N-1435-DOE

February 1980

EVOLUTION OF THE REGULATION OF HIGH COST GAS SUPPLIES

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A Rand Note
prepared for the
U.S. DEPARTMENT OF ENERGY
The work upon which this publication is based was performed pursuant to Contract DE-AC01-79PE70078 with the U.S. Department of Energy.

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This note was prepared for the Office of Policy and Evaluation, U.S. Department of Energy, as part of the Rand energy policy research program.

Earlier Rand research examined the barriers to the commercialization of new energy technologies that could produce substitutes for natural gas or imported oil. The study of high-Btu coal gasification\(^1\) concluded that the regulatory policy applied to the new technology would play a critical role in its prospects for commercialization. The present analysis grew out of that conclusion.

Most of the research for this analysis was completed in the fall of 1978. An effort has been made, where possible, to note later developments, although of necessity in less detail.

SUMMARY

This analysis examines the impasse that has developed in the formulation of a federal regulatory policy for facilities to manufacture synthetic natural gas (SNG) from coal. As of this writing, no policy has been presented that is acceptable to both regulators and those private parties whose support is necessary to proceed with the construction and operation of such facilities.

This note presents a framework for considering the regulations applied to high cost, high technology gas supply projects such as SNG from coal plants. It employs this framework to review the regulatory approaches taken by the Federal Power Commission (FPC), and now the Federal Energy Regulatory Commission (FERC), towards such projects in the past. The Commission has considered proposals for liquefied natural gas (LNG) import projects and coal gasification projects, and the experience of these proposals provide the basis for this analysis.

IMPORTANCE OF GAS REGULATION

Policy options other than regulation certainly could stimulate the commercialization of synthetic natural gas production from coal, also called high-Btu coal gasification, yet for several reasons this analysis examines only regulatory policy. Gas companies are regulated primarily by federal gas regulations. These regulations largely determine the prospects for rewards in return for the risks taken by the utilities. The chance of regulatory changes adds to these risks.

The gas regulatory policy arena has taken on additional importance because of Department of Energy interest, as expressed by its intervention in the Federal Energy Regulatory Commission's deliberations on the authorizations required for a coal gasification plant in Mercer County, North Dakota. DOE has based this action on its judgment that the construction

1The FPC and its successor, FERC, are referenced collectively in this work as "the Commission."

and operation of a commercial high-Btu coal gasification facility would serve the national interest by contributing to reduced dependence upon oil imports.

Budgetary and legislative constraints have hindered DOE efforts to provide direct assistance to those seeking to proceed with a high-Btu coal gasification venture. Thus, through its intervention before FERC, DOE has sought not only to remove regulations it might view as hindering the commercialization of high-Btu coal gasification but also to subsidize this commercialization through favorable regulatory treatment for pioneer efforts such as the Great Plains project.

**Evolving Interest in Coal Gasification**

Federal support of coal gasification is based on a desire to develop environmentally acceptable ways to exploit coal, a plentiful domestic resource. Federal interest in synthetic fuels such as gas from coal first manifested itself as research support to assist the depressed coal mining industry in the early 1960s. The research efforts later expanded to include environmental concerns. After the oil embargo of 1973 demonstrated American dependence on imported energy, funding for the development of liquid and gaseous fuels from coal increased dramatically.

Gas utility interest in high-Btu coal gasification developed for quite different reasons. Federal price ceilings on domestic natural gas production for interstate sales caused natural gas supply shortages to begin in the early 1970s. The gas industry became interested in exploiting unconventional gas supply sources, especially LNG imports and synthetic natural gas, to fill the "supply gap" that federal regulation had stimulated.

The phased deregulation provisions for new natural gas incorporated in the recently enacted Natural Gas Policy Act of 1978 (NGPA) change the supply outlook for domestic natural gas significantly. In addition to these domestic supply outlook changes, recent finds of large gas supplies in Mexico could also affect the need for more exotic sources of gas such as coal gasification. These changes have led to a new industry rationale for coal gasification support from the development of
a needed new gas supply to insurance against shortfalls in other anticipated gas supplies, and federal policy must also reflect these new developments.

REGULATORY APPROACH TO UNCONVENTIONAL GAS SUPPLY PROJECTS

The regulation of unconventional gas projects such as high-Btu coal gasification facilities incorporates three major component policies: pricing policy, curtailment policy, and risk allocation policy. Three primary options exist for pricing: rolled-in (or average cost) pricing, marginal cost pricing, and incremental pricing (i.e., the pricing of selected incremental sales of gas at marginal cost). When gas shortages developed, the Federal Power Commission adopted a rationing policy based on the assignment of all end users to nine end use categories and curtailment of gas deliveries on the basis of a user's curtailment priority classification. Reorganization of curtailment categories provides a potentially important policy tool in a time of uncertain gas supplies.

Several policy tools exist for allocating risk through regulation. They include tariffs guaranteeing repayment of certain costs in any circumstance, surcharges while construction is in progress, adjustments in the allowed rate of return, and surcharges for R&D activities. The appropriateness of these various mechanisms varies with the nature of project risks and with policy decisions about who should bear what risks.

Most federal regulatory experience with high cost, high technology gas supplies has been associated with LNG imports. The FPC tried to implement policies for gas from LNG projects that would differ radically from the traditional approach of rolling any new gas supplies into gas companies' overall supplies for purposes of curtailment and setting average cost prices. Each time, however, the Commission's efforts failed.

The problems with changing pricing and curtailment policies contrast sharply with steady progress towards compromise on the issues related to the allocation of risks. Consensus about appropriate risk sharing arrangements was developed for two large scale LNG import projects, and consensus for the sharing of risks on a commercial coal gasification project appears likely. On the other hand, the same
arguments about pricing and curtailment policy continue between proponents of the importance of the economic efficiency goal of regulation and proponents of the need to build a coal gasification plant.

By pursuing opportunities for compromise, federal policymakers could deal better with two important issues. First, if other, more direct government support for coal gasification were to materialize, flexibility of the alternatives presented would provide useful means for regulators to respond to such initiatives. Secondly, if compromises along the lines suggested in this work were adopted and coal gasification was still not commercialized, then federal policymakers would know to reassess the need for the technology because in such circumstances the technology's lack of commercial utility could be creating more problems than would regulatory inflexibility. That is, without incurring any major economic inefficiencies compromise regulations may provide insights both to the Commission and to DOE about whether or not coal gasification represents a desirable way to achieve either agency's goals.
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I. INTRODUCTION

The Department of Energy (DOE) has proposed several major commercialization efforts to promote the development of synthetic fuels using an abundant and secure domestic resource, coal. High-Btu coal gasification, one of the candidate technologies, must be developed by the gas industry, which is subject to economic regulation at federal, state, and local levels.\(^1\) This analysis develops a framework for describing and designing policy alternatives for the regulation of high cost gas supply projects. It examines the policy tools available within this framework and reviews the evolution of federal regulatory policy towards unconventional gas supplies.

A recent Federal Energy Regulatory Commission (FERC) case indicates how important policy decisions about the commercial introduction of coal gasification must be approached. The present note examines this new approach and discusses how policymakers have reconciled the following conflicting policy objectives:

- Establishing prices that induce efficient production and consumption of gas.
- Allocating service costs and benefits equitably.
- Generating satisfactory revenue in the gas utility industry.
- Stimulating innovation to ensure the long-run viability of the gas industry.
- Developing an administratively feasible pricing system.

Parties to the policy debate on high cost gas development have raised major objections based on one or more of the above policy goals. Issues raised in debates concerning such high cost, unconventional gas supplies as those obtained through coal gasification or the importation of liquefied natural gas (LNG) illustrate these policy problems. For this

\(^1\)Coal gasification can produce low, medium, or high-Btu gas. In this note, coal gasification refers to the production of high-Btu gas, also called synthetic natural gas (SNG), from coal.
reason, a review of the experiences of these early high cost gas projects provides an important part of this analysis.

Federal regulatory policy will play a major role in the efforts (successful or unsuccessful) to commercialize coal gasification. This review finds that FERC and DOE policymakers have not explored all the regulatory alternatives available to them for trading off conflicting policy goals that they must pursue in conjunction with the commercialization of coal gasification.

To appreciate the importance of federal policy to the commercial prospects of coal gasification, it is necessary to understand the barriers to private sector adoption. Earlier Rand analysis of high-Btu coal gasification identified several obstacles to its commercialization. Briefly, they include:

- High estimated costs relative to regulated natural gas.
- Significant remaining performance and cost uncertainty.
- Large capital investment requirements.
- Reluctance of financiers to lend to gas utilities.
- Significant gas supply system changes required.
- Inhibitions to innovation associated with the regulation of natural gas and SNG.¹

**IMPORTANCE OF GAS REGULATION**

Since many of the barriers reviewed above could be reduced by the appropriate regulatory treatment, this analysis focuses on federal regulation, a potential key to the commercialization of coal gasification. The regulatory environment molded by federal gas regulators largely determines the likelihood and magnitude of potential rewards from risks taken by gas utilities. In addition, regulation itself and especially the prospect of future regulatory changes generate important risks for gas utilities.

