TECHNICAL INEFFICIENCY AND PRODUCTIVE DECLINE IN THE U.S. INTERSTATE NATURAL GAS PIPELINE INDUSTRY UNDER THE NATURAL GAS POLICY ACT*

by

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ABSTRACT

The U.S. natural gas industry has undergone substantial change since the enactment of the Natural Gas Policy Act of 1978. Although the major focus of the NGPA was to initiate partial and gradual price deregulation of natural gas at the well-head, the interstate transmission industry was profoundly affected by changes in the relative prices of competing fuels and contractual relationships among producers, transporters, distributors, and end-users. This paper assesses the impact of the NGPA on the technical efficiency and productivity of fourteen interstate natural gas transmission firms for the period 1978-1985. We focus on the distortionary effects that resulted in the industry during a period in which changes in regulatory policy could neither anticipate changing market conditions nor rapidly adjust to those changes. Two alternative estimating methodologies, stochastic frontier production analysis and data envelopment analysis, are used to measure the firm-specific and temporal distortionary effects. Concordant findings from these alternative methodologies suggest a pervasive pattern of declining technical efficiency in the industry during the period in which this major regulatory intervention was introduced and implemented. The representative firms experience an average annual decline in efficiency of .55 percent over the sample period. In addition, it appears that the industry suffered a decline in productivity during the sample period, averaging -1.18 percent annually.

Keywords: Technical efficiency, data envelopment analysis, natural gas transmission.

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I. Introduction

The U.S. natural gas industry has undergone substantial change in the past decade. Enactment of the Natural Gas Policy Act of 1978 (NGPA) set initial ceiling well-head prices and escalation schedules for over two dozen categories of natural gas[1]. The deregulation of well-head gas prices covered in the NGPA applied both to purchases of inter- and intrastate pipeline companies even though state regulated intrastate pipeline companies are not subject to other forms of federal regulation, such as rate of return regulation. By January 1985 between 55 to 60 percent of flowing natural gas had been released from field price control. The transmission industry experienced serious price competition, both from within the industry and from alternative fuels (residual fuel oil, nuclear, and coal) as the relative prices of substitute energy sources fell, due to rising natural gas field prices under deregulation, declining oil prices after U.S. crude price control ended in 1981, and due to technological innovation. Demand declined due to general energy conservation and the disappearance of traditional industrial users with multi-fuel boilers. Supporters of the partial deregulation argued that the new regulatory environment would allow the price of gas to reflect market conditions and would enhance competition and efficiency in the industry. Although the major focus of the NGPA was to deregulate the price of natural gas at the well-head, the natural gas transmission industry was profoundly affected by changes in the relative prices of competing fuels and contractual relationships among producers, transporters, distributors and end-users.

The scope of the NGPA and its distributional effects on end-use consumers has been vast. Estimates by Streitwieser (1989) indicate that over $100 billion was redistributed to primarily industrial consumers through partial decontrol during the period 1977-1985. It is quite remarkable, therefore, that no empirical study of the impact of the NGPA on the natural gas transmission industry has been undertaken at the firm level. This is the first study, to our knowledge, that assesses the impact of the NGPA on the technical efficiency of interstate natural gas transmission firms. We focus on the distortionary effects that resulted in the industry during a period in which changes in regulatory policy could neither anticipate changing market conditions nor rapidly adjust to those changes. The measurement of distortionary effects of the NGPA follows from two alternative methodologies for estimating technical inefficiency: stochastic frontier production analysis and data envelopment analysis. In addition, the rate of total factor productivity and various elasticities are derived from the estimated stochastic frontier model.

The plan of the paper is as follows. In section II we briefly discuss the structure of the industry and its recent regulatory history. Section III discusses the models with which the technical inefficiency will be measured. We introduce a new systems estimator for the stochastic frontier panel data model which allows for time varying technical efficiency that is firm specific and potentially correlated with the regressors in a simultaneous system based on a translog production function and cost-minimizing expenditure share equations. We also outline the standard programming alternatives for the deterministic panel frontier. Section IV provides a discussion of the data and variable construction. Estimation results are discussed in section V while section VI concludes.

II. Structure and Regulation of the Interstate Transmission Industry

The U.S. natural gas industry is composed of a vertically linked set of firms which produce, transport, and distribute natural gas. The firms that provide transmission services have traditionally served as merchant and shipper and are linked upstream to producers and downstream to local distribution companies. The regulatory history of the natural gas transmission industry is long and complicated, beginning in the early 1880s as state and municipal authorities established rate of return regulation over local transmission firms. Interstate transmission was regulated in the 1938 passage of the Natural Gas Act (NGA) which also created the Federal Power Commission (FPC), later to become the Federal Energy Regulatory Commission (FERC). The basic charge of the FPC was to define service areas, to certify changes in pipeline capacity and customer services, and to set transport rates by customer class and service type to allow "fair" rates of return on capital. In 1954, federal price regulation was extended to the well-head for natural gas destined to the interstate market in order to smooth regional price variations. Large discoveries of easily accessible natural gas along with promotion of natural gas as an alternative to coal or petroleum-based fuels lent stability to an industry which showed steady productivity growth through the early 1970s. The 1973 oil price shock abruptly changed this relatively peaceful industrial setting. The NGA prevented well-head prices of natural gas sold in interstate markets from rising at a fast enough pace to keep a dual intra/interstate market from developing. Substantial curtailments of shipments to both industrial and residential customers resulted and the Natural Gas Policy Act of 1978 was passed to allow partial decontrol of the well-head price of natural gas. By 1985 natural gas prices had risen 218 percent. The shortages of the 1970 were replaced by a surplus in the early 1980s. The combination of falling demand for natural gas during the early 1980s due to the recession, a fall in the quantity demanded and thus in need of transport because of the increased price, and an increase in the cost of a key variable input in transport, pipeline compressor fuel, impacted the transmission industry greatly. At a time when rapid adjustment to changing economic conditions was essential, the frequency of formal FERC rate decisions declined and the proceedings lagged by up to two years.

The empirical models we outline below will allow us to examine patterns of technical efficiency among firms in the transmission industry over the period 1977-85, the period during which the NGPA was enacted and changes in natural gas prices were mandated by Congressional legislation instead of market forces. We analyze the productive performance of a newly constructed panel of 14 natural transmission firms that comprise almost 50% of the total interstate sales. Our empirical results point to a substantial and pervasive fall in technical efficiency and productivity during the period in which the NGPA was enacted and its pricing mandate implemented.

