NATURAL GAS TRANSPORTATION CONSTRAINTS IN TENNESSEE

A Report

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EXECUTIVE SUMMARY

Over recent years, the natural gas industry has undergone significant restructuring in response to Federal deregulation initiatives. As a result, natural gas services are now purchased individually, as opposed to a bundled product, and the nation's interstate pipeline companies are subject to open access, offering the promise of increased competition and reduced upward price pressure. Market players, including local distribution companies (LDCs), pipeline transporters, major industrial consumers and state public utility commissions, continue to adapt to the changing economic landscape.

As the natural gas industry evolves, there are questions about its ability to meet the needs of consumers in Tennessee. This report focuses on these questions, as they relate to natural gas transportation and the pricing of transportation services in Tennessee. The report has three key sections. Section I provides essential background on the structure of the natural gas industry and describes the recent wave of Federal deregulation. Section II is a careful assessment of natural gas transportation capacity and transportation pricing in Tennessee. Section III summarizes the constraints confronting the state's consumers of natural gas, explores the implications of these constraints for the state's economic development, examines the proper role for government intervention to address natural gas constraints and lays out state policy options to mitigate the problems.

Some of the primary findings of the study follow.

Section I:

- Tennessee has very modest natural gas productive capacity, requiring the importation of natural gas from other regions.
- Both pipeline transporters and LDCs offer two broad categories of service, firm and interruptible. Consumers typically pay lower prices for interruptible service. Households and most commercial consumers receive firm service whereas industrial consumers frequently rely on interruptible service.
- To address peak load problems, both LDCs and large industrial consumers frequently have "peaking facilities," either fuel storage capacity or alternative fuel capacity. These peak-load facilities tend to be much more costly than the pipeline supply of natural gas.
- Regulation of this industry is limited relative to historical standards. The Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate pipeline companies and transportation tariffs, whereas state public utility commissions oversee intrastate pipelines and privately owned in-state LDCs.
- Under the new rate design mechanism for interstate transportation services (straight-fixed-variable), the users of firm transportation services bear most of the costs of natural gas transportation. This same rate mechanism provides no incentive for pipeline companies to increase the throughput of

natural gas. The new capacity release mechanism, which allows the subscribers of firm transportation services to resell capacity, offers the promise of added competition, but only where there is already competition in transportation services.

Section II:

- West and middle Tennessee are major corridors for a number of North-South interstate pipelines; East Tennessee is served by a single pipeline supplier.
- There is evidence of natural gas availability problems in isolated, largely rural areas of the state. These same areas don't have the market base to support development of natural gas infrastructure.
- There are peak capacity problems on the pipeline distribution system in East Tennessee. This same capacity constraint leads to higher costs for LDCs and industrial consumers who must invest in peaking facilities and pay higher prices for substitute fuels.
- Many initiatives have been and continue to be explored to expand capacity in East Tennessee. Some of these are confined to interconnects with the existing pipeline system. While these efforts can meet short-term capacity needs, they offer little promise of reduced rates. Others have explored new pipeline construction between Middle and East Tennessee. These initiatives have greater promise in meeting short-term and long-term capacity needs, as well as encouraging price competition.

- End-user natural gas prices are somewhat higher in Tennessee than in the U.S. or the Southeast. Residential prices tend to be lower than the regional average, whereas industrial prices tend to be higher.
- Transportation rates are higher in East Tennessee than in other regions of the state. Part of this differential reflects the greater distance required to ship gas to the eastern region of the state. The only real hope for reduced transportation prices is increased capacity and competition.

Section III:

- The natural gas capacity constraints confronting Tennessee are confined to (a) the unavailability of natural gas in many of the state's rural areas; (b) peak-load capacity problems in East Tennessee; and (c) relatively high transportation tariffs in East Tennessee.
- The consequences of natural gas constraints on Tennessee's economic development cannot be quantified with much certainty. What can be said is that while natural gas matters, it matters little for the typical household and the typical firm. There are, however, large industrial users for whom natural gas availability and price are critical.
- The economic justification for state intervention to address the availability problem is equity. The state could choose to facilitate development of natural gas infrastructure in rural regions, although this may not be the most cost-effective development strategy for these communities.

- The economic justification for dealing with capacity and price problems in East Tennessee is that the current situation is a monopoly. The problem is aggravated by the high risks involved for potential new entrants to the transportation market.
- The state's policy goal to address capacity and price constraints should be to promote competition through development of a new pipeline distribution system to East Tennessee.
- The state's policy options to improve capacity and encourage competition range from letting the market continue to nibble away at the problem to the state itself developing a new pipeline. The best strategy would be for the state to continue to support the process of exploring options. More extensive involvement should proceed cautiously. The state could provide financial support (through bridge loans, for example) to facilitate a market solution. The use of state tax dollars, however, is not well justified in terms of the modest economic development impacts that would follow from capacity expansion. As industry participants stand to gain the most from capacity growth, they should in turn bear most of the costs and risks.

NATURAL GAS TRANSPORTATION CONSTRAINTS IN TENNESSEE*

I. Basic Features of the Natural Gas Industry

The natural gas industry of 1995 represents a sharp departure from the industry that prevailed only a decade ago. In the mid 1980s the industry was reeling from a speculative price bubble, excess investments in extractive capacity and excess supplies of natural gas. Deregulation of the industry was moving forward, first through the decontrol of wellhead prices (initiated by the Natural Gas Policy Act of 1977), and second, by a 1985 executive order of the federal government to allow open access to the nation's interstate natural gas pipelines. The market realities of the day, coupled with the inherent uncertainties brought about by diminished government intervention, created a cloud over the industry.

As of 1995, the broad goals of deregulation have been achieved. While some elements of regulation and oversight remain in place at both the federal and state levels, most aspects of the industry are now free of government intervention. Natural gas prices have embarked on a slow ascent and the excess capacity that characterized the industry in the 1980s has been brought into better balance with consumer demand. Now, new

*The authors would like to thank East Tennessee Natural Gas, Associated Valley Industries, Mike Bolin, Craig Carmen, Lynn Elder, Jim Hodges and the many others that provided information during the preparation of this report. Jerry Kettles provided valuable research support.

uncertainties are on the horizon as the players in this deregulated industry grapple with a changing economic landscape.

Probing beneath the surface of these broad trends is a rather daunting task due to the complicated nature of the industry itself. The eras of regulation and deregulation, the host of market players and their interdependency, and the unique jargon that permeates the literature creates a complex web that is exceedingly difficult to penetrate. In order to penetrate this web and provide background on the natural gas transportation system in Tennessee, the remainder of this chapter reviews the key aspects of the natural gas industry, focusing first on the primary industry participants--producers, pipeline transportation companies, local distribution companies (LDCs), consumers and federal/state regulatory agencies. A brief review of deregulation is also presented as it relates to natural gas transportation and pricing.

A. Industry Structure

On the production side of the market, the U.S. has rather large natural gas reserves, with a heavy concentration in the Gulf Coast region. This same region accounts for the majority of natural gas currently extracted in the U.S., although smaller amounts of natural gas are extracted in Tennessee and other southeastern states as well. In 1990, Tennessee had 690 producing wells that accounted for a small fraction (only 0.2 percent) of all operating wells in the U.S. These same wells represented a smaller share--only 0.01 percent--of total market production.[1] According to the Gas Research

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[1] *Tennessee Statistical Abstract*, Center for Business and Economic Research, College of Business Administration, The University of Tennessee, Knoxville, 1994.

Institute (1993) over 75 percent of the natural gas consumed in the Kentucky/Tennessee region comes from the Gulf, while about 20 percent is sourced in Appalachia. In inflation-adjusted terms, annual natural gas prices have fallen from nearly $3.25 per thousand cubic foot (mcf) in 1985 to approximately $2.00 per mcf in 1995.

Pipeline companies provide transportation services for the interstate and intrastate shipment of natural gas. The vast majority of interstate pipelines, of which there are over 40, originate in the Gulf Coast near natural gas supplies and are owned and operated by a handful of companies. Many of these same pipelines pass through Louisiana, Mississippi and Tennessee as they make their way to final consumer markets in the northeast.

While pipelines predominantly serve local utility districts, they frequently provide direct service to larger industrial users of natural gas as well. The pipeline transporters provide two broad categories of service, firm and interruptible transportation services. With firm service, the LDC or industrial user is guaranteed access to contracted volumes of natural gas, although the buyer pays a premium for this guarantee of service. Under interruptible transportation agreements, the LDC or industrial user may have service curtailed by the pipeline company should natural gas supplies be inadequate to meet overall demand. Discounts are provided to compensate for the risk and costs associated with interruption. The LDC or industrial user will frequently have linkages to multiple pipelines, access to "peak shaving" (or storage) facilities and standby facilities that use alternative fuels to meet peak demands.

Transportation charges, which may vary by volume and distance, as well as by type of service (firm or interruptible), have been structured by federal regulators to ensure that pipeline companies recover both fixed and variable costs. A demand (or reservation) charge is levied to reserve a portion of a pipeline for gas shipment. The demand charge is intended to cover the fixed costs of pipeline transportation services. An additional fee, a commodity charge, is imposed on the actual movement of natural gas through the pipeline network. The commodity charge is structured to ensure recovery of variable costs of pipeline operation.

Local distribution companies, which may be publicly or privately owned utilities, transfer natural gas from the main pipelines to their own distribution network serving final consumers (or, in industry jargon, from the "citygate" to the "burner tip"). As with the pipeline companies themselves, the LDCs typically provide both firm and interruptible transportation services to final consumers. Firm customers of LDCs pay higher fees than their interruptible counterparts.

Peak demands are critical to the LDCs and the entire transportation network, as nationally 50 percent of all LDC sales occur during the winter months -- December through February. While the LDCs often have their own peak-shaving facilities to meet peak demands, problems still arise during heavy load periods, and those on interruptible service may be curtailed. Note that peak capacity problems encountered by end users typically have more to do with weather, aggregate supply conditions and system transportation constraints, than with the LDCs themselves.

The consumer side of the natural gas market is dominated by residential, commercial and industrial users, although smaller amounts of natural gas are taken by the "transportation" (i.e., direct user) and electric utility sectors. Residential consumption is primarily comprised of space heating, with such service provided on a firm basis. Commercial enterprises, ranging from small retail outlets to large service operations--such as hospitals and office buildings--may receive firm or interruptible service, depending on their needs and supply constraints.

Unlike the residential and commercial usage of natural gas, which is highly sensitive to temperature, industrial consumption tends to be more stable, reflecting ongoing production schedules. Industrial users are much more likely to subscribe to interruptible service, either because firm service is simply unavailable or because it is too expensive. The risk of interruption--and in some instances the promise of relatively lower energy costs--leads many industrial consumers to fuel switching during peak usage periods. While fuel switching may appear attractive on an energy price basis, unit costs may be high, as alternative storage or generating capacity must be established.

Regulation of the natural gas industry takes place at both the federal and state levels. Historically this regulation reflected concerns over concentration in the extraction sector and monopoly in both transportation and distribution. Following deregulation, the Federal Energy Regulatory Commission (FERC), a division of the U.S. Department of Energy, has maintained its oversight of interstate natural gas transportation and transportation pricing. State public utility commissions typically oversee intrastate pipelines (including safety and rates) and the activities of in-state LDCs. In Tennessee, the Public Service Commission historically had oversight on safety on the interstate pipelines and jurisdiction over the direct-served customers of the interstate pipelines as well. As discussed below, deregulation has reshaped the roles played by both federal and state regulators.

The "burner tip" (or end user) price of natural gas reflects a host of factors, including the cost of the natural gas commodity, the cost of transportation services, LDC markups and taxes. For many years prior to deregulation, various industry products such as gas marketing and commodity acquisition, transportation and specialized services were provided as "bundled" as opposed to independent products. An analogy is the cable television company that provides a bundled package consisting of wired service, a receiver and various grouped programming services, some of which may be of little value to consumers. Bundling of natural gas services restricted consumer choices, made it impossible to determine the costs for specific independent services, and accommodated cross subsidization across the seller's activities. Bundling was an artifact of the Natural Gas Act of 1938, which took the view that control over bundled prices would adequately protect consumers.

In Table 1, end-user prices for natural gas and other standard fuels in the U.S. are presented for the years 1970 and 1992. Note that while coal appears attractive in terms of price, it has high environmental costs. Natural gas, which experienced rapid price escalation in nominal terms between 1970 and 1992, is somewhat more expensive than coal but is a relatively clean fuel. The alternatives--distillate fuel (including diesel fuel), liquid propane gas and electricity--are all relatively poor substitutes for natural gas

Table 1

Selected Energy Price Estimates for the U.S.
Industrial Sector, 1970 and 1992
(Dollars per Million Btu)

Energy Source	1970	1992	Percent Change 1970-1992
Primary energy	.60	3.51	485
Coal	.45	1.69	276
Natural Gas	.38	2.91	666
Distillate Fuel	.72	4.92	583
LPG	1.10	4.90	345
Electricity	2.99	14.18	374
All sources[a]	.83	5.29	537

[a]Includes sources not detailed in table.

