MARGINAL COST PRICING FOR GAS DISTRIBUTION UTILITIES:

FURTHER ANALYSES AND MODELS

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prepared for the

U.S. Department of Energy
Economic Regulatory Administration
Division of Regulatory Assistance

In partial fulfillment of
Grant No. DE-FG01-80RG10268
Modification A003

December 1981

FOREWORD

This report was prepared by The National Regulatory Research Institute (NRRI) under Grant No. DE-FG-01-80RG10268 from the U.S. Department of Energy (DOE), Economic Regulatory Administration, Division of Regulatory Assistance. The opinions expressed herein are solely those of the authors and do not reflect the opinions nor the policies of either the NRRI or the DOE.

The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utility regulation.

Douglas N. Jones
Director

EXECUTIVE SUMMARY

The effects of gas marginal cost pricing on the demand for natural gas and on changes in the capital and operating costs of gas distribution utilities are important issues in the Public Utility Regulatory Policies Act of 1978 (see PURPA: Section 306-Gas Utility Rate Design Proposals). However, to base rates on marginal costs, it is first necessary to confidently calculate these marginal costs. It is the purpose of this study to provide data and methods for such cost calculations and for designing rates based on these costs. In doing so, the study extends and improves the results reported in a former report on the same subject.[1]

Several empirical statistical investigations of the structure of various cost categories of gas distribution utilities, at the exclusion of gas supply costs, are first presented. One stream of analyses focuses on distribution plant (investment) costs at the community/local level, using data gathered from six different distribution utilities. A new specification for the cost model is used, significantly improving the regression fits obtained in previous research. All the results confirm the joint character of gas distribution plant costs and provide ready means to estimate the corresponding marginal costs for the different sectoral markets at the community/local level. The other stream of analyses, in contrast, provides cost models based on data characterizing the whole utility, and gathered from 119 U.S. gas distribution companies. Cost models are developed for the major plant and operating costs categories, with, as arguments, the utility's market characteristics, such as sectoral sales and average customer sizes. Such cost functions can then be used to develop marginal cost functions to calculate marginal costs for any market mix and utility size.

Computerized and simplified approaches to the calculation of gas marginal costs and to the formulation of marginal cost pricing policies are then developed, with, as a major emphasis, the calculation of gas supply marginal costs, accounting for the usual pipeline rate schedules that involve demand charges and take-or-pay clauses in addition to commodity charges. Extensions and improvements brought to the Gas Utility Marginal Cost Pricing Model (GUMCPM) developed in previous research, and the results of some applications of this new version to the East Ohio Gas Company, are first presented. It is shown that a stable solution avoiding the peak-shifting phenomenon may be obtained when applying marginal-cost-based pricing policies involving the spreading of marginal distribution capacity cost over several winter months, and that these pricing policies are clearly superior to the average cost pricing policy, both in terms of load structure and resource allocation efficiency. Second, a simplified

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[1] J-M Guldmann, Marginal Cost Pricing for Gas Distribution Utilities: Preliminary Analyses and Models. NRRI, Report No. 80-12, November 1980.

approach to the calculation of marginal costs, which can be implemented with a hand calculator, is developed. The calculation of transmission and distribution capacity marginal costs is based on the assumed knowledge of the utility's expansion plans. Probabilistic concepts are used to account for peak-load occurrences, and a heuristic iterative procedure is applied with data pertaining to the East Ohio Gas Company to calculate approximate monthly supply marginal costs. A pricing strategy based on aggregated on-peak and off-peak marginal costs is outlined.

ACKNOWLEDGEMENTS

The authors would like to express their sincerest thanks to the following persons and organizations whose help and advice have been essential to the completion of various parts of this study:

Mr. Robert Koblenzer, Vice President-Rates, The East Ohio Gas Company;

Mr. R. G. Petersen, Director, General and Regulatory Accounting, Peoples Natural Gas;

Mr. Stephen P. Reynolds, Manager, Rate Department, and Ms. Linda G. Baldwin, Cost Analysis Supervisor, Pacific Gas and Electric Company;

Mr. Richard J. Gordon, Vice President, Columbia Gas Distribution Companies;

as well as all the staff members of the State regulatory commissions and of the gas utilities under their jurisdiction who provided us the data used in the analysis presented in chapter 4. The corresponding states and companies are listed in appendix E.

Finally, the authors would like to express their appreciation for the continuous administrative support provided by Drs. Douglas N. Jones, Kevin A. Kelly, and Raymond W. Lawton, respectively Director and Associate Directors of The National Regulatory Research Institute, and for their critical review of the present report.

CREDITS

Primary responsibilities have been shared among the research team members as follows:

Jean-Michel Guldmann: project coordination, final report edition and authorship of chapters 1, 3, 4, 5, and 7;

William Pollard: authorship of chapter 6;

Richard A. Tybout: authorship of chapter 2;

Charles Z. Aki and Kyubang Lee: data file preparation and statistical processing.

Typing and retyping of the report was ably done by Gayle Swinger, Sandra Murphy, Bonnie Fairall and Karen Riccio.

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CHAPTER 1

INTRODUCTION

The effects of gas marginal cost pricing on the demand for natural gas and on changes in the capital and operating costs of gas distribution utilities are important issues in the Public Utility Regulatory Policies Act of 1978 (see PURPA: Section 306-Gas Utility Rate Design Proposals). To comply with PURPA directives, the Economic Regulatory Administration at the U.S. Department of Energy conducted the Gas Rate Design Study, with the objective to evaluate alternative pricing policies at the distribution level, including marginal cost pricing. Various state regulatory commissions, in particular the New York Public Service Commission, have expressed an interest in considering marginal costs in the ratemaking process. However, to base rates on marginal costs, it is first necessary to confidently calculate these marginal costs. It is the purpose of this study to provide data and methods for such costs calculations and for designing rates based on these costs. In doing so, it extends and improves the results reported in a former study on the same subject.[1]

The report is organized into three parts. Part I (chapter 2) consists of an extensive review of the most recent and relevant literature on marginal cost pricing, and an analysis of the basic issues related to the application of marginal cost pricing to natural gas distribution. Part II (chapters 3 and 4) consists of several empirical investigations of the structure of gas distribution costs. Chapter 3 focuses on distribution investment costs at the urban/community level, using data gathered from six

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[1]J.-M. Guldmann, Marginal Cost Pricing for Gas Distribution Utilities: Preliminary Analyses and Models. NRRI, Report No. 80-12, November 1980.

different distribution utilities, and attempts to develop a generalized distribution plant cost function. Chapter 4 focuses on investment and operating costs aggregated at the level of the whole utility, using data gathered from 119 utilities. The cost functions developed in Part II have, as arguments, sectoral sales, and therefore the derivation of the marginal costs corresponding to marginal sales is straightforward. Part III (chapters 5 and 6) describes two alternate approaches to the calculation of marginal costs. Chapter 5 presents some extensions and improvements brought to the Gas Utility Marginal Cost Pricing Model developed in the former above-mentioned study. These extensions deal, in particular, with alternative pricing schemes, where prices are based on (but not equal to) marginal costs, and with a mechanism to adjust prices to satisfy the revenue requirement constraint. The model is applied with data from the East Ohio Gas Company. Finally, chapter 6 presents a simplified approach that can be implemented with a hand calculator only. This approach is based on the knowledge of the utility's expansion plans or of its past expansion pattern and costs, and on the use of probabilistic concepts to account for peak-load occurrences.

PART I

BASIC ISSUES IN GAS MARGINAL COST PRICING

CHAPTER 2

GENERAL PRINCIPLES

The purpose of this chapter is to set forth general principles on the basis of which subsequent analysis can be built. The chapter is divided into two parts: "Survey of the Literature" and "Basic Issues." The "Survey" begins with a statement of the rationale of marginal cost pricing and, throughout the discussion of the literature, identifies specific formulations later to be adopted in the analysis of issues. The "Issues" section takes that next step. Concepts of marginal cost are applied to natural gas pricing problems at a general level, providing a framework for more specific applications.

Survey of the Literature

Meaning and Intent of Marginal Cost Pricing

Marginal cost refers to the cost of expanding or contracting the rate of output by one unit. The concept is equally applicable to all productive activities in the economy, not natural gas alone, and not regulated industries alone. Marginal cost pricing is a necessary condition for economy-wide maximum economic efficiency (productivity) in all industries. Economic efficiency, in turn, is defined as the maximization of consumer satisfaction subject to the constraints of existing resources and technology.

In perfectly competitive markets, price automatically adjusts to the marginal cost level. This occurs because each supplier expands output to the level where his incremental, or marginal, revenue received is just sufficient to cover his incremental, or marginal, cost incurred. Such is the nature of profit maximization. To expand output further would produce marginal cost greater than marginal revenue, and hence lower profits. To expand less would leave unexploited an opportunity to increase profits.

In perfectly competitive markets, a seller acting alone has no influence on price. This means that sellers are price takers, as are buyers. With prices determined in the market, the marginal revenue of each unit sold is, of course, equal to the price of that unit. With marginal cost equal to marginal revenue as a condition of profit maximization and marginal revenue equal to price as a result of competition, the equality of marginal cost and price is automatically brought about. There is no need for public policy to establish pricing rules in competitive markets. The need, instead, is to assure that markets are competitive. Further discussion of the theory of marginal cost pricing in relation to economy-wide efficiency can be found in standard texts on the subject. For a classic summary, see Samuelson [11, chapter 8].

The same is not true in regulated utilities. For a variety of reasons, public policy has substituted price (rate) regulation for the market. Though regulation has not necessarily been imposed in the interest of economic efficiency, the fact remains that competition among utilities, for example, gas distributors, would be difficult to achieve at the local level. In place of competitive pricing, regulatory pricing holds sway. The latter is typically governed by legal concepts, including rules of equity, that have no necessary relation to efficiency.

The drive to introduce marginal costs in regulated utilities can be interpreted as an attempt to temper traditional ratemaking with efficiency pricing. This becomes the more important in energy industries as the real (adjusted for inflation) costs of energy rise. Broadly speaking, efficiency is promoted when consumers face in the prices they pay the marginal costs incurred by businesses to serve them. Consumers (buyers) bring their subjective valuations of utility received from consumption into comparison with marginal costs to society, as incurred on behalf of society by producers (sellers). When prices are set at marginal costs, so as to make this comparison possible, consumers by their choices signal which products and which producers of these products best serve the end of consumer utility maximization. Such is the nature of society-wide efficiency.

Problem of the Second Best

The question arises as to whether marginal cost pricing should be adopted in some industries when it is known not to exist in others. Is any good purpose served, one might ask, by forcing the natural gas industry to adopt marginal cost pricing if a competing product, say, fuel oil, is not priced on a marginal cost basis? (The example is purely hypothetical.) The answer is "yes," though the question was answered in the negative by Lipsey and Lancaster [7] when the problem of the second best was first raised many years ago.

Lipsey and Lancaster argued that the existence of divergence between marginal costs and prices in any industry creates a false foundation on which to calculate marginal costs in other industries. All industries serve one another, so to speak. Fuel oil is used to produce equipment that goes into natural gas production and natural gas is used to produce equipment that goes into fuel oil refining, and so on. An absence of marginal cost pricing in one means that marginal costs in the other are not true society-wide marginal costs. Since the two are in competition for sales to households, changing one without changing the other does not lead to society-wide efficiency, according to Lipsey and Lancaster.

There are two reasons to object to the Lipsey-Lancaster argument. First, we will never get economy-wide marginal cost pricing unless we start somewhere. There may be problems in the transition, but it is a no-win approach to fail to take the necessary steps, one at a time, if need be. Moreover, competitive market conditions are approximated sufficiently in large sectors of the economy so that the number of distortions to be eliminated is relatively limited, as are their effects in the transition process.

The second objection is still more persuasive. Davis and Whinston [5] have identified conditions in which marginal cost pricing is an unambiguous gain for the economy. The essence of the Davis-Whinston conclusions is that wherever and whenever there are no cross-effects due to scale in the production or consumption of a good, marginal-cost pricing of that good is not subject to the Lipsey-Lancaster objections. By no "cross-effects due to scale," we mean that second degree cross partial derivatives are zero. For example, suppose that the production function in an industry is $F(x_i \ldots x_m)$ and the constraints on outputs are $G(x_i \ldots x_m) = 0$. Then, if

$$\frac{\partial^2 F}{\partial x_i x_j} = \frac{\partial^2 G}{\partial x_i x_j} = 0 \qquad \forall\ i \neq j, \tag{2.1}$$

technological separability exists and an unambiguous increase in economic efficiency results from pricing any output at marginal cost regardless of pricing practice for other outputs. For example if x and y are both produced with the two inputs, labor, L, and capital, C, and if all second order cross partial derivatives involving x and y are equal to zero, then there are net gains to the economy from pricing either x or y at marginal costs, no matter what the pricing practice in y or x, respectively.

Baumol and Bradford [1] identify pricing practices that are optimal subject to constraints imposed on marginal cost pricing. The relevant constraint for present purposes is the conventional fair-return-on-fair-value floor on profitability. If not achieved with marginal cost pricing in a regulated firm, Baumol and Bradford show that the next best alternative is to set prices in such a way that the differences between marginal costs and such prices is inversely proportional to the elasticity of demand of the customers served. Thus,

$$\left(\frac{P_i - MC_i}{P_i}\right)\eta_i = \left(\frac{P_j - MC_j}{P_j}\right)\eta_j \tag{2.2}$$

where:

p = price,
MC = marginal cost,
η = elasticity of demand,
i,j = types of service.

This has become known as the "inverse elasticity" rule. Practical applications of the rule will be discussed in subsequent analysis.

Baumol-Bradford's derivation maximizes the sum of consumer's surplus (CS) plus producer's surplus (PS):

$$CS + PS = \int_{P_o}^{\infty} D(p)\,dp + \int_{o}^{P_o} S(p)\,dp \quad , \tag{2.3}$$

where:

p = price,

p_o = equilibrium market price,

$D(p)$ = demand function,

$S(p)$ = supply function.

Thus, marginal cost pricing subject to a constraint means getting maximum total welfare in the circumstances. (In a perfectly competitive market, there would be no profit constraint. Marginal cost pricing would automatically produce a competitive level of profits.)

Fully Distributed Costs

The alternative to marginal cost pricing is generally some form of fully distributed cost (FDC) pricing. Braeutigam [2] defines FDC as the sum of direct costs per unit plus shared costs allocated to each service according to one of three well-specified FDC rules: (1) the "relative output" rule, in which shared costs are allocated in proportion to a physical measure of output such as Mcf of gas or kWh of electricity; (2) the "attributable cost" rule, in which shared costs are allocated in proportion to directly attributable costs; and (3) the "gross revenue" rule, in which shared costs are allocated according to gross revenues derived from a service. For each rule, Braeutigam expresses implied relationships between prices, costs and outputs. Using the preceding numbering system and for a benchmark zero level of prices, these relationships are:

Rule 1: $$p_i - \frac{C_i}{x_i} = p_j - \frac{C_j}{x_j} \qquad (2.4)$$

Rules 2 and 3: $$\frac{p_i}{C_i/x_i} = \frac{p_j}{C_j/x_i} \qquad (2.5)$$

where:

C = costs,
p = price,
x = output,
i,j = services.

Both of these results are different from the inverse elasticity rule given in (1), above. Thus, none of the three FDC rules leads to a maximization of social welfare at the zero profit level. Braeutigam shows that the same is true in general at any positive profit level. The extent of deviation varies and can be relatively great.

Braeutigam surveys the effects of FDC on entry where an unregulated firm or industry (such as fuel oil) is in competition with a regulated firm or industry (such as natural gas). As one would expect, entry conditions are distorted as compared with pricing by the inverse elasticity rule. Among other things, this implies that FDC inhibits efficiency elsewhere in the economy. Note that this conclusion is based on static considerations only. Uninhibited entry and effective competition would doubtless also have dynamic effects, particularly in promoting technological change.

Short vs Long Run Marginal Costs

The additional cost incurred to expand the rate of output by one unit, or the cost saved by contracting the rate of output by one unit, depends on the time period over which the expansion or contraction takes place. The short run is defined as a situation in which capital investment is fixed. Hence, in the short run, marginal cost is determined by variable costs only. In the long run, however, investment, or capital, costs may also be expanded and marginal costs required for the given expansion or contraction are composed of optimal combinations of capital and operating costs.

In the usual neoclassical model, short run marginal cost is greater than long run marginal cost. The reason is that, in the short run, combining proportions of capital and operating inputs are not optimized. Expansion or contraction of operating inputs is made in combination with a fixed capital stock. Necessarily, more resources per unit of output at the margin are required than when both capital and operating expenses are simultaneously adjusted optimally in relation to one another. Note that we are discussing rates of increase in costs at the margin, one for operating, the other for capital costs. In optimal pricing, operating and capital marginal costs are equated to price and to each other, per unit of output. They are not added together, at least in the neoclassical model, with its characteristic continuity of combining proportions. Different bases for marginal costs are found, however, in the presence of discontinuities such as examined below for the case of L-shaped production functions.

Short run marginal cost pricing leads to long run adjustments. Assuming that an incremental increase in demand is fixed for the long run, cost minimizing (profit maximizing) firms will soon choose the lesser cost means of satisfying this demand: expand fixed investment just enough to produce the optimal input combination of operating and capital (investment) costs. The relevant marginal cost has become long run and has been reduced accordingly. A completely symmetrical argument applies to contractions in demand.

Whether adequate ("normal") profits are received depends on the aggregate return on capital. The above adjustment process might take place with aggregate profits greater or less than normal. An indirect mechanism in competitive industries assures that profits gravitate toward normal. If above normal, more firms are attracted into the industry and the share of the market (demand, as seen by any one firm) drops. This process continues until profits on the average are driven back to normal. If below normal, firms depart from the industry, in the long run, with opposite effects on demand as seen by any one remaining member of the industry.

A special consideration in the case of natural gas, electric power and certain other industries, especially utilities, is long term decreasing costs, meaning that average total costs decline as firms (systems) get larger, within the relevant size range. This is one characteristic of businesses that are said to be "natural monopolies." The firm that gets large first within a given market area has a cost advantage stemming from its size alone and need not engage in any form of restraint of trade to monopolize. Now, from a strictly mathematical point of view, as long as average costs are declining, marginal costs must be below average. Indeed, one might say that it is the lower margin that brings the average down. The implication is that in the presence of long run decreasing costs, the margin will be below the average. It follows that prices based on long run marginal costs will not cover average total costs. This is the reason that the inverse elasticity rule takes on special significance for natural gas distributors and other utilities.

The above logic applies only to long run marginal costs, since the concept of size ("scale") involves long run adjustments. Short run marginal cost pricing can lead to full coverage of average total costs, but need not, depending on the level of demand.

Both short and long run marginal costs are relevant, depending on the planning horizon over which adjustments are considered. For planning horizons of less than one year, short run marginal costs (referred to later as "marginal variable costs") describe the range of alternatives available to the firm. For planning horizons long enough to retire a piece of capital equipment, long run marginal costs (referred to later as "marginal capacity costs") describe the situation. The short run tends to merge to the long run as the planning horizon lengthens. Exclusive use of either the short or the long run is not recommended, though in most contexts considered below, investment decisions are at issue, and hence long run marginal costs are used.

Neoclassical vs Step Production Functions

Implicit in most analyses of marginal cost pricing for both gas and electricity is the assumption that production functions are L shaped.

Thus, marginal cost variation over a diurnal or annual peak load cycle is viewed as a series of steps as shown in figure 2.1. Each step shows only the level of operating costs. The lowest cost is C_1, the next is C_2, and so on. Corresponding capacity limits are X_1, X_2, and so on, respectively. Each new source is brought on line when the limit of previous capacity is reached. As conceived in traditional analysis, marginal costs are traced by the composite of the L shaped functions, which constitute the step function shown in figure 2.1. At peak, there is no limit on how high marginal costs can go. Marginal costs on the vertical line, at peak and elsewhere, represent scarcity values.

Figure 2.1 can be extended or contracted horizontally to represent long run adjustments. The more capital (capacity) of each technology, the longer the step to which that capital applies.