III. Models

We measure the firm-specific levels of technical inefficiency using both stochastic frontier and data envelopment analysis. We base our panel stochastic frontier model on a simultaneous equations extension of the single equation panel production frontier model introduced by Schmidt and Sickles (1984) and by Cornwell, Schmidt and Sickles (1990). Our data envelopment analysis is carried out using an approach outlined in Good and Sickles (1991) which modifies the efficiency scores from the standard piece-wise linear programming problem of Charnes, Cooper, and Rhodes (CCR, 1978, 1981) to accommodate a panel deterministic frontier that is changing over the sample period.

Our motivation for modeling as we do technical distortions due to FERC regulation in light of the NGPA is grounded in the extremely complicated and often contradictory regulatory process itself. For example, Figure 1 provides us with the maximum ceiling price schedules from 1978 to 1985 which give 24 different combinations of prices over the period for different categories of natural gas. Over the ceiling price schedules are layered regulations dealing with rate filings, infrequent rate hearings, and final disposition of cases for each firm over a nine year period. The information requirements to allow a formal structural analysis of the distortionary effects of such regulation renders its feasibility moot. The stochastic frontier and data envelopment analyses can be viewed as parsimonious approaches to reduced form estimation of the effects that distortions had on firms' abilities to pursue average frontier or best practice technologies.

The panel stochastic frontier production model was first considered by Schmidt and Sickles (1984). In their original model the production function was written as

$$y_{it} = \alpha + X_{it}' \beta + \nu_{it} - u_i , \tag{1}$$

where y_{it} is output, X_{it} is a vector of factor inputs, $<_{it}$ is standard statistical noise, and $u_i>0$ is a firms specific effect that is interpreted as technical inefficiency. Alternative estimators of u_i were proposed which were based on the time invariance of technical inefficiency. In subsequent work, Cornwell, Schmidt and Sickles (1990) generalized the panel frontier production model to allow for consistent estimation of firm-specific and time-varying technical inefficiency and introduced a class of efficient instrumental variables estimators for use when technical inefficiencies were uncorrelated with selected regressors. Here we generalize the panel frontier production model further by nesting it in a system of equations and specify a class of efficient three stage least squares estimates of the production system in which (1) firm-specific technical inefficiency is time varying (2) technical inefficiency may be uncorrelated with selected regressors (3) right-hand-side variables may be correlated with statistical noise.

We begin with a variant of the model considered by Cornwell, Schmidt and Wyhowski (1991) in which the j th structural equation of a G-equation system is written as

(2) $$y_j = Y_j\delta_j + X_j\beta_j + Z_j\gamma_j + W_j\alpha_j + \varepsilon_j \;,\; j = 1,\ldots,G,$$

where observations are ordered as, e.g., $y_j' = (y_{j11} \ldots y_{j1T} \ldots y_{jN1} \ldots y_{jNT})$. Time-varying right-hand-side endogenous variables and exogenous variables are in the data matrices Y_j and X_j, time-invariant exogenous variables are in Z_j, and W_j is a matrix of exogenous variables whose coefficients may exhibit heterogeneity over time and over the cross-section. Individual effects are allowed to vary over the cross-sectional observations but not over time. However, since time can be a regressor in W_j and since heterogeneity in slopes and intercepts is allowed for in this model, firm-specific technical inefficiency can vary over time if we interpret the individual effects as technical inefficiency. The model can be rewritten by letting "$_j$ = "$_{j0}$ + u_j in which case (2) becomes

(3) $$y_j = Y_j\delta_j + X_j\beta_j + Z_j\gamma_j + W_j\alpha_{j0} + \nu_j \;,$$
$$\nu_j = Q_j u_j + \varepsilon_j \;,$$

where $Q_j = \mathrm{Diag}(W_{ji})$, i = 1,...,N. Next write the j th structural equation as

(4) $$y_j = R_j\xi_j + \nu_j \;,$$

where R_j = (Y_j, X_j, Z_j, W_j) and $>_j$ = ($*_j$, $\$_j$, $(_j$, $"_{j0}$). Stacking the G equations gives us the system

$$(5) \qquad y_* = R_* \xi_* + \nu_* \ .$$

We assume that the covariance matrix for each u_j is block diagonal in $)_j$, that the u_{ji}'s are iid with zero mean and covariance E_u, that $(g_{1it},...g_{Git})$is iid with zero mean and covariance matrix G_g and that the terms u_j and g_j are uncorrelated. This implies that the (GNT x GNT) covariance matrix for $<_*$ takes the form

$$(6) \qquad \Omega = \Sigma_\varepsilon \otimes I_{it} + \Sigma_u \otimes Q(I_N \otimes \Delta)Q \ .$$

Were R_* not to contain Y_j's and were the effects $Q_j u_j$ orthogonal to the remaining elements in R_* (X_j, Z_j, W_j), then an efficient estimator for $>_*$ would be the seemingly unrelated regression estimates with the suitably altered covariance structure given in (6). Consistent estimates of the elements of S can be obtained using straightforward extensions of the methods outlined in Cornwell, Schmidt, and Sickles (1990). However, simultaneity introduced by the presence of Y_j and/or the exogenous variables in X_j, Z_j, and W_j means that a suitable set of instruments be found and that an instrumental variables estimator be developed for the system. Doing so requires that we review some terminology which may be unfamiliar to the reader. Following Breusch, Mizon, and Schmidt (1988) and Cornwell, Schmidt and Wyhowski (1991) we refer to an exogenous variable as one which is uncorrelated with statistical noise, a singly exogenous variable as one which is correlated with the effects and a doubly exogenous variable as one which is uncorrelated with the effects. Notationally these are distinguished by partitioning the exogenous variables is the system into X = [$X_{(1)}$, $X_{(2)}$], Z = [$Z_{(1)}$, $Z_{(2)}$], W = [$W_{(1)}$, $W_{(2)}$], where the first partition identifies the regressors that are singly exogenous and the second those which are doubly exogenous. Let M_Q be the projection onto the null space of Q. Then the efficient IV estimator can be written as

$$(7) \qquad \hat{>}_* = (R_* S^{-½} R_* P_A S^{-½} R_*)^{-1} R_* S^{-½} P_{A*} S^{-½} y_*,$$

where $A_* = S^{-½}(M_Q, X_{(1)}, Z_{(1)}, W_{(1)})$ and $P_A = I{=}M_{A*}$. The covariance matrix for $\hat{>}_*$ is $Cov(\hat{>}_*) = (R_* S^{-½} R_* P_{A*} S^{-½} R_*)^{-1}$.

