutional arrangements for governing and overseeing transactions will economize on the cost of negotiating, monitoring and enforcing contracts, including the costs associated with contract failure. In the case of regulated markets, commissions would promote efficiency by choosing institutional forms that tend to minimize the costs of maintaining and enforcing contracts. The spectrum of possible contractual relations includes very short-term transactions such as in a spot market, long-term market contracts between separate entities, as well as differing degrees of vertical and horizontal integration. Thus internal organization and market transactions are part of a continuum of contractual relations. The efficient choice along this range is influenced, in Williamson's framework, by characteristics of the human agents who are party to the contracts and also by characteristics of the transactions themselves.

One characteristic of the economic agent is that although his actions are guided by self interests, the complex, uncertain nature of the world combined with what Herbert Simon calls bounded rationality[8] (the impossibility of completely enumerating and computing the costs of all possible future events) makes uneconomical or impractical the writing of complete contracts that list the actions to be taken by both parties in every possible future contingency. Second, contractual arrangements must respect the proclivity of human agents to act opportunistically. In Williamson's work, such opportunism means that

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[7]See Oliver E. Williamson, Markets and Hierarchies: Analysis and Antitrust Implications (New York: The Free Press, 1975); Oliver E. Williamson, "Transaction-Cost Economies: The Governance of Contractual Relations," Journal of Law and Economics, October 1979; and Paul L. Joskow and Richard Schmalensee, Markets for Power, An Analysis of Electric Utility Regulation (Cambridge, Ma: The MIT Press, 1983).

[8]Herbert A. Simon "Rationality as Product and Process of Thought," American Economic Review, May 1978, pp. 1-16.

agents pursue their self interests in possibly guileful ways, including a willingness to lie, deceive, distort or confuse the other party. Contractual language forbidding such behavior will be respected, in this view, only if doing so is in the party's self interest. Both parties may know that the other cannot be relied upon to be wholly truthful either before or after the contract. Monitoring and enforcement costs, then, are part of the considerations driving the selection of the institutional arrangement.

Apart from human behavior, the nature of the transaction has important ramifications for the contract form. These are mainly the frequency with which such transactions occur, the uncertainty or complexity surrounding the transactions, and the extent to which transaction-specific investments are involved. Transaction-specific investment is called idiosyncratic by Williamson to indicate that its value is associated in some specific way to the contract. Hence, once the contract has been entered into, the value of such investments in other uses is greatly diminished. Williamson intends this concept to be applied broadly, covering for example human-capital investments that are specific to a contract and not easily transferable. In the public utility arena, idiosyncrasy is closely related to the notion of sunk costs that are not easily transferred to alternate applications.

The existence of idiosyncratic sunk costs usually means that both the buyer and seller are locked-in to the transaction after the contract is signed. Prior to award of the contract, competition among a large number of parties is frequently possible; but, this is quickly transformed to a bilateral monopoly afterwards. In such a situation, each party is in a position to negotiate over any incremental gain whenever the other party suggests contract changes or adaptations in the future. Even though both have an interest in maximizing their joint profits, each also would like to appropriate as large a share of the gain as possible. An anticipated need for frequent ex-post adaptations in the contract would require a governance structure that economizes on such opportunism, possibly vertical integration.

When transactions occur frequently, each party is interested in building and maintaining a reputation for good performance. Poor performance can quickly lead to the termination of an ongoing relation that each party would otherwise consider valuable. Consequently, contracts for frequent transactions tend to be self-enforcing and commonly may consist of complex, implicit arrangements. The transaction costs tend to be low in such cases, because the risk of reputation loss reduces opportunistic behavior and the corresponding need for costly oversight. Markets work well in such circumstances. Infrequent transactions, on the other hand, are often characterized by high contracting costs, which may be reduced by internal organization.

Transactions characterized by great uncertainty and complexity are likely to have high costs of contracting. As the number of future contingencies to be considered grows, contracts will either tend to become more complex (and costly to negotiate) or more incomplete (and costly to enforce against opportunism). Internal organizational forms would economize on transaction costs in such a case. Markets would be the efficient choice if uncertainty is either unimportant or easily hedged.

In summary, spot markets are likely to be an efficient form of contracting when transactions are frequent, uncertainty is manageable, and sunk costs are small. Longer-term market contracts or internal organization are likely to be better when transactions are infrequent, uncertain, complex, and require idiosyncratic investment.

Natural Gas Transportation Alternatives

Some insight into the efficient governance of natural gas transportation transactions is gained by comparing the characteristics of the actual transactions with those that Williamson outlined. For this discussion, it is useful to distinguish three alternative arrangements of the transportation portion of the natural gas industry. First, merchant carriage signifies that the pipeline sells gas to which it has title and thus the selling price covers both the commodity cost of the gas itself, as well as the cost of transportation. Most interstate pipelines are currently merchant carriers. Second, voluntary carriage refers to gas owned by others that a pipeline voluntarily transports for a fee. Interstate pipelines are currently expanding their role as voluntary carriers; however, this role remains secondary to that of merchant carrier. The third institutional form considered here is commonly called mandatory carriage, meaning that interstate pipelines would be required to carry gas for others, at an FERC administered fee, if the pipeline capacity were adequate.

Note that the discussion here is focused on a comparison of transportation alternatives. We shall assume that the local gas distribution network and the interstate pipelines themselves will remain regulated, given the nature of the transactions involved, and the long-lived character of the investments. Consumers have no other viable way of being protected from unwarranted exercise of monopoly power once the pipeline company has begun service.

Competitive entry is unlikely to be economically efficient when dealing with local distribution companies. Competition among interstate pipelines may be possible in some areas of the U.S. A recent study by the American Gas Association (AGA) reported that 56 percent of sales for resale are in the service territories of local distribution companies (LDCs) that have two or more suppliers.[9] A FERC study suggests the competitive potential is less than reported by the AGA, since 70 percent of all LDCs are served by only one pipeline.[10] The differences between these two findings may be consistent since the AGA included producers

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[9]American Gas Association, Competition in the Natural Gas Industry (Washington, D.C.: American Gas Association, February 1984).

[10]David E. Mead, "Concentration in the Natural Gas Pipeline Industry," Staff Working Paper, Office of Regulatory Affairs, Federal Energy Regulatory Commission, Washington, D.C.: August 1984.

and even other LDCs in its definition of suppliers. Also, it is possible that those LDCs with two or more suppliers were relatively large and thus accounted for a disproportionate fraction of the gas sales. In any case, the importance of multiple suppliers is itself not clear, since as Williamson points out, the LDC and its single pipeline supplier form a bilateral monopoly, an arrangement with no inherent advantage for either party.

From the viewpoint of the producers, long-term, complex contracts are likely to be required under either a merchant or mandatory carriage system. The high risks of drilling and exploration, and the fixed nature of the pumping and gathering facilities mean that the producer will want protection against future opportunistic behavior that might result in his well being shut in. A mandatory carriage system, however, would increase the producer's range of potential customers and should reduce this risk. Knowing that a spot market is available, for example, should have a favorable effect on the producer's perception of his risk of being shut in. This, in turn, may be reflected in a need for less contract protection against such risk. Long-term contracts, then, could be expected to have lower take-or-pay levels under any institutional arrangement that reduces the producer's shut-in risk. Availability of a spot market and mandatory carriage are likely to have this effect. Lower take-or-pay levels would allow the gas industry to be more responsive to changing market conditions and would serve to lessen the chance of another episode, as occurred in 1982 and 1983, of uneconomical sequencing of gas takes so as to avoid take-or-pay liabilities. Even though long-term, complex contracts would continue to be typical in the industry, the producer's need for protection against shut in is likely to be reduced by a mandatory carriage system. The result is likely to be lower levels of take-or-pay, more reliance on the spot market, and hence an overall shortening of gas contracts that would improve the responsiveness of the market. Long-term contracts are likely to remain quite common, however, and it seems quite unlikely that the industry would rely primarily on a spot market. Some instant-by-instant economic efficiency must be sacrificed in order to provide long-term protection against opportunism, without which the incentive to make idiosyncratic investments in wells and associated gathering facilities is lacking. A mandatory carriage system would appear to strike a better balance here, because it relieves the producer of the perception of being controlled by a single buyer, the interstate pipeline. A voluntary carriage system, of the type existing now or that envisioned in the FERC NOPR, may achieve a similar reduction in the producer's perceived risk, depending on how many pipelines voluntarily choose to become nondiscriminatory contract carriers. Important parts of the U.S. market may remain under the merchant carrier system.

Local distribution companies (LDCs) may benefit from a mandatory carriage system in two ways. First, to the extent that producers are willing to accept lower take-or-pay provisions in contracts, LDCs would incur reduced fixed payment obligations to gas suppliers. Minimum bills intended to reduce the financial risk associated with the gas transporter's sunk costs would be unaffected by this argument. Second, LDCs could shop for gas over a wider range of suppliers. Opportunities for finding attractive gas deals, of course, are better during a surplus condition such as the U.S. is currently experiencing. These can be expected to disappear as the surplus is worked off in the next few years. It is precisely for such conditions, however, that a mandatory carriage system is designed. Transactions between buyer and seller are exactly the activities that ultimately have the effect of eliminating the surplus that created the opportunities to begin with. A mandatory carriage system facilitates such transactions during episodes when they are needed most and thereby improves the responsiveness of the industry to changes in the marketplace. Largely because of federal regulatory apparatus required by the Natural Gas Act, such as certification and abandonment procedures, the current merchant carrier system lacks this kind of flexibility.

The financial risk to the pipelines should not be changed fundamentally by the institutional character of the carriage system adopted. This risk is mostly controlled by the nature of the FERC administered prices. Either fixed-variable or time-of-use rate designs for transportation fees could be used irrespective of the institutional framework.

The Case For Mandatory Carriage

The interstate pipelines' manner of doing business would be changed substantially by adopting mandatory, instead of merchant carriage. Most management spokesmen for the pipelines, including their trade group the Interstate Natural Gas Association of America (INGAA), are opposed to mandatory carriage. A variety of arguments have been used to support this position. The industry notes that many LDCs are served by more than a single pipeline and that voluntary carriage is enough to impose competitive discipline on the market. These are important considerations and it is certainly true that these have the effect of reducing the social benefits from adopting a mandatory carriage system. In this context, the U.S. Department of Energy (DOE) has estimated that mandatory carriage would yield $9.7 billion of net economic benefits, largely because the DOE estimates that transmission margins could be reduced by 8 cents per mcf.[11] The DOE estimate is based on the real increase in transmission margins between 1981 and 1984, which, in DOE's view, was unwarranted. Assuming the estimate is accurate, it is nonetheless a matter of some conjecture to suppose that a mandatory carriage system will impose sufficient competitive pressure on the transportation segment of this industry so as to eliminate such waste. The pipeline's transportation fees would remain under the FERC jurisdiction in a mandatory carriage system. If FERC oversight was incapable of preventing

[11]U.S. Department of Energy, Increasing Competition in the Natural Gas Market (Washington, D.C.: U.S. Department of Energy, January 1985).

an unwarranted 8 cent per mcf increase from 1981 to 1984, it is not clear how a different carriage system that remains regulated by the FERC will be more successful. Note that 70 percent of all LDCs are served by a single pipeline according to DOE's own study, which means that competitive pressure due to LDCs choosing transmission companies will not be a major force in reducing these margins.

A separate argument sometimes advanced in support of voluntary contract carriage is that much carriage is taking place already and there is no need for legislation that would give the FERC the authority to mandate carriage. INGAA issues periodic updates on the status of voluntary carriage showing dramatic increases in the past few years. These show that voluntary carriage has grown from 14.4 percent of the sales and transportation market in 1974 to 37 percent in the first three quarters of 1984.[12] Most of this activity, however, is on behalf of other pipelines when two or more pipelines are needed to move gas to the final user. Only 3 percent of gas is carried for end users.[13] In addition, several instances of pipelines and LDCs discouraging gas transportation for end users were reported in public comments to DOE.[14] Although voluntary carriage, as it is currently structured, seems to be only partially successful in promoting wellhead gas competition, the FERC program outlined in its NOPR and final order may accomplish much by giving pipelines a regulatory incentive to become voluntary, non-discriminatory contract carriers.

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[12]Interstate Natural Gas Association of America, "Voluntary Carriage in the First Three Quarters of 1984," Issue Analysis (Washington, D.C.: Interstate Natural Gas Association of America, February 1985).

[13]U.S. Department of Energy, Energy Information Administration, Statistics of Interstate Natural Gas Pipeline Companies, 1983 (Washington, D.C.: U.S. Department of Energy, November 1984).

[14]See Appendix B of the U.S. Department of Energy, Increasing Competition in the Natural Gas Market.

Some legal experts believe that a pipeline's refusal to transport gas for end users may be remedied under antitrust law. Such a case against Panhandle Eastern Pipeline Company, for example, has been filed by the State of Illinois.[15] Neither the Natural Gas Policy Act nor the Natural Gas Act requires interstate pipelines to provide such services. Despite this, a refusal to transport gas may be interpreted as a "refusal to deal" under the essential facilities doctrine of federal antitrust laws. The _Otter Tail_ case is sometimes cited as an example in which the Supreme Court held that Otter Tail Power Company must provide electricity transmission wheeling services under the Sherman Act, despite the lack of any such mandatory feature in the Federal Power Act.[16] The analogy to natural gas is direct, prompting some observers to believe mandatory gas carriage can be compelled by the courts. The difficulty with this approach is the lengthy and costly litigation required in a single case. In addition, success in precedent-setting cases like _Otter Tail_ does not ensure that the principle will be applied similarly in the next case by the court, and it certainly does not imply that public utilities will transport gas or electricity upon request without litigation. Antitrust may be a costly substitute for more carefully crafted administrative rules, such as the FERC final order, or additional legislation.

Embedded Cost Regulation

In addition to the competitive pressure exerted by the 30 percent of LDCs served by multiple pipelines, a mandatory carriage system is

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[15]State of Illinois v. Panhandle Eastern Pipeline Company, No. 84-1048 (C.D. Ill. filed February 7, 1984).

[16]Otter Tail Co. v. United States, 410 U.S. 366 (1973). See the discussion in U.S. Congress, Congressional Research Service, _Natural Gas: On the Road to Deregulation_ by Alvin Kaufman, Donald P. Dulchinos, and Robert D. Poling, TN880 U.S. B, (Washington, D.C.: July 1985).

likely to reveal, for the first time, problems associated with LDCs choosing transmission paths for uneconomic reasons. FERC-administered regulation based on historical costs means that transportation fees for individual pipelines will reflect the age of the investments. More recently built pipelines command higher transportation fees under cost-plus regulation. LDCs with options will avoid the higher-priced transportation paths. These transportation fees become more visible when they are unbundled from purchased-gas cost. It can be predicted now that 10 years after adopting mandatory carriage, a then recently-built pipeline will ask the FERC to prevent market raiding by an older pipeline that then discovers it can build a short link to its competitor's customer (an LDC, say) and transport gas at a lower system average price. The problem here has nothing to do with carriage, per se, except that unbundling transportation cost from gas cost reveals it more clearly. Its solution requires that economic regulation distinguish between monopoly profits, the source of which is opportunistic behavior made possible by monopoly power and is therefore to be prevented, and other profits, such as those associated with an increasing cost industry or the fortuitous (early) entry into an industry, which does not represent opportunism. The regulatory prevention of the second source of profits has been a major source of the economic disorders experienced under federal regulation of wellhead prices.

Opportunistic Behavior

In Williamson's framework, possibly the most important type of opportunism to consider here occurs in a pipeline's role of gas reseller under the current merchant carriage system. Some profit opportunities may arise because the gas itself is purchased and resold. Whether such opportunism occurs is by no means clear. If it does not occur, however, it most likely has been prevented at the cost of additional regulatory oversight or added complexity in gas contracts. One study, by Graves, Hogan and McWhinney, has estimated that because of affiliated gas production, each 10 percent increase in the gas cost of the 12 largest interstate pipeline companies results in a 6 percent increase in pre-tax profits.[17] This strongly suggests that affiliated production creates profit opportunities. Mandatory carriage would eliminate such opportunism, either that which actually occurs perhaps because of affiliated production, or that which is only latent and prevented by the social cost of regulation or contracts that could be simplified in its absence.