Using a step function as shown in figure 2.1, Dansby [4] has developed conditions for optimal capacity on each step and for optimal pricing. Consider capacity conditions first. Dansby's model is for a series of electric plant technologies having the properties

$$0 < MC_1 < MC_2 < \ . \ . \ . < MC_n, \tag{2.6}$$

$$\beta_1 > \beta_2 > \beta_3 > \ . \ . \ . > \beta_n > 0, \tag{2.7}$$

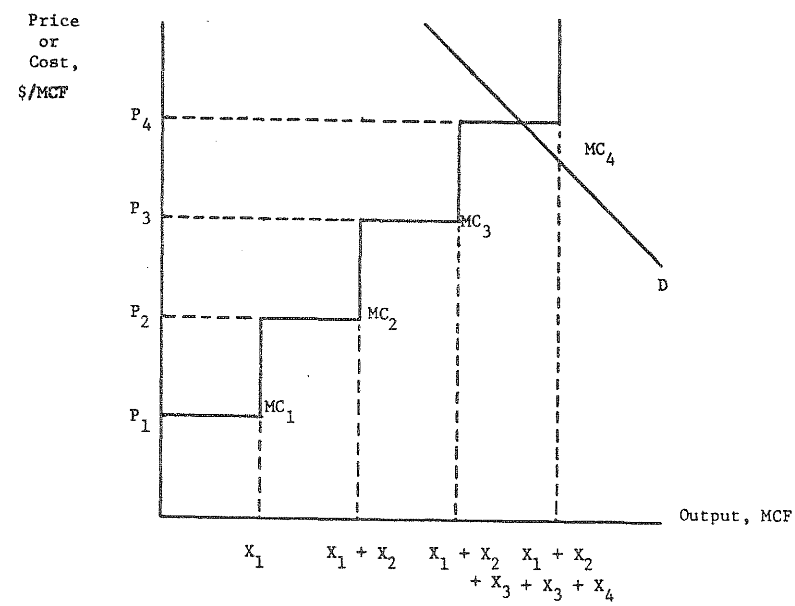

Figure 2.1 L-shaped Production Functions

where MC is the marginal operating cost and β is the marginal capacity cost. In an optimally designed plant with a stationary annual load curve

$$\beta_j - \beta_j + 1 = t_j(MC_{j+1} - MC_j), \qquad (2.8)$$

where subscript j identifies the technology and t_j is the length of time that demand exceeds capacity K_j, the plant capacity up to and including technology type j. Equation (2.8) shows a balance between the difference in annual equipment charges and the difference in annual operating charges for the same two technologies with optimal capacity assigned by technology. We shall illustrate the use of equation (2.8), replacing time with annual load factor, in selecting optimal sources of gas when there are both commodity charges and demand charges. The latter take the place of β in Dansby's formulation.

Dansby's optimal pricing extends the traditional analysis to show that welfare optimal off-peak prices are a convex combination of the marginal operating costs included in whatever time period is relevant. More specifically, each cost level is weighted by the fraction of total time spent at that cost level. Thus, if marginal costs are calculated at monthly levels, as we shall calculate them at a later point, and if it is desired to get the implied marginal cost for a six month period, this is calculated as the weighted (by months) average of marginal costs for the six months. On-peak prices include the same kind of convex combination of operating expenses, plus a factor that depends on marginal capacity cost and the total time on peak. Note that the optimal peak and off-peak price and capacity levels are interdependent, since these variables all influence the quantity of gas consumed from each source.

Dansby's analysis is set in the context of optimal choice of equipment (technologies) for electric power generation, though it has been reinterpreted herein for gas supply. One important extension that will be made herein is to include demand charges. For the purpose of theoretical discussion, demand charges will be allowed to vary by the month or by the year. With monthly demand charges, the demand charge each month depends on the maximum demand that month. With yearly demand charges, it depends on the maximum demand that year. Thus, demand charges are not fixed like capacity charges, though amounts taken on peak are subject to a capacity constraint. A linear programming model is used to bring all three dimensions of gas pricing to a common basis: commodity, demand, and investment costs.

Figure 2.2 shows the implications of neoclassical assumptions for pricing. An elaboration of the model is found in Panzar [8]. Instead of following an L-shaped pattern, every point on each (short run) marginal cost curve is produced by increased variable inputs applied to fixed inputs. There are four technologies. The cumulative marginal costs are shown with each of the technologies brought on the line consecutively. With demand at the indicated level, price is P_4, and all of the technologies are in use. The quantity from source #1 is X_1, from source #2, X_2, and so on.

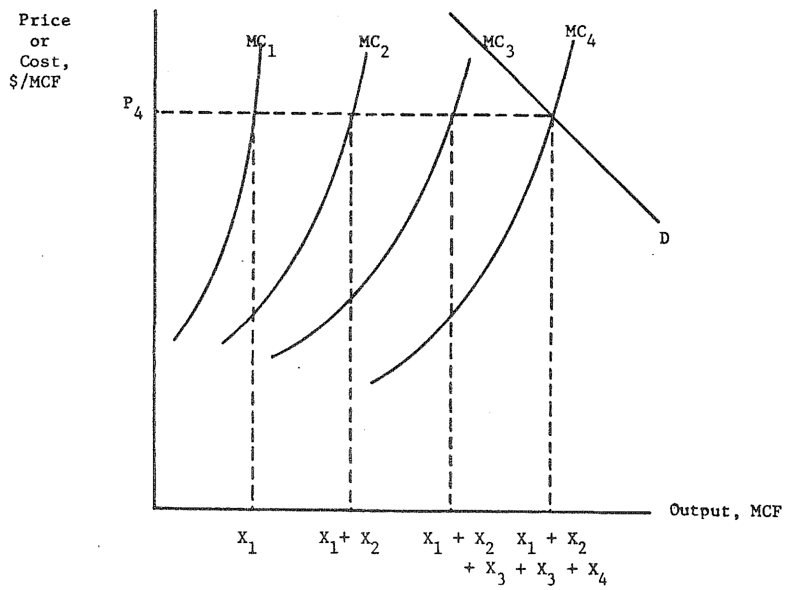

Figure 2.2 Neoclassical Production Functions

Each source is at the margin in figure 2.2, and hence price P_4 contributes to the fixed costs of each source. This is the situation described above under the heading "short vs long run" marginal costs for the neoclassical model. Capacity does not have a fixed limit in figure 2.2. With long run marginal costs, there would be no point in distinguishing the four technologies. Investments would be added among the four at each step in expanding capacity in such a way as to minimize total costs. The slope of the long run marginal cost curve would be less steep than shown for the four short run marginal costs taken together. It would intersect demand below P_4.

A step function such as shown in figure 2.1, rather than neoclassical production functions, will be used in later analysis of the application of marginal cost pricing to natural gas, because the former better describes the case of a distributor purchasing gas under contract with alternative sources. Neoclassical functions are introduced here to tie the present discussion in with the general theory of marginal cost pricing, as noted under the last previous subheading.

Storage

A distinct set of optimization problems is introduced by storage. Pyatt [9] provides a general analysis suitable for either a single L-shaped production function, as in Williamson [12], or for neoclassical production functions. The specific case of a step function such as used herein is not discussed.

For the purpose of our particular application, it is most informative to begin with Pyatt's neoclassical results. In his analysis, the characteristic equation for storage is derived as:

$$s[b(s,t) - a'(x)\dot{x}] = 0, \qquad (2.9)$$

where (notation is amended to fit our use of the model for gas)

s = stocks (of gas) in storage,

t = time,

x = quantity (of gas from suppliers),

$\dot{x} = d\dot{x}/dt$,

$a(x)$ = marginal cost of x (production function is $A(x)$),

$b(s,t)$ = marginal cost of holding stocks.

Equation (2.9) states that either stocks are zero or

$$a'(x)\dot{x} = b(s,t) \tag{2.10}$$

Equation (2.10) states that the marginal cost of gas is changing at the same rate as the cost of storage. Taking the integral of both sides for a time period τ to $\tau + \theta$, it follows that:

$$a[x(\tau+\theta)] = a[x(\tau)] + \int_{\tau}^{\tau+\theta} b(s,t)dt. \tag{2.11}$$

The amount $a[x(\tau)]$ is the marginal cost of an extra unit of gas at time τ. The integral on the right hand side is the marginal cost of storing this unit from time τ to $\tau + \theta$. The left hand side is the marginal cost of an extra unit of gas at time $\tau + \theta$. Thus, optimal storage consists in filling (or depleting) storage in such a way as to incur no greater costs of storage than of acquisition (at the margin). This implies that marginal costs of gas supply will at all times be equal to marginal costs of (past) supply plus storage to the current time. More specifically, there is never any need to take account of the marginal costs of storage. The marginal cost of supply always gives the same result.

The above is derived by Pyatt for the neoclassical case, but can be readily adapted to step functions. The latter differ from the former only in that they can impose discrete jumps on the increase in marginal cost with volume. With optimal operations, gas will be withdrawn from storage only when doing so is cheaper than drawing the same amount from new supply. It follows that the marginal cost of the latter will, in these circumstances, be at least as great as gas from storage. Hence, at such times, new supply defines marginal costs.

Now, consider the situation when gas is being put into storage. Marginal costs are higher, in general, than they would be without the drain on supply that is required to fill storage. But such marginal costs are the correct ones to levy on current consumption since the opportunity cost of current consumption is storage and higher valued consumption later. Thus, no matter whether gas is being injected into or withdrawn from storage, the proper marginal cost to use is that of contemporaneous new supply.

Stochastic Effects

Pervasive qualifications of traditional peak load pricing theory have arisen from the introduction of stochastic considerations.

Early attention in the literature focused on random elements in demand. Uncertainty was treated as both an additive and a multiplicative factor. Rationing of output, when short of demand, was by a variety of criteria: (1) to those with high willingness to pay; (2) to those with low willingness to pay; and (3) by random selection. For the most recent contribution in this tradition and references to earlier works, see Carlton [3].

A recent analysis by Saving and DeVany [10] (referred to hereinafter as SD) breaks new ground and serves as a basis for later recommendations, below, in the application of marginal cost pricing.

The SD model establishes relationships among the four: reliability, demand, supply, and output. Demand, of course, affects reliability insofar as it exceeds or falls short of supply. But there is also an inverse effect: reliability affects demand. At any given price, the less reliable the service, the less demanded. In this respect, the value of reliability is endogenous in market price. The inverse effect is important in SD's analysis.

Output depends on the lesser of supply and demand. When supply is less than demand, rationing takes place. SD do not commit themselves to a form of rationing but represent reliability simply as the expected value of the fraction of demand satisfied by supply.

SD derive first order conditions for price and capacity in both monopoly and perfect competition. Consider price. In monopoly

$$P_i = MC_i - w_i\left(\frac{\partial p_i}{\partial w_i}\right) , \qquad (2.12)$$

where:

MC = marginal cost,
P = full price,
p = price,
w = expected output,
i = index of time period.

In (2.12), each time period is independent. Peak shifting is included in the SD analysis, but is omitted here in the interest of brevity. "Full price" is adjusted market price, as shown in (2.12), (2.13) and (2.14).

The second term on the right hand side of (2.12) is negative. The partial derivative is affected by two phenomena: (1) conventional downward sloping marginal revenue; and (2) the effect of price reduction to compensate for reduced reliability with increased output.

In perfect competition, optimal price is given by an analogous expression:

$$P_i = MC_i + w_i v_i \left(- \frac{\partial \delta_i}{\partial w_i} \right), \tag{2.13}$$

where:

v = unit value of reliability,

δ = reliability.

In the competitive case, full price, P_i, is given by the market at

$$P_i = {}_i + v_i(1 - \delta_i) , \tag{2.14}$$

and individual firms treat both δ_i and p_i as variables. Thus, it is possible for price p_i to vary among perfectly competitive firms, due to variation in reliability. Reliability might be considered a quality difference, though it is constrained by market-determined full price. Since P_i is market determined, peak shifting is not a problem for the individual firm.

In (2.13), the term $v_i \left(- \frac{\partial \delta_i}{\partial w_i} \right)$ is the value of the loss of reliability that comes from adding one more unit of expected output; $(\partial \delta_i / \partial w_i)$ is negative. Thus, the second term on the right side of (2.13) is the total cost of reliability to existing users and is endogenous to price. For example, an increase in expected output simultaneously raises p_i in (2.13) and offsets the increase in p_i with an increase of δ_i in (2.14).

First order capacity conditions in the monopolistic and competitive cases are related in exactly analogous ways. We report here only the SD results for the competitive case:

$$\sum_i w_i v_i \ (\partial\delta/\partial K) = \frac{\partial C}{\partial K} \quad (2.15)$$

The left hand side of (2.15) is the sum of values of the marginal contributions of capital to reliability. Note that, in principle, all periods i are included in the summation. In practice, the effect of incremental capital additions on reliability may be vanishingly small in off-peak periods.

The significance of the Saving-DeVany analysis for practical applications of peak load pricing is illustrated by figures 2.3 and 2.4, adapted from their article. In both figures, the step function marginal cost curve from figure 2.1, above, provides a frame of reference. Figure 2.3 is completely deterministic and the step function is the marginal cost curve. Figure 2.4 introduces stochastic effects and a new curve, $MC + wv(\partial\delta/\partial w)$, gives the relevant costs. The step function is included for reference only.

Consider, first, figure 2.3. There are two time periods, with outputs X_1 and X_2, off-peak and on-peak respectively. Demand is shown by W_1 and W_2 in the corresponding periods. The symbols W_1 and W_2 are meant to suggest expected values, though there is complete certainty in figure 2.3. Price p_2 is above variable costs. With long run equilibrium, it covers fixed costs. Price p_1, however, comes nowhere near fixed costs. These must be covered in the peak period only. Figure 2.3 represents the conventional analysis in the absence of stochastic effects.

The revised supply curve in figure 2.4 is the right hand side of equation (2.13), above. This may be thought of as a marginal cost curve corrected for reliability costs. The new demand curves W_1' and W_2' appear to the left of the original W_1 and W_2 (in figure 2.3) because of the effect of reliability on demand. Consistent with equation (2.15), above, both periods experience some reliability effects and both would benefit from expansion of capacity. The shift is significantly greater for W_2'

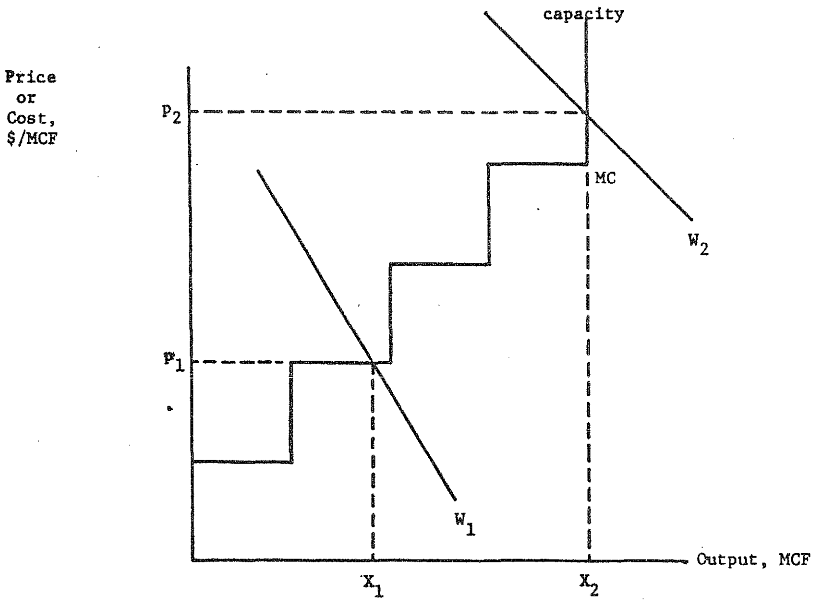

Figure 2.3 Deterministic Case

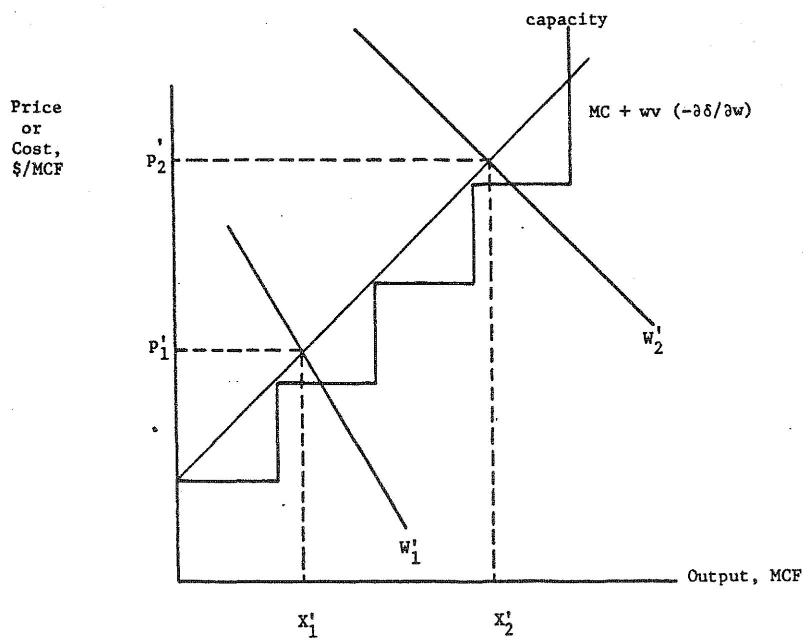

Figure 2.4 Stochastic Case

than for W_1' because reliability drops more at high than at low outputs. The combined effect of these changes is to lower peak price and raise off-peak price, the former more than the latter. In a long run equilibrium adjustment, fixed costs would be covered by the combined total of prices.

A direct application of principles from the SD analysis is made later in this chapter. Prices are interpreted to include endogenous reliability values and to create, in the winter months, an upward sloping supply curve as in figure 2.4. In non-winter months, the probability of demand exceeding supply is judged to be vanishingly small and is set at zero. The effect of reliability on price during the winter months is calculated according to an assumed probability structure, to be described at a later point.

Basic Issues

Previously described principles are made more specific to the distribution of natural gas (including SNG, LNG) in the following analysis. The object is to identify marginal costs, which, by implication, then become the basis for the pricing of gas to ultimate consumers. No attempt is made to evaluate upstream (transmission) pricing practices. These are taken as given. If, as, and when transmission pricing practices are revised, it will be necessary to review the findings of the present analysis to assure that they remain applicable.

Marginal cost pricing inherently assumes optimal allocations within the firm. Accordingly, the analysis is grounded on an optimization model for gas supply. This model is an adaptation of the one developed in the former study by J. M. Guldmann, [6, Ch. 4]. Once supply costs are established, distribution costs present no complexities of optimal choice, though planning for future capacity requires attention to both stochastic and scale effects, especially in the distribution system itself.

The organization follows the three traditional cost categories--commodity, capacity and customer costs. Broadly speaking, costs that are correlated with demand, or load volume, are classified as either commodity or capacity costs. Those that are correlated with number of customers are placed in the third category, customer costs. There are no other categories; these are comprehensive and mutually exclusive. Thus, marginal cost analysis implies two part rates: customer cost and commodity-capacity cost. As we shall see, there are interdependencies in commodity and capacity costs.

All of the interesting problems of cost-finding are in the commodity-capacity category. Very little need be said about customer cost. Commodity and capacity costs are lumped together for two reasons. First and most fundamentally, marginal cost pricing is interpreted herein (and in most other utility studies) as <u>long run</u> marginal cost pricing. Secondly, one of the interesting problems for marginal cost analysis is how to treat demand charges paid to gas suppliers. Demand charges are midway between fixed and variable costs. They have some of the attributes of each, as shown below. Because demand charges are present, the distinction among commodity, demand and investment costs becomes a matter of degree.

The analysis follows a progression from simple to complex optimization. Commodity costs are given first attention, but optimal supply choice cannot be made, even at the beginning, without considering demand charges. To deal with these, a simple optimization model of commodity and demand charges is derived with capacity held constant. This "Simple Supply" model establishes the basic principles of combined commodity-demand charge optimization. It is probably the most important single contribution of the present chapter. A method is described for hand calculation of the "Simple Supply" model.

The next step involves the introduction of a series of special commodity constraints and charges: purchased gas adjustment, winter requirements charge, local supply constraints, storage and "take-or-pay" clauses. These complicate the analysis but do not introduce any new principles into it.

Then, investment costs are introduced and a method is devised for spreading investment costs to allow for stochastic effects. Different kinds of stochastic effects are relevant for (1) distribution investment and (2) supply investment. With distribution investment, stochastic growth projected over the life of the distribution system gives a basis for what is called herein "overdesign". With supply investments, stochastic effects are important only for the identification of peak load.