Utility regulation has traditionally emphasized three sometimes conflicting goals: efficiency, equity, and revenue generation.² The

efficiency goal seeks to set prices for goods in a way that properly signals cost information to potential purchasers so they can weigh the costs of its production against the value of its consumption. At an ideally efficient level of production, the marginal cost of production would equal the marginal utility of consumption. The equity goal seeks to allocate fairly the costs of providing a service among those benefiting from the service (i.e., gas users). Recent gas supply problems have extended the issue of equity to the protection of gas users least able to switch to other fuels (especially residential, small commercial, and "human needs" users). Utility regulators have applied these first two goals within the constraint that the economic regulations imposed had to allow the generation of revenues sufficient to maintain the viability of the utilities regulated. Regulators have managed to balance these goals over time, but the balance has been difficult to maintain in the best of circumstances. Now, the introduction of new high cost and technologically sophisticated gas supplies such as large liquefied natural gas (LNG) importation and coal gasification projects has made the balance especially difficult to attain.

Gas regulatory policy is also of special interest at this time because of the Department of Energy's decision to intervene in the Federal Energy Regulatory Commission's deliberations in the matter of an application for a coal gasification plant in Mercer County, North Dakota. DOE has decided that it is in the national interest to construct and operate a commercial scale high-Btu coal gasification facility as soon as possible to help reduce U.S. dependence on energy imports. DOE

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1"Human needs" refers to such gas users as hospitals and nursing homes (and is sometimes extended to certain agricultural consumption).

2Of course, industry viability in terms of revenue generation could also be viewed as equity towards the sellers. Since this issue has usually been treated separately by the Commission and since the new issue of innovation is of special interest in this work, this analysis treats consumer equity and industry viability separately.


efforts to assist directly companies seeking to proceed with coal gasification ventures have encountered budgetary and legislative problems. As a result, DOE now seeks not only to encourage FERC to remove inappropriate regulatory barriers to the commercialization of coal gasification, but also to request that FERC establish favorable regulatory treatment subsidizing pioneer coal gasification ventures.

In other words, this analysis does not confine itself to federal gas regulation policy because that is the most appropriate policy approach to commercializing coal gasification, but because it appears unavoidable that regulation will play a major part in the success or failure of commercialization efforts. Reasons for federal interest in coal gasification, explored in the second section of this note, strongly suggest that direct economic assistance from a broader set of contributors could be preferable to any outcome possible in the federal energy regulatory arena alone. However, the political and budgetary constraints facing federal energy policymakers that have led them to espouse favorable regulatory treatment are no less real than the constraints that gas companies have encountered in seeking investors for coal gasification ventures. Moreover, even if other, more appropriate, subsidies for the introduction of this technology could be arranged, it is appropriate that some costs associated with the project be paid by the gas consumers that it would serve. This review seeks to provide insights applicable to such cost allocation issues.

CONFLICT OF POLICY GOALS

The policy goals of the gas regulators and of DOE, as well as the interests of those seeking to initiate coal gasification projects, are not necessarily in harmony. As mentioned above, FERC, as the federal natural gas regulator, seeks to maintain each gas utility's viability by allowing it to generate satisfactory revenue; at the same time, it seeks to promote efficient and equitable transactions between the utilities that it regulates and the public whose interest it is charged to protect. On the other hand, DOE has decided that the commercialization of high-Btu coal gasification at this time would serve the nation's broad energy policy objectives of decreasing energy dependence,
protecting the environment, and providing assurance of future energy supplies. Therefore, DOE is seeking to convince FERC that FERC should adopt regulations favorable to the successful completion of a high cost, high risk, coal gasification venture.

The difficulties arising from the conflict among the Commission's primary policy goals for new gas supplies are illustrated in the following discussion of the history of Commission policy on LNG imports and coal gasification. In addition to the internal conflicts among the Commission's goals, DOE's immediate goal of creating a regulatory environment conducive to the implementation of a high cost, risky coal gasification project also conflicts with traditional notions of regulatory efficiency and equity. This is especially true if, as in the case of the proposed Great Plains project, all costs would have to be borne by the particular gas consumers receiving gas from the project.

DOE's objective of encouraging special regulatory treatment of a coal gasification project and FERC's regulatory objectives are compatible only to the extent that the commercialization of coal gasification contributes to the long-term viability of the gas industry. If coal gasification can produce only uneconomical gas, the immediate objectives of these agencies may not be compatible.

Section II of this note reviews the reasons for government and private sector interest in coal gasification. It discusses also how major changes in the gas supply outlook have affected private sector interest in coal gasification.

Section III develops a framework for reviewing or formulating regulatory policy toward high cost, sophisticated technology sources of gas supplies.

Section IV discusses the regulatory treatment of requests to develop LNG import and coal gasification projects. It also examines the contrasting evolution of the three major component policies of unconventional gas regulation: pricing, curtailment, and risk allocation.

Section V summarizes the findings of this study.
II. GOVERNMENT AND INDUSTRY INTEREST IN COAL GASIFICATION

Both federal agencies and gas companies have been trying for several years to develop a commercial coal gasification project. This section explores the reasons for public and private sector interest in the commercialization of this technology. It also discusses important recent changes in the outlook for future natural gas supplies and their implications for coal gasification's adoption.

FEDERAL INTEREST

Many federal agencies have supported the development of technologies to convert coal into synthetic natural gas (SNG). Federal interest in such technology originated through a desire to increase the use of coal and to assist the troubled domestic coal industry. Sponsored coal research began to study the effects of the use of coal on the environment. After the 1973 oil embargo, government interest in the production of synthetic fuels increased significantly because of their potential to reduce energy imports by exploiting domestically plentiful coal.¹ In addition, severe gas shortages beginning in 1976 stimulated the interest of federal policymakers in coal gasification as a "backstop" source of gas supplies that would establish a price ceiling for gas.²

The development of coal gasification technologies has proceeded to the point where several gas companies have expressed an interest in


constructing and operating commercial-scale coal gasification facilities.\(^1\) Since no coal gasification project has yet obtained certification and financing, the Department of Energy (and earlier, the Energy Research and Development Administration) has moved to assist the commercialization of technologies producing SNG from coal.

Early efforts at federal support for large scale synthetic fuel projects, including coal gasification, emphasized loan guarantees. This mechanism would have addressed directly the serious problem of potential lender reluctance to support the technical and commercial risks associated with pioneer synthetic fuel ventures. Because of Congressional concern about loan guarantees as a policy tool, generic loan guarantee authority was not approved until relatively recently.

DOE estimated that it would take two years to win Congressional approval for guarantees large enough to assist a commercial coal gasification project. They judged this to be too long and so requested that tariff arrangements to guarantee loans be approved by FERC.\(^2\)

**UTILITY INTEREST**

Gas utilities developed an interest in coal gasification, as well as other unconventional gas supplies, because federal economic regulation of gas diminished financial incentives for gas production. This led to a shortage of supplies available from natural gas producers. To appreciate the reasons for these shortages, it is helpful to briefly review the history of natural gas regulation.

The production of natural gas was unregulated during the early stages of federal natural gas regulation, but in 1954, the Supreme Court ruled that the Federal Power Commission (FPC) had the responsibility

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\(^1\)El Paso Natural Gas Co. filed the first application for Federal Power Commission approval of a coal gasification plant in 1972. This project is still in planning with a new application expected in early 1979 (according to American Gas Association, *Gas Supply Review*, Vol. 6, No. 12, September 1978, p. 18). Commercial-scale is generally considered to be in the range of 100 to 250 million cubic feet per day. It is worth noting that the Lurgi technology used in all commercial proposals so far is a proprietary technology that has not received federal development support.

\(^2\)This issue is discussed in greater detail in Section III.
of regulating gas field producer sales to interstate pipelines.¹ After various attempts to regulate individual producers through principles based on costs incurred failed, the FPC adopted price ceiling regulations for gas producer sales on the interstate market.² As low cost gas supplies were rapidly depleted, the market clearing price for domestic gas sold interstate rose above the FPC price ceiling and a "natural gas shortage" developed because supplies at the regulated price were inadequate to meet the demand. To deal with these shortages, the FPC developed a type of rationing policy known as the curtailment priority system. First applied in November 1970, the curtailment plan set priorities for access to available gas supplies, based on end uses and volumes of gas consumption.³ These federal regulatory actions led to similar actions at the state and local level, with the addition of another rationing device, moratoria on new gas hookups.

The gas industry turned to several unconventional gas supply sources as candidates to fill the "supply gap" generated by the interstate price ceiling.⁴ The technologies explored to provide gas supplies that could add to available domestic regulated natural gas included the importation of liquefied natural gas (LNG) and the production of SNG from coal and from liquid hydrocarbons.