Source: *State Energy Price and Expenditure Report 1992*, Department of Energy, Energy Information Agency, U.S. Government Printing Office, 1994.

in terms of price and quality.

B. The Era of Deregulation

Deregulation of the natural gas industry began in earnest with Congressional passage of the Natural Gas Policy Act of 1978, which initiated efforts to decontrol wellhead prices. The hope was that competitive pressures would both control prices and provide the proper incentives for exploration and extraction. Further efforts to deregulate the industry continue to the present.

Two particularly noteworthy initiatives of relevance to this study are FERC Orders 436 and 636.[2] Order 436, issued in 1985, was intended to impart additional competition on the market by requiring open access to interstate pipelines. Prior to Order 436, pipeline companies shipped only their own gas through their own pipelines; but under open access, pipelines could compete for customers and consumers could more freely choose their shippers. Order 436 effectively allowed utilities and direct users to acquire gas from any supplier and ship it over a pipeline of their choice. Consumers could also choose to continue to purchase bundled services from the pipeline transporters.

Order 636, the final major contribution to deregulation, was issued in April of 1992 and unbundled the prices for gas marketing/acquisition services and gas transportation. While pipeline companies could still provide a variety of services (such as gas gathering and marketing), these activities must now be undertaken by separate

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[2]For background on industry deregulation and Orders 436 and 636, see Energy Information Agency (1994) and U.S. General Accounting Office (1993).

business entities that receive no preferential treatment from the parent firm or its affiliates. The objective of Order 636 was to encourage competition in the range of natural gas services.

The separate pricing of natural gas services made explicit the components of the previously unbundled package and facilitated consumer identification of lower cost alternatives. But unbundling was not without its disadvantages, as natural gas supply security was shifted away from the pipeline companies to LDCs and direct users. Moreover, LDCs were forced to secure products and services individually and independently, a task many LDCs were ill-prepared to undertake. Deregulation has also led to substantial industry restructuring costs, costs which (with FERC approval) have been passed on to consumers. These costs include gas supply restructuring (GSR) costs arising from termination of long-term contracts between pipeline companies and natural gas producers; stranded costs to reflect pipeline company assets no longer needed in the unbundled price environment; and new investment costs to account for investments required as a consequence of unbundling. These restructuring costs will have been absorbed by 1998.

To enhance competition in transportation in the deregulated environment, pipeline companies were required to allow firm customers to release and resell their capacity allotments. An electronic bulletin board system was to be established by each interstate pipeline company to serve as a clearinghouse for this "capacity release." The capacity release system effectively created a secondary market for natural transportation services, helping to meet customer demands and alleviating the burden on firm customers during nonpeak periods. Prices in the market for capacity release can move up or down, depending on market conditions, but are subject to floors and ceilings. In general, the value of capacity release will be high during peak-load periods and will be low during low-load periods. Hence the secondary or spot market for capacity provides an indirect gauge of how binding constraints are on a given pipeline system.

Perhaps the single-most important element of Order 636 for this report is the shift to straight-fixed-variable (SFV) pricing for natural gas transportation services.[3] Under Order 636, FERC retains regulatory authority over minimum and maximum charges for interstate transportation and state public utility commissions oversee rates charged for intrastate transportation through pipeline company rate filings. The users of firm transportation pay a two-part tariff, the first component of which is a demand charge to cover fixed pipeline costs. A second price, the commodity charge, covers the variable costs (such as compression) of moving gas through the pipeline. Those purchasing interruptible service confront a tariff rate that lies between the maximum combined demand and commodity charge and the maximum commodity charge. Note that in practice users may negotiate directly with the pipeline companies to receive reduced rates (although these rates must exceed the FERC floor), rendering published rate schedules of limited value.

Prior to deregulation, modified-fixed-variable (MFV) pricing was the industry standard for rate design, with a combination of demand and commodity charges covering

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[3]For an accessible introduction to straight-fixed-variable pricing, including examples, see Energy Information Agency (1994).

pipeline fixed costs. Note that under MFV pricing pipeline companies were guaranteed a rate of return on a portion of their variable costs as well as on fixed costs. Under SFV pricing, most cost recoveries (and profits) are derived from firm customers, whereas in the past a greater share of these same costs was recovered from interruptible customers. The switch to SFV pricing thus has resulted in an effective shifting of burdens from interruptible to firm customers. In addition, low-load firm customers--those who do not regularly and fully utilize their pipeline allocation--have confronted increased rates. Finally, there is no rate of return generated from variable costs incurred in operating the pipeline, providing little or no incentive to increase pipeline throughput under SFV.

The demand charges under SFV pricing are determined through the pipeline company's allocation of fixed costs (and FERC's approval of this allocation) and estimates of natural gas throughput. Straight fixed-variable pricing is thus a form of average cost pricing that should ensure the pipeline of cost recovery and a fair rate of return at FERC-approved rates. Included in the rate base are taxes, depreciation and other allocated fixed costs; a rate of return in excess of 10 percent is also accounted for in the design of maximum FERC-approved rates. An important consequence of SFV pricing is that any new investment (as well as the rate of return on this investment) will be recovered largely from the users of firm transportation services. The difficulty in recovering fixed costs--and the inability to cross-subsidize pipeline construction from commodity charges or other activities, such as marketing--has led to a slowdown in capacity expansion (Energy Information Agency, 1994).

One of the most recently addressed regulatory issues is the impact of new transportation investments on tariff rates. Under transition rulings, FERC required that new investments be charged off incrementally to the beneficiaries of the new investment. This made new investments quite unattractive, because opportunities for cross-subsidization were precluded. FERC recently ruled that new investments can be "rolled in" to the rate base insofar as rates for current users don't rise by more than 5 percent."

II. Pipeline System and Transportation Prices in Tennessee

With section I as background, the focus now turns more narrowly to two issues, the capacity of the current pipeline transportation network to meet consumer demands in Tennessee and the pricing of natural gas transportation. The pipeline distribution system is explored first to determine if there are natural gas transportation constraints. The costs of these constraints are illustrated in terms of higher-user costs. End-user prices for natural gas and prices for natural gas transportation are explored next. The price implications of capacity expansion initiatives are also noted.

A. Pipeline System and Capacity

A number of major north-south interstate pipelines traverse West and Middle Tennessee, including branches of Tennessee Gas Pipeline (TGP), Trunkline Gas, Texas Gas Transmission Company, ANR Pipeline, Columbia Gulf and Texas Eastern. Figure 1 illustrates the location of these lines for Tennessee and its contiguous states. In general, the major lines that pass through Tennessee have as their final destination the upper midwestern and northeastern portions of the U.S., and serve a variety of markets on their way. Southern Natural Gas (SONAT), which recently received FERC approval for a pipeline extension into the Chattanooga area, passes through the central portion of the southern states.

The eastern portion of Tennessee, unlike most other regions of the state, is served by a single pipeline, East Tennessee Natural Gas (ETNG). (East Tennessee Natural Gas and Tennessee Gas Pipeline are both part of the Tenneco family.) Most of ETNG's throughput is derived from TGP, although smaller amounts are injected into the system at other points, including Virginia. Note that the single pipeline situation is not unique to East Tennessee, as numerous other regions of the country rely on a single pipeline.

Figure 2 shows that natural gas is widely available in Tennessee, with only a small number of counties concentrated in the rugged terrain of East Tennessee having no access to gas.[4] In general, the larger the population and economic base, the greater is the likelihood of a county's having access to natural gas. This results from the fundamental economics of the industry, which requires a relatively large base of consumers to support major investments in natural gas infrastructure.

While natural gas availability is important, perhaps more important is the ability of the transportation network to adequately meet consumer baseline and peak load needs. In order to better understand the nature of any capacity constraints on natural

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[4]Note that the data in Figure 2 are somewhat dated and the situation may have changed since 1989.

FIGURE 2
Natural Gas Availability in Tennessee, 1989

Source: Tennessee Division of Geology

gas pipelines in Tennessee, a careful review of published documents was undertaken, complemented by both formal and informal surveys of and discussions with key stakeholders. A variety of pipeline companies, LDCs, industrial users, regulators and others--both inside and outside the region--were contacted via telephone. In addition, formal surveys were sent to 98 LDCs in Tennessee by the Center for Business and Economic Research, while a survey of industrials was conducted by Associated Valley Industries.

This information reveals few, if any, capacity problems in Middle and West Tennessee. A number of concerns did surface, however, for the eastern portion of the state, the region served by ETNG. The concerns can generally be placed in two categories. First, the baseline growth in demand on the ETNG system is a growing problem, straining the system's ability to provide firm service in the near term and raising questions about the long-term viability of the system as well. Second, and very much related, are capacity problems arising during periods of peak demand. As capacity is stretched, so is the pipeline's ability to provide interruptible service without what customers view as excessive interruptions. At the same time there is increasingly the awareness that any potential remedies to these problems may be costly. That is, while new capacity and competition may lead to increased fuel supplies, such initiatives would also entail high capital costs that would need to be recovered from consumers. In the eyes of many, progress has been slow. But there has been progress, and as discussed more fully below, there is the promise of substantially increased capacity in the near to mid-term.

The survey of LDCs referred to above provides useful insights into the nature and magnitude of the capacity problem in East Tennessee. Of the 98 survey instruments mailed, there was a strong response rate of 46.7 percent. In total, the 46 respondents account for annual throughput of 155.5 thousand mcf/year of natural gas. Six pipeline companies were identified as suppliers to the various LDCs, TGP, Trunkline, ETNG, Texas Eastern, ANR and SONAT.

The results from the survey are summarized in Table 2.[5] Thirteen LDCs (or 28.3 percent of the total) identified ETNG as their sole supplier; 9 LDCs (or 19.6 percent) receive transportation services from ETNG, as well as at least one additional pipeline; and the remaining 24 LDCs (or 52.2 percent) received no transportation services from ETNG. The data are presented for all respondents (the first column of results) and are also broken out by the various sets of pipeline companies serving the LDCs. Average annual throughput for all LDCs is 3,515,265.6 mcf, which is more than twice the size of the average LDC served exclusively by ETNG. The LDCs served exclusively by ETNG also have a somewhat larger share of residential customers, a smaller mix of LDC-served industrials and a higher share of direct-served (i.e., "other") customers. LDCs on the ETNG system stand out as having smaller peak loads, only 48.3 percent of the overall average. The LDCs served by ETNG, as well as one additional pipeline supplier, confront a higher number of peak days (9.9 versus 7.8).

The difference between LDC peak daily demand and maximum delivery quantity per day from suppliers is labeled "deliverability gap." When such gaps manifest

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[5]The survey instrument is reproduced in the Appendix.

Table 2

Tennessee LDC Survey Results

		Pipeline Supplier		
	All Responses	ETNG	ETNG & Other	Other Pipelines
Average annual throughput (mcf)	3,515,265.6	1,430,267.4	6,257,988.4	3,680,374.9
Throughput accounted for by (%)				
Residential	40.0	45.5	25.6	46.9
Commercial	22.4	19.6	21.1	24.4
Industrial	33.4	22.4	50.1	27.7
Other	4.3	12.5	3.2	1.0
Peak demand (mcf/day)	27,121.2	13,106.0	37,932.5	30,658.6
Peak days per year	7.8	7.3	9.9	7.4
Deliverability gap (mcf)	7,920.3	4,768.2	6,238.3	10,179.4
LDC interruptions (days per year)	9.7	22.2	14.9	1.1
Pipeline interruptions (days per year)	7.2	24.7	7.1	0.1
Maximum firm service LDC could offer today (mcf)	983.2	850.0	1,117.4	1,019.0
Percent LDCs using alternative fuels	50.0	83.3	47.0	30.3
Pipeline could provide 2,500 mcf in additional capacity today (%)	50.0	0.0	22.2	82.8
Percent LDCs that could provide 500 mcf in firm capacity today	78.3	76.9	66.6	87.5
Lead time required to add 1,000 mcf in capacity (months)	7.3	10.3	9.6	5.4
Percent LDCs requiring industrial standby capacity	38.6	46.2	55.5	27.4
Respondents	46	13	9	24

Source: LDC survey administered by the Center for Business and Economic Research.
Note: Some respondents chose not to answer all questions.

themselves, they may be filled by curtailing service to interruptible customers or through the use of various peaking facilities. By far, the largest gaps appear on the "other" pipelines, substantially higher than the overall average. On average, the LDCs were forced to curtail service 9.7 days within the past two years. There are rather striking differences across the three pipeline supplier groups, with an average of 22.2 days of interruption for those served solely by ETNG, 14.9 days for those served by ETNG and other pipelines and only 1.1 days for LDCs receiving transportation services from other pipelines.

Curtailments of service by the pipeline companies themselves average 7.2 days per year, but show wide variation by various pipeline supplier category. The highest propensity for interruption is on the ETNG line, with an average of 24.7 days of interruption per year, versus less than 0.1 day per year for other pipelines. Only 15.4 percent of LDC respondents receiving service exclusively from ETNG reported zero days of curtailment from their suppliers, as opposed to 55.6 percent for ETNG and others, and 83.3 percent for LDCs served by other pipelines.