Requiring that a pipeline's production affiliates sell directly to end users eliminates the opportunism completely. In effect, mandatory carriage would allow a vertically integrated pipeline producer to continue to enjoy the real economic benefits of integration, whether the source is management expertise or the economies associated with holding certain land leases, and at the same time would prevent opportunistic manipulation of prices.

Natural Gas Brokerage

Under the current merchant carrier system, interstate pipelines combine the functions of transportation, storage and brokerage into a single service. The unbundling of these that would occur under a mandatory carriage system raises several important issues. It is undoubtedly true that pipeline companies are relatively efficient gas brokers. Over many years the managements of these firms have accumulated an expertise, an information base, and a set of market contacts that are invaluable tools in bidding for and writing gas purchase contracts. The brokerage

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[17]J.S. Graves, W.W. Hogan, and R.T. McWhinney, Mandatory Contract Carriage: An Essential Condition for Natural Gas Wellhead Competition and Least Consumer Cost (New York: Putnam, Hayes and Bartlett, Inc., September 1984).

function, however, is not a monopolized activity, as witnessed by the emergence of new firms that recently have been established for the purpose of facilitating and brokering gas sales. This competition is a socially healthy development that will lead to least-cost provision of brokerage services.

Efficient brokerage services by pipelines are likely to be encouraged by a system of mandatory carriage also. Combining the transportation and brokerage roles, as under the current merchant carrier system, may allow the pipelines' monopoly control of transportation to be extended to marketing negotiations with producers. Note that from the viewpoint of the ultimate consumer, the wielding of such monopoly power may not be necessarily bad. If such monopoly buying power (called monopsony power, by economists) results in low gas prices because a pipeline is able to exert some control over non-affiliated, captive gas producers, consumers would enjoy at least part of the resulting benefits as these are flowed through under the FERC oversight. Such an outcome, however, is not economically efficient and represents a market distortion from the viewpoint of overall social welfare. In this case, independent producers have been exploited. If a merchant pipeline deals with an affiliated producer, the result may be the opposite, with consumers paying higher than competitive prices. Such an outcome likewise is a market distortion and serves to reduce overall social welfare. Mandatory carriage would tend to prevent both types of distortions since the pipeline would no longer hold the producer nor its customers captive.

If mandatory carriage were adopted, or if a pipeline chooses to be a non-discriminatory contract carrier as outlined in the FERC final order, regulatory oversight will be complicated by the need to recognize the pipeline's competitive brokerage services. In effect, a contract carrier's regulated transportation fees must be established separately from the prices of its competitive brokerage services. This raises the thorny regulatory issue of cost separation, particularly between a regulated entity and a closely associated, but essentially competitive, complementary service. Regulatory experience with the AT&T system and subsidiaries of regulated electric companies suggest one of two approaches: either encourage the pipelines to set up a separate brokerage subsidiary or improve the cost accounting system to include reports on unregulated activities or both. Regulators, then, should be aware that elimination of the pipeline's monopoly power over the brokerage function may come at the cost of some, possibly modest, increase in the cost of regulatory oversight.

Adequate Capacity

Opponents of mandatory carriage point out that the allocation of scarce pipeline capacity during peak demand periods would be complicated by a mandatory carriage system. Determining the capacity of a gas pipeline is complicated by the inherent properties of the substance which, for example, allows "line packing" during the winter heating season, a procedure whereby the pipeline itself acts as a storage reservoir during daylight hours so as to meet overnight demand. Opponents fear that regulatory oversight of capacity availability would be so detailed that the system would not be operated efficiently.

While such fears must be taken into consideration, other observers believe the problem to be manageable. The DOE, the Congressional Research Service and the Illinois Commerce Commission indicate that capacity planning and operation problems should be no more difficult to solve if the system were converted to mandatory carriage.[18] Changing ownership of the gas does not affect the actual physical constraints or the seasonal nature of demand. In the near term, the pipelines have ample capacity to transport substantially more gas than is currently

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[18]See DOE, Increasing Competition, Congressional Research Service, Natural Gas, and Illinois Commerce Commission, The Gas Industry: Changes and Challenges, Sunset Monograph Series 2 (Springfield, Il: Illinois Commerce Commission, December 1984).

flowing,[19] which suggests that this might be a convenient time to affect institutional change. The system has room to accommodate substantial demand growth while adjusting to new carriage rules before encountering the need to turn away carriage requests for lack of capacity. In addition, transportation requests and services provided by pipelines can have a variety of forms. Besides firm transportation service, pipelines may wish to arrange for interruptible carriage or possibly seasonal carriage. Such services combined with seasonal transportation fees are likely to rationalize the use of the pipeline network with little, if any, deterioration in its operating efficiency.

State Transportation Policy

As interstate pipelines decide whether or not to accept the FERC offer of non-discriminatory carriage, some state commissions may have to address similar transportation issues for the first time. Some commissions may need to expand and train their staffs to deal with new regulatory functions such as oversight of gas acquisition practices, transportation alternatives, and spot market operation. In addition, state commissions may encounter the problem of industrial bypass, either actual or threatened, of the local gas distributor. Bypass has become a familiar issue to many commissioners in the telephone sector in particular and to a lesser extent in the electric industry. This issue is basically the same in the natural gas area, although it is in some ways less complex than the bypass problems of local telephone exchanges. Large industrial gas users that currently are served by a local distributor may be able to strike a favorable bargain with a distant gas producer and wish to have the gas transported to a plant currently served by a local distribution company. If the industrial user is successful in arranging for interstate transportation to the LDC's city gate, because all intervening pipelines have voluntarily become non-discriminatory carriers, the policy questions are whether or not

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[19] DOE, Increasing Competition, p. 104.

to allow the gas to flow through the LDC's system to the industrial customer and, if so, at what price?

If the distributor and state commission decide against the industrial customer and do not allow the gas to be transported by the LDC, the industrial user may decide to bypass the LDC altogether by connecting directly to the closest interstate pipeline. The bypass threat also may be exercised if the LDC provides transportation service but does so at such a high price that the industrial user is better off by bypassing anyway. State commissions, of course, are interested in all potential bypass situations but particularly may wish to avoid so-called uneconomic bypass. Bypass which is not economically justified is that which occurs even though the LDC could have provided the transportation for less than the interstate pipeline's cost plus the cost of any needed direct interconnection.

In the opinion of the authors, a view that is shared by the NARUC Staff Subcommittee on Gas,[20] the bypass issue is most appropriately addressed by cost-based transportation tariffs that offer unbundled, transportation service to any user on a non-discriminatory basis. The investment decision of a large gas user to bypass the LDC will be based on a comparison of the costs of alternate transportation choices. This basically involves a comparison of the LDC's transportation fee with the annualized cost of the capital required to build a pipeline spur to the nearest point of connection with the interstate carrier. Several factors work in favor of the LDC in such a comparison. The LDC's tariff based on embedded costs has an immediate advantage over the current cost of building the connection spur. Also, the LDC's expertise in maintaining gas mains would have to be developed by the industrial customer who may have little interest in entering the gas transportation business on an ongoing basis.

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[20]Report of the NARUC Subcommittee on Gas on FERC Rule Making Docket RM-85-1-000, (Washington, D.C.: National Association of Regulatory Utility Commissioners, November 1, 1985).

It is good to recall that the industrial customer's basic motivation for even considering bypass is that the wellhead price which has been negotiated is attractive relative to the LDC's system supply. Such prices will remain attractive as long as the current excess deliverability situation persists. As national demand grows or reserve discoveries slow down, spot market prices will rise and eliminate much of the difference between system supply prices, which are based mostly on long-term contracts, and short-term contract prices, which are currently low.

The current saving in gas costs that an industrial customer can find at the wellhead may be $1.00 per mcf or more compared to the LDC's system supply. Such a price differential is large enough to justify building a connection spur in the event that the LDC refuses to transport the gas. The difference between the LDC's transportation fee and the annualized capital cost plus maintenance costs of the spur is likely to be of a much smaller magnitude, however. Allowing the LDC to offer unbundled, transportation service seems quite likely to diffuse most of the incentive to bypass the local distribution network.

If the LDC embedded cost transportation rate is still too high and an industrial user continues to threaten to bypass, the commission may wish to investigate a further reduction in transportation rates, possibly based on incremental costs. The overall public interest of such a price reduction can be evaluated separately for each case. The discussion of the limits of price discrimination in the previous chapter is relevant in such deliberations. If the price reduction can be pinpointed at the particular customer who would otherwise exercise his bypass option, the remaining system customers are likely to be better off because such a customer would be paying at least some part of the LDC's fixed costs. If, however, the price reduction must be given also to other industrial customers, perhaps because of an unwillingness to discriminate between customers within the industrial category, then the demand elasticity of the aggregate customer group must be considered. That is, in applying the no-loser criterion developed in the previous chapter, the relevant demand sensitivity that a commission must consider is the elasticity of the entire group for which a favored rate is proposed. Only if the demand elasticity of the aggregate set of customers is very high (higher than the reciprocal of the fixed cost fraction recovered in the customers' bills) will it be true that all other customer classes can be held free of any economic harm.

State commissions may wish to evaluate the use of reservation prices that would be assessed on customers who wish separate transportation service but who also wish to maintain the option of being served by the LDC's system supply at a future date. In addition, cost-of-service studies of the LDC may need to take account of greater locational detail than has been included heretofore. Attributing specific portions of the LDC pipeline network to specific customers may be needed in order to develop a rational cost-of-service tariff that is competitive with an industrial user's transportation alternatives.

To prevent all uneconomic bypass, transportation rates need to be based on cost-of-service principles. Such principles allow a reasonable degree of flexibility on the part of the commission and the distribution company in setting rates. A pipeline's demand charge is an example of a quasi-fixed cost[21] that commissions may wish to avoid shifting to transportation customers. Although it is true that such fixed costs of the LDC's gas supply are shifted as transportation customers reduce their takes from system supply and substitute their own contracted supply, these costs are shifted for a variety of other reasons as well. Customers leave an LDC's service area, go out of business, use some other fuel or simply conserve, all of which result in a shifting of the gas supply fixed costs. As the Staff Subcommittee on Gas pointed out, "There is no reason to single out the transportation customer to continue to pay costs associated with a product (gas supply) which it is no longer purchasing."[22] Such a charge is completely inappropriate, of

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[21]Quasi-fixed means fixed in the short run. In this case, pipeline demand charges are changed at each FERC rate hearing. The LDC can adjust maximum rates of gas purchases at such times and on other occasions under the final rule 436.

[22]Report of the NARUC Subcommittee on Gas, p. 7.

course, if the LDC can reduce its supply by an amount corresponding to the transportation customer's volume. Since the FERC final rule 436 allows LDCs to reduce system supply by 25 percent per year, the pipeline's demand charge may not be fixed costs in reality. For these reasons, a cost-based transportation rate would include the distributor's fixed and variable costs of operating the local pipeline system but would not include any quasi-fixed costs of the gas supply contracts.

Summary

The institutional arrangement of the transportation sector of the natural gas market has been the topic of substantial debate in the past year or two. The FERC has deflected much of this polemic by a carefully crafted NOPR that appears to accommodate the wishes of most market participants and regulators. If the FERC is successful in restructuring the industry so that all or at least most pipelines agree to carry gas for others on a nondiscriminatory basis, most of the objectives associated with mandatory carriage proposals will have been accomplished with voluntary programs. The FERC initiative in this area is innovative and while the final rules will undoubtedly be modified in response to comments and criticisms, the basic plan seems to be quite consistent with the promotion of competition within the gas industry while allowing pipelines to operate either as voluntary carriers or as merchant carriers, according to their choice. The clearly defined policy direction of the FERC is likely to supplant any congressional interest in mandatory carriage legislation until its success or failure can be evaluated.[23]

There has been a tendency in the carriage debate to cast the argument in terms of current gas market conditions. These are important. In part, however, the discussion in this chapter has been intended to focus the attention of regulators on fundamental factors that govern the

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[23]CRS, Natural Gas, p. 66.

efficiency of long-term contractual arrangements. In Williamson's terminology, the bounded rationality of human decision-makers combined with a willingness to engage in opportunistic behavior creates a need for contracts and institutions that are tailored for individual economic circumstances. The need to economize on transaction costs is likely to result in complex long-term contracts or perhaps vertical integration when transactions are infrequent, uncertainty is high, and idiosyncratic investment makes possible opportunistic behavior that must be guarded against.

Natural gas pipelines, interstate and LDCs both, have these characteristics. The institution of mandatory carriage is likely to have favorable risk-reducing influences on wellhead gas contracts since producers may have less risk of being shut in opportunistically by their pipeline-buyer. The emerging spot market provides a way of reducing long-term supply risk, also. The long-term nature of most gas demand, however, is likely to mean that most gas contracts would be correspondingly long, so the spot market is not likely to be a predominant force. The need for contract carriage and the importance of the spot market are likely to vary over the business cycle and to depend on the need that producers or end users have for adjusting the contract terms in accordance with market conditions. Hence, carriage and the spot market will act as market stabilizers, and by their actions serve to eliminate the need for such transactions in the first place. Carriage, in effect, enables transactions that take advantage of arbitrage opportunities which disappear as a result of the trading. The current demand for carriage, then, should not be interpreted as meaning that interstate pipelines should no longer buy and sell gas. Their brokerage expertise and the future need for firm, long-term supply contracts are likely to create a major role for pipelines in the gas marketing business. Even under a mandatory carriage system, pipelines most likely would continue to be major brokers. They would compete, however, with other independent brokers in a market that offers a range of contracts from the spot market to long-term arrangements under either a mandatory carriage system or the nondiscriminatory voluntary contract carrier status envisioned in the FERC NOPR.

The transportation system that evolves under the FERC final rule is not likely to involve mandatory carriage. This finesses the issue of regulatory determination of adequate capacity, which might otherwise be a complex problem under a mandatory regime. Rate design issues remain important, however. These include such matters as seasonal transportation fees, optimal demand charges and the difficulties associated with embedded-cost regulation that yield different prices for the same transportation service depending on the age of the pipeline investments. The cost allocation associated with separating competitive brokerage services from the regulated transportation function of pipelines is likely to be a minor, but nonetheless controversial issue.

Cost-based transportation rates for unbundled transportation service by local distributors seem likely to prevent most incentives for large industrial customers, in particular, to uneconomically bypass the local gas utility. If the economic circumstances are such that a large user decides to bypass the LDC despite such cost-based rates, the commission may wish to consider a reservation price for those users who wish the option of being served by the LDC in the future.

In many ways, the final rule that FERC has crafted addresses many of the industry's transportation problems without imposing mandatory rules. Depending on how many pipelines choose to become nondiscriminatory carriers, the industry may be transformed into one with workably competitive purchased-gas markets and an accessible, regulated carriage program. Mandatory carriage is an alternative to the direction chosen by the FERC. Many observers feel that the FERC proposal should be tested before adopting mandatory rules because the incremental benefits from a mandatory program may be quite small if the FERC is successful.

CHAPTER 5

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

The rapidly changing energy scene and the competitive pressures from alternative fuel supplies are likely to produce a growing market of natural gas interruptible 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 as indicated by the discussion in chapter 3, the theoretical and methodological issues relating to the appropriate cost allocation among firm and interruptible customers are still unresolved. The purpose of this chapter is to present a modeling methodology for the design of firm and interruptible rates at the distribution level, with a particular emphasis on (1) alternative cost 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 in the first section of this chapter. Its detailed structure is presented in the next section and includes the principal features of a gas demand, supply-mix cost minimization, Monte-Carlo dispatching simulation, and rate design submodels. The results of applying the model with data pertaining in part to the East Ohio Gas Company (EOGC) under various cost alloction and service reliability policies are presented in the next chapter.

Overview of the Model

The model used to analyze the effects of alternative reliability and cost allocation policies on firm and interruptible retail rates is a partial equilibrium model that determines equilibrium rates for a target year under specific policies for a single utility. The equilibrium rate for each end-use sector 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, and the service reliability and cost allocation procedure selected. A general flow diagram of the model is presented in figure 5-1.