Finally, a comprehensive supply optimization model is developed. The comprehensive model integrates commodity, demand and investment costs. It also takes account of special commodity constraints and stochastic effects for both demand and investment costs on peak.

The entire analysis is framed on a month-by-month basis and provides for adjustment of marginal costs by the month. In point of fact, cost variations take place over shorter periods of time. But, as shown in Dansby [4], marginal costs over short periods of time can be represented by the weighted average over longer periods. Accordingly, if it is found desirable to set natural gas rates at marginal costs that hold over a longer time than a month, further averaging can be imposed as described in previous discussion of Dansby (see literature survey, above).

Optimal Combination of Commodity and Demand Costs

Commodity costs include: commodity charges paid to suppliers, whether pipeline, LNG or SNG; commodity cost adjustments, excises and recovery charges applied to these; special components, such as winter requirements charges or "take or pay" charges; and other noncapacity costs correlated with the volume of gas, such as some (but not all) maintenance costs. In addition, if a distributor sells its own gas, production (but not capital) costs of own gas are part of commodity costs. The costs of pressurizing gas for storage are also commodity costs, but enter into marginal costs in a special way, as shown below.

Demand charges are surcharges based on peak day purchases and added to commodity charges every day of the year. Contrast investment costs, where design capacity establishes a fixed cost regardless of peak volume. The relevant peak for demand charges may be either annual or monthly. For the sake of a more general analysis, monthly peaks are considered herein. These can be converted to annual peaks simply by setting all twelve monthly peaks at the maximum for the year.

A Simple Supply Example. The relation between commodity and demand charges in an optimization model is illustrated by a simple example in table 2.1. This example abstracts from the complication of special

TABLE 2.1

SIMPLE EXAMPLE OF SUPPLY OPTIMIZATION

Source Number (1)	Commodity Charge $/MMcf (2)	Demand Charge $/month / Peak MMcf/day (3)	Total Annual Cost ($) 1 MMcf/Peak day 100% Annual Load Factor* (4)	Total Annual Cost ($) 1MMcf/Peak day 50% Annual Load Factor (5)
1	1202.4	980	450,636	231,198
2	1009.2	1,860	390,678	206,499
3	787.0	2,500	317,255	173,628
4	1481.0	0	540,565	270,283
5	921.1	14,398**	336,202***	168,101***

Source: Author's calculations

*Load factor is the ratio of actual quantity taken to the quantity that would be taken if deliveries were at peak level for the same time period.

**Investment cost of own production, annual equivalent annuity rate with 30 year life, 12 percent interest rate. Annual equivalent has been converted to monthly rate by dividing by 12.

***Based on commodity charge only.

assessments, cost adjustments, correlated maintenance and other complexities, all of which will be considered at a later point.

Figures in table 2.1 are assumed. The first three sources shown in table 2.1 are intended to represent pipelines. The fourth could be wellhead supply, to which no demand charge applies, and the fifth could be own production. No change in investment is considered in table 2.1 and no capacity charges for source #5 are included. These will be introduced at a later point.

Table 2.1 shows in column (4) total annual costs for a supply of 1 MMcf/day, 100 percent load factor, for each of the five sources. Numbers in this column were obtained by multiplying corresponding commodity charges in column (2) by 365 and demand charges in column (3) by 12 and adding the results together, except in the case of source #5, where the $336,202, shown in column (4) represents commodity charges of $921.1 per MMcf multiplied by 365. Totals in column (5) were obtained by multiplying the commodity charges in (2) by 365 and then by 0.5. The result is added to demand charges in column (3) multiplied by 12.

The least cost source for the 100% load factor is #3. See column (4). With a 50 percent load factor, the least cost source is #5, and for a load factor approaching zero, the least cost source is either #4 or #5, since both of these sources have no demand charge.

Now, consider the problem of choosing the optimal source as a function of load factor. One might think of this problem as a matching of sources to the load duration curve. General principles are easiest to illustrate by considering first only the three pipeline sources and assuming unlimited availability of all three. At 100 percent load factor, as we have seen, source #3 is the least cost alternative. Among the first three sources, #1 is clearly least cost as the load factor approaches zero. Somewhere in between, it would appear that #2 is the least cost source. But we shall see that this is not the case.

In order to determine at what load factor to substitute either source #1 or #2 for #3, set up equations between #3 and each of the other sources in which the load factor, LF, that equates total costs is the unknown. For example in comparing sources #3 and #2:

$$1009.2 \times 365LF + 1860 \times 12 = 787 \times 365LF + 2500 \times 12 \tag{2.16}$$

The solution is LF = 9.47%, meaning that source #3 should be employed in the range 100 down to 9.47%, <u>when the alternative is source #2</u>. If the same calculation is made with source #1 as the alternative to #3, the result is LF = 12.03%. Thus, the shift should be from source #3 to source #1 and not to #2, despite the better showing by #2 as compared with #1 in column (4). Now, once the shift is to source #1, it is clear that there will never be a shift to another source (among the first three), since none of them have a lower demand charge.

Now, consider sources #4 and #5. It is easily shown that #4 will never enter as a least cost alternative as long as #5 is available in unlimited amounts. This follows from the presence of zero demand charges for both #4 and #5, with lower commodity costs for #5. (For purposes of analyzing variable costs, investment, or capacity cost, of #5 is ignored.) As before, source #3 is least cost at 100% load factor. But #5 should be the source used at load factors of 61.34% or less, as can be found by solution of the equation

$$921.1 \times 365LF = 787 \times 365LF + 2500 \times 12 \tag{2.17}$$

Sources #1 and #2 would never be used.

It is informative to consider one more alternative. Suppose that source #5 did not exist, but #4 was available. Then, source #3 would be used for all load factors from 100% down to 12.03%, when source #1 would take over. But source #4 would take over from #1 when LF got down to 11.56%, as can be seen by solving the equation.

$$1481 \times 365LF = 1202.4 \times 365LF + 980 \times 12 \tag{2.18}$$

Source #4 would be least cost for all load factors below 11.56%, since it has no demand charge.

The last sequence -- #3, #1, #4 -- illustrates two points. First, it shows that there is no necessary limit to the number of sources that might be optimal when consideration is given to the full range of possible load factors. Second, it illustrates that the LF calculation must always be made between (1) the source already optimal (#1 at 12.03%) and (2) whatever source is considered as an alternative (#4 at load factors less than 12.03%). Whether #4 could have superceded #3 is irrelevant at load factors where #3 is not optimal. The situation is the same as that of basis-shifting in linear programming.

Figure 2.5 illustrates the load factor analysis with a graph. Total costs of purchased gas from each source are shown on the vertical axis and load factors, on the horizontal axis. Source numbers are given for each line, plus one new source, #6, to be explained below. The values on the vertical axis are set for a peak purchase of 1 MMCf. Thus, the left hand intercepts are demand charges for 1 MMCf. The lines are necessarily straight, with slopes equal to commodity charges for 1MMCf. The equation of each line is:

$$TC = CC \times 365LF + DC = CC(ED) + DC, \qquad (2.19)$$

with:

$$\frac{d(TC)}{d(ED)} = CC, \qquad (2.20)$$

where:

CC = commodity charge, \$/MMCf,

DC = demand charge, \$/MMCf on peak days,

ED = equivalent days, 365LF,

TC = total cost, \$/yr. for the source considered.

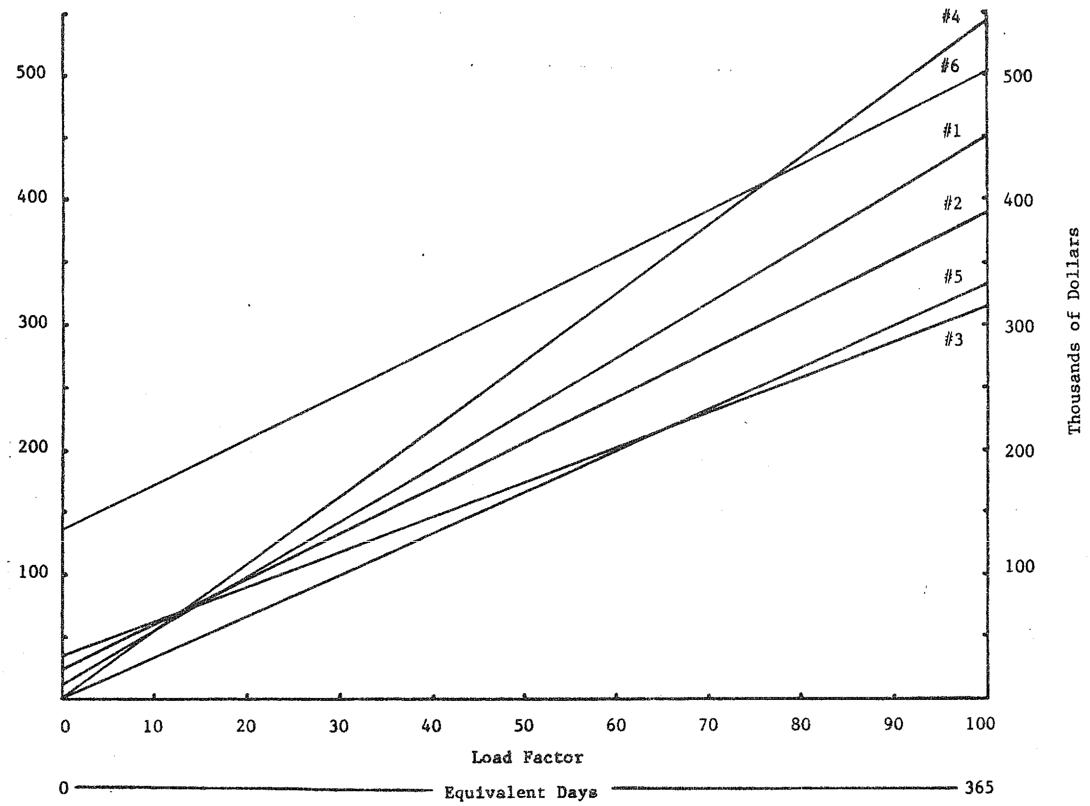

Figure 2.5 Source Cost by Load Factor

Equation (2.20) shows the slope equal to the commodity charge. The concept of equivalent days is introduced for later use in translating from load factors to load duration. ED is the number of days at peak load that corresponds to whatever the annual load factor is. Thus, if the load factor is 30%, than ED = 365 x 0.30 = 109.5 equivalent days.

Intersections of the source lines in figure 2.5 indicate switch-over points, as described in previous discussion.

Generalization of the Example. The preceding analysis can be generalized and made the basis for a simple hand calculated method of optimization.

Assume, for the moment, that all five of the sources are needed on peak to the full extent of their individual capacities, or load limits. With this assumption, demand charges are fixed and the optimization problem reduces to that of minimizing commodity charges. These, in turn, are minimized by always bringing on the line the sources in increasing order of their commodity charges. The source with the lowest commodity charge would be used first, the next lowest, second, and so on. Each source would be used to its full capacity (or load limit) before the next is introduced. The effect is to order annual load factors inversely with commodity charges by source.

Figure 2.6 shows this being done with a load duration curve based on expected values for the year to which the optimization applies. Horizontal lines show cumulative capacity limits of sources. The source (#3) with the lowest commodity charge has the highest load factor. Source #5 has the next highest. These results are consistent with previous analysis and with figure 2.5. Other sources are brought in because they are needed on peak. These sources are "dominated" in that they do not appear on the low cost frontier in figure 2.5. But capacity limits on #3 and #5 make the use of other sources essential. Dominated sources are also assigned load factors ordered inversely with their commodity charges.

Source #6 has been added to figure 2.5 to make the point that commodity charges are the only thing that determine relative ordering on a load duration curve. Source #6 is source #5 with an investment cost of $172,776 per year (12 x $14,398). If it were necessary to expand source #5 because of peak demand, the effect would be to substitute source #6 in place of #5. But nothing in figure 2.6 would be changed. It would be best to use source #6 exactly as #5 has been used because of its relatively low commodity charge ($921 per MMcf).

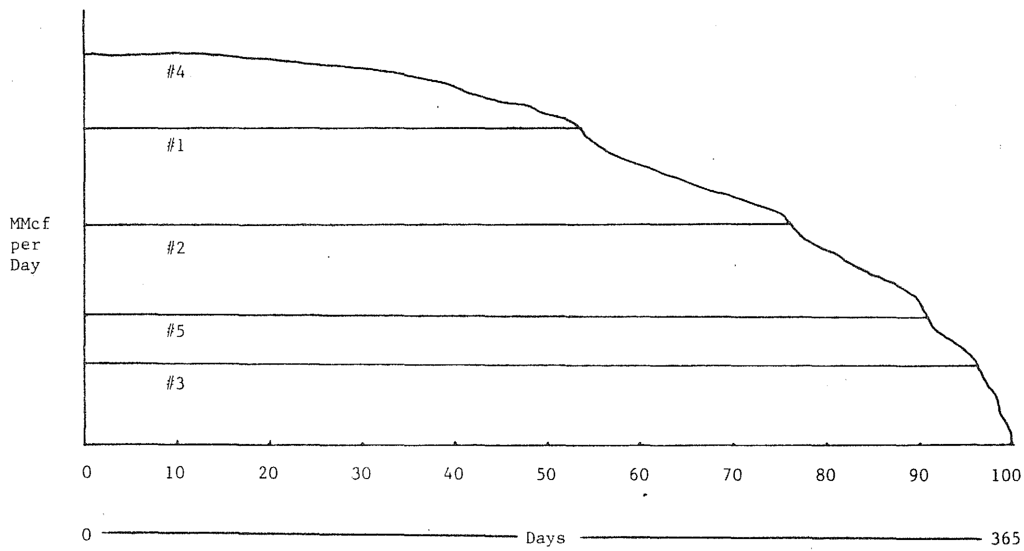

Figure 2.6 Load Duration

Now, return to the case where the total capacity of sources #1 through #5 exactly satisfies peak demand. In this case, all that need be done to find optimal supply is to bring on the line each day the sources in order given vertically in figure 2.6, reading from bottom to top. The total supply in any particular day of the 365 is the height of the load duration curve on that day. But it is not necessary to know which day is which, because the vertical order of sources is the same on all days.

Some adjustments need be made if the supply capacity does not exactly match peak demand. Here, we may think of changing supply capacities, either adding more capacity (without changing the commodity charge) or reducing capacity. Indeed, it would be desirable to increase #3 at the expense of others, as we have seen. The rule for expanding or contracting source capacities is readily derived. Thus, for any one source:

$$TC = [CC(days) + DC](SC) \tag{2.21}$$

$$\frac{d(TC)}{d(SC)} = [CC(days) + DC] + (CC)(SC)\frac{d(days)}{d(SC)} \tag{2.22}$$

where SC stands for source capacity. Equation (2.21) is equation (2.19) generalized to allow for increases and decreases in source capacity, or load limits, among sources. Equation (2.22) shows the marginal cost of adding another unit of capacity, which is the sum of the two terms on the right hand side. The first term represents the rectangular section of the area in an upward or downward movement of one of the lines in figure 2.6. The second term takes account of the change in the number of days attending any such movement. The derivative d(days)/d(SC) is the slope of the load duration curve at whatever point we happen to be and is negative.

When new supply is being added, bring in the source for which d(TC)/d(SC) is smallest. When supply is being contracted, get rid of the source for which d(TC)/d(SC) is largest. If one source can be expanded at the expense of another, substitute a lower cost for a higher cost. In general, an optimal adjustment of capacity will proceed to the point where all sources have the same (low) value of d(TC)/d(SC).

Marginal cost, in this analysis, is the greatest commodity cost of the sources in use on any given day, except for peak day. On the peak day, it is the demand charge of the source that would be curtailed, plus the commodity charge of the same. To see that this is the case, pose the question: "What costs could be saved by a marginal reduction in demand?" Only on peak would any of the demand charges be reduced. The radical jump in marginal cost on peak follows from the assumed deterministic character of the optimization. In later analysis, we shall show that peak costs are spread by stochastic considerations, but no other essential attributes of the analysis are changed.

Linear Programming Generalization. To pave the way for later analysis, the foregoing is expressed as a linear programming problem that is formulated in table 2.2. The purpose is to identify the structure of combined commodity and demand charge optimization. It is not to set up a full scale optimization model. That last purpose is served by table 2.4.

Table 2.2 is oversimplified in that it does not include all of the constraints later to be used in table 2.4. It is also oversimplified in that demand charges are assumed to apply independently to the separated individual peak days in each month, rather than to a single yearly demand peak. The structure of the optimization must be changed if the single yearly demand peak is used. As with table 2.1, there is no capacity expansion taken into account in table 2.2. That, also, must await full scale optimization, in table 2.4.

With these interpretations in mind, refer to table 2.2. The objective function states that costs shown in table 2.1 are to be minimized over a one year period. No variables appear in the objective function for SP4 and SP5 since these sources have no demand charges. Constraints (1), (2) and

TABLE 2.2

OPTIMIZATION OF TABLE 2.1 SOURCES (NO CAPACITY CHARGES)

(All summations are over 12 months)

Min	$\Sigma CC1 \cdot SC1_m$	$+ \Sigma DC1 \cdot SP1_m$	$+ \Sigma CC2 \cdot SC2$	$+ \Sigma DC2 \cdot SP2_m$	$+ \Sigma CC3 \cdot SC3_m$	$+ \Sigma DC3 \cdot SP3_m$	$+ \Sigma CC4 \cdot SC4_m$		$+ \Sigma CC5 \cdot SC5_m$		
(1)	$\Sigma SC1_m$										$\leq LC1$
(2)		$SP1_m$									$\leq LP1$
(3)	$SC1_m$	$-N_m SP1_m$									≤ 0
(4)			$\Sigma SC2_m$								$\leq LC_2$
(5)				$SP2_m$							$\leq LP_2$
(6)			$SC2_m$	$-N_m SP2_m$							≤ 0
(7)					$\Sigma SC3_m$						$\leq LC3$
(8)						$SP3_m$					$\leq LP3$
(9)					$SC3_m$	$-N_m SP3_m$					≤ 0
(10)							$\Sigma SC4_m$				$\leq LC4$
(11)								$SP4_m$			$\leq LP4$
(12)							$SC4_m$	$-N_m SP4_m$			≤ 0
(13)									$\Sigma SC5m$		$\leq LC5$
(14)										$SP5_m$	$\leq LP5$
(15)									$SC5_m$	$-N_m SP5$	≤ 0
(16)	$SC1_m$		$SC2_m$		$SC3_m$		$SC4_m$		$SC5_m$		$= DGMT_m$
(17)		$SP1_m$		$SP2_m$		$SP3_m$		$SP4_m$		$SP5_m$	$= DAYMAX_m$
(18)							SC_i, SP_i				≥ 0
(19)							ΣLC_i				$\geq \Sigma DGMT_m$
(20)							ΣLP_i				$\geq DAYMAX_m$

Nomenclature

CC_i: Commodity charge, source i, \$/MMcf

DC_i: Demand charge, source i, \$/MMcf on peak day

LP_i: Limit on peak MMcf per day, source i

N: Number of days in month

SC_i: Quantity of gas from source i, MMcf

SP_i: Peak quantity of gas from source i, MMcf on peak day

$DGMT_m$: Total commodity demanded, MMcf per month

$DAYMAX_m$: Peak demand, MMcf on peak day of each month

Subscript i: sources 1-5
Subscript m: months 1-12

Source: Author's formulation

(3) apply to source #1. Constraint (1) imposes whatever limit exists on annual purchases from source #1. Constraint (2) represents the capacity (peak) limit on daily rate of use of source #1. Constraint (3) ties commodity and peak purchases together. It is necessary that any increase in $SC1_m$ made in the process of finding the optimal solution be matched with at least as great an increase in maximum (peak daily) use of source #1. The same interpretations apply to corresponding constraints for each of the other five sources.

Constraint (16) sets the load requirements, month-by-month, for the five sources. Constraint (17) sets the flow rate limitations for all sources. Necessarily, the peak day will be the same for all sources in a given month. This follows logically from the requirements of cost minimization. If the peaks of different sources were on different days, the total of all demand charges would be greater. Constraint (18) is the conventional nonnegativity requirement.

