NATURAL GAS PIPELINES AFTER FIELD PRICE DECONTROL

A Study of Risk, Return and Regulation

by

Paul Roger Carpenter

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ABSTRACT

This is a study of a regulated industry undergoing rapid change. For the first time in its history, following the partial decontrol of field prices in 1978, natural gas is being priced at a level which places it in direct competition with competing fuels, chiefly oil. This change is placing considerable stress on the established institutional relationships in the gas industry and is the source of what has been and will continue to be a protracted public policy debate on the subject. It is the chief purpose of this study to interpret the effect of this change on the gas pipeline segment of the industry and its regulation.

A second purpose is to explore the use of information from the capital market's valuation of natural gas pipeline securities, both as a means of characterizing the industry transition in the terms of financial economics and of evaluating the financial performance of the pipelines (and thus indirectly their regulators) during the transition. As such, the continuing decontrol of field prices constitutes a convenient "natural experiment" that allows us to characterize the likely nature of the gas industry of the future and ultimately to evaluate the various proposals for changing it.

To accomplish these purposes, the study is divided into five parts. After describing the principal structural characteristics, transactional arrangements and regulatory procedures in the industry, the study investigates the origins and historical evolution of these features. This history is important in establishing the role of natural gas field price and pipeline regulatory policy and market conditions in determining the nature of the transactional arrangements prevalent today in the industry. This section closes with some conventional measures of the extent of the post-1978 transition and the disequilibrium that now exists between gas market conditions, regulatory policy and industry transactional arrangments.

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In the next two chapters the tools of modern financial economics are used to characterize the effects of the industry transition on the systematic risk borne by gas pipeline industry investors. A significant secular increase in pipeline industry risk is found to persist during the transition period after 1978, an increase that is found to be directly associated with the partial decontrol of field prices. Other sources of risk are examined including what is termed "contractual leverage"--the leverage induced by rigid pipeline contractual relationships. These results are used to evaluate pipeline financial (and thus regulatory) performance during the transition. A significant deterioration in gas pipeline profitability is detected during this period.

The study closes with an examination of the industry's transactional arrangements as they serve to allocate these risks under regulatory service obligations. It is observed that the current regulatory regime ratifies the longstanding transactional arrangements which bundle rights to gas reserves with rights to pipeline capacity. A substantial exogenous change in the risk conditions in the industry may require a regulatory regime which allows for more flexibility in gas supply transactions. It is suggested that to achieve this flexibility it may be necessary to unbundle the two types of rights, allowing a separate, unregulated market for gas reserves and production to form. This could lead to the formation of a liquid spot and futures market for gas, with consequential informational advantages for the rest of the market. This unbundling might be achieved with pipeline deregulation or a system of common carriage, the feasibility of which is examined in a preliminary manner.

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Paul R. Carpenter
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1. INTRODUCTION, ORGANIZATION AND SUMMARY

1.1 Introduction

The natural gas industry is undergoing a remarkable transition. For the first time in the industry's history natural gas is facing serious competition from alternative fuels. This new competition is primarily a product of recent changes in the regulation of natural gas field prices. Field prices for certain categories of gas have been decontrolled with the passage of the Natural Gas Policy Act (NGPA) of 1978. Prices for other categories of gas have been increased, and more will be decontrolled on January 1, 1985, absent legislative intervention. This slow but inexorable process of field price decontrol has continued through the recession of 1981-82, which hit the gas-using industries particularly hard.

The combination of rising average prices (due to decontrol) and rapidly falling demand (due to rising prices and recession) has placed particular stress on the institutions in the gas industry--the regulators who will continue after decontrol to regulate interstate pipelines and distribution companies, and the transactional arrangements employed by the firms in the industry. These stresses have led some observers to question whether the way in which gas pipelines are regulated is appropriate to the new market circumstances, and has led to a plethora of legislative and regulatory proposals for change.

This study is designed to examine the nature of the decontrol transition and its effects on the gas pipelines--a segment of the industry which will remain regulated after decontrol. It also analyzes the stresses being placed on the institutional arrangements in the industry and examines the consequences for pipeline regulatory policy.

A secondary purpose of this study is to explore the use of information from the capital market's valuation of natural gas pipeline securities, both as a means of characterizing the transition in the terms of financial economics and of evaluating the financial performance of the pipelines (and indirectly their regulators) during the transition. As such, the NGPA of 1978 was a convenient "natural experiment" that may allow us to characterize the likely nature of the gas industry of the future and ultimately to evaluate the various proposals for changing it.

1.2 Organization and Summary

The study is divided into five major chapters. A primer on the industry and its regulation is provided in Chapter 2. Basic descriptive information and terms that will be used throughout the study are presented for the physical structure and firms in the industry. The way that transactions are arranged among the firms and the competitiveness of these relationships is discussed, and the methods by which the whole system is regulated are described.

Chapter 3 examines the evolution of regulation and institutional arrangements in the gas industry, and documents the effects of the current transition. The early history of the industry teaches us that the potential for rent-capture by the unregulated pipelines led in important part to the imposition of regulation. These rents were generated by the large quantities of gas discovered in the Mid-continent region and produced at a very low cost relative to the existing Appalachian sources. Due to these rent-capture possibilities, the preferred transactional arrangement in the industry was the pipeline purchase-for-resale system (or "private" carriage), wherein pipelines take title to all gas in their systems under long-term contract and are the exclusive gas purchasing agents in the field. This system of private carriage was essentially ratified and institutionalized by the Natural Gas Act of 1938, which imposed a set of service obligations on the pipelines and established the fixed price, long-term contract as the industry standard.

Field price controls, established after the Supreme Court's Phillips decision in 1954, perpetuated these rents and passed them on to consumers, setting the stage for the gas shortages of the early 1970's. Thus, the partial decontrol of field prices in 1978 has for the first time in history brought the average price of gas to a level at or near its closest competitors and has led to the industry's current trauma. The primary lesson of this history is that the institutional arrangements in this industry are a product both of the gas market conditions and the regulatory system which, in large part, produced those conditions.

Chapter 4 turns to the literature of modern financial economics for a means of characterizing and measuring the effects of the transition on the gas pipeline industry in terms of the risk borne by pipeline company shareholders. Intuitively, the underlying risk of pipeline assets (as defined by the covariance of the return on the firm's securities with the return on the market portfolio) should be greater the more that gas prices and quantities are allowed to vary with demand conditions. It is argued that decontrolled field prices produce these conditions and thus a more risky industry. Three other sources of risk to the gas pipeline industry investor are discussed--financial leverage (large amounts of debt in the firms' capital structures), operating leverage (high fixed costs of operation relative to total costs), and contractual leverage (the use of transactional arrangements with rigid price and quantity terms).

A portfolio of interstate gas pipelines is constructed and its portfolio security returns are examined empirically to detect the influence of field price decontrol and the other sources on the risk borne by pipeline company shareholders. A significant post-NGPA secular increase in risk is detected and the empirical significance of the various sources of risk is examined. It is found that since the 1950's there has been a direct association between the strictness of field price controls in the industry and the degree of risk borne by pipeline industry investors. It is suggested that the reason pipeline industry investors have been bearing this increased risk has to do with the contractual leverage imposed by the traditional industry transactional arrangements.

Because of the close traditional theoretical and legal link between the risk borne by the regulated firm's equity investors and the rate-of-return regulatory procedures employed by the Federal Energy Regulatory Commission (FERC), Chapter 5 examines regulatory performance in light of the secular increase in risk observed in Chapter 4. The purpose of this analysis is to gauge the ability of traditional rate-of-return regulatory procedures to adequately compensate pipeline investors for the risk they bear. This is accomplished through the use of a simulation model which compares the returns on assets actually earned by the pipeline portfolio with the returns which investors would have required in a world where the Capital Asset Pricing Model (CAPM) holds. Also compared is a set of alternative rate-of-return determination procedures that have been employed in practice and in the literature.

It is found that the pipeline portfolio's earned returns fell significantly short of their CAPM equity investor requirements during the post-NGPA period, and that the size of the shortfall is a function both of the level of risk and inflation in the period. This perceived regulatory shortfall is confirmed by the sharp decrease in the capital market's valuation of the pipeline portfolio's total assets relative to its book value over the period. Chapter 5 closes with a brief discussion of some procedural remedies for the regulation-induced shortfall in profitability.

In Chapter 6 the study turns away from the empirical questions of pipeline industry risk and return and to the conceptual and policy questions associated with the institutional arrangements in the industry. The theoretical purposes of certain types of vertical market arrangements are reexamined, and it is suggested that the choice of contractual arrangement involves a trade-off between transaction costs and risk allocation. High transaction costs lead to a preference for rigid long-term contracts, while greater industry risk would favor more flexibility, particularly in contract prices.

Trends in the flexibility of pipeline/producer contracts are examined, and while some increased volume flexibility is observed in the data, regulatory constraints appear to restrict the emergence of price-flexible contracts. To explain this restriction the regulation of the pipeline "service obligation" to its customers is examined. It is argued that the service obligation confers valuable rights on pipeline customers that restrict the ability of parties to contract for gas supplies outside of the purchase-for-resale system. This prevents the formation of a liquid spot market necessary for the writing of effective flexible-price clauses in long term contracts.

Chapter 6 closes with an examination of two institutional arrangements which would unbundle the purchasing of gas reserves and supplies from the provision and regulation of pipeline transportation services. Deregulation of pipelines is examined briefly. Deemed more feasible and effective than deregulation is a scheme designed to unbundle the rights to gas reserves from the rights to pipeline capacity in the regulated service obligation. This scheme, traditionally referred to as "common carriage," is evaluated in terms of the intricacies involved in regulating it, and the problems that might be involved in a transition to such a system.

2. PRIMER ON THE GAS PIPELINE INDUSTRY AND ITS REGULATION

Like other modern industries, natural gas is technically intricate and complex in its institutional framework. To understand the workings of the industry, it is helpful to have some background.

Figure 2.1 classifies the natural gas system by physical structure and economic gain. The physical structure of the industry is examined first in its three main segments--the column headings of the figure. Then the row headings are described: the firms that participate in the business, the nature of the vertical links between those firms, and the different regulators who act upon the firms and upon the vertical links.

2.1 Physical Structure of the Industry

Natural gas is a relatively homogeneous commodity, bought and sold to strict quality specifications.[1] Its provision occurs in three stages: extraction, transmission, and distribution. The extraction (or "production") segment of the industry encompasses the finding and development of gas reserves, the maintenance and operation of gas wells, and any processing required to bring the raw gas up to "spec." The second segment, the focus of this study, involves the gathering of the gas from geographically dispersed wells, and the shipment to market via trunk pipeline.[2] The final segment, distribution for use, takes place indirectly via public-utility gas distribution companies, or directly from trunk pipelines to large customers such as electric utilities and industrial firms.

Actors and Institutions \ Segments	Extraction	Transmission	Distribution
Firms	Producers	Pipeline Companies	Distribution Companies
Vertical Market Arrangements	Purchase-for-resale contracts; Vertical integration; or contract/common carriage		
Regulators	States, FERC	FERC, States	FERC, PUCs

Figure 2.1 The Natural Gas System

All three segments of the industry are capital-intensive and involve long-term investments. The economic life of a successful gas well is several years at a minimum, and the development and exploitation of an entire gas field may stretch over several decades. Long-distance pipeline transmission requires large-scale ventures and very long-lived assets, as does the distribution network of a gas utility. As discussed below, the institutional arrangements commonly found in the industry reflect these aspects of its capital structure.

Figure 2.2 shows the current geographic structure of the U.S. natural gas system. It is vast in area, because of the dispersed locations of gas reserves and of end-use demands. As a result, transportation costs bulk large in the total delivered costs of gas. Moreover, pipeline transmission is characterized by economies of scale in pipe diameter: capacity (or "throughput") past a given point increases approximately as the square of the diameter. As usual, scale economies and the "network" character of a fixed transportation system impart a tendency toward natural monopoly in some markets. Finally, there is no economically effective substitute in most of the U.S. gas system for pipeline transmission. Without trunk pipelines, there would be no distribution segment of the natural gas business, hence no derived demand for wellhead reserves or output.

In a geographic structure such as this, economic theory would lead one to expect a complex set of field prices and economic rents to emerge. Relative prices in the field will depend not only on relative extraction

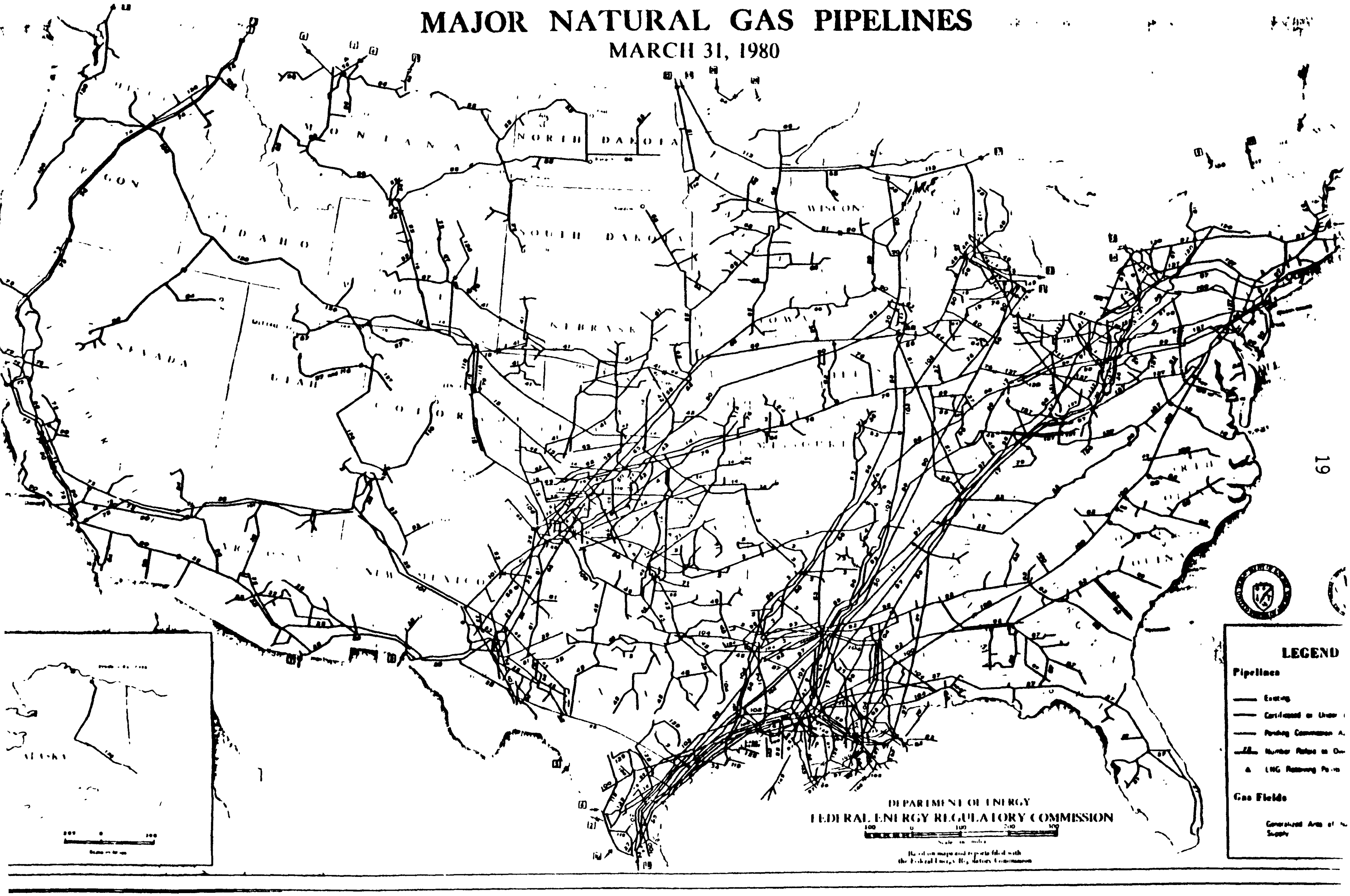

MAJOR NATURAL GAS PIPELINES
MARCH 31, 1980
NORTH DAKOTA
SOUTH DAKOTA
IDAHO
NEVADA
UTAH
NEW MEXICO
ALASKA
LEGEND
Pipelines
Existing
Gas Fields
DEPARTMENT OF ENERGY
FEDERAL ENERGY REGULATORY COMMISSION

Figure 2.2

costs but also on relative distances from gathering points and end-use markets. Infra-marginal gas supplies--from wells with lower costs or locations closer to end-use markets--will earn economic rents relative to marginal supplies. Similarly, customers in end-use markets closer to gas fields will tend to see lower prices than those farther along the pipeline. Moreover, such a structure will tend to give rise to pockets of local market power, and to price discrimination (due to the high costs of reshipping gas). There will also be disputes over "access" to pipeline service--that is, over who (whether producer or end-user) is to be served by whom and at what price. At issue in every case is the fact that the physical structure of the industry provides opportunities for the generation and capture of economic rents (long-run) or quasi-rents (short-run). As in other industries, rent-seeking will give rise to a variety of private activities and public problems.

2.2 Firms in the Industry

2.2.1 Extraction Segment and Field Market Competition

The extraction segment of the gas industry is made up of a wide variety of firms by size and function. For some, the only business is extracting gas; others are owned by gas pipelines or by large oil companies; still others are "conglomerate" subsidiaries of non-energy companies.

An important question to ask about this segment of the industry is whether the natural gas field market can be considered competitive. Suprisingly little analysis of this question has been conducted since the late-1950's and early-1960's when studies by MacAvoy (1962) and Adelman

(1963) found these markets to be competitive. Two reasons stand out for the lack of interest in this question. First, field price controls made the issue of field market power irrelevant, and second, the data required to perform such an analysis at the appropriate level of spatial aggregation (i.e., the individual gas field) is generally not available.

Because of the importance of analysis at the individual field level, standard measures of market concentration on even a regional basis will not necessarily be indicative of competitive conditions. In his landmark study, MacAvoy (1962) recognized this point and designed a methodology to infer competitive conditions in the field by examining the pattern of contract offer prices across fields. But even this methodology only allowed MacAvoy to distinguish between competitive and pipeline monopsony behavior. He too had to rely on standard indicators of concentration to dismiss producer monopoly power as a potential problem. For example, he determined that the ten largest suppliers dedicated only 65 percent of the new reserves in the West Texas - New Mexico region between 1950 and 1953.[3]

To distinguish between competitive and pipeline monopsony conditions MacAvoy postulated that the pattern of contract prices would differ between the two situations. In a competitive market one would expect variation in prices that is related to contract volumes, distance from pipeline to field, and the existance of contract contingency clauses. On the other hand, monopsony prices should not differ with respect to these factors. His empirical tests of this proposition for the early to late-1950's could not reject the hypothesis of a competitive market. In some supply regions there was evidence of some pipeline monopsony power early in his sample period.

Of course, the market conditions in the industry have changed since the sample period of MacAvoy's study. The pipeline industry has matured in the sense that substantial future growth in the network is not expected. But there is no necessary reason to believe that the maturity of the industry would make the field market less competitive. There are always possible exceptional cases in isolated supply regions (e.g., the Colorado overthrust belt) and these areas probably deserve further study.

Recent evidence of field market structure that employ the admittedly inadequate concentration measures do not contradict the MacAvoy/Adelman conclusion. Mulholland (1979), in a Federal Trade Commission report on the subject, computes nationwide and regional concentration ratios for gas production and reserve holdings in 1974 and finds no significant region with a four-firm ratio of greater than 46 percent. He concludes that the level of seller concentration is "relatively moderate" and below the threshold levels of what is generally considered monopolistic.

In the most recent evidence available, the U.S. Department of Energy, Energy Information Administration (Nov., 1983) reaches the same conclusion based on the information indicated in Table 2.1 below. This table reports Herfindahl Index calculations for nine producing areas. The Herfindahl Index (HI) is the sum of the squared individual firm market shares (in terms of volume of proved reserves ownership) in each region and will range between zero and one. The HI equals 1.0 when there is only one seller and approaches zero as the number of sellers increases. The Department of Justice, in merger analysis, views a market as "unconcentrated" when the HI is less than 0.1. As reported, the total HI for natural gas production varies between .022 and .062 (with the exception of Alaska).

On balance, the evidence indicates a lack of significant producer market power in the field. The evidence regarding pipeline field market

Table 2.1

Concentration of Natural Gas
Reserves Ownership, 1981
(Herfindahl Index)[1]

Region[2]	Major Producers	Interstate Pipelines	Independent Producers	Total
Appalachian-Illinois	.012	.011	.006	.029
Other South	.013	.000+	.009	.022
Southern Louisiana	.039	.002	.002	.043
Texas Gulf Coast	.050	.001	.002	.053
Permian Basin	.032	.000+	.001	.033
Hugoton-Anadarko	.018	.003	.002	.023
Rocky Mountain	.021	.036	.005	.062
California	.045	.007	.001	.053
Alaska & Misc.	.238	.001	.000+	.238
Total U.S.	.027	.001	.000+	.028

1. The Herfindahl Index is defined as the sum of the square of the producing firm market shares (in this case of gas reserves ownership).

2. See U.S. DOE/EIA, November 1983, p.24, for definitions of regions.

Source: U.S. DOE/EIA, November 1983, p.24.

power is dated, but indications are that in a decontrolled market it would be limited to certain isolated producing regions if it were to exist.

2.2.2 Transmission Segment

The firms in the transmission segment of the gas business also vary in size, although less so than the producers. The interstate pipeline companies are larger on average than their intrastate counterparts; many of the latter are privately held firms. In 1980, there were approximately 100 separate interstate pipeline entities; 33 were classified as "major" pipeline companies by FERC (exceeding 50 billion cubic feet in annual sales). In a few cases a single parent company owns several pipeline entities. These companies exhibit a mixed pattern of vertical integration, both backward (into extraction) and forward (into distribution). Some of the first interstate pipelines were formed by gas distribution companies, which had been manufacturing gas and distributing it. At present, however, it is rare, and increasingly so, for a pipeline to be affiliated with a gas utility. As shown below, though, there may be a trend toward increased backward integration by pipelines into gas exploration and production. Appendix A lists the largest twenty interstate pipelines (in terms of total sales) along with their producer and distributor affiliates.

2.2.3 Distribution Segment

The distribution segment of the industry consists mainly of public-utility gas companies serving urban areas of varying sizes, with a lesser component of direct sales by pipelines to large customers. Most of the largest gas utilities are investor-owned; many of the smaller ones are publicly-owned, "municipal" gas companies.

While the structure of natural gas field markets is quite competitive, the same cannot be said in general for the market at the distribution end of the pipeline. As will be seen, the ability of gas users to switch to alternative fuels provides a substantial potential constraint on pipeline monopoly behavior. But for physical, technical and regulatory reasons pipelines possess potential market power over the final recipients of their transmission services. Therefore, the present study will not dispute the rationale for the regulation of interstate gas pipeline transmission activities. An indication of this pipeline-distributor concentration is provided in Table 2.2, which shows that of the 1,443 distributors in 1980, 70 percent were served by only one pipeline.

2.3 Vertical Market Arrangements

Linking the physical segments of the industry, and the firms that comprise them, is a set of "vertical market arrangements," as shown in Figure 2.1. These arrangements could encompass various forms of vertical integration by firms (extending from field to burner tip in some cases), long-term contracts between firms, and spot-market transactions.[4] After a brief review of what the current institutional arrangements are in gas, several theoretical bases for the existence of these arrangements is discussed.

2.3.1 Current Arrangements in Gas

No matter what form vertical market arrangements take, they all perform the same basic task. They are the means by which final gas demands are expressed to the intermediate stages of gas production and transmission. Two types of market are of interest. The first--"end-use" markets--

Table 2.2

Pipeline-Distributor Relationship Summary
April 1979 - March 1980

<u>All Distributors</u>	
Total number of distributors	1,443
Total number of separate pipeline-distributor relationships	2,544
Average number of pipelines serving each distributor	1.8
Number of distributors served by only one pipeline	1,012
<u>Distributors Supplied by More than One Pipeline</u>	
Number of distributors	431
Number of pipeline-distributor relationships	1,532
Average number of pipelines serving each distributor	3.6

Source: David Mead, FERC (1981), from U.S. DOE, EIA Form 50.

link the transmission stage with distribution, and involve transactions either between pipelines and distribution companies (which express the derived demands of small customers) or between pipelines and large customers via direct sales. The second market of interest links the extraction and transmission segments of the industry. In these markets--"field" or "wellhead"--gas reserves and output flows are traded; in effect, the pipelines' derived demands for reserves and output are conveyed to producers in these markets.

The transactions in these two markets have a number of distinctive characteristics. Price and volume are (as usual) important, but uncertainty about the future coupled with capital intensity makes duration of deliveries and contingency characteristics important as well. There may be tradeoffs between price and non-price transaction terms--for example, the unit price tends to vary inversely with a customer's priority of delivery during periods of peak demand or shortage. As in any multi-term transaction, regulatory constraints on one term, such as wellhead price controls, may force private actors to focus instead on unregulated terms.

At the distribution end of the pipeline, the typical transactional form between pipelines and public-utility gas companies has been an "administered" long-term contract called a "pipeline tariff."[5] The terms of such contracts are regulated, although they are also in part a matter of negotiation between the parties. A pipeline tariff typically includes both a right to buy gas (in effect, a claim on the committed gas reserves and capacity of the pipeline) called a "service obligation," and a right to sell gas (consisting of a restricted franchise). Ostensibly in the interests of ultimate consumers (especially those lacking ready recourse to alternate fuels), these administered contracts are effectively perpetual--

at least until the regulators (or legislators) change their minds, or the two parties mutually agree to abandon a contract and the regulators concur.

Direct sales by pipelines to large customers are arranged via private-party contracts. These contracts vary in duration, in delivery rights--some are "firm," others "interruptible"--and price (e.g., interruptible gas costs less than firm). Federal regulation applies here only to the certification of facilities, and indirectly, to transportation rates. Even though direct-sale rates are not regulated, the allocated costs of serving direct-sale customers are taken into account (subtracted) in the calculation of the regulated tariff rates (see Section 2.4.3). Since this cost allocation between direct (or "non-jurisdictional") sales and regulated (or "jurisdictional") sales is made on a relative volume basis, there is thus an indirect link between direct sales rates (and the volume of sales) and the regulated tariff rates.

The vertical arrangements at the producer end of the pipeline are less directly controlled by regulation. Here we commonly observe both vertical integration (the direct ownership of reserves by pipelines--"affiliate production") and long-term contracts between pipelines and producers. In both cases, the pipeline owns the gas while it is being shipped; this is known as "purchase-for-resale." Pipelines also occasionally ship gas for others; while this practice (known as contract carriage) has become more common during the current gas surplus, it still accounts for a relatively small portion of total pipeline shipments.[6] From a <u>physical</u> standpoint, there is no difference between affiliate production, long-term contracts, and shipment for others. Unlike crude oil or refined products, there is no way to guarantee that customer X will receive gas from producer Y; nor is it necessary to do so--pipeline-quality gas is pipeline quality gas. From an economic standpoint, however, there may be a significant difference, particularly in defining and allocating rights to pipeline capacity. This question will be encountered again in Chapter 6.

In long term contracts, the price provisions typically consist of a base price, perhaps tied to neighboring contracts (e.g., through "most-favored nation" clauses), and an escalation schedule, which could be tied to a price index or to oil prices. Non-price provisions include the length of the contract term, commodity specifications, and quantity provisions such as maximum and minimum rates of take and take-or-pay requirements. Take-or-pay clauses require the pipeline to pay for a certain quantity of gas, usually a percentage of the committed future production capability or "deliverability" of the field, even if it is unable to take the gas. Contracts may also include contingency clauses, such as a "market-out" that allows the pipeline to modify the contract terms or terminate the contract if warranted by market conditions.

Initial indications from recent industry experience are that pipelines are demanding shorter-term, more volume-flexible contracts. In some cases, pipelines are breaching contracts or forcing litigation (a crude method of flexibility at best). We have yet to see the emergence of truly price-flexible contracts--a question to which we will return in detail in Chapter 6. Some anecdotal evidence of recent trends is available from a recently completed sample survey of pipeline-producer contracts by the DOE Energy Information Administration (O'Neill, 1983).

First, the average percentage take-or-pay quantity requirement appears to be decreasing, but only slightly, and the take-or-pay requirements are relatively low for the NGPA Section 107 "deep gas" which was deregulated in 1978. As Table 2.3 indicates, the average take-or-pay requirement in the

EIA sample of contract sales in 1980 reached 86 percent of well deliverability between 1973 and April 1977 but had declined to 78 percent by 1980. In terms of gas type, take requirements for NGPA Section 107 gas were the lowest for all types of interstate gas across all years in the EIA sample, at 73.6 percent. Intrastate contracts (NGPA Sections 105/106b) in the sample also showed relatively low take requirements of 67.6 precent of well deliverability.

A second indicator of crude contract flexibility is buyer-protection or "market-out" clauses. These clauses permit the buyer to opt out of a contract if the gas is deemed unsellable at the contract price. According to the EIA sample survey, the percentage (by volume) of contracts with market-outs has increased dramatically from 3.6 percent in contracts of vintage 1977-1978 to 45.3 percent in contracts of vintage 1978-1980. For Section 107 deregulated gas, 41.8 percent of the EIA sample interstate contracts had market-out clauses, while 86.5 percent of the intrastate sample had market-out provisions. While the data are not available for all contracts, market-outs do not appear to be significant in terms of the total volume of flowing gas even though they are significant in contracts for high-cost gas.

Finally, the length of contract term has been decreasing. The EIA sample survey indicates that 85.8 percent of pre-1973 vintage contracts were for 20 or more years. Of the contracts signed in 1980 only 7.3 percent were for 20 or more years, while 35.2 percent had terms of less than 10 years.[7]

Contract base prices have been subject to federal price ceilings since the 1954 Phillips Supreme Court decision. In addition, federal regulators at one point (in the late 1950's) disallowed so-called

Table 2.3

Summary of Take-or-Pay Provisions
by NGPA Section and Vintage for 1980 Sales

	Weighted Average* Percent Take Req't
NGPA Section	
102 (New Gas Onshore)	81.6
102 (New Gas Offshore)	89.3
103 (New Onshore Gas Dedicated Before 4/20/77)	77.8
107 (Deep Gas--Deregulated on 11/1/79)	73.6
108 (Stripper Well Gas)	79.6
105/106b (Old Intrastate Gas)	67.6
104/106a (Old Interstate Gas)	85.0
Vintage	
Pre-1973	59.6
1973-April 20, 1977	85.9
April 20, 1977-Nov. 8, 1978	82.3
Nov. 9, 1978-1979	82.5
1980	78.3

*Weighted average percent take requirements based on percentage of deliverability or capacity.

Data do not include take-or-pays for associated (casinghead) gas.

Source: O'Neill (DOE/EIA, 1983) p. ix.

indefinite price escalator clauses. Recently, we have seen a host of proposals to have governments directly regulate non-price terms, especially take-or-pay and market-out clauses, or substitute production regulations for these terms.

The evidence thus supports a movement toward more volume-flexible new contracts. On balance, however, the old contracts under which most gas continues to flow remain inflexible and there is little evidence that new contracts exhibit price flexibility.

The terms for shipping affiliate production are governed mainly by intrafirm arrangements. However, the implicit wellhead transfer prices that figure in delivered gas prices at the plant or utility ("city") gate are covered under federal wellhead price controls. Until 1983, such prices were determined on cost-of-service grounds; however, as a result of the Mid-Louisiana decision, affiliates' transfer prices will be set according to NGPA price ceilings.[8]

The structure of transactions described above has existed throughout the history of the gas industry. There is nothing magic, however, about purchase-for-resale with long-term contracts at the field and service obligations-cum-minimum bills at the distribution end. For example, the practice of end-users transacting directly with producers for gas reserves, and then contracting separately with pipelines for transportation services (as electric utilities do for their coal supplies) could replace the present structure. End-users could buy reserves outright, lease them under a contract--short or long term--or buy rights to output on a spot basis. The same applies to their deals with pipelines. Moreover, as will be argued below, institutional arrangements in the gas industry are heavily influenced by regulation and therefore could change if the regulation were changed. Indeed, in Chapter 3 evidence is cited that institutional changes are already occurring as a consequence of wellhead price decontrol. An understanding of how gas-industry institutional arrangements might change under different pipeline regulatory schemes is thus important to the evaluation of such schemes.

2.3.2 Theoretical Views of Vertical Market Arrangements

Two schools of thought dominate the analysis by industrial economists of why certain institutional arrangements arise in an industry. One school suggests that firms vertically integrate, or alternatively enter into long-term contracts, in order to exploit or create market power (Perry, 1978; Schmalensee, 1973). By definition it would not be possible to do so in the presence of a well-organized spot market. This line of argument is not of much help with respect to natural gas. In the first place, the field market--where transactions between producers and pipelines occur--appears to be workably competitive (MacAvoy, 1963; Adelman, 1963). In the second place, in the end-use market--where transactions between pipelines and gas utilities occur--both entities are subject to rate-of-return regulation (the interstate pipelines at the federal level, the intrastate and the gas utilities at the state level--see Section 2.4).

The second school of thought explains the choice between vertical integration and long-term contracts in terms of minimizing transaction costs (Coase, 1937; Williamson, 1975; Klein et al., 1978; Carlton, 1979). In this view vertical integration is desirable in situations characterized by a high degree of uncertainty, because it would be too costly to specify and enforce enough of the possible contingencies in a long-term contract. With less uncertainty, one would expect to see long-term contracts, with relatively little flexibility in their terms, as the dominant vertical market arrangement.

Transaction costs undoubtedly play a role in determining vertical market arrangements in the gas industry. But they are not adequate to explain the existence of both contracts and vertical integration (as in gas) or how regulation may influence the choice between them. Furthermore, what constitutes "uncertainty" in a transaction has not been clearly spelled out in the literature on this topic. Thus, it is not clear why vertical integration is preferable to a spot market with organized futures trading--a widespread institution for coping with a high degree of uncertainty in other commodity markets.

As will be discussed at length in Chapter 4, however, the field of financial economics may provide an explanation of the role of long-term contracts in this industry as a means of allocating risk.

We shall return to the concepts of market power, transaction costs, and especially the allocation of risk as we discuss the regulation of gas pipelines, the history of the industry, and the various options for regulatory change.

2.4 Regulators

The third row of Figure 2.1 indicates the intersection of the various state and federal regulatory bodies with the segments of the gas supply system. Only the barest summary of the jurisdictional boundaries of the various regulatory bodies and the nature of their activities will be given here, for the regulation of natural gas has evolved into a highly complex mix of standard procedures and exceptions. Nonetheless, some consideration of current institutions will set the stage for discussion of how the system came to be the way it is, and how it might be changed in the face of wellhead decontrol.

2.4.1 Regulation at the Field

Two aspects of regulation at the field are of importance to this discussion. The first is the regulation of field prices, which has been a matter of federal regulation since the 1954 Phillips decision. The second, the regulation of production volumes and procedures, has traditionally been a matter of state regulatory jurisdiction (although recently there have been proposals for federal regulation here).

Current federal field price regulation is embodied in the Natural Gas Policy Act (NGPA) of 1978. The NGPA sets price ceilings and escalation schedules for different categories of gas based on well vintage, whether committed to inter- or intrastate markets, whether produced from on- or offshore fields, and whether produced from particular geological formations (e.g., "tight" gas). One category of gas, that in formations below 15,000 feet, has been decontrolled.[9] The NGPA extended price controls to intrastate gas production, which hitherto had been exempt from federal (interstate) regulation. The price escalation schedules were designed to decontrol the wellhead prices of approximately 50 to 60 percent of flowing gas by January 1, 1985.[10]

The regulation of gas production by states covers two main activities: production volumes and production rates ("ratable take" regulations), and well spacing. Six states regulate volumes and rates of production, and four states regulate the spacing of gas wells. As a rule, the state authorities that regulate production are agencies other than the state public utility commissions.[11]

It should also be mentioned that some states impose severance taxes on gas entering interstate commerce. This is not regulation per se, but such taxes do affect the revenues earned by state producers.