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, nonsupply 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 functions are next used in the formulation of a chance constrained, supply-mix cost minimization submodel, which explicitly

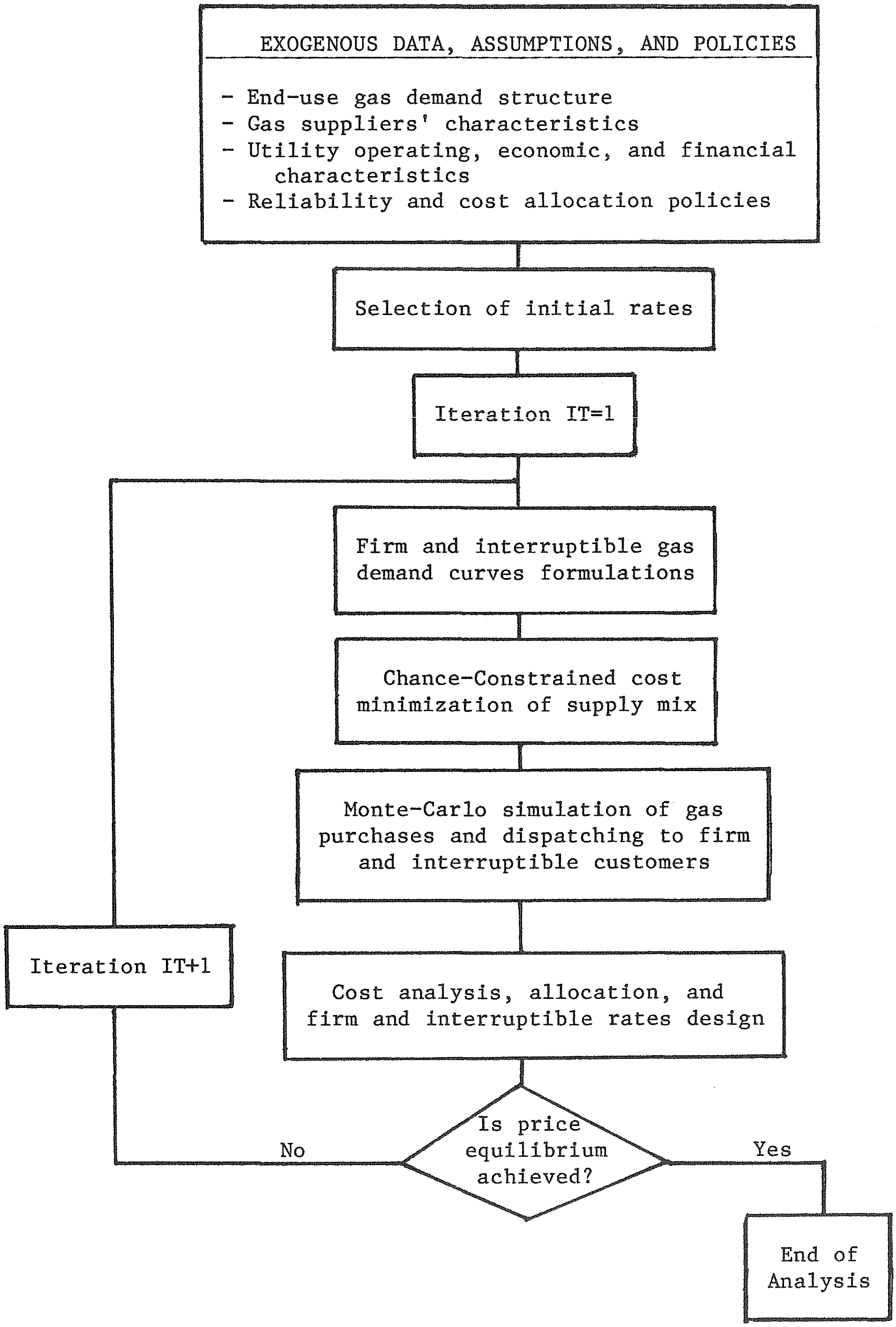

Fig. 5-1 Model overview

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 5-1. The nontechnical reader may wish to skip ahead to the next chapter which describes an application of the model.

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 denoted 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:

$$D_{sm} = D_{sm}(P_{sm}, P_{om}, X_m) \quad s=1 \rightarrow S , \qquad (1)$$

$$D_{Im} = D_{Im}(P_{Im}, P_{om}, X_m, R_m) , \qquad (2)$$

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} = interruptible price of gas 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.

Chance-Constrained Cost Minimization of Supply Mix

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

$$D_m^F = \sum_{s=1}^{S} D_{sm} \quad . \qquad (3)$$

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.[1] In the present model, however, these are treated as exogenous parameters, that is, the existing storage capacity cannot be expanded and the injection-withdrawal schedule is predetermined and is to be adhered to, whatever the pattern of gas demands.

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[1]See, for instance, J.M. Guldmann, "Supply, Storage, and Service Reliability Decisions by Gas Distribution Utilities: A Chance-Constrained Approach," Management Science 29, August 1983, pp. 884-906.

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

$$S_{im} - N_m D_i \leqslant 0 \qquad i=1\to N,\ m=1\to M\ , \tag{4}$$

$$\left.\begin{aligned} T_{im} - S_{im} &\geqslant 0 \qquad i=1\to N,\ m=1\to M\ , \\ T_{im} - t_i N_m D_i &\geqslant 0 \qquad i=1\to N,\ m=1\to M\ , \end{aligned}\right\} \tag{5}$$

$$\sum_{t=1}^{N} S_{im} = D_m^F + SI_m - SW_m \qquad m=1\to M\ . \tag{6}$$

The total cost of gas purchases is then

$$C = \sum_{i=1}^{N} 12\ C_i^D\ D_i + \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\ T_{im}\ . \tag{7}$$

The deterministic model is the linear program consisting of the objective function (7) and constraints (4)-(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.[2] 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 only depends upon the random degree-day variable X_m, as does the aggregate gas supply S_m^T, with

$$S_m^T = \sum_{i=1}^{N} S_{im} = D_m^F (X_m) + SI_m - SW_m , \qquad (8)$$

or

$$S_m^T = S_m^T (X_m). \qquad (9)$$

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

[2]See, for instance, A. Charnes, and W.W. Cooper "Deterministic Equivalents for Optimizing and Satisficing Under Chance Constraints," Operations Research, 11, 1963, pp. 18-39.

minimum purchase requirements are fulfilled and then in the order of least expensive gas first, afterwards. Because of the minimum purchase requirement constrains the sequencing, the dispatch rule is optimal only in a second-best sense. In a general form then

$$S_{im} = F_{im}\left(S_m^T, \overline{D}, \overline{C}^c, \overline{t}\right), \qquad (10)$$

where $\overline{D}$, $\overline{C}^c$, $\overline{t}$ 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

$$S_{im} = F_{im}\left(S_m^T, \overline{D}\right) = F_{im}\left(X_m, \overline{D}\right). \qquad (11)$$

The variable S_{im} depends upon the random variable X_m, and hence is a random function of $\overline{D}$, 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

$$P_{im}^{min} = \int_0^{N_m t_i D_i} P_{im}(v)\, dv. \qquad (12)$$

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

$$E(C) = \sum_{i=1}^{N} 12\, C_i^D D_i + \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c N_m t_i D_i P_{im}^{min}$$

$$+ \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c \int_{N_m t_i D_i}^{\infty} S_{im} P(S_{im})\, dS_{im} . \qquad (13)$$

Minimizing the expected cost is the usual criterion when dealing with cost minimization under uncertainty. Fundamentally, the expected cost (13) is a function of the demand contract variables $\overline{D}$. These may have upper bounds related to the physical and other characteristics of the pipelines, and the optimization problem can be reformulated as

$$\text{minimize } E[C(\overline{D})] \tag{14}$$

$$\text{subject to: } \quad \overline{D} \leqslant \overline{D}^{max} \quad . \tag{15}$$

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 $\overset{T}{S_m}$, with

$$S_{im} = a_{im} \overset{T}{S_m} \quad . \tag{16}$$

The coefficients a_{im} are decision variables to be determined endogenously to the model, with of course the constraint that

$$\sum_{i=1}^{N} a_{im}=1 \quad . \tag{17}$$

Equation (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

$$a_{im} \overset{T}{S_m} \leqslant N_m D_i \quad . \tag{18}$$

$\overset{T}{S_m}$ is a random variable, however, and hence constraint (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 (18) into the chance constraint

$$Pr(a_{im}S_m^T - N_m D_i \leq 0) \geq 1-\alpha_{im} , \qquad (19)$$

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

$$V = a_{im}S_m^T - N_m D_i \ . \qquad (20)$$

Its expected value and standard deviation are

$$E(V) = a_{im}E(S_m^T) - N_m D_i \ , \quad \text{and} \qquad (21)$$

$$\sigma(V) = a_{im}\ \sigma(S_m^T) \ . \qquad (22)$$

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

$$Pr(z \leq z_{\alpha_{im}}) = 1-\alpha_{im} \ . \qquad (23)$$

As $z=(V-E(V))/\sigma(V)$, it can be shown that constraint (19) is equivalent to the deterministic constraint

$$a_{im}\ [E(S_m^T) + z_{\alpha_{im}}\ \sigma(S_m^T)] - N_m D_i \leq 0 \ . \qquad (24)$$

Constraint (24) is linear, with unknowns a_{im} and D_i. As the storage flows SI_m and SW_m are deterministic parameters, we have

$$E(S_m^T) = E(D_m^F) + SI_m - SW_m \ , \qquad (25)$$

$$\sigma(S_m^T) = \sigma(D_m^F) \ . \qquad (26)$$

In addition to the above constraints related to the violations of individual demand contracts, it is necessary to consider the aggregate supply capacity constraint

$$\Pr(S_m^T \leq N_m \sum_{i=1}^{N} D_i) \geq 1-\beta_m \ , \qquad (27)$$

where β_m is a parameter representing the monthly, overall system supply reliability level for firm customers. The deterministic equivalent of (27) is

$$N_m \sum_{i=1}^{N} D_i \geq E(S_m^T) + z_{\beta_m} \sigma(S_m^T) \ , \qquad (28)$$

or

$$N_m \sum_{i=1}^{N} D_i \geq E(D_m^F) + z_{\beta_m} \sigma(D_m^F) + SI_m - SW_m \ . \qquad (29)$$

Chance constraint (27) is redundant and superseded by chance constraints (19) if, and only if,

$$\prod_{i=1}^{N} (1-\alpha_{im}) \geq (1-\beta_m) \ . \qquad (30)$$

This possible redundancy thus depends upon the selection of the policy parameters α_{im} and β_m.

Further approximations to the basic model (14)-(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 (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

$$E(C_1) = \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c \int_{-\infty}^{+\infty} S_{im}\, P(S_{im})dS_{im}$$

$$= \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, E(S_{im}) = \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, a_{im}\, E(S_m^T). \qquad (31)$$

In order to introduce the penalty component into the objective function, it is first necessary to add the following constraints:

$$N_m t_i D_i - a_{im}E(S_m^t) = x_{im}^+ - x_{im}^- \quad \text{for } i=1 \rightarrow N,\ m=1 \rightarrow M, \qquad (32)$$

$$x_{im}^+ \geqslant 0 \quad ,$$

$$x_{im}^- \geqslant 0 \quad .$$

where x_{im}^+ and x_{im}^- are nonnegative variables to be chosen in the optimization. Any expected penalty is associated only with the excess variable x_{im}^+ (that is, whenever $a_{im}E(S_m^T) \leqslant N_m t_i D_i$) and is defined as

$$P_N = \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, x_{im}^+ \,. \qquad (33)$$

The expected supply cost is finally approximated as

$$E(C) = \sum_{i=1}^{N} 12\, C_i^D\, D_i + \sum_{i=1}^{N} \sum_{m=1}^{M} C_i^c\, [a_{im}\, E(S_m^T) + x_{im}^+] \,. \qquad (34)$$

$E(C)$ 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 (34) and the constraints (24), (29), (32), (15) and (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 (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:

$$D_{Tm}^{max} = \sum_{i=1}^{N} D_i N_m \quad , \qquad (35)$$

$$D_{Tm}^{min} = \sum_{i=1}^{N} D_i N_m t_i \quad . \tag{36}$$

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 minimum aggregate purchase requirement, and if the slack can not be used by interruptible customers, minimum bill penalties must be paid. In this case, step 3 is next. If $D_{Tm}^{min} < S_m^T < D_{Tm}^{max}$, no penalties are assessed, 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

$$Cur_{sm} = D_{sm} - D_{sm}^a \quad , \tag{37}$$

$$Pcur_{sm} = Cur_{sm}/D_{sm} \quad . \tag{38}$$

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

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

$$S_{im} = S_{im}^{1} + S_{im}^{2} + S_{im}^{3} + S_{im}^{4} \quad . \tag{39}$$

In the present case, these components are

$$S_{im}^{1} = t_i N_m D_i \qquad i=1 \rightarrow N \quad , \tag{40}$$

$$S_{im}^{2} = (1-t_i) N_m D_i \qquad i=1 \rightarrow N \quad , \tag{41}$$

$$S_{im}^{3} = S_{im}^{4} = 0 \qquad i=1 \rightarrow N \quad . \tag{42}$$

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_i^c) order. Assume that the minimum purchase requirements of the first N_1 suppliers are necessary to provide firm customers' needs. Then

$$S_{im}^{1} = t_i N_m D_i \qquad i=1 \rightarrow N_1-1 \ , \tag{43}$$

$$S_{im}^{1} = S_m^T - \sum_{j=1}^{N_1-1} t_j N_m D_j \qquad i=N_1 \ , \tag{44}$$

$$S_{im}^{1} = 0 \qquad i > N_1 \ , \tag{45}$$

and

$$S_{im}^{2} = 0 \qquad i=1 \rightarrow N \ . \tag{46}$$

Next, interruptible demand, D_{Im}, is fulfilled up to the minimum purchase requirements in the same order. For instance, if $D_{Im} > t_i N_m D_i - \overset{1}{S}_{im}$ for $i=N_1$, then

$$\overset{3}{S}_{im} = t_i N_m D_i - \overset{1}{S}_{im} \qquad i=N_1 \ , \tag{47}$$

and the remaining interruptible demand is satisfied up to the minimum purchase requirements of the remaining suppliers. Thus

$$\overset{3}{S}_{im} \leq t_i N_m D_i \qquad i > N_1 \ . \tag{48}$$

If all minimum purchase requirements are fulfilled, (i.e., $\overset{3}{S}_{im} = t_i N_m D_i$, $i > N_1$), 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

$$\overset{4}{S}_{im} = (1-t_i) N_m D_i \qquad i=1 \rightarrow N_2-1 \ , \tag{49}$$

$$\overset{4}{S}_{im} = D_{Im} - \sum_{j=1}^{N_2-1} (1-t_j) N_m D_j \qquad i=N_2 \ , \tag{50}$$

$$\overset{4}{S}_{im} = 0 \qquad i > N_2 \ . \tag{51}$$

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

$$\overset{I}{S}_{im} = t_i N_m D_i \qquad i=1 \rightarrow N \ , \tag{52}$$

$$\overset{3}{S}_{im} = 0 \qquad i=1 \rightarrow N \ . \tag{53}$$

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_{im}^k as

$$C_m^k = \sum_{i=1}^{N} C_i^c \, S_{im}^k \quad . \tag{54}$$

The actual penalties, if any, for violating any minimum purchase requirements are

$$C_m^{pen} = \sum_{i=1}^{N} C_i^c \, \mathrm{Max}\,(0,\ t_i N_m D_i - S_{im}^1 - S_{im}^3). \tag{55}$$

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 rate base), as allowed by state regulatory authorities.

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

$$CT_I = \sum_{m=1}^{M} (\bar{C}_m^2 + \bar{C}_m^4) + Sh_I(COS) \ , \qquad (56)$$

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

$$D_{IT}^a = \sum_{m=1}^{M} \bar{D}_{Im}^a \ . \qquad (57)$$

The ex-post average price that recovers CT_I is then

$$P_I = CT_I/D_{IT}^a \ . \qquad (58)$$

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 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 commputed as follows. Let p be the peak period for aggregate firm sales. Then the peak-related allocation factors are

$$FP_s = D_{sp} / \left(\sum_{s=1}^{S} \overline{D}^{a}_{sp} \right) \qquad s=1 \rightarrow S \; . \tag{59}$$

The non-peak related allocation factors, based on average annual sales, are

$$FY_s = \left(\sum_{m=1}^{M} \overline{D}^{a}_{sm} \right) / \left(\sum_{s=1}^{S} \sum_{m=1}^{M} \overline{D}^{a}_{sm} \right) \qquad s=1 \rightarrow S \; . \tag{60}$$

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. The allocation factors for the hybrid cost category are then

$$FH_s = CAL_s / \left(\sum_{s=1}^{S} CAL_s \right) \qquad s=1 \rightarrow S \; . \tag{61}$$

The factors are used to allocate hybrid costs. The total costs allocated to secter s is denoted CAL^T_s. The ex-post average prices guaranteeing cost recovery are then

$$P_s = CAL^T_s / \left(\sum_{m=1}^{M} \overline{D}^{a}_{sm} \right) \qquad s=1 \rightarrow S \; . \tag{62}$$

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.

