Natural gas policy and the Midwest

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The complex structure of natural gas market regulations has brought mixed blessings to the Seventh District states of Illinois, Indiana, Iowa, Michigan, and Wisconsin. Federal price ceilings on the domestic production of gas held down consumer prices for natural gas, but only at the cost of occasional supply shortages that the Midwest experienced in the 1970s. These intermittent shortages in supply moved federal policy to major revision of gas market regulations. The Natural Gas Policy Act of 1978 (NGPA) secured greater gas supplies for interstate pipeline customers, including Seventh District residents, through favorable allocation directives and a schedule for decontrolling producer prices. The NGPA price decontrol schedule intended to gradually raise average gas prices to parity with petroleum by 1985. In this manner, decontrol would not subject gas consumers to price shocks. A regulatory middle way was fashioned between spurring energy production and holding consumer prices at bay.

Despite the intent of the NGPA to slowly phase up consumer gas prices, post-NGPA price levels have risen at a much faster rate than had been anticipated. On average, gas prices rose at rates of almost 20 percent per year in recent years, easily outstripping the general rate of price inflation. Most analysts concede that climbing world energy prices, led by the 1979 OPEC round, are primarily responsible for climbing domestic prices of natural gas. Nevertheless, certain regulatory features of the NGPA, coupled with the restrictive market regulation of an earlier era, accommodated these gas price increases by insulating producers and pipelines from declining market demand.

In addition, the structure of NGPA price ceilings may be deterring exploration and recovery of gas for future consumption, portending future prices for natural gas that are greater than they need to be. For these reasons, public interest has grown in amending our most recent gas policy to allow gas consumption and production to respond to market forces.

Participants in the natural gas market

There are four principal agents that bring natural gas from under the ground to the homes and factories of the United States. These agents are wellhead producers, transmission pipelines, distribution utilities, and final customers (Figure 1). Typically, wellhead producers sell their natural gas to interstate or intrastate transmission pipelines under long-term agreements. Allowable prices for all domestic wellhead gas are regulated by the Federal Energy Regulatory Commission (FERC). This agency administers allowable natural gas prices under the authority of the NGPA.

Transmission pipelines serve as an intermediary transport system between wellhead pro-