The panel stochastic frontier production system with which we estimate time-varying technical efficiency levels for our sample firms is a special case of (7). We follow Aigner, Lovell and Schmidt (1977) Schmidt and Sickles (1984), and Cornwell, Schmidt, and Sickles (1990) who use the Zellner, Kmenta, and Dreze (1966) assumption that firms in the industry are maximizing expected profit and specify a stochastic frontier production function. We also assume that firms are cost-minimizing and that any allocatively inefficient errors in setting factor proportions are nonsystematic. Costs are required to be well-documented and reasonable, and FERC has disallow some expenses. Moreover, once the transport rate structure is set, the firm has incentives to minimize costs since any shortfall or excess profit is considered a windfall loss or gain. Previous to the study period the regulatory lag more often than not benefitted the firm since output continually expanded. Since output generally fell through the study period, firms could not get their rates adjusted quickly enough to reflect their increasing input costs and declining throughput. Thus the regulatory process imposed discipline on the pipelines as the regulatory lag increased during the study period. Stich and Smith (1984), for example, found that the time required to process rate cases increased to nearly two years. In addition, the frequency of rate hearings decreased; the representative firm obtained three rate decisions during the time period under study.

We specify the firm effect by a linear function of time, in which case W_j is composed of the constant term and a time trend. The factor inputs are labor, energy, and pipeline and compressor station services. Construction of quantities and prices for output and for the factor inputs is discussed in the next section. Much of the capacity of the transmission firms was in place by the mid- to late 1970s and to the extent that take-or-pay contract provisions and FERC regulations prevented an optimal downward adjustment of pipeline and compressor station services as demand for natural gas fell during the sample period, technical inefficiency and changes therein may be correlated with the two capital inputs. Our seemingly unrelated regressions production system is composed of a translog production function and the associated cost-minimizing factor input requirements.

These are expressed in share form to stay within the linear spaces required by the estimator outlined above. Fixed effects in the production function are time varying and are allowed to be correlated with both compressor and pipeline services. Disturbances in the share equations are assumed to be iid with zero mean and singular covariance G_m.

Previous econometric studies of productivity in the natural gas transmission industry have been typically based on estimates from a Cobb-Douglas production function (cf Chenery, 1949; Cookenboo, 1952, Callen, 1978). We lift the assumption that substitution elasticities are unity and specify a flexible translog production function along with the cost-minimizing input shares derived from it. We allow for technical change to be factor biasing and for neutral technical change to be quadratic in time. We also include dummy variables to represent three different regulatory epochs. The first (D_1) is the period 1977-1978 before the NGPA went into effect. The second (D_2) is for the years after the NGPA was passed, but before the natural gas spot market developed (1979-1983). The third (D_3) is for the years after 1983 when FERC certified Special Marketing Programs (SMP) and the spot market were in operation. The production function and associated share equations are given by:

$$\ln Y_{it} = \beta_0 + \sum_{j=1}^{4}\beta_j \ln x_{it}^{j} + \frac{1}{2}\sum_{j=1}^{4}\sum_{k=1}^{4}\beta_{jk}\ln x_{it}^{j}\ln x_{it}^{k} + \sum_{j=1}^{4}\delta_j \ln x_{it}^{j} t + \delta_t t + \frac{1}{2}\delta_{tt}t^2 +$$

$$\phi_2 D_2 + \phi_3 D_3 + \nu_{it} + u_i \tag{8}$$

$$M_{it}^{j} = \beta_j + \sum_{k=1}^{4}\beta_{jk}\ln x_{it}^{k} + \delta_j t + \varepsilon_{it}^{j}, \quad j = 1,\ldots 4.$$

Time-varying firm efficiency levels are derived from the efficient three-stage least squares estimates based on (7). We first estimate "$_{1i}$ (the fixed effects in equation 1, the production function) by regressing the residuals for firm i on the W_{1it} vector containing the constant term and the time trend. These provide us with consistent (œi,t as t64) estimates of the "$_{it}$. Following the arguments of Cornwell, Schmidt, and Sickles (1990) we identify the most efficient firm in period t by "̂$_{1t}$ = max$_j$ ("̂$_{1jt}$) and relative technical efficiencies by TE_{it} = exp {"̂$_{1it}$ - "̂$_{1t}$}.

The statistical approach to efficiency measurement imposes strong distributional assumptions and economic structure on the data. Although alternative programming approaches such as data envelopment analysis (DEA) use piece-wise linear approximations to model the best-practice reference technology, they remain an attractive alternative to stochastic frontier analysis in that more robust, and presumably more policy relevant inferences and forecasts can be made from concordant results based on differing methodologies. DEA also has some intrinsic appeal in that it does not rely on price data to construct the efficient frontier. Thus when the researcher suspects that correlations may exist between technical inefficiency and certain inputs, DEA may well be preferred over stochastic frontier cost function on *a priori* grounds. In this case the SF production function should be estimated directly using the within estimator, or a suitable instrumental variables analog. If, on the other hand, the correlation is suspected to be between input prices which support the radial measure of technical inefficiency and technical inefficiency itself, then the within estimator should be used on the SF cost function. Since the applied researcher rarely has such foreknowledge, DEA can have substantial appeal. However, the presence and relative variation of statistical noise vis-a-vis deterministic movements in the frontier over the sample is problematic since DEA assumes a deterministic frontier and hence assumed that the data is free from measurement error.

The generic DEA model was introduced to measure the productive efficiency of decision-making units (DMU's), or for our purposes, firms. Charnes, Cooper and Rhodes (1978, 1981) proposed the following measure of efficiency based on the ratio of a single-output to a single-input. Consider a specific firm i at time t which is to maximize a ratio of a weighted s-vector of outputs (Y_{it}) to a weighted M-vector of inputs (X_{it}) subject to the condition that similar ratios for every firm be less than or equal to unity:

$$\text{(9)} \qquad \underset{\mathbf{Q},\ \mathbf{R}}{\text{Maximize}} \ \frac{\mathbf{Q}^T Y_{it}}{\mathbf{R}^T X_{it}} \quad \text{subject to} \quad \frac{\mathbf{Q}^T Y_{it}}{\mathbf{R}^T X_{it}} \leq 1,\ \mathbf{q}_S,\ r_m > \mathbf{0},\ \forall\ s,\ m,$$