To proceed with a coal gasification project, Commission approval is required for the sale and commingling of the SNG from coal with interstate natural gas.⁵ Commission approval is granted through the issuance of a certificate of public convenience and necessity. The Commission typically examines the "sufficiency" of demand for the proposed supply project (with the demand based on prices established in

²Breyer and MacAvoy, Energy Regulation, pp. 57-59.
⁴The gap was also exacerbated by the pricing methods employed in gas tariffs. This point is discussed later in the analysis.
⁵The term "Commission" is used in this report to refer to the FPC or its successor, FERC.
an approved rate schedule as a condition of the certificate). It also assesses the capacity of the applicants to provide the proposed service.

LNG importation has been used as a source of gas supplies. However, as of this writing, no SNG from coal project has been approved with conditions acceptable to the applicants.\(^1\)

**OTHER PARTIES INTERESTED IN COMMERCIALIZATION DECISIONS**

An understanding of the major decisions along the path to successful commercialization of a new gas supply technology helps us distinguish obstacles to private sector adoption that regulators might appropriately seek to reduce from obstacles performing the useful function of keeping uneconomic goods out of the marketplace. For a new gas supply technology to be commercialized, the judgments of many different organizations and individuals must all progress towards adoption decisions. The concerns of two especially important groups are briefly examined here.

For the first group, utility sponsored projects, both creditors and equityholders are conservative investors who can be expected to want to minimize their risks. They will seek pre-start purchase agreements as evidence of demand for the gas that would be produced. They will desire provisions for repayment of their investment even if the plant fails. (Creditors can be expected to insist on such guarantees.) Moreover, investors will want evidence that regulators are likely to remain committed to guarantees made and amenable to the entry of any prudently incurred costs in the rate calculations.

The second important set of actors consists of state public utility commissions (PUCs). Of course, each PUC can interpret its role to protect the public interest of their constituency differently. Nevertheless, each is likely to assess the importance of new supplies from coal gasification relative to alternative supplies or to other means of balancing demand and supply, such as policies promoting conservation. Given a local need for gas from a coal gasification project, the affected PUCs can also be expected to desire that incentives to minimize project costs

\(^1\)SNG from liquid hydrocarbons projects are used for intrastate sales—typically as a peak-load source of gas—and involve no federal jurisdiction.
are maintained. The PUCs can influence the outcome directly through regulatory action or through intervention in federal regulatory proceedings.

CHANGING SUPPLY OUTLOOK

At about the same time that DOE was formulating its policies on the regulation of SNG from coal, Congressional conferees were reaching a compromise on the natural gas policy sections of the National Energy Act. This compromise deals with the pricing of natural gas from all sources (not synthetic natural gas), and therefore, does not deal directly with the issue of coal gasification regulation. Nevertheless, enactment of the compromise alters the institutional environment into which coal gasification must be implemented.

The Natural Gas Policy Act of 1978 (NGPA) adopts a policy of phased deregulation for the price of new natural gas supplies and moves closer to creating future free market conditions for the supply of new gas and the sale of higher cost gas supplies. It grants the President the authority to allocate interstate pipeline supply gas and end-user owned gas transported under FERC authority in an emergency and would call for the study of the need to allocate intrastate gas in such an emergency. The NGPA also extends FERC's authority to regulate the length of time a contract for interstate and intrastate purchases can be in effect. Both gas supply and demand should respond to the resulting gas price increases.

The NGPA establishes a form of incremental pricing, i.e., a tariff for which some additional units of gas must be purchased at a price higher than the price for the first units, for interstate natural gas sales through a two-phased implementation. State PUCs are required to pass through the aggregate surcharge generated by the incremental pricing mechanism to industrial users. The incremental price has a maximum ceiling of the 8tu equivalency price of competitive fuel oil, after which point any additional costs are rolled into the "normal pipeline cost recovery procedures."^2

^1 Natural Gas Policy Act of 1978 (NGPA).
^2 NGPA, Title II, Incremental Pricing.
In addition to changes in the outlook for future domestic natural gas production resulting from the NGPA, recent reports of giant oil and gas fields in Mexico must be incorporated into U.S. energy policy. Although Mexican gas could have many of the problems associated with other energy imports, a re-evaluation of how Mexico's newly discovered energy wealth could affect American-Mexican relations would relate to coal gas policy.

Thus, important changes have occurred in the gas supply outlook for U.S. markets since utilities first began to consider coal gasification seriously. Moreover, the growth of expected costs for SNG from coal plants has widened the gap between SNG from coal and less exotic gas supplies that can be developed under the NGPA.¹ These changes have shifted the rationale for gas industry support of coal gasification from development of a needed new gas supply source to insurance against the chance that other expected supplies may never materialize. This shift is apparent in a recent industry comment in support of a coal gasification venture: "this project (the Great Plains Gasification Project described later) has now become truly a demonstration of the technological, economic, and environmental viability of the coal gasification process."² If the reason for constructing a new coal gasification plant is to provide a form of national insurance, then requiring the consumers receiving the gas from such a demonstration project to pay all project costs may be inequitable.

¹See Hederman, Prospects, for a discussion of coal gasification cost growth.

III. REGULATORY APPROACH TO UNCONVENTIONAL GAS SUPPLY PROJECTS

This section reviews federal regulatory treatment of the gas supply initiatives proposed by gas utilities once these companies saw that regulated domestic natural gas production would be inadequate to meet projected demand. This review is presented within a policy framework developed below.

MAJOR COMPONENT POLICIES

Although there are many related issues associated with the regulation of a coal gasification project, three policy components are of prime importance to federal policymakers:

- Pricing policy
- Curtailment policy
- Risk allocation policy

An understanding of these policy components is critical to understanding the regulation of unconventional gas supplies. Therefore, this analysis examines these policies in detail before proceeding to review regulation of LNG imports and coal gasification projects.

In some cases, a fourth policy element may be relevant, the extent of federal regulatory jurisdiction. Normally, PUCs and other non-federal regulatory bodies retain discretion for rate setting within their jurisdictions. However, federal regulators can limit this discretion and such an option is discussed where relevant.

PRICING POLICY

Three major pricing policies have been used or proposed for gas sales. These policies, called rolled-in pricing, incremental pricing, and marginal cost pricing, can have different efficiency and equity

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1In addition to the economic regulation of natural gas, FERC and the Economic Regulatory Administration have jurisdiction over many regulatory matters for natural gas, electricity, and oil including national security, coordination of planning, and safety.
effects depending on whether costs are increasing, decreasing, or constant.

Rolled-in pricing is the pricing method that has been applied historically by the Federal Power Commission, the predecessor to FERC. With this method, the costs of all supplies of gas sold by an inter-state pipeline company to distribution companies or direct industrial customers are averaged together so that the resulting price level is a weighted average of the costs of the various gas supplies of each natural gas seller.

At one time, the differences in costs were small enough that the administrative convenience of this approach was a sufficient reason for its use. However, in the recent past, the costs of new gas supplies have been rising rapidly. Because of the long term nature of gas supply contracts (typically 20 years), this rapid rise has led to significant differences in the costs of pipelines' various gas supplies. (One gas utility executive mentioned a range on the order of 8 or 10 to 1.) The use of the rolled-in pricing method can result in an average cost significantly lower than the price of a pipeline's most recent or highest cost gas purchases.

Economists argue that when unit costs are increasing rolled-in pricing results in an inefficient allocation of resources because the price facing the consumer does not reflect the value of gas that would be saved if the user consumed less. Tybout describes this method as introducing a subsidy, "The production of non-historic gas is, in effect, subsidized by the prices of historic sources."

Marginal cost pricing is the setting of the price for all units of the same good at the unit cost of the cost of the last unit produced or purchased. Many economists have said that this pricing method would assure economic efficiency because every potential customer would have to value the use of a unit of gas as much as it cost to replace it. One major problem with marginal cost pricing when costs are increasing is the high level of economic rents that would accrue to gas producers who hold low cost historic supplies of gas.

The effects of these two alternative pricing methods can best be understood by considering the following illustrations.\(^1\) Figure 1 shows a situation in which the supply at the retail level of an additional unit of gas costs more than the average unit cost of supply as it might be viewed by regulators. At the market clearing (marginal cost) price (0B), the gas supplier revenues would be OBCO\(_1\). These revenues exceed the cost of supplying Q\(_1\) units of gas (0AEQ\(_1\)), producing economic rents of ABCE.

The use of rolled-in (or average cost) pricing assures that the suppliers do not obtain high rents, but it generates a problem of poor signals to potential consumers, as shown in Figure 2. With rolled-in (average cost) pricing, Q\(_3\) units of gas are demanded. Supplier revenues (OFHO\(_3\)) include no rents for the supply of Q\(_3\) units of gas. Some quantity of gas is supplied for less than the new market clearing price (0F). In Figure 2, Q\(_2\) units are supplied at a cost less than the rolled-in price of OF, and the excess profits on this supply (JFGK) cover the extra cost of the inefficient supplies in excess of the point where the cost of supply equals the value of the gas consumed (AFHI) (equal to GHL). Presumably, the low cost gas is from historic natural gas sources, and this is the phenomenon described by Tybout in an earlier reference as the subsidization of non-historic gas production by historic sources.