Figure 1
Principal agents in the domestic market for natural gas

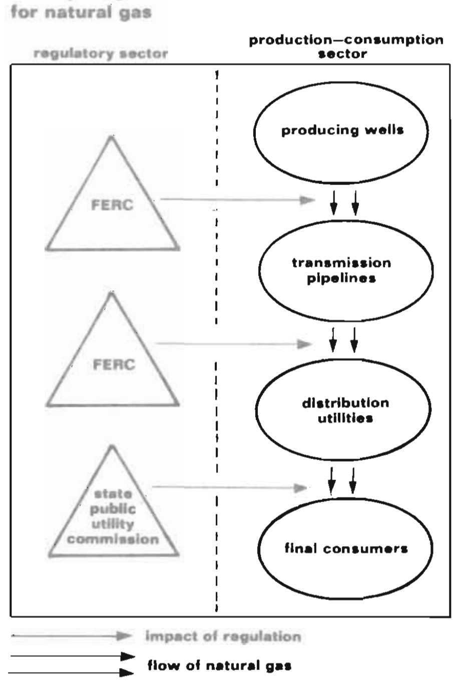

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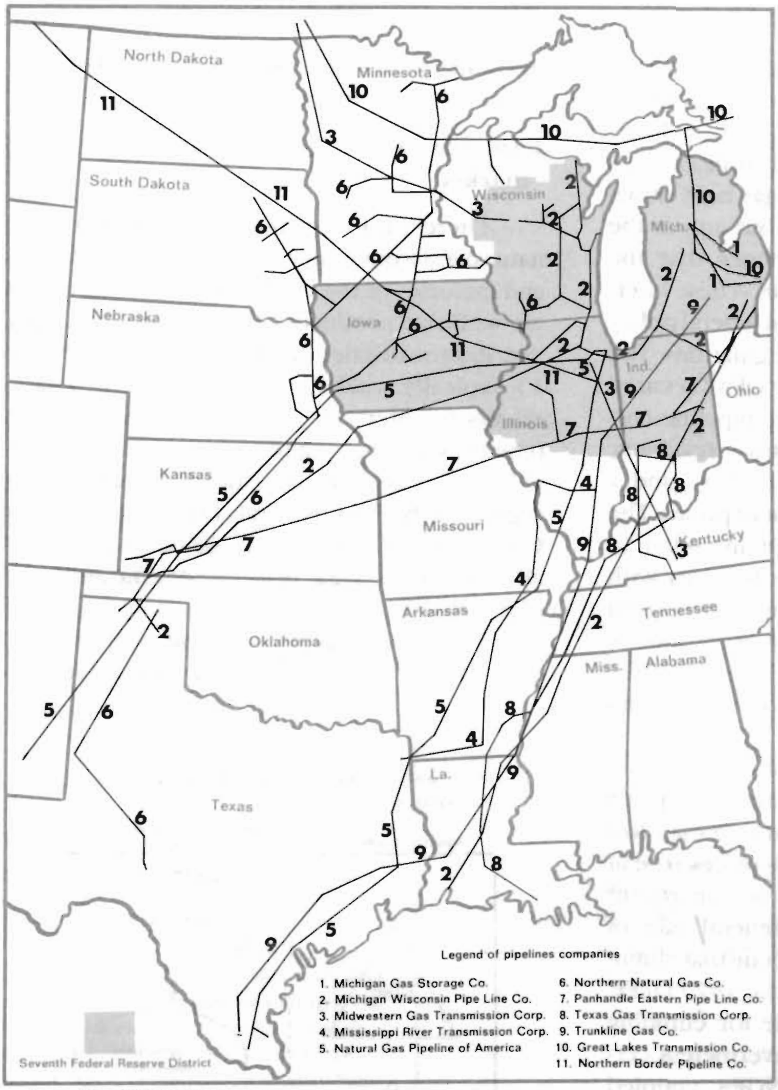
Figure 2
Primary transmission pipelines serving Seventh District states



Source: U.S. Department of Energy, Major Gas Pipelines, U.S. G.P.O., 1979.

ducers and distribution utilities (as well as some large commercial and industrial customers). The major portion of natural gas delivered to the Seventh District states is provided via 11 transmission pipeline companies. In the Midwest, the bulk of natural gas comes from the Southwestern states of Texas, Oklahoma, and Louisiana (Figure 2). Lesser volumes of natural gas originate from local wells, Appalachian gas fields, and foreign countries (largely Canada and Mexico).

Sales of natural gas by transmission pipeline companies are also regulated by the FERC. Increases of gas costs are passed through to utilities via Purchased Gas Adjustment clauses (PGAs). These clauses, filed with the FERC, are intended to compensate pipeline companies for ongoing increases in the price of gas paid to wellhead producers.

Distribution utilities, both public and private, purchase natural gas from transmission pipelines and deliver it to final customers through a network of buried pipes. State regulatory agencies, typically public utility commissions, oversee delivery and pricing of natural gas to final customers.

Natural gas consumption and production

In 1980 natural gas accounted for 27.6 percent of overall energy consumption within the five states (Illinois, Indiana, Iowa, Michigan, and Wisconsin) of the Seventh District. This compares with 26.9 percent for the nation (Table 1). Contrary to what would be expected in an era of rising prices of imported fuels, national and regional dependence on natural gas has decreased from 1970 to 1980, indicating a general substitution of alternative energy sources for natural gas.

Michigan and Illinois are particularly dependent on natural gas. Michigan's 32 percent consumption share and Illinois' 29.5 percent share are significantly greater than the nation's average. Both Iowa and Wisconsin are close to the national average. Consuming only 20.5 percent

Table 1

Share of total energy consumption accommodated by natural gas by sector, 1980 (1970)

	All uses	Residential	Commercial	Industrial	Transportation	Electric utilities
			(percent)			
Illinois	29.5 (32.6)	54.6 (53.4)	36.2 (34.4)	25.1 (26.2)	1.8 (3.7)	1.8 (16.7)
Indiana	20.5 (25.1)	37.0 (40.0)	31.3 (40.7)	19.1 (22.0)	2.1 (3.0)	(—) (5.6)
Iowa	27.0 (40.2)	35.9 (45.7)	40.4 (50.7)	28.4 (29.1)	5.5 (9.0)	2.9 (45.3)
Michigan	32.0 (30.5)	54.1 (50.9)	46.1 (40.7)	25.8 (24.2)	2.0 (1.8)	3.2 (11.0)
Wisconsin	26.4 (26.5)	35.7 (32.5)	37.5 (33.4)	28.2 (26.8)	2.6 (2.5)	3.4 (10.7)
Region	27.6 (30.4)	47.3 (47.0)	38.6 (38.0)	24.1 (24.9)	2.4 (3.4)	2.0 (14.2)
United States	26.9 (32.6)	31.9 (37.3)	25.2 (29.5)	27.6 (32.9)	3.3 (4.6)	15.6 (24.8)

SOURCE: *State Energy Data Report 1960 through 1980*, DOE/EIA-0214(80), July 1982.

of its energy in the form of natural gas, Indiana lies significantly below the national average.