2.4.2 Regulation of Distribution

At the other end of the pipeline there is again an overlap of federal and state jurisdiction. All states (except Nebraska, where all utilities are publicly owned) have public utility commissions (PUC's) that regulate the retail rates charged to end-users by investor-owned utility companies. Sixteen states also regulate the rates charged by publicly-owned utilities. State regulation of retail rates is performed in the traditional public utility cost-of-service fashion. Not unlike FERC pipeline regulation (discussed below), gas distribution companies earn an allowed rate of return on the undepreciated portion of their assets' book value (their "rate base"). Characteristically, state PUC's impose rate structures that are differentiated by customer classes, to serve both efficiency (cost-of-switching) and distributive equity purposes.

Federal jurisdiction over the distribution segment of the gas industry enters through the direct regulation of transactions between pipelines and distribution companies.[12] This regulation takes the form of a "pipeline tariff," which earlier was referred to as a form of administered contract. Three characteristics of the pipeline tariff deserve mention.

First, FERC imposes a service obligation on the pipelines that extends the life of any pipeline-distributor contract. When such a contract expires, pipelines are required to maintain service to the distributor as though the contract were still in force, until a new contract can be worked out.

Second, FERC is responsible for approving a rate structure for the gas exchanged in the pipeline-distribution company transaction. This structure typically includes a "demand" charge (for minimum service) and a "commodity" charge (per Mcf). Purchased-gas costs and other variable costs are allocated to the commodity charge. Fixed costs are split between the demand and commodity charge depending on the specific formula employed and approved by FERC; for example, the so-called United method assigns 75 percent of fixed costs to the commodity charge, the remaining 25 percent being recovered in the demand charge.

The third characteristic is the minimum bill, which is separate from but influenced by the method of allocating fixed costs. A distribution company must pay its minimum bill, regardless of whether it can sell all the gas that it represents. The minimum bill includes the demand charge plus a (FERC-approved) percentage of the commodity charge on a specified contract quantity of gas. Note that the minimum bill operationalizes the distributor's "obligation to buy" which parallels the pipeline's "obligation to serve" as stipulated by regulation.[13]

A final note: inclusion of purchased gas costs in the commodity charge means that they are in effect "flowed through" from the pipeline to the distribution company. Given the physics of gas pipeline transmission, this implies that the pipeline sells all gas to a particular distributor at the same average cost regardless of source. Thus, higher-cost gas is "rolled in" with lower-cost gas. This form of average-cost pricing is both a source of efficiency problems in the pricing of natural gas at end use and a point of controversy (as of this writing) concerning pipelines' gas purchasing policies.[14]

2.4.3 Regulation of Pipelines

Regulatory Procedures. The Federal Energy Regulatory Commission (FERC) regulates two main aspects of the activities of interstate pipelines.[15] First, it "certificates" new pipeline facilities and the abandonment or modification of old ones. Second, it determines "required revenues" based on an allowed rate-of-return on the pipeline's rate base.

In order to construct facilities to serve a new market a pipeline company must apply to the FERC for a certificate of public convenience and necessity. This application is examined for "sufficiency" of demand and supply capacity to support the service. Traditionally, certification has required pipelines to enter into enough long-term purchase and sale contracts to demonstrate a 15 to 20-year supply of and demand for reserves. Other FERC certification procedures include the approval of "off-system" gas sales (to irregular pipeline customers, usually other pipelines for a limited period of time), and of transportation services for self-help gas.[16] Like many other aspects of the vertical market arrangements in the gas industry, certification requirements are in part the result of the regulation of gas prices and pipelines, and are not inherent in the technology or economics of transmitting natural gas.

Required revenues are the basis of the pipeline rate structure set by the FERC. Simplifying for purposes of exposition, required revenue per Mcf in year t, R_t, is determined as follows:

$$R_t = P_t^g + C_t^o + T_t + [d_t + r[\sum_{i=1}^{t}(K-d_i)]]/v_t ,$$

where: P_t^g = average cost of purchased gas/Mcf;

C_t^o = average operating cost/Mcf;

T_t = taxes per Mcf, including those on both income and property;

d_t = depreciation;

K = acquisition cost of capital goods (book value);

r = rate of return on the rate base, $\sum_{i=1}^{t} (K-d_i)$, which is the book value of the remaining undepreciated capital, and;

v_t = volume of gas used to determine unit fixed costs/Mcf.

Every single term above is subject to FERC "determination." P_t^g is currently a focus of controversy, as retail gas prices have risen (despite a surplus) and pipelines' volumes have fallen, requiring them to choose which suppliers to cut back. The last term, v_t, is also frequently a bone of contention. Traditionally, the "test-year volume" has been taken to be the volume of gas delivered in the twelve months prior to the rate filing date--perhaps modified to reflect pipeline projections of changes. At various times (notably during curtailments), this procedure has been changed to allow pipelines to recover certain costs ex post, if actual deliveries differ from those projected. The modified procedure is referred to as the Sales Refund Obligation (SRO) method of rate-making. Pipeline rates change through purchased gas adjustment (PGA) proceedings, or through formal rate hearings at which all aspects of pipeline revenue are considered.[17]

Total required revenues are obtained by multiplying R_t by v_t. This is a system-wide concept (that may or may not be explicitly calculated in rate-filing documents). Actual rates to be charged to particular customers are obtained by allocating required revenues in proportion to transportation work performed (e.g., MMcf-miles) and taking into account the customers' different load compositions (e.g., interruptible vs. firm). All in all, FERC rate-making is an enormously complex affair, requiring huge amounts of data, analysis, monitoring--and legal talent.

Figure 2.3

Glossary of Selected Terms

Pipeline Tariff	The regulatory contract under which sales to jurisdictional customers are made. It includes a rate schedule (two-part tariff) consisting of a demand charge (fixed) and a commodity charge (per Mcf delivered). Usually there is a "minimum bill" on the commodity charge which can range up to 65 percent of contracted volume.
Demand Charge	The fixed portion of the two-part pipeline tariff designed to allow a pipeline to recover some portion of its fixed costs regardless of demand.
Commodity Charge	The variable (per Mcf delivered) portion of the two-part pipeline tariff.
Minimum Bill	A clause in most regulated pipeline tariffs requiring the buyer to pay the commodity charge on some percentage of contracted volume.
Take-or-pay Clause	A clause in pipeline/producer contracts requiring pipelines to purchase some percentage of contract "deliverability" (production capacity) whether or not the gas is taken. Payments for gas not taken are called "prepayments" and are included in the pipeline rate base. Prepayments can be used to pay for future deliverability over contract requirements during a designated "make-up" period (minimum of five years).
Market-out Clause	A clause in pipeline/producer contracts allowing the buyer to reduce the contract price unilaterally or to renegotiate the contract if it becomes impossible to resell the gas at the contracted price.
Direct Sales	Gas sales by pipelines to end-users as opposed to intermediary pipelines or distribution companies. Also called "non-jurisdictional" sales or "mainline" sales, they require regulatory certification but are not made under regulated tariff schedules.
Off-system Sales	Sales of surplus gas to non-traditional customers (usually other pipelines). These sales require regulatory certification and approval of price.
Self-help Gas	Gas contracted for separately by a pipeline customer during emergency conditions under NGPA Section 311. The transporting pipeline does not take title to the gas as it does in purchases for resale.

Contract Carriage Used to describe gas transported, but not purchased for resale, by pipelines (e.g., self-help gas).

Ratable-take Rules Producing-state regulations designed to prevent the drainage of fields with multiple owners from a single owner's well(s). The rules require pipelines to purchase gas on a pro-rata basis from all wells. Also called "common-purchaser" rules, they are a feature of gas "prorationing" proposals.

Footnotes, Chapter 2

1. Gas flow volumes are stated in units of a thousand cubic feet per day (Mcf/d), measured at a standard pressure of 14.73 pounds per square inch, absolute (psia), at 60 degrees Fahrenheit. Standard industry referents are "pipeline-quality" or "high-Btu" gas, which must be (1) low in sulfur; (2) high in methane (well in excess of 95%); and (3) of a minimum Btu content (not much below 1,000 Btu/cf). The sulfur standard is absolute; Btu content can be traded off to some extent against a lower specific gravity.

2. Liquefied natural gas (LNG) is incidental to most U.S. gas markets and thus receives little attention in this paper. Storage of gas for seasonal peak use is provided as part of both transmission (by pipeline companies) and sale-for-use (by gas utilities, sometimes as LNG).

3. MacAvoy (1962), Table 5:1, p.102.

4. I use the term "spot market" to denote an institutional mechanism that allows buyers to purchase and sellers to sell at a prevailing price and without prior notice or contract. No single buyer or seller dominates this market. There is not currently an organized spot market for gas, but the concept will be useful in Chapter 6 when alternative institutional arrangements for gas pipelines are considered.

5. For a general discussion of administered contracts, see Victor P. Goldberg, "Regulation and Administered Contracts," Bell J. Econ. 7:2 (Autumn 1976), pp. 426-48.

6. Contract carriage should not be confused with (standard) inter-pipeline transactions or (less-standard) "off-system sales," (see Glossary, Figure 2.3). Off-system sales have become more common during the surplus but have proved so administratively cumbersome that actual sales have fallen well short of volumes authorized by FERC.

7. O'Neill, U.S. DOE/EIA, (1982), pp. 30, 33, 43; and (1983). See also Broadman and Toman, (1983), for an analysis of these and other data. Note that the revised DOE data in Table 2.3 differ quite substantially from the data presented in O'Neill, (1982). The revised data provide somewhat weaker support for the trend toward flexible contracts. The data should probably not be viewed as more than anecdotal evidence.

8. Public Service Commission of New York v. Mid-Louisiana Gas, 81-1889, et.al., decided by the U.S. Supreme Court on June 28,1983; see Inside F.E.R.C., June 29, 1983, for a good account of the case.

9. For more on the price control provisions of the NGPA, see O'Neill et al., 1979.

10. For an analysis of the NGPA, see U.S. Department of Energy, 1981; and O'Neill, 1983.

11. For more detail on state production regulation, see the Appendix to the report by the National Regulatory Research Institute, "State Regulation of Distribution," in Congressional Research Service, 1982, pp. 265-299.

12. FERC has responsibility for approving transactions between pipelines and large industrial users ("direct" sales), but does not directly regulate the rates associated with these transactions.

13. We will return in Chapter 4 and 6 to the question of minimum bills and fixed cost allocation. While the reasoning behind minimum bill requirements as part of the regulatory service obligation is pretty clear, the reasons for the various fixed cost allocation procedures are not obvious. In Chapters 4 and 6 it will be suggested that the procedures which assign large amounts of fixed costs to the commodity charge portion of the two-part tariff are designed to counteract the financial effects of minimum bills, or they may be implemented for equity purposes (since the commodity charge is a lesser proportion of residential than industrial gas bills).

14. For an excellent discussion of the efficiency implications of average-cost pricing of gas, see Frank A. Camm, 1978.

15. Intrastate pipelines are not regulated by FERC, but by the states. Twenty-eight states have certification authority over the construction of gas transmission lines by privately-owned companies. The states do not, however, regulate intrastate pipelines' rates of return.

16. "Self-help" gas is gas contracted for separately by a pipeline customer during emergencies under NGPA Section 311, (see Glossary and footnote 5).

17. I have ignored potentially significant but complex issues regarding the regulatory treatment of taxes and investment tax credits, because they are not central to the issues addressed in this study.

3. ORIGINS AND EVOLUTION OF THE GAS PIPELINE INDUSTRY AND ITS REGULATION

In what sense is the history of the regulation of the natural gas industry important today? There are at least three reasons for looking back to the early days of the industry and its regulation. First, it is of some interest to determine what forces in the industry prior to 1938 precipitated the regulation of interstate pipelines and determined the particular form of regulation adopted, and if so, whether those forces still prevail.

Second, it is important to understand something of the political economy of pipeline regulation. Purely normative notions like the degree of market competition seldom account fully for either the imposition or the form of regulation. The positive theory of regulation stresses the private use of public powers to parcel out economic rents. The new opportunities to capture economic rents that wellhead decontrol will open up should be considered in evaluating current pipeline regulation and the possible alternatives to it. It will be helpful in doing so to understand better how the capture of rents figured in the early regulation of gas pipelines.

Finally, the evolution of institutional forms in this industry deserves study. Why did purchase-for-resale and not common carrier forms of transaction prevail and why did the fixed-price long term contract become the industry standard?

This chapter is organized chronologically. The history of the gas pipeline industry fits roughly into four eras: the early industry leading up to regulation in 1938; the growth era of 1939 to 1960; the era of field price controls, 1960 to 1980; and the current era of market "disorder."

The early history of the industry teaches us that the potential for rent-capture by the unregulated pipelines led in important part to the imposition of regulation. These rents were generated by the large quantities of gas discovered in the Mid-continent region and produced at a very low cost relative to the existing Appalachian sources. Due to these rent-capture possibilities, the preferred transactional arrangement in the industry was the pipeline purchase-for-resale system (or "private" carriage), wherein pipelnes take title to all gas in their systems under long-term contract and are the exclusive gas purchasing agents in the field. This system of private carriage was essentially ratified and institutionalized by the Natural Gas Act of 1938 which imposed a set of service obligations on the pipelines and established the fixed price, long-term contract as the industry standard.

Field price controls, established after the Supreme Court's Phillips decision in 1954, perpetuated these rents and passed them on to consumers, setting the stage for the gas shortages of the early 1970's. Thus, the partial decontrol of field prices in 1978 has for the first time in history brought the average price of gas to a level at or near its closest competitors and has led to the industry's current trauma. The primary lesson of this history is that the institutional arrangements in this industry are a product both of the gas market conditions and the regulatory system which, in large part, produced those conditions. It follows, therefore, that should market conditions and regulatory policy change, there is no endemic reason why the institutional arrangements should not also be subject to change.

3.1 Forces Leading to The Natural Gas Act (NGA) of 1938

The coming post-decontrol era, in which only two of the three segments of the gas industry will be subject to regulation, will not be new by any means. In fact, in this section it is argued that the pre-existing system of partial regulation, and the resulting potential for rent-capture by the unregulated portions of the industry, led in important part to the imposition of constraints on the interstate pipelines through the Natural Gas Act (NGA) of 1938.

3.1.1 Market Conditions in the Early Industry

From the outset, the structure of the gas industry was affected by the peculiar requirements of the technology. As noted earlier, pipelines are a capital-intensive, long-lived investment. The major consideration in planning a pipeline project is that there be enough gas to transport, and enough demand for it, to keep the line operating at reasonably high load factors for a number of years. Any venture thus had to deal with the twin problems of supply (reserves and deliverability) and of demand.

Pipelines could choose between two methods of assuring the economical use of their facilities in the rapidly growing market: long-term contracts (whether directly, through purchase-for-resale, or indirectly, through brokers), and vertical integration (both backward into production and forward into distribution). In the early years of the gas industry, pipelines relied heavily on the latter. In 1934, for example, 30 of the 36 pipelines transporting gas interstate also engaged in natural gas production, accounting for more than 29 percent of the U.S. total. Their aggregate interstate gas shipments accounted for nearly 91 percent of their aggregate production, and for about 27 percent of total U.S. gas production at the time.[1] The main threat to demand was competitive entry. The holding companies who developed the pipelines met this threat by dominating the distribution of natural gas.[2]

In the 1930's the gas industry operated in three distinct spatial markets: California, Appalachia, and the Mid-Continent region. California was totally isolated from the rest of the market, and conditions there had little impact on the rest of the industry or on the development of federal policy. Production from the two remaining regions served separate end-use markets, with the exception of a single pipeline link (Panhandle Eastern) between the two markets through Missouri, Illinois and Indiana into Ohio (see Figure 3.1).

The Appalachian region included the oldest oil and gas producing areas in the U.S. and served the burgeoning industrial development around the eastern Great Lakes. The producing areas of the Mid-Continent region (Texas, Louisiana, Oklahoma and Kansas) were distant from major consuming centers, but in the 1920's the relatively new technology of long-distance pipelines had permitted extension of limited service from this region to Chicago, Omaha, St.Louis, and Minneapolis-St.Paul.

Much of the impetus to the regulation of interstate pipelines can be traced to significant differences in the character of these two markets and the lack of an interconnecting pipeline system to allow economic forces to equalize between them. Simply put, the Appalachian region was experiencing declining supply, while the Mid-Continent region was awash in surplus gas. This created the frustrating and seemingly irrational coincidence of unmet demands in some gas markets while in other markets gas was being wasted (flared, perhaps after being stripped for natural gasoline, or used in carbon black manufacture). In public debate the pipeline segment of the

PRINCIPAL NATURAL GAS PIPE LINES AND NATURAL GAS FIELDS IN THE UNITED STATES, DECEMBER 31, 1934

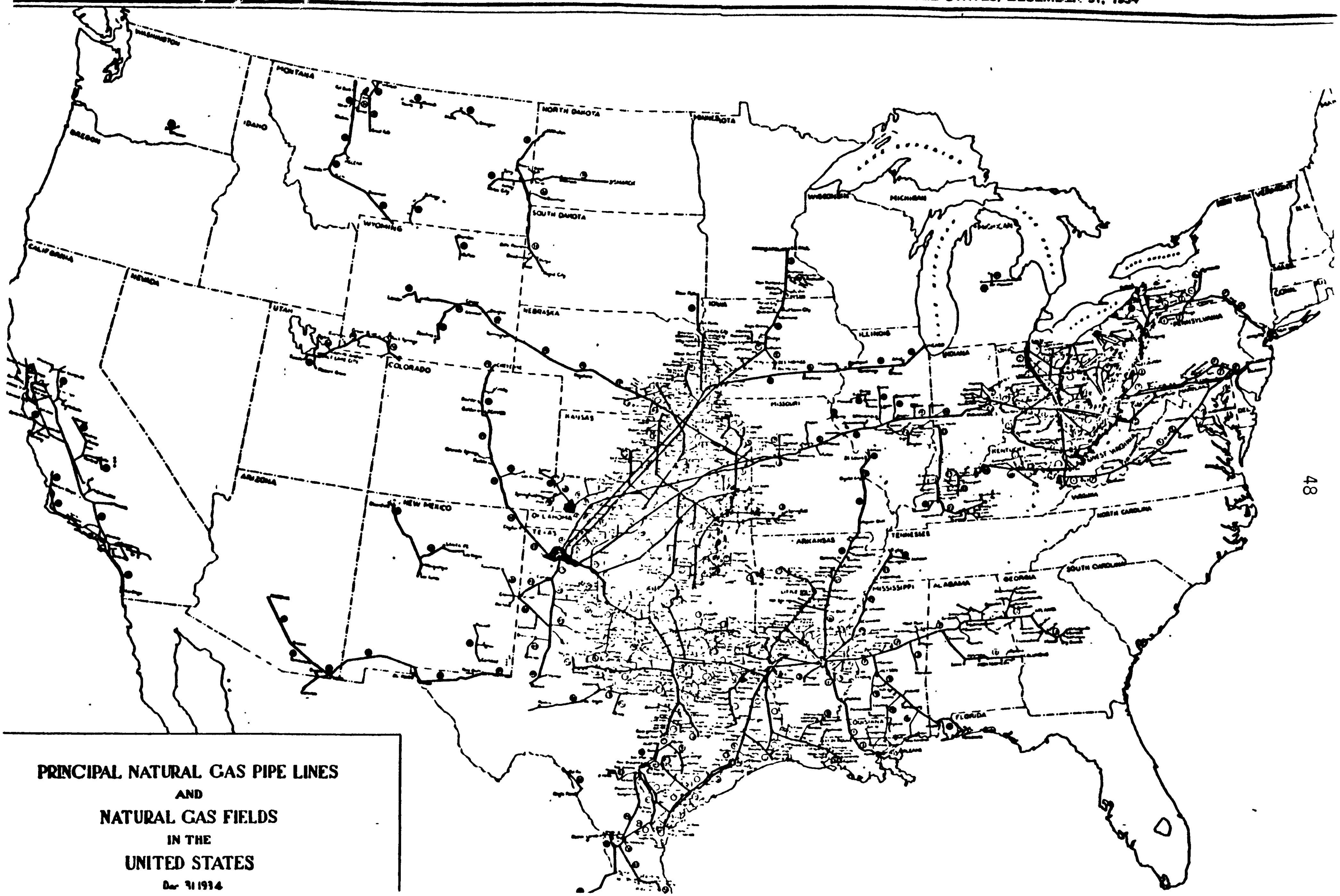


Figure 3.1

industry received the brunt of the blame for these conditions. Typical is the following testimony by Col. William Chantland of the Federal Trade Commission:

> The bald facts and conclusion seem clear that the unregulated, privately owned natural gas and natural-gas pipeline industry presents just another illustration of starvation in their commodity in the midst of overflowing plenty at the points of production, with little or minor consideration given to public needs. Communities are crying for natural gas as a needed industrial power and fuel but receive it not. Producers have plenty but the market is shut off by those in control of the only means of transportation--namely, the pipe lines.[3]

Table 3.1 summarizes supply trends in the Appalachian region.[4] Production peaked in 1916 and dropped fully 50 percent by the time of the 1935-38 regulation debate. More importantly, the process of adjustment to the change in gas supply was distorted by partial regulation. Most states regulated gas production, transportation and distribution within their boundaries. Also, some states controlled intra-state prices in public-utility, cost-of-service fashion. As production declined, states sought to protect their indigenous gas-using industries by attempting to control where gas was committed or by price regulation. However, because the states could not regulate gas transported across state lines, rents on the price-controlled gas were transferred to interstate pipelines. Between 1930 and 1934, the volume of gas transported between states by the three major transmission companies in the Appalachian region increased by 35.6 percent, while total production in the region declined by 17.6 percent. Between 1921 and 1931, West Virginia lost its entire carbon black industry, an industry highly-dependent on cheap gas for profitable operation. To prevent this significant loss of rents from in-state production, the West Virginia legislature passed a law requiring their gas companies to satisfy

Table 3.1

Production in the Appalachian Region*
(mmcf)

Year	Total Production	% of 1916 Peak
1916	507,726	100
1918	458,695	90
1922	354,992	70
1926	341,702	67
1930	305,904	60
1934	252,007	50

*New York, Ohio, Pennsylvania, and West Virginia

Sources: Kitch, 1968; FTC Report.

in-state customers before exporting gas to other states. In 1923 this law was declared unconstitutional, in violation of the commerce clause, by the U.S. Supreme Court.[5]

In contrast, in the Mid-Continent region gas was in surplus. As a result, gas prices there were a small fraction--from a third to a fifth--of their levels in Appalachia, as Table 3.2 shows. Small markets for gas nearby and a lack of long-distance pipelines led to widespread "wastage," as indicated, for example, in Table 3.3 for the Texas Panhandle. Note that, while absolute "wastage" was quite large, it declined rapidly as a percentage of total production from 1926 to 1932, before rising again as the Depression set in. Nevertheless, the perception of waste led to demands for pipeline and producer regulation.

3.1.2 Analysis Underlying the NGA Debate

In addition to gas market conditions, perceived and real, at the time, it is important to set the NGA in the broader context of the prevailing general attitude toward holding companies and other large companies. That attitude can be described as hostile, with persistent questioning whether the economic benefits from large corporate structures justified their social costs.

Thus, the historical context of the NGA was New-Deal federal activism in intervening in the operations of markets. NGA was passed in the same year as the Civil Aeronautics Act. The mid-1930's also saw the passage of the Public Utility Holding Company Act (PUHCA) of 1935 and the Wagner Act; the creation of Social Security and of the Securities and Exchange Commission; and the enactment of a host of direct restrictions on the activities of markets (e.g., the agricultural price-support system and the Robinson-Patman Act).[6]

Table 3.2

Sample Wellhead Natural Gas Prices and Volumes, 1934

State	10^9 cubic ft.	% of US total	Cents/mcf
Appalachia:			
Ohio	50	2.8	17
New York	6	0.35	27
Pennsylvania	86	4.8	22
West Virginia	109	6.2	18
Mid-continent:			
Kansas	50	2.7	5.6
Louisiana	226	13.0	3.5
Oklahoma	254	14.0	3.1
Texas	603	34.0	2.2

Source: U.S. Bureau of Mines study dated October 29, 1935, reported in FTC Report, p. 199.

Table 3.3

Gas "Wasted" to Air in Texas Panhandle Region

	Gas Vented (mmcf)	Total Production (mmcf)	Percent Vented
1926 & earlier	219,510	247,426	89
1928	351,480	533,978	66
1930	252,196	616,572	41
1932	118,298	417,579	28
1934 (6 mos.)	147,634	340,724	43

Source: FTC Report, op. cit., p. 95.

The NGA was originally written as Title III of the PUHCA but was deleted in the final bill sent to the floor for action (for reasons detailed below). Much of the intellectual support for both the PUHCA and NGA resided in a 96-volume study of public utility corporations by the Federal Trade Commission, commissioned by the Senate in 1928.[7] Indeed, the FTC study was prominently cited in the preamble to what eventually became the NGA of 1938.

The gas portion of the FTC report provides a voluminous and detailed analysis of each company involved in gas transportation activities at the time. Its conclusions concerning non-competitive market structure and behavior can be distilled into three categories: industry concentration and holding-company ownership, territorial division of markets, and vertical integration.

With regard to concentration, the measure chosen by the FTC (and most commonly cited in the legislative hearings at the time) was the share of total pipeline mileage owned by the top four firms; apparently, data on sales volumes were not available. Columbia Gas and Electric, Cities Service, Electric Bond and Share, and Standard Oil of New Jersey owned 56 percent of the total pipeline mileage in 1953. Pipeline mileage is not, however, a good indicator of pipeline capacity, nor is 56 percent obviously a high four-firm share for a relatively young and growing transmission system. According to the FTC's own data, in 1930 these four firms accounted for 79 percent of all gas transported across state lines by 22 companies, but by 1934 this figure had dropped to 60 percent, with 36 firms then operating interstate. Entry was obviously occurring even during the Depression, and the industry was undergoing rapid change.

In addition to concentration, the FTC argued that widespread joint ownership of projects and the development of both pipelines and producing properties by certain firms in the industry were anti-competitive. Examples of jointly-owned pipelines are cited, but the link to anti-competitive behavior is merely asserted.[8]

More persuasive than the structural arguments is the behavioral information reported by the FTC on the territorial division of markets by pipeline companies. Although not by itself evidence of collusion, Figure 3.1 shows that there was little parallel construction of competing pipelines at this time. While the documentation of collusive behavior is mostly anecdotal, it nonetheless paints a fairly damaging picture. The FTC cited unwritten "ethics" in the industry which made the invasion or "raiding" of competitors' territory taboo. The most notable example was the refusal of Columbia Gas to extend its major east-west pipeline 65 miles into St. Louis in the late 20's and early 30's because Mississippi River Fuel Co. was already serving the city.[9] Mississippi River Fuel was a subsidiary of Standard Oil of New Jersey, Columbia's major competitor in the Appalachian market. (The pipeline, now owned by Panhandle Eastern Pipeline Company, still does not serve St. Louis.)

Finally, the FTC considered the pipelines' ownership of natural gas production to be a source of anti-competitive behavior. As noted earlier, the interstate pipeline companies were at that time heavily involved in the production of gas. Of the 36 companies engaged in interstate transmission in 1934, all but 6 also engaged in production. These firms accounted for 29 percent of total U.S. natural gas production, but 91 percent of their own production was transported interstate, while only 27 percent of total U.S. production went into interstate commerce. The extent of this backward integration by interstate pipelines increased between 1934 and 1938. The

FTC argued that pipeline-owned production deterred entry by rival pipelines, presumably by locking up gas reserves. The FTC also reported having received complaints that, in fields where both pipelines and independents owned reserves, the pipelines denied transportation to the independents and then drained away their gas through the pipelines' own production.[10]

3.1.3 The Forces Leading to Regulation

Against the backdrop of the market conditions and conduct just outlined, no single theory of regulation is wholly satisfactory in explaining the movement that led eventually to passage of the NGA. An eclectic explanation that braids together individual strands from several different theories seems appropriate here.

One strand comes from the public-interest theory of regulation: government must intervene where markets "fail." The FTC report repeatedly stressed the existence of market failures in the gas industry--not merely failures due to declining long run average costs in gas pipelining, but (more importantly) monopsony in transporting gas and monopoly through the division of end-use markets. These market failures were expressly mentioned in the language of NGA, much of which the FTC actually drafted or helped draft. Curiously, though, public-interest concerns seem to have played only a secondary role in public discussions of the NGA.[11]

A second strand of the explanation comes from the so-called "capture" theory of regulation, in which the ostensible target of government control in fact seeks it in order to reduce competition; cases in point are the railroads and (later) the trucking industry (ICC) and the airlines (CAB). The natural gas pipeline industry is perhaps not as clear a case of capture, but there is some definite evidence for it. The NGA did put in place a formal government procedure (certification) for regulating entry in a rapidly-growing industry; how effectively entry was controlled, however, is not yet clear. The interstate pipelines did oppose the title (III) of the proposed PUHCA that dealt with gas and doubtless lobbied for its removal in 1935; three years later, they embraced the proposal--with certain offending provisions deleted.[12] However, it is not clear whether the pipelines actively sought the bill, as modified, or were merely accepting the inevitable (given the times) and settling for the NGA sans the most offending provisions. Finally, Breyer and MacAvoy have argued that regulation of the pipelines by the Federal Power Commission (FPC) during the era of wellhead price controls yielded rates of return on capital that were not significantly lower than those earned by comparably situated, regulated firms.[13]

A third strand of the explanation is taken from the theory of interest-group dominance, which pervades the political science literature on regulation (and other subjects). There is ample evidence of "interest-group" activity surrounding the passage of the NGA. The interest groups involved grew out of the imbalance between regional resource endowments and end-use centers, and out of the conflicts between intra- and inter-state regulatory authority that (as noted above) characterized the gas market in the 1930's. Given the relative ease with which the NGA was passed, however, it is difficult to explain it as the result of one group, or a coalition of groups, gradually achieving dominance over another (e.g., producers over consumers, or interstate over intrastate pipelines--or the reverse).

A variant of the interest-group theory of regulation is, though, more persuasive. In this view, which may be termed the "state-interest" theory, the regulation of interstate pipelines grew out of a gap in state regulations, owing to the Constitutional division of jurisdiction over interstate commerce. As noted earlier, Appalachian state price ceilings, designed to protect indigenous industrial gas users against rising input costs, were threatened by out-of-state markets offering higher prices (net of transportation charges). If not stanched, out-of-state shipments via interstate pipelines would have permitted the rents the Appalachian producing states sought to secure for their own industries to be captured by the interstate pipelines. Thus, federal regulation of interstate pipelines was, in effect, a means of achieving state regulatory objectives. (Producer-state interests in the Mid-continent region, which were to become important later in the history of natural gas regulation, did not play a significant role in shaping the final form of the NGA.)

The following quotation by Senator Clarence Lea of California sums up the state-interest view of interstate gas pipelines regulation:[14]

> The theory of this bill, I take it, would be that the State regulation is necessary, as on a public-utility basis, and without interstate regulation there is a gap in regulation. The consumption in the State is secured largely through interstate transmission and the cost of the interstate production is, of course, a very material element in determining the price the local people must pay for their gas. So that if complete regulation is necessary, it would involve interstate regulation.

Why Not Common Carrier Regulation?

Beyond establishing certain certification and reporting requirements, the language of the NGA does nothing more than require pipeline companies to apply to the FPC (now FERC) for permission to change prices on sales to retail distribution companies. The resulting prices must be "just and reasonable" and not "unduly discriminatory." Traditionally, regulators have applied the "reasonableness" standard in the form of cost-of-service regulation with an allowed rate-of-return. This method of regulation has remained essentially unchanged since 1938.

Despite FTC concerns about producers' access to pipeline transmission (discussed above), the NGA did not designate gas pipelines as common carriers. In other words, interstate gas pipelines were not required to provide transportation services to anyone who wished to ship some gas. In contrast, oil pipelines have been common carriers by law since the passage of the Interstate Commerce Act in 1887. Gas pipeline companies have long owned virtually all the gas flowing in their systems, having either produced it themselves or purchased it for resale. An interesting question is why the gas pipelines were not regulated as common carriers, as this was the standard approach applied to other transport industries (e.g., oil pipelines, trucking and railroads). The explanation appears to lie in the confluence of history, politics, and technology.

The Interstate Commerce Act expressly excluded gas pipelines from the regulation it imposed on oil pipelines. Subsequent attempts to make gas pipelines into common carriers--in 1906 on behalf of independent producers, and in 1913-1914 on behalf of consumers suffering from winter gas shortages--were thwarted.[15] As already noted, the FTC's draft of Title III of the PUHCA of 1935 would have made gas pipelines common carriers, but that title was dropped from the Act as passed. And common-carrier status for pipelines was removed from the legislation before it was passed as the NGA in 1938--in part owing to the pipelines' political pressure.

The technological argument against regulating long-distance gas pipelines as common carriers centered on their ability to meet seasonal or other variations in demand.[16] The capacity of a gas pipeline cannot be varied significantly in the short run. As gas demand is variable in the short run, smooth operation of the market requires some flexibility. The possibilities include storage near end-use markets, excess compressor capacity, and "interruptible" sales--subject to cut-off during peak periods, hence priced lower than "firm" sales.

Opponents of making interstate gas pipelines common carriers in the 1930's argued that the requisite flexibility was physically impossible--it could not be supplied at any price. Their arguments, however, ignored the proposition that peak-load pricing of gas transport services (whether regulated or not) would have induced firms--whether pipelines, customers, or middle men--to hold positive amounts of storage and excess capacity, and to sign interruptible contracts. Moreover, the opponents of common carriage focused only on storage: natural gas could not be stored at reasonable cost. As it turned out, though, after World War II gas storage near end-use markets became common.[17] Moreover, even without common carriage, pipelines routinely vary the use of compressors as their loads vary over time, and interruptible-service contracts are common.

In retrospect, the technological case against common carriage was weak. Perhaps the argument was perceived at the time to be strong. But the fact that the common carriage approach was the standard for other transportation industries and recommended by the FTC suggests that there may have been other reasons for the ultimate opposition to the common carrier approach. A political-economic argument would suggest that the pipelines wished to retain the purchase-for-resale system in order to retain some of the economic rents associated with the low-cost infra-marginal gas supplies that they had captured prior to regulation, and that they had the political power to eliminate common carriage from the NGA. This topic probably warrants some further historical research.

3.2 Evolution of the Pipeline Industry Under the NGA, 1938-1960

Close on the heels of passage of the NGA in 1938 came World War II, which temporarily halted the development of the U.S. natural gas industry. Following the war, however, the gas industry began a boom that lasted a decade and a half. This boom dominated the evolution of the industry through about 1960. At that point, the wellhead price controls on natural gas, imposed by the FPC in response to a 1954 Supreme Court decision, took over as the dominating force.

Both the size and the geographic character of the U.S. gas industry changed profoundly in the first fifteen years after World War II. The total length of all kinds of pipelines--gathering, transmission and distribution--roughly doubled. The capacity of the transmission segment more than doubled, as the average diameter increased at the same time as its total length was more than doubling.[18] The following description from an investor-advisory service captures some of the euphoria then prevalent about the bright outlook for the gas pipeline industry:[19]

> The continuous growth of the industry is its preeminent feature. Expansion has accelerated since World War II under the stimulus of successive new peaks in demand occasioned by heavy industrial utilization of natural gas, expanded services required for new housing developments, and increasing consumer acceptance of natural gas for space heating as a more ideal fuel. The consumption of natural gas has been quickened by its favorable cost in relation to competing fuels, a high thermal heating content, and ease of handling as compared with coal or oil. Beginning in 1948, natural gas pipeline companies embarked on a phenomenal expansion program, which is still underway.