Options exist for avoiding both (1) the large-scale transfer of wealth to gas utilities associated with marginal cost pricing and (2) the incentives for wasteful consumption of gas associated with rolled-in pricing. For instance, Camm has pointed out that the distributional effect of marginal cost pricing could be negated through such mechanisms as franchise fees or inverted block rates.\(^2\)

To date, rolled-in pricing has continued as the pricing method applied by federal gas regulation, and marginal cost pricing has not

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\(^1\)This discussion draws on analyses by the author (to be reported in a forthcoming study) for the National Science Foundation.

Fig. 1--Increasing marginal costs

Fig. 2--Rolled-in pricing
received serious policy attention. However, an intermediate measure called "incremental pricing" has made significant progress in terms of being considered as a serious policy option.\footnote{An inverted block rate structure (i.e., low prices for first units supplied, higher thereafter) is in effect in California, and this is a form of incremental pricing. Other objections to marginal cost pricing raise questions regarding its administrative feasibility and the uncertainty that it would introduce into private sector decisions. The following examples illustrate some of these problems. With respect to administrative feasibility, marginal cost pricing could provide utilities with the incentive to seek high priced gas at the margin because with this pricing method revenues would rise if the marginal cost rises. With respect to the introduction of uncertainty, this method could be unattractive to utilities. Because of the poor quality of demand data, the price elasticity of demand for gas is not well known. Until such information became available, utilities would have to make gas purchases without having a good idea of what the system demand might be at the marginal cost price.}

\textit{Incremental pricing} can be implemented in many ways, but the basic principle is that supplemental supplies of gas be priced at their incremental costs.\footnote{The term "supplemental supplies" is not precisely defined for natural gas regulation. In general, it refers to any unconventional sources of gas fuels, including offshore natural gas, imported LNG, synthetic gases, and even high-cost, on-shore gas from such sources as tight sands or Devonian shale.} This pricing method has received serious attention by federal energy regulators and was adopted by the FPC for at least one project before being revoked upon reconsideration.\footnote{Federal Power Commission, \textit{Trunkline LNG Co.}, \textit{Trunkline Gas Co.}, "Opinion and order on proposal to import liquefied natural gas to the United States from Algeria," Docket No. CP74-138 et al., Opinion No. 796, April 29, 1977.}

Incremental pricing combines some of the advantages and disadvantages of both rolled-in and marginal cost pricing. It avoids the massive wealth transfers that would result from pure marginal cost pricing, but at the margin faces consumers with a price more closely reflecting the cost of providing an additional unit of gas. An incremental pricing scheme (RSMC) is illustrated in Figure 3. Each consumer would be offered a fraction of his gas demand (the first $Q_1/Q_4$) at price OR. Additional gas would be offered for $P_{TB}$, and this would lead to a balance of supply and demand for $Q_1$ units of gas. This scheme maintains
the quantity demanded at the same level as with marginal cost pricing but reduces economic rents (from ABEC to TMC). ¹

![Diagram](image)

Fig. 3—Simplified illustration of reducing suppliers' surplus through incremental pricing

Although consumers would get better signals with respect to short run consumption decisions, economists argue that consumers are still subsidized by an amount equal to the difference between the cost of a marginal unit of gas and the price of the lower priced units of gas available to users. Depending upon its structure, this subsidy could lead to an economically rational decision to avoid implementing energy conservation measures making sense in the long run if all gas purchases were at the marginal cost of additional gas.

In addition, incremental pricing may introduce administrative feasibility problems. If incremental pricing is to be implemented through some form of price discrimination for different levels of consumption by end use consumers, it is essential to know when a user has

¹Of course, the gas supply system and its economics at each stage are much more complex than any one diagram could present. Rather than walk through the effects of each sale of gas, which would require discussion of many issues that are important but not especially germane here, this illustration seeks only to provide an illustration of incremental pricing's main principle.
shifted his share of low cost unconventional gas to high cost supplemental gas supplies. Is it after x units have been used each month, or when y percent of consumption rate in a benchmark year has been reached? Suggested solutions include quotas and entitlement programs.¹

**CURTAILMENT**

In recent years, the interstate market has experienced serious shortages of natural gas supplies. The establishment of natural gas price ceilings (see above) led to shortages. Moreover, the use of rolled-in pricing widened the gap between the amounts of gas demanded and supplied. The results of combining the price ceiling and rolled-in pricing are shown in Figure 4. Gas is not produced when production costs exceed the price ceiling, because costs above the ceiling price cannot be charged to purchasers. \( P_C \) represents the maximum legal retail price for sales by natural gas producers. Given a ceiling price and rolled-in pricing, consumers would be charged the average cost of production, \( P_{AV} \). The combined regulations would lead to an imbalance between the quantity of gas demanded and that supplied \( (Q_{DC} - Q_{SC}) \).

![Diagram of price and quantity with price ceiling and average cost]

Fig. 4--Combined rolled-in pricing and price ceiling

¹Jon Goldstein and Michael Sedmak discuss this issue in "Incremental Pricing of Supplemental Gas," Federal Power Commission, Office of Economics, August 1976, p. 5. In addition to receiving serious PPC
One response of the Commission to these shortages has been the development of a rationing system called a "curtailment priority plan." This plan, which originated around 1974, sets priorities for gas service when available gas supplies are inadequate to serve all customers.\footnote{1}{See FPC, Order Nos. 467, 467-A, 467-B, 467-C.}

The curtailment plan's priorities are roughly as follows: residential and small commercial users receive the highest priority, followed by other commercial, feedstock and other critical industrial requirements (such as minimum plant protection), firm industrial requirements, and interruptible industrial users.\footnote{2}{The nine priority categories are presented in 18 CFR at 85, (revised April 1, 1977).}

The coordination of pricing method and curtailment policy has important implications for new projects producing high cost gas. A potential purchaser of gas may be willing to pay a premium price for assured gas supplies. However, current regulatory practice results in gas from all sources being viewed as insecure and thus no gas supply is truly assured. The Commission has considered separate purchase agreements for high priced gas supplies on a guaranteed (or non-curtailable) basis but has never succeeded in implementing such an approach. Moreover, some potential users have not believed that the Commission could assure firm supplies.

**RISK ALLOCATION**

The risks of new gas supply projects are sufficiently important that any regulatory policy must consider ways to reduce risks and to allocate remaining risks among investors, users, and the government in a mutually acceptable way. The manner in which risks are treated can have an important influence on whether certain gas supplies will be implemented and this is especially true for risk-laden coal gasification projects.
Types of Risk

The development of new gas supplies involves such risks as:

- Project failure due to (i) problems of basic technology; (ii) social and political events; (iii) poor management.
- Performance levels below expectations (for any of the reasons listed for project failure).
- Incorrect demand forecasts.
- Changes in regulations.

Risks of project failure and unsatisfactory project performance may result, for example, from technological uncertainty involving the large-scale use of novel chemical processes in a major undertaking. The risk of technological uncertainty inherent in any large engineering project can be reduced prior to commercial scale implementation through effective R&D programs. Regulators can provide funding for relevant R&D to encourage risk reduction or provide incentives for accepting the risks. However, the regulators still need to anticipate the residual level of technological risks in setting conditions on the tariffs to be applied to the project.

Social and political factors largely outside the control of either gas companies or federal regulators also may cause project problems. For instance, an exporting country might embargo LNG shipments or a state might prohibit the use of water for energy conversion. These possibilities must also be anticipated by regulators and provided for in the conditions imposed upon project approval.

In providing an environment that encourages gas company management to accept the risks of project failure, unsatisfactory performance, or low demand, regulators must also ensure that the gas companies retain the responsibility for risks associated with potential management problems. Regulators may make allowances for the risks associated with predicting future demands, especially for gas at a cost high above any actual commercial experience. However, regulators must also guard against forcing consumers to pay the costs of any unsuccessful, imprudent risks taken by a gas company in assessing demand.
Finally, regulation itself introduces risks. Because new sources of baseload gas involve long-term projects having useful lifetimes of 20 years or more, the prospect of significant regulatory changes discourages gas company investment in high cost baseload capacity. Gas user and gas utility executives and state regulatory staff have pointed out that regulators have forced gas companies to break contracts in the past, and therefore, even the existence of a contract does not necessarily allay these concerns.\(^1\) To the extent feasible, regulators could seek to guarantee that the "ground rules" established at the onset of a project would remain in effect for the life of the project.\(^2\)

**Mechanisms for Dealing with Risk**

The uncertainties associated with commercial scale high-Btu coal gasification projects are great enough that neither gas industry investors, lenders, gas consumers (as represented by federal regulatory agencies), nor the federal government has been willing to accept the full risk. Several policy tools are available for allocating these risks among a project's potential beneficiaries, making risks acceptable to those who must bear them, and minimizing the social costs associated with the acceptance of risk. These mechanisms include all events tariffs, minimum bills, surcharges for construction work in progress, automatic cost passthroughs, changes in the allowed rate of return, R&D surcharges, loan guarantees, and purchases at guaranteed minimum prices.