Summary

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. The model is used in the next chapter to analyze a variety of regulatory policies and conditions of uncertainty. The intent is to investigate interruptible rate design and service reliability policies under different degrees of demand uncertainty and supply prices.

CHAPTER 6

AN ANALYSIS OF NATURAL GAS RATE DESIGN AND SUPPLY MIX UNDER UNCERTAINTY

The stochastic optimization model described in the previous chapter was used to analyze a variety of regulatory policies and economic conditions. The results are reported in this chapter. The policies include such matters as the share of fixed costs paid by interruptible customers, the reliability of service for firm customers, and supply contract parameters such as minimum purchase requirements. The last of these is not determined solely by regulatory authorities; however, the FERC minimum bill rule discussed in chapter 2 suggests that regulators can influence this contract parameter to some degree. This chapter also reports the sensitivity of these policies with respect to demand uncertainty, demand elasticity, and the presence or absence of an interruptible sector. The chapter has several sections, the first two of which set out the basic data used for this analysis. Each of the subsequent sections deals with particular policies or demand conditions.

Data Description

The data used in this analysis were gathered, in part, from the East Ohio Gas Company (EOGC). EOGC serves the northeastern part of Ohio and is one of the nation's largest gas utilities, with 922,212 residential, 55,653 commercial, and 1370 industrial customers in 1984, the base year of the analysis. Data sources include the 1984 Annual Report of the EOGC to the Public Utilities Commission of Ohio (PUCO) and the 1984 Uniform Statistical Report (USR) submitted by EOGC to the American Gas Association.

A statistical analysis of the weather sensitive component of the demand for natural gas was conducted for the residential, commercial and industrial sectors. A demand equation for each sector was estimated by ordinary least squares using 1984 monthly observations from EOGC. The estimated equations and associated statistics are

$$\text{Residential Demand} = 2534.41 + 17.463\ DD_m\ , \qquad (1)$$

$$\begin{array}{rll} \text{(t-value)} & (4.65) & (23.05) \qquad R^2 = 0.982 \\ \text{(sign.)} & (0.0001) & (0.0001) \end{array}$$

$$\text{Commercial Demand} = 887.09 + 7.038\ DD_m\ , \qquad (2)$$

$$\begin{array}{rll} \text{(t-value)} & (7.32) & (41.79) \qquad R^2 = 0.994 \\ \text{(sign.)} & (0.0001) & (0.0001) \end{array}$$

$$\text{Industrial Demand} = 3283.82 + 3.839\ DD_m\ . \qquad (3)$$

$$\begin{array}{rll} \text{(t-value)} & (7.86) & (6.61) \qquad R^2 = 0.814 \\ \text{(sign.)} & (0.0001) & (0.0001) \end{array}$$

where DD_m is monthly degree-days and demand is measured in millions of cubic feet of gas (mmcf).

As expected, the explanatory power of each equation is very good, especially in the residential and commercial sectors that are relatively sensitive to weather. The intercept and regression coefficients can be interpreted as the base and space-heating requirements. For a total average annual number of degree-days equal to 6255, the average annual space-heating loads of the residential and commercial sectors represent 78 percent and 81 percent of their total loads, respectively. In the case of the industrial sector, this share is only 38 percent. Because industrial load also is influenced by factors other than weather, such as economic conditions, the correlation coefficient is lower, although still statistically significant. The demand functions, equations (1) in chapter 5, are assumed to take the general form

$$D_{sm} = (a_s + b_s\ DD_m)\left(\frac{P_s}{P_{so}}\right)^{EL_s}, \tag{4}$$

where a_s and b_s are the estimated coefficients in equations (1) to (3). Note that the demand functions are assumed to have a constant-price-elasticity form, wherein P_s is the actual gas price to sector s, P_{so} is a calibration reference price, and EL_s is the price elasticity. On the basis of a review of 25 gas demand studies,[1] the following elasticity values are used in this analysis: residential $EL_R = -0.22$; commercial $EL_C = -0.32$; industrial $EL_I = -0.64$. These correspond to the typical magnitudes of short-run price elasticities. Long-term elasticities tend to be 2 to 3 times larger. Using such long-term elasticities would change the equilibrium value of prices in the following analysis but would have little effect on the conclusions, since these deal with the changes induced in the equilibrium by changes in policy parameters or economic conditions. The reference prices P_{so} are taken as equal to the 1984 average prices (i.e., sectoral revenues divided by sectoral sales), with: P_{RO} = \$5.41 per mcf, P_{CO} = \$4.98 per mcf, and P_{IO} = \$4.52 per mcf.

A statistical analysis of degree-days in each month over a 26 year period (1950-1976) is summarized in table 6-1, which shows the sample means and standard deviations for each month. The correlations between the degree-days of consecutive months were insignificant. The conclusion is that the monthly degree-day random variables DD_m are independent of one another. In addition, goodness-of-fit tests at the 5 percent significance level indicate that these monthly observations are normally distributed.

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[1]U.S. Department of Energy, Natural Gas Rate Design Study, (Washington, D.C.: Government Printing Office, 1980).

TABLE 6-1

CHARACTERISTICS OF MONTHLY DEGREE-DAYS DISTRIBUTIONS
(Degree-Days)

Month	Mean	Standard Deviation	Month	Mean	Standard Deviation
January	1207.7	129.5	July	11.0	9.4
February	1046.3	115.2	August	18.9	14.1
March	892.5	125.4	September	120.5	42.1
April	506.6	90.5	October	371.6	91.1
May	248.2	88.3	November	712.6	85.6
June	50.5	28.8	December	1071.6	145.8

Source: Authors' calculations.

Although EOGC has no interruptible customers, such a sector is included in the model to illustrate interruptible pricing policy. The demand of this sector is assumed to be independent of the random degree-day variable, and takes the form

$$D_Z = D_{ZO}\left(\frac{P_Z}{P_{ZO}}\right)^{EL_Z}, \qquad (5)$$

where $EL_Z = -1.5$ is assumed to be the interruptible sector's elasticity. The calibration reference price, P_{ZO}, is \$4.00 per month, and D_{ZO}, the reference demand, is 2500 mmcf. Hence, when the interruptible demand price P_Z is equal to P_{ZO}, the annual interruptible gas demand is equal to 30,000 mmcf, or about 10 percent of the firm gas demand of the EOGC in 1984.

The storage flows, SI_m and SW_m, used in this analysis model are presented in table 6-2. These flows closely reflect, but are not exactly equal to the observed 1984 flows. Some slight adjustments were made so that total deliveries equalled total withdrawals. In 1984, an inventory build-up of 2497 mmcf, or 4 percent of total deliveries, took place.

TABLE 6-2

STORAGE DELIVERIES AND WITHDRAWALS (mmcf)

Month	Deliveries	Withdrawals	Month	Deliveries	Withdrawals
January	0	17856	July	9300	0
February	0	9300	August	9238	0
March	0	11408	September	8742	0
April	8556	0	October	6944	0
May	9796	0	November	0	11036
June	9424	0	December	0	12400

Source: Authors' calculations.

EOGC has two major interstate pipeline suppliers: Consolidated Gas Supply Corporation and Panhandle Eastern Pipeline Company. In lieu of these, three hypothetical suppliers are used in this analysis to illustrate a wider variety of supply opportunities. In particular, the recent advent of a spot market in natural gas is an important development which is of interest to state commissions. The analysis that follows includes a small, but nontrivial, opportunity for the distributor to purchase gas from a spot market. Since it is not possible to purchase exclusively from this market, the analysis incorporated a limit on maximum deliveries of 100 mmcf per day. Considering the size of the utility being studied, this constrains spot market purchases to be no more than about 10 percent of any daily purchase. The spot market is characterized here as having no demand charge and no minimum purchase requirement. Besides these small spot purchases, the distributor has two major pipeline sources of supply in this study. These are depicted, along with the spot market, in table 6-3.

The contract parameters displayed in table 6-3 have been selected so that the optimal supply mix includes some purchases from all three sources, with a distinct limit to the spot market which is supplier 3 in the table. The maximum purchase limits for suppliers 1 and 2 have been set large enough so as never to constrain the distributor's choices. The optimal supply mix includes both of the first two sources because their prices are competitive with one another. Above a load factor of about 45 percent, the average price of gas from supplier 2 is lower than that from supplier 1 because of the lower commodity price of the second supplier. Below that load factor, however, supplier 1 has a lower average price because of its favorable demand charge. The monthly demand pattern described previously in this section has a load factor of about 50 percent. Corrected for storage injections and withdrawals, the load factor is about 70 percent. This demand pattern and set of cost-of-supply characteristics combine in such a way that supplier 2 serves the base load while supplier 1 has more of a peak service role. Both suppliers have a natural market niche, in other words, which is not the result of any constraint on the other.

TABLE 6-3

GAS SUPPLIERS' CHARACTERISTICS

	Supplier		
	1	2	3
Commodity Rate ($/mcf)	3.95	3.80	3.00
Demand charge ($/mcf)	1.50	3.50	0.00
Minimum Purchase (%)	40	50	0
Maximum Purchase (mmcf per day)	1200	1200	100

Source: Authors' calculations.

The spot market source, supplier 3 in table 6-3, dominates both pipeline suppliers in that its commodity price, its demand charge, and its minimum purchase requirements are all smaller. In such circumstances, the optimum would be to purchase all requirements from the spot market. Since such a solution is unrealistic, this supplier is limited to providing up to 100 mmcf per day. In the absence of any minimum purchase requirements by the two major suppliers, this spot market limit always would be purchased as the base load supply. The 40 and 50 percent minimums in table 6-3 have been selected, in part, because these are large enough to prevent such full use of the spot market in some circumstances reported later in this chapter.

The 1984 EOGC operating costs, depreciation costs, plant-in-service values, taxes, and actual rate of return were used in this analysis. The operating costs included: storage ($12,000,000), transmission ($3,00,000), distribution ($35,000,000), customer accounts ($40,000,000), customer services ($7,000,000), sales expenses ($3,000,000), and administration ($49,000,000). EOGC produces some natural gas, but this source was neglected in this analysis, and so were the corresponding operating costs and plant in service. The plant in service included: storage ($64,000,000), transmission ($129,000,000), distribution ($480,000,000), general ($26,000,000). Depreciation costs were $22,000,000, while taxes were $141,000,000. The rate base (or net plant in service) is about 60 percent of the gross plant in service. Finally, the actual rate of return, calculated as the ratio of the operating income to the rate base, was 12.34 percent.

Base Case

To avoid inundating the reader with numerical detail, the remainder of this chapter is organized so as to first present in this section the basic nature of the least-cost equilibrium and then to introduce variations of this basic theme, one at a time in successive sections. The base case described in this section has the following characteristics. Reliability of service in any month has been specified to be 99 percent or better for all firm customers. An interruptible sector is served, but such users pay no portion of the distributor's fixed costs. The suppliers and demand patterns (including the random weather-sensitive component) are as described in the previous section. The equilibrium is described in tables 6-4 and 6-5.

TABLE 6-4

EQUILIBRIUM PRICES, SALES, AND CURTAILMENT RATES

Sector	Prices ($/mcf)	Annual Sales (bcf)	Curtailment Rate (%)
Residential	5.365	139.8	0
Commercial	5.374	53.3	0
Industrial	5.215	57.9	.16
Interruptible	3.709	33.3	N/A

Source: Authors' calculations

TABLE 6-5

EQUILIBRIUM SUPPLY CONTRACTS
(mmcf/day)

	Supplier 1	Supplier 2	Supplier 3	Total
Contract Demand	483.6	581.8	100.0	1165.4

Source: Authors' calculations

The interruptible sector price in table 6-4 is quite low, only $3.71 per mcf compared to $5.37 or $5.22 for the firm customer sectors. Interruptible use comprises about 11 percent of total sales. The maximum actual curtailments in any month is only .16 percent, which is smaller than the one percent reliability as specified in the chance-constrained program. These curtailments occur in April because in that month average demand plus scheduled injections into storage is the largest and hence net requirements occasionally exceed the contracted maximum supply. The average total annual cost associated with this base case is $1,462 million. Of this, a very minor amount, $.38 million, is due to payments for violating contracted minimum purchase requirements. Most of these payments occur in the month of November. Although November has a large average demand, planned withdrawals from storage combined with the random influence of weather (Novembers can be unusually mild) occasionally result in less demand than contracted minimums. The base case has been designed so that although these minimum bill penalties are part of the equilibrium, they are minor. This is meant to reflect circumstances after the FERC minimum bill rule that should alleviate distibutors' problems due to minimum purchase requirements.

The equilibrium maximum contract delivery rates are shown in table 6-5. The maximum obtainable from the spot market, 100 mmcf per day, is selected, of course, since there is no demand charge for maximum delivery rates in this market. The needed contract demand level that remains is divided between the two major pipeline suppliers, somewhat favoring the second supplier because of its lower commodity rate.

A variety of circumstances and policies have been studied using this base case as a benchmark. These are described in the following sections.

Minimum Purchase Requirements

The effects of various levels of the pipelines' minimum purchase requirements are summarized in table 6-6. If no minimum purchases are required, pipeline 2 is the biggest supplier, with total contract demand levels from the three sources being 1167.9 mmcf (not shown in the table). The total contracted demand decreases as the minimum purchase

TABLE 6-6

INFLUENCE OF MINIMUM PURCHASE REQUIREMENTS

Minimum Purchase (%) Supplier 1	2	Contract Demand (mmcf per day) Supplier 1	2	3	Prices ($/mcf) Res	Comm	Ind	Inter
0	0	230.3	837.6	100	5.32	5.33	5.17	3.82
30	30	244.3	822.6	100	5.34	5.35	5.18	3.81
40	40	81.6	984.8	100	5.35	5.36	5.19	3.77
50	50	0	1064.2	100	5.39	5.40	5.23	3.57
60	60	0	1060.7	100	5.40	5.47	5.29	3.65
70	70	0	1046.9	100	5.72	5.73	5.55	3.67

Source: Authors' calculations

percentage is raised, falling to 1046.9 mmcf if the minimums are set equal to 70 percent. The residential price begins at 5.32 per mcf. As the minimum purchase requirements are increased, prices to firm customers are increased, while interruptible users actually have a reduction in price until the 50 percent minimum level is reached, at which point this price also rises as the minimum purchase percentage increases even further.

The reason why the price paid by firm customers increases along with the minimum purchase requirement is that more and more payments must be made for gas not actually taken. At the 60 percent level, these payments are still small, only about .7 percent of total costs. At the 70 percent level, however, these have ballooned to 4.1 percent of total costs and cause a corresponding increase in the prices paid by firm customers. It should be noted that these price increases are paid on average. If such prices were paid year after year in order to cover the cost of occasionally violating minimum purchase levels, the pipeline would recover revenue in excess of its costs, assuming the demand charge and commodity price are set so as to allow the pipeline to break even. Three actions could then be taken by the FERC. One is to allow the overrecovery. A second is to reduce the commodity price or demand charge to compensate for the expected level of minimum bill payments. The third is to allow distributors to take gas in later years that has been paid for under the minimum purchase agreement. This would convert the minimum purchase requirement into a more traditional take-or-pay type of contract that allows buyers to make up purchases at later dates. In any case, the first policy is implicit in the NRRI model and results in more revenue recovered by pipelines as the minimum purchase percentage increases.

The reason why the interruptible sector's price initially decreases is more subtle and has to do with the least-cost dispatching of the spot market supplies in particular. With no minimum purchases required by the two pipeline suppliers, gas is dispatched in what would be called the most efficient manner, least cost first. All cheap, spot-market gas is dispatched solely to firm customers in these circumstances. As the pipelines' minimums increase, however, the appropriate dispatching, which might be termed second-best, is to use the most expensive gas first up to the minimum purchase requirements since such a policy avoids the largest possible amount of minimum bill penalty. Since a large fraction of the pipelines' more expensive supply is dispatched first, some of the cheaper, spot-market gas is occasionally left over and is used to serve interruptible customers. Hence, an unintended side effect of the minimum purchase requirement is that the appropriate dispatching in such circumstances shifts cheaper gas to low-priority customers. This is an example of a perverse and uneconomic ordering of supplies that society as a whole presumably would prefer to avoid. It illustrates that subtle economic distortions can result from well-meaning policies, in this case, a minimum purchase requirement intended to reduce the financial riskiness of the pipeline company.