Interestingly, in the early 1950's this source repeatedly forecast a quick end to the expansion, only to report record gains the following year. By 1957, the tune had changed: "Another period of unprecedented expansion is projected for the 1957-1965 decade ..."[20]

The rapid increase in the size of the gas industry also brought about changes in its geographic character. As noted earlier, prior to World War II there were three different markets within the continental United States. By 1960, however, there were only two distinguishable markets, California, and the whole country east of the Continental Divide. Even that boundary was swiftly eroding as new pipelines were interconnecting the entire interstate pipeline system and adding production from Canada and Mexico.[21] The decline of production in the Appalachian region had hastened the integration of the northeastern market with the Mid-Continent gas fields, where production was expanding rapidly. One consequence of the increasing trend toward an interconnected national market, with the accompanying thickening of the pipeline network, was the steady erosion of the incidence of monopsony power in the field market. As of about 1960, MacAvoy and others found positive evidence of pipeline monopsony power only in the Permian Basin (West Texas-New Mexico); and even there pipeline entry and new capacity was increasing competition for gas production (See Section 2.1).[22]

It is worth pointing out here, for later reference, that wellhead prices on new long-term contracts rose steadily during the postwar pipeline-building boom. Data for new contract prices during this era in the Mid-continent region are available from a study by Adelman (1962). These data and nominal average U.S. purchased gas prices and general price inflation are indicated from 1948 to 1961 in Table 3.4. Between 1948 and 1958 nominal new contract prices in the Mid-continent increased by over 200 percent while total inflation over the period was only 25 percent. The increase in average purchased gas prices for the U.S. as a whole lagged behind the new contract price only slightly. Purchased gas as a percent of

Table 3.4

Post-war Trends in Nominal Average Prices of Gas Purchased by Interstate Pipelines

Year	Average New[1] Contract Price in Tx. and La.	Average Price[2] of Purchased Gas (cents/Mcf)	Purchased Gas[2] as a Percent of Revenues (cents/Mcf)	Percent Change in GNP Delfator
1948	4.8	6.6	38.3%	6.9%
1949	5.0	7.3	42.0	-0.9
1950	6.7	7.9	43.4	2.1
1951	7.8	8.4	42.7	6.6
1952	8.4	9.9	45.2	1.4
1953	9.8	11.8	48.2	1.6
1954	11.2	12.6	48.8	1.2
1955	12.8	13.4	47.6	2.2
1956	14.4	14.1	49.0	3.2
1957	16.9	15.0	50.0	3.4
1958	15.7	16.2	50.7	1.7
1959	-	18.1	52.7	2.4
1960	-	19.8	53.5	1.6
1961	-	20.7	53.8	0.9

1965	-	20.2	56.3	

Sources: (1) Adelman, 1962, p.37.
(2) FPC, Statistics of Interstate Natural Gas Pipeline Companies 1958, 1968.

total pipeline revenues increased from 38 percent in 1948 to 54 percent in 1961. This price increase might not seem surprising, in view of the pipeline boom and the implied increase in demand for gas reserves. Yet sizeable field price increases were not expected in the early postwar period, apparently because of the enormous backlog of gas reserves waiting to be hooked up to trunk pipelines. Morris Adelman noted:[23]

> Associated and dissolved gas was available at zero marginal cost of exploration and development; non-associated gas at marginal development cost only... [There was] a large amount of gas available at...near-zero marginal cost...Much new pipeline building was expected. But there was no clear expectation of a rise in price...

Expectations apparently did not square with the emerging facts. The reason _why_ the price increase actually occurred in the competitive field market during this period is not apparent. The best candidate explanation is that there were not unlimited supplies available at zero marginal cost in the Mid-continent region, and the price of new contract gas was starting to be bid up to the price of its nearest competitor, oil (see Section 3.4.1).

One consequence of the unclear expectations about field prices was to include contingent price-escalator clauses in long-term contracts. These clauses probably caused initial prices in long-term contracts to be somewhat lower than without them. But they also had the effect of increasing the impact on _average_ prices (shown in Table 3.4) of the unexpected increases in new-contract field prices that occurred during the 1950's. Especially since many people had expected gas prices to remain stable, the effects--real and feared--of higher gas prices on final consumers became the focus of public-policy concern as the 1950's wore on. To quote Adelman again, "The resulting surprise and chagrin made a lower gas price an end in itself, a Good Thing, and a clamorous political issue where the small voice of reason is drowned out."[24]

As the FPC moved to implement the 1954 Supreme Court order to regulate field prices as well as pipeline rates, it came under pressure to do something about escalating prices due to the indefinite contingent clauses, and in 1959 and 1960 actually disallowed them in existing contracts. As the data in Table 3.4 indicate, the field price controls did not become binding on the industry until this time. Later, in a different era, the contingent clauses were to reappear, for different reasons but again with politically volatile consequences.

The advent of federal regulation of interstate pipelines effected certain changes in the vertical market arrangements in the gas industry. Whereas prior to passage of the NGA, pipeline companies had shown a pronounced preference for owning their own reserves, afterward they switched more and more to purchasing gas from others under long-term contracts. The reason for this change from integration to long-term contracts are probably varied. But central to any explanation has to be the fact that the policy of the Natural Gas Act, as implemented by the FPC, was to regulate the price of gas from integrated pipeline production at original cost. Thus, after 1938 there was a great advantage to be gained from purchasing gas at arm's length and avoiding regulation of this transaction. In April 1954 the FPC allowed pipelines to establish a "fair market value" for their own production, but a Supreme Court ruling in 1956 required that original production cost be given due consideration in the pipeline rate hearings.[25] Thus, it was apparently preferable to keep wellhead prices out of the rate-of-return proceedings of pipelines and in the area-rate proceedings used (after 1960) to determine field-price ceilings.

FPC regulation of pipelines imposed a standardization on long-term contracts that had previously been lacking. The pipelines financed the postwar building boom with a relatively large amount of debt. One reason was that the FPC included interest costs in the "demand" component rather than the "commodity" component of the two-part tariff structure used to set their transportation rates. While the debt financing increased pipelines' financial risk, including interest in the demand charge allowed the pipelines to pass the cost of the debt through to ratepayers in a manner that was invariant to swings in demand. The FPC also required minimum reserve-to-production ratios and sinking funds tied to reserve life in the long-term contracts, to protect gas customers and bondholders against the pipeline companies' "bleeding" cash to shareholders while the reserve-base behind their service obligations and debt was eroding.[26] Further, the FPC sought to protect the "stability" of the industry by setting take-or-pay provisions in producer-pipeline contracts that more or less matched the minimum-bill provisions in pipeline-distributor contracts. We will see later that this attempt to provide industry stability would prove to have just the opposite effect as market conditions changed. Thus, the vertical market arrangements in the gas industry came--during the period of the industry's most rapid growth--to be closely determined and monitored by the federal regulatory agency responsible for the industry.

3.3 The Imposition of Field Price Regulation

3.3.1 The Origins of Field Regulation

The discussion above makes clear that conditions in the field market for gas were of substantial concern in the 1930's--to the FTC, the FPC, state and federal legislators, and the public at large. Yet the language of the NGA was ambiguous on the regulation of field prices: "The provisions of this chapter shall apply to the sale in interstate commerce of natural gas for resale..." (sale for resale would logically include the first sale gas purchase price as within the NGA provisions), ..."but shall not apply to the production or gathering of natural gas" (the first sale price could also be interpreted here as being excluded from the NGA).[27] There was support for both interpretations in the hearings that preceded passage of NGA.

The best explanation for the ambiguity is the simplest: Congress intentionally left it vague, in effect turning the issue over to the FPC and (in the event) to the Supreme Court. It is worthwhile to review the sources of legislative ambivalence on this question, to understand better the then-current perception of how the gas industry operated. There are three basic points.

First, while the FTC was concerned about the wellhead as well as the pipeline tier of the gas industry, its view of field-market problems focused on pipeline control of production. For instance, to the FTC the pipelines' restrictions on access by independent producers were the root cause of the "wastage" problem:[28]

> It should be understood that gas is wasted because of lack of a suitable and adequate market and not out of sheer perversity. While it may be physically desirable to prohibit physical waste of gas for the benefit of future consumers and producers, it should be recognized that the immediate benefit of such conservation will redound to the interests which bestride the market outlets, unless they can somehow be required to transport to market the gas of independent producers.

The implication was that the regulation of pipelines would suffice to solve any problems at the field. Note, however, that the pipeline regulation advocated by the FTC did not include exclusive purchase-for-resale rights for interstate pipelines; rather, as noted earlier and reiterated in the above passage, the FTC favored common-carrier regulation. Moreover, in early drafts of the NGA the agency advocated "common-purchaser" (or "ratable-take") regulation in field markets and actively encouraged state prorationing laws, to protect producers against variations in demand (see Section 2.3.1). The FTC did not, apparently, see monopoly in field markets as a problem.

Second, there was considerable doubt that federal regulation of independent gas producers was constitutional. Just as states were responsible for intrastate transmission and gas distribution, they were thought also to have jurisdiction over production, even if the gas eventually entered interstate commerce. It was hoped that interstate compacts would spring up, without federal legislation, to deal with the "wastage" problem. Consider this exchange between Senator Lea and Mr. Dozier Devane of the Federal Power Commission:[29]

> Mr. Lea: The theory is that it has been a matter for State jurisdiction. The Government does not have charge of mining or manufacturing raw products and is without sufficient power to assume control over waste.
>
> Mr. Devane: The general opinion is that it can best be handled by State compacts. Now, whether that is practical or not I am unable to say, but there is no question but what...compacts are legal.

Third, it should be stressed that the <u>level</u> of field prices was not a concern in the 1930's. Field prices in the Appalachian region were regulated by the states, and (as it was mostly interstate pipelines' own production that was flowing in interstate commerce) the field price of independent production in the Appalachian region was not being bid up. The prospect of declining supplies and rising field prices in the Mid-Continent region was not yet conceivable.

In contrast, by the time the Supreme Court was called upon to determine the applicability of the NGA to wellhead prices in Phillips Petroleum Co. v. Wisconsin in 1954, the level of field prices in the Mid-Continent and elsewhere had become an issue. As noted earlier, field prices were rising (spurred in part by the "contagion" effect of contingent price-escalator clauses), and producing states were competing with consuming states for the rents that accompanied the postwar expansion of the gas industry. Also contributing to concern over the field market was the emergence of what has been called the Old-Mother-Hubbard's-Cupboard view of gas supply.[30] This view held that, because gas supplies in the Mid-Continent region were becoming less abundant, any increases in demand would simply raise wellhead prices without eliciting further increases in output. Old Mother Hubbard, when she went to look for new gas reserves, would find the cupboard bare.[31]

It is popular now for economists and legal scholars, in looking back at this period, to be critical of the Supreme Court's decision in Phillips. The case is sometimes held out as the quintessential economic example of improper intrusion by the judicial system into the legislative process. Undeniably, the field-price controls imposed as the result of the Phillips decision have wrought havoc in natural gas markets. At the same time, that decision was not inconsistent with the historical context of the NGA, or for that matter with one part of the language in the bill. The Congress and President Eisenhower did miss two good chances to decontrol wellhead prices in the 1950's.[32]

Finally, the wellhead controls (together with the allocation rules for dealing with excess demand) served to pass any economic rents, which would have accrued to producers, down the pipeline to those customers who were fortunate enough to have been connected to the system, and thus may have served certain distributive equity purposes. Of course, there were many customers without access to the system who did not benefit from the rent redistribution, due to the adverse incentive effects of the price controls on gas supply and demand.

3.3.2 Effects of Wellhead Controls on the Pipeline System

As has been documented a thousand times,[33] the wellhead price ceilings on natural gas production dedicated to the interstate market led to shortages--first, in the market for reserves (causing, <u>inter alia</u>, a decline in drilling activity) in the mid-1960's, and then in the market for flowing gas in the late 1960's and early 1970's. With the regulation-induced shortage as backdrop, the surge of world oil prices in 1973-74 forced the radical rethinking and revision of federal gas policy. The Natural Gas Policy Act of 1978 was the first legislative manifestation of the change, but four years earlier the FPC itself had initiated higher price ceilings by replacing area rates with "national rates."

More germane to present concerns, the excess demand in the <u>inter</u>state market spilled over into the several <u>intra</u>state gas markets, of which Texas and Louisiana were the largest. Prices there rose to (different) market-clearing levels, well above the FPC's interstate ceilings. But a precondition for realizing the higher prices was the creation of entirely separate intrastate pipeline systems to keep the intrastate gas completely free of any taint of interstate commerce. These systems provide convenient examples of largely unregulated pipeline markets that may provide data for empirical tests of certain propositions about deregulating pipelines.

However, at present a paucity of published data, and even of basic information on the intrastate pipeline companies themselves (many of which are privately held), limits their usefulness for such empirical tests. Only since passage of the NGPA in 1978 (which brought intrastate field prices under federal regulation) have the intrastate pipelines begun to stir as a public-policy interest group--probably a precondition for getting publicly available data on them. As yet, though, there is no one group that can speak for the intrastates.

The price ceilings in the interstate wellhead market made it increasingly difficult for the interstate pipelines to obtain new reserves. For a sustained period in the early 1970's, the only major new contracts signed by interstate pipelines were for gas from federal (but not state) offshore leases; federal offshore gas was declared "interstate" by the FPC (which was in turn supported by the federal courts) even if it was brought ashore and used without crossing a state line.

Two consequences of note flowed from the interstates' plight. First, the NGPA took away much of the intrastate pipelines' offer-price advantage, enabling the interstate pipelines to begin to sign up new reserves once again. But still unable to bid the full free-market dollar prices for the reserves, the interstates resorted to non-price terms--in particular, to contingent price-escalator clauses tied to residual or No. 2 fuel oil, or to almost open-ended "deregulation" trigger clauses--in bidding for gas supplies. But when oil prices and some new-contract gas prices rose sharply in 1979 and 1980, the interstate pipelines were vulnerable to sharp price increases on already flowing gas--not unlike those experienced in the 1950's except much larger in magnitude.

Second, the interstate pipelines (and their gas-distributor customers further downstream) grew used to operating in a seller's market--literally, "off the demand curve." Whatever gas could be delivered would be taken and sold, with more desired, without having to worry about the demand constraints familiar to firms operating in functioning markets. Again, when prices rose sharply in the later 1970's and 1980's, the interstates had to reorient themselves to "marketing" their gas--to finding the demand curve and figuring out how elastic it was in the different segments of their markets. Pipeline managements have had to re-educate themselves--a task some intrastate pipelines think they do not face because they never got off their demand curves. (Under the NGPA, however, the intrastates for a while faced supply problems now that their field prices are federally regulated and they have to compete with interstate pipelines more than previously.)

3.4 Current Events in the Gas Industry: Effects on the Gas Pipelines

As a preface to any analysis of long-run changes in the institutional and regulatory structure of the gas industry it is important to understand the environment out of which these changes would evolve. Not only do the present market conditions color policymakers' attitudes toward particular alternatives (e.g., are pipelines really behaving anti-competitively or earning excess profits?), but it is also important to determine how the industry may evolve of its own accord after decontrol, absent legislative or regulatory intervention. Current industry reactions to decontrol and the Great Recession may indicate the kind of evolution we would expect upon full field-price decontrol.

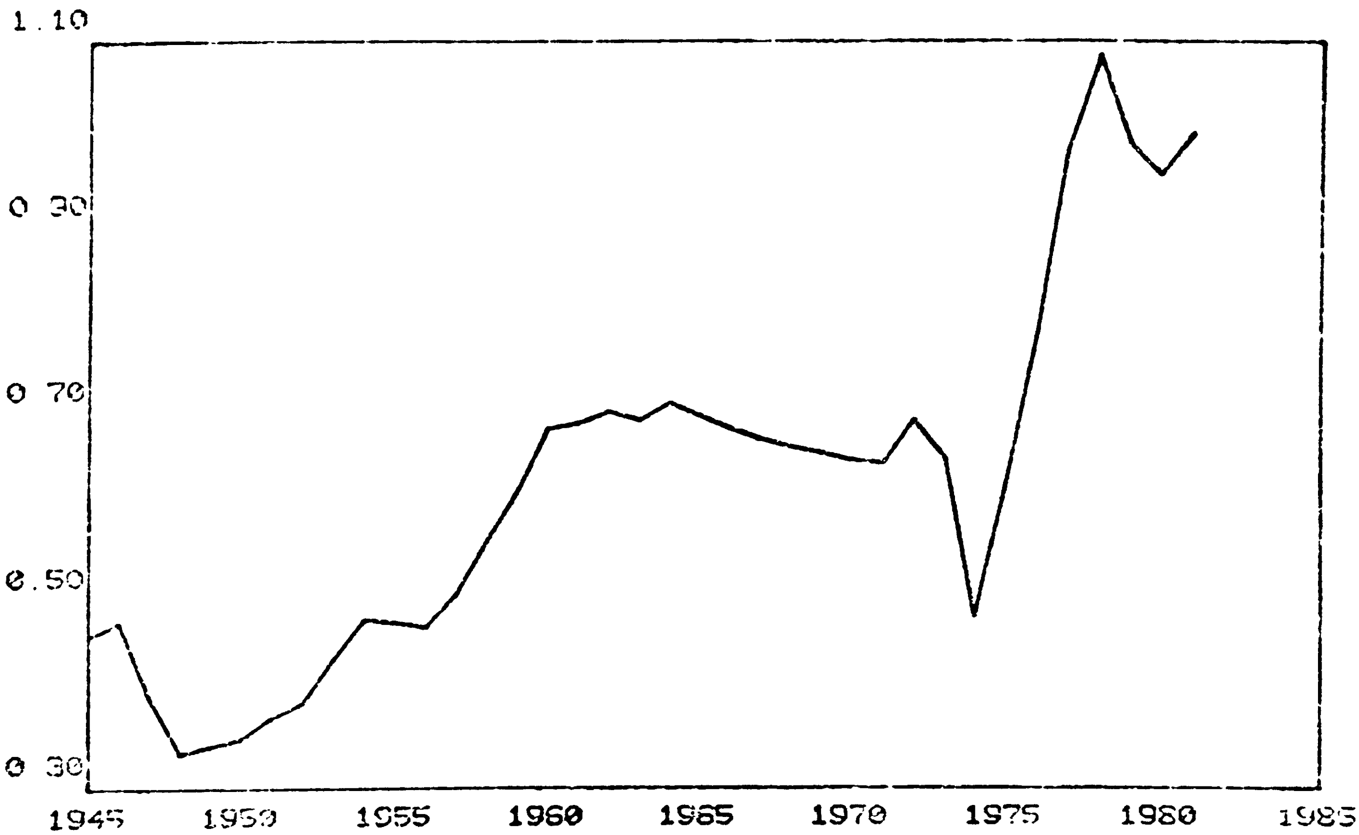
In this section, the effects of decontrol and the current market conditions on gas pipelines are summarized in three areas: the binding demand constraint, contractual rigidities and demand volatility. The section closes with a discussion of a commonly-used measure of pipeline economic performance.

3.4.1 A Binding Demand Constraint: Prices and Recession

It is apparent to most observers of the gas industry that the partial decontrol of wellhead prices and the effects of the recent recession have brought natural gas "back on the demand curve," and have produced a short-run gas glut or "surplus deliverability" condition. This can be appreciated by examining various statistics.

Even absent full decontrol, natural gas prices have undergone a significant transformation relative to oil. Figure 3.2 plots an index (1981=1) of the ratio of wholesale utility (distribution company) purchased gas prices to a wholesale fuel oil price (in this case #2 heating oil). This plot illustrates several points. First, it confirms the observation above of the price advantage of natural gas even before the imposition of field price controls, due to the large supplies of low-cost reserves flooding the market.[34] Second, it provides some indication that field price controls did not bind significantly until approximately 1960. While the picture does not provide absolute proof, one would have expected, absent controls, a continuing rise in the index after 1960 as the lowest cost mid-continent reserves were gradually being exhausted. There were no large low-cost reserve discoveries made at the time which could otherwise have accounted for the flattening of the price ratio. Finally, the differing effects on this ratio of the two oil price shocks of the 1970's are indicative of the gas industry transition. The first price shock, "OPEC I", in 1974 increased the price of oil relative to gas. Field price controls were binding and the gas-oil price ratio shows a downward spike. The second price shock, "OPEC II", coupled with the NGPA in 1978-79 produced a dramatic upward spike in the gas oil price ratio.

The recent effects of decontrol and the recession are apparent in recent changes in quantity demanded by customer class. These trends are



TIME BOUNDS: 1945 TO 1981

DATA NAMES: GORATIO

Figure 3.2

Ratio of Wholesale Natural Gas
to #2 Oil Price, (1981=1)

indicated in Table 3.5. Note that income and price-sensitive industrial and electric utility demand fell by 18 and 11 percent, respectively, in 1982. The weather-sensitive residential and commercial demand dropped by 15 and 13 percent, respectively, in the first four months of 1983 over the previous year, presumably due to the mild winter temperatures. Boiler fuel use in the industrial and electric utility sectors is the marginal source of demand for most pipelines. A survey by the American Gas Association in 1982[35] indicated that in 1981, 52 percent of the gas sales in the industrial sector were to dual-fuel capable users, while 89 percent of electric utility sales were to dual-fuel capable users. This implies that approximately 40 percent of total U.S. gas sales are readily switchable, since approximately 40 percent of total gas consumption is by industrial customers and 20 percent is by electric utilities. First Boston Research estimated the pipeline vulnerability to #6 residual fuel oil at the then-current prices, and estimated potential losses for their sample at approximately 11 percent of total sales, as indicated in Table 3.6. Note that a quarter of these exposed sales are direct sales (non-jurisdictional) and thus not subject to minimum bill requirements (see Section 2.3.1).

Table 3.7 indicates the relationship between changes in average prices and pipeline system sales (normalized as a percentage of total U.S. sales) for the major interstate pipelines.[36] Note that between the two comparable seasonal periods (July 1982 and July 1983), those pipelines that tended to lose the greatest share of the total gas market tended to experience the largest increase in average system prices.

Finally, Table 3.8 provides an estimate of the total "deliverability surplus" between 1981 and July 1983 based on a survey of 100 pipeline companies for the U.S. Department of Energy. As indicated, the estimated

Table 3.5

Recent Changes in U.S. Natural Gas
Demand by Customer Class
(Billion Cubic Feet)

	1981	1982	1983	% Δ 81-82	% Δ 82-83
Residential					
Jan-April	2528	2746	2344	+8.6	-14.6
May-Aug	687	668	694	-2.8	+3.9
Sept-Dec	1330	1288	NA	-3.2	--
Total	4545	4702		+3.5	
Commercial					
Jan-April	1217	1277	1106	+4.9	-13.4
May-Aug	447	410	413	-8.3	+0.7
Sept-Dec	741	682	NA	-8.0	--
Total	2405	2369		-1.5	
Industrial					
Jan-April	2184	1939	1820	-11.2	-6.1
May-Aug	2218	1710	1622	-22.9	-5.1
Sept-Dec	2729	2200	NA	-19.4	--
Total	7131	5849		-18.0	
Elec. Utility					
Jan-April	1018	951	796	-6.6	-16.3
May-Aug	1498	1268	1132	-15.4	-10.7
Sept-Dec	1125	1008	NA	-10.4	--
Total	3641	3227		-11.4	
Total Deliveries					
Jan-April	6999	7050	6172	+0.7	-12.5
May-Aug	4876	4108	3901	-15.8	-5.0
Sept-Dec	5962	5233	NA	-12.2	--
Total	17837	16391		-8.1	

Source: U.S. DOE, Natural Gas Monthly, July 1983, December 1983.

Table 3.6

Estimated Volumes Exposed to No. 6 Fuel Oil Competition

	Sales For (Bcf) Resale	Use	Total	As a % of 1981 Total System Sales
American Natural Resources, Inc.	30	--	30	4.7%
Arkla, Inc.	--	--	--	--
Celeron Corp.	--	24	24	9.1
Colorado Interstate Gas (Coastal Corp.)	--	--	--	--
Columbia Gas Systems, Inc.	83	--	83	6.9
Consolidated Natural Gas Co.	52	--	52	6.5
El Paso Co.	245(1)	70	315	25.0
ENSERCH Corp.	2	91(2)	93	17.6
Houston Natural Gas Co.	1	70	71	10.6
InterNorth, Inc.	52	--	52	7.2
MidCon Corp.	110	--	110	11.5
Northwest Energy Co.	56	--	56	16.9
ONEOK, Inc.	4	24	28	7.7
Panhandle Eastern Corp.	110	1	111	11.0
Pioneer Corp.	--	--	--	--
Sonat, Inc.	55	30	85	13.6
Tenneco, Inc.	105	--	105	7.7
Texas Eastern Corp.	96(3)	--	96	7.2
Texas Gas Transmission Corp.	56	--	56	8.5
Transco Energy Co.	144	--	144	16.0
United Energy Resources, Inc.	28(4)	110	138	8.6
Total	1,395	420	1,815	11.2%

(1) El Paso includes 34 Bcf of electric Generation.
(2) ENSERCH includes 34 Bcf of electric generation.
(3) Texas Eastern Pipeline - 51 Bcf; Transwestern Pipeline - 45 Bcf.
(4) United Gas Pipe Line - 24 Bcf; United Texas Transmission Co. - 4 Bcf.

Source: First Boston Research, Large Volume Sales of Natural Gas: Their Importance and Vulnerability, Special Report, GT1398.82, August 1983, p. 32.

Table 3.7

Changes in Relative Pipeline Sales
and Average Prices 1982-1983

	July 1982		July 1983			
	Share*	Price	Share*	Price	% Δ Share	% Δ Price
Mississippi River	0.76%	$3.15	0.74%	$5.64	-3%	79.0%
Panhandle Eastern	5.24	2.91	3.84	4.54	-26	56.0
Trunkline	4.63	3.57	2.22	5.50	-52	54.1
National Fuel	1.47	4.02	0.65	5.68	-56	41.3
Michigan Gas	0.96	3.30	0.90	4.52	-6	37.0
Columbia Gas Corp.	7.59	3.98	5.98	5.20	-21	30.7
Mountain Fuel	0.63	2.62	0.73	3.32	16	26.7
Northern	3.39	3.69	3.93	4.67	16	26.6
Texas Gas	5.08	3.21	4.41	3.98	-13	24.0
El Paso	8.05	3.26	9.39	3.97	17	21.8
Transwestern	2.20	3.68	2.62	4.36	19	18.5
Natural Gas Pipeline	5.72	3.00	5.50	3.50	-4	16.7
Transco Gas	0.79	2.81	0.85	3.27	8	16.4
Transcontinental (Transco)	7.77	3.80	6.49	4.34	-16	14.2
Mich-Wis (ANR)	3.07	4.12	3.96	4.69	29	13.8
Consolidated Gas	3.90	3.97	3.31	4.48	14	12.8
Colorado Interstate	1.98	3.20	1.73	3.50	-13	9.4
Southern	3.31	3.78	3.92	4.13	18	9.3
United	6.73	3.96	5.50	4.25	-18	7.3
East Tennessee	0.54	4.07	0.54	4.26	0	4.7
Texas Eastern	7.53	3.34	9.04	3.49	20	4.5
Tenneco, Inc.	8.11	3.93	7.39	4.07	-9	3.6
Cities Service (Northwest Central)	1.16	3.28	1.52	3.31	31	0.9
Midwestern Gas	1.70	3.98	1.88	3.95	11	-0.8
Florida Gas	1.62	3.41	2.10	3.35	30	-1.8
Algonquin Gas	0.97	3.92	1.53	3.79	58	-3.3
Pacific Gas	2.24	7.09	2.74	6.72	22	-5.2
Northwest	1.28	4.73	1.53	4.36	20	-7.8
Sea Robin	1.66	3.05	1.55	2.80	-7	-8.2
	Avg.	3.68		4.25	0	15.5

*Percent of total U.S. sales of gas accounted for by pipeline company.

Source: U.S. DOE, Natural Gas Monthly, November 1982, 1983.

Table 3.8

Estimated Surplus Gas Available for Sale during Next 6 Months, 100 Companies

(1) Date of Survey Estimate	(2) Estimated Surplus (Bcf)	(3) Previous Six Months' Consumption* (Bcf)	(4) Column (2) as Pct. of Column (3)
1/81	219	9,143	2.4
3/81	437	10,645	4.1
7/81	410	10,297	4.0
10/81	242	8,119	3.0
1/82	456	9,109	5.0
4/82	864	11,349	7.6
7/82	1,229	9,958	12.3
10/82	1,189	7,172	16.6
1/83	1,715	8,045	21.3
4/83	2,605	9,836	26.5
7/83	2,357	8,767	26.9
10/83	2,077	6,881	30.2

Source: DOE/EIA, Natural Gas Monthly, September 1983, December 1983.

Note: The absolute estimates include some double counting. For example, a pipeline would report as "surplus" all gas in excess of estimated "requirements." But a distributor planning to take 80% of its contract volume from that pipeline would also report the remaining 20%, to which it has contract rights, as "surplus."

*Actual except for 1/81 and 3/81, which assume .46 and .23 (respectively) times actual 1980 consumption.

gas surplus peaked in April 1983 at 2.6 trillion cubic feet. As calculated in the last column, this amounts to 26.5 percent of the previous six months' consumption and represents a very large, unprecedented departure from previous experience that has not subsided as of the end of 1983.

Taken together, these figures provide convincing evidence that gas is "back on the demand curve." But why should this result in a glut of surplus gas that INGAA estimates will amount to 5.6 trillion cubic feet between 1982 and 1985?[37] In a freely functioning market these demand effects would be reflected in the prices paid to producers. This is not occurring in the current market due to certain contractual rigidities.

3.4.2 Contractual Rigidities

Dominating discussions of natural gas pipelines as never before is the inflexibility of the current set of pipeline-producer supply contracts. It is this rigidity that has led to the deliverability surplus as well as to the exposure of gas pipelines to greater business risk, which will be discussed below.

Two measures of this rigidity are useful. The first is the estimated level of take-or-pay prepayment liabilities for gas not taken. Recall that prepayment liabilities are the accumulated account of payments made to producers for gas which the pipeline could not sell but was obligated to pay for (see Figure 2.3, glossary, definition of take-or-pay clause). As indicated in Table 3.9, INGAA has estimated these liabilities to be between approximately 5 and 10 billion dollars between 1982 and 1985, depending on further demand losses or recovery. The duration of these liabilities is important due to the time limits (often of five years) on the exercise of prepayment makeup provisions in the contracts. These liabilities are quite large, amounting to approximately 50 percent of estimated major gas pipeline net income after tax over the 1982-1985 period.

A second measure of contract rigidity involves surplus gas which was taken but not sold, and instead injected into underground storage. As described in Table 3.10, net injections into gas storage, which should be near zero in years without production growth (such as 1980) were large in 1981 and 1982. Figures for the first four months of 1983 indicate that the trend is continuing, as winter-season withdrawals were substantially down from the previous year. The value of this "excess" stored gas at an average wellhead price of approximately $2.50 is approximately $1.60 billion, and of course, there are not-insubstantial carrying costs associated with this gas in storage.

3.4.3 Demand Volatility: Changing Oil Markets and Natural Gas Demand

We have seen, because of the prevalence of dual-fired boiler capacity, the close competitive connection between oil and natural gas. This connection leads to a third important current event for the gas pipelines, one that is not fully appreciated due perhaps to a preoccupation with the more immediate industry problems cited above. That is, world oil markets and prices have become, and will arguably stay, much more volatile. The close competition between gas and oil implies that this volatility will be transferred to the gas market, and as will be shown in Chapter 4, this volatility will be levered into the risk faced by gas pipeline investors.

The empirical evidence for this increased oil market volatility is still sketchy, but the conceptual argument is as follows. Since the embargo and Iranian price shocks, the institutional structure of the world oil market has changed such that crude contracts are of shorter term, and an active spot market has developed that is handling an increasing percentage of crude trade. Secondly, governmental authorities (notably

Table 3.9

Estimates of Prepayment Liabilities
for Gas Not Taken
(billions of dollars)

Year	Prepayment Liability					
	Nominal Dollars			1983 Dollars*		
	Best Estimate	+10% Sales	-10% Sales	Best Estimate	+10% Sales	-10% Sales
1982	0.5	0.5	0.5	0.5	0.5	0.5
1983	3.3	2.2	4.2	3.3	2.2	4.2
1984	2.3	1.4	3.7	2.3	1.3	3.4
1985	0.9	0.6	1.5	0.8	0.6	1.3
1982-85 Total	7.0	4.7	9.9	6.9	4.6	9.4

Source: INGAA, Contract Issues Survey, 1983.

*Assumes a 6% annual inflation rate. Since 1982 dollars were reported for mid-year, the inflation rate used was 3% for conversion to 1983 dollars.

Table 3.10

Net Injections into
Underground Gas Storage - Interstate Operators
(Billion Cubic Feet)

	1980	1981	1982	1983	80-81	81-82	82-83
Net Injections*							
Jan-April	-697	-673	-895	-789	24	-222	106
May-Aug	790	968	1026	NA	178	58	--
Sept-Dec	-101	1	118	NA	102	117	--
Total	-8	296	249				

*Positive numbers indicate injections in excess of withdrawals.

Source: U.S. DOE, Natural Gas Monthly, July 1983.

OPEC) have taken on a greater role in managing supplies, and they are likely to do it less effectively than the oil companies (notably the Aramco partners) did previously. To a certain extent, prior to the embargo, oil supply management by Aramco was disciplined by the market--Aramco was unable to effectively restrict supply and raise prices. As the OPEC governments took over supply management, they were able to act as an effective cartel, but recently (especially after the shock of 1979-80) OPEC's ability to manage worldwide supplies has seriously deteriorated. This combination of less-effective government oil supply management and an active secondary market should result in more volatile prices. As John Mitchell, a noted market observer with British Petroleum, has observed:[38]

> We are left with a market in which international crude and product trade between the oil exporters and the rest is the dominant international operation. It is carried out on the basis of very short term contracts as regards price and I believe this is likely to continue. Fluctuations in demand and supply will be quickly transmitted. . . Stability in oil prices therefore depends on the main exporters managing supplies and prices flexibly and coherently in response to the effects of all these complex forces. This is a very different world from the world of two or three dollar oil ten years ago. I believe this change is permanent and irreversible and stability will be permanently at risk.

3.4.4 Gas Pipeline Profitability

Given the rapidly-changing conditions in the gas market outlined above, a natural question to ask is whether they have had an adverse effect on the gas pipelines, the remaining market segment regulated by the Federal Government.

Well-respected observers of the pipeline industry have recently answered this question in the negative. These observers include many of the widely publicized gas pipeline security analysts and even the U.S.

Secretary of Energy.[39] If anything, they conclude from their analysis that gas pipelines have been earning profits in excess of a competitive return. Tables 3.11 and 3.12 report the results of one such analysis.

In Table 3.11 an average return on book equity for the year 1982 is computed for a sample of major pipelines. In Table 3.12 this 17.5 percent ROE is compared with the book equity returns earned by other U.S. industries, which averaged 12 percent in 1982. On the basis of these statistics it is concluded by the analysis that the pipelines are overly profitable and that the FERC may want to think about giving closer regulatory scrutiny to the pipelines.

Unfortunately, the profitability measure and approach used in this analysis is quite misleading. In general, it is never a good practice to evaluate industry and regulatory performance by examining a "snap-shot" of data for only one year. Numerous factors can cause a single abnormality in accounting-based earnings figures, even for regulated firms. More significantly, however, when one accounts for the differences in capital structure and risk between these firms, the apparent profitability of the pipelines diminishes. To show this, the concept of business risk must be introduced. As will be seen, risk is a very convenient way of interpreting in a single measure the effects of interfuel competition, contract rigidity and demand volatility on pipeline performance. At the end of the next chapter we will return to the question of whether gas pipelines are too profitable in the current environment.