where the weight vectors $Q = \{q_1, \ldots q_S\}$ and $R = \{r_1, \ldots, r_M\}$ are the ARGMAX of (9) whose solution can be based on the nonlinear, nonconvex and non-Archimedean fractional programming problem as formulated by Charnes and Cooper (1985). This later problem can be stated as

$$\text{(10)} \quad \underset{Q,\ R}{\text{Maximize}} \quad \frac{Q^T\, Y_{it}}{R^T\, X_{it}} \,,$$

$$\text{subject to} \quad \frac{Q^T\, Y_{it}}{R^T\, X_{it}} \le 1,\ -(Q^T Y_{it})^{-1} R^T \le -\varepsilon \cdot \ell^T,\ -(R^T X_{it})^{-1} Q^T \le -\varepsilon \cdot \ell^T,$$

$$X_{it},\ Y_{it} > 0,$$

where g is a non-Archimedean infinitesimal and R is a vector of ones. Using the Charnes-Cooper transformation of fractional programming, the primal linear programming problem (DEA) is set up to

$$\text{(11)} \quad \begin{array}{l} \underset{\Lambda,\, \lambda,\, s^+,\, s^-}{\text{Minimize}} \ (\Lambda - \varepsilon \ell^T s^+ - \varepsilon \ell^T s^-) \\ \text{subject to} \ \ Y\lambda - s^+ \blacksquare\ Y_{it},\ \Lambda X_{it} - X\lambda - s^- \blacksquare\ 0,\ \lambda,\ s^+,\ s^- \ge 0,\ Y_{it} > 0, \\ \qquad\qquad X_{it} > 0,\ \forall\ i,\ t\ \lambda \ell^T \blacksquare\ 1. \end{array}$$

The primal problem minimized the intensity (7) of the input under the constraint that the output vector Y_{it} is enveloped from above and the input vector X_{it} is enveloped from below. After we carry out N x T optimizations we obtain solution values for the primal problem and utilize them in the measurement of firm-specific technical efficiency and production characteristics of the underlying technology. In order to determine the level of technical inefficiency we adopt the convention used by Charnes and Cooper (1985) in their <u>Non-Archimedean Theorem</u>: A firm is technically efficient if and only if, minimizing (or optimal) values of the primal problem satisfy $7^* = 1$, $s^{*+} = 0$ and $s^{*-} = 0$, i.e., the intensity is unity and all slacks equal zero, where an optimal solution to (11) is denoted by (7^*, 8^*, s^{*+}, s^{*-}). Inefficient firms are projected onto their efficient frontier (or efficient facet) by means of the transformation,

$$X_{it} \longrightarrow X'_{it} = \Lambda^{*} X_{it} - s^{*-} \wedge Y_{it} \longrightarrow Y'_{it} = Y_{it} + s^{*+}.$$

The movement from X_{it} to X'_{it} is a pure radial measure of inefficiency and indicates by how much inputs can be scaled down and still be able to produce the frontier level of output. Output slackness may still be in evidence, however, in that output(s) may still be increased without increasing input use. The differences,

$)X_{it} = X_{it} - X'_{it} = (1 - 7)X_{it} + s^{*-}$, $)Y_{it} = Y'_{it} - Y_{it} = s^{*+}$, representing the estimated amounts of technical inefficiency at the point (X_{it}, Y_{it}). For the single output technology considered herein, a necessary condition for output slackness is that the production function is piecewise linear and only weakly monotonic. Thus the output slackness variables (s^{*+}) are zero and the (radial) technical inefficiency measure is completely characterized by a nonunitary intensity vector (7). We construct the index of technical inefficiency for a specific firm i by regressing the (output) technical efficiencies for each firm against a constant term and a time trend and normalize efficiency scores to unity for the most efficient firm in a particular period just as we do with the panel stochastic frontier estimates discussed above. Since DEA is a non-statistical method, standard asymptotic arguments that apply to the consistency of technical inefficiency estimates using the statistical methods above do not apply here, although in principle a weak law of large numbers argument should be applicable to prove weak convergence of the DEA estimate of technical inefficiency as T becomes large.[2]

IV. Data

The technology of the natural gas pipeline industry is fairly straightforward in that the firm acts as a merchant and/or carrier of natural gas. As a merchant it buys natural gas from the producing fields, compresses and transports it through long distance pipelines, and resells the gas at the point of delivery to local distributors (sales for resale) or industrial users (mainline sales). The firm also transports gas for others without being a gas merchant. Transport for others became an important activity for the transmission industry as FERC sought to unbundle transport and merchant services. The volume of natural gas transported for others in our sample increased from 20.3% of total volume transported in 1977 to 42.8% in 1985. The major factor inputs are the pipeline itself, compressor stations to regulate the flow of gas, energy to fuel the compressors (primarily natural gas), and labor. We have collected data on fourteen major interstate natural gas pipeline companies for nine years, 1977-1985. The firms are: Algonquin Gas Transmission Company, ANR Pipeline Company, Colorado Interstate Gas Company, Columbia Gas Transmission Corporation, Columbia Gulf Transmission, Florida Gas Transmission Company, Mississippi River Transmission Company, Northern Natural Gas Company, Sea Robin Pipeline Company, Southern Natural Gas Company, Texas Eastern Transmission Corporation, Texas Gas Transmission Corporation, Transwestern Pipeline Company, and Trunkline Gas Company. These are major interstate natural gas pipeline companies, each with combined gas sales for resale, transport, or storage exceeding 50 billion cubic/year, and have combined sales that amount to almost half of the interstate industry total in 1985.

We measure the output and input variables with a similar methodology as Aivazian, et al. (1987) in order to allow for comparisons between their study of the natural gas transmission industry during its years of expansion prior to the NGPA and our study of a mature industry coping with shrinking markets and a different regulatory environment. Data are from the 1977-85 firm specific FERC Form-2: Annual Report of Major Natural Gas Pipeline Company, supplemented with the Annual Statistics of Interstate Natural Gas Pipeline Companies (ASI) unless otherwise indicated. Both are available from the Federal Energy Regulatory Commission. The FERC Form-2 contains very detailed information on the financial and operating expenses of the pipeline company, as well as a breakdown of types of output and sources of revenues earned. These reports are not generally distributed, aut are available through the Public Information Office at FERC.