Constraints (19) and (20) are feasibility requirements. These are necessary only because fixed capacity is assumed in table 2.2. Before undertaking to solve the system (1) through (18), a quick calculation (by hand, if convenient) should be made to assure that the total commodity availability is sufficient for the load, as in (19). It is also necessary that the peak requirement be available each month, as in (20) and (17) combined. If either of these two feasibility requirements cannot be met, then the problem cannot be solved. It is necessary to make some adjustments. For example, assume that the peak requirement is exceeded in some months. A possible solution would be to impose curtailments on some peak users in these months, as necessary to get a feasible load. Whether this alternative is realistic would depend, of course, on how great the curtailments might be. The other alternative is to expand capacity, either on peak or total. This might be done in many ways. A new source might be added via a contract with a supplier. A supplemental purchase gas agreement might be made with an existing supplier. In the case of either of these alternatives, new costs would enter the objective function and the addition should be treated as a new source, whether or not from an existing supplier. Still another alternative would be to expand own supply capacity (source #5) or add storage. Both of these last two alternatives take us beyond the scope of the model shown in table 2.2. Necessary adjustments to take them into account are discussed at various points below.

An alternative way of thinking of the optimization process is as follows: Sources with relatively low demand charges have the advantage at peak times. Sources with relatively low commodity charges have the advantage at other times. An optimum is found when these properties are reconciled, subject to the 100% load factor constraints given by constraints (3), (6), (9), (12), and (15) in table 2.2.

Finally, we come to the identification of marginal costs. Marginal commodity costs per MMCf are found as the difference in the objective function due to an expansion or a contraction in commodity demand, $DGMT_m$ in (16) by 1 MMcf. Marginal peak costs per MMcf on a peak day are found by expansion or contraction of $DAYMAX_m$ by 1 MMcf on a peak day. These two marginal costs are independent if the changes are independent. If changes are made simultaneous to $DGMT_m$ and $DAYMAX_m$, the change in the objective function is the marginal variable cost of the combined changes. It is not appropriate to add the independent changes together. Rather, bring both changes into (16) and (17) simultaneously if marginal variable costs are to be found. Those costs are by months. If marginal costs for the year are desired, take the average of marginal costs by months, weighted by $DGMT_m$ and $DAYMAX_m$ for each month.

In general, only one source expands (or contracts) and the CC for this source, such as shown in column (2) of table 2.1, is the marginal commodity cost. The analysis in table 2.2 is necessary in order to identify which source it is, unless, of course, one knows that limits can be ignored and the simpler calculations made above in table 2.1 can be used to get the answer.

To illustrate the use of table 2.1 for this purpose, assume that we know that any expansion in $DGMT_m$ will be met by source #3. Then the marginal commodity cost is $787. per MMcf (see table 2.1). We do know that source #3 will be the one expanded (or contracted) if the unit expansion (or contraction) of $DGMT_m$ is of loads having load factors greater than 61.34% (see previous analysis) and there is no limit on the amount of source #3 available.

Special Commodity Constraints

A series of special commodity constraints must be introduced to bring the above principles into the usual context of optimization as seen by a gas distributor.

Purchased Gas Adjustment. The first complication of the above-described "simple supply" example is for purchased gas adjustments. These are easily included in the objective function of table 2.2, as long as introduced a month at a time. Instead of a constant CCi, the commodity charge can become a different amount each month, reflecting purchased gas adjustments. For purposes of optimization, the full year's schedule of adjusted CCi_m should be listed in advance.

Winter Requirements Charge. The winter requirements charge is basically no more than a winter excise added to the commodity charge. It is generally calculated as a dollar amount per MMcf sold during winter months, which are defined as November through March, or months 8 through 12. (Numbering of months begins with April = 1).

One method of assessing the winter requirements charge is to calculate it on the basis of the preceding winter's consumption, then to spread it over all twelve months of the current year in commodity charges to customers. This method is inconsistent with marginal cost pricing and should not be used. Whether or not the distributor is forced by the supplier to pay over twelve months, customers should pay only in the winter months, since this is the time of year to which the charge applies. Even more important, the winter requirements charge should be based on this year's winter consumption, not last year's. The point of marginal cost pricing is to present consumers with the economy-wide costs incurred on their behalf. If these costs are too high, consumers reduce consumption and the resources are not used. Obviously, it is this year's winter costs, not last year's, that are relevant for consumption adjustments.

The winter requirements charge should be added to commodity costs during the winter months in exactly the same way that the purchased gas adjustment is added. As noted above, each month enters the objective function in table 2.2 separately. No problem is created by having the commodity charges for the winter months higher than for other months.

Local supply constraints. There may be circumstances in which a distributor is required by a regulatory body to purchase a certain minimum share of natural gas from a particular source. Thus, Guldmann [6, p. 101] reports that the East Ohio Gas Company is required to get at least a certain minimum fraction of its gas from its own wells in the state of Ohio. Such a requirement interferes with the free choice of least cost sources in accordance with table 2.2. But no analytical problems are created. All that need be done is to add a constraint specifying the necessary purchase restriction, as will be illustrated in table 2.4, below. Marginal costs are almost inevitably raised by such restrictions, since the restriction would be unnecessary if the distributor would be guided by a cost minimization model, to purchase the specified amount from the local supply source.

Storage. The advantage of storage arises, of course, from the opportunity it offers to reduce fluctuations in the time profile of gas purchases. Low-cost gas in off-peak months is substituted for high-cost gas in peak months.

For the sake of present discussion, consider the variable costs of storage only. Capacity costs of storage will be introduced later.

Variable costs include compression for injection into storage, annual losses of natural gas from storage, carrying costs of the variable component of inventory and other operation and maintenance costs, to the extent these are correlated with commodity flows into and out of storage.

With storage capacity given, total costs of natural gas are reduced as long as the variable cost (commodity plus peak) of inputs to storage are no greater than the variable cost (commodity plus peak) of whatever source is displaced by storage withdrawals. Thus, the difference between the variable cost of input and the variable cost of the source displaced by withdrawal is at least as great as the variable cost of storage per MMcf in an economically efficient system.

It is important not to count the variable cost of storage in the marginal cost of gas. Pyatt [9] argues that in off-season months, gas purchased for delivery to storage raises the price of gas for current consumption. But the higher cost of gas is the proper marginal cost of current consumption, simply because the opportunity cost of consumption is storage. Thus, during the period that gas is being injected into storage, the proper marginal variable cost to reflect in price for current consumption is based on current purchase price.

In on-season (on-peak) months, when gas is being withdrawn from storage, the erstwhile higher costs of gas (in the absence of storage) are not incurred. Instead, gas from storage that was purchased at prices lower than the sources then current is in use. Thus, the sources that are being drawn upon are marginal in that they are higher cost than storage and would be the first curtailed if load during the peak months should drop. Hence, once again, the sources currently in use establish marginal variable cost. Theoretically, that gas would not have been put in storage in the first place if doing so had not been less expensive than direct purchase.

To summarize: marginal variable cost is found as before. It is the highest cost source of supply, whether or not storage is in use. Variable costs of storage do not enter into marginal variable cost.

It is still necessary, however, to enter the calculus of storage into our optimization model. Otherwise, the effects of storage on the time profile of purchases, and hence on marginal costs of purchased gas, would not be taken into account. The way storage enters into the model is shown below in table 2.4.

"Take-or-Pay" Clauses. Take-or-pay clauses require that the distributor pay a minimum fraction of the monthly load limit, LCi, whether or not the amount paid for is actually taken. Obviously, such a requirement increases the desirability of storage. If the situation arises in which the distributor would, in the absence of sufficient storage, have to pay for gas not taken, then that gas has a zero marginal cost to the distributor. Whatever the cost of increasing storage capacity, that cost will be compared with a greater gain from storage with the take-or-pay clause than without it.

Present discussion, however, takes capacity as given, including storage capacity. In this case, circumstances in which the distributor would have to pay without taking cannot be ruled out. When a take-or-pay clause is activated, the marginal cost of gas is literally zero (to the distributor, though not to society). The distributor's losses would be reduced by selling the gas at any price, down to zero, and this is, indeed, the efficient thing for the distributor to do. To see that marginal variable cost is zero, expand $DGMT_m$ and/or $DAYMAX_m$ in these circumstances. If the gas is already paid for, no variable cost is incurred to take it.

Appropriate constraints can be introduced in the optimization model, as shown in table 2.4, below. Once this model is adjusted for cost minimization with "take-or-pay" an integral part of it, other marginal costs in other months and other sources are likely to be greater than in the absence of the take-or-pay restriction, simply because any such restriction changes the results from what they would otherwise have been, i.e. from erstwhile least cost. Consumers at one time or another, perhaps off-peak as well as on-peak, will incur higher marginal costs and hence higher prices. One expects that peak consumers are most often responsible for circumstances leading to activation of a take-or-pay clause, but it could be a decline in off-peak as easily as an increase in on-peak demand that leads to the result. All we can say in general is that costs to the distributor are produced by the consumers' actual load profile as compared with the suppliers' desired load profile. The optimization model automatically imputes marginal costs if the optima before and after introduction of a take-or-pay clause are compared.

Interruption of Service. It is just as possible that not enough will be available, and that service will be interrupted, as that too much gas will be available, and a take-or-pay clause will be activitated. Either might take place by design with a perfectly predictable and deterministic load. The logic of cost minimization does not preclude deliberate design for payment without taking, nor does it preclude deliberate curtailment in the absence of adequate capacity. Even in the long run, when capacity adjustments can take place, marginal peak costs, for example, might exceed customers' willingness to pay. The situation calls for distinctions among customers as to quality of service.

Stated differently, it is entirely appropriate to distinguish marginal costs among customers if the quality of service they receive is different. Thus, marginal peak costs are incurred more for customers with claims to noninterruptible service. If information is available on willingness to pay for peak service, or conversely, on willingness to accept interruptible service for a price, then this information can be used to assign to one customer class or another marginal peak costs. Two cautions should be noted. First, interruptions must actually take place regularly on peak to assure the validity of whatever information is used. Second, curtailment priorities set up by regulation do not, in themselves, give information on the value of service. These should be ignored in cost allocations. The best evidence for determining marginal costs would be based on observed willingness to pay or to sustain interruptions for a price.

The relevant calculation would proceed in the following way. Suppose that a class of interruptible service is set up and the distributor cuts off service (with notification) to all customers taking this service wherever load exceeds amount X. Then, the only peak charges assignable to interruptible customers when an interruption takes place are based on marginal peak costs at X. If load X is exceeded on nonpeak days as well, then marginal commodity costs assignable to interruptible service are based on load X on those days, when they occur. Marginal variable costs applicable to non-interruptible customers are unaffected.

Stochastic Effects. Analysis of marginal variable cost has proceeded to the present point on the basis of assumed predictible and deterministic loads. In point of fact, of course, the future is uncertain and loads can be predicted only with some approximation. Indeed, it is stochastic effects that often give rise to activation of a take-or-pay clause or an interruption of service.

For purposes of the analysis of marginal variable cost, however, no special consideration need be given to the problem. Historic load patterns already include within them historic reactions to uncertainty, though, of course, at historic prices. See previous discussion of the Saving-DeVany analysis [10], in which reliability is a component of market price. True marginal costs in these circumstances include costs of reliability, as shown by equation (2.13), above. It follows that any prices based on marginal costs in the future, as derived herein, will also implicitly take account of reaction to risk or reliability value, and no explicit finding of such value need be made.

This is not to say, however, that stochastic effects can be ignored. We shall find, below, that uncertainty as to the actual time of occurrence of a peak day and the magnitude of demand on that day make desirable the use of statistical concepts in the imputation of peak costs among calendar dates.

Capacity Costs

Capacity costs include all return on fixed investment, depreciation on fixed investment, carrying costs on gas in the storage cushion, property taxes and insurance on property. Also included in capacity costs are capacity maintenance costs, overhead and administration costs, insofar as these are more closely correlated in the long run with volume of gas delivered than with number of customers. Capacity costs in the latter category are treated as part of customer costs.

Marginal capacity cost is the cost of enlarging capacity by a small, or marginal, increment. Capacity is a stock concept, but must be converted to a flow concept in order to be treated in the same context as marginal variable cost. This is done by multiplying capital investment by the "capital recovery factor"

$$CRF = \frac{r}{1 - (1 + r)^{-n}} \tag{2.23}$$

where r is the rate of interest and n is the number of years over which amortization takes place. The result will be referred to hereinafter as the "annual equivalent" of an investment. Included in the annual equivalent are both depreciation and interest costs.

Marginal capacity costs continue over the life of the same capacity as long as demand is great enough, as defined under the next subheading. If demand does not hold up to the necessary level, as there defined, marginal capacity cost can fall to zero. In this respect, marginal capacity cost has the same significance for regulated as for unregulated industries.

The "Overdesign" Concept. There are circumstances in which apparent overdesign of capacity is justifiable. Such circumstances do not extend to all gas distributor investments but include enough of them to warrant special consideration.

Two effects are relevant in producing overdesign: (1) stochastic effects and (2) expansion allowances.

Stochastic effects arise from year to year variations in demand and from normal breakdowns in the supply chain, but not from systematic biases in either of these. Corporate planners are expected to anticipate any of the latter. Because of stochastic variations, it is necessary to overdesign in order to achieve a certain level of reliability. If design were only for the expected value of demand, there would be supply interruptions half the time, on the average. With design for some higher level of reliability, it is appropriate that this be the capacity measure, not the expected value of demand.

Expansion allowances similarly lead to overdesign in relation to actual realized demand. Future demand over the life of an installation is never known with precision. The least-cost method of achieving a future target capacity is often to overbuild in the first instance, on the ground that subsequent expansions would be exceedingly expensive if made piecemeal. The classic example is the pipeline in the ground. It costs very little more to install a larger diameter line at time of initial investment, but much more to install a parallel line or dig up and replace the first at a later date.

The economic calculation consists in balancing (1) the certain increase in cost from overdesigning today against (2) the (discounted) actuarial value of the least cost way of expanding the same plant tomorrow, assuming it were not overdesigned today. Note that we are here talking about another concept of stochastic variation, in this case, derived from the difficulty of predicting load growth. With scale effects being what they are in natural gas distribution, it is likely that overdesign can be justified to rather significant levels.

In order to determine the extent of overdesign, multiply the stochastic and expansion factors together. This gives the capacity that corresponds to a given current expected demand. Thus, if stochastic effects call for a capacity increase of 1.25 times and the expansion (growth) allowance factor is 1.6, then capacity can be 2 times (1.25 x 1.60 = 2.00) expected demand. Stated differently, our standard of when demand is great enough to "press on capacity" for purposes of marginal capacity cost pricing is, in this example, when expected demand is 1/2 of capacity. If expected demand falls below this level, then marginal capacity cost falls below the marginal investment cost actually incurred, and can fall to zero.

For convenience in future analysis, we shall define a level of "threshold" demand as the current expected value of demand multiplied by the stochastic and expansion factors. Thus, threshold demand is not a true demand, but an inflated demand defined in such a way as to have an expected value of peak exactly equal to overdesign capacity, as the latter is defined herein.

Distribution Capacity. The preceding concepts are most simply illustrated by the case of distribution capacity. For purposes of the present discussion, all capacity will be divided into three groups: distribution capacity, supply capacity and other capacity. Supply capacity is distinguished by the ability to separate investments according to source of supply, such as own production, gas storage, transmission, and so on. Distribution capacity is that part of the system in which gas is delivered without ability to distinguish sources. The third category, other capacity, lumps together all capacity expenditures not in the first two categories.

In the absence of stochastic effects or expansion allowances, i.e. with a perfectly deterministic and static load, demand would be "pressing on capacity" only at the annual peak and all marginal capacity cost for the year would be assigned to this peak. This would create a radical increase in charges for a single day or, if prorated over a month, for a single month.

In the presence of stochastic effects, account is taken of the fact that the time of annual peak cannot be predicted precisely. Instead, it can be predicted only with some probability distribution among days or months. Assume, for example, that the probability distribution is as shown in table 2.3. In accordance with a convention noted earlier, month 8 is November, 9 is December, 10 is January, 11 is February and 12 is March. The probability that the peak occurs in January is as great as the probability that it occurs in all the other four months combined. See column (2).

Two sets of multipliers are shown, in columns (3) and (4), respectively. The multipliers are designated by the symbol k for later reference in table 2.4. To get marginal capacity costs, multiply annual equivalent marginal investment costs by the appropriate multiplier in each month. This procedure spreads marginal investment costs over periods for which the investments are useful in a statistical sense, in contrast to the deterministic case, cited above, in which the entire investment is assigned to a single peak day, week, month or whatever. Stated differently, marginal capacity cost is the actuarial value of marginal investment cost when actuarial value is defined with consideration for the stochastic and expansion factors.

With threshold demand at or above capacity, the multipliers are equal to the probabilities of peak occurring in the corresponding months and, of course, sum to 1.0 over the five months. See column (3). Recall that threshold demand has an expected peak equal to capacity. Thus, the multipliers in column (3) calculate marginal capacity cost by distributing marginal investment cost according to the probable incidence of the peak.

An additional effect is illustrated by column (4), which assumes that demand has dropped to a level equal to 90 percent of threshold. In this case, demand has an expected peak below capacity and we have assumed that the probability of a peak as high as capacity is only 80 percent as great as it is with threshold demand. Hence, the multipliers in column (4) are 80 percent of their values in column (3), the sum of the multipliers over the five months is 0.8, and marginal capacity cost is only 80 percent of

TABLE 2.3

HYPOTHETICAL MULTIPLIER

Months	Probability of Peak in Month	Multiplier, k: Threshold Demand at or Above Capacity	Multiplier, k: Threshold Demand at 90% of Capacity
(1)	(2)	(3)	(4)
8 and 12	0.05	0.05	0.04
9 and 11	0.20	0.20	0.16
10	0.50	0.50	0.40
1 through 7	0	0	0

Threshold Demand as a % of Capacity	Ratio of Probabilities of Peak at Capacity, Actual Threshold Demand Compared with 100% Threshold Demand
(5)	(6)
100%	1.0
90%	0.8
80%	0.6
70%	0.4
60%	0.2
50%	0.0

Source: Author's calculations

annual equivalent marginal investment cost. This is a case in which capacity turned out to be overdesigned by a larger factor than could be justified.

The relationship of 0.80 between the probability of peak at capacity with 90% threshold as compared to 100% threshold was obtained by a linear approximation shown in columns (5) and (6). Numerical values correspond to our previous example in which capacity is 1.25 x 1.60 = 2 times the expected value of demand. This means that 100% threshold demand is twice expected demand, or 50% threshold value equals expected demand. Now, with capacity designed so that the probability of service interruption is very small, the probability of peak equal to capacity is close to zero. We have placed it at zero for the sake of an approximation in column (6). Other figures in column (6) are obtained by simple linear interpolation between threshold demand at 50 percent and at 100 percent of capacity.

In this example, if, many years after investment in distribution facilities, expected demand drops to one quarter of capacity, threshold demand will be half of capacity and marginal capacity cost will be zero. The result depends, of course, on the numerical values used for the stochastic and expansion factors. With values other than 1.25 and 1.60, the results would be numerically different, but the principle would be the same.

Now, in the event of a demand contraction of the magnitude described above, it is likely that capacity would be contracted, and at lower capacity, higher values in column (6) would apply.

A second general point with respect to distribution is that capacity adjustments frequently occur by geographic areas, as, for example, with expansion of a distribution system into a new suburban subdivision. In the interest of marginal cost pricing, it is desirable to subdivide investments so as to approximate such differences. Thus, expansion of demand could produce full recovery of expenditures in one geographic area, while contraction of demand could lead to partial or no recovery in another.

Supply Capacity. Supply investment plays an ancillary role in most distribution systems, as compared with distribution investment. This follows, of course, from the importance of purchased gas as a supply source. To the extent that gas is purchased, it does not come from own supply.

Consistent with our earlier "simple supply" model (table 2.1), supply source #5 is own production, which constitutes one type of supply investment considered here. Two other types are: investment in storage and investment in transmission.

Whether the same arguments for overdesign apply to supply as to distribution is a matter to be decided on a case-by-case basis. The argument for overdesign is probably not applicable to own supply. The choice of supply is a choice of least cost. With as many sources of supply as there are, variations in demand can be easily accommodated. The same logic would seem applicable to storage, which is a form of supply. On the other hand, transmission appears to be an investment more like distribution from an economic point of view and hence could justifiably be subject to the same considerations discussed above for distribution.