Table 3.11

1982 Average Return on Equity for Natural Gas Pipeline

Pipeline	Percent
Colorado Interstate (Coastal)	36.34%
Columbia Gas Transmission	11.31
Consolidated Gas Supply	22.27
El Paso Natural Gas*	13.50
Michigan Wisconsin Pipeline (American Natural)	18.30
Natural Gas Pipeline of America (MidCon)	21.30
Northern Natural Gas* (InterNorth)	14.00
Northwest Central Pipeline (Northwest Energy)	20.29
Northwest Pipeline (Northwest Energy)	16.35
Panhandle Eastern Pipeline	13.20
Southern Natural Gas (Sonat)	18.10
Tennessee Gas Pipeline* (Tenneco)	17.00
Texas Eastern Transmission	15.46
Texas Gas	19.04
Transcontinental Gas Pipeline (Transco)	25.18
Transwestern Pipeline (Texas Eastern)	14.22
Trunkline Gas (Panhandle)	16.52
United Gas Pipe Line (United Energy)	27.44
Average	17.50%

* Our estimates. Companies would not provide all statistics to compute ROE.

Note: Colorado Interstate's return on equity was calculated with production earnings included in net income. After excluding production earnings, we estimate that the pipeline's return on equity would approximate 23.0%.

Transco's net income in 1982 included about $24 million that was collected for prior years. After excluding that amount, we estimate the pipeline's ROE was about 19.9%.

Michigan Wisconsin's 1982 net income contained $22.7 million that should have been collected in prior years. Adjusting for that, Michigan Wisconsin's 1982 ROE was 16.8%.

After incorporating these three considerations, we estimate the pipelines collectively earned 16.8% on equity in 1982.

Table 3.12

1982 Average Return on Equity for Natural Gas Pipeline

Industry	Percent	Industry	Percent
Tobacco	20.2%	Conglomerates	10.8%
Drugs	19.2	Trucking	10.7
Oil Service & Supply	18.0	Retailing/Non-Food	10.4
Appliances	17.7	Instruments	10.3
Pipelines	**17.5**	Miscellaneous Manufacturing	10.2
Beverages	17.2	Textiles/Apparel	9.2
Personal Care	16.7	Railroads	8.7
Publishing, Radio & TV	16.6	Chemicals	8.3
Office Equipment	15.9	Containers	7.7
Food/Lodging	15.5	Real Estate/Housing	6.3
Electrical/Electronics	15.1	Tire & Rubber	5.3
Leisure Time	14.1	Paper & Forest Products	3.9
Food Processing	13.5	General Machinery	3.8
Natural Resources	13.1	Building Materials	2.8
Service Industries	13.0	Special Machinery	0.0
Aerospace	12.9	Automotive	- 4.0
Retailing/Food	12.9	Metals & Mining	- 5.8
Banks	12.7	Airlines	- 8.9
Utilities	12.7	Savings & Loan	-14.2
Non-Bank Financial	12.3	Steel	-19.0

Source: *Business Week*, except for natural gas pipelines, where ROE was computed from company-supplied data and our own estimates.

Source: Merrill Lynch Capital Markets, Securities Research Division, Natural Gas Monthly, August 1983, p. 2.

Footnotes, Chapter 3

1. U.S. Senate, 1934 (hereafter cited as "FTC Report"). Part 84a of this study is the summary report on natural gas.

2. *Ibid.*, Chapter X.

3. U.S. House of Representatives, 1936, pp. 55-6.

4. For a comprehensive discussion of the Appalachian gas market, see Edmund W. Kitch, 1968.

5. *Pennsylvania V. West Virginia*, 262 U.S. 544 (1923).

6. "It was ... the federal assumption of the power to impose [nonmarket controls over persons] together with its prolific activism in the economy that made the New Deal such a critical change in American history and that qualified it for the word *revolutionary*." -- Jonathan Hughes, "Roots of Regulation: The New Deal," in Gary M. Walton, ed., 1979, p. 32 (emphasis in original).

7. FTC Report. Not to be outdone, the House of Representatives commissioned its own study of utility holding companies, which reached similar policy conclusions; see Dr. Walter Marshall William Splawn, H.R. Report No. 2192, 72nd Congress, 2nd Session, 1935 ("The Splawn Report").

8. It was quite popular at the time to consider "interlocking directorates" as potentially anti-competitive. In contrast to their study of electric utility holding companies, the FTC did not find significant evidence of interlocking directorates in the gas industry.

9. FTC Report, p. 593.

10. *Ibid.*, p. 591.

11. See, for example, the testimony of Dozier DeVane, Solicitor for the Federal Power Commission, in favor of the NGA. When pressed, he could not offer a "public interest" rationale for the Act. U.S. House of Representatives, 1936, pp. 24-46.

12. See M. Elizabeth Sanders, 1981, pp. 36 *et seq*. The most strenuous objections seem to have centered on provisions for common-carrier status. I do not agree in every instance with Sanders' version of the facts and the sources of the pipelines' several objections. But her book is a useful source on the politics of the NGA.

13. Stephen G. Breyer and Paul W. MacAvoy, 1974, pp. 16-55. Their definition of "comparably situated" firms for the comparison of rates of return implies firms in the same risk-class as the gas pipelines. They perform no explicit analysis to determine whether or not the chosen comparison group (electric utilities) are in fact of the same risk class.

14. U.S. House of Representatives, 1936, p. 26.

15. Cf. Beard, 1941, pp. 21-24. Senator Tillman of South Carolina introduced the 1906 legislation, arguing for common-carrier status to prevent the pipelines' draining away of independents' gas (see above). Senator Reed of Kansas sponsored the 1913-1914 legislation, arguing that common-carrier status would compel pipelines to transport additional gas that the local distribution companies would purchase themselves. The implication is that the pipelines deliberately created the shortages, or at least refused to ship extra gas to alleviate them.

16. This argument draws on Beard, 1941, pp. 23-24.

17. Standard and Poor's Industry Surveys, "Natural Gas Transmission," May 1953, p. U1-10.

18. Standard and Poor's Industry Surveys, "Natural Gas Transmission," May 1962, p. U-33.

19. Ibid., May 1954, P. U1-9.

20. Ibid., May 1956, p. U32.

21. Adelman, 1962, p. 47-8.

22. MacAvoy, 1962; see also Adelman, 1962, p. 39n.

23. Adelman, 1962, p. 42.

24. Ibid., p. 43.

25. Standard and Poor's Industry Surveys, May 1957, p. U36.

26. These sinking fund provisions are essentially means of paying off bondholders in a way which controls the potential conflict between bondholders and stockholders when the gas reserves embodied in the firm's contracts end up being smaller than originally anticipated. In this sense they are like financial reserves to protect the bondholders (and ratepayers) from potential default caused by an unexpected drop in reserves. These indenture provisions require the firm to submit a periodic Certificate of Available Gas Supply. If the expected date of exhaustion is revised to an earlier date (less than the term of the debt), the size of the sinking fund installment is increased to produce the "financial reserves" to cover the shortfall.

    For a discussion of the purposes of various bond covenants of this sort see, Smith and Warner (1979).

27. 15 U.S.C. 717(b) 1964.

28. FTC Report, p. 601.

29. U.S. House of Representatives, 1936, p. 36. Note that there was already a federal interstate compact for oil.

30. See Jacoby and Wright, 1982.

31. This view was championed at the time by economists Alfred Kahn and Joel Dirlam, among others. See, for example, Joel B. Dirlam, 1958.

32. Standard & Poor's Industry Surveys, May 1957, p. U36.

33. For example, by Paul MacAvoy, Edward Erickson, Robert Pindyck, and a host of other analysts.

34. Adelman (1962), p. 74, observed this phenomenon. "But there is no reason for 'shock' or surprise at a 'superior' fuel selling at a lower price. Nor have United States field prices been 'artifically' low because of Federal Power Commission regulation (which did not even have judicial warrant before 1954, and only began to 'bite' later). ... That price was once very low because gas was very plentiful in relation to demand, which in turn was due to lack of outlet, higher cost of out-shipment than oil and inability to reduce the amount of new gas reserves because of joint supply."

35. American Gas Association, Survey of Industrial Fuel Switching and Alternative Fuel Capability 1981-1982 (update), Arlington VA, September 3, 1982.

36. Of course, a better approach to normalizing the sales data would be to compare pipeline shares of their own service areas. But these nationwide statistics are indicative for our purposes.

37. NGAA, Contract Issues Survey, May 1983, p. 10.

38. John V. Mitchell (British Petroleum), Changing Structure of the International Oil Industry, address to International Gas Markets Conference, Calgary, Alberta, September 26, 1983, p. 7.

39. See for example Donald Dufresne, "Those Poor Pipelines," Natural Gas Monthly, Merrill Lynch Capital Markets, Securities Research Division, August 1983. In a speech to an industry group in the autumn of 1983 Secretary of Energy Donald Hodel referred to the gas pipelines as "feeding at the regulatory trough."

4. RISK AND GAS PIPELINES

In this chapter we turn to the literature of financial economics for a conceptual and empirical method of characterizing the gas industry transition and its effects on the pipeline segment of the industry.

4.1 Concept of Risk and its Measurement

Recent work in the theory of financial economics has produced a set of unifying concepts and tools for characterizing the behavior and performance of a firm in terms of the underlying riskiness of its business. This theoretical view, under a set of assumptions which will be described below, is that a firm's performance, as measured by the market return earned on its assets, should be directly related to the underlying riskiness of its assets. Common stocks and bonds are securities issued by corporations to raise funds to invest in physical assets, such as plant and equipment. The risk of these securities is thus a direct reflection of the risk of the corporate assets underlying them. This fact enables one to use the market behavior of the firm's securities, notably its common stock, to measure the firm's asset risk.

Prices and rates of return for common stocks[1] are arrived at through the participation of large numbers of investors in the capital markets. Under the assumption that investors are on average averse to risk, stocks with higher risks must be priced to provide higher expected rates of return, else they will not be held by investors.

While there is no strong consensus as to the precise measure of risk which should be used, one or two risk measures have stood out in practice. These measures arise from the problem of an individual investor selecting his portfolio of securities, as formulated by Markowitz (1952). The risk-averse investor is assumed to trade off the expected single period return on his portfolio, r_p, against the portfolio risk (i.e., its variance σ_p^2). If there were only a single security to choose from, then the portfolio variance would equal the individual security variance, σ_i^2, and this would be the appropriate measure of the firm's risk. (Note that all return measures, r, used in this paper are expectations unless a time subscript is added, in which case it is an observed value.)

If there are K candidate securities to choose from, then

$$r_p = \sum_{i=1}^{K} w_i r_i \quad \text{and}$$

$$\sigma_p^2 = \sum_{i=1}^{K}\sum_{j=1}^{K} w_i w_j \sigma_{ij} \quad .$$

where $\sum w_i = 1$ and

σ_{ij} is the covariance between security i and security j ($\sigma_{ii} = \sigma_i^2$).

In this circumstance we are worried only about the <u>marginal</u> contribution of a particular firm's security to the overall portfolio risk. That is,

$$\frac{\partial \sigma_p^2}{\partial w_i} = 2w_i \sigma_i^2 + 2\sum_{i \neq j} w_j \sigma_{ji}$$

$$= 2\sum_{j=1}^{K} w_j \sigma_{ij} \; = \; 2\sigma_{ip} \quad .$$

Thus, in the presence of many securities (as is the case for diversified investors in the New York Stock Exchange, for example), an appropriate measure of an individual security's risk is its marginal contribution to the variance of a well-diversified portfolio. This contribution is proportional to the covariance of the security with this portfolio. Since the most diversified portfolio possible contains all the available securities (call its expected return r_m and variance σ_m^2 for the "market portfolio"), this suggests that σ_{im} is a good indicator of the firm's "systematic" or "undiversifiable" risk. This measure is proportional to the coefficient β_i in the following simple linear regression,

$$r_{it} = \alpha_i + \beta_i r_{mt} + \varepsilon_t \ ,$$

since $\beta_i = \sigma_{im}/\sigma_m^2$ by definition. This equation is called the "market model" (Fama, 1976).[2] In Section 4.3, historical changes in gas pipeline systematic risk are estimated using this model, from observations on r_i and r_m during the period from 1945 to 1982.

To determine whether these risk changes are of significance, we will need a method to translate changes in $\hat{\beta}_i$ into changes in rates of return which investors would require in compensation. To do this we must make the further assumptions that all investors can borrow and lend at the risk-free rate, r_f, and that they have identical information bases on which to make assessments of risks and return. These are the additional assumptions of the Capital Asset Pricing Model (CAPM) of Sharpe (1964) and Lintner (1965). In equilibrium in a single period, and under these assumptions,

$$r_i = r_f + \hat{\beta}_i(\overline{r_m - r_f}) \ .$$

This equation, then, provides a technique for estimating changes in r_i

given changes in the level of risk β_i, since $(\overline{r_m - r_f})$, the expected (average) risk premium on the market portfolio, is roughly observable.[3]

To summarize, these two equations, the "market model" and the equilibrium asset pricing relationship, give us the tools to first estimate whether systematic risks have changed in the gas pipeline industry, and second, to assess the significance of the change from the investor's (and consequently a regulator's) point of view.

It should be pointed out here that the most basic version of the Capital Asset Pricing Model described above is not necessarily the complete story behind security risk and expected return. Like any model it is a simplification, and statistical studies have had trouble validating it.[4] There are also problems with the estimation of beta, problems that will be identified below where appropriate. On the other hand, the argument as developed above implies that beta is a reasonable measure of risk even if the CAPM is not perfectly valid, and the CAPM itself is superior to other asset valuation models in that it is consistent with the well-established view that capital markets are efficient.

4.2 Sources of Risk to Pipeline Company Shareholders

In the last section we reviewed the theoretical relationships between shareholder risk and security returns, but what exactly are the factors which contribute to this risk in the gas pipeline industry? There are four prominent sources.

4.2.1 Financial Leverage

As a firm relies more heavily on debt relative to equity as its source of financing, the risk borne by equity holders can be expected to increase. This is because bondholders have a prior claim on the firm's operating income.

In a world of perfect capital markets and no taxes,[5] Modigliani and Miller (1958) showed in their Proposition I that the value of a firm's assets and thus the expected return on those assets, r_a, will be the same regardless of the nature of the claims against them. For an investor who holds all of a firm's debt and equity, we can write the expected return on the firm's assets as a value-weighted average of the expected return on the debt claims, r_d, and the expected return on the equity claims, r_e.

$$r_a = r_d \times D/(D+E) + r_e \times E/(D+E) \quad ,$$

where D is the market value of the firm's debt, and

E is the market value of the firm's equity.

Likewise, since covariances are additive, we can also write the beta of the firm's assets, β_a, as a value-weighted average of the betas of the debt and equity claims.

$$\beta_a = \beta_d \times D/(D+E) + \beta_e \times E/(D+E)$$

Rewriting each of these equations in terms of r_e and β_e respectively,

$$r_e = r_a + D/E \times (r_a - r_d), \text{ and}$$

$$\beta_e = \beta_e + D/E \times (\beta_a - \beta_d),$$

illustrates the implications of Modigliani and Miller's Proposition II, which states that the expected return on the firm's equity should increase as the debt to equity ratio increases. This increase in expected equity return with a rise in the proportion of debt in the firm's capital is compensating the equity investors for the rise in risk, β_e, caused by the increase in the debt to equity ratio. This increase in risk with increased debt in the capital structure is termed financial leverage.

4.2.2 Operating Leverage

Firms with a high proportion of fixed operating costs--costs which do not depend on the rate of output--are said to have high operating leverage. Operating leverage contributes to systematic risk in a manner exactly analogous to financial leverage.

To see the nature of this form of leverage it is useful to construct a simplified balance sheet for the firm as follows,

Assets	Liabilities
PV(Revenues)	Debt
- PV(Fixed operating costs)	Equity
- PV(Variable operating costs)	
Market Value	Market Value

On the liabilities side of the balance sheet are the debt and equity claims, the interaction of which was the source of financial leverage. On the assets side is the value of the firm (defined as the present value of future cash flows), the components of which are the present value of revenues minus fixed and variable operating costs.

As was done above for the liabilities side of the balance sheet, an expression can be written for the firm's asset risk, β_a, as a weighted-average of the risk associated with each cash flow component.

$$\beta_a = \beta_{rev} \times PV(\text{Revenues})/V \; - \; \beta_{foc} \times PV(\text{Fixed operating costs})/V$$
$$- \; \beta_{voc} \times PV(\text{Variable oper. costs}/V,$$

where V is the market value of the firm.

The cash flow component risks (i.e., the revenue risk, β_{rev}, and the fixed and valuable operating cost risk, β_{foc} and β_{voc}) are defined as the covariance of changes in the cash flow component with the return on the market, divided by the variance of the market return. Intuitively, they are measures of the cyclicality of the cash flow compenents.

The source of operating leverage can be seen most clearly from this formula by making the two simplifying assumptions that $\beta_{rev} = \beta_{voc}$ and $\beta_{foc} = 0$. That is, if the cyclicality of the firm's revenues corresponds to the cyclicality of its variable costs, and if its fixed costs are invariant (by definition), then the formula can be simplified as follows,

$$\beta_a = \beta_{rev} \, [1 + PV(\text{Fixed operating costs})/V] \quad .$$

The firm's asset risk will be proportional to the ratio of the present value of the firm's operating costs to the value of the firm.

Empirical tests of the operating leverage concept seem to confirm this result (Lev, 1974).[6] In the case of gas pipelines, we would expect those firms with high fixed operating costs, such as might be embodied in fixed labor contracts and maintentance requirements, to have more risky assets, all else equal.

4.2.3 Interfuel Competition (Field Price Policy)

In the framework above, the firm's asset risk is directly related to the cyclicality of its revenues and costs. Intuitively, this cyclicality should be related to the degree to which economy-influenced shifts in demand influence prices and quantities.

There are two ways in which these demand shifts would not be directly translated into movements in prices or quantities. They are both related to conditions of excess demand.[7] The first is if regulatory controls hold the price outside of the range necessary to clear the market (i.e., when price controls lead to excess demand conditions). By definition, prices will not vary, and chronic excess demand will insulate quantities sold from shifts in demand--any variance in demand is absorbed by the excess demand.

A second condition in which prices and quantities might be insulated from economy-induced shifts in demand would be a disequilibrium situation where non-systematic factors (e.g., technological change or resource discovery) induced rapid demand growth, while physical limitations exist on how fast this new demand could be served--a supply-induced condition of excess demand.

The first condition describes the gas industry under binding price controls. The second condition describes the industry growth period immediately prior to price controls where the new technology of long-distance pipelines gradually connected the low marginal cost Mid-continent production fields to the industrialized Northeast (see Chapter 3). Since both of these conditions are related to excess demand, they are thus related to the price of natural gas relative to its closest substitute. For lack of a better term we will describe this determinant of risk as interfuel competition.

4.2.4 Contractual Leverage

Finally, in tiered industries such as natural gas, the nature of the contracts between firms across the tiers can affect the covariance of revenues with the market and thus the systematic risk borne by investors in those firms. The total risk borne by all the investors in all the firms may not change, but the allocation of the risks among the firms may substantially depend on the flexibility of the price and quantity provisions in these contracts.[8]

To see how this form of leverage works and to relate it to the sources of risk just described, it is useful to add an element to the simplified balance sheet for a pipeline company, introduced above,[9] as follows:

Assets	Liabilities
PV(Revenues)	Debt
- PV(Fixed operating costs)	Equity
- PV(Variable operating costs)	PV(Net Contract Obligations)
Market Value	Market Value

On the asset side of the balance sheet, the market value of the firm is equal to the sum of the present value of the firm's cash flows. These are defined as the present value of the stream of future revenues minus operating costs. On the liabilities side, the value of the firm is equal to the market value of its long term debt plus its shareholders' equity, plus the present value of its net gas supply contract obligations. In this view, the long-term supply contract is like a fixed nominal liability (i.e., like debt). Producers are like bondholders in the sense that they hold a prior claim on the pipeline's future cash flows.

In reality, of course, these long-term contracts are not purely fixed claims (like debt), but they do have characteristics which make this analogy reasonable. Primary among these characteristics is the take-or-pay clause, previously described. Also important, however, are the fixed price provisions in these contracts. Fixed prices imply that all shifts in demand must be reflected in changes in quantity purchased and transported by the pipeline. Quantity changes are a problematic equilibrating mechanism for gas pipelines for two reasons. First, quantity changes may cause the pipeline to run up against the take-or-pay constraints in its contracts. Second, quantity changes affect the pipelines (and producers) average transportation (and production) costs. If volume drops with an economy-induced reduction in demand, the pipeline will attempt to pass the fluctuation in supply requirements onto producers. But due to the fixed costs associated with pipelining and geological constraints on production, the per unit costs associated with each activity will be very sensitive to any volume fluctuation. Thus, there is ultimately a connection between contractual leverage, as induced by the price-rigidity of long-term supply contracts, and operating leverage, described above. For if there were no fixed costs to pipeline or production activity, all market demand fluctuations could be costlessly transmitted through volume changes.

The reason these contract effects are referred to as net contract obligations in our simple balance sheet is that the pipelines face contract obligations at both ends of the pipeline. To this point we have mentioned only the effects of contracts at the producer end of the pipeline. Recall from the discussion of contractual arrangements in Chapter 2 that primary among the contract characteristics at the distribution end of the pipeline are the "minimum bill" and the fixed cost allocation procedures employed in the calculation of the two-part tariff (see Section 2.4.2).

Like a take-or-pay clause, the "minimum bill" translates the effects of economy-induced shifts in demand to the buyer (in this case the distribution company). Thus, the pipeline is being given a claim on distribution company assets just as it has given a claim on its assets to producing firms in the form of the take-or-pay under a fixed price. But here, unlike at the producer end of the pipeline, pipeline regulation offsets the minimum bill effect by allocating up to 75 percent of pipeline fixed costs to the commodity charge portion of the two-part tariff. Thus, pipeline cash flow, despite the minimum bill's tendency to offset its producer contract leverage, will again be sensitive to economy induced shifts in demand since the recovery of pipeline fixed costs will now depend critically on demand.

The net position of the pipeline with respect to contractual leverage thus depends on the relative sizes of its take-or-pay liabilities, its minimum bill claim, and the fixed cost exposure in the pipeline two-part tariff. Historical practice in the setting of the tariff requirements would lead one to conclude that the pipelines faced a net contractual liability.

In the next section the results of an empirical examination of changes in systematic risk from 1947 to 1982 are presented for a portfolio of six interstate pipeline companies. The results indicate that the changes in risk have been quite dramatic and that the historical control of field prices, followed by the post-NGPA partial decontrol are (through their effects on interfuel competition) the most convincing explanations of these risk changes.

4.3 Empirical Analysis of Field Price Regulation and Risk

To determine whether systematic risks in the gas pipeline industry have changed in the last thirty-five years and to examine the causes of these changes, a market value-weighted portfolio of six interstate pipelines was constructed.

The reasons for the choice of six companies and the use of the data in portfolio form are two. First, the pipeline industry is not homogeneous. Most pipeline companies are subsidiaries or divisions of large energy companies or holding companies. Since these non-pipeline business activities may differentially affect the firms' market values and risks, they could seriously distort the analysis by making pipeline-specific phenomena difficult to observe. To minimize the effects of extraneous business activities on the calculations, the pipeline companies chosen were those whose revenues from pipeline operations were at least 75 percent of total company operating revenues in 1981. Second, combining the companies in a portfolio further reduces the effects of these outside business activities by washing-out much of the company specific "noise" in the data, contributing to more precise econometric estimation. The six companies in the portfolio are:

American Natural Resources (Michigan-Wisconsin Pipe Line Co.)
Columbia Gas System (Columbia Gas Transmission Corp.)
Equitable Gas Co.
Mountain Fuel Supply Co.

Panhandle Eastern Co. (Panhandle Eastern Pipe Line and Trunkline)
Peoples Energy Corp. (Nat. Gas Pipeline Co. of America)

4.3.1 Changes in Pipeline Systematic Risk 1945 - 1982

Historical monthly security returns for each company in the portfolio, and the corresponding monthly return on the value-weighted New York Stock Exchange index, were obtained for the period 1945 to 1982 from the computer tapes of the Center for Research in Security Prices (CRSP) of the University of Chicago. The individual company data were combined into a value-weighted portfolio. These two return series r_p and r_m were then used to estimate the "market model",

$$r_{pt} = \alpha_p + \beta_p r_{mt} + \varepsilon_t .$$

A "centered" portfolio beta, $\hat{\beta}_p$, was estimated for each year in the period 1947 - 1980, using sixty months (or five years) of data. For example, the "centered" beta for 1980 was based on data from 1978 through 1982.[10] The result is a five-year moving average beta for the pipeline portfolio.

As in any empirical analysis, a set of tradeoffs between data and estimation techniques, in the context of the question one is asking, determines the best approach to the analysis. In this case two choices have been made. First, the length of the return period was chosen as monthly (as opposed to daily or weekly). Daily or weekly returns would provide substantially more observations over a shorter time period and thus the econometric requirement that the coefficients be stable over the estimation period would more likely hold. On the other hand, daily and weekly returns are less likely to meet the requirement that the joint distribution of r_{pt} and r_{mt} be bivariate normal for estimation of the market model (Fama, 1976, shows that these return distributions tend to have fat tails). Potentially more serious is the complication that over short intervals the non-trading of securities may introduce serious errors in variables problems in the market model, although there are estimation techniques to deal with this (Scholes and Williams, 1977). Finally, given the time period to be studied (35 years), the use of daily data starts to become intractable. Since we are primarily interested in long-term structural shifts in the market model slope coefficient, the use of monthly data seems appropriate and tractable.

Second, the length of the sample period was chosen to be sixty months. Here the tradeoff has to do with the precision of the coefficient estimates relative to the length of the period over which the coefficients will be stable. Sixty months (five years) is considered a reasonable period in this regard (Fama, 1976). If it appears desireable over certain periods to examine shorter intervals, some precision will be sacrificed for the purpose of analyzing the shorter interval.

Table 4.1 and Figure 4.1 report the results. It is immediately apparent from Figure 4.1 that systematic risks in the pipeline industry have undergone dramatic changes since World War II. Note from Table 4.1 that the standard errors associated with each of these estimates is quite small. Thus we can be very confident that the changes we have observed are not the product of mere statistical "noise".

To make these statements more precise, a statistical test of changes in the beta coefficient (or slope) of the market model was performed for five-year, non-overlapping intervals from 1948 to 1982.

Year	$\hat{\beta}_p$	S.E.	Year	$\hat{\beta}_p$	S.E.
1947	1.20	(.14)	1964	.64	(.09)
1948	1.19	(.12)	1965	.57	(.10)
1949	.96	(.11)	1966	.49	(.11)
1950	.97	(.10)	1967	.56	(.10)
1951	.83	(.12)	1968	.63	(.10)
1952	.74	(.11)	1969	.60	(.10)
1953	.59	(.09)	1970	.65	(.11)
1954	.52	(.08)	1971	.69	(.10)
1955	.44	(.08)	1972	.70	(.10)
1956	.49	(.10)	1973	.67	(.10)
1957	.46	(.11)	1974	.72	(.10)
1958	.60	(.12)	1975	.70	(.09)
1959	.68	(.13)	1976	.72	(.09)
1960	.74	(.11)	1977	.73	(.09)
1961	.71	(.11)	1978	.90	(.10)
1962	.71	(.11)	1979	.96	(.11)
1963	.64	(.10)	1980	.97	(.10)

Table 4.1

Five-year "Centered" Equity Betas
for Interstate Gas Pipeline Portfolio
(Standard Errors in parenthesis)

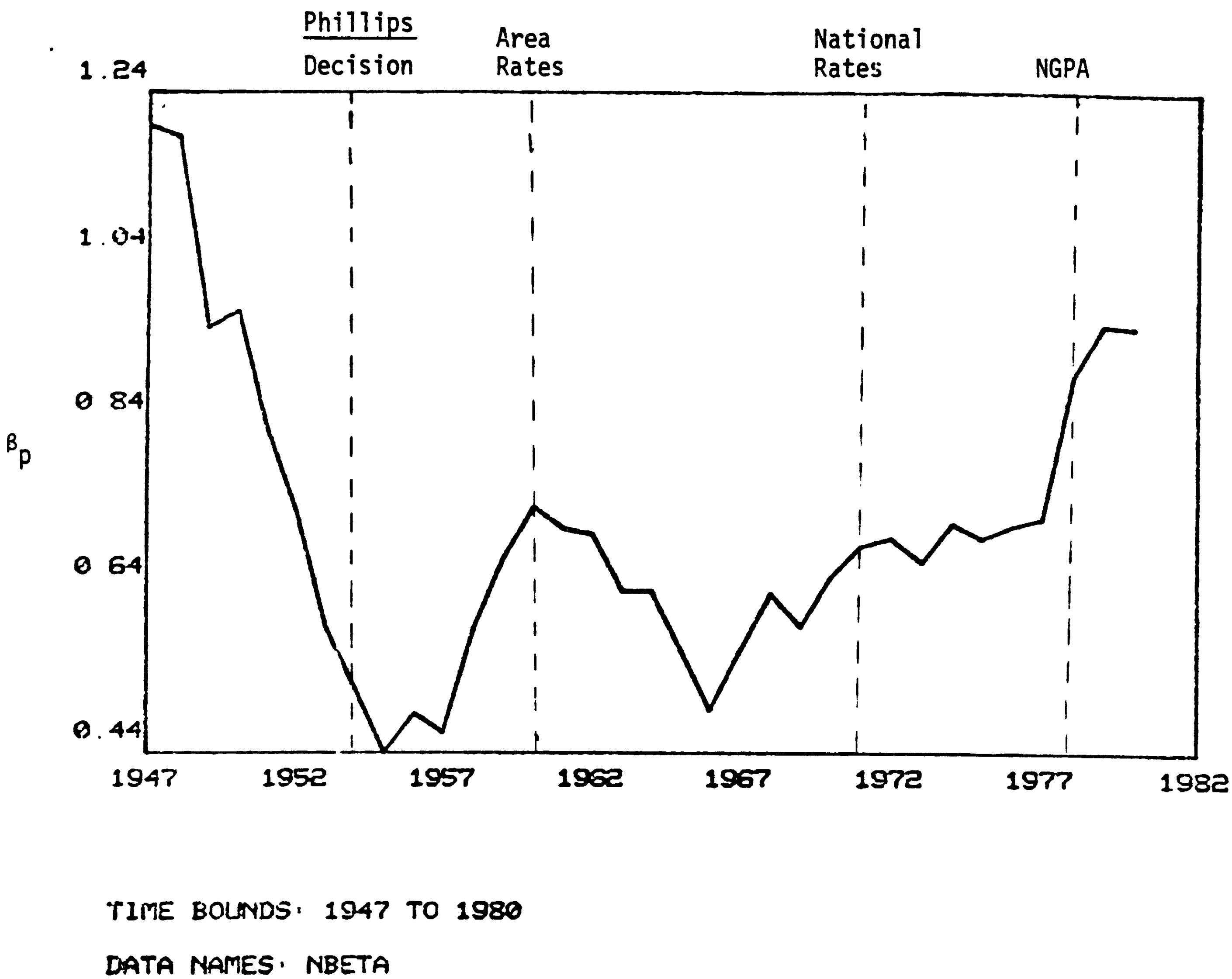


Figure 4.1

Five-year Centered Equity Betas
for Interstate Gas Pipeline Portfolio

The results are detailed in Table 4.2. Statistically significant changes in the beta coefficient occurred in every consecutive five-year interval except during the relatively stable decade from 1968 through 1977.

For reference purposes, Figure 4.1 also indicates the timing of certain critical events in natural gas regulatory policy: the Supreme Court decision in Phillips Petroleum vs. Wisconsin (1954) which established field price controls; the first Area Rate decision of the FPC in 1960, which set the procedures whereby field prices would be controlled; the so-called "National Rate" decision of the FPC in 1971, which moved the field price control process away from strict cost-based methods; and finally, the Natural Gas Policy Act (NGPA) of 1978, which initiated the process of field price decontrol.

We will return to Figure 4.1 when the various sources of risk are analyzed below. But because of the importance of the events in the 1976-1982 time period, and the structural change that occurred in the market model, it will be useful to examine the results in this period over shorter intervals. Table 4.3 reports the results of 36 and 24-month market model estimations over the period. Despite the increased estimation standard errors, the pattern observed in the 60-month estimation continues into the 1981-1982 time interval, with the shorter-period equity betas rising above 1.0 in 1980 and 1981.

The overall results indicate that systematic risk was historically lowest at about the time of the Phillips decision, $\hat{\beta}_p \cong .50$, and is currently at its highest level since then, $\hat{\beta}_p \cong 1.0$. To appreciate the significance of an approximate doubling in the portfolio equity beta since 1954, and indeed since 1966, we can make a rough calculation of the additional revenues which would be required to compensate investors for

Table 4.2

Tests for Structural Changes
in the Market Model, 1948-1982

Intervals		Coefficient	S.E.	T-Stat	Sig.Level
1948-1952	β	.95	.088	10.8	.001
1953-1957	$\Delta\beta$	-.49	.125	3.9	.001
1953-1957	β	.41	.101	4.1	.001
1958-1962	$\Delta\beta$	.35	.136	2.6	.001
1958-1962	β	.78	.096	8.2	.001
1963-1967	$\Delta\beta$	.29	.153	1.9	.05
1963-1967	β	.51	.130	3.9	.001
1968-1972	$\Delta\beta$	.17	.156	1.1	n.s.*
1968-1972	β	.65	.113	5.8	.001
1973-1977	$\Delta\beta$	.05	.145	.3	n.s.*
1973-1977	β	.70	.097	7.2	.001
1978-1982	$\Delta\beta$	.22	.141	1.6	.1

*not significant

Table 4.3

Changes in the Market Model
Coefficients for Gas Pipeline Portfolio
1976-1982

	60-month[1] Equity Beta		36-month Equity Beta		24-month[2] Equity Beta	
	$\hat{\beta}_p$	S.E.	$\hat{\beta}_p$	S.E.	$\hat{\beta}_p$	S.E.
1976	.72	(.09)	.69	(.14)	.67	(.17)
1977	.73	(.09)	.77	(.12)	.75	(.17)
1978	.90	(.10)	.77	(.12)	.77	(.14)
1979	.96	(.11)	.96	(.12)	.77	(.13)
1980	.97	(.10)	1.04	(.15)	1.01	(.17)
1981	---		1.05	(.15)	1.16	(.19)
1982	---		---		.90	(.19)

1. From Table 4.1.
2. Reported as start-of-year estimate.

this change, using the equilibrium asset pricing model described in Section 4.1.

Recall that under a set of not-unreasonable assumptions, in equilibrium, asset returns should be determined according to the relationship

$$r_p = r_f + \hat{\beta}_p(\overline{r_m - r_f}) \ .$$

Historically, the risk premium on the market $(\overline{r_m - r_f})$ has been approximately 8 percent.[11] This implies that a change in $\hat{\beta}_p$ of .5 would translate into a change in required pipeline portfolio returns of approximately 4 percentage points. To achieve a 4 percentage-point increase in pipeline rate of return in one year would have required in 1981 an increase in required revenues of approximately \$2.7 billion, based on the net book value of the assets (rate base) of the U.S. class A and B pipelines of \$45 billion in 1981.[12]

To reemphasize, this \$2.7 billion in additional revenue requirements would be just for the purpose of compensating investors in gas pipelines for bearing additional risk, and nothing more. In Chapter 5 the implications of this result for pipeline regulatory policy will be discussed in more depth. In the remainder of this section, the causes of the historical change in risk will be investigated.