The residential and commercial sectors in Seventh District states are far more dependent on natural gas than the overall nation. All five states have a higher proportion of residences with gas heating than the nation's average (Table 2). In this regard, Illinois ranks first in the nation and Michigan, sixth.

Regions vary not only in their relative dependence on natural gas but also in their absolute consumption of energy and natural gas. Seventh District residents consumed about 91,000 cubic feet of gas per capita in 1980, exceeding national per capita consumption by about 3,000 cubic feet (Table 3). The Seventh District con-

Table 2

Percent of residential units heating with natural gas, 1980

State	Percent housing units	Rank in U.S.
Illinois	82.5	1
Indiana	61.3	16
Iowa	66.7	13
Michigan	76.5	6
Wisconsin	58.1	21
U.S. average	53.3	—

SOURCE: U.S. Department of Commerce, Bureau of the Census, "Provisional Estimates of Social, Economic, and Housing Characteristics," Table H-3, *Fuels and Financial Characteristics of Housing Units 1980*.

Table 3

Per capita natural gas consumption and production, 1980

	Consumption		Production	
	Thousand cubic feet	Percent change from 1970	Thousand cubic feet	Percent change from 1970
Illinois	95.4	-10	.1	- 68
Indiana	89.1	-15	.1	200
Iowa	92.5	-25	0.0	0
Michigan	93.4	3	17.1	291
Wisconsin	74.8	- 2	0.0	0
District states	90.7	- 9	4.8	254
United States	87.8	-16	90.0	- 17

SOURCE: *Natural Gas Annual 1980*, February 1982, DOE/EIA-0131(80), and *State Energy Data Report 1960-1980*, DOE/EIA-0214(80).

sumes much more natural gas than it produces. Michigan produces the only significant amounts of natural gas among District states. That state produced over 17 thousand cubic feet (mcf) of gas per capita in 1980, an increase of almost 300 percent from 1970.

Natural gas prices in the Seventh District

Natural gas prices have risen in approximate unison among states of the Seventh District over the last decade. From 1970 to 1981, retail natural gas prices increased by almost six-fold (Table 4). While the nation's gas prices climbed at a compound annual rate of just over 17 percent over this period, the increase in each District state was slightly lower. Four of five Seventh District states witnessed an average gas price level above the national average in 1970, but only Michigan's and Wisconsin's average gas price remained above the national average in 1981. The price of gas in the highest-priced District state, Wisconsin, exceeded that of the lowest price state, Indiana, by just over 28 percent in 1981.

In the period preceding NGPA, national average gas prices rose at a slower pace than in the post-NGPA era. Post-NGPA price acceleration was consistent with NGPA intentions of spurring national gas development to a limited degree through price incentives. Among District states, the average annual growth rate of prices lagged behind the nation in the eight years preceding the NGPA of 1978, a period characterized by restrictive price controls on interstate gas and intermittent supply shortages in the Midwest. In the post-NGPA era, the average annual increase in gas prices exceeded the national average in every Seventh District state except Illinois.

Federal government regulation: a synopsis

The development of the seamless welded pipe in the 1920s ushered in the era of natural gas and natural gas delivery systems. Because pipeline systems require large fixed costs, Congress moved to prevent the monopoly pricing of natural gas to local utilities by interstate pipeline transmission companies. The Natural Gas Act of 1938 (NGA; Pub.L. 75-688) gave the Federal Power Commission (FPC) the authority to regulate interstate pipeline gas price and contract terms. Transmission companies that did not cross state boundaries—intrastate pipelines—remained uncontrolled by federal authority.

In 1954, the United States Supreme Court altered the structure of gas markets. Contending that wellhead prices substantially affect ultimate consumer prices, the Supreme Court in *Phillips Petroleum* v. *Wisconsin* interpreted the FPC's regulatory power as extending to wellhead prices of interstate natural gas. In essence, pro-

Table 4

Gas utility industry average prices (all customers) 1970-1981 ($/million btus)

	1970	1978	1979	1980	1981	Compound annual rate of increase 1970-78 (percent)	1978-81 (percent)	1970-81 (percent)
Illinois	$.73	2.27	2.72	3.26	3.66	15.2	17.3	15.8
Indiana	.71	1.93	2.38	2.82	3.26	13.3	19.1	14.9
Iowa	.62	1.96	2.36	2.81	3.45	15.5	20.7	16.9
Michigan	.78	2.17	2.51	3.06	3.70	13.6	19.5	15.2
Wisconsin	.80	2.26	2.66	3.42	4.19	13.9	22.8	16.2
United States	.64	2.18	2.52	3.13	3.66	16.6	18.9	17.2

SOURCE: American Gas Association.