Spot Market Price

The base case used in this study is intended to reflect current (1985) market conditions, which are somewhat unusual in that spot market prices are much lower than current pipeline prices. This is partly a disequilibrium condition that has resulted from the combination of long-term contracts signed before 1982 and the subsequent recession that suppressed the demand for natural gas. In more normal circumstances, spot market prices would be much closer to the pipelines' commodity rates, in all likelihood. The effects of a wide range of spot market prices on the distributor's equilibrium are shown in table 6-7.

TABLE 6-7

INFLUENCE OF THE SPOT MARKET PRICE

Spot Market Price ($/mcf)	Contract Demand (mmcf per day) 1	2	Spot Market Purchases (bcf)	Prices Res	Inter
3.00	483.6	581.8	35.18	5.37	3.71
3.80	276.6	783.2	34.76	5.47	3.81
3.90	277.0	782.8	7.06	5.47	3.82
4.00	277.1	782.6	1.24	5.47	3.83
4.10	277.2	782.5	1.24	5.47	3.84
4.20	277.2	782.5	1.24	5.47	3.84

Source: Authors' calculations

Because of the 100 mmcf per day limit incorporated into this study, the maximum annual purchases from the spot market are 36 billion cubic feet (bcf). As table 6-7 shows, the annual amount purchased from the spot market is close to 36 bcf as long as the spot market price is less than the smallest commodity price from any pipeline supplier. In table 6-7, as the spot market price rises above $3.80, the second major supplier becomes the cheapest source of gas in terms of commodity cost. (The average cost of pipeline supplies is somewhat higher, about $3.95 to $4.00 per mcf). Hence, at $3.90 the spot market becomes much less attractive and annual purchases are reduced to 7.06 bcf, only about 20 percent of the available supply. At $4.00, the spot market is dispatched last and serves only in the role as the "peaker" supply. In this role, about 1.245 bcf are used annually which is only about .5 percent of total sales.

Hence, the role of the spot market in a gas distributor's optimal supply mix depends critically upon its price in relation to other suppliers. If the price is quite low, the spot market provides base load supplies to whatever extent is allowed by the market. At higher prices, the spot market becomes the peak supply source, the importance of which depends on the shape of the distributor's load curve. The demand pattern incorporated into this analysis has a load factor of about 70 percent, which leaves a relatively small role for the spot market in this particular study.

Demand Elasticities

For completeness, a brief mention of the effect of demand elasticities on the distributor's equilibrium is warranted. In most cases, the solution to the cost-minimization problem studied here was not particularly sensitive to variations in the various demand elasticities, within reasonable ranges. The reason is that the model is intended to investigate least-cost gas purchasing strategies under conditions of uncertainty. The model does not find prices according to the inverse-elasticity rule, for example. Because the pricing is based on traditional, embedded cost-of-service principles, there is a tendency for a specific fraction of fixed costs to be assigned to particular customer classes. As the demand elasticity is increased, there is a tendency for sales to decline and prices to rise as the same fixed costs are spread over fewer units.

As discussed in chapter 3, very large demand elasticities can induce self-reinforcing reductions in sales so that the higher prices lead to ever shrinking demand. This type of death spiral was artificially induced for the interruptible sector using the NRRI model to see whether the presence of demand uncertainty changed the rule that was described in chapter 3. The analysis showed that a death spiral is triggered in this chance-constrained, reliability of service model by virtually the same conditions as are discussed in chapter 3 in the context of nonstochastic demands.[2] Hence, there is no need to elaborate upon the previous discussion, although this conclusion was not readily apparent before the analysis.

An Analysis of Interruptible Rate Design, Uncertainty, and Reliability

The chance-constrained programming model allows the analyst to investigate the nature of the least-cost equilibrium under a variety of uncertainty and service reliability conditions. Four factors, in particular, were studied jointly in order to detect any interactions within this group. The factors are (1) the presence or absence of an interruptible sector, (2) the fraction of fixed cost payments made by interruptible users, (3) the degree of uncertainty, and (4) the reliability of firm service, as defined by β_m in equation (27) in chapter 5. The influence of each of these four factors on retail prices and the contract demand levels, as well as any interactions among these factors are described in the following four subsections. Each of these factors was studied at only two levels.

The interruptible sector was either omitted or specified to be 2500 mmcf per month at the reference price, as described in the first section of this chapter. Interruptible users, if served, paid either 0 or 5 percent of the distributor's fixed costs. The degree of demand uncertainty, as measured by the standard deviation of degree-days, was specified to be either 75 or 125 percent of the level in the base case, described in the first section. Hence, uncertainty is either 25 percent more or 25 percent less than the benchmark case. The service reliability for firm customers was either 1 or 5 percent. All possible

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[2]The condition that induces instability, as described in chapter 3, is that the demand elasticity is larger than the reciprocal of the fraction of fixed costs recovered in a particular sector's bills.

combinations of these parameter settings were studied. The effects of each factor and the interaction among them are described next.[3]

Presence of An Interruptible Sector

The existence of a set of customers willing to accept interruptible service generally has a favorable effect on the prices paid by the remaining customers. Recall that the size of the interruptible sector is about 10 percent of total sales. Adding such a sector has the advantage of reducing minimum bill penalties. If these interruptible customers pay some of the fixed costs, in addition, firm customer prices can be reduced even further. In the context of the constant-profit ellipsoids presented in chapter 3, the addition of a new set of customers is similar to a movement from point F' to point G in figure 3-1. That is, the sudden introduction of a customer group that pays no fixed costs is similar to an abrupt change in the price paid by that sector. Initially, the price is so large that the sector does not exist, and next, the price is very low. Point G is only an example. In effect, the interruptible sector price skips from one extreme to another. The effect on the remaining customers depends on the position of points F' and G in figure 3-1. In the present case, the favorable effects on firm customers of introducing an interruptible sector are small. Firm prices drop by about .8 cents per mcf. The improvement to firm prices would be larger if minimum bill penalties were larger and hence could be avoided by the addition of such flexible customers. The average price effect just described was itself influenced by uncertainty and reliability conditions.

The residential and commercial prices were reduced by only .5 cents with the introduction of the interruptible users if demand

[3]To simplify the arithmetic, these effects and interactions were found using standard statistical procedures. Technically, the parameter settings comprise a full factorial design, which allows ordinary least squares to be used to "estimate" or "determine" all first and second-order effects.

uncertainty was small (75 percent of the base case). The drop was somewhat larger, 1.7 cents, if demand uncertainty was 125 percent of the base case. The residential and commercial price effects did not change with reliability level since these sectors were never curtailed.

The industrial price effect was similar to that just described for residential and commercial uses, except that the reliability level also mattered. In particular, the price reduction (due to the introduction of the interruptible sector) was about .3 cents smaller if reliability was specified to be 5 percent, instead of 1 percent. Hence, the presence of interruptible users has a more favorable price effect for customers who are likely to be curtailed if a policy of requiring a high degree of reliability is followed.

Interruptible Users' Share of Fixed Cost

The advantage to firm customers of introducing an interruptible sector, as just described, is relatively small in this example because minimum bill penalties are minor to begin with. There is a more substantial benefit enjoyed by firm customers if the interruptible sector pays some fraction of fixed costs. The following analysis is based upon a comparison of 0 and 5 percent of such cost being paid by the interruptible users.

Residential and commercial prices declined by about 8.8 cents per mcf in response to 5 percent of fixed costs being recovered from nonfirm users. The similar benefit to firm industrial users was slightly smaller, about 8.1 cents per mcf. These price reductions were not particularly sensitive to either the degree of reliability or the extent of demand uncertainty.

By comparison, the 5 percent fixed cost burden caused interruptible prices to increase by about 77.4 cents per mcf. Since the interruptible sector is only about 10 percent of total sales, the interruptible price naturally must increase by about 10 times as much as any decrease in firm prices. This necessary price increase paid by interruptible users was somewhat sensitive to reliability and uncertainty conditions. Since high reliability and a high degree of demand uncertainty increases costs that are paid for by firm customers (which is appropriate since interruptible users are not responsible for such costs), these same conditions require a smaller price increase for interruptible customers when their fixed cost burden is increased. The needed interruptible price increase was about 2.6 cents smaller if supply reliability for firm users was 1 percent instead of 5 percent. Similarly, the price increase was about 3.8 cents smaller if demand uncertainty was 125 percent of the base case instead of 75 percent. Hence, the burden of paying a specified fraction of fixed costs is smaller if the remaining users enjoy a high service reliability or have a larger random component in their demand.

Note that 5 percent of the distributor's fixed cost was about 17 percent of interruptible users' bills. Depending on the price elasticity of this nonfirm sector, the fixed cost burden could be increased beyond the 5 percent level studied here, and still remain in the stable region depicted in figure 3-1 between points A and B. Hence, prices paid by firm customers could be increased even further, the limit being the point at which a death spiral is induced.

Demand Uncertainty

Greater demand uncertainty requires larger contract demands in order to maintain the same level of service reliability. The resulting higher cost, in turn, leads to higher average prices for firm customers. Contract demand levels, in the aggregate, increased by about 68 mmcf per day when uncertainty increased from 75 to 125 percent of the base case if reliability was low (that is, a 5 percent chance of curtailment). The contract demand increase was even larger, 96 mmcf, if a 1 percent curtailment probability was maintained. These represent a 6 to 8 percent increase in maximum contracted delivery rates.

The corresponding price increases associated with these higher contract demand levels were much smaller as a percentage because the pipelines' demand charges comprise less than 5 percent of their total bills. Residential and commercial prices increased by about 3.3 cents per mcf, which was about a .5 percent increase. In the absence of any interruptible customers the needed increase was somewhat larger, 4.6 cents.

The required price increase for firm industrial customers in response to greater demand uncertainty was about 3.4 cents per mcf. As with the residential and commercial sectors, this increase was a little larger, 4.3 cents, if the distributor served no interruptible customers. Unlike the residential and commercial sectors, industrial users were occasionally curtailed in the examples used in this study. Consequently, the specified reliability also affected the price increase induced by demand uncertainty. The increase was about 3.9 cents per mcf at the high reliability level (1 percent curtailment probability) and only 2.6 cents at the lower level (5 percent curtailment chance).

Demand uncertainty affected the interruptible sector in the opposite fashion--the interruptible price went down by about 6.5 cents as uncertainty increased. The reason can be traced to the uneconomic dispatch order associated with the minimum purchase requirements. As demand uncertainty is raised, higher levels of contract demand are needed. Since minimum purchases are specified as a percentage of these demand levels, the absolute sizes of the minimums increase as well. Least-cost dispatching requires that the most expensive gas be used first, up to the minimum. This rule results in more of the expensive pipeline supplies being assigned to firm users, thereby freeing up more of the cheaper, spot-market gas for interruptible users. This is clearly an unintended and inefficient consequence of the minimum purchase requirement.

This analysis suggests that regulators can offset greater uncertainty, in part, if reliability of service can be lowered.

Whether this is a wise social policy depends on the value that consumers attach to high quality service. This analysis suggests only that the opportunity for offsetting greater demand uncertainty with reduced service reliability exists and is a viable policy choice. By contrast, the introduction of an interruptible sector is not a viable alternative, because the presence or absence of such an entire sector is not normally a policy option to begin with. Even if it were, the benefits to firm customers of adding an interruptible sector (which is about 10 percent of total sales) are only about a half or less of the benefits of reducing reliability. In the event that a regulatory commission has the opportunity to encourage a distributor to serve new interuptible customers, however, it is true that firm customers benefit more from such an addition when uncertainty is greater.

Reliability of Service

The chance-constrained programming model offers the analyst the opportunity to study the effects of service reliability on demand contracts and retail prices. Maintaining a greater reliability level is basically accomplished by higher contract demand levels. Aggregate maximum delivery rates were required to be about 43 mmcf higher for the 1 percent curtailment chance as compared to the 5 percent probability, at the low level of demand uncertainty. If demand uncertainty was high, this increase in contract demand was about 71.3 mmcf, much higher.

The result of the higher contract demand levels was higher prices for firm customers and somewhat lower prices for interruptible users. All firm customers paid about 1.6 cents per mcf more at the higher reliability level. This effect for residential and commercial customers remained essentially the same for various combinations of demand uncertainty, fixed cost share of interruptible users, and the presence or absence of an interruptible sector.

The industrial price effect was sensitive to some of the other conditions. For example, the reliability-induced price increase was about 2.4 cents per mcf if demand was highly uncertain, whereas it was only 1.3 cents if this uncertainty was low. The presence of an interruptible sector also reduced this price effect by about .3 cents per mcf, although the cost-sharing parameter was of no consequence to this effect.

The interruptible sector typically enjoyed a price reduction in the event that firm customers were provided with more reliable service. Although there is no a priori reason to expect interruptible prices to increase along with firm prices as reliability is improved, it nonetheless seems somewhat unusual that interruptible prices actually decreased. The reason has to do with the previously explained perverse role of minimum bills.

An increase in reliability and the associated greater contract demand levels lead to larger absolute quantities of gas that are covered by minimum purchase requirements since these are expressed in percentage terms. In the presence of these minimums, the appropriate dispatch order is to take the most expensive gas first, up to the required minimums. With higher reliability levels, more expensive pipeline supplies are assigned to firm customers, leaving more of the cheaper spot market gas to be sold to interruptible users. Consequently, interruptible prices declined about 4 cents per mcf in response to higher reliability, if demand uncertainty was low. This favorable effect was even larger, 6 cents per mcf, if the interruptible users paid 5 percent of fixed costs.

That interruptible users benefit from increasing the service reliability of firm customers is clearly an unintended side effect, traceable once again to the albeit optimum but nonetheless perverse dispatching that takes place because of minimum purchase requirements. The expected effect is completely neutral, neither positive nor negative, which would have been the case in the absence of such minimums.

Summary

The NRRI model determines least-cost solutions to a natural gas distributor's problem of selecting the optimum mix of gas supplies and best dispatching policies in the face of demand uncertainty. The role of an interruptible sector and its share of payments for fixed costs, as well as the implications of a spot market, minimum purchase requirements, service reliability levels, and demand uncertainty have been discussed in this chapter.

Minimum purchase requirements were shown to have several inefficient outcomes. The base case used in this study (see table 6-3) resulted in more contract demand being purchased from supplier 1 than was optimum in the absence of the minimum purchase requirements (compare tables 6-5 and 6-6). This is a distortion of the longer-term planning process. In addition, short-term dispatching is distorted by such minimums in that the least-cost sequence is to take the most expensive gas first up to the minimum required. This is clearly uneconomic and indeed is the opposite of an efficient resource use. Two inefficient consequences of this second-best dispatching policy were discussed in this chapter. In both, interruptible prices declined as the result of greater quantities of cheaper, spot market gas being dispatched to this sector. The examples involved increases in demand uncertainty and reliability levels, both of which increased contract demand and the associated minimum requirements. In each case, firm customers received more expensive pipeline supplies because of the second-best dispatching rule, leaving more of the cheaper, spot-market gas for interruptible users. This distortion is likely to be smaller now than before the adoption of the FERC minimum bill rule discussed in chapter 2.

The spot market is particularly attractive as a source of natural gas in the current circumstance of its price being lower than most pipeline sources. As the current market disequilibrium is corrected over the next several years, the spot market is likely to be used primarily as a peak supply source, principally because this source has relatively few fixed charges associated with it. Its importance will be greater for distributors with greater demand uncertainty and for those with more pronounced seasonal demand patterns.

The presence of an interruptible sector that pays no fixed costs had only a moderate advantage for firm customers in this analysis. This was due to the relatively small amounts of minimum purchase penalties in the examples studied. The payment of some fraction of the distributor's fixed costs by interruptible customers, however, did reduce the firm customers' prices. The issue here is basically price discrimination, the limits of which are discussed in chapter 3.

Demand uncertainty and service reliability affect the need for maximum contract demand levels. Each tends to raise the prices paid by firm customers, and in this analysis each also had the effect of reducing interruptible prices. The latter effect was the result of the second-best dispatching, as discussed previously. The model used in this analysis determines the optimum supply mix for specified levels of reliability, demand uncertainty, and minimum purchase requirements.