The remaining data in Table 2 raise doubts about the capacity of certain LDCs and ETNG to meet natural gas needs of their customer base. The LDCs on the ETNG system feel they could offer, on average, 850 mcf/day in firm service to a new industrial customer, substantially less than the overall average of 983.2 mcf/day. At the same time, the vast majority (83.3 percent) of respondents receiving exclusive service from ETNG noted that this would require the use of alternative capacity, versus 30.3 percent of the LDCs deriving gas from other pipelines. None of the LDCs in the eastern portion of the state feels that its pipeline supplier could add 2,500 mcf/day in capacity. Lags in the perceived time it would take to add capacity were highest for LDCs served solely by ETNG at 10.3 months, versus an overall average of 7.3 months. Finally, about 50 percent of LDCs served exclusively by ETNG, or by ETNG and at least one other pipeline, required industrial users to have some form of standby capacity to deal with interruptions. The comparable figure for the "other" pipeline category is only 27.4 percent.

In summary, the LDCs served solely by ETNG have smaller throughput and smaller peak gaps, but more frequent interruptions of service. As a result, customers served by these same LDCs will be subject to greater supply uncertainty and greater LDC/industrial dependence on alternative fuels and capacity. There is also the perception that the needs of future industrial growth cannot be met as adequately nor in as timely a fashion as in other regions of the state.

ETNG recognizes that its system suffers from capacity constraints, although the immediate problem is perceived to have more to do with peak day as opposed to baseline demands for its transportation services. While few problems surfaced during the 1980s, both consumers and ETNG have noted that constraints have become more prevalent. In the past, those who subscribed to interruptible transportation services seldom were curtailed, and modest increments in firm service were typically available. Currently, interruptible customers face a greater likelihood of curtailment and firm service on the ETNG system is 100 percent subscribed.

Efforts have been made by ETNG to expand its capacity, as illustrated in Table 3. Substantial new investments came on line in 1987 and 1990, the former corresponding to a liquified natural gas (LNG) storage facility near the Tri-Cities. Note, however, that when adjusted for inflation, the numbers show little growth over the long term and in many years illustrate actual contraction in real plant values.

ETNG insists that it can add capacity on the margin to adequately meet demand, and to date it has been successful. In some instances this expansion process can take up to two years due to regulatory and construction constraints, resulting in frustrated consumers. There are limits to what these marginal improvements in compression and looping (i.e., laying more pipe) can achieve, however. In the midterm--by the year 2000--ETNG projects base load growth to produce a shortfall of 200,000 mcf per day. This shortfall would be much more acute if any large industrials were to tie into the system.

A number of initiatives have been explored by pipeline companies currently not in operation in East Tennessee. In some instances these initiatives have involved ETNG (as with the proposed ETNG-CNG interconnect), whereas others have not (as with Texas Eastern's efforts to market peak shaving facilities to LDCs and to build a pipeline from Middle to East Tennessee).

Figure 3 is an illustration of ETNG's pipeline system, extending from the TGP in middle Tennessee, through Chattanooga and Knoxville, to Roanoke Virginia. The vast majority of natural gas moving on the ETNG system originates from the TGP. The rather modest pipeline diameter of the ETNG lines, coupled with limited opportunities

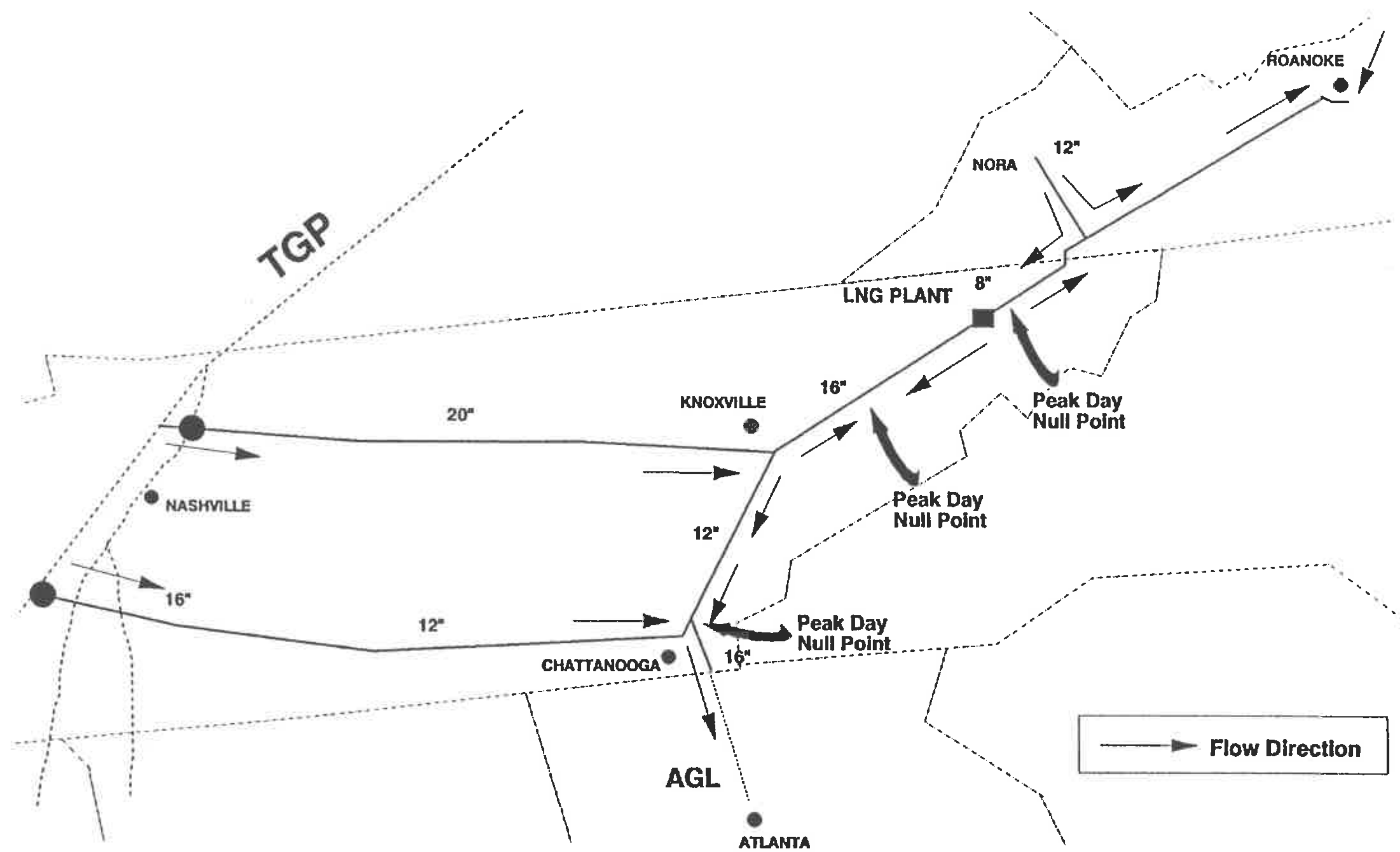
Table 3

Gas Plant in Service: East Tennessee Natural Gas (Dollars)

Year	Total Gas Plant in Service: Nominal	Total Gas Plant in Service: Inflation-Adjusted	Percent Change in Inflation-Adjusted Gas Plant
1982	$ 76,170,567	$ 119,746,214	--
1983	$ 78,223,902	$ 117,365,194	-2.0
1984	$ 85,034,282	$ 122,722,301	4.6
1985	$ 88,884,286	$ 123,467,546	0.6
1986	$ 90,000,071	$ 121,195,894	-1.8
1987	$ 135,935,381	$ 175,763,358	45.0
1988	$ 143,470,433	$ 177,958,860	1.2
1989	$ 151,889,782	$ 179,666,172	1.0
1990	$ 185,741,776	$ 208,956,886	16.3
1991	$ 209,201,320	$ 225,870,568	8.1
1992	$ 212,927,191	$ 222,913,726	-1.3
1993	$ 218,529,819	$ 223,194,586	0.1
1994	$ 226,495,863	$ 226,495,863	1.5

Source: Nominal gas plant data provided by East Tennessee Natural Gas.

FIGURE 3
East Tennessee Natural Gas System



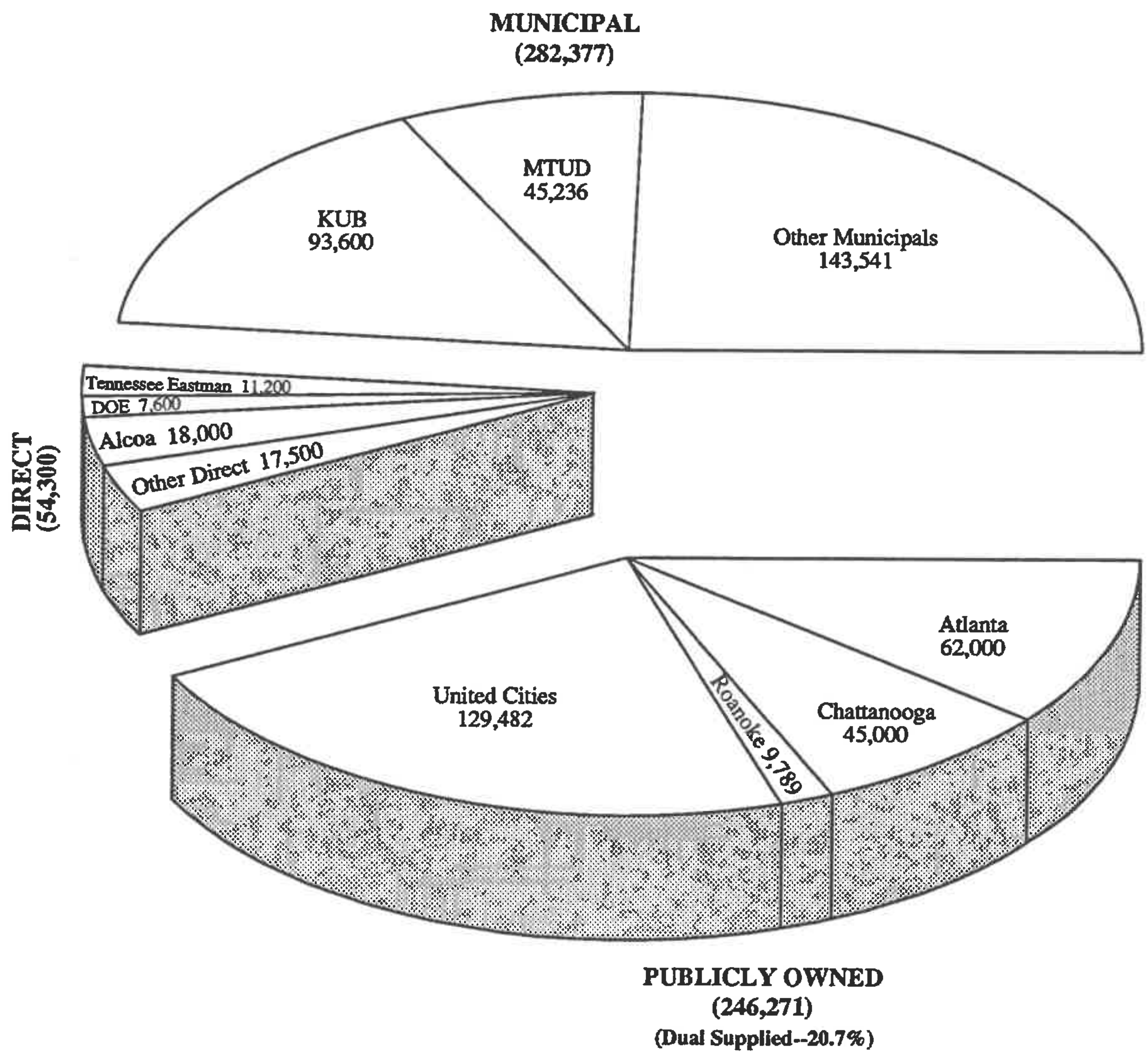
Source: East Tennessee Natural Gas.

for injection of gas at intermediate points, gives rise to some capacity problems during peak periods. The problem areas on the ETNG pipeline are denoted null points, indicating there is insufficient gas to maintain adequate pipeline pressure. The problems become more acute between Knoxville and the Tri-Cities. Note that as a complete system, efforts to inject gas at one point of the system can meet the needs of users across the system.

A number of the state's larger LDCs and industrial users of natural gas have actively pursued options for capacity expansion at various points on the ETNG system. Their stake in these activities is apparent from Figure 4, which illustrates ETNG's subscriber base and contract deliverability for 1994/1995. In a sense, all these players stand to gain from capacity expansion initiatives, as increased capacity for one LDC (industrial) offers the promise of freed-up capacity for others. For example, should the Knoxville Utilities Board (KUB) acquire peak-shaving capacity, more natural gas could move to the Tri-Cities during periods of heavy demand. Middle Tennessee Utility District (MTUD) and United Cities Natural Gas have each developed modest lines to Texas Eastern that will reduce their dependence on ETNG, freeing up capacity for other users of the ETNG system. The initiative by SONAT in the Chattanooga area, while also modest in scope, provides further incremental relief. And new salt cavern storage facilities either under construction or in the planning stage by Virginia Gas Storage will help meet existing and future peak needs as well.