But the argument for seasonal cost and price variation is as applicable to supply investments as it is to distribution investments. For this reason, preceding logic, as explained with the help of table 2.3, will be used to justify a seasonal k_m factor. The only difference in the case of supply investment is that no "overdesign" factor is included in k_m, except possibly in the case of transmission investment, as noted in the preceding paragraph.

Other Capacity. Investments not included in the categories of supply or distribution are divided into two classes: (1) those correlated with firm-wide gas sales and (2) those correlated with the number of customers. Only the former are relevant here. Included are administration and some maintenance investments.

No unique concepts are involved in finding marginal capacity costs for this group, and no special problems are foreseen. The complexities introduced by alternative supply sources are inapplicable. There would seem to be no reason for overdesign, except for possible lumpiness in growth, which should be smoothed out by the use of trends, estimated by statistical regression. Neither is it appropriate to allocate marginal "other" capacity costs to peak consumption. Investments of the type considered here are not correlated any more with peak than with off-peak sales, but rather with long term trends in size of the firm. Accordingly, the proper treatment is to calculate annual equivalents of investments in whatever amount is required and smooth the data by regression to get a trend line that gives marginal "other" capacity cost directly, assuming growth or at least static capacity. If there is a decline in progress, marginal "other" capacity is zero as long as capacity is excessive, but could take on a positive value if capacity is contracted at least as rapidly as sales.

Optimization Model

To the present point, costs have been discussed in three groups: (1) commodity, (2) demand, and (3) capacity. Capacity costs have been further subdivided into three categories: (1) supply, (2) distribution and (3) other capacity. The last two, "distribution" and "other", are incurred independently of one another and of supply costs; they present no further problems of analysis. Marginal distribution and other capacity costs have been identified and the conditions for their calculation described.

Supply costs, on the other hand, remain for comprehensive analysis. A simple supply model (table 2.1) was used, above, to show the method by which an optimal choice is made among sources having different commodity and demand costs. This was followed by a description of special commodity constraints. Then, capacity costs were analyzed and the concept of marginal capacity cost explained. Now, it remains to pull together these various aspects of the supply problem. That is done in the model shown in table 2.4.

TABLE 2.4

OPTIMIZATION WITH ADJUSTABLE CAPACITY
(all summations are over 12 months)

Min	$\Sigma CC1 \cdot SC1_m$	$\Sigma DC1 \cdot k_m \cdot SP1$	$\Sigma CC2 \cdot SV2_m$		$\Sigma DC2\ k_m \cdot SP2$	$\Sigma CC3 \cdot SC3_m$	$\Sigma DC3\ k \cdot SP3$	$\Sigma CC4 \cdot SC4_m$		$\Sigma CC5 \cdot SC5_m$		$\Sigma IC5\ k_m \cdot DSP5$	$\Sigma C1ST\ k_m \cdot DSTC$	ΣCS $(GINST_m$	$+ GOUST_m)$	$\Sigma CIPI\ k_m \cdot DPT1$	
(1)		SP1															$\leq$ LP1
(2)	$SC1_m$	$-N_m SP1$															$\leq$ 0
(3)					SP2												$\leq$ LP2
(4)				$SC2_m$	$-N_m SP2$												$\leq$ 0
(5)			$SV2_m$	$-SC2_m$													$\geq$ 0
(6)			$SV2_m$														$\geq 0.75N_m LP2$
(7)							SP3										$\leq$ LP3
(8)						$SC3_m$	$-N_m SP3$										$\leq$ 0
(9)									SP4								$\leq$ LP4
(10)								$SC4_m$	$-N_m SP4$								$\leq$ 0
(11)								$\Sigma SC4_m$									$\geq SH \cdot \Sigma DGMT_m$
(12)											SP5	-DSP5					$\leq$ LP5
(13)										$SC5_m$		$-N_m DSP5$					$\leq N_m LP5$
(14)													DSTC				$\geq$ -STCO
(15)														GINST			$\leq$ MAXINS
(16)															GOUST		$\leq$ MAXOUS
(17)																DPT1	$\geq DGDT_d - PT1$
(18)	$SC1_m$			$SC2_m$		$SC3_m$		$SC4_m$		$SC5_m$				GINST	GOUST		$\geq DGMT_m$
(19)		SP1			SP2		SP3		SP4			DSP5		$\frac{1}{N_m}$ GINST	$\frac{1}{N_m}$ GOUST		$\geq DGDT_d - LP5$

All variables $\geq$ 0.
GINST and $\overline{GOUST}$ defined in submodel table 2.5.
Source: Author's formulation

TABLE 2.4

(Continued)

NOMENCLATURE

CCi	Commodity charge, source i, \$/MMcf
CIPI	Annual equivalent \$/MMcf per peak day of DPT1
CIST	Annual equivalent \$/MMcf of DSTC
CS	Cost of storage, \$/MMcf
$DAYMAX_m$	Peak demand, MMcf on peak day of each month
DCi	Demand charge, source i, \$/MMcf on peak day
$DGDT_d$	Annual peak in daily demand MMcf/day
$DGMT_m$	Total commodity demanded, MMcf per month
DPT1	Increment of transmission #1 capacity, MMcf/peak day
DSP5	Increment of source #5 peak capacity MMcf/peak day
DSTC	Increment of storage capacity, MMcf
GINST	Gas into storage, MMcf per month
GOUST	Gas out of storage, MMcf per month
IC5	Annual equivalent \$/MMcf per peak day of DSP5
k_m	Multiplier to distribute annual equivalent charges to months. $\sum_1^{12} k_m = 1.0$; $k_m = 0$, $m = 1 \cdots 7$; $k_m \geq 0$, $m = 8, 9, 10, 11, 12$
LCi	Limit on annual MMcf, source i
LPi	Limit on peak MMcf per day, source i
MAXINS	Maximum rate of GINST
MAXOUS	Maximum rate of GOUST
N_m	Number of days in month m
PT1	Capacity of transmission #1, MMcf/day
SCi	Quantity of gas from source i, MMcf
SH	Share of demand assigned to source #4
SPi	Peak quantity of gas from source i, MMcf on peak day
SP5	Annual peak of source #5 capacity MMcf/day
STCO	Storage capacity, MMcf
$SV2_m$	Surrogate for $SC2_m$ to allow for "take or pay"

Index i: Sources $1 \cdots 5$

Subscript m: Months $1 \cdots 12$

Consider first the objective function shown in table 2.4. Commodity charges are identified in the same way as in table 2.2. Demand charges, however, appear in table 2.4 multiplied by k_m. The significance of k_m here is the same as previously described for supply capacity. Demand changes (for sources in use) are determined by gas purchases on the peak day of the year. The k_m factors spread the charges over the winter months in proportion to the long term probabilities of annual peak days occuring in those months.

Three supply investments are shown. Each is preceded by the letter D, for "delta", to distinguish the incremental cost of capacity from pre-existing (book) cost. It is only the incremental capacity on which expenditures need be made, and hence which is relevant for the optimization model. The three investments are: DSP5, increment of source 5 on peak; DSTC, increment of storage capacity; and DPT1, increment of peak transmission #1, as defined in Guldmann [6, pp. 107-110]. In each case, the incremental component enters the objective function multiplied by the k factor, defined in the same way as described above for distribution. The consequence, as noted above, is to spread investment costs over peak (winter) months, but not over other months. (k_m is defined as zero in nonwinter months, as previously noted.)

Finally, included in the objective function are increments of storage input, $GINST_m$, and storage output, $GOUST_m$, multiplied by variable costs of storage, CS. Storage is an integral part of the optimization model, but for convenience in exposition, and also because the storage submodel has been adequately explained elsewhere, it is given separately in table 2.5. See also the Source listed in table 2.5.

Consider next the constraints shown in table 2.4. The relation of commodity to demand charges is the same as previously set forth in table 2.2. A "take or pay" minimum is set by constraint (6) on source 2. Winter requirements charges can be included, to the extent desired, by allowing

TABLE 2.5

STORAGE INPUT AND OUTPUT

Maximum Delivery:	$GINST_m - A_{10} \sum_{\mu=1}^{m-1} (GINST_\mu - GOUST_\mu) - (A_{10}R_{min} + B_{10})DSTC \leq (A_{10}R_{min} + B_{10})STCO$
Maximum Withdrawal:	$GOUST_m - A_{20} \sum_{\mu=1}^{m=1} (GINST_\mu - GOUST_\mu) - (A_{20}R_{min} + B_{20})DSTC \leq (A_{20}R_{min} + B_{20})STCO$
Max. Saturation Rate:	$\sum_{\mu=1}^{m} (GINST_\mu - GOUST_\mu) - (R_{max} - R_{min})DSTC \leq (R_{max} - R_{min})STCO$
Min. Saturation Rate:	$\sum_{\mu=1}^{m} (GINST - GOUST) \geq 0$

Refer to Guldmann [6, pp. 102-107] for a description of the above equations and parameters.

the commodity charges to vary monthly, i.e. by setting the CCi higher in winter months than at other times of the year. A local supply constraint is applied in constraint (11). Constraints (12), (14) and (17) apply to the three previously identified incremental investments. Stochastic effects, as previously noted, are taken into account in the objective function via k_m multipliers.

The two constraints (18) and (19) assure adequate commodity and peak load supply, respectively. Constraint (19) takes the form of an equality on the yearly peak day only. GINST and GOUST are calculated as monthly averages; hence, nothing is lost by using their daily notes. Costs of storage, CS, include only compression costs and other costs associated with the injection and removal of gas from storage. It is assumed that carrying costs (interest on capital) for the variable component of gas in storage are exactly offset by appreciation of the value of gas in storage. This assumption makes it unnecessary to consider how long gas is held in storage. At peak demand, GINST would normally be zero. Limits are set for the sources by constraints (1), (3), (7), (9) and (12), respectively, though in the case of source #5, own production capacity, the limit may be raised by whatever new investment, DSP5, is required.

Constraint (18) takes the form of an equality (of different magnitude) each month. As previously noted, the model is set up for monthly total purchases, though optimization takes place over the period of a year. The formulation in table 2.4 makes unnecessary any constraints on total consumption by source. Thus, constraint (2) limits monthly consumption in relation to peak. Constraint (1) limits peak consumption of source #1. Together, these imply a total commodity limitation on source #1. The same structure of constraints applies to all other sources.

Marginal Costs. An optimal solution of the model in table 2.4 implies marginal costs, month by month. The supply curve faced by the gas distributor is a step function described by the sequence of sources in the order in which they are brought into the solution each month. In going from one step to the next, demand is implicitly assumed to be infinitely inelastic, within the relevant range.

To get marginal costs from the table 2.4 model, incrementalize $DGMT_m$ or $DGDT_d$ or both. The incremental change in the value of the objective function is marginal cost for either of these individually or for the two jointly, depending on how the incrementalization is designed.

A special problem arises when supply encounters the limits of all five sources. At this point, the model permits only one source, #5, via DSP5, to be expanded. This is because limits on peak purchases of gas from other sources are taken as given, while new investment in own production is unconstrained. In using the model to project what marginal cost would be beyond the present peak limits, it would be best to allow any of these limits to be extended and demand charges in the objective function to be adjusted to whatever new higher levels are appropriate for the extensions. This could be done in either of two ways, either (1) replace present LPi and DCi or (2) add new LPi and DCi as though new sources were introduced, leaving present constraints and variables as they stand. The two ways are not equivalent. The choice between them depends on whether any renegotiation of limits with suppliers affects the prices of previously committed supplies.

Consider the opposite situation, in which no new investments are called for but, on the contrary, there is underutilization of existing capacity. In this case, refer back to the principle illustrated in table 2.3, columns (5) and (6). Because of stochastic considerations, it is nevertheless appropriate to make some charge against already installed investments, at least until the k_m multipliers illustrated in table 2.3 reach zero. Such a charge would enter into marginal cost. It could be provided for in table 2.4 by removing LP5 from the right hand sides of (12), (13) and (19) and inserting a capacity term on the left hand side of the same constraints, with annualized cost times k_m in the objective function.

The model in table 2.4 differs from that given in Guldmann [6, chapter 4] in its treatment of investments and yearly demand charges. In both of these, the Guldmann model permits marginal cost to include the affected variable as many times during the year as demand permits. Here, in contrast, either of these terms can be counted only once, via the k_m mechanism. Marginal costs for these variables are, indeed, experienced only once a year.

A final comment pertains to storage. To whatever extent storage is used, GINST and/or GOUST take on nonzero values and CS is a part of marginal cost. But table 2.4 does not "tag" particular inputs to storage. Instead, and in keeping with Pyatt's reasoning (see preceding survey) marginal cost is always calculated at the price of whatever source is in use, regardless of whether storage is being expanded or contracted or neither.

Customer Costs

Customer costs include billing, metering and some small investment in facilities on the customer's property. Marginal customer ("service") costs are, then, incurred per unit of time for billing and metering, and are taken as a rental rate based on annual equivalent costs times a k_m multiplier defined for customer capacity costs in the same way as other capacity costs.

Customer costs are distinguished from commodity and capacity costs in that they are very little correlated with sales. It is convenient to think of the distributor as selling two commodities, natural gas and service. The same logic suggests that there should be two-part rates, one for marginal customer costs, the other for marginal commodity plus capacity costs.

Total Revenues - Total Cost Comparisons

Prices based on marginal costs, as defined above, may or may not provide a fair-return-on-fair-value, but are likely to do so even in the event that costs are not fully reflected in the k_m multipliers.

The reason is that marginal cost prices are set at the highest variable marginal costs, as explained at the beginning of this chapter (see "Meaning and Intent of Marginal Cost Pricing"). For this reason, resulting revenue generally makes a contribution to the coverage of fixed costs and may cover all fixed costs. With demand charges and annual equivalent charges of investments taken into acount, as is appropriate in our stochastic approach, the coverage of all fixed costs is even more likely. Indeed, excess revenue is as likely to result as deficient revenue.

Either way, adjustment of marginal cost prices to assure a total revenue goal is made possible by the Baumol-Bradford "inverse elasticity" rule. See equation (2.2), above, and related discussion of the Baumol-Bradford contribution. A difficulty in using the Baumol-Bradford formula is that elasticities of demand must be known by customer classes. It is unlikely that such elasticities are known at the level of the individual gas distribution company. When such information is lacking, national average elasticities may provide a satisfactory approximation.

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PART II

EMPIRICAL ANALYSES OF THE INVESTMENT AND OPERATING COSTS OF GAS DISTRIBUTION UTILITIES

CHAPTER 3

STATISTICAL MODELS OF COMMUNITY DISTRIBUTION PLANT COSTS

The purpose of this chapter is to present the results of various statistical analyses of distribution plant costs, based on community-level data obtained from six U.S. gas distribution utilities. These analyses extend and improve in many ways those presented in an earlier report.[1] Better and newer data have been obtained for some of the four utilities studied previously, in particular Long Island Lighting Company, and completely new data have been gathered for two new utilities, East Ohio Gas Company and Peoples Natural Gas (Iowa). In addition, the specifications of the cost models have been modified by introducing new variables related to customer size, which led to significant improvements in the explanatory, and thus predictive, power of these models.

In the first section of this chapter, the general structure of the new statistical models is discussed. The next section presents the results of the analysis applied to the 1979 historical (or book) value of the total distribution plant of Long Island Lighting Company (LILCO), Columbia Gas of Ohio, Inc. (CGO), Pacific Gas and Electric Company (PG&E), National Fuel Gas Distribution Corporation (NFGDC), East Ohio Gas Company (EOCG), and Peoples Natural Gas (PNG). The third section consists of a comparison of the previous models and a tentative explanation of the variations of the models' coefficients. The fourth section presents the results of more refined analyses applied to Pacific Gas and Electric Company and Peoples Natural Gas, for which data unavailable for the other utilities could be used. The fifth section presents the results of the same cost analysis applied to the 1979 historical values of the different components of the

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[1]J.-M. Guldmann, Marginal Cost Pricing for Gas Distribution Utilities: Preliminary Analyses and Models, NRRI, Report No. 80-12, November 1980 - Chapter 3: Econometric Modeling of Distribution Plant Costs.

distribution plants of Long Island Lighting Company and National Fuel Gas Distribution Corporation. Finally, the last section deals with the analysis of distribution plant increments between 1978 and 1979 for Pacific Gas and Electric Company. This dynamic analysis refers to mainly short-term plant costs, whereas the previous static analyses refer to long-term equilibrium plant costs.

General Considerations

The various problems involved in estimating and predicting distribution plant costs as well as the scarcity of available data have been discussed in the previously mentioned study, to which the reader is referred for more details. In this former study, the historical value of the distribution plant in service in a given community at the end of a given year, DPS, was related to market variables such as sales or numbers of customers during that same year, and both additive and multiplicative models were tested. For example, if RMCF, CMCF, and IMCF[2] are the residential, commercial, and industrial sales in that same community during the same year, then the tested models were:

$$DPS = a_0 + a_1*RMCF + a_2*CMCF + a_3*IMCF \quad (3.1)$$

$$DPS = b_0*RMCF^{b_1}*CMCF^{b_2}*IMCF^{b_3} \quad (3.2)$$

Additional variables were considered, such as population density (TEDN) and various degree-days measures, whenever available. The multiplicative model proved to be superior in all cases, pointing to (1) economies of scale and (2) the non-separability of the distribution plant costs incurred to serve the different sectoral markets of the utility. Although the regression fits turned out in general to be quite good, inter-utility variations in the models coefficients were noticeable, and were deemed to constitute an area for further analysis and research. It was in particular hypothesized that the variations in the sales elasticities (the coefficients b_1, b_2,

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[2] The most frequently used symbols are summarized in a glossary at the end of the chapter for convenient reference.

and b_3) might be due to variations in the customer sizes and in the load factors and peak loads characterizing the various communities served by the utility.

The approach presented here introduces customer sizes as new variables in the regression models. If RCUS, CCUS, and ICUS are the numbers of residential, commercial, and industrial customers in a given community, then the corresponding residential (RCUZ), commercial (CCUZ), and industrial (ICUZ) average customer sizes are defined as follows:

$$RCUZ = RMCF/RCUS \tag{3.3}$$

$$CCUZ = CMCF/CCUS \tag{3.4}$$

$$ICUZ = IMCF/ICUS \tag{3.5}$$

The average total customer size is defined as

$$TCUZ = TMCF/TCUS \tag{3.6}$$

where total sales, TMCF, and the total number of customers, TCUS, are defined as:

$$TMCF = RMCF + CMCF + IMCF \tag{3.7}$$

$$TCUS = RCUS + CCUS + ICUS \tag{3.8}$$

A two-sector disaggregation is also considered, where commercial and industrial sales, CIMCF, and number of customers, CICUS, are considered. In this case, the average commercial/industrial customer size is defined by:

$$CICUZ = CIMCF/CICUS \tag{3.9}$$

Customer size variables can be associated alternatively to sales or number of customers variables. The second combination appeared unsatisfactory in all cases (low R^2, wrong signs) and was therefore discarded. The first combination was analyzed with both additive and multiplicative specifications. In all cases, the multiplicative ones turned out to be superior, further confirming the economies of scale and joint costs properties revealed by the former study. The three models considered, corresponding to the three levels of market sector aggregation, are:

$$DPS = k_0 * TMCF^{\alpha_0} * TCUZ^{\beta_0} \quad (3.10)$$

$$DPS = k_1 * RMCF^{\alpha_1} * CIMCF^{\alpha_2} * RCUZ^{\beta_1} * CICUZ^{\beta_2} \quad (3.11)$$

$$DPS = k_2 * RMCF^{\alpha_1} * CMCF^{\alpha_2} * IMCF^{\alpha_3} * RCUZ^{\beta_1} * CCUZ^{\beta_2} * ICUZ^{\beta_3} \quad (3.12)$$

In models (3.10) - (3.12), the coefficients α_0, α_1, α_2, and α_3 are expected to be positive, whereas the coefficients β_0, β_1, β_2, and β_3 are expected to be negative. The sales variables characterize scale effects that are system-wide within the community, whereas the customer size variables characterize localized scale effects, at the level of the customers themselves. For example, the distribution plant portion related to large mains or compressor stations is probably better explained by the sales variables, whereas such items as services and meters are probably better explained by customer size variables.