CHAPTER 7

SUMMARY AND CONCLUSIONS

The natural gas industry in the United States currently faces major forces from several directions that may result in some painful reorganization. The U.S. economic recession of the early 1980s, the reduction of world oil prices, and regulatory pressure to transport significantly more gas as contract carriers have called into question the traditional merchant carrier role of the interstate pipelines. The availability of cheap, spot market gas combined with the inability of many users to arrange for it to be transported has led to congressional and federal regulatory scrutiny of the nation's pipeline network. Most pipeline companies appear, at this writing, to be resisting the Federal Energy Regulatory Commission (FERC) offer to become voluntary, nondiscriminatory carriers of gas. The industry is clearly in a period of transition, the outcome of which has yet to be revealed.

State commissions are interested in natural gas rate design as well as transportation issues. These issues at the federal level must be understood by state commissions in order to adopt appropriate policies at the retail level. This report has addressed both rate design and transportation matters, although emphasis has been placed on the former.

The design of natural gas rates is addressed in chapter 3 and also in chapter 6 in the context of the numerical examples studied with the NRRI simulation model. A principal conclusion of this research is that natural gas pricing would be improved by unbundled, time-of-use rates for separate services such as the gas commodity, its transportation, and its storage. Such rates would be based on cost-of-service principles and would be available for all users on a nondiscriminatory basis.

A second principal conclusion of this research is that there are important limits to price discrimination, which tend to induce market instability, if violated. Because fixed costs exist, price discrimination can be an important way of improving aggregate economic well-being and at the same time, recovering the revenue requirement. If a utility or regulator attempts to discriminate excessively, however, a death spiral may result instead. Interestingly, the point at which such a self-reinforcing collapse of demand occurs is at the price an unregulated monopolist would change. That is, a death spiral is brought about by an attempt to recover such a large portion of fixed costs from a particular customer group or market that the resulting price is higher than even that which would occur in the absence of any regulation to begin with. The particular condition that causes such market instability is that the fixed cost fraction of a customer group's bills exceeds the inverse of that group's price elasticity of demand. In most cases, this condition establishes price discrimination limits that do not constrain the regulator in practice, since the regulatory process most likely produces a compromise set of prices that falls within the extremes at which a death spiral would be induced. Nonetheless, the conceptual link between the notions of a death sprial, unregulated monopoly pricing, and fixed cost recovery may be of value to regulators in assessing the merits of claims such as those associated with no-loser price discrimination.

It is important to note that the argument concerning these limits to price discrimination is equally applicable to any of the unbundled services that might be offered by a gas distributor or pipeline. Hence, price discrimination is not an issue solely for full-service gas suppliers who can load the fixed costs of the embedded pipeline onto the single commodity price paid by users for a combination of services. It also pertains to companies that offer separate services at unbundled prices, each of which is limited by the maximum price at which instability occurs.

The role of demand charges in such unbundled, time-of-use rates is likely to be small compared to its current importance. A time-of-use variation in transportation fees would capture most of the economic efficiency benefits of a capacity-conserving nature in pipeline rate designs. This most likely would leave only a small role for pipeline demand charges in an efficient rate design. The risk reduction arguments that support the current design of pipeline demand charges, for example, are rather weak on economic efficiency grounds and are unsupported by empirical evidence.

The presence of interruptible customers in a distributor's service area can be important to the other, firm customers in times of uncertainty. It is important to remember, however, that much of this advantage to firm users is due to the reduction in minimum purchase penalties that accompanies such an addition of interruptible users. From the narrow focus of the gas distributor, such minimum purchase requirements are inherently inefficient as evidenced by the optimum (but clearly second-best) dispatching sequence in which the most expensive gas is taken first, up to the specified minimums. This is a socially perverse order in which to use the nation's natural resources. The resulting distortion to social well-being is justified only if the financial risk of the pipeline company is reduced substantially. The resulting decline in the pipeline's cost of capital must be sufficiently large to offset the misallocation that is induced in the distributor's supply planning and dispatching processes.

One regulatory option in times of greater uncertainty is to economize by reducing the quality of service. In the chapter 6 analysis, service reliability has been the major indicator of service quality. In this study, a reduction in planned reliability, from a curtailment rate of 1 percent to that of 5 percent, enabled the distributor to significantly reduce maximum contract delivery rates. Hence, degrading service reliability is a viable alternate as a response to greater uncertainty. Whether such an action would be wise social policy has not been addressed in this analysis. The optimum provision of public utility capacity is a subtle matter that requires an estimate of the value that consumers attach to high quality service. The purpose here is only to report that the capacity savings associated with a reliability reduction are not trivial and could become part of a commission's regulatory deliberations as a way of dealing with the increased uncertainty facing the natural gas industry.

Finally, as the interstate pipeline companies decide whether or not to accept a nondiscriminatory carrier role, state commissions are likely to be faced with the need to encourage or allow gas to be transported by local distributors. This may require separate transportation tariffs based on cost-of-service principles. Such unbundling of a local distributor's services may be required to prevent uneconomic bypass of the local pipeline network, in particular, by large industrial customers.

The current turmoil in the natural gas industry is basically traceable to the historical link between gas transportation services and the supply of the commodity itself including the associated brokerage services. The discovery and selling of natural gas and, to a lesser extent, the long-distance transportation of the commodity are services for which some degree of competition is possible. As this competition actually materializes, there is a natural tendency for it to erode the historical full-service role of interstate pipelines and local distributors. Regulators are familiar with this interface between competition and local natural monopoly in the telephone industry; the issues have a similar root in the natural gas industry.

APPENDIX A

SUPPLY AND DEMAND CONDITIONS IN THE NATURAL GAS MARKET

This appendix is an extension of the discussion of natural gas supply and demand that appears in the first section of Chapter 2. It is included here as a more detailed review of natural gas market conditions that are responsible, in part, for much of the current policy discussion about gas transportation and pricing issues. The appendix has four sections, beginning with a discussion of demand conditions, and ending with an overview of price forecasts that are made by several agencies.

Natural Gas Demand

This section presents information concerning the consumption of natural gas. Table A-1 lists yearly consumption levels and annual percentage changes in these levels by customer class for the period 1978 to 1983. Table A-2 lists information for the residential class and displays the relationship between the level of sales and the price of natural gas as well as the relationship between the level of sales and heating degree days. These tables show that total consumption as well as consumption by each class has declined since 1978. Total consumption in 1983 was 13 percent below the 1978 level, which is a reduction of 2.6 tcf. Among customer classes, the largest decline occurred in the industrial class--a decline of 21 percent. Commercial consumption, by contrast, declined only 3 percent.

Residential consumption, which is about 25 percent of the total, peaked in 1979 at 4.97 tcf and then decreased to 4.53 tcf by 1983. This trend is due partly to energy conservation and partly to

TABLE A-1

NATURAL GAS CONSUMPTION, 1978-83,
BY CUSTOMER CLASS
(trillion cubic feet)

Year	Total Residential Sales	% Change	Total Commercial Sales	% Change	Total Industrial Sales	% Change	Total Electric Utility Sales	% Change	Total Other Sales	% Change	Total NG Consumption	% Change
1978	4.90	—	2.60	—	6.76	—	3.19	—	2.18	—	19.63	—
1979	4.97	+1.43	2.79	+7.31	6.90	+2.07	3.49	+9.40	2.09	-4.31	20.24	+3.11
1980	4.75	-4.63	2.61	-6.90	7.17	+3.91	3.68	+5.44	1.66	-25.90	19.88	-1.81
1981	4.55	-4.40	2.52	-3.57	7.13	-0.56	3.64	-1.10	1.57	-5.73	19.40	-2.47
1982	4.63	-1.76	2.61	+3.57	5.83	-18.23	3.23	-12.69	1.70	+8.28	18.01	-7.72
1983	4.53	-2.21	2.53	3.16	5.50	-6.00	2.91	-11.00	1.56	-8.97	17.03	-5.75

Source: Energy Information Administration, Natural Gas Annual, 1982 and Energy Information Administration, Natural Gas Monthly, March 1984. As cited in DOE/PE-0069.

TABLE A-2

RESIDENTIAL CONSUMPTION AND DEMAND DETERMINANTS
COMPARISON FOR FIRST SIX MONTHS, 1982-1984

Year	Residential Sales[a] (bcf)	Percentage Change	Residential Price[a] (1983$/mcf)	Percentage Change	Heating Degree Days[b]
1982	3103	--	4.97	--	3142
1983	2789	-10.12	5.94	+19.52	2889
1984	2850	+2.19	5.78	-2.77	3019

Source: [a]Volume-weighted average price from Natural Gas Monthly, July 1984, adjusted using the GNP Deflator; [b]Energy Information Administration, Short Term Energy Outlook, (Washington, D.C.: August 1984).

saturation of gas appliance markets. Evidence presented in table A-2 suggests residential demand is only moderately sensitive to price. Estimates of short- and long-run price elasticities are commonly around -0.4 and -0.7, respectively.[1] Most observers attribute this low elasticity to the fact that natural gas heating, in particular, is a necessity for most residential users. Another factor that affects residential consumption is the weather. Not surprisingly, residential consumption is largest among states with the coldest winters.[2]

The consumption pattern for the commercial sector during these years was very similar to that of the residential sector. Commercial consumption, which is approximately 14 percent of the total, peaked in 1979 at 2.79 tcf and then declined to 2.53 tcf by 1983. Most estimates of this sector's long-run price elasticity are approximately -1.0

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[1]Douglas Bohi, Price Elasticities of Demand for Energy: Evaluating the Estimates, prepared for the Electric Power Reseach Institute, (Washington, D.C.: Resources for the Future, September 1982).

[2]U.S. Department of Energy. Increasing Competition in the Natural Gas Market, The Second Report Required by Section 123 of the Natural Gas Policy Act of 1978, (Washington, D.C.: January 1985).

suggesting that commercial consumption is slightly more sensitive to price and to economic activity in general than is residential consumption.[3] Climate conditions also affect commercial consumption, but the influence is less than that on residential users. Nationally, states with the largest levels of commercial consumption are California, Illinois, Michigan, Ohio, New York, Texas, and Pennsylvania.[4]

Industrial users consume approximately 34 percent of all natural gas produced and comprise the largest consuming sector. Industrial consumption increased from 1978 to 1980 when it peaked at 7.17 tcf. The period 1981 to 1983 was characterized by a rapid decline in consumption to a 1983 consumption level of 5.5 tcf--23 percent below the 1980 level. Estimates of long-run price elasticity are commonly above -1.0 suggesting that economical and technically feasible energy alternatives are available.[5]

Natural gas provides 30 percent of the energy needs for the industrial sector, where its major use is to generate steam and process heat. Over one-third of all industrial sales are in Texas and Louisiana.[6] In addition, approximately 60 percent of industrial gas sales occur in the petroleum, coal products, and chemical industries.

Electric utilities consume about 18 percent of natural gas produced, third largest among customer classes. Comparatively, the electric utility consumption resembles that of the industrial class. Electric utility use of natural gas gradually increased from 1978 to 1980 reaching a peak of 3.68 tcf, and then rapidly declined. The 1983 consumption level was 2.91 tcf--21 percent less then in 1980. Estimates of long-run price elasticity generally exceed -1.4 implying that electric utility demand for natural gas is relatively elastic.[7]

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[3]Bohi, Price Elasticities.

[4]U.S. DOE, Increasing Competition.

[5]Bohi, Price Elasticities.

[6]U.S. DOE, Increasing Competition.

[7]Bohi, Price Elasticities.

In short, two consumption patterns can be distinguished. For both the residential and commercial classes, consumption peaked in 1979 and then gradually declined until 1983 although the decline was not steady. For each, the percentage difference between the peak and minimum levels of consumption was about 9 percent. The demand of each class is relatively insensitive to price and is heavily influenced by weather.

The second consumption pattern is associated with industrial and electric utility users. For both, consumption peaked in 1980 and then rapidly declined thereafter. By 1983 consumption in each class had decreased by about 20 percent. Also, natural gas consumption for both is relatively sensitive to price but not to weather.

Natural Gas Supply

Over recent years the consumption of natural gas has declined while total reserves and deliverability therefrom have remained relatively constant. Estimates of the resulting surplus deliverability range between 1.8 and 3.5 tcf for the period 1982 to 1983 and 2.0 tcf for the year 1984.[8] Price theory suggests that such excess supply should induce a reduction in price that would reestablish market equilibrium. Regulation combined with long-term supply contracts, however, is preventing price from falling sufficiently to eliminate the excess supply. Consequently, most observers project a surplus deliverability until 1988.

High, low and best-guess estimates of surplus deliverability for the period 1985 to 1990 by the DOE are presented in table A-3. In this analysis, surplus deliverability depends on past, present, and future domestic regulation as well as Canadian export pricing policies. The high estimates were based on the following assumptions:

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[8]See American Gas Association, "Natural Gas Production Capability," Gas Energy Review, July 1984, and Energy Information Agency U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves. (Washington, D.C.: U.S. Department of Energy, 1984).

TABLE A-3

ESTIMATES OF NATURAL GAS SURPLUS
(trillion cubic feet)

Estimate	1985	1986	1987	1988	1989	1990
High	2.0	2.0	2.0	2.0	1.6	1.2
Low	0.8	-	-	-	-	-
Best-guess	1.4	.8	.2	0	-	-

Source: Energy Projections to the Year 2010: A Technical Report in Support of the National Energy Policy Plan (Washington, D.C.: U.S. Department of Energy, October 1983).

- Canadian imports to the U.S. increase annually at the rate of 400 bcf to a level of 2.6 tcf by 1988,
- U.S. natural gas consumption increases at the moderate rate of 100 bcf per year as a result of low economic growth,
- Domestic gas prices have low variability, and
- Nonassociated reserves increase to 12 tcf.

The assumptions used in formulating the low estimates were:

- A moderate rise in Canadian exports to the U.S.,
- Domestic gas prices having high variability,
- Domestic gas consumption increases at a high rate as a result of high economic growth and declining gas prices, and
- Nonassociated reserves stay below 8 tcf.

The best-guess estimate was an average of the high and low scenarios and incorporated the following assumptions:

- Canadian exports to the U.S. increase annually by 300 bcf,
- Domestic gas consumption increases at an annual rate of 350 bcf in response to a 4 percent annual growth rate of industrial output, and
- Nonassociated reserves are 9.6 tcf.

The speed of reserve dissipation depends on several factors: the policy measures taken by the FERC and other regulatory agencies, the export policies of Canada and Mexico, and the amount of spot market activity.

Natural Gas Imports

For the past 12 years, annual exports of natural gas to the U.S. have been about 1 tcf. In 1979 as a result of rising oil prices the U.S. imported 1.25 tcf; however, in recent years natural gas imports have substantially decreased. In addition to Canadian and Mexican imports, the U.S. also imports natural gas from Algeria. The amounts imported from each of these countries for the period 1979 to 1984 are listed in table A-4.

Canada is the main gas exporter to the U.S. and in 1984 supplied 90 percent of our import needs. Algeria supplied 20 percent of U.S. imports in 1979, but only 4 percent in 1984. Natural gas from Mexico similarly declined and in 1984 accounted for only 6 percent of U.S. imports. The explanation for the decline in Mexican and Algerian imports is essentially that Canadian gas became relatively cheaper. In February 1984, the Secretary of Energy reduced regulatory barriers which had contributed to high import prices. This, along with existing gas surpluses, reduced domestic gas prices prompting importers to adjust their buying policies. Also, differences between policies of the exporting countries enabled Canadian exporters to acquire a competitive advantage.

According to the Canadian export policy, effective November 1, 1984, the price of gas exports is determined by one of two methods:

1. If a contract price negotiated between a Canadian exporter and a U.S. importer differs from the current government administered price, then the exporter must demonstrate that the negotiated price, in combination with other contract provisions, results in an enhanced economic return to Canada.

2. Until a contract is negotiated and approved by the appropriate regulatory authority, the export price is determined by the provisions of a volume-related incentive pricing program as determined by the National Energy Board (NEB).

TABLE A-4

U.S. NATURAL GAS IMPORTS BY COUNTRY

Year	Canada (bcf)	Canada (Percent)	Mexico (bcf)	Mexico (Percent)	Algeria (bcf)	Algeria (Percent)	Total
1979	1001	80%	-0-	-0-	253	20%	1253
1980	797	81	102	10%	86	09	985
1981	762	84	105	12	37	04	904
1982	783	84	95	10	55	06	933
1983	712	78	75	08	131	14	918
1984	740	90	50	06	35	04	825

Source: Energy Information Administration, Natural Gas Monthly, July 1983 and July 1984.