Gas companies have sought *all events tariffs* to shift all risks from them and their financial backers to gas users. An all events tariff would accomplish this by committing a gas company's customers to paying all the costs incurred in connection with an unconventional gas project whether or not any gas is ever produced.

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1\(^\text{A common example of gas companies' being forced to break a contract is the forced curtailment of gas users with firm supply agreements.}\)

2\(^\text{Grandfather clauses to exempt ongoing activities with regulatory changes provide one method for this problem. Ground rules requiring new legislation to change them provide another.}\)
An intermediate measure that can share risks between gas users and producers, *minimum bill provisions*, has also been introduced. Such provisions require users to cover certain ongoing expenses—typically including debt service, property taxes, insurance, and other costs incurred independent of gas production levels—whether or not a project produces the planned levels of gas output. The risks can be shifted to the gas suppliers from gas users by the establishment of a *maximum gas price*, which may be adjustable after project completion and further regulatory review.

Capital intensive unconventional gas supply projects such as coal gasification facilities involve significant capital expenditures during construction, prior to the operational phase of the project. These expenditures are significant to project investors. By approving a *surcharge for construction work in progress* on current gas use, regulators can permit the shifting of some front-end risk from gas company investors to those consuming gas during the construction period.

Production facilities to process or manufacture new sources of gas should have useful lifetimes of about 25 years. The operation of such ventures involve significant risks concerning the future costs of necessary inputs to production processes. These risks may be shifted to gas consumers through the adoption of *cost of service tariff provisions* that allow gas producers to automatically pass certain prespecified cost increases through to customers as gas cost increases.

Proponents and opponents of unconventional gas projects argue about the *appropriate rate of return on invested equity*. A rate higher than the standard return on equity for gas utilities (about 13 percent) acknowledges the existence of greater than normal risks. This regulatory mechanism does not reallocate risk in the same direct way as the tools mentioned above, but it makes acceptance of the risks of failure more attractive through the enhancement of the potential rewards.

Some gas supply projects may produce information of value to all gas users. The Gas Research Institute (GRI) was established recently as a means of conducting such projects, and gas users pay for these activities through an *R&D surcharge* levied on each member gas utility (and allowed
by regulators). Certain aspects of pioneer coal gasification project expenses might be shared among all gas users using such a mechanism. 2

Loan guarantees and guaranteed minimum prices are not within the scope of regulatory powers, but regulatory approval of their inclusion in an unconventional gas supply project would be required. These tools would shift some risks from project investors to taxpayers through the assumption of selected risks by the federal government.

EXTENT OF FEDERAL CONTROL

State and local utility regulators may or may not share the philosophy associated with a particular federal gas regulation. Federal regulations control interstate sales of gas, but intrastate regulations for final retail sales could stymie the intent of the federal regulatory policy. The problem is illustrated in the case of curtailments. There are many differences among states which have dealt with gas shortages, and their approaches are not always identical to the Commission's. For instance, in a 1974 survey by the National Association of Regulatory Utility Commissioners, only three states listed "FPC Guidelines" as a factor considered in establishing curtailment priorities. Yet no major discrepancy between federal intent for curtailment priorities and state curtailment regulations was mentioned in conversations with state and federal regulatory staff or with the private sector.

Pricing policy is another matter. Several state PUCs joined in the opposition to FPC attempts to price high cost gas on an incremental basis, and no official state support has been shown for the proposal.

1Utility-specific R&D costs are sometimes also approved by regulators. In such instances, the R&D expenses are immediately flowed through to the utilities' customers in a manner much like the automatic cost passthroughs just discussed.

2It is the author's understanding, however, that some state public utility commissions approved the R&D surcharges required to establish the GRI only because GRI agreed not to fund large demonstration projects.

Congress, recognizing this opposition, specifically mandated in the NGPA that the incremental pricing provisions of that Act must be implemented at all levels of sales.¹

For unconventional gas supplies not covered by the NGPA, including SNG from coal, federal regulators could consider several actions to avoid having state and local regulators negate the intended effects of federal regulation. Among the weaker actions that FERC could take are expressions of a desire that federal pricing regulations be extended to retail sales² and federal interventions at state PUC rate hearings.³ Federal regulators may also be able to condition project approval on the extension of federal regulatory policies to retail sales. Analysts have mentioned this option for ERA and FERC, but the legal basis for such a policy has not yet been established. The current limitations of federal jurisdiction, however, result from laws that Congress can alter rather than from any constitutional limits. Perhaps the strongest action available would be to seek a legislative extension of federal authority to retail gas sales for certain gas projects, much like the incremental pricing provisions of the NGPA.

¹NGPA, Title II, Sec. 204.
²This approach was taken in FPC Opinion No. 796, in April 1977, in the Trunkline LNG import case.
³This approach is being used in electric utility rate reform efforts.
IV. THE ECONOMIC REGULATION OF HIGH COST GAS SUPPLIES TO DATE

This section reviews Commission decisions concerning the regulation of high cost gas supply projects. The types of high cost gas supply projects that have received the most attention from the Commission include liquefied natural gas (LNG) importation and high-Btu coal gasification projects. Base load LNG projects have been implemented, but no coal gasification projects have proceeded past the design and proposal stages.

LNG IMPORTS

LNG imports were the first successfully implemented projects to bring unconventional sources of base load gas supplies on-line. A brief review of the Federal Power Commission (FPC) decisions on the economic regulation of LNG imports follows.

Opinion No. 622

In 1970 and 1971, Columbia LNG Corporation, Consolidated System LNG Company, and Southern Energy Company (Columbia) filed applications for the first project to supply base load gas by importing LNG. Columbia sought to import and sell over a 25 year period about one billion cubic feet per day of LNG. In their applications, Columbia sought to

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1 Some of this discussion is based on work analyzing federal regulation for the National Science Foundation.

2 "Base load" gas supplies involve large volumes of gas to supply steady, long term (usually 20 year) supplies of gas for the pipeline company. Gas utilities (usually distribution companies) sometimes maintain smaller scale unconventional production capability to serve peak system demands. Although producing SNG from liquid hydrocarbons is the most common peak shaving measure, at least one utility (Districtgas, in Boston, Massachusetts) has imported LNG on a small scale to meet peak demands.

3 FPC Docket No. CP71-68, et al.

4 This is about four times the capacity of the most commonly mentioned commercial scale coal gasification plant, 250,000 Mcf (thousand cubic feet) per day.
include the LNG with its other gas supplies, but in Opinion No. 622 the FPC said "we reject the concept of rolling in relatively expensive supplemental gas supply costs with a pipeline's unit cost of gas supply." They imposed an incremental pricing scheme for which separate tariffs would have to be filed reflecting "incremental costing concepts." The FPC also ruled that the LNG supplies should be included in system-wide volumes in time of shortages, and thus would be curtailable. The Commission also conditioned approval of the LNG imports on the setting of ceiling prices (77 cents per million Btu at Cove Point, 83 cents per million Btu for Southern Energy). The Commission said that the "incremental pricing concepts which we adopted in this opinion should be 'flowed-through' to the ultimate gas consumer." State and local regulation was to have been circumvented by requiring that LNG could only be made available to distribution companies with separate rate schedules for LNG service and to direct sales customers only for "incremental volumes over and above historical volumes of purchased gas." This first federal regulatory policy position is outlined in Column A of Table 1.

Opinion No. 622-A

The applicants responded that the LNG project could not be financed under the conditions imposed by Opinion No. 622. After a rehearing, the Commission made some concessions to the applicants' concerns. Reconsidering the appropriate curtailment policy for the high priced LNG, the Commission decided that charging users the higher full cost for LNG purchases would justify contracting for such LNG "on a firm basis, not subject to curtailment."

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2 Ibid., p. 17.
3 Ibid., p. 18.
4 Ibid., p. 17.
5 Ibid., p. 19.
6 Ibid., p. 19.
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<td>Incremental sales on a firm basis exempt from curtailment</td>
<td>Rolled-in supply (same curtailability as other gas)</td>
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<tr>
<td>Risk allocation</td>
<td>All risks to investors, with maximum LNG prices (subject to review) and no payments if no deliveries</td>
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<td>Limited minimum bill provisions</td>
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<td>Adjusted col. D's minimum bill provisions: -- annual rather than daily basis -- no penalties if 90% volumes delivered</td>
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<td>PUC discretion for retail sales</td>
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"Burner tip" implies to the ultimate consumers.
The FPC also altered the extent to which it tried to enforce incremental pricing. Rather than be forced to test in the courts its authority to require incremental pricing for sales to gas users, the Commission decided to leave the determination of the appropriate end-user rate schedule to state and local regulatory commissions. Incremental pricing through separate rate schedules was still required for sales by the pipelines.¹

Although the Commission was still not prepared to accept the "cost of service" proposals made by the applicants, they decided that some risk sharing by the pipelines' customers was appropriate. The Commission allowed the sellers to collect for certain out-of-pocket expenses from sellers during periods of non-delivery.² However, LNG company stockholders would not have been allowed to recover equity through depreciation nor a return on equity during any period of non-delivery.³ This decision is summarized in Column B of Table I.