4.3.2 Causes of Historical Changes in Systematic Risk

In Section 4.2 four underlying sources of systematic risk in the gas pipeline industry were postulated: financial leverage, operating leverage, interfuel competition and contractual leverage. In this section each of these sources will be examined to determine if they can explain the changes in systematic risk we have observed in the industry since the 1950's, and particularly the increase observed in the late 1970's.

a. Financial Leverage

An increase in equity risk could be explained by pipeline companies taking on added debt in their capital structure. To examine this hypothesis, a time series was constructed from 1958 to 1980, for the pipeline portfolio, of the market value of long-term debt as a percent of total market capitalization. The market value of the portfolio's debt is calculated as the capitalized value of the long-term debt book value plus the present value of the stream of interest payments on the debt.

$$\text{Market Value of Debt} = \text{Book value of Debt}/(1+k)^N + \sum_{i=1}^{N} \text{Interest on Long-Term Debt}_i/(1+k)^i \; .$$

The discount rate chosen, k, is the historical rate on Moody's AA-rated industrial bonds. An average maturity of 11 years is assumed for the outstanding debt (see fn. 8, Chapter 5).[13] This series was converted to a five-year moving average to conform to the portfolio beta time series and is depicted as the dashed line in Figure 4.2.

As the figure indicates, there has been some increase over the period in pipeline financial leverage. But during the critical transition period of the late 1970's, when the secular increase in equity risk was the most dramatic, financial leverage was falling.

The net effect of financial leverage can be computed by "unlevering" the equity beta time series using the relationship between equity and asset betas described above. That is,

$$\beta_a = \beta_d \times D/(D+E) + \beta_e \times E/(D+E) \; .$$

Under the assumption that $\beta_d = 0$,[14] the first term drops out. Note,

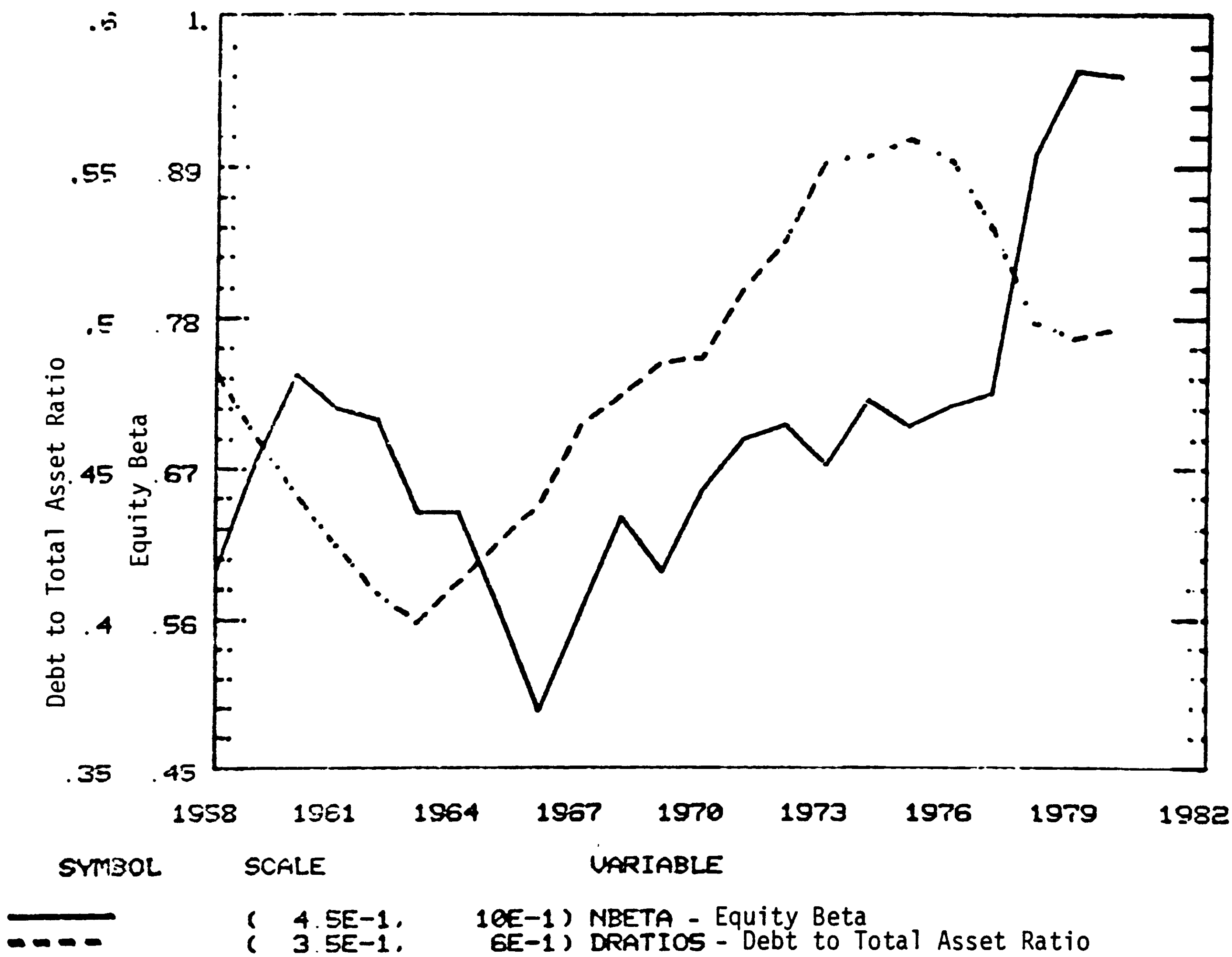


Figure 4.2

Equity Betas and Financial Leverage
of Interstate Gas Pipeline Portfolio

again, that tax effects are excluded because regulation treats taxes as an expense that is passed through directly to the ratepayers.

Figure 4.3 depicts the asset beta time series for the 1958 to 1980 time period. Note again the dramatic rise in risk experienced by pipeline industry investors in the late 1970's and early 1980's.

b. Operating Leverage

The observed increase in pipeline systematic risk could perhaps be explained by an increase in the present value of pipeline fixed costs relative to total pipeline cash operating costs.

To examine this hypothesis a proxy variable for operating leverage was chosen. As discussed above, the fixed costs of interest here are not those that are sunk in pipeline capacity, but are instead those cash operating costs of the firm which do not vary with output. The variable was constructed by subtracting from total pipeline operation and maintenance costs (these include purchased gas, transmission operation and maintenance, storage and overhead costs) those that vary with output. The variable costs were judged to include purchased gas and production-related expenses, transmission operation (mostly the cost of compressor gas) and storage operating costs. The remaining fixed costs (mostly labor, maintenance and administrative costs) are divided by total O and M costs to complete the proxy for operating leverage.[15]

This time series from 1945 to 1981 was also converted to a five-year moving average to correspond to the beta time series and is plotted in Figure 4.4. As indicated, there has been a steady decrease in this measure over the period, as might be expected with the general rise in purchased gas prices. Again, in the latter part of the period, operating leverage does not appear to explain the observed secular increase in risk.

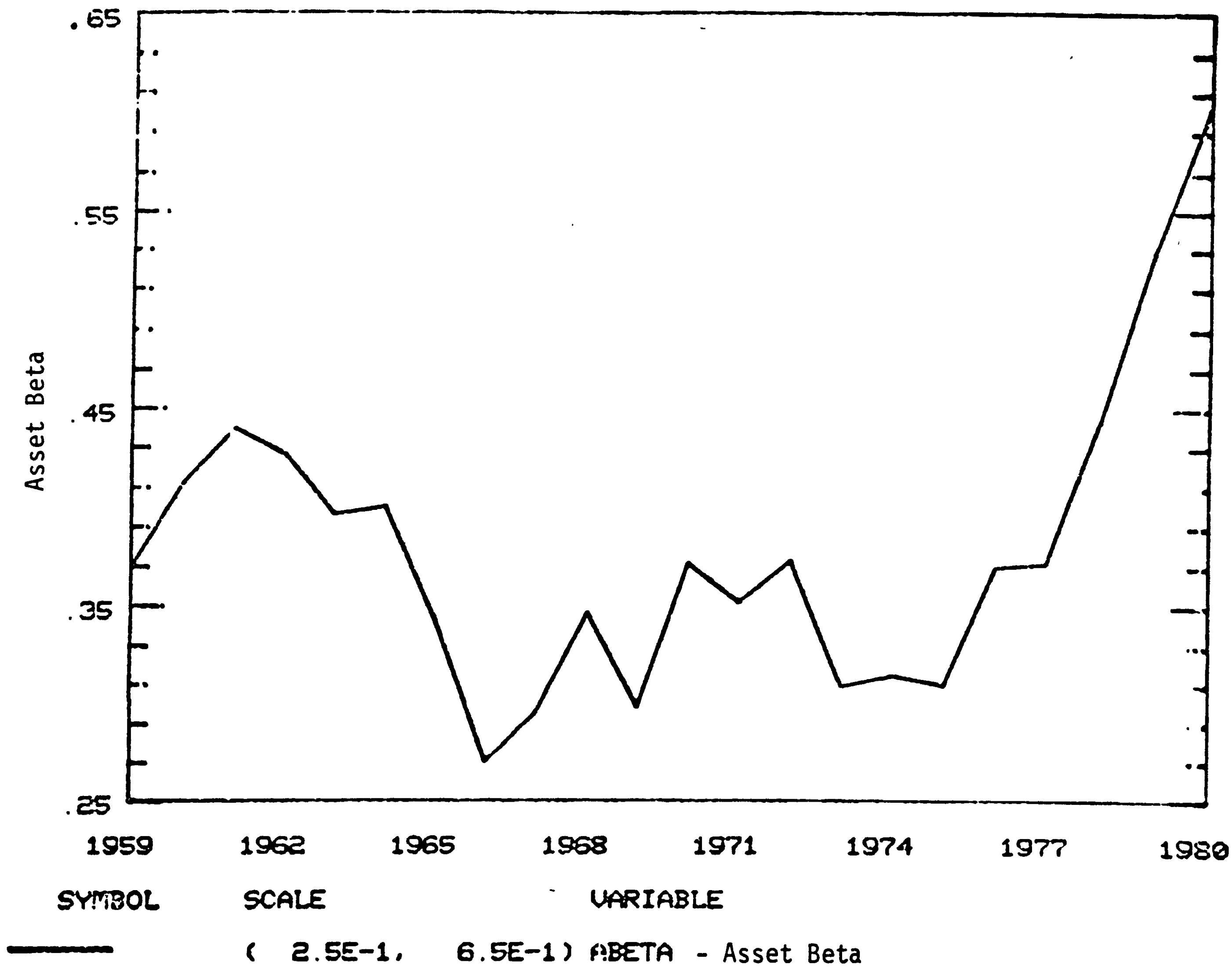
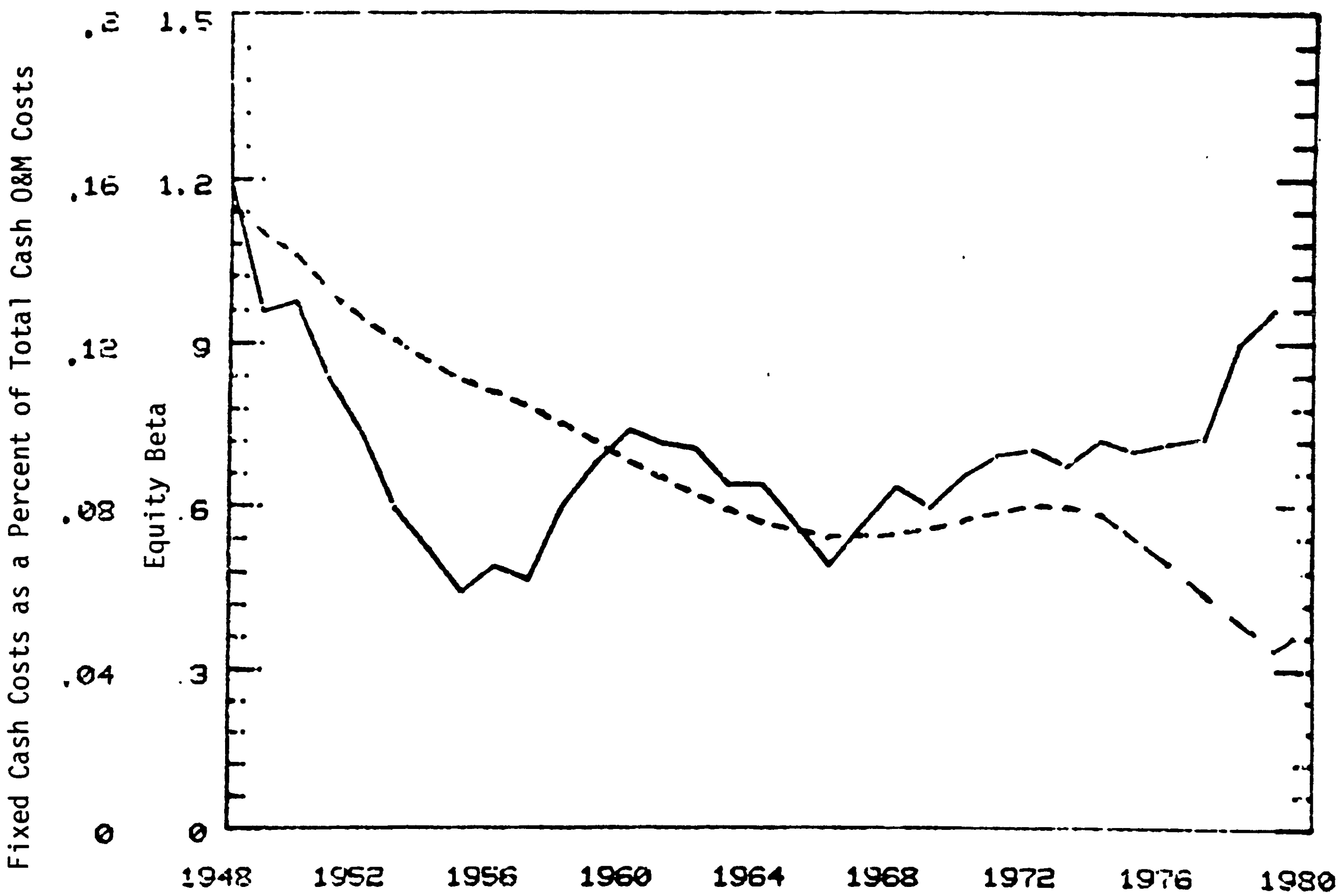


Figure 4.3

Asset Betas for Interstate
Pipeline Portfolio



SYMBOL	SCALE	VARIABLE
solid line	(0. 1.5)	NBETA - Equity Beta
dashed line	(0E-1. 2E-1)	OPLEVS - Operating Leverage

Figure 4.4

Equity Betas and Operating Leverage
of Interstate Gas Pipelines

It may explain part of the decrease experienced in the 1950's and early 1960's. This will be examined statistically below.

c. Interfuel Competition, Field Price Policy

In the conceptual discussion above of this source of risk, two market conditions were suggested which might insulate gas prices and quantities from economy-induced variations in demand--thus reducing systematic risk. Both conditions are related to excess demand conditions and thus the price of gas relative to its competitors. The first condition is binding price controls. The second is demand growth due to technological change and low-cost resource discovery coupled with physical limitations on how fast the new demand can be served.

This second condition may account for the large decrease in risk experienced by the pipeline portfolio in the late-1940's (see Figure 4.1). A statistical characterization of this effect may not be possible, but the conceptual argument is as follows.

Recall from Chapter 3 that during World War II growth in the gas pipeline industry was essentially halted. Without growth in demand, and absent field price controls, gas prices and quantities were free to vary with economic conditions. At the conclusion of the War, and during the subsequent gas market boom (see Section 3.2), it is possible that demand growth outstripped the ability of the pipeline industry to expand by hooking-up the low-cost Mid-continent fields. If so, this excess demand could have led to the insulation of gas prices and quantities sold from the same variations experienced by the prices and quantities of gas's competitor fuels. This might account for a dramatic decrease in systematic risk even before field price controls became "binding" in the early 1960's.

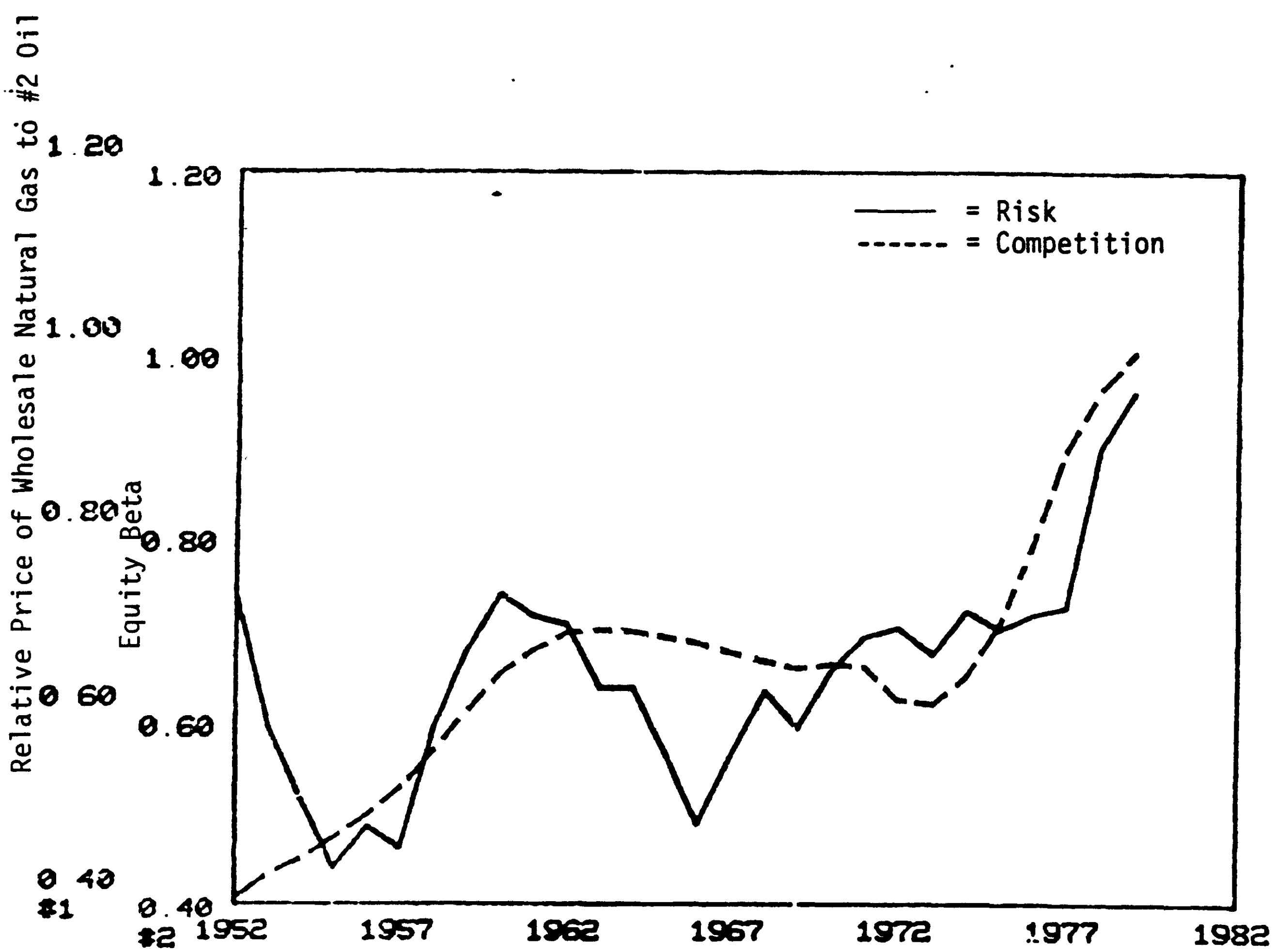
The effect of field price controls on risk can be described statistically. For the period after the late 1950's a variable which reflects the price of natural gas relative to that of its main competitor, oil, should be a good proxy for the strictness of field price controls (i.e., the more binding were the controls, the lower the gas-oil relative price should be).

The variable created was an index, defined as the ratio of the average cost of gas as sold to the ultimate customer to the number two fuel oil wholesale price (see Figure 3.2).[16] These data from 1950 to 1981 were also converted into a five-year moving average. The ratio is depicted by the dashed line in Figure 4.5.

It is immediately obvious from Figure 4.5 that there is a close association between the gas-oil relative price index and pipeline systematic risk as measured by beta, but how close? To provide an indication of this relationship, a multiple regression was run of the measure of risk versus the identified sources of risk. A generalized least squares technique for first-order autocorrelation was used to control for the autocorrelation induced by the averaging process intrinsic to the construction of the data. The test encompasses the period 1958 to 1979 and employs the asset beta (unlevered to account for financial leverage) as the dependent variable. The results are (standard errors in parenthesis):

$$\text{ASSET BETA} = \underset{(.32)}{-.83} + \underset{(2.18)}{6.55} * \text{OP LEVERAGE} + \underset{(.23)}{.95} * \text{GAS-OIL INDEX}$$

$\bar{R}^2 = .52$ Rho = .289 (.199)



TIME BOUNDS: 1952 TO 1979

DATA NAMES: NBETA GORATIO5

Figure 4.5

Equity Betas and Interfuel Competition
of Interstate Gas Pipelines

Both operating leverage and the competition (gas-oil index) sources of risk are significant positive contributors to the variation in asset betas over the period, accounting together for 52 percent of the variation in risk. The fact that operating leverage enters the equation positively means that when this source of risk is taken into account, the underlying secular increase in asset risk in the 1970's and 80's is even more dramatic. Incrementally, competition/field price policy explains 40 percent of the total variation in risk over the period.

While these measures explain a large part of the risk variation experienced by the pipeline investors, they do not explain all of the variation. Are there other possible explanations which we have not considered?

Related to the interfuel relationship of gas with a oil are recent changes in the structural characteristics of the energy/oil market itself (see Section 3.4.3) and its relationship with the economy as a whole. Two factors here interact. First, the value share of oil in total economic activity has increased since the first oil price shock in 1973-74. For example, the cost share of energy in total factor inputs to U.S. manufacturing has more than doubled from about 4 percent in the early 1970's to approximately 11 percent in the 1980's.[17] This share is still relatively small, however, to dominate the total market. Perhaps more important is the effect that the increase in energy (oil) prices has had on the market value of capital assets in place. Berndt and Wood (1984) estimate that as much as 18 percent of the value of U.S. capital stock (equipment and structures) has been eliminated by the energy price increases of the 1970's. If the importance of the energy/oil market on economic activity is measured roughly by the ratio of energy's share in total factor costs to the value of assets in place, then the increase in the share of energy in costs (the numerator), and the induced devaluation of assets in place (the denominator) would imply that energy now plays a greater role in economic performance and returns on the market as a whole may now be more sensitive to energy price fluctuations. Thus, any energy-based security's return will likely have a greater covariance with the market, due purely to the increased influence of energy on economic activity.

d. Contractual Leverage

One source of risk introduced above has not yet been discussed in this section. Could changes in contractual leverage be responsible for the variation in risk borne by gas pipeline industry investors?

We saw in Chapter 2 that contracts with rigid price and quantity terms have been the primary transactional arrangement in the industry since the 1938 Natural Gas Act. While there was some limited anecdotal evidence of increased contractual flexibility since 1978 (see Section 2.3.1), this flexibility would work against the observed recent increase in pipeline asset systematic risk.

On the other hand, contractual leverage may be the reason why <u>pipeline</u> industry investors are bearing the increased risk induced by the factors above.

Because of the paucity of data on the terms of pipeline-producer contracts, it is currently impossible to measure the extent of this leverage. Future research into the relative risk borne by investors in the other gas industry segments, relative to the rigidity of the terms of producer-pipeline contracts and pipeline-distributor tariffs might be productive. For this and other reasons the collection of data on gas industry contract terms by company and contract vintage would be useful for regulatory and public policy purposes.

To summarize, the evidence to this point has indicated that gas pipeline industry investors have experienced dramatic secular changes in the risk they bear. We have explored the potential sources of these risk changes and have found that they are closely related to the relationship of the price of gas to the price of its competitor fuel. This provides some indication that field price decontrol, to the extent that it has eliminated excess demand, is responsible for the large secular increase in risk in the 1970's and 1980's. It has been suggested that pipeline company investors have been bearing this increased risk due to contractual leverage.

It is now logical to return to the question of whether the industry transition, now understood in risk terms, has affected the profitability of the regulated gas pipelines.

4.3.3 Gas Pipeline Profitability: Accounting for Risk

Previously (in Section 3.4.4) it was asserted that the popular method of comparing single-year pipeline rates of return on book equity with other industries' ROE is inherently misleading. We are now in a position to discuss why this is so.

First, we now know that return on equity comparisons between firms and industries with different levels of debt in their capital structures are misleading. We know from the financial leverage concept that shareholders will require higher rates of return to compensate them for the added risk imposed by the prior claims of bondholders on the firms' assets. Gas pipelines, and most regulated firms, have high debt to total asset ratios. In 1981 this ratio was approximately .50 for the pipelines and .30 for average non-financial corporations in the U.S. Thus, one would expect pipeline ROE to be high relative to the ROE of an "average" U.S. industry. To avoid this problem, the appropriate measure to use is not return on equity, but return on total assets.

Second, even if differences in capital structure are accounted for, differences in underlying systematic risk between industries must be accounted for in cross-industry comparisons, particularly when considering only a single year's performance. For example, in Table 3.11 of Section 3.4.4 we see that firms with relatively low asset risks (such as gas pipelines, electric utilities, financial and service industries) had relatively high rates of return in 1982, while the high risk industries (such as the airlines, steel, housing, etc.), had very low rates of return. The reason for this is quite obvious, if one picks a recession year, like 1982, stable industries will do well <u>relative to the average</u>, while risky industries do poorly. If one picked a growth year, the result would probably be just the opposite. Of course neither comparison would tell us how well any particular industry was doing relative to what its investors <u>required</u> (i.e. its cost of capital). For this we need a different sort of analysis, as will be developed in the next chapter.

Footnotes (for Chapter 4)

1. The expected return on a stock is equal to the sum of the expected dividends and capital gains divided by the current stock price.

2. Note that in this derivation, β_i is _a_ reasonable measure of risk in the absence of any theory of asset pricing. The famous Capital Asset Pricing Model (CAPM) asserts that β_i is _the_ measure of risk. (See Sharpe (1964), Lintner (1965))

3. See Merton (1980) for difficulties in the observation of r_m. The term r_f would be closely approximated by the return on U.S. Treasury Bills.

4. See for example, R. Roll, "A Critique of the Asset Pricing Theory Tests; Part I: On Past and Potential Testability of the Theory." _Journal of Financial Economics_, 4: March 1977, pp. 129-176.

5. A world of no taxes is assumed throughout this study not because taxes are not a feature of the gas pipeline industry, but because taxes are treated as a simple expense by the pipeline regulatory process and are directly passed through to ratepayers. Thus, in this regulated world, the best assumption is that there are no significant advantages to tax shields and the like to affect our calculations of risk and return as in traditional capital budgeting analyses.

6. For further discussion of so-called "cash-flow" betas and their relation to asset betas, see Brealey and Myers (1981), Foster (1978) and Carpenter (1982). The Lev (1974) study of operating leverage is flawed because he includes depreciation as a fixed cost.

7. Stewart Myers suggests another possible model that is unrelated to any excess demand conditions, which could explain why regulated firms tend to be less risky than unregulated firms. Loosely, the idea is that under uncertainty regulatory lag (or simply the setting of allowed rates of return _ex ante_) may allow firms with (assumed) market power to restrict output and raise price, and thus not be restricted to competitive returns _ex post_.

   An interesting feature of this model is that under certain demand and cost conditions the firm in this world will be less risky, in that profits will tend to be greater (more monopolistic) in poorer economic states of nature (see Myers, 1973 for more detail).

   This model may then explain why gas pipelines and other regulated firms are less risky than unregulated firms even after the current industry transition. But since there is no evidence that there has been dramatic change historically in regulatory lag or regulatory procedures toward the pipelines, it is thus unlikely that this model would be useful in explaining the substantial changes in risk which we observe in this industry.

8. For more discussion of the literature on vertical market arrangements and risk, see Carpenter (1982) and Broadman, et. al., (1982, 1983).

9. My thanks to Stewart Myers for this suggestion.

10. The "centering" of beta around five years of data is of no particular significance in this part of the analysis, since we will be examining structural shifts in the market model over five-year, non-overlapping periods. But it will have certain behavioral implications in Chapter 5 when these coefficients are used in the context of the CAPM.

11. See Ibbotson and Sinquefield (1982) and Merton (1980).

12. U.S. Department of Energy, Energy Information Administration, Statistics of Interstate Gas Pipeline Companies - 1981, DOE/EIA-0145(81), October 1982.

13. Data sources for this computation are the Compustat tapes and Ibid., various volumes 1956-1981). Due to data limitations it is not possible to compute the market value of long-term debt for this portfolio prior to 1958.

14. A gas pipeline's debt is not necessarily perfectly riskless, as the assumption of a zero debt beta would imply. But a regulated firm's risk of default is probably lower than that of an unregulated firm and it is unlikely that the debt beta would change significantly through time. For our purposes the assumption of a zero debt beta is not significant.

15. The data source for this measure is U.S. DOE/EIA, op. cit., various issues 1945-1981, which is a compilation of annual gas pipeline financial information from the FPC/FERC Form 2.

16. American Gas Association, Gas Facts, various issues 1955-1981, Arlington, VA. Bureau of Labor Statistics, Retail Prices and Indexes of Fuels and Utilities.

17. Ernst Berndt, personal conversation.

5. FERC REGULATION AND RISK

Beyond providing an alternative description of the current gas industry transition, is there additional insight gained by the examination of the risk characteristics of the industry? First, we have already hinted at the need for risk information in order to judge the profitability of the industry. But in addition, because of the close connection between risk and the procedures employed by the FERC in its rate regulation duties, risk is a critical factor in the judgement of the effectiveness of these procedures. This chapter provides an empirical examination of both of these issues. We begin by describing the economic/legal connection between risk and rate of return regulatory procedures.

In describing in Chapter 2 the complex mechanics of natural gas pipeline regulation as conducted by the FERC, no mention was made of the logic by which the results of these rate-making procedures could be deemed "just and reasonable" under the Natural Gas Act. Since the Supreme Court review in Federal Power Commission, et.al. v. Hope Natural Gas[1] of 1944, this logic has been embodied in two related standards. The court held that[2]

> ...the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The first standard of "comparable earnings" and the second of "capital attraction" are, of course, closely linked. A firm whose investors are not adequately compensated for the risks they bear will suffer a decline in the capital market's valuation of its assets.

Two points are worth noting about these standards in connection with the finance theory outlined at the beginning of Chapter 4. First, from an efficiency viewpoint, the emphasis was correctly placed by the Court on the interests of the equity owners of the firm. This emphasis is consistent with the objectives of shareholder wealth maximization (albeit a constrained maximization in the case of a regulated firm). And second, these standards explicitly recognized an investor risk-return tradeoff, although at the time of the Hope decision no usable theory of the risk-return tradeoff had been developed. Not surprisingly, in the absence of a usable theory, the Court refused to review or sanction any particular method of implementing these standards (despite the strong dissent on this point by Justice Frankfurter in the Hope case.[3]) As the majority ruled, "under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling."[4]

In the spirit of Justice Frankfurter's dissent, that the methodology employed by the FERC may significantly affect the result achieved,[5] this chapter examines the behavior of the FERC in its rate regulation role. Because of the non-stationarity of systematic risk in the gas pipeline industry observed in Chapter 4, the particular focus here will be on how the procedures for determining the allowed rate of return on a pipeline's rate base adequately take into account non-stationary risk.

The allowed rate of return is not, of course, the only factor in a rate decision which may determine the ultimate compensation of a pipeline investor for bearing risk. But it is arguably the most important factor, and its importance is reflected in the fact that it is typically the most contested issue in a pipeline rate proceeding.[6] Other relevant factors include the determination of the "test-year" volume, the calculation of the rate base itself, and the allocation of fixed and variable costs in the pipeline tariff. We will return to these potentially important factors later.

This chapter is organized as follows. First, the efficiency consequences of a risk-return mismatch will be discussed. Why should we be concerned with whether FERC rate-of-return procedures adequately compensate pipeline investors for bearing risk? Second, the literature on economic regulation will be examined to determine whether there is an "ideal" model of rate of return regulation for a world where risk is non-stationary through time. This will help us determine an appropriate benchmark to use in the next section where the FERC procedures will be examined empirically. This examination will use a simulation model which compares the results of alternative rate of return methodologies with the benchmark and with the actual results of FERC procedures from 1960 through 1982. The gas pipeline portfolio employed in Chapter 4 will again be used in this analysis. The results will show that none of the practical approaches to rate of return determination takes into account non-stationary risk, although some methods are better than others. Furthermore, the results of actual FERC behavior during the period of risk instability are only slightly better than the results produced by the worst of the alternative methods. The chapter will close with a discussion of some possible procedural remedies for the problem.

5.1 Social Costs of a Risk-Return Mismatch

Why should we be concerned with whether the rate of return allowed on a pipeline's rate base is appropriate to the risks its investors are bearing?

There are two economic efficiency[7] consequences of the over- or under-estimation of a pipeline's required return. The first relates to the pricing of gas to the ultimate customer and its effect on his consumption/investment decisions. And the second involves the effects on the investment decisions of the pipeline itself.

5.1.1 Inefficient Pricing at End Use

Because the allowed rate of return is one of the major determinants of pipeline required revenues, it is also central to the determination of the ultimate delivered price to end users. Misestimation of this return can thus contribute to a deviation of price from marginal cost (or from the second-best Ramsey price criteria for a declining-cost industry).

This is not to imply that a risk-return error is the only source of deviation from efficient prices in this industry. Indeed, in the present circumstances rate of return error is probably not as severe as the distortions caused by "roll-in pricing" or industrial rate cross-subsidization of residential rates. But these other sources of inefficiency are arguably the products of field price controls. After decontrol the "roll-in" pricing phenonenon will be much attenuated and it will be much more difficult for state regulators to maintain the cross-subsidization of residential rates.

It should also be noted that, even if there were no risk-return mismatch, the mere fact that in a regulated industry prices are set ex ante means that there will be ex post deviations from the prices which "should" have been set. In other words, there is no market "auctioneer" who acts to simultaneously set prices as demand uncertainties are resolved. Thus when reference is made to pricing distortions due to risk-return error, it is clear that we are not talking about distortions from a first-best pricing world. Finally, note that this ex ante - ex post pricing distinction, coupled with regulatory lag, can act to magnify the distorting effect of a risk-return mismatch from rate case to rate case. That is, suppose the required return is over-estimated and prices ex ante are set too high. Because unit prices are fixed in a given rate period (in this case too high), when demand uncertainty is resolved volume will be lower than expected, and in the next rate period prices will rise further due to the now underestimated test-year volume -- exacerbating the pricing distortion.

To the extent, then, that return misestimation contributes to inefficient pricing, this leads to a distortion in gas consumption decisions in the short run and to over or under-investment in gas-using appliances and industrial processes in the long-run.

5.1.2 Inefficient Pipeline Investment Decisions

The second form of inefficiency due to a misestimation of the investors' required return concerns its effect on pipeline investment decisions. If, say, an under-estimation of the required return by the regulatory authority is expected to lead to a marginally lower rate of return, then pipeline managers acting in their stockholders' interest will not undertake investment projects which would normally be marginally profitable at their opportunity cost of capital (positive net present value projects). In other words, for a given level of risk, investment projects in unregulated lines of business that are expected to earn their required return (or simply dividend payments) will be preferred to the pipeline investment project expected to earn the under-estimated regulated return.

Perhaps more importantly, the under-estimation of the return on capital creates incentives for the underutilization of capital relative to other factors of production (such as labor) -- in this case the reverse of an effect identified in a static framework by Averch and Johnson ("AJ", 1962, see Section 5.2.2).