Presented below is a list of the seven requirements necessary for the acceptance of a negotiated contract:

1. The price must recover appropriate cost.
2. The price must be greater than or at least equal to the wholesale price at the Toronto city gate.
3. The export price must be set so that the resulting U.S. price does not undercut the prices of major domestic competitors.
4. Export contracts must be flexible in order to accommodate changing market conditions.
5. The exporter must guarantee that the volume contracted will be sold.
6. Producers supplying gas for export must endorse the terms of the export contract.
7. For renegotiated contracts, the exporter must demonstrate the gains to the Canadian economy.

These Canadian and U.S. policies have created incentives to redesign contracts. Recent contracts have lower take-or-pay clauses and incorporate a two-part pricing system to share the risk associated with unanticipated market shifts. The implementation of a flat charge ensures the exporter of fixed cost recovery while lower take-or-pay provisions reduce the burden on importers of paying for untaken gas. The use of semiannual reviews, or even more frequent reviews if warranted by changing market conditions, enables the new contracts to maintain the required flexibility. These conditions effectively have reduced the import price of Canadian gas, thereby benefiting U.S. consumers.

These conditions were liberalized even further in October 1985 when the Canadian Government dropped the Toronto city-gate pricing floor. This has been replaced by a pricing benchmark that is linked to the Canadian price in the area adjacent to the export point. Also, the condition that restricted the export price from undercutting the prices of alternative fuels has been eliminated. The result is likely to be even more vigorous competition by Canadian exporters.

Future imports from Canada will depend on the level of excess supply in Canadian markets. The NEB predicts a positive but declining level of excess supply in Canadian markets until the year 2005, this implying a gradual reduction in exports to the U.S.[9] Canadian projections of future exports to the U.S. differ somewhat from those of the NEB. Some Canadian prognosticators anticipate that exports to the U.S. will be zero by 1996.

Energy Prices

Energy prices have been volatile over the past decade because of changing circumstances in the oil, coal, electricity and natural gas production industries. A highly influential event was the formation of the Middle East oil cartel. The cartel enabled owners of the world's largest oil reserves to take control of their assets and make decisions concerning production and price. In addition to international events,

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[9]National Energy Board, Canadian Energy Supply and Demand, 1983-2005, Tables 6-1, 6-3, 6-4, September 1984.

internal circumstances have created changes in domestic energy markets. In 1981, the price of domestic oil was decontrolled, prompting competition in the open market. In 1978 the Natural Gas Policy Act (NGPA) was enacted causing a phased decontrol of domestic gas prices. The Staggers' Rail Act of 1980 reduced the ICC jurisdiction over railroad carrier rates, a move which increased transportation cost in the coal industry. The Three Mile Island nuclear incident heavily influenced the electric industry by creating a need for stricter safety regulations. For this and other reasons, the cost of bringing a nuclear plant on-line has increased, emphasising coal for future electricity generation. In addition to the aforementioned events, the economic recession of the early 1980s depressed the demand for energy, resulting in excess generating capacity in electricity and excess reserves of natural gas. These latter events are partially responsible for the moderate energy prices experienced in recent years.

As the economy recovered from the recession, the DOE anticipated expansion in all energy markets: electricity first, followed by oil, and then natural gas.[10] In 1983, the DOE predicted that the demand for electricity would double over the next 25 to 30 years. World oil demand was expected to remain stable throughout the 1980s but to expand in the 1990s. The DOE concluded that oil prices would increase at an annual rate of 3 to 8 percent. In addition, the on-going deregulation of natural gas is likely to make it competitive with oil for the remainder of the century. Based on this, the DOE projected the price of natural gas to remain stable for the remainder of the 1980s and then to increase in response to rising oil prices.

Many agencies regularly forecast energy prices by customer class. Table A-5 lists some forecasts from Data Resources Inc. (DRI), the National Energy Policy Plan (NEPP), and the Annual Energy Outlook

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[10]U.S. Department of Energy, Energy Projections to the Year 2010: A Technical Report in Support of the National Energy Policy Plan, (Washington, D.C.: October 1983).

(AEO). In particular, table A-5 represents the projected prices of natural gas and other major competing fuels (except electricity) for the years 1985, 1990 and 1995.

The projections of the AEO are provided by the Department of Energy. Essentially, these projections are based upon the premise that world oil prices drop sharply in the mid 1980s followed by substantial price increases between 1985 and 1990. This premise in combination with competitive energy markets underlies the AEO forecast that the price of natural gas will increase substantially after 1985. Using 1985 as the base year and 1995 as the year in comparison, the AEO predicts the price of natural gas to increase by 77 percent in the residential sector, 81 percent in the commercial sector, and by as much as 99 percent in the industrial sector.

The DRI makes use of a broad macroeconomic model to formulate its projections. The "base case" forecast of DRI assumes that OPEC will act conservatively for the remainder of the century, staying close to the $29 per barrel as agreed in Geneva during the December 1983 meetings. As a result of stable oil prices, the DRI predicts that the prices of all end-user energy will increase at low real rates. Comparing 1985 prices to those forecasted for 1995, the DRI predicts the price of natural gas to increase by 32 percent in both the residential and commercial sectors and by 26 percent in the industrial sector.

Table A-5 presents the NEPP-B forecast which is the middle of three scenarios analyzed by the NEPP. The NEPP-B forecast is based upon the following assumptions:

- The price of world oil increases after 1985 to $32 per barrel by 1990 and to $84 per barrel by 1995.
- When the price of world oil surpasses $50 per barrel, oil production from unconventional sources becomes profitable.
- Current environmental laws and tax incentives are substantially unchanged.

TABLE A-5

ALTERNATIVE FUEL PRICE FORECASTS
(1982 Dollars per Million Btu)

	Residential Sector				Commercial Sector						Industrial Sector					
	Distillate		NG		Residual		Distillate		NG		Residual		Distillate		NG	
Year	Price	%	Price	%	Price	%	Price	%	Price	%	Price	%	Price	%	Price	%
1980																
Actual	$8.18		$4.16		$5.30		$7.57		$3.83		$4.45		$7.00		$2.74	
1985																
NEPP-B	6.75	-3.92%	5.83	6.98%	4.55	-3.10%	6.14	-4.28%	5.47	7.39%	4.30	-0.68%	6.11	-2.76%	4.35	9.69%
DRI	7.26	-2.41	5.70	6.50	4.51	-3.28	-	-	5.10	5.89	4.03	-2.00	6.22	-2.39	3.87	7.15
AEO	7.01	-3.14	5.77	6.76	4.45	-3.56	5.60	-6.21	5.33	6.83	3.63	-4.16	5.57	-4.68	4.16	8.71
1990																
NEPP-B	7.89	3.17	6.22	1.30	5.59	4.20	7.20	3.24	5.91	1.56	5.43	4.78	7.07	2.96	4.91	2.45
DRI	7.77	1.37	6.37	2.25	4.88	1.59	-	-	5.67	2.14	4.40	1.77	6.72	1.56	4.17	1.50
AEO	8.92	4.94	7.08	4.18	5.78	5.37	7.50	6.02	6.55	4.21	4.97	6.49	7.46	6.02	5.34	5.12
1995																
NEPP-B	10.81	6.50	7.19	2.94	7.96	7.32	9.95	6.68	6.88	3.09	7.71	7.26	9.73	6.60	5.83	3.49
DRI	8.78	2.47	7.51	3.35	5.82	3.59	-	-	6.71	3.43	5.22	3.48	7.74	2.87	4.88	3.19
AEO	11.63	5.45	10.24	7.66	7.60	5.63	10.19	6.32	9.64	8.04	6.79	6.44	10.15	6.35	8.29	9.19

Source: Energy Projections to the Year 2010: A Technical Report in Support of the National Enertgy Policy Plan. (Washington, D.C.: U.S. Department of Energy, October 1983); Annual Energy Outlook, (Washington, D.C.: U.S. Department of Energy, 1984), Annual Economic Forecast (Cambridge, MA: DRI, Inc. 1984).

- The federal land leasing programs and federal support for long-term reseach and development continue at current levels.
- The Natural Gas Consumer Regulatory Reform legislation is implemented.
- The Synthetic Fuels Corporation continues its efforts.
- Energy use per unit of output decreases at the rate of 2 percent per year.
- In the commercial sector, energy usage per square foot decreases at the rate of 2 percent per year.

Comparing 1985 projections to those for 1995, the NEPP predicts that the price of natural gas will increase by 23 percent in the residential sector, by 26 percent in the commercial sector, and by 34 percent in the industrial sector.

In short, each of these forecasts is for increasing energy prices, and in addition, predicts that natural gas will remain price competitive for the remainder of the century.

APPENDIX B

SURVEY ON NATURAL GAS RATE DESIGN AND INNOVATIVE PRACTICES

This appendix contains the survey instrument regarding natural gas rate design and innovative practices that the National Regulatory Research Institute (NRRI) sent to nineteen state public utility commissions in January 1985. The letter requested information on interruptible rates, flexible pricing, special marketing programs and associated transportation programs, and gas-on-gas competition. The responses are briefly discussed in chapter 2 and are summarized more completely in appendix C.

The National Regulatory Research Institute

Survey on
Natural Gas Rate Design and Innovative Practices

January 1985

We are interested in pricing policies for major natural gas distributors within your jurisdiction. Although it is not necessary that these questions be answered for every major gas distributor, we would appreciate sufficient information to understand regulatory policies and practices within your state.

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 February 15, 1985 to

J. Stephen Henderson
NRRI-Archer House
2130 Neil Avenue
Columbus, Ohio 43210

I. NATURAL GAS RATE DESIGN

1. Interruptible Rates

a. Are such rates commonly used by gas distributors in your state?

b. Please send a copy of representative tariffs based upon interruptible service principles.

c. What general principle is used in differentiating interruptible from firm service rates? Examples of such principles would include

- Cost of service studies based on peak-load responsibility in some form.

- Interruptible customers do not pay the demand component of the pipeline rates as set by FERC.

- Interruptible customers pay a smaller fraction of the distributor's margin, but perhaps not directly based on cost-of-service studies.

2. Flexible Pricing

a. Please send a copy of representative tariffs that include flexible pricing.

b. Are such tariffs commonly used by distributors in your state?

c. Are these tariffs typically linked to alternate fuel prices? Which ones and how?

d. Is the distributor's revenue reconciled with its total purchased gas cost, and if so, to what extent? Such a reconcilation might include adjustments in the rates for other customers, so as to prevent over- or under-recovery of purchased gas cost.

II. INNOVATIVE REGULATORY PRACTICES

1. Special Marketing Programs and Rates

a. Please send information about special marketing programs within your jurisdiction.

b. Have distributors taken advantage of such programs to retain industrial load?

c. How do rates under special marketing programs and ordinary tariffs compare? Examples of each would be appreciated.

2. Gas-on-Gas Competition

a. Is there direct competition between gas suppliers in your state? If so, please describe some specific examples. (This might include competition between pipelines for direct industrial sales or for distributor sales.)

b. Please describe the general nature of any such competition.

c. Is such competition encouraged or discouraged by your commission?

THANK YOU FOR YOUR PARTICIPATION. RESULTS OF THE OVERALL SURVEY WILL BE SENT TO YOU.

APPENDIX C

STATE COMMISSION USE OF INNOVATIVE NATURAL GAS RATE DESIGNS AND PRACTICES

In early 1985 a survey of selected state commissions was conducted by the NRRI to request information regarding pricing policies and regulatory practices for major natural gas distributors. A letter, a copy of which appears in appendix B, was mailed to nineteen state commissions. Of these, sixteen responded either by letter or through follow-up phone calls. The sixteen states providing information were: California, Florida, Illinois, Kentucky, Louisiana, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Texas, Washigton, West Virginia, and Wisconsin. The NRRI survey requested information about interruptible rates, flexible pricing, special marketing programs (SMPs) and gas-on-gas competition within each state's jurisdiction. This appendix summarizes the responses. It has two sections. The first reports the state commissions' policies regarding interruptible tariffs and flexible pricing. The second summarizes any SMP activity or gas-on-gas competition.

Natural Gas Rate Design

The NRRI asked state commissions to report on the use of interruptible rates and flexible pricing, policies that are available only to large, usually industrial customers. Commissions responded to these questions in a variety of ways. Some included tariff sheets, or excerpts from commission orders, while other described such rate designs in general terms. Of the states queried, two indicated a complete absence of interruptible pricing (Ohio and West Virginia).

Four states do not apply flexible pricing. One state (Louisiana) does not regulate its industrial natural gas sales; thus, these questions do not apply. What follows is a brief summary of the important points, presented separately for interruptible rates and flexible pricing.

Interruptible Rates

California

Interruptible rates are used widely by distributors in California. The rate is typically set so that an interruptible customer pays a smaller fraction of the distributor's margin. To be eligible for these interruptible rates, the customer must have alternative fuel capability. The reader should note that the entire California ratemaking apparatus, of which interruptible tariffs for low priority users is a part, is under review and may be changed soon.

Florida

The industrial customer is offered an interruptible rate based solely on an energy charge. This charge is determined by using peak load cost-of-service methods. The tariff includes minimum bill provisions as well as penalties for using gas during times of interruption. Interruption of service is under the sole discretion of the distributor.

Illinois

Eleven of the sixteen utilities offer interruptible service and out of the five which do not, only one has industrial customers. The interruptible rate incorporates both a facility charge and a commodity charge. The minimum bill is the facility charge and possibly more depending on the distributor. The distributor must give prior notice to interrupt service.

Kentucky

Five companies are currently offering interruptible service. The customers of this service pay a lower commodity charge and a smaller fraction of the distributor's margin. The minimum bill is based on the contract capacity and a penalty is assessed for excessive use. The distributor must give prior notice for interruption.

Michigan

Interruptible service has been available for more than thirty years in Michigan. The typical tariff incorporates a customer charge (the minimum bill) plus a distribution charge that is based on a smaller fraction of the distributor's margin. In addition, there is a penalty charge for excessive use. The distributor must provide a thirty-day written notice to interrupt service unless there is an emergency in which case an oral notice is sufficient.

Missouri

Nine of the twelve distributors offered interruptible service. The tariff is composed of a customer charge (the minimum bill) and a commodity charge. Although no set method is used, the commission staff indicated that interruptible rates are determined with a lower distributor's margin in mind. Also, there is a penalty charge for excessive use. Interruptions are at the discretion of the distributor and are implemented by recourse to a priority system.

New Jersey

All distribution companies offer interruptible service to industrial customers. Non-firm customers purchase gas at a rate less than the tail-block rate used in firm customer tariffs. The tariff includes a flat charge (the minimum bill) as well as a penalty charge for excessive use. Conditions for interruption are specified within individual contracts.

New York

Most distributors offer interruptible service, and in some cases, offer multiple interruptible service. The distinction is that a customer with multiple interruptible service can be only interrupted for pre-agreed reasons, where as with regular interruptible service, interruption is at the discretion of the distributor. Interruptible rates are set with reference to the prices of competing fuels, in an authorized range bounded at the floor by the commodity cost of gas, and at the ceiling by the lowest firm gas rate.

North Carolina

Interruptible rates are set so that non-firm customers pay a smaller fraction of the distributor's margin. Interruption is decided by recourse to a priority system which is on file at the commission. The penalty rate on excessive use increases with the size of the overrun.

Pennsylvania

Interruptible rates are frequently used by gas distributors with the rate being determined monthly. The minimum bill is contractually set and priced according to the monthly rate. Distributors must give at least seventy-two hour notice prior to interruption.

Texas

All industrial customers can select their interruptible status. The tariff is composed of a commodity charge which is based on a lower distributor's margin. Interruptions are made on a priority basis.

Washington

Distributors frequently offer interruptible service to industrial customers. A declining block commodity charge which reflects a lower distributor's margin is used in setting the tariff rate. The tariff incorporates minimum bill provisions plus penalties for excessive use.

Wisconsin

Interruptible service is available to steam generators who meet a minimum usage level. The tariff includes a fixed charge (which is the minimum bill) as well as a variable charge. Penalties for overruns are assessed on a per-unit basis. Interruption requires a one-hour notice.