NOTE: A British thermal unit (btu) equals the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

ducers who chose to sell natural gas to interstate pipelines became public utilities while producers who sold to the intrastate pipelines market remained largely unregulated by the federal government.

As a result of this court decision, producers became reluctant to develop and sell gas to interstate pipelines. Regulated prices to interstate gas producers began to lag significantly behind the market-determined price of gas sold to intrastate pipelines because FPC price administration proved to be a slow and costly process. The pricing differential encouraged drilling in areas served by intrastate pipelines at the expense of areas served by interstate pipelines.

Two natural gas markets thus arose in this regulated environment. The intrastate market, located in gas producing states, experienced higher gas prices but plentiful supplies. In contrast, the interstate market had lower relative prices than the intrastate market but also dwindling gas supplies. By the winter of 1972, shortages were occurring at places in the interstate markets where market demand at stated prices could not be met by pipeline supply. Severe shortages occurred again in the winter of 1976-77, temporarily closing many factories and schools in the Midwest.

In response to these regulatory failures, Congress moved to redress the imbalance in the natural gas market. During 1978 several legislative enactments markedly altered the regulatory environment. The most significant legislative reform was the NGPA. NGPA replaced the Federal Power Commission with the Federal Energy Regulatory Commission (FERC) as the regulatory authority of natural gas distribution. FERC's regulatory authority was extended to intrastate gas production in an effort to partially unify the two markets that had developed over the preceding 25 years.

The NGPA alleviated supply shortages in interstate pipelines by several methods. First, NGPA capped intrastate gas prices, thus diverting a greater available supply to interstate markets. In addition, gas production from federal land on the outer continental shelf could no longer be sold to intrastate pipelines.

A primary feature of NGPA was the establishment of an extensive and complex schedule of wellhead price ceilings. These price ceilings vary in their application to interstate and intrastate markets and in their price decontrol dates, in 1985 and 1987 (Table 5). Maximum prices also vary according to the physical characteristics of the well, its proximity to other wells, prior commitment to interstate pipelines, and the date of well initiation.

NGPA ceilings on wellhead gas prices apply to all except Section 107 wells, which are characterized by a drilling depth of over 15,000 feet. (Prices of gas from Section 107 wells are determined by market forces.) All ceiling prices are allowed to rise at the rate of inflation. Ceilings on "new gas," gas from new wells and gas from those wells placed in production since 1977, rise at an additional four percent per year. Price ceilings for most new gas are to be eliminated on January 1, 1985. Some classes of older intrastate gas also become decontrolled in 1985. It is estimated that the wellhead price on 55 to 65 percent of all domestically produced gas will be unregulated in 1985.

In addition to the wellhead ceilings and a price decontrol schedule, the NGPA set forth a scheme of incremental pricing that insures that industrial users of natural gas pay prices for natural gas that subsidize commercial and residential customers. Incremental pricing allocates a portion of the costs of certain high-cost gas to certain industrial uses, large industrial boilers in particular.

Concurrent with NGPA, the Powerplant and Industrial Fuel Use Act of 1978 (FUA) altered the demand for natural gas. The Act sought to encourage the use of coal, shale oil, and alternate fuels for industrial purposes in place of oil and gas. The FUA prohibits new electric powerplants and industrial boilers from burning oil or gas if coal or other fuels remain an alternative. Exemptions are granted to the extent that alternative fuels are prohibitively costly or environmental regulations deny the use of alternatives.