Whether or not these and other initiatives will adequately meet consumer demands remains unclear in the absence of detailed projections on natural gas supply

FIGURE 4
1994/95 Contract Deliverability
East Tennessee Natural Gas
(582,948 Mcf/d)



Note: Includes LNG.
Source: East Tennessee Natural Gas.

and demand. Most agree that capacity will expand incrementally to meet baseline needs; there is less agreement on whether capacity will expand sufficiently to meet peak needs, especially in the near term.

As capacity and energy costs are intertwined, an important consequence of the peak demand problem is that it gives rise to higher costs, costs that are incurred by pipeline companies, industrials and LDCs. For example, ETNG operates a LNG storage facility near the Tri-Cities to meet regional spikes in demand. This facility still requires the transportation of natural gas, but entails the added cost of the storage facility and liquification. Many LDCs and industrials have also invested in peaking facilities to meet the needs of their customer base, adding to their cost of service.

Industrials that subscribe to interruptible service often rely on expensive substitute fuels to meet their own needs. As shown in Table 4, the cost of LPG was 131 percent higher than natural gas per Btu in 1992. Industrials also rely heavily on coal, distillates and electricity, all of which are more expensive than natural gas. Note that due to environmental considerations the price of coal is higher than implied by Table 4.

The consequences of fuel switching during supply interruptions can, with some simplifying assumptions, be readily illustrated. Such an illustration is provided in Table 5 for hypothetical firms utilizing different volumes of fuel. The first column shows the assumed amount of natural gas that would be consumed each day of a firm's operation, for small to very large users of natural gas. The next column shows the annual energy costs (using statewide average prices for industrial users) assuming no natural gas supply interruptions. For a small firm, annual energy costs without curtailment are only

Table 4

Energy Price Estimates for Tennessee's Industrial Sector
(Dollars per Million Btu)

	1985	1990	1992
All Primary Energy	$ 3.87	$ 3.32	$ 3.17
Coal	1.61	1.41	1.41
Natural Gas	4.11	3.29	3.34
LPG	8.66	9.36	7.73
Distillate Fuel	5.91	5.65	4.44
Electricity	14.22	13.74	13.49

Source: *State Energy Price and Expenditure Report 1992*, Department of Energy, Energy Information Agency, U.S. Government Printing Office, 1994.

Table 5

Hypothetical Annual Energy Costs With Fuel Switching
[In dollars]

	Annual Energy Costs									
		Five Weeks of Interruption			Three Weeks of Interruption			One Week of Interruption		
Firm Size (fuel)	No interruption	LPG	Distillate*	Elec-tricity	LPG	Distillate*	Elec-tricity	LPG	Distillate*	Elec-tricity
Small Firm (1 mcf/day)	$1,219.10	$1,372.75	$1,270.20	$1,574.35	$1,311.29	$1,249.76	$1,432.25	$1,249.83	$1,229.32	$1,290.15
Medium Firm (5 mcf/day)	6,095.50	6,863.75	6,351.00	7,871.75	6,556.45	6,248.80	7,161.25	6,249.15	6,146.60	6,450.75
Large Firm (75 mcf/day)	91,432.50	102,956.25	95,265.00	118,076.25	98,346.75	93,732.00	107,418.75	93,737.25	92,199.00	96,761.25
Very Large Firm (900 mcf/day)	1,097,190.00	1,235,475.0	1,143,180.00	1,416,915.00	1,180,161.00	1,124,784.00	1,289,025.00	1,124,847.00	1,106,388.00	1,161,135.00

* Light oil distillates only

Source: *State Energy Price and Expenditure Report, 1992*, U.S. Department of Energy, Energy Information Administration, Office of Energy Markets and End Use. U.S. Government Printing Office, 1994.

$1,219.10. For very large firms, the annual energy costs exceed $1 million.

The remaining data in Table 5 illustrate the costs of fuel switching under three scenarios, 5 weeks of interruption, 3 weeks of interruption and 2 weeks of interruption. The consequences for three of the more common substitutes to natural gas are shown, including LPG, distillate fuel and electricity. Total annual energy costs for these three interruption scenarios thus equal the cost of the substitute fuel for the period of interruption and the cost of natural gas for the remainder of the year. For example, with five weeks of natural gas supply interruption per year, energy costs rise by 12.6 percent when the switch is made to LPG. For a small firm, this amounts to only $154 per year, whereas for a very large firm the differential is over $138,000. Switching to distillate fuels imposes a 4.2 percent penalty, whereas electricity is 29.1 percent higher than natural gas. The differentials are more modest as the length of curtailment is reduced. Not shown in Table 5 are the consequences of fuel switching for the largest industrial customers, those firms that use upwards of 20,000 mcf/day. The costs for these firms rise in the same proportion as the costs for smaller firms, although the dollar costs are themselves much higher.

It should be recognized that added to these marginal energy costs are the capital costs associated with developing stand-by facilities. The Gas Research Institute (1993) has estimated that peaking facilities entail marginal costs three times higher than the cost of pipeline supply. The Tennessee and Kentucky region receives 3 percent of its gas through various peaking facilities, versus 2 percent for the nation as a whole. The same region in turn relies more heavily on pipeline supply (89.9 percent) than the U.S. (80.0 percent).

An important qualification is in order regarding the use of peak-shaving facilities by industrial firms. For some users, given the pricing structure for transportation services, peaking facilities may be preferred even if natural gas is available on the transportation network. Consider, for example, a firm that subscribes to interruptible service, service that is curtailed during peak-load periods. The issue confronting the firm is how to fill gaps during peak periods. One option would be to subscribe to higher-priced firm transportation services, if available. For at least some users, a second option of storage or peaking facilities may prove cost-effective. Moreover, with alternative capacity, the user may find cost advantages if, for example, natural gas commodity prices were to climb rapidly or alternative fuel prices were to fall. A recent *Statistical Brief* from the U.S. Census noted that many of the nearly 15 percent of the nation's manufacturing sector firms that have fuel switching capacity have made this choice as a result of fuel price volatility problems. Many of the firms contacted over the course of this study, including those surveyed by Associated Valley Industries, offered similar reasons for having fuel switching capacity.

B. Pricing

The burner tip price of natural gas is dominated by three components, the cost of the natural gas commodity itself, transportation services and LDC markups. Natural gas prices are determined competitively in international commodity markets, such that buyers pay largely standardized prices. (Natural gas prices are currently in the neighborhood of

$2 per mcf.) Transportation services and LDC markups, on the other hand, are subject to much broader variation. Making detailed comparisons of prices within and across states, as well as across consumer sectors, is complicated by the lack of comparable data. The problem is that there is no systematic reporting process for natural gas prices beyond the wellhead. While transportation tariff data are reported to FERC, these rates reflect the maximum and minimum charges that pipeline companies charge, and not the actual rates paid for transportation. Nonetheless, there are some available data that shed light on the price situation in Tennessee and other states.

Table 6 provides average end-user natural gas price estimates for the various states in 1992. The national average price was $3.89 per million Btu, with a high of $13.33 in Hawaii and a low of $1.75 in Alaska. Tennessee's average price across all consumer sectors in 1994 was $4.14 per million Btu, or 6.4 percent above the national average. Twenty-seven states and the District of Columbia have higher average rates, whereas 27 states have lower rates. Of the states in the southeast region, only Virginia and Georgia had higher prices in 1992. Note that in general, states in close proximity to the source of natural gas supply, including Florida, Mississippi and Louisiana, pay some of the lowest end-user prices in the nation.

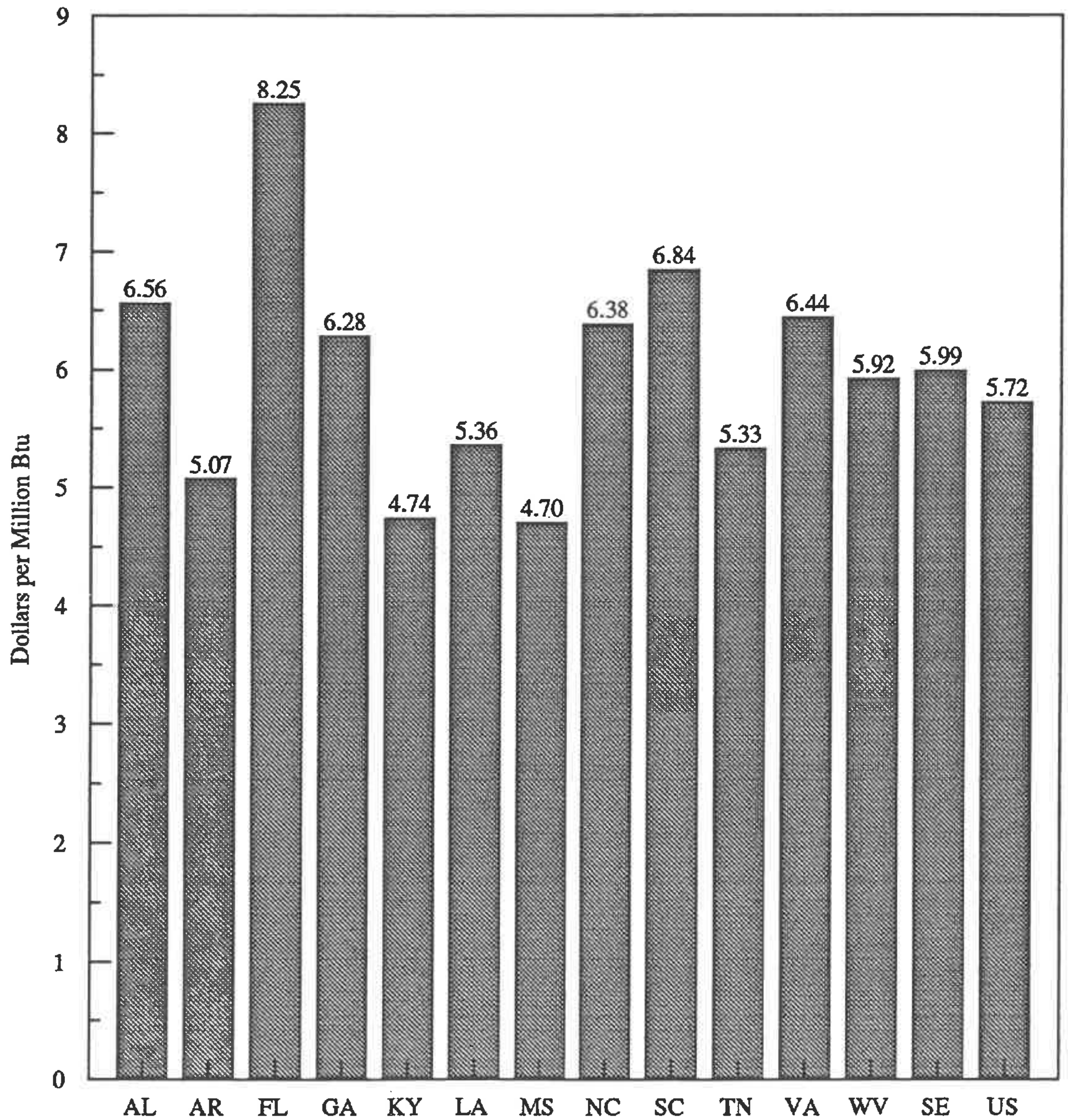
Figures 5, 6 and 7 illustrate the end-user prices of natural gas for residential, commercial and industrial consumers, respectively, across the southeastern states in 1992. In general, residential consumers pay higher per-unit prices than commercial consumers. Commercial consumers, in turn, pay higher prices than industrial consumers.