Output is measured in trillion cubic feet-miles, derived by multiplying the total volume of gas delivered under "sales for resale", "mainline sales", and "transport of gas of others" by the miles transported. Aivazian, et al. (1987) did not include transport for others or consider the distance transported in their measurement of output. We have include transport of gas of others here because of its increasing importance to the industry during the 1977-85 period. Gas quantities were extracted from the "Gas Accounts-Deliveries" schedule. As miles transported are not reported for resale and mainline sales, we use the average length of the major transmission trunklines from the main production area(s) to the major delivery point(s) for these two categories. The mileage figures are calculated with the use of firm specific pipeline system maps. The weighted average miles transported for gas transported for others is calculated from the "Revenue from Transportation of Gas of Others" schedule.

The quantity of labor is calculated by multiplying the total number of firm employees by the proportion of transmission labor expenses relative to total labor expenses, from the "Distribution of Wages and Salaries" schedule. Energy (natural gas) consumed in production is measured in thousand cubic feet (mcf), as reported in the "Gas Used by the Utility" schedule. The expenses for energy consumed are from the Transmission Expense section of the "Operations and Maintenance Expense" schedule. The price of labor and energy are derived by dividing total labor and energy expenses by their respective quantities.

Two measures of capital input are used: total horsepower ratings of transmission compressor stations as a proxy for compressor capital services and tons of steel as a proxy for pipeline services. In measuring the quantity of compressor and pipeline capital services used in production, we draw on additional data sources as the horsepower rating and pipeline diameters are often not explicitly reported in the FERC Form-2 after 1979. To determine the post-1979 horsepower and pipeline diameter we turned to the "Pipeline Economics Report" published in the Oil and Gas Journal. The OGJ "Pipeline Economics Report" is published once a year, usually in November, and contains data on the configuration and cost of current pipeline and compressor station construction. Data are given, by state, for specific projects. By comparing the location of the individual projects in the OGJ with the areas of operation for each firm and information from the FERC Form-2, we are usually able to determine which company is undertaking which project.

Beginning with the horsepower total for 1979, this quantity is up dated for each successive year by close examination of information in the "Compressor Stations" schedule and Section 5 of the "Important Changes During the Year", both in the FERC Form-2. This information is checked against the information given in the OGJ. In a similar fashion, we are able to obtain the weighted average diameter of the pipelines after 1979. The size and length of additional transmission lines, or abandon segments, was often specified in the FERC Form-2 "Transmission Lines" or "Important Changes During the Year" schedules, or the pipeline projects from the OGJ. Thus the miles of transmission pipeline is multiplied by the weighted average diameter, and then by Callen's proportionality constant for converting size and length into ton-miles.[3] Since the firms have not significantly expanded their pipeline systems during the period of study, the method of calculating horsepower and pipeline diameter is not as cumbersome as might be expected.

Neither prices not expenses for capital services is directly reported; we rely on the value added methodology. First, total revenues from sales for resale, mainline sales, and transport of gas of others are obtained from the "Gas Operating Revenues" schedule. The cost of labor, energy, and gas purchased are netted out. This net revenue was allocated between compressor and pipeline services based on the ratio of book value cost and operating costs of compressors to pipelines (referred to as "mains"). End of year book value costs are from the Transmission Plant section of the "Gas Plant in Service" schedule. The operating and maintenance costs are from the Transmission Expenses section of the "Gas Operation and Maintenance Expenses" schedule. The resulting two residuals are divided by the appropriate quantity, horsepower or pipeline steel tons, to obtain user prices for the two capital categories.

V. Estimation Results

First, we present the results of the stochastic frontier model estimation. Coefficient estimates for the panel stochastic frontier systems estimator are found in Table 1. The system contains the production function, labor, energy, and compressor services share equations. The system R^2 = 0.892. Estimates of the derived own- and cross-demand elasticities, Morishima substitution elasticities, and average total factor productivity growth rate are given in Table 2. Table 3 provides comparable summary statistics based on estimates of Aivazian et al. using data from the period 1958-79 and our data for the period 1978-85. We have included the results from Table 3 in order to examine the potential for changes in structure of production between two very different regulatory epochs: pre-NGPA and post-NGPA. Table 4 contains χ^2 Wald statistics for various test of hypotheses regarding returns to scale, homogeneity of the regulatory regimes, efficiency differentials, presence of technological change, the appropriateness of the Cobb-Douglas functional form as a special case of the translog production function, homogeneity of production, and Hausman-Wu results for the correlatedness of regressors and statistical noise.

We begin by pointing out that monotinicity conditions are met for all but three of the 126 sample observations using our stochastic panel systems estimator. These violations were for firm 1 (Algonquin Gas Transmission) for years 1, 2, and 3 and related specifically to a negative estimate for the energy share. Given the wide fluctuations in the price of energy during this period it is surprising that more violations did not occur. Convexity conditions were not met by 14 of the 126 sample observations. Firms 1, 6, and 7 (Algonquin Gas Transmission, Florida Gas Transmission, and Mississippi River Transmission) failed to met convexity conditions for early years in the sample period. Estimation of a single equation translog (or even Cobb-Douglas) model without the cost minimizing share equations resulted in negative returns to scale and/or failure of regularity over much of the sample space. Our estimates of derived own-demand elasticities (Table 2) indicate near unitary elasticity of demand for pipelines with substantial firm responsiveness to price variations in the other three inputs. Cross-demand elasticities are all positive and are generally inelastic although pipeline demand is quite responsive to changes in the prices of compressor services. Morishima substitution elasticities indicate substantial scope for substitution among the factor inputs. The results in Table 4 indicate that technical change is significant. Our estimates indicate that factor biases of .6%/year for energy and -.9%/year for pipeline services, the later a possible artifact of the patterns of pipeline capacity utilization toward the end of the sample period. The hypothesis of no efficiency differentials was strongly rejected as was that of no technical change, a Cobb-Douglas technology, and the presence of correlation between selected inputs and statistical noise. The hypotheses of no scale economies and no differential regulatory regimes were not rejected at conventional significance levels. Moreover, the technology appears to be homogeneous and nonhomothetic.

A final test was conducted to determine if the current production technology was appreciably different from that of the 1954-79 period. This was done by using the estimated model from Aivazian, et al., (1987) with our data and recalculating price elasticities and productivity measures. These results are in Table 3. We found that there was some difference in elasticities, with the biggest differences occurring in the cross-demand elasticities between energy/pipelines, and compressors/pipelines, but also remarkable comparability in terms of relative magnitudes and signs. Only the labor/energy cross-demand elasticity changed sign, from 0.536 using our estimates and data to -0.013 using Aivazian et al.'s estimates and our data. The structure of factor substitution possibilities appears to have changed somewhat after the NGPA although all input pairs remain Morishima substitutes. Morishima substitution elasticities are in general larger using our estimates. Average annual total factor productivity growth for the post-NGPA period using the two set of estimates are quite close: -0.0189/year using our estimates and -0.0195/year using the Aivazian et al. estimates.