Through the NGPA and the FUA, Congress intended to steer a middle course between allowing gas prices in the long term to rise to oil-price equivalents and holding down the

Table 5

Scheduled decontrol dates of NGPA gas categories*

NGPA classification	Description	Date of decontrol
102, New natural gas	• certain new onshore wells	1/1/85
	• new onshore reservoirs	1/1/85
	• offshore leases effective after 4/20/77	1/1/85
	• new reservoirs on old offshore leases	not decontrolled
103, New onshore wells (certain wells started post 2/19/77)	• wells deeper than 5,000 feet	1/1/85
	• wells shallower than 5,000 feet	1/1/87
104, Gas dedicated as interstate pre-11/9/78	• various categories	not decontrolled
105, sold under existing intrastate contracts	• all types	1/1/85 1/1/85
106, sales under "rollover" contracts	• interstate	not decontrolled
	• intrastate	1/1/85
107, high-cost gas	• wells greater than 15,000 feet drilled after 11/1/79 and other types	11/1/79
	• tight sands and other types	not decontrolled
108, stripper wells	• produced at rate less than 60,000 ft^3/day	not decontrolled
109, other	• Prudhoe Bay and other	not decontrolled
Imported gas	• price set by approval of the FERC and the Economic Regulatory Administration	not decontrolled

*In general, wells qualifying under more than one category are eligible for the price ceiling and decontrol status of choice.

increases in the short term to protect certain classes of customers. Although price ceilings served to limit the rise in gas prices to residential and commercial customers, Congress foresaw continuing gas shortages in the short run because of the ceilings. Consequently, allocation directives such as curtailment priorities, demand restrictions, and incremental pricing of industrial gas attempted to contain expected shortages to industrial users and electric utilities. At the same time, the removal of ceilings on "deep wells" and the accelerated price increases on new gas were designed to encourage gas development and production in order to foster alternatives to petroleum imports and augment future supplies of natural gas. By increasing future supplies and gradually raising average gas prices, it was thought that protective price controls would become unnecessary.

Post-NGPA natural gas market behavior

The scheduled partial decontrol of natural gas, beginning in 1985, was to be preceded by an average gas price that was close to parity with competitive oil products. However, the NGPA schedule of price decontrol did not anticipate the near-doubling in the price of crude oil from 1978 to 1981. As a result, the price of natural gas fell significantly below the price of crude oil in the years immediately following NGPA. At that time, many observers predicted a sharp price spike to accompany partial decontrol in 1985 because consumption of natural gas, which is a close substitute for fuel oil in industrial use, was expected to rise as customers switched from oil to gas to lower overall energy costs.

Forebodings of sharp price hikes in 1985 were exacerbated by certain contract provisions between interstate gas producers and interstate pipelines. In anticipation of eventual price decontrol and rising energy prices, gas producers included "escalator" clauses in contracts with transmission pipelines which raise the price of previously committed gas over time. Interstate pipelines accepted many of these contract terms under the duress of looming shortages. One type of escalator clause, the deregulation provision, causes particular alarm in discussion over price hikes accompanying partial decontrol. Contracts covering approximately 59 percent of contract volume of post NGPA wells have deregulation clauses. In the event of price decontrol, these provisions lift wellhead prices of contracted gas to free market rates, or to indefinite levels such as 110 percent of the price of residual fuel oil, or the average of the two or three highest prices being paid in the vicinity of the gas well.

Some of the early concern over a sudden price jump in 1985 has abated as natural gas prices climbed much faster than anticipated, lowering the extent of potential price hikes. While many gas industry analysts were asserting that acceleration of the decontrol schedule would lessen the economic costs associated with a sharp price spike in 1985, residential gas prices were rapidly rising. These rapid price hikes were accompanied by falling energy consumption, falling prices for substitute fuels, and falling natural gas consumption.

The current gas market

The recent recession lowered domestic demand for all energy products. Total domestic gas consumption declined from 19,877 billion cubic feet (Bcf) per year to 19,404 Bcf from 1980 to 1981. In the first three quarters of 1982, consumption fell by over 6 percent in comparison to the first three quarters of 1981. Decreases in consumption cannot be wholly attributed to downturns in the domestic economy. Year-to-year changes in weather conditions may have influenced gas consumption. Moreover, rising prices themselves encourage conservation by gas customers.

Despite this downturn in demand for natural gas, both consumer and wellhead prices continue to climb. The average wellhead price of gas increased by over 21 percent from September, 1981 to September, 1982 while average residential gas prices rose almost 19 percent. In comparison, average heating oil prices declined by almost 4 percent over the same period and the domestic average wellhead value of crude petroleum declined by over 10 percent.

Rising gas prices accompanied by slack demand for natural gas leads many observers to conclude that gas price decontrol, as exemplified by the NGPA, fails to benefit anyone except wellhead gas producers. Baffled at price increases in the face of slack demand, many consumers maintain that price decontrol allows monopoly rents to accrue to producers with no benefit whatsoever to consumers.

Why have gas prices continued to climb?