Table 6
Natural Gas Prices by State, 1992 [Dollars per Million Btu]

State	Rank	Price
United States	--	3.89
Hawaii	1	13.33[a]
Connecticut	2	6.85
District of Columbia	3	6.46
New Hampshire	4	6.23
Massachusetts	5	5.66
Rhode Island	6	5.52
New York	7	5.48
Maine	8	5.43
Pennsylvania	9	5.22
Vermont	10	5.03
New Jersey	11	5.02
Maryland	12	4.97
Virginia	13	4.77
Georgia	14	4.69
Wisconsin	15	4.60
Missouri	16	4.60
Arizona	17	4.57
Ohio	18	4.55
Illinois	19	4.50
South Dakota	20	4.44
Montana	21	4.42
West Virginia	22	4.41
Michigan	23	4.38
North Carolina	24	4.29
North Dakota	25	4.24
Iowa	26	4.24
Utah	27	4.18
Indiana	28	4.18
Tennessee	29	4.14
California	30	4.11
Nebraska	31	4.10
Alabama	32	4.06
Minnesota	33	3.99
South Carolina	34	3.96
Kentucky	35	3.92
Oregon	36	3.85
Delaware	37	3.82
Washington	38	3.70
Colorado	39	3.68
New Mexico	40	3.67
Nevada	41	3.65
Idaho	42	3.62
Arkansas	43	3.44
Kansas	44	3.38
Wyoming	45	3.17
Oklahoma	46	3.02
Florida	47	3.00
Mississippi	48	2.71
Texas	49	2.47
Louisiana	50	2.09
Alaska	51	1.75

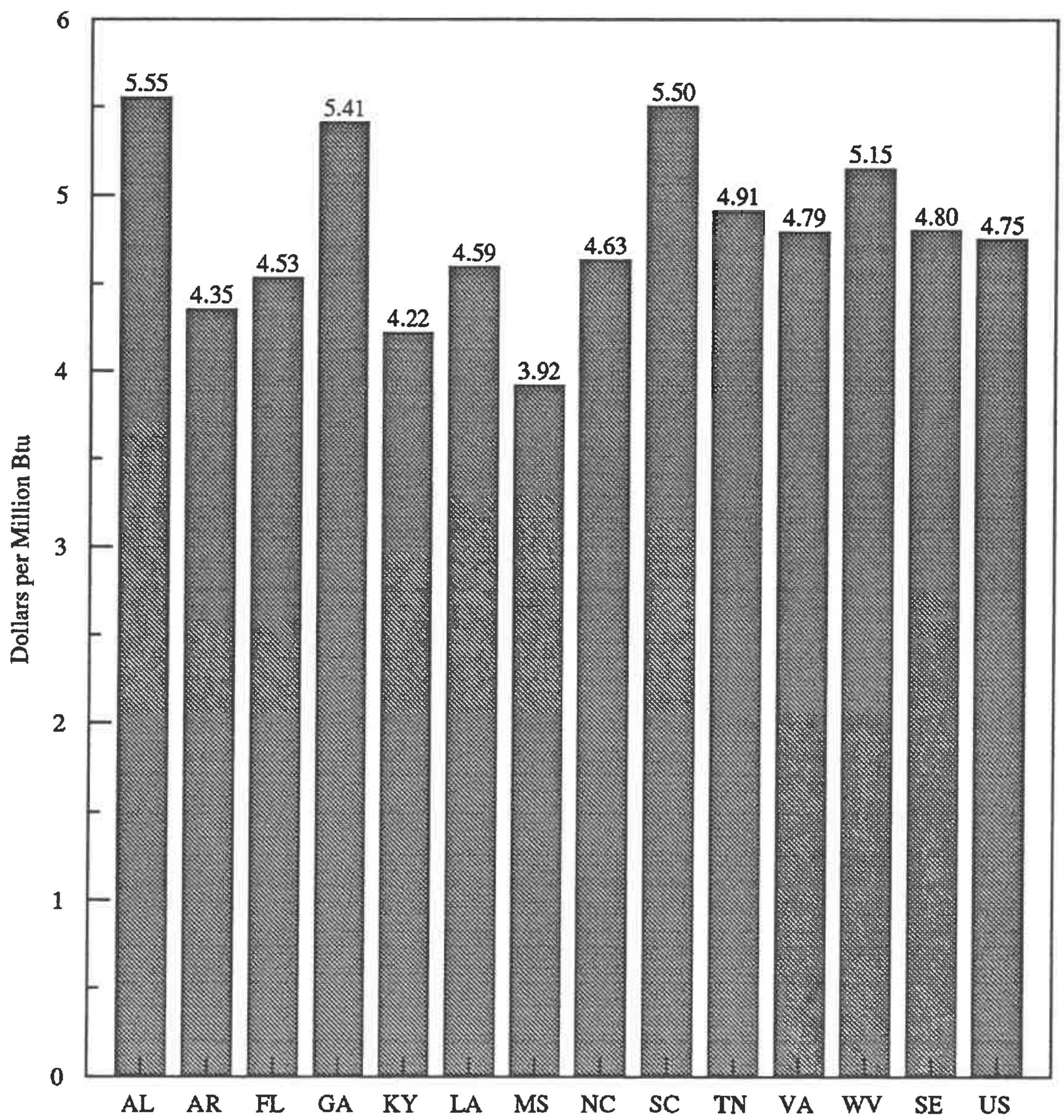
Note: Rankings are based on unrounded data. a. Based on small quantities of liquefied natural gas.
Source: *State Energy Price and Expenditure Report 1992*, Department of Energy, Energy Information Agency, U.S. Government Printing Office, 1994.

FIGURE 5
Natural Gas Prices for Residential Consumers, Southeastern States and United States 1992



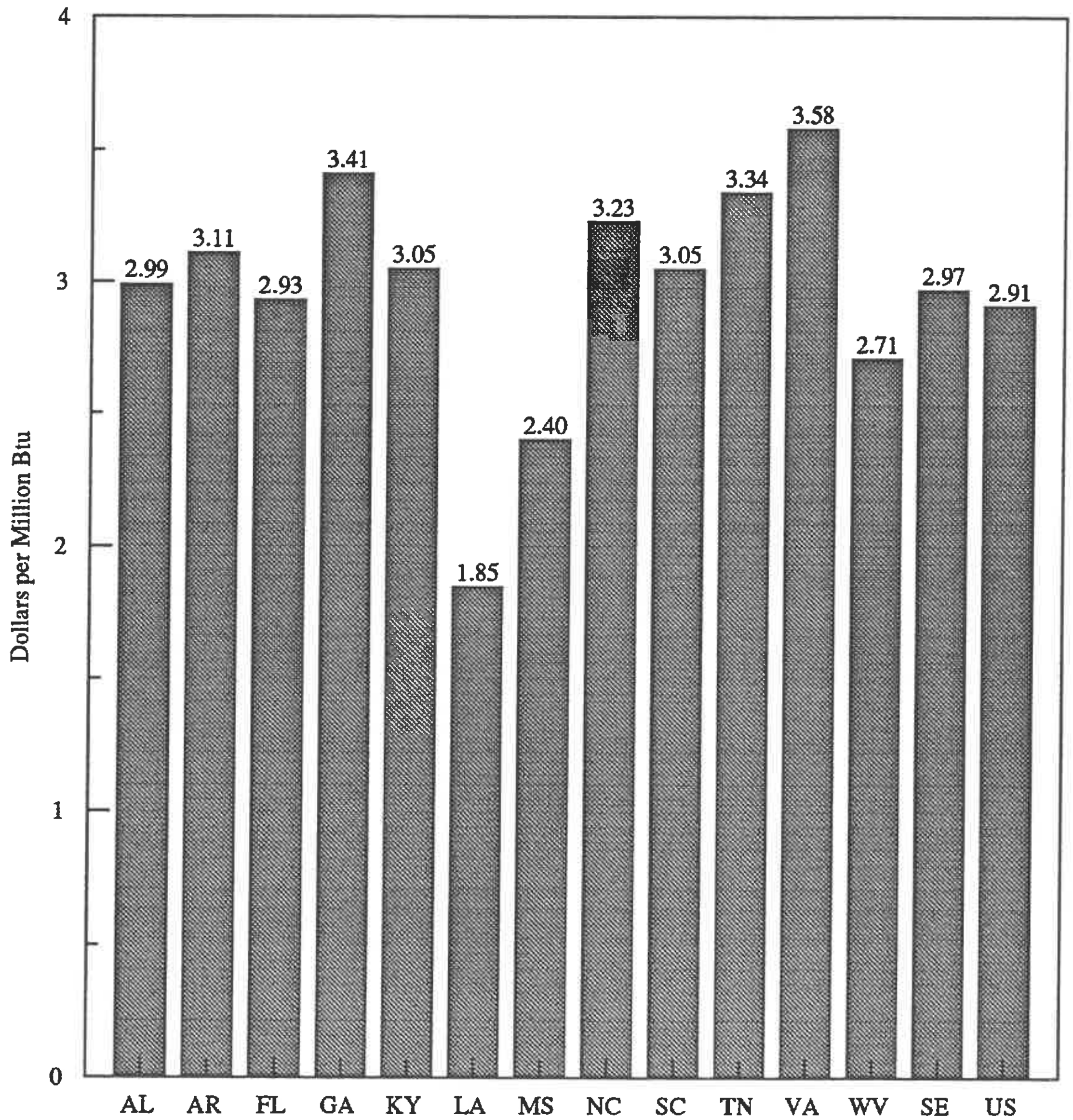
Source: *State Energy Price and Expenditure Report 1992*, Energy Information Agency, U.S. Government Printing Office, 1994.

FIGURE 6
Natural Gas Prices for Commercial Consumers,
Southeastern States and United States
1992



Source: *State Energy Price and Expenditure Report 1992,* Energy Information Agency, U.S. Government Printing Office, 1994.

FIGURE 7
Natural Gas Prices for Industrial Consumers,
Southeastern States and United States
1992



Source: *State Energy Price and Expenditure Report 1992*, Energy Information Agency, U.S. Government Printing Office, 1994.

Note from Figure 5 that residential consumers in Tennessee face some of the lowest prices in the region, with only Mississippi, Arkansas and Kentucky having lower prices. On average, residential consumers pay 89 percent of the southeast average and 93 percent of the U.S. average.

Prices paid by commercial users of natural gas tend to be slightly higher in Tennessee than in the Southeast and the U.S., as illustrated in Figure 6. Only 4 states in the Southeast--Alabama, Georgia, South Carolina and West Virginia--have higher average prices than Tennessee.

Industrial consumers in Tennessee confront prices that are relatively higher than for the U.S. and the Southeast. As shown in Figure 7, only Georgia and Virginia have higher average prices. On average, Tennessee's industrial consumers pay a 12 percent premium relative to the states in the Southeast, and a 15 percent premium relative to industrials across the country. Prices in Tennessee are at least 10 percent higher than those in 7 southeastern states, with the most dramatic differentials for Louisiana and Mississippi, states that benefit from close proximity to both natural gas fields and multiple interstate pipelines.

The implications of these higher prices for industrial users can be illustrated using hypothetical firms, as was done above in the examination of the consequences of fuel switching. Table 7 provides such an illustration for the southeastern states and the U.S. For small firms, the cost disadvantage in Tennessee is quite modest, at $134.75 (or 11.1 percent) versus the Southeast and $156.95 (or 12.9 percent) versus the U.S. The cost disadvantage becomes quite large for heavier users of natural gas. For the largest

Table 7

Hypothetical Annual Natural Gas Costs by Firm Size
[In dollars]

State	Annual Natural Gas Costs: Small Firm (1 mcf/day)	Medium Firm (5 mcf/day)	Large Firm (75 mcf/day)	Very Large Firm (900 mcf/day)
Alabama	$1,091.35	$5,456.75	$81,851.25	$982,215.00
Arkansas	1,135.15	5,675.75	85,136.25	1,021,635.00
Florida	1,069.45	5,347.25	80,208.75	962,505.00
Georgia	1,244.65	6,223.25	93,348.75	1,120,185.00
Kentucky	1,113.25	5,566.25	83,493.75	1,001,925.00
Louisiana	675.25	3,376.25	50,643.75	607,725.00
Mississippi	876.00	4,380.00	65,700.00	788,400.00
North Carolina	1,178.95	5,894.75	88,421.25	1,061,055.00
South Carolina	1,113.25	5,566.25	83,493.75	1,001,925.00
Tennessee	**1,219.10**	**6,095.50**	**91,432.50**	**1,097,190.00**
Virginia	1,306.70	6,533.50	98,002.50	1,176,030.00
West Virginia	989.15	4,945.75	74,186.25	890,235.00
Southeastern Region	1,084.35	5,421.75	81,326.25	975,915.00
United States	1,062.15	5,310.75	79,661.25	955,935.00

Source: U.S. Department of Energy, Energy Information Administration, Office of Energy Markets and End Use, *State Energy Price and Expenditure Report, 1992.*

firm--size category, costs are $121,275 higher in Tennessee than the Southeast and $141,255 higher than the national average.

In general, comparable end-user natural gas prices are not systematically collected at the substate level in Tennessee. The East Tennessee Development District did, however, conduct a natural gas rate survey for its coverage area as part of a broader survey of utilities in 1994. Selected monthly rate data from the gas component of the survey are presented in Table 8. As can be seen from this table, there is considerable variation in natural gas prices across providers and across service levels. For the lowest quantity of natural gas shown in Table 8--500 cubic feet--the average price is $6.57, with a high of $11.90 and a low of $4.00. (The average price translates into a fee of $13.14 per mcf.) The highest level of demand also displays wide variation across utilities, with an average price of $2,534.67, a high of $3,407.65 and a low of $1,602.00. (For this higher level of utilization, the price per mcf falls to $6.34.)[6]

An important component of the total end-user price of natural gas is the embedded fee for transportation services. Daily demand charges for a number of interstate pipelines are presented in Table 9. Five of these pipelines--Texas Eastern, ETNG, TGP, Trunkline and ANR--correspond to pipeline suppliers that were identified in the survey of LDCs reported above (see Table 2). In addition, two other pipelines, Texas Gas and Columbia Gulf, also have a presence in Tennessee. Note that the demand charges on Texas Eastern were the second highest of any pipeline reported in

[6]Readers interested in the issues confronting LDCs after deregulation should see Brady (1994) and the National Regulatory Research Institute (1993).