Tables 5 and 6 provide estimates of the temporal pattern of firm efficiencies relative to the average frontier and firm efficiencies relative to the DEA best practice frontier. Although the levels and relative rankings of efficiencies are often not the same for the two methods, there is an unambiguous downward trend in firm efficiency levels during the sample period. Concordance in these trends is further highlighted by considering the temporal pattern of efficiency levels in the industry. If we weight the relative efficiencies by the firm's share in total industry output, in which case the technical efficiency scores from DEA intuitively become closer in spirit to the average efficiency construct of stochastic frontiers and further from the best practice efficiency construct of DEA, then the evidence from the two methodologies become strikingly similar, as indicated in Figure 2. A representative firm in the sample, or alternatively an industry comprised of these sample firms, found its efficiency falling at a rate averaging 0.55% per year during the period in which the NGPA was implemented.

VI. Conclusions

In this paper we have estimated the production technology of the natural gas transmission industry during a period in which a major regulatory intervention was implemented, the Natural Gas Policy Act of 1978. We have examined firm-specific and temporal patterns of technical efficiency for a newly constructed panel of fourteen major firms in the industry. These firms comprise almost half of the total output of major natural gas transmission firms. We have introduced a new panel stochastic frontier systems estimator which exploits the potential exogeneity of certain regressors from firm effects which can cause heterogeneity in slopes as well as in intercepts. Our systems estimator also can accommodate a simultaneous equations structure. We found that the historic trend of moderate productivity increases was reversed during this time period. Patterns of technical efficiency based on our structural stochastic model are compared with those based on deterministic programming methods involving data envelopment analysis. Concordant findings based on these alternative methodologies suggest a pervasive pattern of declining technical efficiency in the industry during the period in which this major regulatory intervention was introduced and implemented. The broad policy implications from the rather robust industry trends suggest that the NGPA had a substantial distortionary effect on the productive performance of the natural gas transmission industry.

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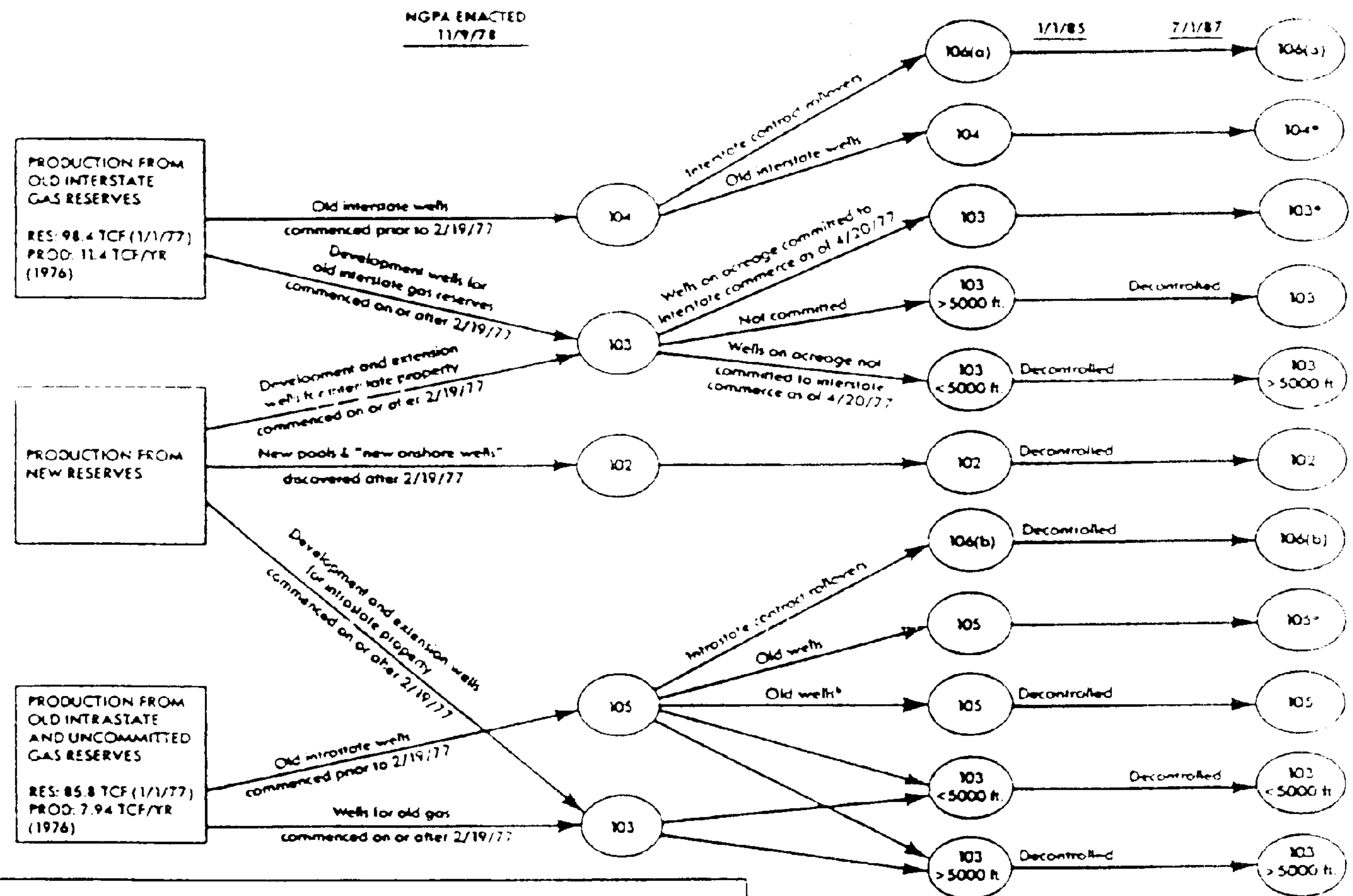
Figure 1 Maximum Ceiling Price Categories: NGPA Title I for Onshore Lower-48 Natural Gas Above 15,000 Feet



a. Not decontrolled.
b. Price greater than $1.00 per million Btu under a definite escalator clause.

Note: Stripper wells and high cost gas omitted.

Source: U.S. Energy Information Administration, *Natural Gas Market* (1981), p. 16.
From: Teece, David J. "Structure and Organization of the Natural Gas Industry" The Energy Journal, 11, No.3, pg 17, 1989.