Natural gas prices have continued to rise in the wake of slack demand for several reasons. First, the second OPEC round of petroleum price hikes in 1979 led to a doubling in world oil prices. Insofar as petroleum and natural gas are substitutes in energy consumption, petroleum price hikes placed upward pressure on the demand and price of natural gas.

The structure of NGPA price ceilings on domestic gas accommodated and exacerbated upward pressure on gas prices in several respects. The NGPA created a price-decontrolled category of gas, Section 107 gas, as a production incentive. Some pipelines used their surfeit of price-controlled gas to subsidize their price bids on Section 107 gas and imported gas. As the price of Section 107 gas subsequently increased, it helped to pull the average price of gas up to unforeseen levels.

In addition to the price increases in Section 107 gas, NGPA price ceilings themselves have grown at a rate outstripping the general rate of price inflation. While ceiling prices on some categories of gas climb at the rate of inflation, the ceiling price on Section 102 gas (new natural gas), was permitted to increase at an annual rate of 3.5 percent more than inflation through April 20, 1981, and at a rate of 4 percent more than inflation through the end of 1984. As older vintage supplies of gas have been depleted, a greater proportion of production has fallen into NGPA categories covered by higher ceiling prices and into categories with ceilings that rise more rapidly than inflation, further contributing to gas price increases to final customers.

In addition to the price ceiling structure of NGPA, the federal gas regulation of an earlier era contributed to recent gas price hikes. Contract terms between pipelines and wellhead producers reflect the relative strength of these two parties in bilateral contract negotiation. In this regard, the tight producer price ceilings imposed on wellhead gas in the pre-NGPA era restricted available reserve commitments by producers to interstate pipelines. In the absence of adequate price rewards, producers were able to bargain for inclusion of "non-price" or "shadow price" conditions into interstate contracts that were entered into during the last decade, including the period immediately following the passage of the NGPA. In an effort to secure adequate supplies in anticipation of continuing shortages, pipelines included escalator clauses, take-or-pay clauses, and other onerous terms in contracts with wellhead producers. These contract clauses have partly protected some producers from unanticipated declines in final market demand, much to the detriment of transmission pipelines, utilities, and especially final consumers.

"Take-or-pay" provisions insure that pipelines pay above-market prices in periods of slack demand. These provisions require pipelines to pay for contracted volumes of gas on a specified schedule regardless of whether pipelines can market the gas. Department of Energy surveys indicate that pipelines were most willing to accept take-or-pay provisions in the 1973-77 era, though they apply to over 80 percent of post-1978 contracted volume as well.

While take-or-pay contract features have partly protected some wellhead producers from recent declines in gas demand, purchased gas adjustment clauses, PGAs, have insulated pipelines from much of the sagging market demand. To date, FERC has granted pipeline price hikes to pipelines via PGAs without major delays. PGAs can be filed up to twice a year to reflect increases in the prices that pipelines pay for gas at the wellhead.

Perhaps more upsetting to consumers than recent price increases in the presence of falling demand, transmission pipelines continue to purchase high-priced categories of natural gas for resale to customers while available supplies of cheaper wellhead gas remain in storage or in the ground. For example, Columbia Pipeline Co. stopped taking gas from 20,000 low-volume wells in Appalachia that was available at prices as low as $.45 per mcf. At the same time, the pipeline continued to purchase gas from other sources at prices exceeding $5.00 per mcf. These practices have further raised the average price of gas that pipelines sell to distribution utilities.[1]

Pipelines are thought to decrease their takes of low-cost gas during periods of slack demand because PGAs allow a price pass-through only for wellhead gas that is sold by the pipeline to a distributor or other customer. Pipelines may elect to sell expensive wellhead gas to their customers and make pre-payments to producers on their takes of low-priced gas in order to increase revenues via PGA price compensation.

Distribution utilities usually have little choice in paying increased pipeline prices. First, distribution utilities themselves have often signed contracts containing high "takes" from transmission pipelines. Distributors served by interstate pipelines have agreed to contract terms under the similar duress of anticipated shortages in supply that interstate pipelines experienced in the 1970s.

One additional market feature enhances the ability of pipelines to pass on price increases to

[1]On December 30, 1982, the FERC ruled that Columbia Gas Transmission Corp. must refund $100 million or more to customers residing in Northeastern states because the pipeline had purchased excessive quantities of high-priced gas while reducing purchases of cheaper gas. More recently, some pipelines, including Columbia, are attempting to abrogate purchase contracts with producers. Similar actions are placing downward pressure on prices and revenues of wellhead producers.

distributors. Unlike petroleum pipelines, natural gas transmission pipelines are not considered common carriers. Hence, gas distributors are not free to purchase less-expensive gas directly from producers because their pipeline connection may refuse transport of this gas at reasonable prices.