The applicants were still dissatisfied with the FPC's conditions on the LNG project, and they appealed to the courts on the issue of incremental pricing. The United States Court of Appeals for the Fifth Circuit, noting that there were only "ten pages of testimony out of a total record of 14,500 pages of testimony, affidavits, briefs, opinions, etc.," ruled that the Commission had adopted incremental pricing on the basis of insufficient evidence to depart from the longstanding practice of rolled-in pricing.⁴ The incremental pricing requirement was reversed and the case remanded to the FPC for an evidentiary hearing.⁵

Opinion No. 786

After hearings on incremental pricing, the Commission again acted on the Columbia project in January 1977. The membership of the Commis-

¹Ibid., p. 9.
²The following expenses were to be reimbursed: O&M expenses, taxes payable, interest on debt, debt repayment requirements, and amount, if any, gas producer would owe LNG suppliers for failure to accept deliveries. ³Ibid., pp.10-11. The expenses to be reimbursed would have included operating and maintenance expenses, taxes payable, interest on the existing debt for the LNG project construction, and requirements for that debt's repayment. ⁴Columbia LNG Corp. v. FPC, 491 F. 2d 651, 652 (1974). ⁵Ibid., p. 655.
sion had changed significantly since the earlier Columbia decisions, and a major concern of some of the new members was the long delays caused for the Columbia LNG project by regulatory problems. For this and several other reasons, including the onset of a severe gas shortage, the Commission reversed itself and approved the rolling in of the LNG into the applicants' other gas supplies. In this opinion, the Commission emphasized that it was not setting a precedent applicable to other supplemental gas supply projects (see Column C of Table 1).

The applicants accepted Opinion No. 786, the project proceeded, and operation began recently.

Opinion No. 796

Shortly after resolving the Columbia LNG case, the Commission considered the applications of the Trunkline LNG Co. and Trunkline Gas Co. (Trunkline) to import and resell about 460,000 Mcf equivalent of LNG per day. The FPC considered ten issues relevant to this case, including economic, environmental, safety, and technical and commercial feasibility questions. We concentrate here on the economic issues.

The new Commission returned to an LNG pricing policy based on incremental pricing, stating that a "necessary complement" to this decision was the exclusion of the LNG supplies from Trunkline's curtailment plan. The Commission also encouraged state commissions to require

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4 This is slightly less than twice the capacity of a "commercial scale" coal gasification facility.


6 Ibid., p. 24; see also Eads et al., *The Role of Cross Subsidization*.

local distributors to sell the LNG on an incrementally priced, firm basis.¹

Opinion No. 796 also addressed several aspects of the risks associated with LNG importation. The Commission set an initial rate ($3.37 per Mcf) for the sale of LNG by Trunkline LNG to Trunkline Gas, with provisions to review this rate for purposes of adjustment as a result of changes in the cost of service. Rate changes due to automatic currency adjustments could be passed through without a full rate filing. The Commission rejected Trunkline's proposed tariff but did provide for the recovery of nonequity related fixed costs, including those related to debt, taxes, and fixed operating and maintenance expenses. The Commission did not adopt provisions for allocating the costs of project failure, but stated that a filing after project failure would be considered for the purpose of amortizing the project costs remaining at the time of failure to Trunkline's cost of service.²

Opinion No. 796-A

Opposition to Opinion No. 796 arose from gas companies, industrial gas consumers, and the affected state regulatory commissions. The gas companies asserted that the project could not be financed under the conditions imposed by the Commission. The industrial gas users opposed the higher prices because they did not believe they could be assured gas at any price. The state regulatory commissions opposed incremental pricing for base load gas supplies and noninterruptible sales to industry and expressed concerns about administrative feasibility. Only a group of environmental/consumer interests led by the Environmental Defense Fund supported the FPC staff position for incremental pricing.

Two factors appear to have been influential in the Commissioners' reconsideration of their decision on the Trunkline case. First, the severe curtailments of the previous winter made the possibility of future curtailments to residential gas users a major concern. Second, the new Carter administration energy initiatives, which included a reorganization of the energy agencies and the end of the FPC as well as proposals

¹Ibid., pp. 26, 27.
²Ibid., pp. 19-23.
for gas pricing, made it easier for the Commission to allow the Trunkline project to follow the path of traditional FPC policy and to "pass the buck" to the new administration to develop a LNG import policy.\(^1\)

In Opinion No. 796-A the Commission, concerned primarily with enabling the project to be financed, decided to allow rolled-in pricing.\(^2\) In conjunction with the pricing decision, the Commission ruled that the LNG should be rolled in with other Trunkline gas supplies under its end-use curtailment plan.\(^3\)

The Commission rejected Trunkline requests to alter the procedures for rate adjustments based on changes in shipping costs or costs for the LNG receiving terminal; however, it did accept some suggested modifications of the minimum bill provisions. The suggested modifications found acceptable by the FPC included permitting calculations related to the minimum bill on an annual (rather than daily) performance basis, and imposed no penalty (i.e., loss of return on or return of equity) if at least 90 percent of the annual volumes were delivered. These provisions were integrated into the minimum bill provision set in Opinion No. 796.

About one month after Opinion No. 796-A, Trunkline filed an official acceptance of the certificate issued.

**COAL GASIFICATION**

While some gas companies looked overseas for new gas supplies, others turned to a modernized form of the original energy source for the gas utility industry, coal gasification. Instead of the low-Btu gas produced from coal in the early days of gas utilities, gas pipeline companies sought to manufacture high-Btu gas, which could be transported economically from the mine sites through pipelines to gas users.

\(^1\)See Eads et al., *The Role of Cross Subsidization*, for an expanded discussion.


\(^3\)Ibid., p. 9.

\(^4\)Incremental pricing has been mentioned as one likely condition.
Opinion No. 663

In 1972, El Paso Natural Gas Co. (El Paso) filed an application for a project to provide synthetic natural gas produced from coal in New Mexico to the El Paso system. Shortly afterwards, Transwestern Coal Gasification Co., Pacific Coal Gasification Co., and Western Gasification Co. applied for authorization of a similar project in a nearby area. The SNG produced at this plant was to be sold to the Transwestern Pipeline Co.

The two projects were similar in size and technology, but there was a significant difference in the applications for the two projects. The Transwestern project sought FPC authorization for the coal gasification plant, and the pipeline to the commingling point, but El Paso claimed that such facilities were non-jurisdictional. The FPC, anticipating the likely future importance of coal gasification, consolidated the two applications to determine the Commission's jurisdiction over such projects. The FPC concluded that the gas produced was artificial gas, and therefore, under the provisions of Section 2(5) of the Natural Gas Act, the feedstock, plant, and transportation facilities for unmixed artificial gas were not within the Commission's jurisdiction. Origin-ally there was gas industry concern that if a coal gasification plant were non-jurisdictional and outside a gas company's rate base, then the economic risks of developing coal gasification would be too great to proceed. However, other mechanisms developed for SNG from coal sales contracts have eliminated this concern.

Opinion No. 728

Shortly after Opinion No. 663 was issued, Trans Coal, Pac Coal, and Wesco amended their application to the Commission to seek authorization for the direct sale of the SNG produced from coal to Pacific Lighting Service Co. (Pacific Lighting) and Cities Service Gas Co. (Cities), two Transwestern Pipeline customers. Transwestern sought

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2Ibid., p. 3.
authorization to provide the transportation services required for these sales.\(^1\) The proposed Lurgi process coal gasification plant, to be located on a Navajo Reservation in New Mexico, was to have the capacity to process daily about 25,000 tons of coal into 250,000 Mcf of SNG. The plant and connecting pipeline costs were estimated at $447 million (mid-1973 estimate).

The Commission listed several major issues, including jurisdiction, pricing, distribution of risk, the need for the supplies the project would produce, and supply alternatives that they saw posed by this project.\(^2\) They identified the pricing of the SNG as the central issue in the proceeding.\(^3\) The SNG purchasers, Pacific Lighting and Cities, had agreed to purchase the entire output of the gasification plant on a cost of service, all events basis.\(^4\) The Applicants asserted that such a contractual agreement was needed to arrange project financing.\(^5\)

The issues of how the gas supplied should be priced to a purchasing distributor and whether incrementally priced supplies should be protected from curtailment were not a part of the legal record of this case, which precluded FPC action on these matters. However, the Commission noted that since Pacific Lighting, which would be purchasing 75 percent of the gas direct from the SNG plant at the California border for intrastate deliveries, this 75 percent of the project's gas would be incrementally priced at the distributor's level. The FPC also "put the parties on notice" that these pricing and curtailment issues would be considered in the future.\(^6\) The direct sales from the coal gasification project to the distributors were under FPC jurisdiction, but no attempt was made to affect the pricing methods for retail sales or other intrastate sales.