Figure 2
Comparison of Temporal Patterns of Efficiency Change
Based on Stochastic Frontier and Data Envelopment Anaysis

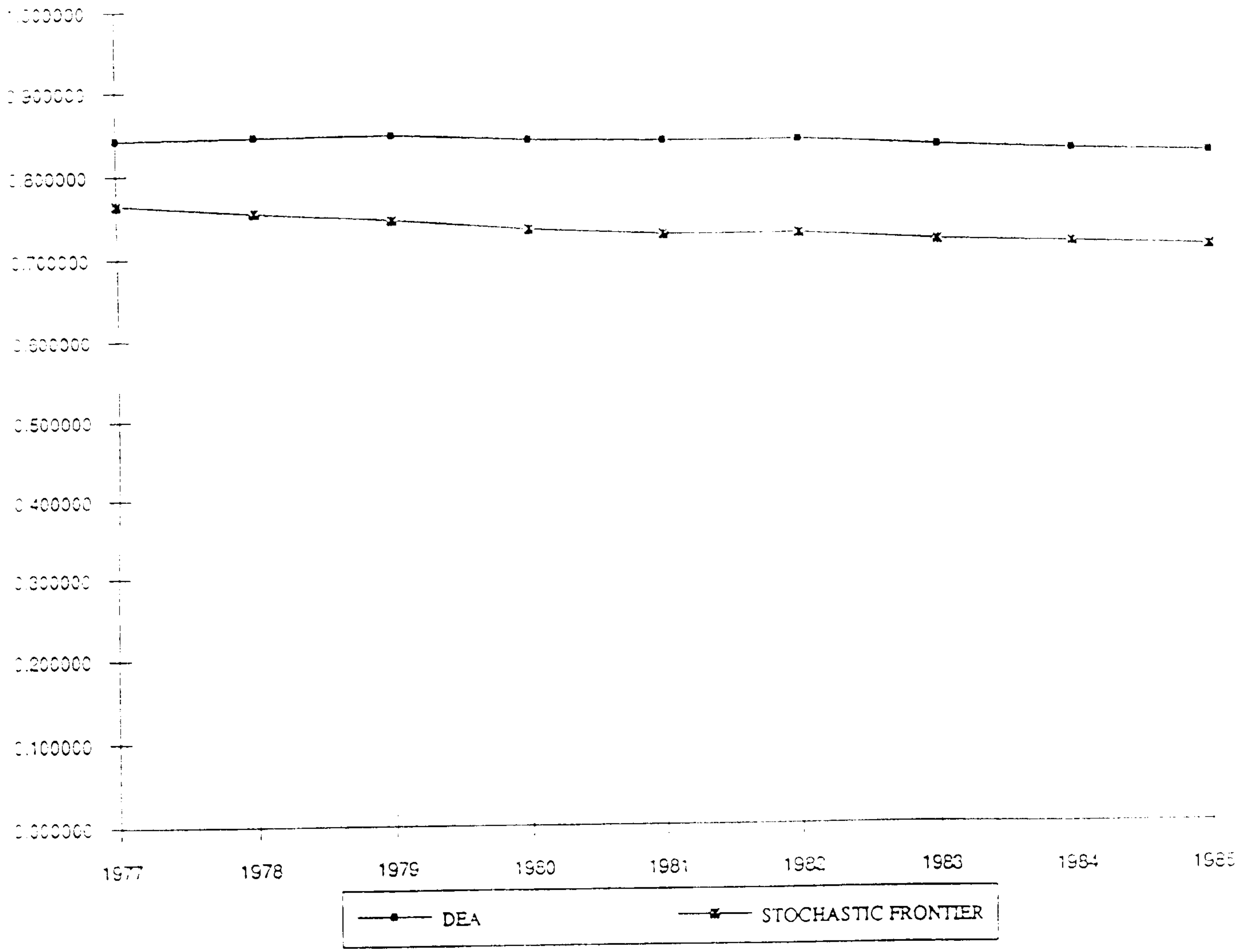


TABLE 1

Parameter Estimates for the Stochastic Frontier Model*

Coefficient	Estimate	T-statistic
$\$_{1}$	0.072	5.01
$\$_{2}$	0.074	4.48
$\$_{3}$	0.201	4.98
$\$_{4}$	0.806	3.21
$\$_{11}$	0.029	4.16
$\$_{12}$	-0.014	-3.30
$\$_{13}$	-0.008	-1.07
$\$_{14}$	-0.007	-0.75
$\$_{22}$	0.040	4.10
$\$_{23}$	-0.014	-1.24
$\$_{24}$	-0.012	-0.97
$\$_{33}$	0.132	3.42
$\$_{34}$	-0.110	-3.09
$\$_{44}$	-0.129	-3.63
$*_{1}$	0.001	1.15
$*_{2}$	0.006	3.29
$*_{3}$	0.002	0.57
$*_{4}$	-0.009	-2.66
$*_{t}$	0.047	1.02
$*_{tt}$	-0.018	-1.98
D_{2}	0.028	0.42
D_{3}	0.131	1.56

*The order of the factor inputs is labor, energy, compressor services, pipeline services.

TABLE 2

Summary Statistics

Average Demand Elasticities

$O_{labor} = -1.634$

$O_{energy} = -1.674$

$O_{comp} = -3.621$

$O_{pipe} = -0.942$

Cross Demand Elasticities

	Energy	Compressor	Pipeline
Labor	0.536	0.561	0.536
Energy		0.792	2.746
Compressor			3.003

Morishima Substitution Elasticities

	Labor	Energy	Compressor	Pipeline
Labor	-----	2.201	4.172	1.479
Energy	2.170	-----	4.403	1.428
Compressor	2.915	2.465	-----	3.946
Pipeline	2.170	2.159	6.613	-----

Average Annual Total Factor Productivity Growth ($T\dot{F}P$)

$T\dot{F}P = -0.0118$

TABLE 3

Summary Statistics

(Based on Production Function Coefficients of Aivazian et al.
Estimated from 1954-79 Data and Using our 1978-1985 Sample)

Average Demand Elasticities

$O_{labor} = -1.334$

$O_{energy} = -2.961$

$O_{comp} = -1.142$

$O_{pipe} = -0.796$

Cross Demand Elasticities

	Energy	Compressor	Pipeline
Labor	-0.013	0.642	0.704
Energy		0.230	2.746
Compressor			.699