Distribution utilities pass through price increases to final consumers of gas in much the same manner that transmission pipelines pass along price increases in wellhead gas. State public utility commissions usually maintain their own versions of PGAs to reflect ongoing price increases resulting from increased costs of gas purchases.

Despite the apparent ability of pipelines and distributors to pass higher costs on to consumers, many pipelines and distribution utilities worry about a cost squeeze resulting from recent slack gas demand and rising producer prices. Price increases by utilities and pipelines have been met by consumer resistance in both the market and political arena. For example, voters in Michigan recently passed a ballot issue to abolish automatic fuel and gas adjustment clauses and limit the number of rate cases the commission can hear at one time. Legal challenges by consumer groups can delay or minimize expected price hikes by gas distributors as state public utility commissions become reluctant to increase allowable rates in the face of consumer outrage. Transmission pipeline companies may confront similar difficulties in rate cases held before the FERC.

In addition to unyielding regulatory commissions, pipelines and distribution utilities can suffer from sudden declines in demand as natural gas prices approach parity with residual fuel oil. In particular, industrial customers often switch to fuel oil when it becomes more economical than gas. These demand swings force utilities to spread the fixed portion of delivery costs (and take-or-pay provisions) over fewer customers, thus further raising the delivered price of gas. In some instances, price increases of any magnitude cannot preserve a profitable position for pipelines or utilities as total revenues decrease with loss of volume.

Many distribution utilities are attempting to design rate structures to limit load loss by discounting rates charged to those customers with the most elastic demand. Typically, discounts are offered to industrial customers to prevent switching from gas to alternative fuels such as fuel oil or to prevent actual plant closings. These discounts are often unpopular with the general public. But under certain conditions these discounts can limit price increases to all gas customers by spreading the high fixed overhead costs of utilities across a greater volume.

Issues in the current policy debate

Recent price increases and speculation over price jumps accompanying 1985 decontrol have greatly increased public discussion surrounding gas policies. In addition to concern over the burden of higher gas bills, concern over NGPA-induced inefficiencies has grown. The Reagan administration has directed energy policy toward a greater free market orientation. Those who favor free market policies, including immediate decontrol of all natural gas, point out the market distortions and inefficiencies that NGPA has cost the nation.

One inefficiency arises from NGPA's decontrol of deep-well gas. This has created a so-called "market-ordering" inefficiency in production. Insofar as deep-well gas remains free from price controls at the same time that other gas prices are capped, some production of high-cost deep-well gas is exploited in place of low-cost gas. For an equal output of gas, fewer of society's resources could be spent by extracting gas under a single-price scheme.

A second inefficiency stems from regional allocation of gas supply under NGPA pricing. Pre-NGPA regulation redirected regional gas consumption by capping interstate prices while ignoring intrastate prices. This diverted gas supplies to the gas producing regions of the South and Southwest. The NGPA alleviates supply shortages in interstate pipelines by favoring interstate pipelines over intrastate lines. Advocates of accelerated decontrol argue that these inefficiencies should be removed to promote national economic growth and development.[2]

Other advocates of accelerated decontrol point out that a potential "fly-up" of gas prices in 1985 and beyond, caused by the current decontrol schedule, will throw gas-dependent commerce into a tailspin. As an alternative, accelerated decontrol will smooth out the inevitable price hike, enabling commerce to more easily adjust to higher prices over time. In addition, some analysts maintain that accelerated decontrol will moderate future gas price levels by bringing rational production incentives to producers. For example, some analysts forecast that, in addition to smoothing price climbs over the coming years, immediate decontrol will lower the eventual level of prices confronting consumers by the latter 1980s.

Although some observers have advocated an acceleration of the NGPA schedule since its inception, decontrol has recently gained momentum from the current market conditions of slack demand and rising price. To the extent that these market conditions indicate market prices above their market-clearing levels, it is argued that accelerated decontrol can be attained without an immediate price increase to consumers. To accomplish this end, complementary legislation, such as amendment of take-or-pay contracts and PGA clause procedures, must accompany accelerated decontrol.