Another important variable explaining variations in the distribution plant is the population density, TEDN, expressed as the ratio of the 1970 population of a community to its 1970 acreage. Most of these data were drawn from a 1970 Census report.[3] However, in the former study these uniform Census data, which characterize only those communities with a 1970 population of 2500 or more, were complemented by data from other sources (telephone calls to city officials, census tract data) in the case of Long Island Lighting Company and Columbia Gas of Ohio, Inc. It was suspected

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3 1970 Census of Population - Population of Places of 2500 or more - 1960 and 1970, Supplementary Report PC(S1)-26, U.S. Government Printing Office, Washington, D.C. (August 1972).

that the variations in the density elasticities, as well as the statistical insignificance of the density elasticity in the case of Columbia Gas of Ohio, Inc., might be partly due to poor data quality and data heterogenity. It was therefore decided to apply the regression analyses only to those communities with available Census density data.

The next section presents the results of the applications of models (3.10)-(3.12) to the six utilities, while adding the density, TEDN, as another independent variable. This analysis therefore only refers to communities with a population of 2500 or more in 1970.

Application of the Statistical Models to Communities of 2500 or More

Long Island Lighting Company

The results presented in this section pertain to 58 communities (as compared to 83 communities in the former study). In addition, instead of using the total plant-in-service data, the exact value of the distribution plant-in-service at the end of 1979 was calculated with disaggregated plant data provided by the New York State Board of Equalization and Assessment (NYSBEA). The LILCO gas distribution system is made up mostly of mains, services, and measuring and regulating station equipment. The detailed plant data are presented in appendix A.

Market data are available for the combined commercial and industrial sectors, and therefore only the aggregate and two-sector models are considered. The definitions and means and standard deviations of the different variables are presented in table 3.1.

The following multiplicative models were obtained:

$$DPS = 111.4007 * TMCF^{0.9617}_{(29.81)} * TCUZ^{-0.5371}_{(5.42)} * TEDN^{-0.2622}_{(3.88)} \quad (R^2 = 0.943) \qquad (3.13)$$

$$DPS = 262.82542 * RMCF^{0.6783}_{(8.85)} * CIMCF^{0.2626}_{(3.85)} * RCUZ^{-0.1756}_{(1.26)} * CICUZ^{-0.2789}_{(2.64)} * TEDN^{-0.2505}_{(4.00)} \quad (R^2 = 0.952) \qquad (3.14)$$

TABLE 3.1

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS - LONG ISLAND LIGHTING COMPANY

Variable	Definition	Mean	Standard Deviation
DPS	Distribution Plant in Service ($) - End of 1979	2,219,367	4,622,761
TMCF	Total Gas Sales (MCF) - 1979	663,598	1,384,375
RMCF	Residential Gas Sales (MCF) - 1979	390,906	813,865
CIMCF	Commercial/Industrial Gas Sales (MCF) - 1979	270,968	595,220
TCUS	Total Number of Customers - 1979	5,929	12,029
RCUS	Number of Residential Customers - 1979	5,462	11,106
CICUS	Number of Commercial/Industrial Customers - 1979	467	938
TCUZ	Total Customer Size (MCF) - 1979	150.338	210.903
RCUZ	Residential Customer Size (MCF) - 1979	81.648	50.724
CICUZ	Commercial/Industrial Customer Size (MCF) - 1979	703.106	1021.413
TEDN	Population Density (people per acre) - 1970	9.734	7.174

Source: Author's calculations

The performances of the above models, as measured by their R^2, are very good and superior to those achieved in the former study when the sales variables only were considered. However, part of the improvement is most likely also due to the use of the actual distribution plant value instead of the total plant value. The t-statistics, which are indicated in parenthesis below the corresponding coefficients, are generally very significant, except in the case of the residential customer size variable, RCUZ, probably because this variable does not vary significantly among the 58 communities considered. In all cases the coefficients have the expected sign and point to economies of scale both system-wide and at the localized level.

Columbia Gas of Ohio, Inc.

The results presented in this section pertain to 24 communities.[4] As in the former study, the dependent variable is the net plant in service, or rate base. This rate base is adjusted by a multiplier of 1.4642 to closely approximate the distribution plant in service, DPS. This is so because the ratio of total to net plants in service is equal to 1.512, and the ratio of distribution to total plants in service is equal to 0.9684. These ratios are assumed uniformly applicable to all the communities. Another problem is related to the fact that the data do not all pertain to the same year, hence the need to normalize gas sales to neutralize the short-term effects of weather variability. The impact of sales normalization will be analyzed later on, but in the present section the original raw sales data are used.

Market data are available for the three sectors. The definitions, means, and standard deviations of the different variables considered are presented in table 3.2.

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[4] Toledo, Lorain, Mansfield, Parma, Westlake, Bexley, Columbus, Gahanna, Grove City, Reynoldsburg, Upper Arlington, Westerville, Whitehall, Worthington, Granville, Springfield, Columbiana, Martins Ferry, Shadyside, Mingo Junction, Chillicothe, Middleport, New Boston, Portsmouth.

TABLE 3.2

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS - COLUMBIA GAS OF OHIO, INC.

Variable	Definition	Mean	Standard Deviation
DPS	Distribution Plant in Service ($) -Different Years	7,078,089	13,662,084
TMCF	Total Gas Sales (MCF) - Different Years	4,099,850	8,552,690
RMCF	Residential Gas Sales (MCF) - Different Years	2,994,690	6,070,650
CMCF	Commercial Gas Sales (MCF) - Different Years	1,022,300	2,339,940
IMCF	Industrial Gas Sales (MCF) - Different Years	82,860	170,750
CIMCF	Commercial/Industrial Gas Sales (MCF) - Different Years	1,105,150	2,503,530
TCUS	Total Number of Customers - Different Years	19,729	40,751
RCUS	Number of Residential Customers - Different Years	18,428	38,094
CCUS	Number of Commercial Customers - Different Years	1,227	2,404
ICUS	Number of Industrial Customers - Different Years	74	316
CICUS	Number of Commercial/Industrial Customers - Different Years	1,301	2,669
TCUZ	Total Customer Size (MCF) - Different Years	197.839	33.446
RCUZ	Residential Customer Size (MCF) - Different Years	159.718	23.141
CCUZ	Commercial Customer Size (MCF) - Different Years	688.059	263.549
ICUZ	Industrial Customer Size (MCF) - Different Years	5164.042	4,769.474
CICUZ	Commercial/Industrial Customer Size (MCF) - Different Years	742.513	267.197
TEDN	Population Density (people per acre)-1970	5.502	2.343

Source: Author's calculations

The three-sector model does not yield acceptable results (wrong signs for the industrial-sector variables), probably because of the small size of the industrial sector as compared to the other two sectors (see table 3.2). The following multiplicative models were obtained:

$$DPS = 358.45102 * TMCF^{0.9669}_{(54.33)} * TCUZ^{-0.8228}_{(5.38)} * TEDN^{-0.2301}_{(4.48)} \quad (R^2 = 0.994) \quad (3.15)$$

$$DPS = 452.81516 * RMCF^{0.8493}_{(12.41)} * CIMCF^{0.1324}_{(2.11)} * RCUZ^{-0.5835}_{(3.62)} * CICUZ^{-0.2066}_{(2.67)} * TEDN^{-0.2548}_{(4.43)} \quad (R^2 = 0.995) \quad (3.16)$$

The performances of the above models, as measured by their R^2, are excellent and superior to those achieved in the former study when the sales variables only were considered. In all cases, the coefficients have the expected sign, are highly significant, and point to economies of scale both system-wide and at the localized level. Also, the density variable has become significant, whereas it was not so in the former study, which would confirm the suspicion of poor quality data (most of the other density data were gathered through telephone calls to community officials).

Pacific Gas and Electric Company

The results presented in this section pertain to the 94 communities in PG&E service area with a population of 10,000 or more. Thus the data used here are the same as in the former study. The definitions, means, and standard deviations of the different variables considered are presented in table 3.3.

The following one-sector and two-sector models were obtained:

$$DPS = 1116.7936 * TMCF^{0.9282}_{(36.27)} * TCUZ^{-0.9108}_{(16.38)} * TEDN^{-0.2864}_{(7.42)} \quad (R^2 = 0.937) \quad (3.17)$$

TABLE 3.3

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS
PACIFIC GAS AND ELECTRIC COMPANY

Variable	Definition	Mean	Standard Deviation
DPS	Distribution Plant in Service ($) - End of 1979	7,384,459	10,184,724
TMCF	Total Gas Sales (MCF) - 1979	3,454,267	6,229,610
RMCF	Residential Gas Sales (MCF) - 1979	1,742,436	2,979,162
CMCF	Commercial Gas Sales (MCF) - 1979	969,256	2,586,112
IMCF	Industrial Gas Sales (MCF) - 1979	742,575	1,738,055
CIMCF	Commercial/Industrial Gas Sales (MCF) - 1979	1,711,831	4,205,098
TCUS	Total Number of Customers - 1979	21,139	36,008
RCUS	Number of Residential Customers - 1979	19,800	33,841
CCUS	Number of Commercial Customers - 1979	1,321	2,188
ICUS	Number of Industrial Customers - 1979	18	32
CICUS	Number of Commercial/Industrial Customers - 1979	1,339	2,218
TCUZ	Total Customer Size (MCF) - 1979	170.937	211.534
RCUZ	Residential Customer Size (MCF) - 1979	89.853	13.270
CCUZ	Commercial Customer Size (MCF) - 1979	934.194	2,940.374
ICUZ	Industrial Customer Size (MCF) - 1979	40,313.730	65,270.414
CICUZ	Commercial/Industrial Customer Size (MCF) - 1979	1,430.808	3,646.284
TEDN	Population Density (people per acre) - 1970	5.960	3.639

Source: Author's calculations

$$DPS = 390.50977 * RMCF^{0.7872}_{(12.59)} * CIMCF^{0.1435}_{(2.54)} * RCUZ^{-0.4416}_{(2.03)}$$

$$* CICUZ^{-0.1437}_{(2.51)} * TEDN^{-0.2746}_{(7.04)} \qquad (R^2 = 0.940) \qquad (3.18)$$

The performances of the above models, as measured by their R^2, are excellent and superior to those achieved in the former study when the sales variables only were considered. In all cases, the coefficients have the expected sign, are highly significant, and point to economies of scale both system-wide and at the localized level. It is also noticeable that the significance of the density variable in the one-sector model (3.17) is much higher than in the former study.

The three-sector model is not acceptable when including simultaneously industrial sales and customer size. When adding only industrial gas sales, the following model is obtained:

$$DPS = 325.9161 * RMCF^{0.7618}_{(12.56)} * CMCF^{0.1501}_{(2.63)} * IMCF^{0.0019}_{(0.29)}$$

$$* RCUZ^{-0.3598}_{(1.61)} * CCUZ^{-0.1407}_{(2.40)} * TEDN^{-0.2439}_{(6.80)}$$

$$(R^2 = 0.939) \qquad (3.19)$$

The R^2 of model (3.19) is very slightly inferior to the R^2 of model (3.18). Also, the t-statistics of the industrial sales variable IMCF is very low, and the corresponding regression coefficient cannot be deemed significantly different from zero. Thus it can be concluded that the three-sector model does not yield statistically acceptable results for PG&E, and further analyses should be restricted to the one- and two-sector models.

National Fuel Gas Distribution Corporation

The results presented in this section pertain to the 33 communities in NFGDC service area with a population of 2500 or more in 1970. The definitions, means, and standard deviations of the different variables considered are presented in table 3.4.

The commercial, industrial, and Public Authorities (P.A.) sectors have been combined into one sector, because three- and four-sector disaggregated models proved unsatisfactory (wrong coefficient signs). The results for the one- and two-sector models are presented below:

$$DPS = 462.89859 * TMCF^{0.9772}_{(12.92)} * TCUZ^{-0.9293}_{(5.15)} * TEDN^{-0.1856}_{(1.46)} \quad (R^2 = 0.894) \tag{3.20}$$

$$DPS = 142{,}279.68 * RMCF^{0.6863}_{(3.75)} * CIPMCF^{0.3401}_{(1.74)} * RCUZ^{-1.6755}_{(2.30)} * CIPCUZ^{-0.3168}_{(1.61)} * TEDN^{-0.2049}_{(1.56)} \quad (R^2 = 0.904) \tag{3.21}$$

The performances of the above models, as measured by their R^2, are superior to those achieved in the former study when the sales variables only were considered. In particular, it is noticeable that the significance of the density variable has been greatly increased in both models. In all cases, the coefficients have the expected signs, are moderately to highly significant, and point to economies of scale both system-wide and at the localized level.

East Ohio Gas Company

East Ohio Gas Company (EOGC) is a privately-owned distribution utility providing service to northeastern Ohio, including the metropolitan areas of Cleveland, Akron, and Youngstown.

The data in tables 3.5 and 3.6 provide an overview of EOGC gas market during 1979 and of its plant in service at the end of 1979. EOGC has a diversified market as well as a diversified plant in service, including sizable natural gas production, underground storage, and transmission investments. The distribution plant makes up for about 61% of the total

TABLE 3.4

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS
NATIONAL FUEL GAS DISTRIBUTION CORPORATION

Variable	Definition	Mean	Standard Deviation
DPS	Distribution Plant in Service ($) - End of 1979	2,217,766	4,818,647
TMCF	Total Gas Sales (MCF) - 1979	2,338,234	6,600,771
RMCF	Residential Gas Sales (MCF) - 1979	1,177,212	3,907,125
CIPMCF	Commercial/Industrial Gas Sales (MCF) - 1979	1,161,022	2,973,113
TCUS	Total Number of Customers - 1979	7,419	22,570
RCUS	Number of Residential Customers - 1979	7,045	21,571
CIPCUS	Number of Commercial/Industrial Customers - 1979	374	1,002
TCUZ	Total Customer Size (MCF) - 1979	293.948	209.704
RCUZ	Residential Customer Size (MCF) - 1979	157.234	15.119
CIPCUZ	Commercial/Industrial Customer Size (MCF) - 1979	2,747.253	5,628.147
TEDN	Population Density (people per acre) - 1970	6.053	4.527

Source: Author's calculations

TABLE 3.5

VOLUMES OF GAS SALES, NUMBERS OF CUSTOMERS, AND AVERAGE CUSTOMER SIZES
EAST OHIO GAS COMPANY

Sector	Gas Sales (MCF)	Number of Customers	Average Customer Size (MCF)
Residential	168,952,061	908,820	185.903
Commercial	67,348,944	53,252	1,264.721
Industrial	134,851,447	1,251	107,794.920
Total	371,152,452	963,323	385.283

Source: Annual Report of EOGC to the Public Utilities Commission of Ohio - 1979

TABLE 3.6

VALUE OF GAS PLANT IN SERVICE OF THE END OF 1979
EAST OHIO GAS COMPANY
(IN DOLLARS)

Plant Component	Value
Overview	
Natural Gas Production and Gathering	$ 84,787,754
Underground Storage	57,851,255
Transmission	104,632,461
Distribution	402,314,588
General	13,121,441
Total	$ 662,707,499
Distribution Plant	
Land and Land Rights	$ 2,146,005
Structures and Improvements	12,399,436
Mains	284,859,994
Measuring and Regulating Station Equipment - General	10,232,286
Services	57,990,081
Meters	29,737,665
House Regulators	2,248,383
Industrial Measuring and Regulating Station Equipment	$2,700,738

Source: Annual Report of EOGC to the Public Utilities Commission of Ohio - 1979 plant. Mains and services, in turn, make up for about 71% and 14% of the distribution plant. On the basis of the data in tables 3.5 and 3.6, the 1979 historical unit distribution costs per MCF and customer are the following:

- 1.084 \$/MCF, and
- 418 \$/customer.

The community-level data used in the EOGC analysis have been provided by EOGC's management, and pertain to 85 communities. These data include the distribution plant in service at the end of 1979, and the residential, commercial, and industrial sales and numbers of customers for 1979. These data are presented in appendix B. However, density data could be prepared for only 43 communities with a population of 2500 or more in 1970, and thus the present analysis is based on these 43 communities data. The definitions, means and standard deviations of the different variables considered are presented in table 3.7. The results for the three levels of aggregation are presented below:

$$DPS = 975.34639 * TMCF^{0.9308}_{(35.82)} * TCUZ^{-0.7754}_{(13.82)} * TEDN^{-0.0771}_{(1.80)} \quad (R^2 = 0.978) \qquad (3.22)$$

$$DPS = 678.00521 * RMCF^{0.7494}_{(14.47)} * CIMCF^{0.1649}_{(3.69)} * RCUZ^{-.5035}_{(2.00)} * CICUZ^{-0.0985}_{(1.77)} * TEDN^{-0.0672}_{(1.58)} \quad (R^2 = 0.981) \qquad (3.23)$$

$$DPS = 415.005002 * RMCF^{0.7401}_{(13.36)} * CMCF^{0.1445}_{(2.71)} * IMCF^{0.0182}_{(0.60)} * RCUZ^{-0.5455}_{(2.08)} * CCUZ^{-0.0126}_{(0.14)} * ICUZ^{-0.0098}_{(0.30)} * TEDN^{-0.0359}_{(0.83)} \quad (R^2 = 0.981) \qquad (3.24)$$

TABLE 3.7

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS
EAST OHIO GAS COMPANY

Variable	Definition	Mean	Standard Deviation
DPS	Distribution Plant in Service ($) - End of 1979	3,503,185	5,700,037
TMCF	Total Gas Sales (MCF) - 1979	3,638,460	6,519,002
RMCF	Residential Gas Sales (MCF) - 1979	1,457,492	2,784,227
CMCF	Commercial Gas Sales (MCF) - 1979	571,985	1,022,709
IMCF	Industrial Gas Sales (MCF) - 1979	1,608,984	3,366,640
CIMCF	Commercial/Industrial Gas Sales (MCF) - 1979	2,180,969	4,134,800
TCUS	Total Number of Customers - 1979	8,441	15,006
RCUS	Number of Residential Customers - 1979	7,918	14,157
CCUS	Number of Commercial Customers - 1979	511	843
ICUS	Number of Industrial Customers - 1979	11	16
CICUS	Number of Commercial/Industrial Customers - 1979	522	858
TCUZ	Total Customer Size (MCF) - 1979	399.245	280.573
RCUZ	Residential Customer Size (MCF) - 1979	173.551	18.024
CCUZ	Commercial Customer Size (MCF) - 1979	1,034.467	362.331
ICUZ	Industrial Customer Size (MCF) - 1979	150,155.953	404,013.461
CICUZ	Commercial/Industrial Customer Size (MCF) - 1979	3,468.004	3,410.048
TEDN	Population Density (people per acre)-1970	4.186	2.181

Source: Author's calculations

Although their coefficients display the expected signs, the significances of the variables IMCF, ICUZ, and CCUZ are very low in the case of model (3.24), which should not be retained for further analyses. On the other side, the one- and two-sector models yield very good results as measured by both their R^2 and the values of the t-statistics. Again, the results point to economies of scale both system-wide and at the localized level.

Peoples Natural Gas

Peoples Natural Gas (PNG), a division of Northern Natural Gas Company (renamed InterNorth, Inc. in 1979), serves communities in Kansas, Nebraska, Iowa, and Minnesota. The present analysis refers exclusively to the Iowa division, which makes up for about 47% of the PNG customers and 43% of its sales in 1979.

The data in tables 3.8 and 3.9 provide an overview of PNG gas market during 1979 and of its plant in service at the end of 1979 in the Iowa division.

TABLE 3.8

VOLUMES OF GAS SALES, NUMBERS OF CUSTOMERS, AND AVERAGE CUSTOMER SIZES
PEOPLES NATURAL GAS (IOWA)

Sector	Gas Sales (MCF)	Number of Customers	Average Customer Size (MCF)
Residential	15,421,436	98,892	155.942
Commercial	8,819,110	11,899	741.164
Industrial	15,923,054	324	49,145.228
Total	40,163,584	111,115	361.460

Source: Annual Report of Northern Natural Gas Company to the Federal Energy Regulatory Commisison - 1979

TABLE 3.9

VALUE OF GAS PLANT IN SERVICE OF THE END OF 1979

PEOPLES NATURAL GAS (IOWA)

(IN DOLLARS)

Plant Component	Value
Overview	
Intangible	$ 1,064,182
Manufactured Gas Production	4,022,001
Transmission	835,201
Distribution	52,970,857
General	2,686,232
Total	$ 61,578,473
Distribution Plant	
Land and Land Rights	$ 95,083
Structures and Improvements	1,188,660
Mains	24,136,563
Measuring and Regulating Station	
Equipment - General	1,188,293
Services	16,271,349
Meters	5,403,014
House Regulators	963,905
House Regulator Installations	1,016,966
Industrial Measuring & Regulating Station	438,384
Equipment	1,579,087
Other Equipment	689,553

Source: Annual Report of Northern Natural Gas Company to the Federal Energy Regulatory Commission - 1979

PNG distribution plant makes up for about 86% of the total plant. Mains and services, in turn, make up for about 46% and 31% of the distribution plant. On the basis of the data in tables 3.8 and 3.9, the 1979 historical unit distribution costs per MCF and customer are the following:

- 1.319 $/MCF, and
- 477 $/customer.