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\(^1\) FPC, "Opinion and order granting certification of transportation and sale of gas produced from coal," Opinion No. 728, Docket No. CP73-211, April 21, 1975, p. 2.

\(^2\) Ibid., p. 1. The jurisdiction issue listed by the Commission dealt only with the question of whether the Commission had jurisdiction under the authority of the Natural Gas Act over a plant that produced synthetic gas. The applicants desired the Commission to assert that it had jurisdiction.

\(^3\) Ibid., p. 11.

\(^4\) Ibid., p. 12.

\(^5\) Ibid., p. 11.

\(^6\) Ibid., pp. 21-22.
The various risks associated with the project and related to the ultimate price of the SNG from coal received extensive attention in Opinion No. 728. The Commission agreed with the applicants that some assurance of recovery of investments would be required to attract capital for the project and that none of the companies involved with the project could provide such guarantees. Nevertheless, the FPC was unwilling to make an open-ended commitment on the part of the consumers of the type proposed by the Applicants' full cost of service, all events tariff. The Commission adopted a California Public Utility Commission (PUC) suggestion. This proposal set an initial price ($1.38/Mcf) for SNG from the gasification plant during its testing period and provided for the establishment of the "ultimate just and reasonable rates" after testing, when uncertainty had been reduced to a reasonable level. Feedstock (coal) rates were allowed to be tied to a coal mining inflation index, and passed through automatically, except that any "radical changes" in coal costs would require new Commission hearings. This decision is summarized in Column A of Table 2.

Opinion No. 728-A

The conditions imposed on the Wesco project by the certificate of public convenience and necessity granted in Opinion No. 728 were not acceptable to the Applicants. The State of California and the CPUC (California) also applied for a rehearing. After a rehearing, the FPC revised the conditions imposed on the authorizing certificate.

The Commission accepted a major increase in the price for SNG produced during the test period (from $1.38 to $2.50 per Mcf) based on "rapidly increasing" construction and feedstock costs. The Commission also agreed that rejection of a minimum bill provision could preclude

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1 Ibid., p. 15. As mentioned in Hederman, Prospects, the assets of most large gas pipelines are not much greater than the full capital requirements of a coal gasification plant.
2 Ibid., pp. 17-20.
3 Ibid., pp. 18-19.
plant financing and devised a minimum bill provision that "adequately balances the parties' interests." The FPC established a minimum bill provision with a sliding scale penalty provision basing the allowed

Table 2
FEDERAL ECONOMIC REGULATIONS FOR COAL GASTIFICATION PROPOSALS

<table>
<thead>
<tr>
<th>Policy Variable</th>
<th>(A) FPC Opinion No. 728 4/21/75</th>
<th>(B) FPC Opinion No. 728-A 11/21/75</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pricing method</td>
<td>75% incrementally priced because of direct sale to gas distributor</td>
<td>75% incrementally priced because of direct sale to gas distributor</td>
</tr>
<tr>
<td>Curtailment</td>
<td>No exemption</td>
<td>No exemption</td>
</tr>
<tr>
<td>Risk allocation</td>
<td>Fixed initial gas rate for start-up period ($1.38/Mcf)</td>
<td>Higher fixed initial rate ($2.50/Mcf)</td>
</tr>
<tr>
<td></td>
<td>Establish &quot;just and reasonable rates&quot; when uncertainty reduced to a reasonable level</td>
<td>Minimum bill provision with variable return on equity based on performance</td>
</tr>
<tr>
<td></td>
<td>Automatic feedstock costs adjustment</td>
<td>Rate revision protected from long regulatory delays</td>
</tr>
<tr>
<td>Nonfederal discretion</td>
<td>No extension sought, state PUC independent</td>
<td>No extension sought, state PUC independent</td>
</tr>
</tbody>
</table>

return on equity on the plant's actual performance in comparison to its projected performance.\(^1\) The Commission also shortened the allowed length of rate suspensions, which helped protect the project from delays in rate revision due to regulation.\(^2\) The provisions of this policy are outlined in column B of Table 1.

In filings for the rehearing, both Transwestern and California called for the federal government to assume the risk their customers did not assume, but the form and magnitude of this assistance was not made clear. The Commission, unwilling to commit itself to a set of

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\(^1\)Ibid., p. 4. The sliding scale was the following: 100% - 75% load factor (or of 950 Btu/cf heat content): 15% return on equity; 75% - 50%: 10% return; 50% - 25%: 5% return; 25% - 0%: 0% return.

\(^2\)Ibid., p. 5.
tariff conditions without knowledge of other federal assistance, said, "Pending the receipt of federal aid, the apportionment of risk cannot be clearly defined. Therefore at the time we review a proposed financing plan, it will be necessary that we re-evaluate the provisions of the minimum bill set forth above."\(^1\)

The Wesco project has not proceeded past this point because negotiations for site lease have not yet been completed.\(^2\)

**Great Plains Gasification Project**

At the time this is being written, the fate of a proposed high-Btu coal gasification project in Mercer County, North Dakota using Lurgi technology has not been decided upon by FERC, but the Initial Decision by a FERC Administrative Law Judge turned down the project's application.\(^3\) The physical and ownership characteristics of the plant have changed since the first proposal, from a 250 million cfd plant to a plant half that size and from single company ownership by American Natural Resources Company (ANR) to consortium ownership.\(^4\) Also, several significantly different approaches to regulating this project have been proposed. This section traces the evolution of the ANR project, currently considered the prime candidate to be the nation's first commercial scale SNG from coal project.

**Private Sector Proposed Certificate Conditions.** The original joint applicants for the ANR project, ANG Coal Gasification Co. (ANG) and the Michigan Wisconsin Pipe Line Co. (Michigan Wisconsin), proposed

\(^1\)Ibid., p. 5.


\(^4\)The 250 million cfd size was based on estimates of 275 million cfd maximum capacity and sustained operations at 91 percent of maximum output. The member companies of the consortium are American Natural Resources Co. (now American Natural Services), Peoples Gas Co., Columbia Gas Systems, Inc., Tenneco, Inc., and Transco.
in their initial brief a set of conditions under which they were willing to attempt to proceed with the coal gasification project. Rolled-in pricing was an important element of this proposal.\textsuperscript{1} Rolled-in pricing effectively removes any pricing policy options for the state PUCs. The rolling in of the SNG also implied that the gas produced by the proposed project could receive no protection from curtailment.

A great deal of attention was given to limiting and sharing the financial risks in this proposal. The major action to reduce the risk associated with the project is the reduction in size to one-half the scale of the earliest project proposals.\textsuperscript{2} The applicants sought a full cost of service, all events tariff, with several exceptions. They offered to accept fully the risks of project abandonment for the equity investments but the loans would have to be repaid by the potential gas users.\textsuperscript{3} The applicants offered to share the risks associated with plant operation by agreeing that no return on equity would be paid by plant customers if operations fell below 50 percent of capacity for 45 consecutive days. They also offered to accept the sliding scale provisions approved for the Wesco plant if the proposed approach was not acceptable. Other related provisions included automatic inflation adjustments in feedstock (coal) contracts and the payment of debt and equity costs on a current basis during construction and testing by means of a surcharge on Michigan Wisconsin gas sales.\textsuperscript{4}

One other important development in the private sector's actions on this project has taken place. Since obtaining federal loan guarantees in a timely fashion for this project did not appear feasible, the project sponsors sought to assure lenders repayment of loans in another

\textsuperscript{1}Michigan Wisconsin and ANG, "Joint initial brief of ANG Coal Gasification Company and Michigan Wisconsin Pipe Line Company," FPC Docket No. CP75-278, July 20, 1976, p. 45.
\textsuperscript{2}Ibid., p. 3.
\textsuperscript{3}Ibid., pp. 28-30. FPC approval would be required to abandon the project. The applicants stated that although they were willing to attempt to arrange financing without federal loan guarantees, they believed that such guarantees would be required.
\textsuperscript{4}Ibid., pp. 35-36.
\textsuperscript{5}Ibid., pp. 16, 19.
way. A consortium of five major natural gas pipeline companies representing about 20 percent of the gas pipeline industry was formed to finance the equity portion of the ANR project and to assure repayment of loans in conjunction with already mentioned tariff provisions to repay lenders.¹ This proposal is summarized in Column A of Table 3.

### Table 3

**PROPOSED POLICIES FOR GREAT PLAINS COAL GASIFICATION PROJECT**

<table>
<thead>
<tr>
<th>Policy Variable</th>
<th>(A) Private Sector Proposal</th>
<th>(B) Commission Staff Proposal</th>
<th>(C) DOE Proposal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pricing method</td>
<td>Rolled-in pricing</td>
<td>Incremental pricing</td>
<td>Rolled-in pricing</td>
</tr>
<tr>
<td>Curtailment</td>
<td>No exemption</td>
<td>Exemption</td>
<td>No exemption</td>
</tr>
<tr>
<td>Risk allocation</td>
<td>All events tariff with equity risks for abandonment (risk types not addressed)</td>
<td>All events tariff with equity lost for abandonment</td>
<td>All events tariff with equity risks for abandonment for technical or cost reasons and 60 percent equity covered in plant abandoned for other reasons</td>
</tr>
<tr>
<td></td>
<td>Full cost of service tariff with return on equity forfeited for &quot;marginal operations&quot;⁸</td>
<td>Full cost of service tariff with a variable return on equity based on plant performance</td>
<td>Higher rate of return if incremental pricing adopted than if rolled-in pricing adopted</td>
</tr>
<tr>
<td></td>
<td>Payment of debt and equity costs on a current basis during construction</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nonfederal discretion</td>
<td>No state options</td>
<td>At states' discretion anticipating incremental pricingpassthrough by relevant states</td>
<td>No state options</td>
</tr>
</tbody>
</table>

⁸The applicants also expressed a willingness to accept a variable return on equity scheme similar to that devised in connection with the Wesco project.