An argument parallel to the above for over-investment and over-employment of capital relative to other factors can be constructed for the case of an over-estimated required return. If these misestimation errors are expected to persist, entry into the industry may also be affected.

5.2 Is there an "Ideal" Model of Rate of Return Regulation?

5.2.1 Literature

There are three basic strands in the literature on regulation. The first attempts to answer the question of why we get regulation in particular industries. (Stigler, 1971; Posner, 1974; and Peltzman, 1976 are the prime examples of the "Chicago" school of thought in this literature). As we saw in Section 3.1.3, this strand helps explain why gas pipelines were originally regulated[8], but it is not particularly relevant to the question of the effects or effectiveness of various forms of regulation.

The second strand, where by far the majority of the work has been done, concerns the effects of rate of return regulation on firm behavior, particularly on the choice of factor inputs and production technology. This has been investigated under a variety of settings and assumptions. The seminal work, in a static framework under certainty, is by Averch and Johnson ("AJ", 1962). Subsequent articles to AJ are surveyed by Baumol and Klevorick (1970) and Bailey (1973). In the basic AJ model the firm is assumed to be constrained to earn some fair rate of return on its capital stock that is greater than its cost of capital but less than the unconstrained monopoly return. The fundamental result is that such a firm will employ excess amounts of capital relative to other factor inputs and thus produce output at greater than minimum cost all along its expansion path. Das (1980) and others have extended the AJ model and its basic results to a world of uncertainty, where the firm is characterized as maximizing expected utility. This characterization of the firm is, of course, unsatisfactory when ownership and management are separated and there are efficiently functioning capital markets. Klevorick (1973), while not incorporating a world of uncertainty, extends the AJ approach to a dynamic setting, where the firm anticipates regulatory decisions made at stochastic intervals under a known rule.

The AJ literature and its variants have come under substantial criticism for failing to come to grips with how regulators actually behave and how firms function in a world of uncertainty with efficiently functioning capital markets. Three problems are particularly serious. First, regulators do more than merely set an allowed rate of return. Their objective ultimately is to set prices, where the allowed rate of return is only one factor. Second, regulatory decisions are not exogenous to the model. The *ex post* results (e.g., profits and prices) determine to a great extent regulatory actions. And finally, there are substantial lags in capital investment, and investment decisions are scrutinized by the regulators. These investment decisions in a world of uncertainty will depend on the firm's expectations of regulatory actions (i.e., it is not exactly clear how the AJ effect manifests itself in the reality of capital investment under uncertainty and regulation).

In connection with the behavioral criticism of the AJ literature, Joskow (1973, 1974) has constructed a model of the behavior of regulated firms in seeking price increases from state regulatory authorities or in "volunteering" price decreases.

Joskow observed that regulation is not a continuous process, but takes place in the context of periodic regulatory hearings. Price adjustments cannot be made by the firm indepedent of regulatory approval, and therefore the seeking of price increases or the "volunteering" of price decreases are the firm decisions of interest. He postulated that regulated firms trade off the desirability of frequent price increases when costs are rising against the costs of the hearing and the probability that prices might actually be decreased by the regulators after a complete examination of the facts. When costs are falling, firms will not wait to initiate hearings, but may "voluntarily" decrease prices to avoid forced regulatory review, which might decrease prices further. These decisions, to seek price increases or to volunteer price decreases, are made by the firms, he postulated, only when the threshold values of certain financial indicators are reached.

Joskow's empirical results give some significant support to the behavioral model, and (because of the behavioral asymmetry between price increases and decreases) cast some light on why electric utilities may have been earning more than their costs of capital in the 1960's.

The third strand of the literature has moved away from the AJ preoccupation with the effect of rate-of-return regulation on firm input and production choices, and from the behavioral model as well. Instead, it focuses on the two-way causality between regulation and the valuation of the firm and investor risk. Out of this literature comes a normative notion of "optimal" regulation. Myers (1973), with a one-period model in the "time-state-preference" framework for the analysis of firm behavior under uncertainty, shows that only under very special demand and cost conditions and under strict behavioral assumptions can a rate-of-return constraint force a monopolist to make competitive investment and output decisions. Marshall et al., (1981) and Robichek (1978) recognize the fundamental endogeneity of risk in the interaction of firms and regulators. "To require that the rates be set after giving due consideration to 'risk' is circular when such 'risk' is determined to a large extent by the rate-making process."[9] Myers (1972a), and the last two authors mentioned, advocate the use of the Capital Asset Pricing Model (CAPM) to determine the appropriate risk-adjusted rate-of-return for a regulated firm, recognizing that the estimation problems inherent in this approach are significant (Breen, 1972; Myers, 1972b).

In recent work, Brennan and Schwartz (1982) develop a dynamic model of the valuation of a regulated firm under uncertainty. They define a "consistent" regulatory policy as a procedure which sets the allowed rate of return such that, when anticipated by investors, it causes "the market value of the regulated firm to be equal to the value of the rate base"[10] at the time of the procedural hearing. Their model which meets this criterion has the important features that risk is appropriately endogenized and investor expectations of regulatory policy are correctly taken into account by the regulatory authorities. An intertemporal version of the CAPM is consistent with their "consistent" procedure, but "there can be no assurance, and indeed it would be only by coincidence, that the beta coefficient estimated from the non-stationary time series of equity returns would yield a cost of equity capital close to the appropriate allowed rate of return under the consistent regulatory policy."[11] Unfortunately, Brennan and Schwartz offer no superior practical alternative means of implementing "consistent" regulation.

As mentioned, this important strand of the literature is normative in nature. The consequences of a regulatory policy which deviates from the optimal are explored, but no one has yet determined how far away the current rate-of-return regulatory approach is from the ideal. As Myers (1973) argues, this work does not constitute "a plea for tossing rate-of-return regulation in the ash can right away. First, there is no evidently superior alternative. Second, we lack an empirical assessment of the extent of departure from the competitive solution. Third, rate-of-return regulation can at least provide equitable treatment of consumers and utility investors."[12]

5.2.2 Evaluation

In terms of the question which headed this section, the modern literature appears not to provide us with an "ideal", usable model of rate of return regulation. While recognizing that the CAPM is probably an incomplete model, the literature does, however, indicate that a near-consensus exists for the use of the CAPM as the standard for rate of return determination, with two major reservations.

(1) Risk-Endogeneity

It is quite rightly emphasized that risk may be influenced by the regulatory decision itself. Thus, the use of the individual firm's security returns to estimate risk could lead to a "fatal circularity." This leads the near-consensus to advocate the use of a "risk-class" approach to rate of return estimation. Robichek (1978) suggests that a portfolio of unregulated firms of equivalent risk be used. The crucial question of how one identifies equivalent risk in practice remains unanswered. Certainly a portfolio measure of risk is called for, but there is a trade-off between the danger of circularity and the danger of constructing a portfolio composed of an inappropriate risk-class of firms.

In the empirical analysis which follows, the risk-classification of the portfolio is deemed more important than the potential circularity, and thus a portfolio of regulated pipelines is employed. Chapter 4 provides a partial justification for this position in the sense that the non-stationarity in risk that is of concern in this study is due to factors such as field price controls and the volatility of world oil prices which are exogenous to pipeline regulation. Moreover, there is no indication that significant changes in the FERC approach to pipeline regulation itself has occurred over this period.

(2) Risk Non-Stationarity

The literature also emphasizes the operational limitations of the CAPM when risks are non-stationary, but does not indicate how potentially serious this problem may be or how it interacts with other methods of rate of return determination. These empirical qustions are among the motivations for the analysis which follows.

Finally, by no stretch of the imagination is the current approach to rate of return determination close to the near-consensus CAPM. Book (as opposed to market) measures of comparable earnings are still employed in gas pipeline rate of return determination by the FERC staff. In light of this, the following analysis also calculates how far away the current practice is from the near-consensus.

5.3 An Evaluation of Current Approaches to Gas Pipeline Rate of Return Determination

It is impossible to describe the current FERC approach to pipeline rate of return determination as the implementation of any one particular methodology. This is because allowed rates of return are determined in the context of an adversarial proceeding wherein rates are decided after a presentation of evidence. This evidence usually includes required rate of return (or "cost of capital")[13] calculations employing a variety of methods. In fact, there are usually as many (or more) methods employed as there are witnesses sponsoring rate of return testimony.

The current approach can be evaluated in two ways, however. First, the results of these procedures, in terms of the returns actually earned by the pipelines, can be compared with the capital market's valuation of the firms and with the results which would have been obtained through the pure application of a spectrum of representative methods. Second, the FERC's rationale for selecting particular methods, as delineated in a recent important rate case involving the Consolidated Gas Supply Corporation (FERC RP81-80-000), can be evaluated. Both of these approaches are employed in this section, the first through the implementation of a simulation model.

The simulation model employed is a deterministic financial model. It is designed to perform required rate of return calculations (using the measured betas from Chapter 4), and to compare these results with alternative methodological approaches, and the actual earned return experience of the sample. Company-specific financial data is the raw input to the model and a portfolio is constructed for use in all parts of the analysis.

5.3.1 Alternative Approaches

To simplify the discussion, the plethora of rate of return methodologies will be condensed to four representative types. They are applied within the Weighted Average Cost of Capital (WACC) framework. The WACC computes the firm's required return as:

$$r^* = r_d*D/(D+E) + r_e*E/(D+E)$$

Where r_d = the firm's cost of debt,

r_e = the firm's cost of equity,

D = the value of the firm's long-term debt,

E = the value of the firm's equity.

The firm's cost of capital is a weighted average of its cost of equity and cost of debt. The distinction between each of the methods below has to do essentially with whether book or market values of debt and equity are employed and the method used to compute the cost of equity. The first two methods discussed are book value oriented.

(1) Historical Book Earnings Method

The book earnings method, which appears to remain the most popular of the methods with FERC staff[14], employs the following conventions in applying the WACC:

r_d = "embedded" cost of debt = interest expense/D,

D = book value of long-term debt,

E = book value of equity,

r_e = the return on book equity for a set of unregulated firms (e.g., the Standard and Poor's 400 Industrials).

The cost of equity, r_e, is typically "adjusted" to reflect the perception of a particular pipeline's riskiness relative to the average unregulated firm. This method, therefore, relies heavily on analyst judgement.

(2) Book - Discounted Cash Flow (DCF) Method

The book DCF method differs from the book earnings method in the procedure used to estimate the pipeline's cost of equity r_e. The basic premise of the DCF method is that the current price of the firm's stock is the present value of future dividends to be paid. The rate at which these future dividends are discounted can be considered the required return on the firm's equity. Since this discount rate is unobservable, the key to the method is to use predictions of future dividend growth and the current stock price to estimate it.

A typical DCF calculation assumes that dividends will grow perpetually at some rate g. (This is the "Gordon Model", after the analyst who popularized it.)[15]

Thus,

$$P_o = \sum D_t/(1 + r_e)^t \quad ,$$

where P_o is the current stock price and D_t is dividends in period t. Assuming constant, indefinite growth, g, we can write:

$$P_o = D_1/(r_e - g) \quad \text{and,}$$

$$r_e = D_1/P_o + g \quad .$$

Thus, the DCF model is a "market-based" method in the sense that it uses information embodied in the firm's stock price to infer the required equity return. However, its implementation is typically a hybrid of market-based and book-based procedures, since the usual practice is to employ book-based estimates of dividend growth, g, and book-value weights in the WACC formula -- consistent given the use of embedded debt costs.

The trick to the DCF, then, is in the estimation of g. Many methods are popular. One traditional approach is to assume that the dividend growth rate is the product of the firm's average return on book equity for the last five years and its average "retention rate" (the proportion of net income not paid out in dividends).

(3) Market - DCF Method

There are many possible variants of the DCF method. One that is internally consistent and attempts to utilize a more market-based approach would employ a market measure of the cost of debt, such as the observed return on long-term bonds. In this circumstance, the use of market values of debt and equity in the WACC formula would be appropriate. This method is included in the analysis for comparison purposes.

(4) Capital Asset Pricing Model (CAPM)

The assumptions behind and implementation of the CAPM for required rate of return determination were described at the beginning of Chapter 4. To reiterate, the procedure involves the estimation of the elements of the following equation:

$$r^* = r_f + \hat{\beta}_a(\overline{r_m - r_f}) \quad ,$$

where r^* = the required expected return on total assets,

r_f = the risk-free rate,

$\hat{\beta}_a$ = the asset beta (unlevered equity beta), the slope coefficient from the estimation of the "market model",

$(\overline{r_m - r_f})$ = the expected risk-premium on the market portfolio.

The calculation shown here directly computes the required expected return on total assets using an unlevered asset beta. This is equivalent to the computation of a CAPM return on equity using the levered equity beta and inserting this result in the market-value weighted WACC.

5.3.2 Simulation Model

The model employed in this section is designed to answer two types of questions: first, how close various rate-of-return methods come through time to a practical "ideal," and second, what factors are responsible for significant deviations from the ideal. Because any "ideal" can only be measured with uncertainty, the model must be able to explicitly account for this uncertainty. Because of its ability to perform time-oriented simulations, and sensitivity analysis, the Interactive Financial Programming System was chosen.[16] The model, listed in Appendix B, contains the following base structure.

(1) Portfolio Data Structure

Accounting and security market data from 1956 through 1982, for the six interstate pipelines employed in Chapter 4, were obtained from the Compustat tapes and other supplementary sources[17], and are combined by the model into a single portfolio. The accounting and valuation data are summed over the six firms while the portfolio stock price is determined as a market value-weighted average of the six firms' prices.

The market value of the firms' debt is calculated as the present value of the long-term debt book value plus the present value of the stream of interest payments.

$$\text{Market Value of Debt} = \text{Book Value of Debt}/(1 + k)^N + \sum_{i=1}^{N} \text{Interest on Long Term Debt}_i/(1 + k)^i$$

The discount rate used in this calculation is the historical rate on Moody's AA-rated industrial bonds. An average maturity of 11 years was assumed for the outstanding debt.[18]

(2) "Ideal" Rate of Return Standard

The "ideal" rate of return is assumed to be that which would be obtained from the application of the CAPM based on perfect foresight of the CAPM parameters in period t. These parameters are the nominal risk-free rate, the expected market risk premium, and the portfolio asset beta, which is derived from the uncertain measurement of the portfolio equity beta. Notice that the assumption of perfect foresight of the nominal risk-free rate implies perfect foresight as to both inflation and real interest rates.

A complication in interpretation arises here due to the fact that the beta time series computed in Chapter 4 and used again below is a five-year moving average (i.e., the beta is "centered" around five years of data). The basic question is, why should the result of the calculation be reported as the point estimate for the mid-point of the sample period? This problem occurs whenever a time series is necessary to compute a point estimate. The position taken here is that there is no basis for placing more or less emphasis on data from earlier or later in the sample period.

Does this procedure influence the results, and if so, in what way? To a certain extent this procedure "smooths" the results. That is, discrete changes in risk that occur over short periods of time will be deemphasized in the moving five-year average. Any discrete increases will take longer to work their way into our ideal rate of return standard and thus, during the periods of increasing risk, the results below will be conservative to the extent that it takes time for the regulators to respond. Just the opposite would be true during periods of decreasing risk.

Since these calculations are made ex post we are making no behavioral assumptions that investors somehow "know" events that occur in the future. But when the results from our "ideal" standard are compared with an ex ante CAPM procedure we will impose the constraint that the regulators can only use observable security price information.

The third method implemented is the market-based DCF, where r_d is taken as the rate on constant 10 year maturity U.S. government bonds.[19] The market values of D and E are employed.

These methods are designed to be typical of the methods used in current regulatory practice, and can be varied to test the sensitivity of the results to any particular assumption and to determine which assumptions regarding method or data are controlling.

(4) Earned Return on Assets

Also calculated for comparison purposes is the actual return on total assets of the portfolio during the simulation period. This is defined as net income after tax plus interest payments, divided by the book value of debt plus equity at the start of the period.

Note that the comparison of book returns with market returns is only consistent for firms that are regulated based on the historical book value of their assets. We will look directly at the relationship of market and book values below to evaluate regulatory performance.

5.3.3 Results

A complete set of results from the base case of the model are reported in Appendix C. The rest of this section is designed to interpret these results graphically and numerically.

(1) Required vs. Actual Returns

A natural first comparison to make is between the return on assets actually earned by the pipeline portfolio and the return on assets their investors would have required in a CAPM world, as measured by our "ideal" standard. If one assumes that the *ex post* return is the best proxy for what the regulators intended *ex ante*, then this is a simple measure of regulatory performance.

(3) Alternative Methods

Three alternative methods of rate of return determination are implemented in the model. The first is a standard CAPM calculation. This method is implemented based only on the information available to the regulators at the time of the rate decision. That is, they will have only the past 5 years of security market information and the last years' nominal risk-free rate. The beta is thus effectively lagged three years from that employed in our "ideal" measure, and the nominal risk free rate is lagged one year.

The second method implemented is a typical Book-DCF calculation with the following terms:

$$r^* = r_d * D/(D + E) + r_e * D/(D + E),$$

where r_d = cost of debt = interest expense/book debt,

D = book value of long-term debt,

E = book value of common equity.

$$r_e = \text{(DCF) cost of equity} = \frac{D_{t+1}}{P_t} + g_t,$$

where D_{t+1} = forecast dividends per share = $D_t(1+g_t)$

P_t = current stock price

g_t = estimated dividend growth rate =

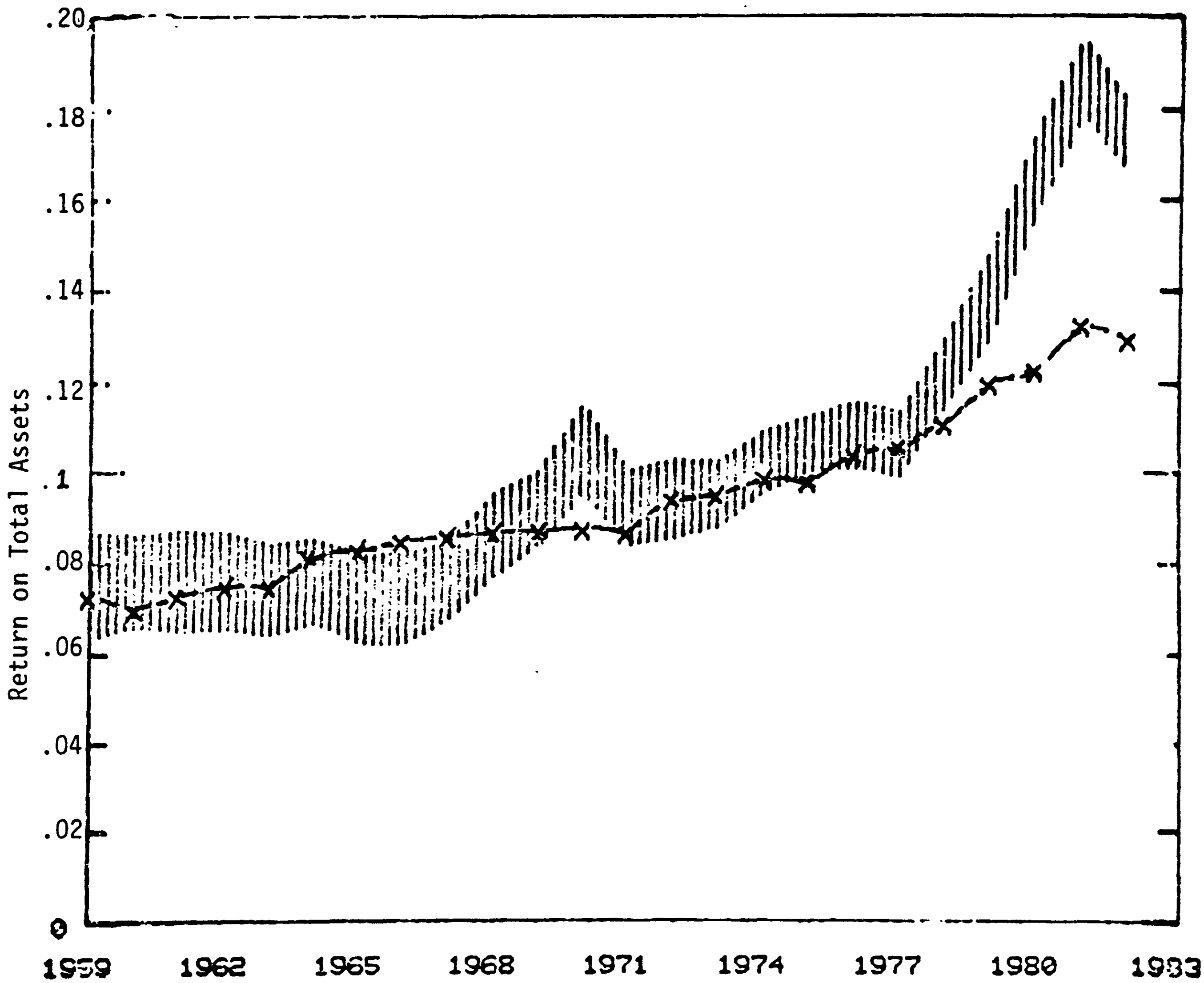
= average earned ROE*average retention rate for the previous five years

The earned return on equity used in the calculation of g is defined as net income divided by the start-of-period book equity. The retention rate is defined as net income not paid out in dividends divided by net income. Like the CAPM, the Book-DCF is lagged to reflect only the information available at the time of the rate hearing, usually twelve months prior to when the rate goes into effect.

The shaded region of Figure 5.1 represents a 95 percent confidence interval around the "ideal" required return defined above (where the uncertainty is due to measurement error in the equity beta time series). The major movements in this region through time are due to changes in inflation and risk. In comparison, the dashed line indicates the actual return-on-asset experience of the pipeline portfolio.

The earned return results reported here for the pipeline portfolio are consistent with the results found in previous work (Carpenter, Dec. 1983) for the regulated operations of all the major class A & B pipelines during the 1970's and early 1980's. (This provides some confidence that the six-pipeline portfolio is fairly representative of the pipelines in general). Overall, the pipelines appear to have earned a return ex post in the 1960's that equaled or even exceeded the return their shareholders would have expected according to the CAPM.[20] This corresponds to the industry folklore of the period, as well as early empirical work on this subject (Breyer and MacAvoy, 1974). In the late 1970's and early 1980's this situation significantly deteriorated as the difference in means test at the bottom of Table 5.1 indicates. The average difference between required expected returns and earned returns was 2.5 percent during the 1976-1982 period.

What is the potential average impact of this difference on pipeline revenues and delivered gas prices? Based on the size of the pipeline rate base (net book value of pipeline assets), the average annual deficiency in pipeline required revenues from 1976 to 1982 was approximately $1.5 billion dollars, as Table 5.1 indicates. A $1.5 billion increase in required annual revenues (assuming no demand adjustment) would translate into a 10.5 cents/Mcf increase in gas prices at the city gate. This is large given the average pipeline transportation markup of 70 cents/Mcf in 1982.



Shaded = 95% confidence interval on required returns.
--X-- = Earned Return on Assets

Figure 5.1

Required and Earned Returns
on Pipeline Total Assets

Table 5.1

Comparison of Actual and
Required Nominal Return on Assets, 1960-1982

	(1) Mean "Ideal" ROA	(2) Earned ROA	(3) Deviation[1] (2)-(1)	(4) Rev. Deficiency[2] ($Mill.)	(5) Market to Book
1960	.076	.070	.006	$86	1.26
1961	.076	.073	.003	42	1.49
1962	.076	.075	.001	16	1.42
1963	.074	.075	-.001	-24	1.48
1964	.076	.082	-.006	-97	1.51
1965	.072	.083	-.011	-190	1.41
1966	.072	.085	-.012	-223	1.21
1967	.076	.086	-.010	-188	1.13
1968	.086	.087	-.001	-15	1.18
1969	.092	.087	.005	111	1.03
1970	.105	.088	.017	424	1.06
1971	.092	.087	.005	134	1.04
1972	.094	.094	.000	0	1.10
1973	.095	.095	.000	0	.92
1974	.102	.099	.004	126	.85
1975	.106	.098	.008	287	.84
1976	.108	.104	.004	151	.99
1977	.106	.106	.000	0	1.01
1978	.122	.111	.011	474	.91
1979	.139	.120	.019	968	1.01
1980	.166	.123	.043	2388	1.02
1981	.187[3]	.133	.053	3573	.87
1982	.173[3]	.130	.043	2888	.73
Avg 60-75	.086	.082	.001	$31	1.18
s.d.	(.012)	(.017)	(.008)	(170)	(.23)
Avg 76-82	.143	.118	.025	1492	.93
s.d.	(.053)	(.011)	(.021)	(1439)	(.11)

Means Test F(1/21) = 20.66[4] = 9.34[4]

1. May not sum due to rounding.
2. Computed as (3) * (1+T) * (rate base of class A & B pipelines).
3. Assumes no change in equity risk 1981-1982.
4. Significant at the .01 level.

Of course, a sustained distortion of this type, if significant, should have had an effect on the financial health of the firms. One way to measure this is to look for changes in the market's valuation of the firms' total assets relative to a standard such as book value. Table 5.1 also indicates the trend over this period in the market-to-book ratio of total assets. While there is some natural fluctuation in these values, there appears to have been a significant reduction in market-to-book values, from an average of 1.18 (s.d.=.23) for 1960 to 1975, to an average of .93 (s.d.=.11) for 1976 to 1982. A difference of means test shows this change to be statistically significant at the .01 level as indicated in Table 5.1. Figure 5.2 plots the relationship between the required-earned return differential and the market-to-book ratio. Note the general inverse relationship between the two. As the differential grows (pipelines are being under-compensated) the market-to-book ratio falls.

Why should market-to-book value ratios be good indicators of market perceptions of regulatory behavior in this industry, particularly when evidence (Holland and Myers, 1983) shows a secular decline in an analagous measure, Tobin's q (the ratio of market value to replacement cost), for U.S. corporations in general during this period? The difference here is that regulatory procedures which set prices based on an expected return on book assets should, if successful, result in a market valuation of those assets equal to the book value. This is the "consistent" regulation definition of Brennan and Schwartz, cited above. Independent of what happens in the unregulated economy, then, market-to-book ratios for regulated gas pipelines should be a reasonable indicator or regulatory performance.

(3) Sources of Deviation from the "Ideal"

What is responsible for the large deviation between required returns and earned returns since 1976? There are two candidate causes. The first is the secular increase in systematic risk which may not have been detected by the regulatory authorities or reflected implicitly in their procedures. A second candidate cause is general inflation. To the extent that regulators do not properly anticipate inflation in the rate of return allowed the pipelines, earned returns may fall below required returns ex post. Thus inflation and risk changes would both be ideally reflected in both the nominal target required rate of return and the nominal earned rate of return. There should be no significant causal interrelationship between changes in risk and inflation.

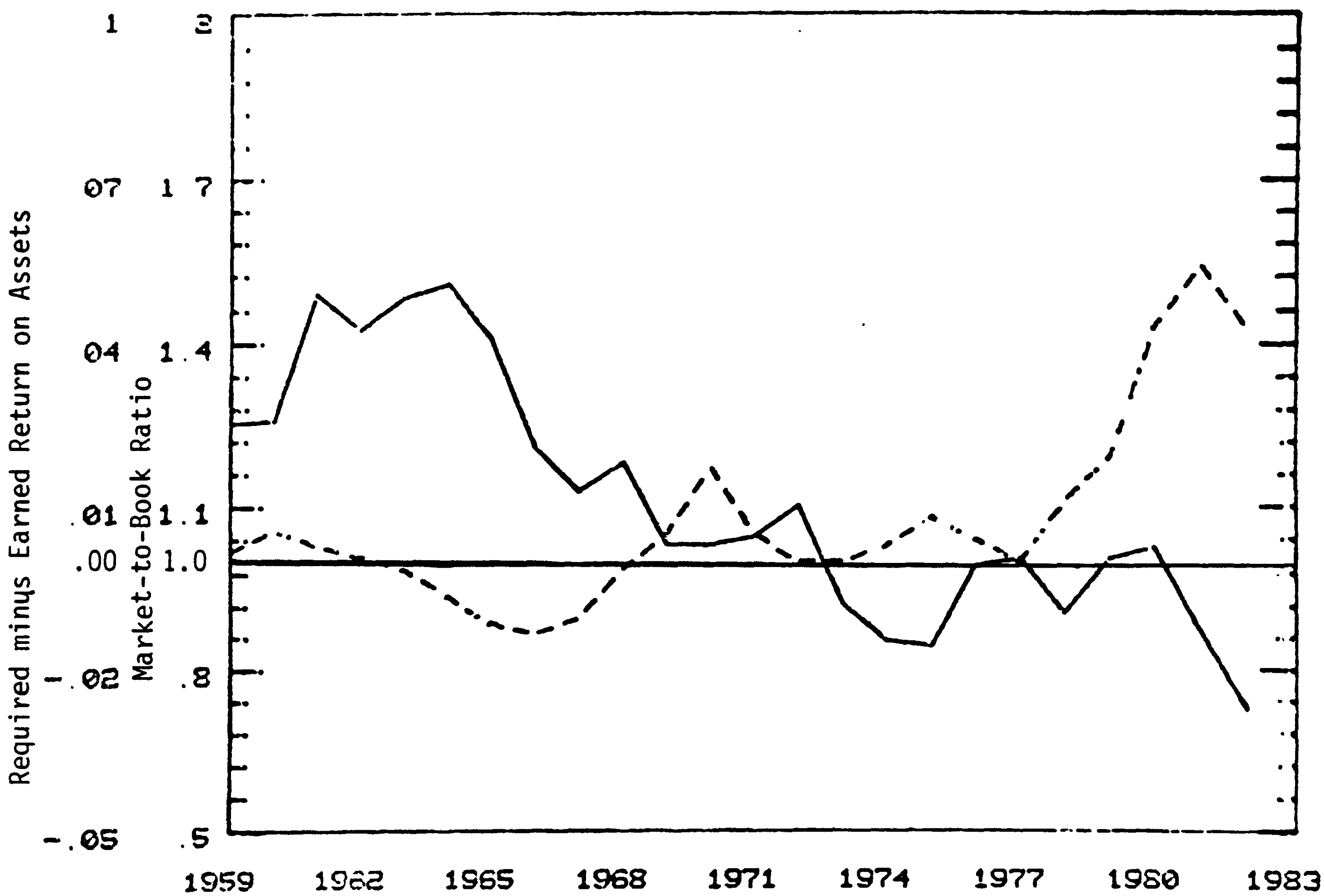
To separate the relative magnitudes of the two effects some simple regression statistics are computed. First, the earned return series from 1959 to 1982 is regressed on the asset beta time series and the inflation rate. (Again a generalized least squares approach for first-order autocorrelation is used.)

$$\text{Earned Return} = \underset{(.03)}{.18} + \underset{(.016)}{.023} * \text{Asset Beta} + \underset{(.051)}{.030} * \text{Inflation}$$

$\bar{R}^2 = .02 \qquad \text{RHO} = .98$

Clearly, earned returns have not responded contemporaneously to changes in risk or inflation, the two causes explaining less than 2 percent of the variation in earned returns.

The second relationship considered is the differential between the required and earned returns. Figure 5.3 provides an initial indication of the relationship between the required-earned return differential from Table 5.1 and the two candidate causes of the differential. Note from the Figure



SYMBOL	SCALE		VARIABLE
———	(.5,	2)	MKTTOB - Market-to-Book Ratio
----	(-5E-2,	10E-2)	ACTDEV - Required minus Earned Returns

Figure 5.2

Required - Earned Return Differential
and Pipeline Market-to-Book Ratios

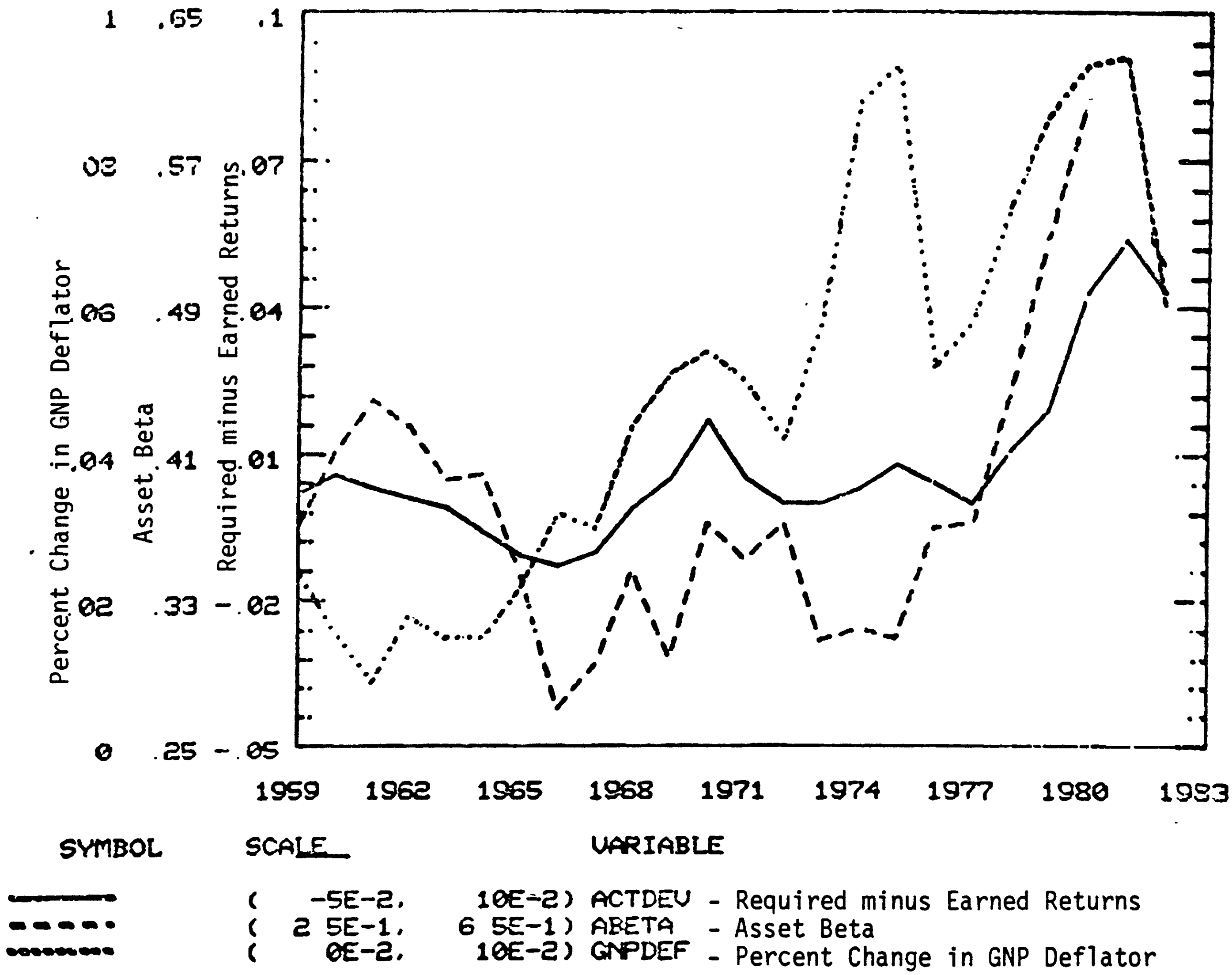


Figure 5.3

Sources of the Required - Earned
Return Differential

that part of the recent increase in asset risk was contemporary with an increase in inflation. But in general, and particularly during the inflation of the mid-1970's, risk and inflation have not been highly correlated.

A generalized least squares regression for first-order autocorrelation was run of this relationship for the period 1959 to 1980. The dependent variable is the differential between required and earned returns, and the independent variables are our hypothesized causes of the differential.

$$\text{DIFFERENTIAL} = \underset{(.008)}{-.048} + \underset{(.019)}{.106} * \text{ASSET BETA} + \underset{(.061)}{.245} * \text{INFLATION RATE}$$

$$R^2 = .74 \quad \text{Rho} = \underset{(.20)}{.46}$$

The results indicate that both variables are statistically significant positive explanations of the required-earned return differential. Together they explain 74 percent of the variation in the differential over the period. The risk variable, however, explains incrementally 56 percent of the variation and is thus the dominant source of the differential.