Morishima Substitution Elasticities

	Labor	Energy	Compressor	Pipeline
Labor	-----	2.948	1.784	1.499
Energy	1.321	-----	1.372	3.541
Compressor	1.976	3.191	-----	1.494
Pipeline	2.037	5.706	1.841	-----

Average Annual Total Factor Productivity Growth ($T\dot{F}P$)

$T\dot{F}P = -0.0119$

TABLE 4

Results of Wald and Hausman-Wu Hypothesis Tests

I. H_o: Constant returns to scale

$P^2_1 = 0.51$

II. H_o: No differential regulatory regimes

$P^2_2 = 2.93$

III. H_o: No efficiency differentials among firms

$P^2_{28} = 502.04$

IV. H_o: No technical change

$P^2_6 = 36.08$

V. H_o: Cobb-Douglas technology

$P^2_6 = 27.14$

VI. H_o: Homogeneous technology

$P^2_3 = 6.88$

VII. H_o: Factor inputs labor and energy are exogenous

$P^2_{10} = 2.17$

VII. H_o: All factor inputs are exogenous

$P^2_{14} = 11.10$

TABLE 5

Technical Efficiency Relative to the Stochastic Frontier

FIRM/YEAR	1977	1978	1979	1980	1981	1982	1983	1984	1985
ALGONQUIN	67.48%	67.46%	67.44%	67.42%	67.40%	67.37%	67.35%	67.33%	67.31%
ANR	65.93%	65.14%	64.37%	63.61%	62.85%	62.10%	61.37%	60.64%	59.92%
COLORADO	89.99%	88.17%	86.39%	84.65%	82.93%	81.26%	79.62%	78.01%	76.43%
COLUMBIA GAS	93.67%	91.46%	89.31%	87.22%	85.17%	83.16%	81.21%	79.30%	77.44%
COLUMBIA GULF	58.69%	58.30%	57.91%	57.52%	57.13%	56.75%	56.37%	56.00%	55.62%
FLORIDA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
MISSISSIPPI	80.83%	78.78%	77.21%	75.67%	74.16%	72.68%	71.23%	69.81%	68.42%
NORTHERN	63.31%	62.91%	62.52%	62.12%	61.73%	61.34%	60.95%	60.57%	60.19%
SEA ROBIN	69.80%	67.66%	65.58%	63.57%	61.62%	59.73%	57.89%	56.12%	54.39%
SOUTHERN	60.58%	59.58%	58.61%	57.65%	56.71%	55.78%	54.87%	53.97%	53.09%
TEXAS EASTERN	91.43%	90.66%	89.90%	89.14%	88.40%	87.65%	86.92%	86.19%	85.46%
TEXAS GAS	67.73%	67.14%	66.56%	65.98%	65.41%	64.84%	64.28%	63.72%	63.17%
TRANSWESTERN	93.83%	92.31%	90.82%	89.36%	87.91%	86.49%	85.09%	83.72%	82.37%
TRUNKLINE	85.19%	83.49%	81.82%	80.19%	78.59%	77.01%	75.48%	73.97%	72.49%

TABLE 6

Technical Efficiency Relative to the Best Practice Technology

FIRM/YEAR	1977	1978	1979	1980	1981	1982	1983	1984	1985
ALGONQUIN	100.00%	99.50%	98.67%	97.84%	96.76%	95.24%	93.73%	92.26%	90.26%
ANR	74.99%	75.85%	76.46%	77.07%	77.48%	77.52%	77.56%	77.60%	77.17%
COLORADO	83.70%	82.91%	81.85%	80.80%	79.55%	77.94%	76.37%	74.83%	72.88%
COLUMBIA GAS	99.99%	96.35%	92.52%	88.85%	85.10%	81.11%	77.31%	73.68%	69.81%
COLUMBIA GULF	85.50%	88.97%	90.15%	91.35%	92.31%	92.84%	93.37%	93.90%	93.88%
FLORIDA	78.86%	81.87%	84.71%	87.65%	90.45%	92.89%	95.39%	97.96%	100.00%
MISSISSIPPI	95.06%	92.64%	89.99%	87.41%	84.67%	81.63%	78.69%	75.87%	72.70%
NORTHERN	68.47%	69.57%	70.45%	71.35%	72.06%	72.43%	72.80%	73.17%	73.10%
SEA ROBIN	83.89%	79.10%	74.33%	69.84%	65.46%	61.05%	56.97%	53.10%	49.23%
SOUTHERN	67.29%	66.53%	65.56%	64.60%	63.49%	62.10%	60.73%	59.40%	57.75%
TEXAS EASTERN	99.66%	100.00%	100.00%	100.00%	99.73%	98.99%	98.25%	97.51%	96.20%
TEXAS GAS	70.74%	70.99%	70.99%	70.99%	70.79%	70.26%	69.74%	69.22%	68.29%
TRANSWESTERN	98.95%	95.95%	92.74%	89.63%	86.39%	82.87%	79.49%	76.25%	72.71%
TRUNKLINE	96.98%	98.04%	98.78%	99.52%	100.00%	100.00%	100.00%	100.00%	99.40%

Footnotes

1.Natural gas is classified according to sell vintage, commitment to intra- or interstate markets, type of geological formation, rate of production, and the provisions of existing has sale contracts. For a summary of the NGPA gas categories and their respective pricing regulation see The Natural Gas Regulation Handbook, Pierce (1980).

2. Modifications of the CCR or Banker, Charnes, and Cooper (BCC) (1984) programming set up can be made in which a nonconvex technology is allowed for due to the presence of increasing economies of scale. Although out estimates do not indicate scale economies, previous studies of the natural gas transmission industry (Robinson, 1972; Callen, 1978; Aivazian and Callen, 1981; Aivazian, et al., 1987) have indicated the presence of scale economies with an engineering upper bound estimated by Robinson of 2.07. As pointed out by several authors, efficiency estimates based on either BCC or CCR are inconsistent with the nonconvex technology set implied by increasing returns to scale. Recently Peterson (1990) and Charnes, Cooper, and Sinha (1990) have discussed alternatives to the CCR and BCC when the technology set exhibits increasing returns to scale, i.e. it is nonconvex. By specifying convex input and output sets and with a suitable modification of the standard linear program used in the CCR or the BCC formulation, efficiency measures for a technology set exhibiting increasing returns to scale can be obtained by a two stage program which provides a nonconvex spanning of the piecewise linear reference technology.

3. See equation A8, page 320: $P = .382d^2L$, where P = pipeline capital services, d = weighted average diameter, and L = miles of transmission pipelines.