FPC Staff's Proposal. The Commission staff's recommendations, as reflected in staff's initial brief, differed significantly from the applicants' proposals. The staff recommended incremental pricing of the gas produced. The staff also recommended that the gas be exempted from curtailment so that it could be offered for sale on a firm basis. The staff did not seek to extend federal jurisdiction to impose its pricing and curtailment recommendations on state PUCs; however, it did note the "forward looking" character of the PUCs in the states of original interest, Michigan and Wisconsin.

The staff also gave serious attention to the issues of risk associated with the proposed project. In recognition of the higher risks, the staff recommended that a higher return on equity be allowed if incremental pricing were required than if rolled-in pricing were allowed (13.5 percent vs. 12 percent). The staff agreed that the Wesco tariff should be satisfactory for the ANR project, but they said that the applicants were actually proposing a tariff that did not go far enough in protecting consumers because it did not include a fixed initial price for gas ($4.36 per Mcf was recommended). This proposal is summarized in column B of Table 3.

DOE's Proposal. DOE has intervened in the Great Plains case to support regulatory treatment that would encourage the applicants to proceed with the project. DOE recommends rolled-in pricing for all plant output and curtailment of the gas produced on the same basis as for other gas supplies.

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2 Ibid., p. 44.
3 Ibid., p. 50.
4 Ibid., p. 50.
5 Ibid., pp. 32-33.
6 Ibid., pp. 27-31.
DOE supports minimum bill provisions that would cover the full repayment of debt and interest in any circumstances, and of 60 percent equity and return on equity in the event of abandonment "attributed to justifiable causes other than technological reasons or cost overruns." It also states that in the event of project abandonment for non-technology or cost reasons the applicants should have the right to seek recovery of the 40 percent remaining approved costs in a separate FERC proceeding. In addition DOE supports payment of interest on debt during the construction period and a cost of service tariff with a decreasing return on equity if production is less than planned and with periodic retrospective justification of costs automatically passed-through. This proposal is outlined in column C of Table 3.

**Initial Decision.** In June 1979, an administrative law judge for the Commission denied the application for the ANR project, renamed the Great Plains Gasification Project (GPGP), based on objections to the proposed financing plan. The judge stated that there might "well be a national need to get on with efforts to develop a coal gasification technology, but the costs have to be borne by America's taxpayers, not some of its ratepayers." He asserted that since the entire country would share any benefits derived from the project, it would "be inequitable to have perhaps one-third of the country pay all the costs." The judge went on to deny provisions for the all-events tariff, for the 15 percent return on equity (for the life of the project), and for surcharges to recover the cost of capital during construction. He also concluded that "since the Commission is asked by the sponsors to consider

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1 Ibid., p. 5.
2 Ibid., pp. 6, 7.
4 Ibid., p. 5.
5 Ibid., p. 6.
the financing plan as an indivisible package to be approved or rejected on an all-or-nothing basis, the plan must be rejected."\(^1\)

The Commission is currently considering this case.

**CONTRASTS IN POLICY DEVELOPMENT**

Probably the most striking fact to emerge from this policy review is the contrast between the progress made in developing compromise risk allocation measures and the continuation of radical swings in pricing and curtailment policies. In limiting and sharing the risks of coal gasification, gas utilities have shown initiative by decreasing the size of pioneer coal gasification projects and spreading risks among themselves by forming consortia. Federal regulators and applicants have discovered means of allocating remaining risks among supplier investors and gas users. They base this allocation on identifying circumstances for which one group should assume risks or cases where risks should be shared by both equity holders and gas customers. The policy tools now available appear capable of making it possible to develop a risk allocations policy acceptable to all parties for a technically feasible project.

On the other hand, pricing and curtailment policy has achieved negligible progress since the issues of incremental versus rolled-in pricing and normal versus special curtailment treatment were first raised in connection with the Columbia LNG import project. By failing to identify new opportunities that better balance the efficiency concerns embodied in the incremental pricing proposals and the project viability concerns embodied in the rolled-in pricing proposals, regulators have continued to confront the self-imposed dilemma of whether to force a full market test and endanger a project's feasibility or ignore efficiency goals to bring new gas supplies on line.

\(^1\) Ibid., p. 5.
V. FINDINGS

Before coal gasification can become an attractive commercial gas supply option important uncertainties must be resolved. These uncertainties involve (i) technological unknowns associated with actual coal gasification plant costs and performance, (ii) supply unknowns associated with the likely quantities and costs of future natural gas production, and (iii) demand unknowns associated with potential users' willingness to purchase gas at higher prices with varying degrees of supply firmness.

The Department of Energy has moved to support the commercialization of coal gasification because it has judged the potential net benefits to society from the commercial development of this technology to substantially outweigh the expected costs of development. The advantages include the national security benefits of reducing energy imports, the potential environmental benefits from using plentiful domestic coal in an environmentally acceptable manner, and the supply insurance benefits of developing a backstop technology that can provide a price ceiling for gas supplies.

For self-sustained private sector adoption to proceed successfully, uncertainty must be reduced to normal business levels. Moreover, the technological, supply, and demand information available must indicate that coal gasification can produce gas at a cost competitive with alternative gas supplies and potentially attractive to gas utility customers. Otherwise commercialization could only proceed with some continuing government intervention to cover any public benefit resulting from implementation of the new technology.

Since DOE anticipates benefits to society from a viable coal gasification industry, it has sought to encourage the gas industry to begin a pioneer coal gasification project. Arguments for subsidization of such a project rest not only on the public benefits of a coal gasification industry but also on the public benefits from the uncertainty reduction likely to result from the project. Thus, DOE wants FERC to arrange subsidies and risk sharing to provide an environment conducive to the construction of this country's first commercial coal gasification
plant. In this way, policymakers hope to reduce perceived and actual uncertainty about such a plant.

Because of budgetary and legislative constraints, DOE has sought to subsidize SNG from coal producers through the economic regulations adopted by the FERC for specific coal gasification projects. FERC, however, has traditionally aimed to fulfill a set of multiple objectives -- efficiency, equity, and industry viability. To the extent that commercialization of coal gasification is necessary for maintaining the long term welfare of the gas industry, DOE and FERC seek similar policy objectives.

FERC's problems of grappling with its own conflicting goals are illustrated by its regulatory policy history in dealing with unconventional gas supplies. The Commission first tried to impose incremental pricing principles without any changes in its curtailment priority schemes. Although the Commission's incremental pricing method would have been economically more efficient than the applicants' requested pricing methods, it (i) discriminated against industrial users in the matter of equity, (ii) added demand uncertainty to existing unknowns, and (iii) caused the applicants to refuse to proceed under the conditions approved. In an attempt to reduce demand uncertainty to an acceptable level, the Commission then sought to exempt from curtailment gas subject to incremental pricing. The coal gasification developers' and their customers' lack of faith in the guaranteed exemption from curtailment, as well as new equity issues (such as the removal of gas from residential sales) and political pressures for immediate gas supply increases, caused this Commission policy to fail.

In prior LNG cases, the Commission has had to revert to treating the high cost gas supplies as it has treated other gas sales, on a rolled-in basis. DOE supports similar treatment for several pioneer coal gasification ventures because gas companies have expressed a willingness to proceed with a project if rolled-in sales and certain risk allocation measures are allowed. DOE and a set of gas companies basically agree about acceptable regulatory treatment. As of this writing,

1In light of very recent statements by the current administration, budgetary may become less important.
however, FERC has not evidenced a willingness to approve such regulations for coal gasification.

Because FERC's policy objectives are multifaceted and support of technology innovation can conflict with the goals of economic efficiency and equity, supporters of high cost gas supply technologies might wish to consider policy initiatives more balanced in their treatment of gas regulation's policy objectives. Efforts to relate pricing policy to curtailment policy appear especially attractive for developing regulatory compromises. These efforts could explicitly account for the fact that the value of gas supplies is a function not only of its energy content but also of its sureness of availability.

Such compromises could provide federal policymakers with more solid information about the costs of new gas supplies and the demand for gas at high costs (with varying levels of assurance of delivery). With this information the policymakers can better determine whether the introduction of such new gas supply technologies are hindered by unreasonable regulatory barriers or by the commercial unreadiness of the technology.