Market data for 109 communities have been drawn from the 1979 Annual Report of Northern Natural Gas Company to the Federal Energy Regulatory Commission, and have been complemented by disaggregated distribution plant data provided by the company's management. These data, which are presented in appendix C, are more detailed than those available for the other companies. For example, residential and commercial customers are divided into heating and non-heating customers, the number of industrial interruptible customers is known, and so are the 1979 peak-day total sendout and the normal and 1980 degree-day characteristics of each community. Also, the replacement (reproduction) value of the distribution plant is available for 96 communities. These additional data open the way for new statistical analyses that will be presented in the fourth section. In this section, the same models applied to the previous companies are considered, and fitted with the data of only 21 communities for which density could be computed. The definitions, means, and standard deviations of the variables considered are presented in table 3.10.

Satisfactory results were obtained for the one- and two-sector models only, with:

$$DPS = 105.86493 * TMCF^{1.0246}_{(18.53)} * TCUZ^{-0.7933}_{(3.64)} \quad (R^2 = 0.957) \qquad (3.25)$$

$$DPS = 1,739,607 * RMCF^{0.6186}_{(6.36)} * CIMCF^{0.5103}_{(4.30)} * RCUZ^{-2.1955}_{(5.05)} * CICUZ^{-0.5290}_{(2.92)} \quad (R^2 = 0.979) \qquad (3.26)$$

The performances of the above models, as measured by their R^2 and t-statistics, are very good. The coefficients have all the expected signs, and display economies of scale both system-wide and at the localized level, except in the case of the total sales variable, TMCF, which displays very slight diseconomies of scale.

TABLE 3.10

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS
PEOPLES NATURAL GAS (IOWA)

Variable	Definition	Means	Standard Deviation
DPS	Distribution Plant in Service ($) - End of 1979	1,871,923	3,115,200
TMCF	Total Gas Sales (MCF) - 1979	1,092,571	1,733,556
RMCF	Residential Gas Sales (MCF) - 1979	481,381	701,041
CMCF	Commercial Gas Sales (MCF) - 1979	284,952	389,316
IMCF	Industrial Gas Sales (MCF) - 1979	326,238	764,197
CIMCF	Commercial/Industrial Gas Sales (MCF) - 1979	611,190	1,114,269
TCUS	Total Number of Customers - 1979	3,611	5,239
RCUS	Number of Residential Customers - 1979	3,267	4,873
CCUS	Number of Commercial Customers - 1979	336	361
ICUS	Number of Industrial Customers - 1979	9	10
CICUS	Number of Commercial/Industrial Customers - 1979	345	370
TCUZ	Total Customer Size (MCF) - 1979	283.386	67.347
RCUZ	Residential Customer Size (MCF) - 1979	149.039	11.644
CCUZ	Commercial Customer Size (MCF) - 1979	738.063	195.278
ICUZ	Industrial Customer Size (MCF) - 1979	26,339.397	24,630.293
CICUZ	Commercial/Industrial Customer Size (MCF) - 1979	1,329.680	677.053
TEDN	Population Density (people per acre)-1970	2.615	1.326

Source: Author's calculations

Inter-Utility Comparative Analysis of Distribution Plant Cost Functions

The Approach

The statistical cost functions derived in the previous section for the six gas distribution utilities in the cases of the one- and two-sector levels of aggregation, all display striking similarities: (1) the multiplicative specification is appropriate in all cases, demonstrating the non-separability of the costs incurred in serving different market components, (2) economies of scale are nearly always present, both system-wide and at the localized level, and (3) the elasticities characterizing the residential sector (sales and customer size) are always greater than the corresponding ones for the commercial/industrial sector, reflecting, as expected, the impact of the lower load factors of residential customers, or, in other words, the impact of the residential customers higher peak usage for a given total annual usage. Despite the above general similarities, the regression coefficients of any given variable may vary, sometimes substantially, across the six utilities. The purpose of the present analysis is to try to explain the variations of these coefficients, leading hopefully to some generalized distribution plant cost function that might be applied to any gas distribution utility without having to gather community-level data and conduct the kind of statistical modeling described in the previous section.

Model Adjustment for Sales Normalization

Market gas requirements depend heavily upon weather, all other factors such as prices and economic activity remaining constant, and may vary significantly from an abnormally warm to an abnormally cold year. To neutralize weather effects, requirements are generally normalized, that is, adjusted to reflect the requirements in an average-weather year, defined as having a total number of degree-days equal to the average number of annual degree-days in the last 30 years. The normalization procedure is as follows. First, load equations are derived through regression analyses of monthly sales on monthly degree days. A typical load equation is:

$$DG_{im} = BL_i + SL_i * DD_m \qquad (3.27)$$

where DG_{im} is the gas requirement of market sector i during month m, BL_i the monthly base load requirement of sector i, independent of weather, SL_i the space-heating load per degree-day for sector i, and DD_m the number of degree-days during month m. If DDT_y and $\overline{DDT}$ are the numbers of degree-days for year y and for the average year, the corresponding requirements, DGT_{yi} and $\overline{DGT_i}$, are, for sector i:

$$DGT_{yi} = 12 * BL_i + SL_i * DDT_y \qquad (3.28)$$

$$\overline{DGT_i} = 12 * BL_i + SL_i + \overline{DDT} \qquad (3.29)$$

The actual requirements for year y must be multiplied by the following adjustment coefficient, AC_i, to yield the normalized requirements:

$$AC_i = \frac{\overline{DGT_i}}{DGT_{yi}} = \frac{1}{(DGT_{yi}/\overline{DGT_i})} = \frac{1}{\left[\dfrac{12 * BL_i}{\overline{DGT_i}}\right] + \left[\dfrac{SL_i * \overline{DDT}}{\overline{DGT_i}}\right] * \left[\dfrac{DDT_y}{\overline{DDT}}\right]} \qquad (3.30)$$

Normalized load shares are defined as follows:

$$BLS_i = 12 * BL_i/\overline{DGT_i} \quad : \quad \text{base load share} \qquad (3.31)$$

$$SLS_i = SL_i * DDT/DGT_i \quad : \quad \text{space-heating load share} \qquad (3.32)$$

with, of course:

$$BLS_i + SLS_i = 1 \qquad (3.33)$$

and the adjustment coefficient is finally

$$AC_i = 1/\left[BLS_i + SLS_i * \left(\frac{DDT_y}{\overline{DDT}}\right)\right] \qquad (3.34)$$

Load equations were developed for LILCO, PG&E, NFGDC, EOGC, and PNG, on the basis of the monthly sales and degree-days data included in the utilities 1979 Uniform Statistical Reports (USR) submitted to the American Gas Association (AGA). The load shares for Columbia Gas of Ohio, Inc. were provided directly by the company in an earlier study. The load shares, the 1979 numbers of degree-days, and the average annual numbers of degree-days are presented in table 3.11.

Some remarks must be made with respect to the data in table 3.11. First, note that the total market base load share of LILCO is larger than the same shares for the residential and commercial/industrial sectors. This inconsistent result is most likely attributable to a poor statistical fit, as measured by the R^2, as compared to the other companies regression models. Second, note that the PG&E degree-days measures have 70°F as a basis, while all the other measures refer to the 65°F basis. The 70°F basis was found to be more appropriate for PG&E service area climate and customers' behavior. Third, the results confirm logical expectations, namely that residential base load shares are low (generally, between 20% and 30%) and the industrial ones are high (generally, between 75% and 100%). There is greater variability of these shares in the commercial sector, reflecting the heterogeneous mix of this sector's customers.

While the adjustment coefficients need to be computed only for 1979 in the case of LILCO, PG&E, NFGDC, EOGC, and PNG, they need to be calculated also for the years 1976, 1977, and 1978 in the case of Columbia Gas of Ohio, Inc. (CGO) because the market data of the 24 communities considered refer to these different years (11 communities for 1976, 5 for 1977, 5 for 1978, and 3 for 1979). The actual numbers of degree-days for these years are: 6441 for 1976, 6196 for 1977, and 6648 for 1978. All the adjustment coefficients are presented in table 3.12.

The adjustment of the cost functions of all the companies, except CGO, is as follows. First, the adjusted sales and customer sizes are called ATMCF, ARMCF, ACIMCF, ATCUZ, ARCUZ, ACICUZ, with:

TABLE 3.11

LOAD SHARES, 1979 NUMBERS OF DEGREE-DAYS, AND AVERAGE ANNUAL NUMBERS OF DEGREE-DAYS

	LILCO	CGO	PG&E	NFGDC	EOGC	PNG
Residential Shares						
Base Load	0.417	0.261	0.258	0.264	0.227	0.308
Space-Heating Load	0.583	0.739	0.742	0.736	0.773	0.692
Commercial Shares						
Base Load	N.A.	0.326	0.754	0.262	0.218	0.444
Space-Heating Load	N.A.	0.674	0.246	0.738	0.782	0.556
Industrial Shares						
Base Load	N.A.	0.882	0.779	0.759	0.834	0.979
Space-Heating Load	N.A.	0.118	0.221	0.241	0.166	0.021
Commercial/Industrial Shares						
Base Load	0.438	0.685	0.757	0.584	0.633	0.789
Space-Heating Load	0.562	0.315	0.243	0.416	0.367	0.211
Total Market Shares						
Base Load	0.579	0.506	0.488	0.423	0.450	0.606
Space-Heating Load	0.421	0.494	0.512	0.577	0.550	0.394
1979 Degree-Days	4622	6286	3744	7026	6574	6818
Average Annual Degree Days	5137	5857	3998	6927	6258	6710

Source: Author's calculations.

$$ATMCF = ACT * TMCF \tag{3.35}$$

$$ARMCF = ACR * RMCF \tag{3.36}$$

$$ACIMCF = ACCI * CIMCF \tag{3.37}$$

$$ATCUZ = ACT * TCUZ \tag{3.38}$$

$$ARCUZ = ACR * RCUZ \tag{3.39}$$

$$ACICUZ = ACCI * CICUZ \tag{3.40}$$

where ACT, ACR, and ACCI are the adjustment coefficients for the total, residential, and commercial/industrial markets. The cost functions reflecting the effects of normalized sales and customer sizes are obtained by combining equations (3.11)-(3.12) and equations (3.35)-(3.40), with:

$$DPS = (k_0 ACT^{-(\alpha_0+\beta_0)}) * ATMCF^{\alpha_0} * ATCUZ^{\beta_0} \tag{3.41}$$

$$DPS = [k_1 ACR^{-(\alpha_1+\beta_1)} * ACCI^{-(\alpha_2+\beta_2)}] * ARMCF^{\alpha_1} * ACIMCF^{\alpha_2} * ARCUZ^{\beta_1} * ACICUZ^{\beta_2} \tag{3.42}$$

TABLE 3.12
ADJUSTMENT FACTORS FOR GAS REQUIREMENTS NORMALIZATION

		Sector				
Company	Year	Residential	Commercial	Industrial	Commercial/ Industrial	Total Market
LILCO	1979	1.062	N.A.	N.A.	1.060	1.044
PG&E	1979	1.049	1.016	1.014	1.016	1.034
NFGDC	1979	0.989	0.989	0.997	0.994	0.992
EOGC	1979	0.962	0.962	0.992	0.982	0.973
PNG	1979	0.989	0.991	0.999	0.997	0.994
CGO	1979	0.948	0.953	0.991	0.977	0.965
CGO	1978	0.909	0.917	0.984	0.959	0.937
CGO	1977	0.959	0.963	0.993	0.982	0.972
CGO	1976	0.931	0.937	0.988	0.969	0.953

Source: Author's calculations

Because of the multiplicative structure of the models, the exponents of the adjusted variables remain the same, and only the multiplicative constant is modified. However, the above procedure is not applicable to CGO because sales pertain to different years. Sales were therefore first normalized, and the regression analyses reapplied, with:

$$DPS = 361.23475 * ATMCF^{0.9678}_{(55.00)} * ATCUZ^{-0.8248}_{(5.43)} * TEDN^{-0.2302}_{(4.48)} \quad (R^2 = 0.994) \qquad (3.43)$$

$$DPS = 446.63782 * ARMCF^{0.8502}_{(12.50)} * ACIMCF^{0.1329}_{(2.13)} * ARCUZ^{-0.5789}_{(3.57)}$$

$$* ACICUZ^{-0.2084}_{(2.70)} * TEDN^{-0.2559}_{(4.44)} \quad (R^2 = 0.995) \qquad (3.44)$$

The comparison of equations (3.43)-(3.44) and (3.15)-(3.16) shows that CGO sales normalization brings very small changes in the cost functions, mainly at the level of the multiplicative constants. The final coefficients of the models are presented in tables 3.13 and 3.14.

TABLE 3.13
MODELS COEFFICIENTS IN THE CASE OF THE ONE-SECTOR AGGREGATION

Company	Multiplicative Constant	Sales Elasticity	Customer Size Elasticity	Density Elasticity
LILCO	113.459	0.9617	-0.5371	-0.2622
CGO	361.324	0.9678	-0.8248	-0.2302
PG&E	1,117.444	0.9282	-0.9108	-0.2864
NFGDC	462.715	0.9772	-0.9223	-0.1856
EOGC	589.978	0.9308	-0.7754	-0.0771
PNG	106.012	1.0246	-0.7933	-0.0000

Source: Author's calculations.

Note, in table 3.14, that the high residential customer size elasticities for NFGDC and PNG lead to very high multiplicative constants necessary to calibrate the functions.

TABLE 3.14

MODELS COEFFICIENTS IN THE CASE OF THE TWO-SECTOR AGGREGATION

Company	Multiplicative Constant	Residential Sales Elasticity	Commercial/ Industrial Sales Elasticity	Residential Customer Size Elasticity	Commercial/ Industrial Customer Size Elasticity	Density Elasticity
LILCO	270.65	0.6783	0.2625	-0.1756	-0.2789	-0.2505
CGO	446.64	0.8502	0.1329	-0.5789	-0.2084	-0.2559
PG&E	397.02	0.7872	0.1435	-0.4416	-0.1437	-0.2746
NFGDC	143,738.80	0.6863	0.3401	-1.6755	-0.3167	-0.2049
EOGC	434.50	0.7494	0.1649	-0.5035	-0.0985	-0.0672
PNG	1,709,431.80	0.6186	0.5103	-2.1955	-0.5290	-0.0000

Source: Author's calculations.

Explanatory Variables

Two categories of variables that may explain the variations of the elasticities presented in tables 3.13 and 3.14 have been considered: (1) load-related variables, and (2) market-size-related variables.

In addition to the space-heating and base load shares computed and presented in the previous section, different types of load factors have been computed. Given the typical monthly load equation (3.27), and given the maximum of the twelve, 30-year, average monthly degree-day values, DD_{max}, a monthly load factor can be computed, for sector i, as:

$$LFM_i = \frac{12 * BL_i + SL_i * \overline{DDT}}{12 * BL_i + SL_i * (12*\overline{DD}_{max})} = \frac{1}{BLS_i + SLS_i * \left[\frac{12 * \overline{DD}_{max}}{\overline{DDT}}\right]} \quad (3.45)$$

The above load factors, based on monthly requirements, do not account for intra-monthly load variations, and therefore constitute upper bounds on the load factors computed on the basis of daily or hourly flows. Such flows are not available at the sectoral level. However, each company indicates, in the Uniform Statistical Report, its peak-day sendout during the year. The 1979 peak-day sendouts, PDS_{79}, and the 1979 actual total annual sales, TS_{79}, have been used to compute a total market daily load factor, with:

$$LFD = TS_{79}/(365 * PDS_{79}) \quad (3.46)$$

It is important to note that LFD is based on the actual 1979 values of total annual and peak-day sendouts, and not on an average or quantile (probability) measure of these variables.[5] However, it is impossible to ascertain the range of variations of LFD over years without other years records. The monthly and daily load factors, and the maximum monthly degree-day values DD_{max}, are presented in table 3.15.

TABLE 3.15

LOAD FACTORS AND MAXIMUM MONTHLY DEGREE-DAYS

Company	Maximum Monthly Degree-Days DD_{max}	Monthly Load Factors: Residential Market	Commercial Industrial Market	Total Market	Daily Load Factor (1979) Total Market
LILCO	1029	0.550	0.559	0.628	0.354
CGO	1150	0.499	0.701	0.599	0.425
PG&E	692	0.556	0.793	0.645	0.494
NFGDC	1280	0.527	0.664	0.587	0.436
EOGC	1208	0.496	0.674	0.580	0.404
PNG	1414	0.486	0.756	0.624	0.556

Source: Author's calculations.

In addition to or instead of the load factors, it is possible that market size has an impact on the elasticities values. Such an influence cannot be measured within a given service area because the model tested explicitly assumes constant elasticities. However, if such an influence does exist, then the inter-utility variations might be explained by size parameters characterizing the whole service area. The mean values, adjusted for normal weather, of total and sectoral sales and customer sizes for the sets of communities considered for each utility have been selected as possible explanatory variables. They are presented in table 3.16.

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[5] Based on the observed distribution of daily temperatures (or degree-days), a quantile measure of the daily sendout is estimated by the gas utility and used to determine the level of the contract demand with its supplier(s). This measure corresponds to a very low probability of occurrence. Using such a measure (unfortunately unavailable) would lead to the calculation of a quantile measure of the load factor, or "contractual" load factor, that would, most likely, be lower than LFD.

The Results

The various dependent variables were regressed on the independent ones with both additive and multiplicative specifications. Only simple regression models with one independent variable were considered, mainly because of the small size (6) of the sample. In general, the load shares and monthly load factors turned out to be higly insignificant in explaining the variations of the independent variables, possibly because the monthly aggregation of the data hides a significant intra-monthly variability. Such an explanation is supported by the fact that the daily load factor LFD turns out to be a satisfactory explanatory variable, as discussed below. The best fits are presented below for the one- and two-sector models.

a. Case of the One-Sector Model

The relevant variables are noted as follows:

YTF: total sales elasticity
YTZ: total customer size elasticity
YTD: population density elasticity
XTF: average total sales
XLFD: daily load factor
XD: average population density

The total sales elasticity is best explained by the average total sales. The additive and multiplicative models are equivalent from the viewpoint of the residual sum of squares criterion, with:

$$YTF = 1.006498 - \underset{(1.64)}{0.1658818} * 10^{-17} * XTF \qquad (R^2 = 0.403) \quad (3.47)$$

$$YTF = 1.4504762 * XTF^{\underset{(1.33)}{-0.028036}} \qquad (R^2 = 0.306) \quad (3.48)$$

The above results would point out that the larger the market (XTF) the lower the elasticity (YTF), and thus the larger the system-wide economies

TABLE 3.16

AVERAGE MARKET SIZE PARAMETERS FOR THE SIX UTILITIES

Company	Residential Sales (MCF)	Commercial/ Industrial Sales (MCF)	Total Sales (MCF)	Residential Customer Size (MCF)	Commercial/ Industrial Customer Size (MCF)	Total Customer Size (MCF)	Population Density (people/acre)
LILCO	415,169	304,293	692,843	86.716	745.088	156.963	9.734
CGO	2,749,610	1,025,960	3,775,570	149.218	700.241	185.334	5.502
PG&E	1,827,815	1,739,220	3,571,712	94.256	1,453.701	176.749	5.960
NFGDC	1,164,969	1,154,172	2,319,060	155.590	2,731.041	291.540	6.053
EOGC	1,402,734	2,141,275	3,540,149	167.463	3,404.882	388.219	4.186
PNG	476,086	613,004	1,092,571	147.361	1,025.545	283.386	2.615

Source: Author's calculations.

of scale. Such increasing economies of scale are most likely due to the wider use and therefore lower unit cost of fixed equipment.