Flexible Pricing

California

Gas rates for low priority customers are indexed and adjusted in accordance to the price of an alternative fuel; usually a No. 6, low sulphur residual fuel oil. The adjustments generally occur on a semi-annual basis. The price for high priority customers is set residually, implying that residential and commercial customers assume some of the risk associated with volatile energy prices.

Florida

There is no flexible pricing of natural gas in Florida.

Illinois

Two utilities practice flexible pricing: Peoples Gas Light & Coke Company and its sister company, North Shore Gas Company. In part, the rate is obtained by averaging the lowest quoted prices of low-sulphur No. 6 fuel in the Chicago area as published in Platt's Oilgram Price Report for the first twenty days of the filing month. The rate is determined by adjusting this average price for differences in Btu content, taxes, as well as differences in the cost of oil and gas. An Alternative Fuel Adjustment is filed monthly by the utilities along with relevant cost and revenue information. Any revenue discrepancies are compensated by the Uniform Purchase Gas Adjustment. Annual reconciliation of practices and procedures is required by the commission.

Kentucky

Columbia Gas of Kentucky is the only gas distributor which employs flexible pricing for industrial customers. The procedures are detailed in the company's Alternative Fuel Displacement Service tariff. The company sets the rate to insure competitiveness with No. 2 fuel oil, and is required to use one or more of the following sources to establish the alternative fuel's price:

- Platt's Oil Gram,
- Energy User News,
- Oil Daily,
- Platt's Bunkerwise.

Normally, the flexible price must be at least ten cents above the tax-adjusted commodity charge, but below the customer's regular tariff. In practice this price has never been used because the rate as calculated under Alternative Fuel Displacement has always been higher than the regular tariff rate.

All gas utilities have Purchased Gas Adjustment Clauses which allows their rates to adjust to changes in the cost of gas.

Michigan

All customers capable of using an alternative fuel are eligible for flexible pricing if they obtain an affidavit certifying such eligibility. Customers desiring service under the recent Load Development and Retention Rate must provide an affidavit of eligibility to the utility on a monthly basis. The affidavit must state the location and intended use of the gas. The rate includes a customer charge equal to the interruptible rate plus a flexible commodity charge.

A 1982 Public Act requires gas utilities to render a detailed reconciliation of revenues and costs for all gas sold in the Michigan Public Service Commission jurisdiction.

Missouri

There is no flexible pricing of gas in Missouri.

New Jersey

Flexible rates are commonly used in New Jersey under the term parity-pricing. The tariff rates are linked to the prices of a variety of alternative fuels ranging from No. 6 oil to No. 2 oil. The parity-price of gas is calculated by adjusting the selected alternative fuel for Btu equivalence and multiplying this by its per-gallon price. The flexible rate is generally combined with interruptible service tariffs.

The monthly rate per therm of gas is set by the distributor and ranges from 100 percent to 110 percent of the chosen alternative fuel's price. The price selected for the alternative fuel is the lesser of either the consumer tank car price, or the average of the high and low price as posted by sellers and published in the Journal of Commerce.

The N.J. Board claims that gas contracts are necessary to meet firm demand loads during peak periods. As a consequence, if flexible pricing is offered only to interruptible customers then no discrepancies will occur between a distributor's revenue and the cost of purchase gas since the responsibility of covering the gas costs is placed on firm customers.

North Carolina

Distributors are permitted to use flexible pricing if they are selling gas that otherwise would be lost to the company and its customers. To be eligible to purchase the gas, the customer must be non-residential, have alternative fuel capability, and be located on or adjacent to the company's mains. The gas price is based on current competitive fuel prices and cannot exceed the commodity charge on the customer's normal tariff, nor be less than the pipeline tax-adjusted commodity rate plus a penny. The North Carolina Commission reviews this pricing procedure annually.

Pennsylvania

Many of the larger gas utilities use flexible pricing to sell gas that otherwise could not be sold under existing conditions. The company is permitted to sell the gas at reduced rates to commercial and industrial customers who have the capability to use alternative fuels in their production process. To be eligible, the customer must file an affidavit with the distributor testifying that he has alternative fuel capability as well as government authorization to use this capability. In addition, the customer must provide estimates of his alternate fuel requirements for each of the preceding 12 months. The affidavit is to be filed on or before the twenty-fifth day of each month and includes information concerning the prices of the alternative fuels as well as a statement asserting that the customer will switch unless gas is competitively priced. The flexible rate cannot be above the customer's normal tariff, and depending on which is used, not below the average cost of purchased gas or the alternative fuel price. Revenue information is collected monthly with reconciliation occurring on an annual basis via the purchased gas adjustment.

Texas

Texas state law prohibits flexible pricing of natural gas.

West Virginia

According to the commission staff, interest in flexible pricing is growing even though current use is minimal. Flexible rates are applicable when the distributor has gas that cannot be sold pursuant to filed tariffs. Under this condition, the company is permitted to offer such gas at reduced rates to commercial and industrial customers who have the capability to use alternative fuels.

The tariff we examined was from a company that has a similar tariff in Pennsylvania. Thus the terms and conditions comprising the West Virginia tariff are essentially the same as we described in the Pennsylvania case.

Wisconsin

The use of flexible pricing by gas companies is prevalent. As an example of such a tariff, the commission made available Wisconsin Gas Company's Special Dual Fuel Service tariff. This tariff is available to customers for whom the gas company has established a separate purchase contract with the pipeline company. The tariff includes a fixed charge, a meter billing charge, and a flexible commodity charge based on the customer's alternative fuel price. The flexible rate cannot exceed the customer's normal tariff rate and must remain above the city-gate purchased gas cost. The customer's rate is determined by private negotiations.

Innovative Regulatory Practices

The survey respondents reported a wide range of activity in the areas of special marketing programs and gas-on-gas competition. In some states these activities are strongly governed with detailed regulations; in other states the commission has adopted a laissez faire approach. In some, the issues have not yet surfaced.

Special Marketing Approaches

The mode by which state commissions are able to regulate or monitor SMP activities is through the distribution company's transportation rate. Two broad approaches to state regulation of SMP activities could be discerned from the responses. One is to allow transportation tariffs only for delivery of gas which is displacing alternate forms of energy, rather than firm sales previously sold by the distribution company. This method is espoused by the Kentucky and Missouri commissions. The other approach, used by Illinois and North Carolina, as examples, is to allow gas transportation tariffs for any SMP gas.

The recent Notice of Proposed Rulemaking by the FERC regarding interstate carriage of natural gas and also the U.S. Court of Appeals' decision that SMPs were discriminatory, undoubtedly will change the nature of the interstate transportation sector of the natural gas industry. State commissions may be influenced by these events to consider policy modifications within their own jurisdictions. In addition to developments at the federal level, a knowledge of the activities in other states may be useful. The following report reflects the status of intrastate transportation issues in early 1985. Many states will continue with the policies described here; others may choose to follow in the direction that the FERC has recently taken.

California

The California Public Utilities Commission (CPUC) and the gas utilities have merely watched the progress of SMPs, thus far. The CPUC has not authorized any tariffs for gas carriage within the state; although, discussions regarding a distribution company's purchase of transportation gas are proceeding and the Commission expects a final order shortly.[1]

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[1]Taken from Janice E. Kerr, et al. "Comments of the Public Utilities Commission of the State of California," (FERC Docket No. RM85-1-000: Washington, D.C., February 1, 1985).

Florida

No SMP activity reported by the Public Service Commission.

Illinois

Panhandle Eastern's Penmark Program is the source of SMP activity in Illinois. Essentially, distributors act as carriers transporting customer-owned gas which is then made available to all industrial customers within the utility's service area. To be eligible for the gas, an industrial customer must accept the following conditions:

(1) The gas delivered cannot be resold or redistributed,
(2) The customer must purchase at least 100 mcf per day, and
(3) The service is temporary with a specified time limit.

Currently, there are several tariff schemes employed to charge customers. In one, the transported gas is considered the first gas metered during the billing period and results in a credit to the customer's regular billing. The quantity of transported gas multiplied by the company's gas charge becomes the credit amount. In another, the transported gas is billed according to a fixed-variable method. The fixed charge is based on the service charge whereas the variable charge is the commodity charge minus the cost of purchased gas.

Kentucky

Presently, there are five gas utilities that offer transportation rates to customers. A customer is eligible for delivery service if the following conditions are met:

(1) The customer has submitted an affidavit to the utility verifying that gas obtained from delivery service will be used solely as a replacement for alternative fuels, and

(2) The customer has executed a contract with the distribution company for delivery service.

The transportation rate is the base rate within the regular tariff structure.

Michigan

Although no information regarding transportation rates was sent, the information provided indicated that SMP activity was being encouraged.

Missouri

Interest in SMP activity is growing and currently several companies employ transportation rates. These rates can be employed if the transported gas purchased is not replacing normal purchases; in other words, the new purchases must represent new demand.

New Jersey

The New Jersey Board's response indicated no SMP activity in New Jersey.

New York

There has been limited use of SMPs by distributors. Several companies participated in Transco's first SMP, but discrimination issues impelled the New York Commission to restrict its use.

Currently, Consolidated Gas Supply's Con Gas Market Retention Plan is the only known SMP. Here distributors have established a transportation service which moves gas from city gates to end users at rates equal to the sales rate minus gas cost and revenue taxes.

North Carolina

Transportation rates are available to industrial customers who are currently connected to a distributor's mains and have a legal title on gas to be delivered. The customer must enter into a service agreement with the company, which lists total entitlement volume and average daily entitlement volume to be delivered in each seasonal period.

Ohio

Since 1972, Ohio has had a Self-Help intrastate carriage program. Since Ohio is a gas producing state, distribution companies provide the gathering and transmission services to transport gas to end-users. The commission has authorized independent pipelines to provide transportation service for some end users.

Pennsylvania

All major distributors have been directed by the Public Utility Commission to file transportation rates under specific guidelines. The following is a list of recommendations established by the Commission:

- Interruptible as well as firm transportation service will be provided,
- A customer must have a minimum annual use of 50,000 mcf and groups of three or less may form to meet this requirement,
- Transportation gas will be the last gas through the meter,
- The bill for transportation service will be based upon the regular rate for owned gas minus the utility's average commodity cost,
- The burden of proof regarding insufficient capacity to deliver gas is upon the utility,
- Utilities have the right to purchase gas not used, and
- Utilities have the right to purchase customer-owned gas during emergencies.

Texas

The staff indicated that the Commission is beginning to investigate their role in SMP activity. Currently, one-to-one negotiations between suppliers and distributors is the major way of reducing the price of natural gas. An example of this occurred in 1983 with an agreement that enabled the release of surplus gas for resale in new markets. The gas was sold to customers willing to accept interruptible service.

Washington

SMP rates are set lower than regular tariff rates in an attempt to recover lost load, to retain existing load, or to procure a new load. The Commission requires that the rate be set to provide adequate margin to contribute to the demand costs. No information about transportation rates was provided.

West Virginia

SMP activity is increasing rapidly. All negotiated contracts between suppliers, distributors, and customers must be approved by the Commission.

Wisconsin

Currently there is no SMP activity; however, the Commission expects some activity in the near future. The Commission decided that appropriate compensation for transportation service will be the gross margin above the purchased gas costs as set under the present gas tariff structure. The gross margin is the difference between the customer's normal rate and the transporting utility's average commodity cost.

Gas-on-Gas Competition

According to the survey responses, gas-on-gas competition is not common in intrastate markets. Only four respondents indicated such competition and these cases are quite diverse.

Illinois

The Illinois Commerce Commission strongly encourages competition within the gas industry. Presently, there is competition between pipeline and distribution companies in which utilities attempt to purchase low cost gas subject to the limitations of take-or-pay provisions as well as physical limitations within their distribution system. Utilities involved include Peoples Gas Light & Coke Company, which purchases gas from Natural Gas Pipeline Company and Midwestern Gas Transmission Company, and Northern Illinois Gas Company, which purchases gas from Natural Gas Pipeline Company, Midwestern Gas Transmission Company, Panhandle Eastern Pipeline Company, and Nicor Supply Inc.

New York

Regulation, in conjunction with legislation, has encouraged competition through the requirement that distributors purchase the least-cost reliable supplies. Presently, there are no direct sales to end users by interstate pipelines, but interest in the idea is growing. Only a few major distributors still rely on a single supplier since most have adapted to the more competitive environment and purchase gas from multiple sources.

Pennsylvania

In some areas of the state there is gas-on-gas competition between distributors servicing the same industrial load. As a result, territorial disputes have arisen placing pressure on the Commission to resolve the issue. Presently, the Commission resolves each dispute separately since no general rule has been advocated.

As yet, there have been no instances of gas-on-gas competition between pipelines.

Texas

Gas-on-gas competition is strong in the Texas Gulf Coast Region because several pipeline companies have the capability to serve the same industrial end user. In addition, there is competition between producers as well as between interstate and intrastate pipelines.

The Railroad Commission is supportive of the more competitive environment.

APPENDIX D

MONOPOLY PRICING AND REGULATED MARKET STABILITY

This appendix contains the technical details that support two propositions that were used in chapter 3: (1) constant-profit schedules display a negative relationship between the prices of any two services if both prices are below the unregulated profit-maximizing monopolistic level and are backward bending if one or the other exceeds this level, and (2) a constant allocation of fixed costs that results in a price in excess of the unregulated monopoly level is inherently unstable.

First, the profit of a regulated firm can be written as

$$\pi = \Sigma \; P_i Q_i(P_i) - C\;(Q_1(P_1),\; Q_2(P_2),\; \ldots,\; Q_n(P_n)),$$

where P_i is the price of service i and $Q_i(P_i)$ is the corresponding demand schedule. Holding constant profit and all prices but two, say 1 and 2, the slope of the relation between P_1 and P_2 can be found by the implicit function rule as

$$\frac{dP_1}{dP_2} = -\frac{\pi_{P_2}}{\pi_{P_1}}, \qquad (1)$$

where $\pi_{P_i} = \partial\pi/\partial P_i$. The reaction of profits to price changes, π_{P_i}, is the difference between marginal revenue and marginal cost, multiplied by $\partial Q_i/\partial P_i$. It is positive for prices below the monopolist's profit maximizing level and negative above that level. Hence, if both P_1 and P_2 are less than the profit-maximizing level, called either P_1^M or P_2^M in figure 3-1, then dP_1/dP_2 is negative as claimed. If P_1 is equal to P_1^M, then $\pi_{P_1} = 0$, and the constant-profit locus is vertical since the denominator of dP_1/dP_2 is zero. If P_2 is equal to P_2^M, then $\pi_{P_2} = 0$ and the constant-profit locus is horizontal. These are the properties of the constant-profit schedules illustrated in figures 3-1 and 3-2.

Note that the profit equation has been written as if the service demands, $Q(P_i)$, are independent of one another. This corresponds to customer class demands since industrial demand does not depend on residential price, for example. The reasoning embodied in equation (1), however, can be extended to interdependent demands with no loss of generality. The key is that equation (1) contains a ratio of two profit-maximizing, first-order conditions, regardless of the exact structure of the profit function.

Second, suppose the regulator allocates a particular fraction, f_i, of fixed costs to be recovered from service i. The stability of this allocation is most easily demonstrated by specifying the cost function to be linear. That is,

$$C = \Sigma b_i Q_i + F ,$$

where b_i is the marginal or variable costs of service i and F is overall fixed costs. By allocating a particular fraction, f_i, of fixed costs to service i, the regulator sets price in accordance with the formula

$$P_i = b_i + \frac{f_i F}{Q_i} , \qquad (2)$$

which is termed the "Regulated Pricing Schedule" in figures 3-3 and 3-4. The stability condition is that the absolute value of the slope of this regulated pricing schedule is smaller than the slope of the demand curve. The slope of equation (2) is

$$\frac{dP_i}{dQ_i} = - \frac{f_i F}{Q_i^2} ,$$

and the elasticity of this curve is

$$-\frac{dP_i}{dQ_i}\frac{Q_i}{P_i} = \frac{f_iF}{b_iQ_i + f_iF} = \frac{P_i-b_i}{P_i} .$$

Note that $MC_i = MR_i$ can be expressed as

$$\frac{P_i-b_i}{P_i} = -\frac{1}{e_i} , \qquad (3)$$

where e_i is the demand elasticity. Hence, the regulated market, with a constant allocation of fixed costs, is stable if and only if the price that results from the cost allocation is less than the monopoly level in equation (3).