(3) Alternative Methods

Using the simulation model described above we can explore how the various alternative methods of rate of return determination perform with respect to our measure of required returns.

Table 5.2 and Figure 5.4 report the results of the various alternatives for the time period of greatest interest, 1975 to 1982. The three alternatives examined are the Book-DCF method, the market-DCF method and the CAPM method, as each was described in Section 5.3.2. When compared against our measure of required returns, each of the alternatives falls short during the 1975-1982 transition period. As might be expected, the alternatives rank in the order of how market-oriented their procedures are.

Table 5.2

Results of Alternative Methods
of Rate of Return Determination
1975-1982

	Required	Book-DCF	Mkt.-DCF	CAPM	Earned
1975	.106	.091	.096	.107	.098
1976	.108	.100	.107	.106	.104
1977	.106	.104	.108	.103	.106
1978	.122	.100	.102	.101	.111
1979	.139	.111	.113	.116	.120
1980	.166	.123	.125	.126	.123
1981	.187	.111	.122	.152	.133
1982	.173	.116	.136	.184	.130
Avg. 75-82	.138	.107	.114	.124	.116
Mean Deviation from Required Returns 75-82		.031	.025	.014	.022

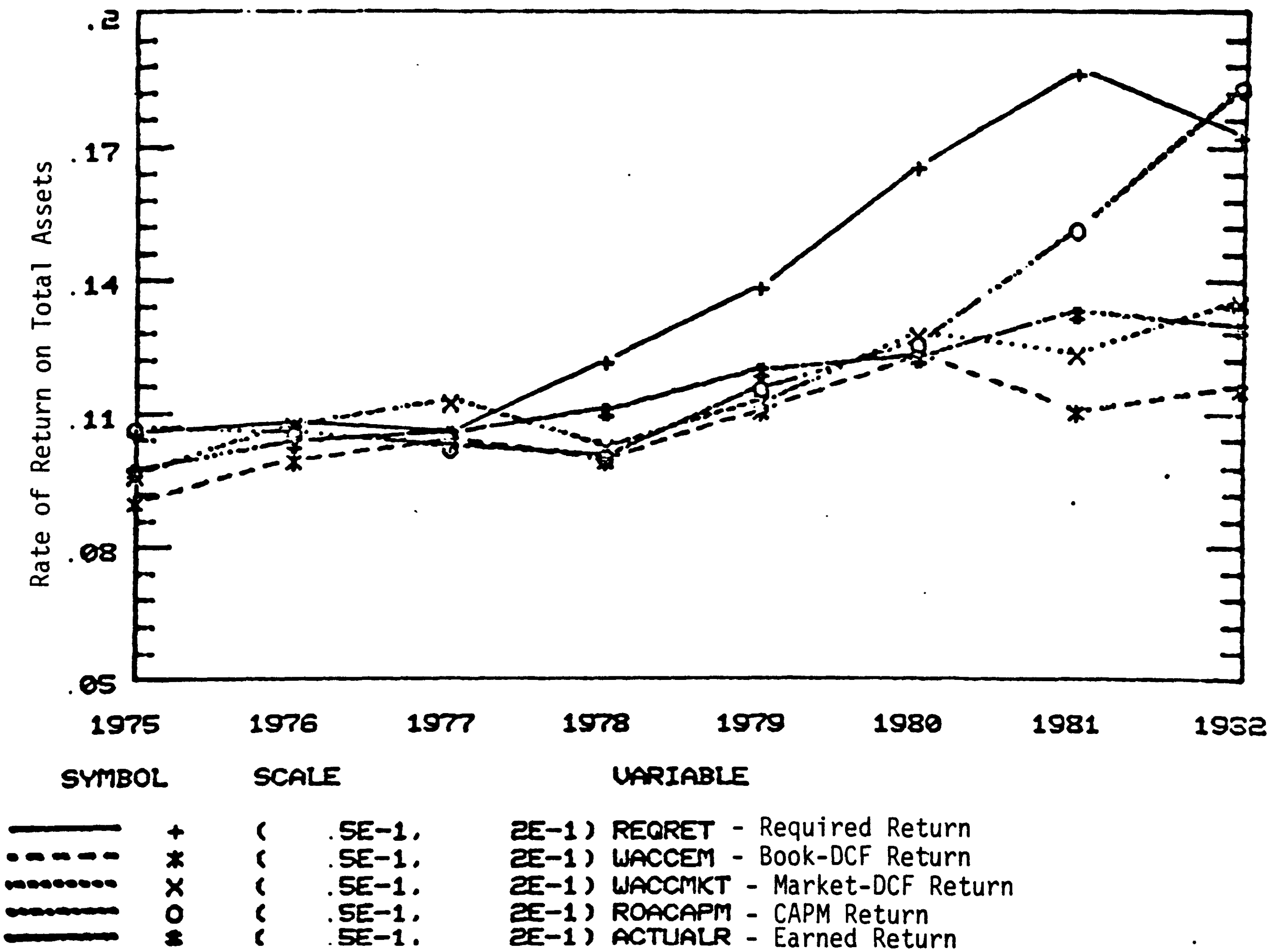


Figure 5.4

Results of Alternative Methods
of Rate of Return Determination
1975-1982

As indicated in the last row of Table 5.2, the CAPM method has the lowest mean deviation from the required returns over the period, followed by the market-DCF method and the book-DCF method.

Comparing the earned returns with these results (the last column of Table 5.2) indicates that as a proxy for the rate of return methodology employed by the FERC, earned returns have performed slightly better than the pure implementation of the market-DCF approach, and somewhat worse than the CAPM method. This might provide some indication that market-oriented factors make their way into the results of FERC procedures, and if not in the actual calculation of allowed returns then in some other way (such as in the treatment of test-year volumes).

(4) Summary

Evidence has been presented of a significant decline in gas pipeline financial performance in the 1970's and early 1980's, and that this decline is related to pipeline rates of return which have failed to compensate pipeline investors for bearing increased risk. If one accepts the assumption that the *ex post* earned returns are a good proxy for regulatory intentions and procedures *ex ante*, then it can be concluded that the FERC regulatory procedures for gas pipelines have not yet adequately responded to the gas industry transition and will not respond to future gas pipeline industry risk instability. Further efficiency losses due to the mispricing of gas at end-use and distorted pipeline investment decisions will be the result of a continuation of this pattern.

5.3.4 Conceptual Issues: Market vs. Book Measures

The characterization of FERC regulatory procedures in strictly methodological terms in the previous section belies what appears to be some serious confusion in recent rate of return decisions regarding the issue of risk and return.

The recent decision before the FERC regarding the rate of return to be allowed the Consolidated Gas Supply Corporation[21] is widely viewed as the latest definitive statement by the Commission on the matter of rate of return. According to FERC staff,[22] in this case for the first time they were required by the Commission to employ in evidence "market-based" measures for rate of return determination. Despite the relatively long-standing use of market-based measures in electric utility regulation, their use has been resisted in gas, largely on the grounds that market measures are volatile and not "controllable" by the regulators as are book measures. Furthermore, it is argued, many pipelines' market valuations are not observable due to their subsidiary status to unregulated parent firms.[23]

Of course, this view misses the point on the use of market measures in that, as we have seen, it is precisely this volatility that has important implications for appropriate regulatory behavior. The observational problem inherent in parent-subsidiary relationships is of concern, but implies merely that care need be taken in the construction of portfolios used to determine pipeline risk exposure. Furthermore, the apparent stability of book earnings measures, while comforting, masks potential arbitrary effects due to the vagaries of utility accounting practices. In the Consolidated case, the Commission listened to, and rejected, nearly all of the rate of return studies presented to it (which spanned the spectrum of methods), including those of FERC staff. In the end, they implemented their own Book-DCF methodology, not unlike the one modeled above.

5.4 Procedural Remedies

Two types of procedural remedies to the regulatory problem evidenced above will be discussed in this section. The term "procedural" is meant to imply those changes which could be adopted within the existing regulatory structure. In the next chapter changes which would entail more dramatic institutional restructuring (and probably legislation) will be examined. These two types of remedies involve changes in the rate of return determination procedures and changes in pipeline-distribution company tariff structures.

5.4.1 Rate of Return Remedies

The most obvious remedy for the regulatory problem above would entail a change in the accepted methods of determining rates of return to more closely approximate the near-consensus ideal. The use of the CAPM as the method of choice would move a long way in the right direction, but recall that even the best implementation of the CAPM would result in a potential *ex post* risk-return mismatch, as depicted above in Figure 5.4, particularly during periods when risk is the most unstable.

Even the best available methods for required rate of return determination promise potentially significant pricing errors due to the non-stationarity problem. And perhaps more significantly, the best methods require the construction of equivalent-risk portfolios in order to detect the underlying movements in risk. As more and more pipelines diversify toward unregulated activities or are acquired, the more difficult this detection will become.

Recalling the discussion in Chapter 4, a second source of risk to pipeline investors is the leverage induced by pipeline-producer fixed price contracts. To the extent that these contracts can be thought of as fixed nominal liabilities (like debt), then it is conceivable that, given a profile of the pipeline's contracts, a value and an "embedded cost" of the contracts could be determined and included in the WACC. The practical difficulty would be in determining the appropriate contract valuation.[24] Moreover, the incentives this kind of a policy would create in the private negotiation of contract terms might prove counterproductive (i.e., this policy would further institutionalize a system of rigid contracting procedures and place even more complex procedural requirements on the regulatory system). In particular, all gas supply contract details would have to be supplied to the FERC on a regular basis, leading effectively to the regulation of these contracts and their specific terms.

5.4.2 Tariff Structure Remedies

A second way to deal with the risk non-stationarity problem is to attempt to shift the risks to the other elements of the industry. One way to accomplish this within the current regulatory regime would be to increase distribution company minimum bill requirements or decrease the allocation of fixed costs in the commodity charge portion of the two-part tariff. If these changes serve to lever non-stationary risks only onto regulated distribution companies, however, it is questionable whether much is being accomplished, since the fundamental problem is just being shifted from Federal to state regulatory jurisdiction.

Interestingly, there is currently a lot of discussion at the Commission about modifying these tariffs.[25] But the kinds of tariff modifications being recommended are just the opposite of those above (e.g., <u>reduced</u> minimum bills). There is a view on the Commission that pipelines should be bearing <u>more</u> risk in the current environment. This view bespeaks the confusion that seems to exist in regulatory circles regarding the nature and allocation of risk in this industry.

A superior alternative, for all of these reasons, would be one that shifted the non-stationary risks to elements of the industry that are outside regulatory control (e.g., producers, brokers or other agents). We explore this alternative in the next chapter.

Footnotes (for Chapter 5)

1. Federal Power Commission, et.al., v. Hope Natural Gas, 320 U.S. 591, January 3, 1944.

2. Ibid., at 603.

3. Ibid., at 624.

4. Ibid., at 602.

5. Ibid., at 627. "It will little advance the public interest to substitute for the hodge-podge of the rule in Smith v. Ames, 169 U.S. 466, an encouragement of conscious obscurity or confusion in reaching a result, on the assumption that as long as the result appears harmless its basis is irrelevant."

6. A recent article in the FERC house organ observed the following: "One analyst has said that a rate of return analyst can sneeze and loose (sic) more money for the consumers than hours of deliberation on cost of service, depreciation, and rate design issues would do!" FERC Monitor, Vol III, No. 23, November 17, 1983, p.10.

7. The focus here is on economic efficiency questions. Certainly, as we saw in Chapter 3, distributive equity considerations had much to do with the original movement toward regulation of the gas industry. But in evaluating the efficacy of the regulatory procedures employed, I would argue that efficiency considerations should dominate (indeed this is the logical implication of the fundamental finding in the Hope decision). There are always more or less expensive ways of achieving distributive equity goals, and distorted regulatory practice is probably one of the more expensive.

8. The "Chicago" literature has developed a model of the demand for and supply of regulation that grows out of the economic interaction of various interest groups. We saw in Chapter 3 that much of the early regulation of pipelines could be traced to various constituent economic interests battling for economic rents in Congress and the Courts. This is also not a bad description of the current legislative debate.

9. Robichek (1978), p.699. The suggested way around this endogeneity is to use a portfolio of risk-comparable firms in the calculations and not the firm itself.

   Actually, Justice Douglas recognized this endogeneity in his majority opinion in the Hope case: "The heart of the matter is that rates cannot be made to depend upon "fair value" when the value of the going enterprise depends on earnings under whatever rates may be anticipated." 320 U.S. 591, 601 (1944).

10. Brennan and Schwartz (1982), p.509. This may be a "consistent" standard, but not necessarily a good standard. Depending on how the rate base is measured, (e.g., if it is not based on replacement cost princples), driving the market value of the firm to the rate base may violate the capital attraction standard and be financially detrimental to the firm.

11. Ibid., p.516.

12. Myers (1973), p.314.

13. I will use the terms "required rate of return" and "cost of capital" interchangeably, although, as pointed out later in this chapter, "cost of capital" is a conceptually confusing term in the sense that it does not correctly distinguish the opportunity cost of a firm's capital from its "embedded" cost -- the sources vs. uses fallacy of finance theory.

14. Personal conversation with George Shriver, FERC Office of Producer and Pipeline Regulation, Rate of Return Branch.

15. M.J. Gordon and E. Shapiro, "Capital Equipment Analysis: The Required Rate of Profit", Management Science, Vol. 3, October 1956, pp.102-110.

16. IFPS, Execucom Inc., Austin, Tx., June 1980.

17. In some cases Compustat data are not available for certain firms prior to 1970 and for certain income statement items. To fill the gaps, financial data from firm annual reports, 10-K's, and FERC Form 2'a were used. Data from these sources were checked for consistency against the Compustat data.

18. The assumption of an average 11 year maturity is based on the fact that most pipelines issue 20 year bonds at fairly regular intervals. These bond issues appear to have remained fairly regular even though new trunk pipeline construction projects are not as numerous as they once were. Due to inflation we would expect the average maturity for the value-weighted portfolio of outstanding bonds to be slightly greater than one-half of 20 years. This assumption is not critical to the results.

19. The government bond rate is used instead of a corporate bond rate under the assumption that government bonds more closely reflect the risk characteristics of regulated pipeline debt. This assumption makes no difference to the final results.

20. No claim is being made here that investors did indeed have the expectations consistent with our ex post application of the CAPM. The argument being made is that an appropriate benchmark for the required return involves the assumption that investors process instantaneously all available information regarding risk and return as related by the CAPM.

21. Consolidated Gas Supply Corporation, Docket No. 81-80-000, July 12, 1983.

22. George Shriver, op.cit.

23. Harold Leventhal advocated this view as follows:

> The securities markets have something of the lure of Adam Smith's "invisible hand" regulating commodity prices under the pressure of competition. But securities market prices are unstable and reflect many non-rational pulls. Though securities prices may be useful, if considered with judgement, the rapid gyrations and broad swings in securities prices (and in the ratios thereof accounted for by current dividends and earnings) minimize confidence in any regulatory program that focuses on them as the principle or the exclusive guide to determining fair return.

"Vitality of the Comparable Earnings Standard for Regulation of Utilities in a Growth Economy", Yale Law Journal, Vol 74, No.6, May 1965, p.1007.

24. A valuation approach using options-pricing theory might be possible. See Robyn McLaughlin, "Contract Terms as Options in a Fixed Price Market," mimeo, MIT, August 1982.

25. See for example "Butler Advances Risk/Reward Solution to Columbia, Other Major Cases", Inside F.E.R.C., July 4, 1983, p.1.

6. ALTERNATIVE INSTITUTIONAL ARRANGEMENTS FOR GAS PIPELINES AND POLICY IMPLICATIONS

6.1 Introduction: The End of Institutional Equilibrium

Discussion in the previous chapters has stressed the importance of the linkage between gas pipeline regulatory policy, the risk characteristics of the industry, and the forms of transaction between the various industry segments--referred to as "vertical market arrangements" (VMA). We have seen that the regulation of field prices directly influenced (kept low) the risks borne by pipeline industry investors. As will be further elaborated below, low risk influenced the preferred form of transactional arrangement in the industry, the rigid long-term, fixed price contract. This contract form was further institutionalized by the regulatory enforcement of the pipeline-distributor service obligation.

During the era of strict field price controls cum shortages, one can think of these institutional arrangements and consequences as being in equilibrium. This equilibrium between the three elements of risk, pipeline regulatory policy, and vertical market arrangments, evolved in the era of controls such that the allocation of risk was of little concern in determining the characteristics of the other two elements. Price controls made contract rigidity (high percentage take-or-pays and fixed prices) a valuable form of non-price competition for pipelines, and the rigidity reduced transaction costs. The pipeline regulatory system, intent on protecting the rights (and rents) of the customers who had access to the scarce gas, continued to ratify these arrangements as it had done since 1938. This was an equilibrium in the sense that none of the three elements acted to modify the others. Given the market conditions of that era, the system would have remained unaffected.

The new gas industry environment, documented in Chapters 3 and 4, of market-clearing average prices, no excess demand and even surplus, has provided an exogenous shock to this institutional equilibrium. We have described this shock as being transmitted through the risk element in the system. In Chapter 5 we explored one avenue for coping with this shock--modification of FERC rate-of-return regulatory practices. In this chapter we consider more comprehensive alternatives. That is, might it be advantageous to modify or relax the whole natural gas pipeline regulatory regime to allow a new configuration of transactional arrangements to evolve, with a consequential reallocation of risk among the elements of the industry? Or will the industry evolve a new set of institutional arrangements on its own, without legislative or regulatory policy actions?

In the discussion which follows the nature and functions of the vertical market arrangements in the industry will be reexamined in greater depth to better understand this disequilibrium. Two alternative regulatory regimes, pipeline deregulation and common carriage, are briefly described as to their likely effects on the gas industry. Issues regarding the practical implementation of these alternatives are discussed in a preliminary manner so as to provide a focus for future research.

6.2 Vertical Market Arrangements and Regulated Firms

Traditional theoretical models of competitive markets in economics frequently assume that exchanges between purchasers and suppliers over time will be instantaneous, discrete spot market transactions. Of course, in most real markets we do not observe this behavior when a repetitive supply relationship is involved. Usually we observe vertical integration or long-term contracts in which prices and other transaction terms are sticky.

To explain this behavior the literature has relied on two approaches. The first argues that these real markets may not be in fact competitive, and that long-term contracts and vertical integration are employed in order to exploit market power (for example, Schmalensee, 1973; Perry, 1978). It is, of course, difficult to apply this explanation to the natural gas case because of the aforementioned evidence of substantial field market competition, and the regulation of pipeline activities which should act to limit the capture of any benefits from the exercise of potential pipeline monopsony power with respect to producers.

The second branch of the literature, as developed primarily by the work of Coase (1937) and more recently, Williamson (1975), in which contracts or integration are said to be employed in order to minimize transaction costs, is more applicable to our case as described below.

6.2.1 VMA and Transaction Costs

The transaction cost literature emphasizes that when firms desire to make repetitive purchases or sales of a commodity, there are cost advantages to formalizing a relationship with the supplier-purchaser, either through long-term contracting or integration. But what should these contracts look like? From standard microeconomic theory we know that absent transaction costs the Pareto-optimal contract will allow for instantaneously varying prices as supply or demand conditions change. These prices are the same as would be determined in a classic arms-length spot market (Bohn, 1982 formalizes this). Once a bilateral relationship is established, however, there are not insignificant costs associated with allowing prices to vary. These transaction costs will be high when:

1. Price determinants are expensive to monitor (especially in the absence of a parallel spot market).
2. The costs of informing the parties of price changes is high, or,
3. Investments associated with the transactions are "idiosyncratic" in nature. (Williamson, 1979)

This last condition is of some importance to the case at hand and deserves elaboration. An "idiosyncratic" investment is one that effectively locks the buyer or seller into a bilateral contractual relationship once the investment is made. For example, once a gas pipeline is constructed to a producing field, the pipeline and producer are effectively (spatially) locked into a relationship in that field. This situation of "bilateral monopoly" may lead to "opportunistic behavior" by either party if certain enforcement or litigatory procedures are not prespecified. The least costly way to deal with this may be through a long-term contract or integration (Klein, et. al, 1978).

Thus, when any of these three conditions are present we would expect to see long-term contracting or integration, and particularly when (1) or (2) are present, we would expect to see contracting with sticky prices.

6.2.2 VMA and Risk Allocation

In the view articulated by the transaction cost literature on contracting, there is a clear trade-off implied between the cost associated with writing long-term supply contracts with flexible prices and the efficiency costs of Pareto-suboptimal contracts with sticky prices. But how does this relate to the concept of risk as discussed in earlier chapters?

We saw in Chapter 4 that a fixed price supply contract is analogous to long term debt from the purchaser's point of view, in the sense that a fixed nominal claim on the purchaser's future cash flow is given to the supplier.[1] This claim acts to increase the risk borne by the purchasing firm's shareholders, since both the bondholders and the producing firm will have prior claims on the purchasing firm's assets. Correspondingly, the fixed claim held by the producing firm acts to decrease the risk borne by its shareholders.

There is thus a direct connection between the flexibility of contract prices in the presense of a volume requirement such as a take-or-pay and the amount of risk borne by the purchasing firm's shareholders relative to the producing firm's shareholders.[2]

6.2.3 Price Versus Volume Flexibility

One might ask at this stage why contract volume flexibility and <u>fixed</u> prices would not be sufficient to achieve the desired allocation of risk between purchaser and supplier. In principle, volume flexibility could provide the cash-flow variability necessary to achieve the same allocation of risk as could be achieved with flexible prices. Which is most desireable in a given situation depends on the costs of volume flexibility versus those of price flexibility. As described above, price flexibility is costly when price determinants are expensive to monitor (especially in the absence of a spot market) and when the costs of informing the parties of price changes are high (such as might be the case in the household metering of electric power).

The following four conditions could be expected to lead to high costs of volume flexibility:

1. Product storage by producers or brokers is expensive.
2. It is expensive for users to shift their demands in time.
3. Short run marginal costs of production are steeply increasing.
4. Production capacity is often fully used.

In the presence of a spot market (and thus lower costs of price flexibility) a prima facie case can probably be made that the costs of volume flexibility in the gas industry dominate those of price flexibility.

6.2.4 VMA and the Gas Industry Transition

This trade-off between risk allocation and transaction costs allows us to interpret the evolution of contract forms in the gas industry.

As we have seen, prior to the late-1970's risk allocation was not as comparatively important an element in the choice of vertical market arrangements as the other factors alluded to above. First, even before field price controls and the era of shortages, rigid long-term contracts were the preferred arrangement. Presumably this reflected a desire on the part of the contracting parties to minimize transaction costs. During the shortage era of binding controls, the preference for rigid contract provisions was intensified, since these provisions were a source of non-price competition for pipelines seeking increasingly scarce supplies (see Broadman and Toman, 1983).

The exogenous increase in risk experienced by the industry has by all indications induced a change in these contract preferences. Initial indications from recent industry experience are that pipelines are demanding shorter-term, more volume-flexible contracts from producers (see the survey evidence in Section 2.3.1). The non-price competitive advantages of very high take-or-pays have become increasingly expensive. In some cases, pipelines are breaching contracts or forcing litigation (a crude method of flexibility at best). We have yet to see the emergence of truly price-flexible contracts--a question to which we will return.

What about vertical integration in the gas industry? Is it an alternative to the price-flexible long-term contract? Historically, since the initiation of pipeline regulation in 1938, vertical integration has not been a dominant feature of the gas producing and transmission industry. In 1980 roughly 12 percent of total contracted reserves were owned by gas pipelines.[3] The explanation for this lack of integration rests largely on the fact that under FERC pipeline regulation, pipeline production affiliates are regulated on a cost-of-service basis. To the extent that the price allowed for flowing gas was above the average cost of production (as was the case in the early development of the Mid-continent fields and nearly everywhere after the "national rate" decision of the early 1970's), then it was to the producer's advantage to avoid regulatory control by contracting instead of integrating.

Recently, with the Supreme Court decision in PSC of New York v. Mid-Louisiana Gas,[4] 1983, affiliate production is allowed to receive prices in accord with NGPA price ceilings. How intra-firm pricing of deregulated gas will be treated in the future by the FERC is still somewhat uncertain, and this uncertainty may act to continue to limit vertical integration.

6.2.5 Barriers to Price-Flexible Contracts: Spot Markets and the Regulatory Service Obligation

As discussed above, there is some evidence of a movement in the industry away from inflexible long-term contracts. But we also saw that most of the recent changes involve either limited restrictions in take-or-pay requirements or rather crude "market-outs" and other forms of contract abrogation. We have not yet seen the emergence of price-flexible contracts. Is there a reason for this?

In Section 6.2.1 it was argued that fixed price contracts would dominate when there are high costs associated with the monitoring of price determinants in an industry. This is especially true in a commodity industry where there does not exist a liquid[5] spot market. The referencing of price in a long-term contract to a liquid spot market price would constitute a low-transaction-cost method of writing price-flexible contracts. Price flexibility could also be attained in the absence of a spot market by referencing the contract price to some index or "market basket" of competing fuels. Indeed, this approach is becoming more common in international LNG trade, where the contract price is often referenced to a market basket of crude oils. There are some disadvantages to this approach, however, that should be noted relative to the use of a spot market reference price. When derived demands vary substantially across pipelines, among types of end users (e.g., industrial and residential) and seasonally, the appropriate market basket of competing fuels will vary. There is no optimal single proxy for a true spot price that would likely be consistent through time or appropriate across pipelines. This problem, like many other problems in writing contingent contracts when information is asymmetrically distributed, could lead to "opportunistic" behavior.

Nonetheless, the referencing of future gas contract prices to some index of competing fuels is one way of introducing greater flexibility in the market, and in the absence of a liquid spot market it is probably the best way of doing so. Further research could usefully attempt to measure the various costs of volume flexibility versus price flexibility in the presence or absence of a natural gas spot market.

Are we likely to see a true, liquid spot market for gas emerge under current regulatory procedures? The answer to this question lies in an aspect of gas pipeline regulation often ignored by analysts--the pipeline service obligation.

Service Obligations and Reserve Rights

As stressed in Chapter 2, gas pipeline regulation involves substantially more than the setting of rates. Through the assignment of a set of obligations on the regulated firms, regulation effectively assigns certain valuable economic property rights to the recipients of the commodity or service (the "reliance interests"). In natural gas the pipeline tariff contains the "administered contract" (Goldberg, 1976) which assigns these rights.

As the name suggests, the tariff includes the rates charged by a pipeline to its distribution customers. But it also includes volume terms that assign matching rights to buy and sell gas. The right to buy gas (or the duty to sell gas) is known as the pipeline's service obligation. Under a system in which the pipeline is the sole purchasing agent in the field (purchase-for-resale), this obligation effectively confers on the distribution company a package of rights--to a portion of the gas reserves under contract to the pipeline, and (as gas reserves, to be used, must be delivered) also to part of the pipeline's transport capacity. The right to sell gas (or the duty to buy gas) is called the minimum bill, which, as in the case of a take-or-pay clause, the distributor must pay to the pipeline regardless of how much gas is taken. A pipeline tariff can be said to be "administered" in the sense that, while it is an agreement between private parties, by FERC fiat its provisions continue in effect after the private contract _per se_ expires. Thus both the service obligation and the minimum bill are continuing obligations, on the pipeline and the distribution company respectively, by dint of federal regulation.

The key aspect of this arrangement for our purposes is the fact that under the purchase-for-resale (PFR) system with service obligations, the rights to gas reserves conferred on the distribution companies and customers is bundled together with the rights to pipeline capacity (i.e., without the implicit right to transmission capacity it would be meaningless under PFR to have a right to gas reserves).

Spot Markets and Purchase-For-Resale

Returning to the question of whether a spot market for gas could emerge under the existing regulatory regime, it should now be apparent that the service obligation, and its conferral of bundled reserve and pipeline capacity rights, is a major constraint on the emergence of a liquid spot market. As long as rights to _reserves_ are conferred on distributors and end-users by regulation, any attempt by pipelines to serve these customers by spot transactions would effectively confiscate the value of the reserve property right, and would transfer it to the producers, pipelines or brokers, depending on the nature of the spot transactions and the difference between the spot price and the average price (i.e., an end user who had rights to a long-term supply of low-cost inframarginal gas would lose those rights in exchange for the opportunity to purchase gas at the spot price).[6] This confiscation is, naturally, something the regulators will seek to prevent.

Strong evidence for this argument is available in the response of the pipelines and FERC regulators to the "special pipeline sales programs" now being proposed to deal with the gas surplus. The current surplus, as argued in Chapter 3, is a result of the contractual rigidities which prevent prices to producers from falling with demand. While the surplus consists of gas that is still under contract, existing end-users might be willing to temporarily give up their rights to this gas. In response, several pipelines have petitioned FERC to allow them to sell the surplus gas on a spot basis, at a lower average price.[7]

The response of the FERC to the proposals has been consistent with the view that regulation acts to preserve existing property rights. The special programs are viewed as a positive response to the gas surplus, but <u>only</u> to the extent that the programs do not endanger existing customers' <u>long-run</u> rights to reserves. For example, in November 1983, FERC approved Tenneco's special sales program "Tenneflex" but imposed 22 separate restrictions on it. These restrictions are to apply to <u>all</u> special programs. The basic thrust of the restrictions is to protect the existing "core" markets of other inter- and intrastate pipelines, and to give the participant's existing customers the right of first refusal to buy gas released to the special programs.

Under these conditions it is unlikely that the spot market which may arise will be liquid, and it would likely not be sustained after the gas surplus diminishes.

To summarize, it has been argued in ths section that the new risk conditions in the industry should lead to the desirability of more-flexible long term contracts, ideally price-flexible contracts that are tied to the price information provided by a spot market. The existing regulatory regime, however, enforces a set of service obligations in the context of pipeline purchase-for-resale which confers a bundled set of valuable rights to reserves and pipeline capacity on end-users. The protection of these rights makes the evolution of a liquid spot market unlikely under current pipeline regulatory policy.

6.2.6 Common Carriage, Deregulation, Service Obligations and Reserve Rights

What regulatory changes would be necessary to encourage the formation of a liquid spot market for gas? If the current service obligations, which bundle rights to reserves with rights to pipeline capacity, are a major obstacle to a spot market, it is logical to think about approaches that modify these rights.

One approach would be to eliminate the service obligations altogether. Rights to reserves as well as pipeline capacity would no longer be conferred by regulation but would be bid for in an open market. This approach would involve the deregulation of the gas pipelines. Deregulation would no doubt accomplish the objective of releasing pipelines and other agents to engage in spot transactions for gas supply, but it would likely be replaced by the exercise of pipeline market power at the distribution end of the system. As we saw in Chapter 2, most distributors are served by only one pipeline. In most cases pipelines would be able to use this sunk cost advantage by denying pipeline access to competing non-pipeline suppliers. Thus, in many regions, the regulatory restriction that ties reserve rights to pipeline capacity rights would be replaced by a private market power restriction that would again tie the user to the pipeline-supplied reserves. As Goldberg (1976) argues, there is not a conceptual distinction from a relational point of view between a regulatory system that is designed to protect certain interests by restricting contractual relations and a private market system that restricts contractual relations for market power or other reasons (e.g., transaction costs).[8]

A second alternative to the current system as well as deregulation would involve the continued protection of the right to pipeline capacity, but would unbundle this right from the right to reserves. This approach, used in the regulation of most other commodity transportation industries (e.g., oil pipelines, trucks and railroads), imposes an obligation to serve on the transporter that confers only transportation capacity rights on the shipper and receiver. This scheme is common carriage. A common carriage system for natural gas would essentially create two separate markets. The market for reserves and gas supply would be deregulated and unbundled from the market for transportation services which would remain regulated. There would be no restrictions on who could contract for gas reserves or short term deliveries. As in other commodities industries, agents and brokers would likely perform this role. In the remaining sections of this chapter, further details of what the gas industry under common carriage might look like and potential problems with the approach will be discussed. But first, two conceptual advantages of such a system in light of the concepts introduced previously should be emphasized.

(1) Potential emergence of a liquid spot market.

The unbundling of reserve rights from capacity rights removes the regulatory obstacle to the emergence of a liquid spot market. Note that this advantage does not rely on any notion of pipeline market power in the field. Recall that the reason many agents and brokers are not now engaging in spot gas transactions in the field is that gas reserves are now tied to the transportation function by the regulatory service obligaton.

(2) Reduced regulatory jurisdiction.

A market for reserves that is unbundled from the provision of transportation services would remove risks that are inherent in the brokerage of gas from regulatory jurisdiction. The risks impounded in contracts for reserves would be priced by the market instead of by regulatory authority. Thus, the pipeline regulatory authority would not need risk information from this market in order to set prices based on allowed rates of return in the transportation market--the problem examined in Chapter 5. And as has been emphasized, if regulated pipelines chose to continue to function as gas brokers under common carriage, the ability to write price-flexible long term contracts reduces their investors' risk exposure due to contractual leverage.

6.3 Some Institutional Details of a Common Carriage System

While there appear to be conceptual advantages to a common carrier regulatory system which unbundles the gas reserve and transportation markets, the practicality of such a system is a more difficult question to evaluate. The purpose of the remainder of this chapter is not to evaluate definitively these practicalities, but instead it is to point out how such a system might look and indicate which issues deserve research scrutiny.

6.3.1 Industry Structure

Based on the way other commodity industries are structured, one might expect a common carriage gas industry to evolve three structural characteristics.

(1) Brokers and Agents

It is likely that one would see the emergence of third parties in the industry whose function would be to pool short term stochastic demands and take advantage of transactional economies of scale in the purchase of gas supplies. Brokers of this sort have long existed in the largely unregulated intrastate gas market and are beginning to emerge now in the interstate market for the purpose of trading surplus gas. These agents may also be involved in gas storage.

(2) Gas Storage Industry

Gas storage in the current industry structure is typically owned by distributors or pipelines and is used as a supply source of last resort for the purpose of meeting seasonal peak requirements. Since this storage is part and parcel of the purchase-for-resale system, it is typically not differentially priced, but is instead "rolled into" the pipeline's or distributor's weighted average cost of gas.

One advantage of an unregulated and unbundled gas supply market is that an incentive would exist for seasonal or peak-load pricing of short-term gas sales from storage. Third parties or brokers would likely enter the storage business as it would be compatible with their function of pooling stochastic demands.

(3) Natural Gas Futures Market

The emergence of a liquid spot market for natural gas, that common carriage might encourage, leads naturally to the question of whether a futures market for gas would form and be beneficial to the industry. As a rule, a gas futures market would not necessarily provide any substantial additional risk allocation benefits beyond those provided by the combination of spot and long-term contracts, as described above. But a futures market might provide substantial information benefits, particularly to those agents who need to plan for seasonal production and storage requirements (see Black, 1976, for a complete discussion of the role and pricing of commodities futures contracts).

The New York Mercantile Exchange has recently designed and submitted for approval a prototype natural gas futures contract.[9] It is hoped by the Exchange that there is now enough spot trade in surplus gas in the industry to support such a market. Given the current regulatory restrictions on these spot sales and the possible temporary nature of the gas surplus, it is unlikely that such a contract will be successful absent common carriage regulation. The industry reaction to this development has been lukewarm to date.[10]

6.3.2 Regulatory Structure

Speculating about the likely industry structure that would emerge under common carriage is probably not as difficult an exercise as is speculating about the required regulatory intricacies of such a system. In principle, the regulatory details should not be more complex than those of the current system, and given the evidence in Chapter 5, they may be less complex. But it is frequently argued that gas pipeline common carriage would be an inherently more regulated system than the status quo (Russell, 1983; INGAA, 1984). This view asserts that pipelines perform a valuable "coordination function" (i.e., the physical matching-up of supply and demand across their systems) that is facilitated by their purchase-for-resale transactions. A common carriage requirement, it is argued, would necessarily substitute regulatory control of this function. It would seem that this could only be a problem when pipeline capacity limitations are reached, and thus this view is predicated on the assumption that the allocation of scarce pipeline capacity by the regulatory authority would be a substantial problem (more on this below). Recall, however, that even under the status quo arrangements pipeline capacity rights are implicitly allocated under the terms of the pipeline service obligation. Common carriage would merely make this regulation explicit by removing the market for gas supply (in terms of the allocation of reserve rights) from regulatory control. In this sense, common carriage is a less regulated system.