Table 8

East Tennessee Development District Gas Bills
Municipalities, Utility Districts, and Companies, 1994

	Cubic Feet of Natural Gas							
Utility	500	1,000	2,500	5,000	10,000	50,000	100,000	400,000
Harriman	$ 4.80	7.85	$ 17.00	$ 32.25	$ 62.75	$ 306.75	$ 611.75	$ 2,441.75
Knoxville	8.85	12.71	24.27	39.83	69.54	307.22	604.32	2,386.92
Lenoir City	5.90	9.90	21.70	41.20	79.20	383.20	763.20	3,043.20
Loudon	6.25	9.25	18.25	33.25	63.25	303.25	603.25	2,403.25
Madisonville	4.90	8.40	18.80	36.05	69.55	337.55	672.55	2,682.55
Rockwood	4.00	6.00	12.00	22.00	42.00	202.00	402.00	1,602.00
Sweetwater	4.86	7.89	16.68	31.33	59.13	281.53	559.53	2,227.53
Citizens (1)	7.10	10.70	21.50	39.50	75.50	363.50	723.50	2,883.50
Jefferson-Cocke (2)	7.23	10.48	20.20	36.40	68.79	327.97	651.95	2,595.78
Jellico	11.90	16.15	28.90	50.15	92.65	432.65	857.65	3,407.65
Oak Ridge (3)	6.65	9.80	19.25	35.00	66.50	318.50	633.50	2,523.50
Powell Clinch	4.63	7.88	17.63	34.77	66.02	335.38	665.58	2,646.78
Sevier County	4.17	7.97	19.37	38.17	75.67	368.67	733.67	2,923.67
United Cities - Blount	8.70	11.40	19.50	33.00	60.00	276.00	546.00	2,166.00
United Cities - Hamblen	8.60	11.20	19.00	32.00	58.00	266.00	526.00	2,086.00
Lowest	4.00	6.00	12.00	22.00	42.00	202.00	402.00	1,602.00
Highest	11.90	16.15	28.90	50.15	92.65	432.65	857.65	3,407.65
Average	6.57	9.84	19.60	35.66	67.24	320.68	636.96	2,534.67
Average Price/mcf	13.14	9.84	7.84	7.13	6.72	6.41	6.34	6.34

Conversion Factor: 96.15 Cubic Feet = 1 Therm.

Notes:
(1) Based on 1,200 Btu
(2) $4.00 demand charge
(3) No gas usage included in minimum bill

Source: *Annual Utility Rate Survey*, East Tennessee Development District, August 1994.

Table 9
Pipeline Transportation Rates (Dollars per thousand cubic feet)

Supplier	August 1993	August 1994	July 1994
Williston Basio	.56	1.14	.75
Texas Eastern	.87	1.13	.66
Panhandle Eastern	.61	.92	.68
Williams Natural Gas	.26	.78	.75
Algonquin Gas	1.11	.75	.73
Kern River	.77	.74	.74
Columbia Gas	.41	.74	n.a.
East Tennessee Natural Gas	.50	.57	.74
Tennessee Gas	.42	.51	.53
Iroquois Gas	.54	.50	n.a.
El Paso Natural Gas	.53	.46	.49
Transwestern	.37	.42	.33
CNG Transmission	.29	.42	.48
Northwest Pipeline	.44	.38	.42
Mojave Pipeline	.51	.35	n.a.
Northern Border	.33	.33	.32
Trunkline	.23	.33	.31
Texas Gas Transmission	.30	.33	.33
ANR	.35	.33	.33
Transcontinental Gas	.35	.32	.32
Natural Gas Pipeline of America	.20	.29	.29
Pacific Gas Transmission	.12	.28	.32
Questor	.20	.26	.28
Columbia Gulf	.16	.25	.24
Northern Natural Gas	.27	.24	.25
Overthrust	.31	.23	.24
Midwestern Gas Transmission	.06	.22	.15
Trailbrazer	.25	.19	.18
High Island Offshore	.15	.14	.14
Stingray	.16	.11	.13
Viking Gas	.12	.11	.10
Wyoming Interstate	.10	.10	.09
Soa Robin	.09	.09	.08
Sabine	.05	.05	.05

Source: *Industrial Energy Bulletin* - February 24, 1995.

NOTE: Rates are based on revenue and volume figures filed by pipelines monthly on FERC Form 11. Some pipelines are excluded due to late filings.

Table 9, and rose sharply between July 1994 and August 1994. Columbia Gulf had the lowest rates of any pipeline passing through the state, while Trunkline, Texas Gas and ANR were in the middle of the pack. The remaining pipelines, ETNG and TGP, ranked 8th and 9th, respectively. Explanations for this variation include different degrees of competition, differently aged capital stocks and different distances gas is shipped by the various pipelines.

Not apparent in Table 9 is the fact that end-users that require two (or more) pipelines to ship gas must pay a double tariff, one each corresponding to the respective pipeline used. This can generally be avoided in Western and Middle Tennessee due to access to any of a number of major North-South interstate pipelines. In East Tennessee, however, consumers have no recourse but to ship gas via one pipeline prior to shipment and delivery on ETNG. Hence the total transportation tariff for those in East Tennessee will include the demand and commodity charges for at least two pipelines.

The demand and commodity rates for a number of pipelines serving the United Cities Gas Company, the largest privately owned natural gas utility in the state, are shown in Table 10. The rate data correspond to an mcf of natural gas per month. Note that these data, unlike those in Table 9, are directly comparable as they reflect delivery of the same amount of gas to a common destination. The data clearly illustrate how overall transportation rates are dictated by demand and commodity fees. The highest demand charges are on the Trunkline, Pan Handle Eastern and ANR lines, whereas the lowest rates are on Columbia Gulf and Texas Gas. The demand charges for ETNG are the fourth lowest and the commodity rates are the lowest of any pipeline supplier shown

Table 10

Natural Gas Transportation Rates for Pipelines Serving United Cities Gas Company, March 1, 1995
(mcf/month)

	Firm Transportation Demand Rates					Firm Transportation Commodity Rates				
Pipeline	Demand	GSR Surcharge	Other Surcharge	GRI	Total	Commodity	GSR Surcharge	Other Surcharge	ACA/ GRI	Total
ANR	$10.0100	$1.4510	($0.1930)	$0.2180	$11.4860	$0.0099	$0.0000	$0.0386	$0.0109	$0.0594
Columbia Gulf	$4.9537	$0.0000	$0.0000	$0.2180	$5.1717	$0.0227	$0.0000	$0.0000	$0.0107	$0.0334
East Tennessee	$7.3300	$0.0000	($0.0100)	$0.2180	$7.5380	$0.0011	$0.0000	($0.0027)	$0.0107	$0.0091
NGPL	$7.9000	$1.4610	$0.0000	$0.2180	$9.5790	$0.0280	$0.2052	$0.0000	$0.0108	$0.2440
Panhandle Eastern	$12.0500	$0.1700	$0.7100	$0.2180	$13.1480	$0.0302	$0.0000	$0.0210	$0.0109	$0.0621
Southern	$8.8000	$1.4000	$0.0000	$0.2180	$10.4180	$0.0130	$0.0800	$0.0000	$0.0108	$0.1038
TGP	$7.4600	$2.1000	$0.4400	$0.0000	$10.0000	$0.0060	$0.0000	$0.0310	$0.0023	$0.0393
Texas Eastern	$9.2564	$0.0000	$0.0000	$0.2180	$9.4744	$0.1566	$0.0000	$0.0000	$0.0108	$0.1674
Texas Gas	$6.8900	$1.7358	$0.0000	$0.2189	$8.8447	$0.0276	$0.0000	$0.0000	$0.0107	$0.0383
Transco	$7.0514	$0.0000	$0.0413	$0.2260	$7.3187	$0.0147	$0.0000	$0.0287	$0.0108	$0.0542
Trunkline	$12.6027	$0.0000	$0.0000	$0.2180	$12.8207	$0.0382	$0.0000	$0.0000	$0.0108	$0.0490
Williams	$8.4183	$0.0000	$0.0000	$0.1340	$8.5523	$0.0247	$0.0000	$0.0000	$0.0131	$0.0378

Notes:

ANR includes gathering in demand and commodity rates.
Columbia Gulf includes FTS-1 Rayne to Pts. North and FTS-2 On-Shore.
Panhandle Eastern includes field zone and market to 400 mile zone.
TGP is zone 0 to 1.
Texas Eastern FT is an average of production zones weighted by our contract quantity plus M1.
Texas Gas is zone SL to 2.
Transco is an average of production zones weighted by our telescoped entitlements and market capacity to zone 4.
Trunkline rates are field zone to 1B.
Williams includes FTS-P plus FTS-M (production and market areas).

Source: United Cities Gas Company.

in Table 10.[7] Unfortunately, at least one additional pipeline must be used to first ship gas to the ETNG system. The total rate is then the rate on ETNG plus the rate on some other pipeline. For example, if gas were initially shipped via TGP at a demand charge of $7.46, an additional demand charge of $7.33 would accrue (as well as surcharges, the commodity charge and the cost of natural gas itself), for a total demand charge of 14.79 per month. This combined rate clearly exceeds the single rate charged by any one pipeline.

The LDCs and industrial users of natural gas served exclusively by ETNG voice the strongest objections to this double-tariff price structure. Many feel they should have access to natural gas transportation services at rates commensurate with their counterparts in other regions of the state (and country), and attribute rate differentials to ETNG's market power and monopoly position in transportation services. (Part of the problem may be the postage stamp rate structure on ETNG, as those in close proximity to the major interstate pipelines pay the same tariff as those in upper East Tennessee and beyond.) The response from ETNG is that their rates reflect investments in capacity that consumers should pay for. Moreover, as noted by ETNG, the movement of natural gas from the Nashville area to Knoxville is approximately 175 miles. Were gas shipped on a single pipeline such as TGP from the Gulf to Lexington, Kentucky, an additional demand charge of $3.91/mcf would accrue. This moves the total distance-based

[7]Most pipelines follow a zone designation for transportation services, with higher tariffs for greater shipping distances. The rates for ETNG are akin to a postage stamp, a flat fee regardless of point of delivery. Subscribers to ETNG generally supported the shift to this flat-fee rate structure.

transportation cost closer to, but nonetheless short of, the combined TGP and ETNG rate.

As discussed above, numerous initiatives have been pursued to expand capacity on the ETNG system. Unfortunately, all of these options appear to entail rather high end-user costs, diminishing support amongst industrials and LDCs. Table 11 provides firm transportation rate data supplied by ETNG regarding its current rate structure and the rate structure for selected existing and proposed interconnected lines. (The rate data were current as of February 20, 1995.) The first column, which totals $0.7059, reflects the total charge per day (net of the cost of the natural gas commodity itself) to move one mcf of natural gas, if the user ships via TGP and subsequently ETNG. (This translates into a monthly fee of nearly $21.50.) The demand charges are thus equal to the sum of the individual demand charges for each pipeline, or $0.4314 per day (or approximately $13.11 per month). Note that users in certain areas of Middle and West Tennessee that have access to TGP pay only the first demand charge, or $0.1884 per mcf/day. The second column includes higher rates for firm transportation service from TGP, as reflected in a rate filing recently forwarded by the company. This would add 8.5 cents to the daily demand charge, or nearly $2.60 per mcf per month. To place this tariff hike in perspective, a large firm that uses 1,000 mcf per day would face increased costs of over $31,000 per year.

The remaining rate figures pertain to a select number of proposed interconnects between ETNG and other pipelines. An important point regarding all of these proposals, with the exception of the Columbia Gulf-ETNG interconnect, is that the

Table 11

Firm Transportation Tariff Rates, East Tennessee Natural Gas and Other Selected Pipelines
(mcf/day)

	Current TGP/ ETNG	RP 95-112 TGP/ ETNG	CNG/ ETNG	Proposed SONAT ETNG	Settlement SONAT ETNG	Columbia Gulf/ ETNG	TETCO/ ETNG
Pipeline #1							
Demand	$0.1884	$0.2712	$0.2300	$0.4350	$0.3817	$0.1180	$0.2430
Commodity	$0.0050	$0.0076	$0.0180	$0.0210	$0.0140	$0.0160	$0.0300
Fuel @ $2	$0.0382	$0.0382	$0.0460	$0.0520	$0.0520	$0.0680	$0.0460
Total	$0.2316	$0.3170	$0.2940	$0.5080	$0.4477	$0.2020	$0.3190
ETNG							
Demand	$0.2430	$0.2430	$0.2430	$0.2430	$0.2430	$0.2430	$0.2430
Commodity	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011	$0.0011
Fuel @ $2	$0.0440	$0.0440	$0.0440	$0.0440	$0.0440	$0.0440	$0.0440
Total	$0.2881	$0.2881	$0.2881	$0.2881	$0.2881	$0.2881	$0.2881
Subtotal	$0.5197	$0.6051	$0.5821	$0.7961	$0.7358	$0.4901	$0.6071
Capital Surcharge			$0.0800				
Subtotal	$0.5197	$0.6051	$0.6621	$0.7961	$0.7358	$0.4901	$0.6071
Other Surcharge	$0.1862	$0.1862	$0.0060	$0.0000	$0.1751	$0.0000	$0.0490
Total	$0.7059	$0.7913	$0.6681	$0.7961	$0.9109	$0.4901	$0.6561

Source: East Tennessee Natural Gas.

resulting demand charges are all of a similar order of magnitude.