At the same time that market inefficiencies have heightened interest in accelerating gas decontrol, others have increased their support of continued controls under NGPA. Some even go so far as to advocate the extension of price controls beyond current NGPA mandates and the imposition of immediate price ceilings on all wellhead prices of natural gas. Views favoring continued controls are largely based on the belief that gas prices would indeed rise under accelerated decontrol, much as prices have risen in the post-NGPA era. It is argued that consumers have suffered enough from recent gas price jumps. The distress of presently climbing residential and commercial fuel bills leads to arguments that decontrol of gas await a future date, a date that is approached by a long transition of gradually rising prices.

[2]Although regional gas allocation is certainly redirected under NGPA regulations, the NGPA allocation may well represent a significant improvement over the pre-NGPA allocation. Shortages and curtailments in gas delivery have vanished from intrastate and interstate markets alike, though the present recession and above-equilibrium gas prices may be largely responsible for the current gas glut.

The impact of accelerated decontrol on gas prices in the Seventh District

Despite difficulties in untangling the complex web of regulatory influences, short-term estimates of market prices for gas under accelerated price decontrol can be tied to the market prices of substitute fuel products, particularly residual fuel oil. Such estimates are based on the assumption that (1) natural gas and fuel oil are ready substitutes on a large scale; (2) supplies of neither fuel are sufficient to back the use of the competing fuel out of the market; and (3) complementary legislation accompanies the lifting of NGPA price ceilings, allowing market bidding for the use of these fuels. In this environment, natural gas and residual fuel oil are substituted for each other until price parity is attained. At the point of price parity, both fuels are consumed with a large segment of energy consumers indifferent between these fuels.

These assumptions are supported by the use of both gas and fuel oil as boiler fuels in U.S. energy markets. Industrial boilers are estimated to have consumed approximately one-third of the energy used in manufacturing in 1976. Natural gas was the primary industrial boiler fuel, with more than a 40 percent share of the total. In addition many boilers can switch fuel consumption between oil and gas at moderate cost. One estimate indicates that 53 percent of large-boiler fuel use in 1979 occurred in boilers capable of switching between fuel oil and natural gas use at the turn of a valve.

Insofar as petroleum prices have been very erratic in recent years, forecasts of energy prices become increasingly unreliable further into the future. For this reason, this type of gas price estimate must be limited to near-term approximations of gas prices under accelerated decontrol. Among Seventh District states, it is estimated that if natural gas had risen to parity with residual fuel oil in August, 1982, price jumps in

District states would have ranged from 1 percent in Illinois to 14 percent in Indiana (Table 6). In contrast, the price of natural gas in Wisconsin appears to have exceeded parity with fuel oil by approximately 12 percent.

Table 6

Relationship of natural gas and No. 6 residual fuel oil prices, August 1982

	Gas price	Fuel oil price*	Difference
	($/mmbtu)		*(percent)*
Illinois	4.46	4.52	1
Indiana	3.97	4.52	14
Iowa	4.21	4.52	7
Michigan	4.51	4.52	—
Wisconsin	5.11	4.52	(-12)
United States	4.46	4.52	1

SOURCE: American Gas Association and the U.S. Dept. of Energy.

*National average price is assumed for each state.

Conclusion

Insofar as natural gas prices have already approached approximate parity with fuel oil within Seventh District states, accelerated decontrol of natural gas would have limited negative impact, on average, in this region. Of course, intra-regional variation in natural gas prices to consumers suggests that accelerated decontrol would produce higher gas prices to some homes and factories while other regional gas prices would decline. Moreover, prevention of general gas price increases under accelerated decontrol can only be accomplished with complementary state and federal legislation.

Whether or not the federal government moves to accelerate the NGPA schedule of wellhead gas, changes in regulatory policy will be considered to make the gas industry more responsive to falling gas demand. These include conversion of interstate pipelines to common carrier status so that distributors and main line customers can choose among alternative suppliers of natural gas. Federal legislation to lower the obligations of pipelines to take delivery of high-priced gas under existing contracts presents another possible remedy. In addition, the incentive for pipelines to voluntarily renegotiate existing contracts and discontinue practices of selling high-priced gas to customers when low-priced gas is available may be established by amending PGA procedures.

Both federal and state governments will also consider rate designs that allow pipelines and distributors to offer discounts to large industrial users and electric utilities who are on the verge of switching from gas to fuel oil consumption. In the absence of properly designed rate structures, load loss may foist a larger share of pipeline and distributor costs of gas delivery onto commercial and industrial customers. As an alternative method, state regulators may decide to lower the rate of equity return to pipelines and distributors rather than discount prices to large industrial customers.