While it is outside the scope of this study to consider in detail all of the economic technicalities of a common carriage regulatory system, let us briefly consider three questions of significance, each of which deserves study and perhaps experimentation.[11]

(1) Allocation of Scarce Pipeline Capacity

Since the key aspect of common carrier regulation is the ability of shippers/customers to assert claims on pipeline capacity, a key regulatory question concerns how the various claims are to be mediated when total claims exceed pipeline capacity. In other common carrier industries this allocation is frequently performed on a pro-rata basis. In effect, when capacity is exceeded, all claimants are curtailed in proportion to the size of their claim. Of course, a pro-rata scheme of this sort is probably not the most economically efficient method of allocation since the relative value of the various claims is not considered in the allocation.

Various types of bidding schemes might be designed to elicit the valuations for the purpose of capacity allocation, but the problem might be considerably simplified by promoting the use of interruptible sales contracts.

Interruptible sales contracts can be thought of as a gas pricing system which stratifies the claims on pipeline capacity. Shippers that may be able to take advantage of a lower-priced interruptible contract are self-selecting a lower "curtailment priority." With sufficient interruptible sales the capacity allocation problem (which will usually only occur during seasonal peak demand) would likely be substantially alleviated. The emergence of an active gas storage industry (particularly if close to end-use markets) would also assist greatly in the problem of pipeline capacity management.

More troublesome than the allocation of pipeline capacity may be the definition of capacity itself. As mentioned in Chapter 2, the capacity of a pipeline is not a fixed amount. It can be increased (at a cost) in the short run through the addition of compressors. But furthermore, the definition of available capacity at different points along the line will vary because gas enters and leaves a pipeline at various points. The amount of capacity available to ship from point A to B will thus depend in an unpredictable manner on all other parties' demands and supplies in the system.

Whether or not the difficulty of precisely defining capacity would make natural gas common carriage unworkable is a matter of some debate. It is doubtful whether capacity allocation by regulation will need to be so precise as to require the regulators to micro-manage pipeline operations. It bears reemphasizing that the more flexible the gas supply relationships are (e.g., interruptible sales and storage) in the industry, the less troublesome will be short term demands on scarce pipeline capacity from a regulatory point of view.

At this stage, these questions surrounding regulatory capacity allocation are necessarily inconclusive.

(2) Transportation Rate Determination

Compared to the capacity allocation questions in a common carriage system, the question of the design of regulated transportation rates is not particularly troublesome. In principle, the same approach now employed to design the pipeline transportation tariff could be employed under common carriage. Two questions that deserve further study are:

- o Would the same types of minimum bills on the commodity charge portion of the two-part pipeline tariff be appropriate in the transportation tariff under common carriage?
- o Are current fixed cost allocation procedures (e.g., the "United" method of assigning 75% of fixed costs to the commodity change portion of the two-part tariff) appropriate for the common carriage transportation tariff?

Preliminary answers to these questions are suggested by recalling the purpose of two-part tariffs in declining cost industries and the reasons why minimum bills and allocation procedures which assigned fixed costs to the commodity change were originally implemented.

The two-part tariff is a means of efficient pricing in an industry where marginal cost is likely to be less than average cost. Marginal cost pricing would thus not provide sufficient revenues to keep the firm in business, necessitating the addition of a lump-sum demand charge to make up the revenue deficiency. Typically, in cost-based regulation the demand charge is calculated as the fixed costs of capacity (depreciation, taxes and return on investment).[12] In the case of gas pipelines a series of regulatory decisions since the mid-1950's[13] has allocated a certain amount of the fixed costs away from the demand charge. As described in Chapter 4, these procedures tend to increase the contractual leverage on the pipelines, as a larger percentage of their revenues are now subject to demand fluctuations. This leverage was counteracted to a certain extent by the imposition of minimum bills on the commodity charge portion of the tariff.

The reasons for the institution of minimum bill provisions are clearly related to the pipeline service obligation, as described above. They constitute the reciprocal "duty to buy" that is associated with conferral of reserve rights on distribution customers. As such, minimum bill provisions on the commodity charge of a two-part transportation tariff under common carriage are probably inappropriate.

The reasoning behind the allocation of some fixed costs to the commodity charge is less clear. Two reasons suggest themselves. First, it is possible that this was viewed purely as a means of counteracting the minimum bill's effect of shifting risk away from the pipelines and toward end-users. Second, this allocation may be a result of equity concerns. The more fixed costs that are allocated to the commodity change, the less per unit is paid by low load-factor customers (e.g., residential and commercial users) and the more per unit is paid by high load factor customers (e.g., industrial users). In either case, these practices are probably less appropriate in a common-carriage system. There should no longer be substantial minimum bills to counteract and the transportation charge itself will be small relative to the current pipeline tariff. And equity goals, to the extent they are an objective of regulatory policy, can be best (more efficiently) pursued through means other than pricing policy.

(3) Scope of Common Carriage: Is a Mixed System Practicable?

To this point no mention has been made of the concept of contract carriage or the currently-popular legislative proposals, euphemistically referred to as "mandatory contract carriage." Are they alternatives to a full common carriage regulatory system?

From a legal point of view, contract carriage refers to a regulatory system that permits pipelines to <u>voluntarily</u> provide transportation services to others. As such, it does not confer to the parties any rights to pipeline capacity, and is thus subject to the restriction that existing customers' rights to reserves are not infringed. The special sales programs described above can be considered contract carriage in this sense.

Proposals currently before both houses of Congress[14] would impose "mandatory contract carriage" on the gas pipeline industry. These proposals would require pipelines to transport gas for others, but generally only to the extent that existing service obligations and rights were preserved. Mandatory contract carriage is thus a hybrid of common carriage regulation imposed on top of the existing purchase-for-resale system.

Is mandatory contract carriage a workable alternative to the full common carriage system described above? Two points are worth noting. First, mandatory contract carriage does not unbundle the existing rights to reserves from the rights to pipeline capacity, and thus, like the spot sales programs, is unlikely to foster the emergence of a true spot market for natural gas. Consequently, it is not likely to have a meaningful effect on the gas market after the gas surplus has been worked off. Second, such a mixed system raises some serious technical issues in the design of pipeline transportation tariffs, issues that are not confronted by either a pure purchase-for-resale or common carriage system.

Briefly, the problem has to do with how fixed costs (now joint costs of pipeline transportation) should be allocated to the two separate tariffs--the common carriage transportation tariff and the pipeline purchase-for-resale tariff. The continued enforcement of minimum bill provisions for the traditional customers would make the problem particularly complex. In all likelihood, retaining the current procedures for fixed cost allocation and minimum bills would result in different rates for common carriage transportation and the transportation portion of purchase-for-resale. The existence of different rates for the same service would, in the long run, result in the dominance of one or the other regulatory system.

6.4 Obstacles to a Common Carriage Regulatory System

Just as certain regulatory barriers prevent the existing institutional arrangements in the gas industry from adjusting to the new market environment, certain obstacles will make the transition to any new regulatory regime difficult. The entire history of the natural gas industry has shown that economic interests, bent on protecting their valuable rights and rents, determine the course of gas regulatory policy. The following discussion briefly focuses on two such classes of interests.

6.4.1 Holders of Existing Rights to Gas Reserves

This chapter has emphasized that the institutional arrangements in the gas industry define a structure of claims or rights to the economic rents generated by the industry. The most valuable rights (the largest rents) inhere in the large reserves of "old" price-controlled gas. Any of the regulatory changes analyzed above, to the extent that they have long-term effects on the gas market, will modify these rights such that a new distribution of claims to the economic rents will emerge.

Even if these changes have overall efficiency benefits, rent redistribution may impose losses on some claimants (particularly those whose rights to reserves are on pipelines with large old gas "cushions"). The resistance to the changes by these claimants could block what otherwise would be effective regulatory policy. If one was intent on fostering a regulatory change like common carriage, research should focus on ways that policy could be designed to compensate the losing claimants out of the redistributed rents.

Note, incidentally, that this problem is not unique to the more "radical" regulatory changes. Current legislative proposals to explicitly allow long-term gas contract abrogation, for example, cause a similar redistribution of rents.

For efficiency reasons, the preferred compensation scheme usually involves lump-sum transfers to the affected parties. Often, such transfers are not workable, and in any case would require that an explicit valuation of the existing rights be made. Research should focus on how these rights should be valued or on other mechanisms besides the lump-sum transfer to perform the redistribution.

6.4.2 State Regulatory Interests

The analysis and discussion throughout this study has made little mention of the fact that, no matter what regulatory regime controls the pipelines, the distribution segment will remain regulated by state public utility commissions (PUC's). PUC's, while they differ state to state, have tended to pursue policies designed to protect residential customers from rises in gas prices. To accomplish this they have often "tilted" their rate structures to subsidize residential customers at the expense of industrial customers.

Should PUC's continue to pursue this policy under a flexible regulatory regime such as common carriage it would be logical to see industrial customers "dropping off the system" and contracting directly with producers for supplies and pipelines for transportation. Two concerns arise under this scenario, each of which warrants further study. First, would the regulated distribution company be required to provide the linkage to the trunk pipeline for an industrial customer that dropped off the system? How would this linkage be priced and regulated? Second, does the logical extension of this scenario imply that the regulated gas distribution company of the future will be merely a gas purchasing agent for residential/commercial customers? Would state PUC's find this prospect disadvantageous enough to resist any policy changes?

6.5 Some Institutional Conclusions

In this chapter we have examined the transactional arrangements in the gas industry as they serve to allocate risk. It was suggested that the new conditions in the gas market have upset the longstanding institutional equilibrium in the industry between the regulatory regime, the nature of the transactions at both ends of the pipeline, and the risks faced by industry investors.

The regulatory regime ratifies the transactional arrangements which bundle rights to gas reserves with rights to pipeline capacity. A substantial exogenous change in the risk conditions in the industry (as documented in Chapter 4) may require a regulatory regime which allows for more flexibility in gas supply transactions. It was suggested that to achieve this flexibility it may be necessary to unbundle the two types of rights, allowing a separate, unregulated market for gas reserves and production to form. If the experience in other commodity industries is any guide, this could lead to the formation of a liquid spot and futures market for gas, with consequential informational advantages for the rest of the market.

This unbundling might be achieved under a deregulated pipeline system, or a system of common carriage. The competitive characteristics of the gas pipelines at the distribution end of the system (as reviewed in Chapter 2) mitigate against the feasibility of pipeline deregulation.

While conceptually attractive, the feasibility of a common carriage regulatory regime depends on a number of questions concerning the design of transportation rates and capacity allocation rules, all of which probably require some degree of study and experimentation before firm conclusions can be drawn. Of greater importance to the feasibility of such a system may be the political economy of any changes which reallocate the set of valuable existing rights to gas reserves. If there are true efficiency advantages to these changes, then it should be possible to compensate the short-term rent losers out of the net gains to the winners. If research could identify such a scheme, it might make common carrier regulation a more politically palatable option for dealing with the current gas market mess.

Footnotes (for Chapter 6)

1. The producer/pipeline contract is used to illustrate these risk-allocation features. As pointed out in Chapter 4, there is a reciprocal claim at the distribution end of the pipeline embodied in the minimum bill. The risk allocation effects of the contracts at the distribution end of the pipline depend both on the fixed claim in the minimum bill and on the the procedures which determine how much of the pipeline's fixed costs are allocated to the commodity charge. Current procedures that allocate substantial proportions of fixed costs to the commodity charge tend to cancel out the risk shifting effects of the minimum bills (see also Section 5.4.2).

2. This risk-shifting property of price-flexible contracts, as a general matter, would also depend on the systematic variability of gas supply costs as well as derived demands. As a practical matter one would not expect supply costs (particularly natural resource supply) to be as systematically variable as demand and thus it is the purchaser's obligation to buy at a fixed price and not the producer's obligation to deliver that is the controlling factor in determining which party bears the contractual leverage.

3. U.S. DOE/EIA, Gas Supplies of Interstate Natural Gas Pipeline Companies, derived from FERC/FPC Form 15 filings, DOE/EIA-0167, 1981.

4. Public Service Commission of New York v. Mid-Louisiana Gas, 81-1889, et. al., decided by the Supreme Court on June 28, 1983; see Inside FERC, June 29, 1983 for a good account of the case.

5. Liquid in this sense means the existence of enough transactions and transactors such that all participants in the market are price-takers.

6. Note that these rights have even greater value when they are from inframarginal or "old" price-controlled gas (i.e. rights to old gas reserves on a pipeline system are also rights to the pipeline's cheap gas "cushion").

7. See Carpenter and Wright, 1983, for a more detailed description and discussion of these programs.

8. Goldberg, 1976, p. 435, ". . . institutional arrangements relying on private agents will frequently have restrictive mechanisms similar to those employed in regulated industries."

9. See report in Inside FERC, January 9, 1984, pp. 1-2.

10. For a good discussion of the practicalities of a gas futures market in the current regulatory environment, see M. Gorham, 1983.

11. Means and Cohn, 1983, present a good initial survey of some of the economic and legal technicalities of gas pipeline common carriage.

12. We will put aside in this discussion the question of whether this is the appropriate way to calculate the demand charge.

13. In Atlantic Seaboard Corp., et. al., 11 FPC 43 (1952), 50 percent of fixed costs were assigned to the commodity charge. In United Gas Pipe Line Co., 50 FPC 1348 (1973), 75 percent of fixed costs were allocated to the commodity charge.

14. See Senate Bill S 1715 and the "Shelby-Corcoran" proposal to the House Energy and Commerce Committee, July 18, 1983.

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APPENDIX A

Major Pipelines and Producer Affiliates

Pipeline Company	Producer Affiliates
(1) Cities Service Gas Co.	(1) CSG Exploration Co.
(2) Colorado Interstate Gas Co.	(2) Coastal Corp. CIG Exploration, Inc.
(3) Columbia Gas Transmission Co.	(3) Columbia Gas Development Co.
(4) Consolidated Gas Supply	(4) Consolidated Natural Gas Co. CNG Producing Co.
(5) El Paso Natural Gas Co.	(5) El Paso Natural Gas Co. El Paso Natural Gas Exploration
(6) Florida Gas Transmission Co.	(6) Florida Exploration Co.
(7) Kansas-Nebraska Pipeline Co.	(7) Midlands Gas Corp. Excelsior Oil Corp. Kan-Col Co.
(8) Michigan-Wisconsin Pipeline Co. (ANR Pipeline Co.)	(8) American Natural Resources Production Co.
(9) Natural Gas Pipeline Co.	(9) MCN Exploration Co. NAPECO Inc. Exeter Co. Peoples Exploration NGPL Explration Co.
(10) Northern Natural Gas Co.	(10) NNG Exploration Northern Natural Gas Production Co.
(11) Northwest Pipeline Corp.	(11) Northwest Exploration Co. NGL Production Co.
(12) Panhandle Eastern Pipeline Co.	(12) Pan Eastern Exploration Co. Pan Western Exploration Co. Panhandle Western Gas Co. Anadarko Production Co. Trunkline Exploration Co. Panhandle Coop. Panhandle Royal
(13) Southern Natural Gas Co.	(13) Sonat Exploration Co. Southern Energy Co. South Georgia Natural Gas Co.

(14) Tennessee Gas Pipeline Co.	(14) Tenneco Inc. Tenneco Exploration LTD. Tenneco Oil Co. Tennessee Gas Supply Border Gas Co. Houston Oil and Minerals Marlin Drilling Co.
(15) Texas Eastern Transmission Co.	(15) Texas Eastern Exploration Co. Transwestern Gas Supply Co.
(16) Texas Gas Transmission Co.	(16) Texas Gas Exploration Corp.
(17) Transco Gas Supply Co. Transcontinental Gas Pipeline	(17) Transco Exploration Company
(18) Transwestern Pipeline Co.	(18) Texas Eastern Exploration Co. Transwestern Gas Supply Co.
(19) Trunkline Gas Co.	(19) Trunkline Exploration Co. Pan Eastern Exploration Co.
(20) United Gas Pipeline Co.	(20) Cotton Petroleum Corp.

Source: U.S. Department of Energy

Major Pipelines and Distribution Affiliates

Pipeline Company	Distribution Affiliate
(1) Cities Service	(1) None
(2) Colorado Interstate	(2) None
(3) Columbia	(3) Columbia Gas of Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia, W. Virginia Commonwealth Gas Services, Inc.
(4) Consolidated Gas Supply	(4) The East Ohio Gas Co. Peoples Natural Gas Co. River Gas Co. West Ohio Gas Co.
(5) El Paso	(5) None
(6) Florida Gas	(6) None
(7) Michigan-Wisconsin (ANR)	(7) Michigan Consolidated Gas Co.
(8) Kansas-Nebraska	(8) Northern Gas Co. Northern Mountain Gas Co. Northern Utilities Co. Western Gas Co.
(9) Natural Gas Pipeline	(9) North Shore Gas Co. Peoples Light and Coke Co.
(10) Northern Natural	(10) Peoples Natural Gas Co.
(11) Northwest Pipeline	(11) None
(12) Panhandle Eastern	(12) None
(13) Southern Natural	(13) None
(14) Tenneco	(14) None
(15) Texas Eastern	(15) None
(16) Texas Gas Transmission	(16) None
(17) Transco	(17) None
(18) Transwestern	(18) None

(19) Trunkline	(19) None
(20) United Gas Pipeline	(20) None

Source: U.S. Department of Energy

APPENDIX B

```
MODEL FERC56P  VERSION OF  12/11/83  15:06
10 COLUMNS 1956-1982, AVG
15 *
20 *CONSTRUCTION OF PORTFOLIO DATA
25 *
30 MV EQUITY = STOCK PRICE PE*SHARES PE + STOCK PRICE ANR*SHARES ANR +'
40   STOCK PRICE CG*SHARES CG + STOCK PRICE EQ*SHARES EQ + STOCK PRICE MFS*'
50   SHARES MFS + STOCK PRICE PEO*SHARES PEO
51.1 MV EQUITY PE = STOCK PRICE PE*SHARES PE
51.2 MV EQUITY ANR = STOCK PRICE ANR*SHARES ANR
51.3 MV EQUITY CG = STOCK PRICE CG*SHARES CG
51.4 MV EQUITY EQ = STOCK PRICE EQ*SHARES EQ
51.5 MV EQUITY MFS = STOCK PRICE MFS*SHARES MFS
51.6 MV EQUITY PEO = STOCK PRICE PEO*SHARES PEO
52 STOCK PRICE = STOCK PRICE PE*(MV EQUITY PE/MV EQUITY)+STOCK PRICE ANR*'
52.1   (MV EQUITY ANR/MV EQUITY)+STOCK PRICE CG*(MV EQUITY CG/MV EQUITY)+'
52.2   STOCK PRICE EQ*(MV EQUITY EQ/MV EQUITY)+STOCK PRICE MFS*'
52.3   (MV EQUITY MFS/MV EQUITY)+STOCK PRICE PEO*(MV EQUITY PEO/MV EQUITY)
55 SHARES = SHARES PE+SHARES ANR+SHARES CG+SHARES EQ+SHARES MFS+SHARES PEO
60 YEARS TO MATURITY = 11
69 BOND INDEX RATE = .0347,.0403,.0391,.0449,.0458,.0450,'
70      .0443,.0437,.0447,.0455,.0526,.0572,.0639,.0726,'
71   .0833,.0761,.0736,.0763,.0890,.0921,.0888,.0836,.0894,.0991,.1244,'
72   .1462,.1500
80 BOND FACTOR = (1+BOND INDEX RATE)
90 DEBT CAP FACTOR = XPOWERY(BOND FACTOR,YEARS TO MATURITY)
95 INTEREST PE = TOTAL INT PE * LT INT FACTOR
100 MV DEBT PE = DEBT PE/DEBT CAP FACTOR + NPV(INTEREST PE,BOND INDEX RATE,'
110   YEARS TO MATURITY,0)
115 INTEREST ANR = TOTAL INT ANR * LT INT FACTOR
120 MV DEBT ANR = DEBT ANR/DEBT CAP FACTOR + NPV(INTEREST ANR,BOND INDEX RATE,'
130   YEARS TO MATURITY,0)
135 INTEREST CG = TOTAL INT CG * LT INT FACTOR
140 MV DEBT CG = DEBT CG/DEBT CAP FACTOR + NPV(INTEREST CG,BOND INDEX RATE,'
150   YEARS TO MATURITY,0)
155 INTEREST EQ = TOTAL INT EQ * LT INT FACTOR
160 MV DEBT EQ = DEBT EQ/DEBT CAP FACTOR + NPV(INTEREST EQ,BOND INDEX RATE,'
170   YEARS TO MATURITY,0)
175 INTEREST MFS = TOTAL INT MFS * LT INT FACTOR
180 MV DEBT MFS = DEBT MFS/DEBT CAP FACTOR + NPV(INTEREST MFS,BOND INDEX RATE,'
190   YEARS TO MATURITY,0)
195 INTEREST PEO = TOTAL INT PEO * LT INT FACTOR
200 MV DEBT PEO = DEBT PEO/DEBT CAP FACTOR + NPV(INTEREST PEO,BOND INDEX RATE,'
210   YEARS TO MATURITY,0)
220 MV DEBT = MV DEBT PE+MV DEBT ANR+MV DEBT CG+MV DEBT EQ+MV DEBT MFS+'
230   MV DEBT PEO
240 DE RATIO = (PREVIOUS 2 MV DEBT+PREVIOUS MV DEBT+MV DEBT+FUTURE MV DEBT+'
241   FUTURE 2 MV DEBT)/((PREVIOUS 2 MV EQUITY+PREVIOUS MV EQUITY+MV EQUITY+'
242   FUTURE MV EQUITY+FUTURE 2 MV EQUITY)/1000)
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250 BOOK DEBT = DEBT PE+DEBT ANR+DEBT CG+DEBT EQ+DEBT MFS+DEBT PEO
255 BOOK EQUITY = EQUITY PE+EQUITY ANR+EQUITY CG+EQUITY EQ+EQUITY MFS+'
256  EQUITY PEO
260 INTEREST = INTEREST PE+INTEREST ANR+INTEREST CG+INTEREST EQ+INTEREST MFS+'
270   INTEREST PEO
275 LT INT FACTOR = .919,.945,.952,.937,.873,.867,.834,.849,.903,.912,'
276   .905,.887,.924,.878,.774,.828,.825,.783,.759,.774,.809,.824,.838,'
277   .770,.711,.705,.705
280 DIVIDENDS = DIVIDENDS PE+DIVIDENDS ANR+DIVIDENDS CG+DIVIDENDS EQ+'
290   DIVIDENDS MFS+DIVDS PEO
300 NET INCOME = NET INCOME PE+NET INCOME ANR+NET INCOME CG+NET INCOME EQ+'
310   NET INCOME MFS+NET INCOME PEO
315 *
320 *BENCHMARK CAPM
325 *
330 RISK FREE RATE REAL = .002
339 GNP DEFLATOR = .032,.034,.017,.024,.016,.009,'
340      .018,.015,.015,.022,.032,.03,.044,.051,.054,.05,.042,'
350   .058,.088,.093,.052,.058,.074,.086,.093,.094,.06
360 MARKET RISK PREMIUM = .085
369 MEAN EQUITY BETA = .49,.46,.60,.68,.74,.71,'
370     .71,.64,.64,.57,.49,.56,.63,.60,.65,.69,.7,.67,.72,.70,'
380   .72,.73,.9,.96,.97,.97,.97
382 SD EQUITY BETA = .10,.11,.12,.13,.11,.11,.11,.10,.09,.10,.11,.10,.10,'
383   .10,.11,.10,.10,.10,.10,.09,.09,.09,.10,.11,.10,.10,.10
390 CORP TAX RATE = .48
395 EQUITY BETA = NORRANDR(MEAN EQUITY BETA, SD EQUITY BETA)
396 DEBT BETA = 0
400 ASSET BETA = DEBT BETA*(MV DEBT/(MV DEBT+MV EQUITY/1000))+'
401   EQUITY BETA*((MV EQUITY/1000)/(MV DEBT+MV EQUITY/1000))
410 RISK FREE RATE NOM = (1+RISK FREE RATE REAL)*(1+GNP DEFLATOR)-1
420 ROA IDEAL = RISK FREE RATE NOM + ASSET BETA*MARKET RISK PREMIUM
425 *
430 *CAPM AS APPLIED WITH LAGS
435 *
440 ROA CAPM =  PREVIOUS RISK FREE RATE NOM + PREVIOUS 3 ASSET BETA*'
450   MARKET RISK PREMIUM
455 *
460 *WEIGHTED AVERAGE COST OF CAPITAL
465 *
470 FORECAST DIVS PS = DIVIDENDS*(1 + DIV GROWTH)/(SHARES/1000)
480 EARNED ROE = NET INCOME/PREVIOUS BOOK EQUITY
481 AVG EARNED ROE = (PREVIOUS EARNED ROE+PREVIOUS 2 EARNED ROE+'
482   PREVIOUS 3 EARNED ROE+PREVIOUS 4 EARNED ROE+PREVIOUS 5 EARNED ROE)/5
490 COST OF DEBT = INTEREST/PREVIOUS BOOK DEBT
500 RETENTION RATE = (NET INCOME-DIVIDENDS)/NET INCME
501 AVG RETENTION RATE = (PREVIOUS RETENTION RATE+PREVIOUS 2 RETENTION RATE+'
502   PREVIOUS 3 RETENTION RATE+PREVIOUS 4 RETENTION RATE+'
503   PREVIOUS 5 RETENTION RATE)/5
510 DIV GROWTH = AVG EARNED ROE*AVG RETENTION RATE
520 COST OF EQUITY = (FORECAST DIVS PS/PREVIOUS STOCK PRICE) + DIV GROWTH
530 CALC WACC = COST OF DEBT*(BOOK DEBT/(BOOK DEBT +'
531   BOOK EQUITY)) + COST OF EQUITY *'
540   (BOOK EQUITY/(BOOK DEBT+BOOK EQUITY))
```

```
545 WACC = PREVIOUS CALC WACC
550 *
560 *DEVIATION DUE TO CAPM LAGS
570 *
580 CAPM DEV = ROA IDEAL -  ROA CAPM
590 *
600 *DEVIATION DUE TO WACC
610 *
620 WACC DEV = ROA IDEAL -  WACC
630 *
640 EARNED ROA = (NET INCOME + INTEREST )/'
645   (PREVIOUS BOOK EQUITY + PREVIOUS BOOK DEBT)
660 *
670 *DEVIATIONS FROM ACTUAL
680 *
690 ACTUAL DEV = ROA IDEAL - EARNED ROA
700 *
710 *REVENUE DEFICIENCY - CLASS A & B PIPELINES
720 *
725 LONG RATES=.0318,.0365,.0332,.0433,.0412,.0388,.0395,.0400,.0419,'
726   .0428,.0492,.0507,.0565,.0667,.0735,.0616,.0621,.0684,.0756,'
727   .0799,.0761,.0742,.0841,.0944,.1146,.1391,.1300
729 RATE BASE = 6399,7604,8341,9209,9890,10322,10961,11121,11065,11311,'
730   12086,13134,14375,15528,16383,17655,18605,20953,22518,24735,26802,'
740   28696,30389,34460,37928,45384,0
750 EV RATIO = (MV EQUITY/1000)/(MV DEBT + MV EQUITY/1000)
760 REVENUE DEF = ACTUAL DEV*(1 + CORP TAX RATE)*RATE BASE
770 COLUMN AVG  = SUM(COLUMN 1963 THRU COLUMN80)/18
780 MARKET TO BOOK = (MV DEBT +MV EQUITY/1000)/(BOOK DEBT+BOOK EQUITY)
END OF MODEL
```

APPENDIX C

Base Case Output

	1959	1960	1961	1962
EV RATIO	.546	.556	.619	.601
RISK FREE RATE REAL	.002	.002	.002	.002
RISK FREE RATE NOM	.043	.041	.039	.040
GNP DEFLATOR	.024	.016	.009	.018
MARKET RISK PREMIUM	.085	.085	.085	.085
EQUITY BETA	.680	.740	.710	.710
ASSET BETA	.371	.412	.440	.426
ROA IDEAL	.075	.076	.076	.076
ROA CAPM	.054	.063	.068	.070
DEVIATION CAPM	.020	.014	.008	.005
AVG EARNED ROE	--	--	--	.116
COST OF DEBT	.042	.042	.042	.041
AVG RETENTION RATE	.190	.263	.331	.333
DIV GROWTH	--	--	--	.039
COST OF EQUITY	--	--	--	.071
WACC	--	--	--	--
DEVIATION WACC	--	--	--	--
EARNED ROA	.073	.070	.073	.075
DEVIATION ACTUAL	.002	.006	.003	.001
REVENUE DEF	$ 30	$ 86	$ 42	$ 16
MARKET TO BOOK	1.256	1.261	1.489	1.424

	1963	1964	1965	1966
EV RATIO	.618	.626	.602	.552
RISK FREE RATE REAL	.002	.002	.002	.002
RISK FREE RATE NOM	.040	.042	.043	.049
GNP DEFLATOR	.015	.015	.022	.032
MARKET RISK PREMIUM	.085	.085	.085	.085
EQUITY BETA	.640	.640	.570	.490
ASSET BETA	.396	.400	.343	.271
ROA IDEAL	.074	.076	.072	.072
ROA CAPM	.074	.077	.078	.076
DEVIATION CAPM	-.001	-.001	-.006	-.004
AVG EARNED ROE	.118	.120	.123	.128
COST OF DEBT	.040	.045	.044	.046
AVG RETENTION RATE	.355	.361	.361	.371
DIV GROWTH	.042	.043	.044	.047
COST OF EQUITY	.078	.079	.077	.089
WACC	.053	.056	.059	.057
DEVIATION WACC	.020	.020	.013	.015
EARNED ROA	.075	.082	.083	.085
DEVIATION ACTUAL	-.001	-.006	-.011	-.012
REVENUE DEF	$ -24	$ -97	$ -190	$ -223
MARKET TO BOOK	1.481	1.507	1.406	1.208

	1967	1968	1969	1970
EV RATIO	.528	.550	.499	.573
RISK FREE RATE REAL	.002	.002	.002	.002
RISK FREE RATE NOM	.051	.057	.067	.074
GNP DEFLATOR	.030	.044	.051	.054
MARKET RISK PREMIUM	.085	.085	.085	.085
EQUITY BETA	.560	.630	.600	.650
ASSET BETA	.296	.347	.299	.372
ROA IDEAL	.076	.086	.092	.105
ROA CAPM	.083	.080	.079	.092
DEVIATION CAPM	-.007	.006	.013	.013
AVG EARNED ROE	.132	.135	.137	.138
COST OF DEBT	.048	.053	.056	.054
AVG RETENTION RATE	.375	.375	.381	.388
DIV GROWTH	.049	.051	.052	.054
COST OF EQUITY	.104	.109	.102	.119
WACC	.064	.070	.075	.075
DEVIATION WACC	.012	.016	.017	.030
EARNED ROA	.086	.087	.087	.088
DEVIATION ACTUAL	-.010	-.001	.005	.017
REVENUE DEF	$ -188	$ -15	$ 111	$ 424
MARKET TO BOOK	1.129	1.181	1.032	1.065

	1971	1972	1973	1974
EV RATIO	.512	.532	.461	.438
RISK FREE RATE REAL	.002	.002	.002	.002
RISK FREE RATE NOM	.062	.062	.068	.076
GNP DEFLATOR	.050	.042	.058	.088
MARKET RISK PREMIUM	.085	.085	.085	.085
EQUITY BETA	.690	.700	.670	.720
ASSET BETA	.353	.373	.309	.315
ROA IDEAL	.092	.094	.095	.102
ROA CAPM	.103	.087	.094	.098
DEVIATION CAPM	-.011	.007	.001	.004
AVG EARNED ROE	.138	.136	.137	.138
COST OF DEBT	.058	.060	.061	.068
AVG RETENTION RATE	.393	.395	.409	.426
DIV GROWTH	.054	.054	.056	.059
COST OF EQUITY	.108	.113	.107	.124
WACC	.080	.078	.082	.080
DEVIATION WACC	.012	.016	.012	.022
EARNED ROA	.087	.094	.095	.099
DEVIATION ACTUAL	.005	.000	.000	.004
REVENUE DEF	$ 134	$ -13	$ -5	$ 126
MARKET TO BOOK	1.045	1.100	.923	.854

	1975	1976	1977	1978
EV RATIO	.443	.514	.510	.493
RISK FREE RATE REAL	.002	.002	.002	.002
RISK FREE RATE NOM	.080	.076	.074	.084
GNP DEFLATOR	.093	.052	.058	.074
MARKET RISK PREMIUM	.085	.085	.085	.085
EQUITY BETA	.700	.720	.730	.900
ASSET BETA	.310	.370	.372	.444
ROA IDEAL	.106	.108	.106	.122
ROA CAPM	.107	.106	.103	.101
DEVIATION CAPM	-.001	.002	.003	.021
AVG EARNED ROE	.139	.140	.144	.145
COST OF DEBT	.068	.069	.071	.079
AVG RETENTION RATE	.442	.454	.477	.483
DIV GROWTH	.062	.064	.069	.070
COST OF EQUITY	.144	.148	.131	.143
WACC	.091	.100	.104	.100
DEVIATION WACC	.015	.008	.002	.022
EARNED ROA	.098	.104	.106	.111
DEVIATION ACTUAL	.008	.004	.000	.011
REVENUE DEF	$ 287	$ 151	$ 11	$ 474
MARKET TO BOOK	.845	.994	1.006	.906

	1979	1980	1981	1982
EV RATIO	.551	.620	.575	.525
RISK FREE RATE REAL	.002	.002	.002	.002
RISK FREE RATE NOM	.094	.115	.139	.130
GNP DEFLATOR	.086	.093	.094	.060
MARKET RISK PREMIUM	.085	.085	.085	.085
EQUITY BETA	.960	.970	.970	.970
ASSET BETA	.529	.602	.558	.510
ROA IDEAL	.139	.166	.187	.173
ROA CAPM	.116	.126	.152	.184
DEVIATION CAPM	.024	.040	.034	-.011
AVG EARNED ROE	.146	.148	.151	.154
COST OF DEBT	.091	.093	.099	.101
AVG RETENTION RATE	.485	.485	.490	.498
DIV GROWTH	.071	.072	.074	.077
COST OF EQUITY	.156	.130	.133	.155
WACC	.111	.123	.111	.116
DEVIATION WACC	.029	.043	.075	.057
EARNED ROA	.120	.123	.133	.130
DEVIATION ACTUAL	.019	.043	.053	.043
REVENUE DEF	$ 968	$ 2,388	$ 3,573	$ --
MARKET TO BOOK	1.007	1.025	.871	.728

BIOGRAPHICAL NOTE

The author, Paul R. Carpenter, is currently a post-doctoral fellow at the MIT Center for Energy Policy Research and is the Vice President of Incentives Research Inc., an economic and financial consulting firm. He was previously an Associate of the firm Putnam, Hayes and Bartlett, Cambridge, Massachusetts, and an energy economist with the NASA - CalTech Jet Propulsion Laboratory, Pasadena, California. He received a Bachelor of Arts with honors in Economics from Stanford University in 1976 and a Master of Science in Management from the Massachusetts Institute of Technology, Sloan School of Management in 1978.