At least based on the proposals considered to date, efforts to increase capacity in East Tennessee through pipeline interconnects or the development of new pipelines will be able to increase system capacity and largely keep rates at existing levels. But none of the projects being considered would lead to an appreciable reduction in rates. This outcome would likely occur (if at all) only under conditions of broader competition for transportation services. From the perspective of the pipeline companies, the proposed rate structures are a reflection of their need to recover costs and realize a rate of return on their investments, as well as limits on their opportunity to cross-subsidize rates. To provide greater certainty in cost recovery, pipelines have asked for long-term contracts extending out 20 years on deliverability. From the perspective of the LDCs and the industrials, there is a certain amount of anxiety and frustration regarding these and other capacity expansion proposals. While pleased with the potential opportunity to increase their allotments of natural gas, they hoped that more capacity would be accompanied by greater price competition. While this may be in the cards, especially as it relates to new pipeline development between Middle and East Tennessee, the lower rates have to date yet to materialize.

III. Assessment and State Policy Options

Environmental and efficiency considerations make natural gas an extremely attractive fuel source for both households and the business community. To the extent these consumers of natural gas confront relatively higher prices or more binding constraints on transportation capacity in Tennessee than in other states, Tennessee's prospects for economic growth will be diminished. But tracing the impacts of infrastructure generally and the role of natural gas infrastructure in particular in the economic development process is problematic. An analogy is the heated national debate over infrastructure decay and economic performance, which has failed to produce a consensus on the nature and extent of the problem, as well as potential solutions.

This section explores the more specific linkage between natural gas infrastructure and economic development in Tennessee. There are three objectives to this section. The first is to provide a summary of primary natural gas constraints confronting consumers in Tennessee, drawing on the data and information presented above. The second objective is to evaluate the economic development consequences of these constraints on the state economy. The final objective is to provide justification for state intervention in the private sector to address these problems, as well as lay out state policy options.

A. Natural Gas Constraints in Tennessee

Three problem areas surfaced above in the analysis of natural gas transportation and pricing in Tennessee. The first is that natural gas is not available in a number of areas across the state. While most counties have at least some access to natural gas (see Figure 2), there are numerous rural communities and a small number of counties which simply have no access. This situation makes such communities much less attractive, as households and private industry must utilize alternative and often times less desirable fuel sources (such as propane or electricity).

The second problem is the peak capacity constraint on the ETNG pipeline. With firm service 100 percent subscribed, interruptible customers--including industrials and LDCs--confront increasing periods of curtailment as baseline service demands grow. (See Table 2.) At this point there are few indications that baseline demands themselves cannot be met. Support for this conclusion is provided by conversations with private market players throughout the region, as well as the low-capacity release rates for natural gas capacity on the ETNG system during nonpeak periods. At the same time, the interruption of services during peak periods is a growing problem for many users, translating into greater supply uncertainty and higher fuel costs for numerous industrial consumers and LDCs. (The annual energy costs associated with fuel switching for industrials are illustrated in Table 5.) These concerns were voiced strongly in the context of discussions with private industry and local service providers over the course of this study.

The third problem, very much related to the capacity problem, is the relatively high price for natural gas transportation in East Tennessee. Average natural gas prices for final consumers are somewhat higher in Tennessee than the national average and exceed prices in a number of contiguous states (see Table 6), which is somewhat surprising in light of the number of major interstate pipelines passing through Tennessee. In addition, industrial consumers in Tennessee confront some of the highest prices in the southeast region, with only two states--Georgia and Virginia--having higher average prices (see Figure 7 and Table 7). As natural gas commodity prices are determined competitively in international markets, variations in the final delivered cost of natural gas can be attributed primarily to differentials in transportation costs and LDC markups.[8] The transportation cost differentials are most pronounced when comparing prices in East Tennessee with prices in other regions of the state (see Tables 9, 10 and 11). An important contributing factor to relatively high statewide prices is thus the cost of transportation services in East Tennessee.

An important qualification, noted above, needs restatement here. In light of distance-based transportation charges for most natural gas carriers, it is inappropriate to simply compare rates in West or Middle Tennessee to rates in the eastern portion of the state. As noted in Section II, an additional transportation tariff of nearly $4 per mcf/month would accrue in moving gas from Nashville to Lexington, roughly equivalent to the distance between Nashville and Knoxville. At the same, ETNG imposes a flat tariff of about $7.40 to move the same volume of gas anywhere on its system. Hence, some of the price differential is clearly justified by distance-based market considerations.

B. Consequences of Natural Gas Constraints

Natural gas availability, supply and price will all influence the location pattern of households and business and affect economic development. The question is not whether

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[8]There is rather wide variation in prices across utilities, at least in East Tennessee (see Table 8). LDC pricing practices--and other aspects of LDC behavior and performance--were not explored in any detail in this report.

natural gas matters, but instead, how important natural gas is to the economic development process.

Households desire natural gas as a clean and economical fuel source for space and water heating, as well as cooking. While natural gas may be an important consideration in deciding where to locate one's home, other factors--such as proximity to the work site, school quality, recreational opportunities and family ties--are also important. Households typically seek out desirable regions on the basis of labor market considerations and job opportunities. Once this initial decision is made, the next step is to make the more specific choice of residential location within the broader region. For most households, natural gas would become an issue only at the second stage of this decision process. But even then, natural gas availability and price must be balanced against the strengths and weaknesses of all community attributes. This implies that natural gas constraints serve primarily to influence where households locate *within* one region as opposed to their choice *across broad regions*. In light of the myriad factors households consider in their location decisions, natural gas can be expected to have very small impacts.

Business and industry also requires access to adequate and economical fuel sources, including natural gas. As profit maximizers, firms will seek out the optimal site for their activities, weighing all relevant costs and benefits. While natural gas may be an important consideration, especially for firms that utilize energy intensive production processes, other geographically variable factors--such as labor market conditions, taxes and proximity to markets--are also critically important.

Firm location decisions, much like household location decisions, are often a two-stage process. In the first stage, a general decision is made regarding the optimal region to locate, based largely on product market considerations. For businesses serving localized markets, such as retailers and personal service firms, the regional choice may focus on areas as small as or smaller than a city. For footloose firms such as manufacturers producing for national or international markets, the initial region of focus may include several states. Only for the most energy intensive firms would this initial location decision hinge on natural gas availability and price. In most instances, natural gas considerations can be expected to play a role in the more specific second-stage decision of where to site a facility within the broader region.

This site selection process has two implications for industrial development in Tennessee. First, natural gas constraints in East Tennessee may discourage the location and expansion of highly energy-intensive firms. Such firms may not consider East Tennessee in the first stage of their site selection process, although other regions of the state may remain viable due to ample fuel supplies and rather extensive competition. In the second stage, a site in Middle or West Tennessee, or a site in another state may be identified by energy intensive firms, but location in east Tennessee would be precluded. Second, for the more typical firm that relies less heavily on natural gas as a productive input, natural gas becomes an issue only at the second stage of the decision process. If the broader region under consideration is the state and the firm's concerns over natural gas are substantial, location would take place outside of East Tennessee. On the other hand, if product market concerns were paramount, location might still take place in East Tennessee. In general, natural gas constraints can be expected to shift the location of economic activity both to other portions of the state and to other states.

Natural Gas as Basic Infrastructure. While there is little doubt that natural gas constraints discourage economic development, there is far less certainty regarding the magnitude of the dislocation response. If natural gas is viewed as a form of basic infrastructure--as with road, water, sewer and telecommunication facilities--there are only isolated instances where natural gas constraints can be expected to hinder growth.[9] If there are numerous bottlenecks limiting economic growth, as might be the case with isolated rural regions that have limited transportation facilities and small, unskilled pools of labor, access to natural gas would be of limited value. On the other hand, if the only bottleneck constraining development is the market for natural gas, elimination of this constraint will undoubtedly facilitate economic growth. Unfortunately, the extensive research on infrastructure and economic development provides little guidance on how much growth might result from infrastructure improvements, or whether new capacity will be a cost-effective development strategy. Hence caution must be exercised in the use of public resources to expand natural gas infrastructure.

Energy Prices and Economic Development. Some additional insights can be garnered from research exploring linkages between energy prices--including natural gas--and the economic performance of firms and regional economies. An extensive review of this research was undertaken as a part of this study. An example is a study by Leonard

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[9]See Fox and Murray (1993) and Fox (1988).

Wheat (1982), which utilized statistical techniques to explain manufacturing employment growth across the states on the basis of industrial natural gas prices and other factors, such labor costs and tax burdens. Wheat found no statistically significant relationship between natural gas prices and employment growth. Another example is the work of Randall Eberts (1991) examining how responsive new firm openings are to natural gas prices and other location determinants. Eberts, contrary to Wheat, found some evidence that natural gas prices discourage firm openings, although the effects were very small.

The research on energy prices and development is summarized in Table 12. Note that most of this research focuses on energy forms other than natural gas. Of particular interest in Table 12 are the results for the "response coefficients" reported in the fifth column. The response coefficients are the statistical estimates of the sensitivity of economic development (as variously defined and measured in column 2) to variations in energy prices (as defined in column 4). A negative response coefficient means that higher energy prices are associated with lower rates of economic development, and vice versa. The number of statistically significant response coefficients for each of the studies is indicated in the final column of Table 12.

In total, these studies have estimated 43 economic development-energy response coefficients, of which 22 are statistically significant. In five instances the statistically significant response coefficients are positive, yielding the counterintuitive conclusion that higher energy rates are associated with higher rates of economic growth. (An example is the study by Plaut and Pluta that produced a positive response coefficient with a value of 6.1525.) Hence, less than half of the results (17 out of 43) support a linkage between

Table 12
Research Exploring Linkages Between Energy and Economic Development

Author(s)	Study Focus	Data	Energy Measure Used	Response Coefficient	Statistically Significant
Harris	Formation of new manufacturing establishments	Pooled, annual 35 SMSAs, 1976-1980	Average commercial electric bill	-0.76 to -0.56*	2 yes
Terkla and Doeringer	Employment growth	Pooled, annual, 48 states, 1970-1982	Average business electric bill (index)	-0.91 to -0.06*	2 yes, 2 no
Bartik	Business location	1607 plants	Average energy cost per Btu	-0.036 to -0.018*	3 no
Eberts	Firm openings	Pooled, annual, 40 SMSAs, 1976-78	Natural gas price	-0.29 to -0.001*	1 yes, 3 no
Duffy-Deno and Eberts	Real per capita income	Pooled, annual, 28 SMSAs, 1980-84	Price of electricity (300 KWH-1200 KWH Class)	-0.01 to -0.003*	2 no
Rasche and Tatom	Aggregate output	Time series, annual, 1949-75	Relative price of energy	0.1363	yes
Tatom	Output per unit of investment	Time series, quarterly, I/48-II/78	Relative price of energy	0.1081	yes
Tatom	Output in private business sector	Time series, quarterly, I/55-III/78	Relative price of energy	0.0930	yes
Papke	New capital expenditures per worker	Cross section, 20 states	Average cost of a million Btu's of energy	0.0010	no
Papke	New firm births	Cross section, 5 industries, 22 states	Average cost of a million Btu's of energy	0.1630	yes
Carlton	Firm location and employment	Pooled, 1967-71, SMSAs	Natural gas price (city gate price)	-0.49 to 1.24*	1 yes, 5 no
Carlton	Firm location and employment	Pooled, 1967-71, SMSAs	Price of electricity (300 KWH-1200 KWH Class)	-2.39 to -1.48*	6 yes
Bohi and Powers	Gross state product	Pooled, 1978-80, 1985-87, 50 states	Ratio of industrial energy consumption to gross state product	-3.77 to -2.36*	2 yes
Bohi and Powers	Total state employment	Pooled, 1978-80, 1985-87, 50 states	Ratio of industrial energy consumption to gross state product	-1.95 to -1.92*	1 yes, 1 no
Carrol and Wasylenko	Total nonagricultural employment	Pooled, 1967-1988, states	Price of electricity (30 KWH-6000 KWH Class)	-0.0001	yes
Carrol and Wasylenko	Manufacturing employment	Pooled, 1967-1988, states	Price of Electricity (30 KWH-6000 KWH Class)	-0.0800	no
Wheat	Manufacturing employment	Pooled, annual, 48 states	Price of industrial natural gas	-0.0800	no
Wasylenko and McGuire	Employment growth	Pooled, annual, 1973-80, 48 states	Price of electricity (30 KWH-6000 KWH Class)	-0.0100	yes
Plaut and Pluta	Employment growth	Pooled, annual, 1967-1977, 48 states	Cost per Btu	1.7494	no
Plaut and Pluta	Growth of capital stock	Pooled, annual, 1967-1977, 48 states	Cost per Btu	6.1525	yes
Papke and Papke	Capital investment per worker	Cross section, 20 industries, 20 states, 1978	Energy cost	-0.1110	no

*These response coefficients are elasticities.

lower energy prices and increased economic development. Eleven of the overall response coefficients were specific to natural gas, although only two of these showed statistical significance.

Another feature to note from Table 12 is that most response coefficients are quite modest in size, typically taking on values between zero and -1.[10] The interpretation is that even substantial differences in energy prices have only modest impacts on economic development.

Together, the literature reviewed above and the findings summarized in Table 12 indicate that while natural gas prices matter, they matter very little for the typical firm. Hence, to the extent end-user natural gas prices are relatively higher in East Tennessee than other regions of the state or the Southeast, the eastern portion of the state will realize slightly lower rates of growth. In some instances, economic activity will be shifted to other regions of the state, and in other instances the relocation will be in other states. But generally, with the exception of certain specific firms that use large volumes of natural gas, these impacts will be very small. These conclusions are supported by the survey administered by Associated Valley Industries, as well as direct consultations with industry participants. Unfortunately, the research summarized here on infrastructure, energy prices and economic development provides an insufficient basis to make more precise statements regarding the potential negative consequences of natural gas constraints.

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[10]In economic parlance, there is an inelastic relationship between energy prices and economic development. This means that large changes in energy price are associated with small changes in economic growth.

C. State Policy Options

The use of state policy to address any of the natural gas constraints identified in this report must be predicated on some notion of market failure. That is, if markets work reasonably well, there is little justification for state intervention in the private sector. If, on the other hand, markets perform poorly, there may exist an economic basis for state policy action. Yet even in these latter instances the costs and benefits of government intervention must be weighed against the performance of the private sector.

The availability constraint. Equity is the primary justification for state intervention in addressing the absence of natural gas availability in isolated regions of the state. In most instances, those communities without natural gas services are rural, isolated and sparsely populated; labor markets are often thin, offering employers a limited pool of skilled labor; highway, road, air and rail transportation services are limited; education services are poorly funded; and so on. The market realities are such that many of these communities cannot make natural gas a viable economic option to providers. If the critical mass of consumers existed to support development of natural gas infrastructure, the market would likely provide such infrastructure. While natural gas represents an impediment to growth in these areas, there are typically other impediments and constraints that may warrant greater concern. Unless all the conditions are ripe for economic growth and development, providing natural gas infrastructure to these communities will not likely be a cost-effective development strategy.

Since private markets in many communities cannot support natural gas infrastructure, the state could choose to intervene on equity grounds. The best strategy for the state to pursue would be to provide targeted loans--or for hard-pressed communities, grants--to finance natural gas infrastructure. Grants could be provided under the umbrella of the Tennessee Industrial Infrastructure Program (or TIIP program), which is used to meet the community-specific needs of new industry. Federal Community Development Block Grant funds can also be utilized as can resources from the Appalachian Regional Commission. Expanded use of these programs, or development of any new programs, should proceed cautiously. In light of the State's scarce economic development resources, access to these funds should be competitive and merit based. State funds must be allocated to those communities that have the potential to provide the greatest return, even if the justification for state policy action is equity.

Capacity and price constraints. There are two interwoven justifications for state intervention to deal with capacity and price constraints in east Tennessee. The first is that the ETNG transportation system is effectively a monopoly not subject to broad state control or regulation. Under monopolistic market structures, providers have economic incentives to restrict output and raise prices above levels that would be sustained by competition. The evidence presented in this report is largely consistent with this classical view of the monopoly problem.

The question naturally arises as to why the market has not responded with new entrants. That is, if market transportation rates are inflated and there exists some excess demand, why haven't other pipeline transportation companies entered the East Tennessee market? A primary reason is that there remains substantial risk associated with the enormous capital investments required to enter the market. For example, development of new pipeline capacity from Middle to East Tennessee would cost in excess of $100 million. These risks, which have slowed the pace of private sector action, provide a second justification for state policy intervention.

Pipeline transportation companies have two broad options under federal regulations when developing new infrastructure. The first is to secure long-term contracts that can demonstrate a market base that will provide an adequate return on the capital investments. The second is to make "at-risk" investments, that is, investments that are based on speculation that future market conditions will support the capital investment. In this latter instance, federal regulations preclude the shifting of any losses that might be realized to consumers of the transportation service. For example, should an at-risk pipeline be extended into East Tennessee that was subject to underutilization, the company--as opposed to ratepayers--must bear the financed burden. The potential entrants to the East Tennessee market are simply concerned with the long-term expected payoff associated with their investments and have to this date requested buyers to enter into long-term contractual relationships so as to protect their financial position.

It should be recognized that there are other reasons for slow movement in developing new capacity and competition in East Tennessee. One primary reason is that all of the relevant players are continuing to test the waters. Potential new entrants have uncertainties not only about future demands, but also about how much LDCs and industrials are willing to pay for natural gas. Not surprisingly, when new initiatives have been presented to the LDCs and industrials, the transportation charges have been roughly commensurate with existing rates. The buyers of transportation services have balked at these initiatives, hoping for a better rate structure and more flexible contractual agreements. These discussions and negotiations will continue, although pressure will mount as most deliverability contracts for the LDCs and industrials expire by the year 2000.

A final obstacle to capacity expansion is that FERC had maintained that new capital investments must be charged off incrementally to new users of the infrastructure, rather than being rolled into the existing rate base. In anticipation of a review of this ruling, many market participants have been slow to act. A new ruling issued recently by FERC clarifies the situation, and now allows new investments to be rolled into the broader rate base, as long as tariff rates paid by existing customers increase by no more than 5 percent. This will provide pipeline transportation companies with some added flexibility in meeting the expectations of consumers in East Tennessee, although this might raise the ire of some existing ratepayers.

As the natural gas transportation market continues to evolve and adapt, the state has a number of options that it might pursue to address the capacity and price problem. The goal should be to address both problems as one. That is, modest increments in capacity will do little to affect price, and the state has no direct leverage over natural gas transportation rates. The best strategy is to pursue options that would both add capacity and encourage competition in the market for transportation services. Competition will help reduce prices, but by how much is uncertain. At a minimum, the state should keep the process moving forward, as with its support of this report. The very modest negative economic development impacts identified above, coupled with a market that is working (albeit slowly), suggests that further state involvement should proceed cautiously and remain limited.

Options for Capacity and Price Problems

1. Option One

A first option would be to simply do nothing and let the market work. The peak-load capacity problem would likely persist for some time, with the costs being borne by large industrial users and the LDCs (and their consumers). The relatively high prices on the ETNG system would be maintained until new entrants imparted competition on the overall transportation system. The persistence of capacity and price constraints in the East Tennessee area would cause some industry to choose alternative sites for entry and expansion, both in other parts of Tennessee and in other states. While these impacts would be small in the aggregate, it is conceivable that some of the region's larger firms might choose to relocate.

2. Option Two

A second option would entail the state providing indirect and in-kind support to facilitate market-based solutions to the monopoly problem. A leadership role could be provided by the new Tennessee Regulatory Authority, in cooperation with the Energy Division of the Department of Economic and Community Development. The state could serve as a catalyst, bringing relevant parties together to arrive at a mutually beneficial remedy. This might be achieved by establishing the proper process for dialogue, as opposed to other specific actions on the part of state government. Should the development of new pipeline capacity ultimately be pursued, the state could use its own expertise and the expertise of others to identify expansion options and their implications, the proper ownership structure for the pipeline supplier (including consortiums of market participants) and appropriate financing mechanisms. This work might be conducted in a follow-up study to this report, focusing on the more technical aspects of pipeline development. The state could also seek to facilitate right-of-way acquisition (which is perceived as slow and arduous in Tennessee) and help with regulatory filings at the state and federal levels. (Many observers note that "FERC listens" to localized concerns.)

3. Option Three

A third option is for the state to use its resources to leverage private sector initiatives to develop new pipeline facilities in east Tennessee. This would address the risk problem identified above, culminating with the elimination of the monopoly in transportation services. Bridge loans could be used to cover a portion of the overall financing costs of new pipeline construction, although most funds for project development should be derived from private sector participants, those who stand to gain the most from capacity expansion and lower prices. (An important issue in this context is what party might receive the loan.) The loans should be provided at or near market rates, to be repaid by pipeline operators, whether the operators are traditional pipeline companies or a consortium of shippers, industrials and LDCs. There is little justification for simply subsidizing a private sector operator of an intrastate pipeline. State funds for the loan could be generated through the issuance of bonds, minimizing the commitment of state tax dollars.

4. Option Four

A fourth and more aggressive option would be for the state to become a direct financial stakeholder in new pipeline construction. (There is no basis whatsoever for the state taking a more aggressive role in the actual construction or operation of a natural gas pipeline.) Direct financial support would again address the risk problem, and through capacity expansion, alleviate the current monopoly problem in East Tennessee as well. Three alternatives are:

- **A special gross receipts tax** levied on the in-state sale of natural gas, either prospectively or retrospectively, to help finance new capacity initiatives. One drawback of this approach is that it would shift the burden of infrastructure development to all consumers of natural gas throughout the state, as opposed to those who stand to gain directly from new pipeline capacity.
- **State tax incentives for pipeline development.** The incentive could take the form of tax credits under the state excise or franchise taxes. This is a somewhat more aggressive position for the state to take, as it involves the outright expenditure of state tax dollars and shifts the costs of capacity expansion away from players in the natural gas market to all state taxpayers.
- **Direct state grants for new infrastructure development.** This more extensive role is very hard to justify, as market participants will be the primary beneficiaries of any state support, and the burden of financing will

again be shared by all taxpayers. Moreover, any state-provided grant would be have to paid for with state tax revenues, and additional taxes would serve to discourage economic growth across the state.

IV. APPENDIX

Appendix: LDC Natural Gas Survey Instrument

Instructions: The following questions pertain to the natural gas capacity of your utility and the pipeline(s) serving your utility. If you have any questions about the survey, contact Matt Murray at The University of Tennessee, Knoxville (615) 974-6084.

Please answer all questions. If actual data are unavailable, please provide your best estimate. Note that there is no way to identify individual respondents; all information will remain strictly confidential.

1. Current/recent pipelines serving your utility........... ______________

   ____

   ____

2. Annual natural gas throughput for your utility (mcf).... ______________

3. Percent of annual throughput accounted for by

   Residential.................................... ______________

   Commercial..................................... ______________

   Industrial..................................... ______________

   Other.. ______________

4. What is the peak demand for your utility (mcf/day)?..... ______________

   Over a typical winter season, how many days would this peak demand occur?.................................... ______________

5. What is the differential (mcf), if any, between your system's peak demand and total citygate pipeline firm maximum delivery quantity (MDQ)?....................... ______________

6. How many days per year in the past two years did your utility interrupt service to curtailable end users?..... ______________

7. How many days per year is your utility's curtailable service interrupted by your pipeline?.................. ______________

8. At what level could you provide firm service to a new industrial customer today without requesting additional capacity from your pipeline?.......................... ______________

   Would this require the use of alternative fuels such as LNG or propane?.. ______________

9. If you needed 2,500 mcf per day in additional capacity, could your pipeline meet this need today?.............. ______

If your answer is no, how long do you estimate it would take your pipeline to meet this need?.................. ______

10. Could you provide firm service today to a new industrial user requiring 500 mcf/day?......................... ______

If so, would this require the use of alternative fuels such as LNG or propane?................................. ______

11. How much lead time would your utility require to meet the capacity needs of a large new firm requiring 1,000 mcf of natural gas per day?...................... ______

12. Are industrial users of natural gas required to have their own alternative or standby capacity to receive natural gas from your utility?........................ ______

13. Have any industrial firms chosen not to locate in your community recently because of their concerns over adequate natural gas capacity?......................... ______

Please explain: ______

______

______

______

14. Have any industrial firms chosen not to locate in your community recently because of their concerns over the total delivered cost of natural gas?................... ______

Please explain: ______

______

______

______

15. Has your utility been forced to deny firm service to any industrial firms in recent years?...................... ______

Please explain: ______

______

______

______

16. Do you feel confident that your utility can meet the natural gas capacity needs of industry today?.......... ____________

If so, would this require the use of alternative fuels such as LNG or propane?................................ ____________

17. Do you feel confident that your utility can meet the natural gas capacity needs of industry within 18 months? ____________

If so, would this require the use of alternative fuels such as LNG or propane?................................ ____________

Please explain: ____

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18. For the most recent year for which complete data are available, what percent of your utility's total cost of natural gas acquisition is accounted for by transportation costs?................................. ____________

19. Please provide any additional information or examples regarding the natural gas capacity of your pipeline or your utility, or the total delivered cost of natural gas to your utility in the space below.

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Thank you very much for your time and patience in completing this survey. Please forward your responses to:

Natural Gas Survey
Center for Business and Economic Research
The University of Tennessee
100 Glocker Building
Knoxville, Tennessee 37996-4170

Phone: (615) 974-5441
FAX: (615) 974-3100

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