The total customer size elasticity is best explained by the daily load factor. The additive and multiplicative models are equivalent with the residual sum of squares criterion, with:

$$YTZ = -0.3023144 - \underset{(1.35)}{1.108334} * XLFD \qquad (R^2 = 0.312) \qquad (3.49)$$

$$YTZ = -1.5163175 * XLFD^{\underset{(1.66)}{0.80489}} \qquad (R^2 = 0.408) \qquad (3.50)$$

The above results would point out that the larger the load factor (XLFD), the lower the elasticity (YTZ), and thus the larger the localized economies of scale. This result is consistent with the fact that a higher load factor leads to a better use of fixed capacity, hence to a lower cost per unit of annual usage.

The density elasticity is solely related to the average density. The additive and multiplicative models are equivalent, with:

$$YTD = 0.0391091 - \underset{(2.60)}{0.037482} * XD \qquad (R^2 = 0.628) \qquad (3.51)$$

$$YTD = -0.258 * 10^{-5} * XD^{\underset{(3.11)}{5.99444}} \qquad (R^2 = 0.707) \qquad (3.52)$$

The above results would point out that the higher the average density the larger, in absolute terms, the elasticity. In other words, the impact of a marginal gain in density is higher in the higher density range. Such a result could be expected: in highly dense urban areas, the same pipeline layout may serve the same buildings pattern, whatever their number of stories and the number of gas customers they contain, hence the significant economies of scale achieved if additional stories are considered.

b. Case of the Two-Sector Model

The relevant variables are noted as follows:

YRF: residential sales elasticity

YCF: commercial/industrial sales elasticity

YRZ: residential customer size elasticity

YCZ: commercial/industrial customer size elasticity

YSD: population density elasticity

XRF: average residential sales

XCF: average commercial/industrial sales

XRZ: average residential customer size

XCZ: average commercial/industrial customer size

XLFD: daily load factor

XD: average population density

The residential sales elasticity is best explained by the average residential sales. The multiplicative and additive models are statistically equivalent, with:

$$YRF = 0.60667 + \underset{(6.17)}{0.9077469} * 10^{-7} * XRF \qquad (R^2 = 0.905) \qquad (3.53)$$

$$YRF = 0.1046 * XRF^{\underset{(4.29)}{0.13924}} \qquad (R^2 = 0.821) \qquad (3.54)$$

The above results would point out that the larger the residential market the lower the rate of economies of scale. Such a sectoral effect is in contradiction with the same result pertaining to the total market (equations 3.47 and 3.48). However, the residential market effect is compensated by the opposite effect in the commercial/industrial sector, for which the following equivalent models have been obtained:

$$YCF = 0.39942 - \underset{(1.36)}{0.120743} * 10^{-6} * XCF \qquad (R^2 = 0.318) \qquad (3.55)$$

$$YCF = 56.5957 * XCF^{\underset{(1.26)}{-0.39986}} \qquad (R^2 = 0.284) \qquad (3.56)$$

The customer-size-related elasticities, YRZ and YCZ, are best explained by the daily load factor, XLFD. In the case of the residential sector, the following equivalent models have been obtained:

$$YRZ = 2.65454 - \underset{(2.00)}{8.058268} * XLFD \qquad (R^2 = 0.500) \tag{3.57}$$

$$YRZ = -23.7464 * XLFD^{\underset{(2.20)}{4.3633}} \qquad (R^2 = 0.548) \tag{3.58}$$

The additive model only is appropriate in the ease of the commercial/industrial sector with:

$$YCZ = 0.2602 - \underset{(1.29)}{1.175655} * XLFD \qquad (R^2 = 0.295) \tag{3.59}$$

The above results are in agreement with those obtained in the case of the one-sector model. They probably would have been much better if sectoral daily load factors had been available.

Finally, as for the one-sector model, the density elasticity is best explained by the average density, with the following equivalent models:

$$YSD = 0.03051 - \underset{(2.31)}{0.036307} * XD \qquad (R^2 = 0.572) \tag{3.60}$$

$$YSD = -0.249 * 10^{-5} * XD^{\underset{(3.11)}{6.01187}} \qquad (R^2 = 0.708) \tag{3.61}$$

In conclusion, the results obtained in the two-sector case are in agreement with those obtained in the one-sector case. These results may be summarized as follows:

1. Sectoral sales elasticities are sensitive to sectoral market sizes, but in different ways: higher economies of scale are achieved with larger commercial/industrial markets, and the reverse is true for the residential market.
2. Higher economies of scale are achieved at the local level with higher daily load factors.
3. Higher economies of scale are achieved with higher population densities.

In view of the small sample (6 companies) used, a generalized usuage of the previous equations might be somewhat hazardous. Nevertheless, they clearly point to interesting trends, which should be confirmed by a wider analysis pertaining to more companies.

Extensions of the Distribution Plant Cost Functions

The availability of additional, more precise data for two utilities--Pacific Gas and Electric Company and Peoples Natural Gas--made it possible to extend in various ways the models presented in the previous sections and to test more complex specifications. These extensions are presented in this section.

Pacific Gas and Electric Company

a. Sales Normalization Impact Analysis

PG&E service area is divided into 13 divisions: Coast Valley, Colgate, De Sabla, Drum, East Bay, Humboldt, North Bay, Sacramento, San Francisco, San Joaquin, San Jose, Shasta, and Stockton. Specific variables were computed on the basis of division-level data and assigned to the communities included in the corresponding divisions.

Monthly load data for 1979, provided by PG&E for the specific purposes of this study, were regressed on the corresponding 1979 monthly degree-days (with 70°F as a basis). The resulting load equations are presented in appendix D. Given the 30-year average values for the monthly and annual degree-days, the following variables were computed: base load and space-heating load shares, sales normalization adjustment coefficients for 1979, and normalized monthly load factors. These calculations follow the procedure developed in the previous section. The various degree-day data and the values of the above variables are also presented in appendix D.

Using the same notations for normalized sales and customer sizes as in section 3, the one- and two-sector adjusted models are:

$$DPS = 1251.5349 * ATMCF^{0.9127}_{(36.18)} * ATCUZ^{-0.8979}_{(15.89)} * TEDN^{-0.2554}_{(7.24)} \qquad (R^2 = 0.936) \qquad (3.62)$$

$$DPS = 350.64629 * ARMCF^{0.7575}_{(11.80)} * ACIMCF^{0.1593}_{(2.70)} * ARCUZ^{-0.3630}_{(1.60)} * ACICUZ^{-0.1613}_{(2.72)} * TEDN^{-0.2465}_{(6.98)} \qquad (R^2 = 0.940) \qquad (3.63)$$

Unsatisfactory results were obtained for the three-sector model. The comparison of the sales adjusted models (3.62)-(3.63) with the original models (3.17)-(3.18) shows that using normalized sales at the division/community level does not improve the statistical fit (similar R^2's) and that the elasticity coefficients are only very slightly modified.

b. Degree-Days Impact Analysis

In this section, the normalized sales and customer size variables are complemented by the normal (30-year average) maximum monthly degree-days, DDM. The following fits were obtained for the one- and two-sector models:

$$DPS = 16.310613 * ATMCF^{0.9157}_{(37.08)} * ATCUZ^{-0.8979}_{(16.19)} * TEDN^{-0.2368}_{(6.68)} * DDM^{0.6529}_{(2.27)} \qquad (R^2 = 0.940) \qquad (3.64)$$

$$DPS = 0.09798705 * ARMCF^{0.7492}_{(12.37)} * ACIMCF^{0.1773}_{(3.17)} * ARCUZ^{-0.0878}_{(0.38)}$$

$$*ACICUZ^{-0.1778}_{(3.17)} * TEDN^{-0.2132}_{(6.16)} * DDM^{1.0490}_{(3.47)}$$

$$(R^2 = 0.947) \qquad (3.65)$$

The above models slightly improve over models (3.62)-(3.63): their R^2's are higher, DDM has the expected sign, and it is statistically significant. One drawback is the low significance of ARCUZ in model (3.65). Accordingly, the two-sector model was recalibrated without ARCUZ, leading to:

$$DPS = 0.05526552 * ARMCF^{0.7337}_{(16.34)} * ACIMCF^{0.1927}_{(4.98)} * ACICUZ^{-0.1908}_{(4.28)}$$

$$* TEDN^{-0.2097}_{(6.31)} * DDM^{1.0893}_{(3.86)} \qquad (R^2 = 0.947) \qquad (3.66)$$

Model (3.66) is clearly more satisfactory than model (3.65) because all its coefficients have a high level of significance. Their R^2's turn out to be the same when rounded up to three decimal digits.

c. Load Structure Impact Analysis

The analysis of the impacts of the space-heating load shares and load factors has been carried for both the one- and two-sector models.

In the case of the one-sector model, the load share variable appeared inappropriate, having the wrong sign. On the other hand, the total market monthly load factor, LFTM, turned out to have the expected negative sign, that is, the higher the load factor the lower the cost, all other things remaining equal. The following models, with and without the degree-day variable DDM, were obtained:

$$DPS = 1001.602 * ATMCF^{0.9121}_{(36.61)} * ATCUZ^{-0.8879}_{(15.77)} * TEDN^{-0.2429}_{(6.84)}$$

$$* LFTM^{-0.3843}_{(1.81)} \qquad (R^2 = 0.938) \qquad (3.67)$$

$$DPS = 35.561977 * ATMCF^{0.9148}_{(36.92)} * ATCUZ^{-0.8929}_{(15.95)} * TEDN^{-0.2344}_{(6.57)} * DDM^{0.5190}_{(1.55)} * LFTM^{-0.1911}_{(0.78)} \quad (R^2 = 0.941) \qquad (3.68)$$

The significance of LFTM in model (3.68) is rather low, most likely because of its significant correlation (-0.53) with the degree-day variable DDM, which turns out to be more powerful in explaining cost variations than the load factor variable. Model (3.64) presented in the previous section can be considered superior to the above two models.

In the case of the two-sector model, the load share variables had again to be discarded because they turned out to have the wrong sign. However, the monthly sectoral load factors - LFRM for the residential sector and LFCIM for the commercial/industrial sector - turned out to have the expected sign. The following models, with and without the degree-day variable DDM, were obtained:

$$DPS = 71.316948 * ARMCF^{0.7412}_{(11.96)} * ACIMCF^{0.1785}_{(3.12)} * ARCUZ^{-0.1021}_{(0.44)} * ACICUZ^{-0.1769}_{(3.06)} * LFRM^{-0.7248}_{(2.97)} * LFCIM^{-0.1624}_{(0.97)} * TEDN^{-0.2147}_{(6.12)} \quad (R^2 = 0.946) \qquad (3.69)$$

$$DPS = 0.50666563 * ARMCF^{0.7434}_{(12.18)} * ACIMCF^{0.1817}_{(3.22)} * ARCUZ^{-0.0205}_{(0.09)} * ACICUZ^{-0.1802}_{(3.17)} * LFRM^{-0.4117}_{(1.42)} * LFCIM^{-0.1185}_{(0.71)} * DDM^{0.7167}_{(1.94)} * TEDN^{-0.2050}_{(5.88)} \quad (R^2 = 0.948) \qquad (3.70)$$

The significance of LFCIM is relatively weak in both models but remains stable. On the other hand, the significance of ARCUZ, already quite low in model (3.69), further decreases in model (3.70) when the degree-day variable DDM is added. This result is most likely due to multicollinearity among the variables ARCUZ, LFRM, and DDM, and this feature was already noted in the case of model (3.65). The model was recomputed without the variables ARCUZ and LFCIM, leading to a much more satisfactory fit:

$$DPS = 0.37455456 * ARMCF^{0.7325}_{(16.43)} * ACIMCF^{0.1929}_{(5.02)} * ACICUZ^{-0.1920}_{(4.34)} * LFRM^{-0.4227}_{(1.49)} * DDM^{0.7646}_{(2.15)} * TEDN^{-0.2051}_{(6.18)} \quad (R^2 = 0.948) \qquad (3.71)$$

Peoples Natural Gas

a. Replacement Costs Analysis

The replacement (or reproduction) value, at the end of 1979, of the total distribution plant has been provided by PNG for 96 communities. This value has been computed by applying the appropriate Handy-Whitman index to the different plant vintages that make up the distribution plant. If the distribution plant vintages are distributed similarily, percentage-wise, across all the communities, then the regression models obtained by using historical and replacement costs should only differ with respect to the multiplicative constants, the ratio of which should be equal to the constant replacement multiplier. While the above assumption is unlikely to be exactly verified in most cases because of the different historical evolutions of the distribution plant (and of the gas customers market) in the different communities of a utility's service area, the exact deviation is generally very difficult to assess. To do so, a complete analysis of community plant vintages would be necessary. However, many utilities do not keep such records at the community level, thus precluding such analysis.

In a first stage, the analysis was applied to the 21 communities for which density data are available. The average replacement value of the distribution plant for these communities is \$4,915,069. The corresponding historical value is \$1,871,923, leading to a replacement ratio of 2.6257 (= 4,915,069/1,871,923). The replacement multiplier defined for each of the 96 communities varies between 1.700 and 5.912, with a mean of 2.631 and a standard deviation of 0.688. Although the variability of this parameter is not very great, it clearly shows that the vintage structure of the distribution plant across communities is not homogeneous. The replacement value of the distribution plant is noted RDPS. The following models were obtained for the three levels of sector aggregation:

$$RDPS = 299.6227 * TMCF^{1.0762}_{(36.30)} * TCUZ^{-0.9338}_{(7.98)} \quad (R^2 = 0.988) \qquad (3.72)$$

$$RDPS = 22{,}600.335 * RMCF^{0.8442}_{(13.21)} * CIMCF^{0.2672}_{(3.43)} * RCUZ^{-1.4913}_{(5.23)} * CICUZ^{-0.2486}_{(2.09)} \quad (R^2 = 0.991) \qquad (3.73)$$

$$RDPS = 58{,}449.008 * RMCF^{0.7010}_{(6.12)} * CMCF^{0.4169}_{(2.71)} * IMCF^{0.0402}_{(0.71)} * RCUZ^{-1.5407}_{(4.76)} * CCUZ^{-0.3266}_{(1.50)} * ICUZ^{-0.0665}_{(1.11)} \quad (R^2 = 0.992) \qquad (3.74)$$

The comparison of models (3.72) - (3.73) with the historical cost models (3.25) - (3.26) shows that (1) the R^2's with replacement costs are higher, (2) the regression coefficients have higher t-statistics, and (3) there are significant changes in the regression coefficients values, in particular for the two-sector model. As in the previous analyses, the density variable turned out to be insignificant and was discarded. Notable is also the fact that an acceptable three-sector model was obtained, where all the coefficients display the correct sign and expected relative magnitudes, with, however, rather low significances for the industrial-sector related variables.

In view of the insignificant role of the density variable, the basic sample was extended to the 96 communities with replacement plant values, and the previous analysis was applied to this extended sample. The means and standard deviations of the variables considered are presented in table 3.17.

The following models were obtained for the three levels of aggregation.

One-Sector Models

$$DPS = 201.16692 * TMCF^{1.0011}_{(44.48)} * TCUZ^{-0.8655}_{(12.89)} \quad (R^2 = 0.955) \qquad (3.75)$$

$$RDPS = 427.30883 * TMCF^{1.0313}_{(47.08)} * TCUZ^{-0.8947}_{(13.69)} \quad (R^2 = 0.960) \qquad (3.76)$$

Two-Sector Models

$$DPS = 5,925.6875 * RMCF^{0.6965}_{(9.04)} * CIMCF^{0.3239}_{(3.63)} * RCUZ^{-1.1695}_{(4.21)} * CICUZ^{-0.2699}_{(2.62)} \quad (R^2 = 0.957) \qquad (3.77)$$

$$RDPS = 696.93002 * RMCF^{0.6946}_{(9.28)} * CIMCF^{0.3638}_{(4.20)} * RCUZ^{-0.5551}_{(2.06)} * CICUZ^{-0.3300}_{(3.30)} \quad (R^2 = 0.961) \qquad (3.78)$$

Three-Sector Models

$$DPS = 8,159.4986 * RMCF^{0.6538}_{(8.17)} * CMCF^{0.3385}_{(3.64)} * IMCF^{0.0792}_{(1.53)} \; RCUZ^{-1.1135}_{(3.92)} * CCUZ^{-0.3135}_{(2.33)} * ICUZ^{-0.0846}_{(1.55)} \quad (R^2 = 0.957) \qquad (3.79)$$

TABLE 3.17

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS - EXTENDED PNG SAMPLE

Variable	Definition	Mean	Standard Deviation
RDPS	Replacement Value of the Distribution Plant ($) - End of 1979	1,395,992	4,244,396
DPS	Historical Value of the Distribution Plant ($) - End of 1979	530,150	1,600,733
TMCF	Total Gas Sales (MCF) - 1979	310,509	899,993
RMCF	Residential Gas Sales (MCF) - 1979	142,218	370,072
CMCF	Commercial Gas Sales (MCF) - 1979	82,781	209,418
IMCF	Industrial Gas Sales (MCF) - 1979	85,510	375,755
CIMCF	Commercial /Industrial Gas Sales (MCF) - 1979	168,292	564,950
TCUZ	Total Customer Size (MCF) - 1979	280.414	246.607
RCUZ	Residential Customer Size (MCF) - 1979	148.970	14.379
CCUZ	Commercial Customer Size (MCF) - 1979	509.357	206.407
ICUZ	Industrial Customer Size (MCF) - 1979	13,513.21	25,439.163
CICUZ	Commercial/Industrial Customer Size (MCF) - 1979	992.240	1,192.688

Source: Author's calculations

$$RDPS = 508.02416 * RMCF^{0.6258}_{(8.40)} * CMCF^{0.3721}_{(4.30)} * IMCF^{0.1133}_{(2.36)}$$
$$* RCUZ^{-0.4381}_{(1.66)} * CCUZ^{-0.2608}_{(2.08)} * ICUZ^{-0.1256}_{(2.48)}$$
$$(R^2 = 0.965) \qquad (3.80)$$

In general, the replacement cost models' performances are better, although by a narrow margin, than those of the historical cost models, as measured both by the R^2 and the t-statistics. It should be noted that the sales elasticities are very close in both models, and the major difference lies with the residential customer size elasticity. The impact of this variable is less in the case of the replacement cost models.

b. Load Factor and Degree-Day Impact Analysis

The 1979 maximum day sendout and total sales were used to compute the 1979 daily load factor for 88 communities for which the maximum day sendout is available. This load factor varies between 0.100 and 0.709, with a mean of 0.354 and a standard deviation of 0.112. In addition, the normal (30-year average) values of the annual and maximum monthly numbers of degree-days were also considered as explanatory variables. (See appendix C) The normal annual number of degree-days varies between 6218 and 7770, with a mean of 7221 and a standard deviation fo 475. The normal maximum monthly number of degree-days varies between 1327 and 1559, with a mean of 1479 and a standard deviation of 68.

The above variables turned out to be of no use in further explaining the cost variations of the distribution plant. Combined with the sales and customer size variables, they turned out to have the wrong sign in most cases. Such disappointing results are probably due to (1) the possible non- representativity of the year 1979 for estimating design peak day sendouts and load factors, and (2) the narrow variability of the degree-day variables, which points to a rather homogeneous service area climatologically.

c. Market Segmentation Impact Analysis

The available detailed data of PNG made it possible to further disaggregate the residential, commercial, and industrial markets, and to test whether the corresponding disaggregated market variables do further explain the variations of the value of the distribution plant. The following variables were considered:

RPT: the saturation rate of the residential gas market, that varies betweeen 27% and 100%, with a mean of 74.33% and a standard deviation of 14.93%;

RMCFH: the residential gas consumption for heating purposes, with a mean of 140,760 MCF, and a standard deviation of 365,778 MCF;

RMCFN: the residential gas consumption for non-heating purposes, with a mean of 1,457 MCF, and a standard deviation of 6,226 MCF;

RCUZH: the average residential heating-customer size, that varies between 111.11 MCF and 188.89 MCF, with a mean of 154.008 MCF, and a standard deviation of 12.953 MCF;

RCUZN: the average residential non-heating-customer size, that varies between 0 MCF and 100 MCF, with a mean of 28.215 MCF, and a standard deviation of 16.362 MCF:

SHC: the share of heating commercial customers in the total commercial market; this share varies between 83.10% and 100.00%, with a mean of 96.59% and a standard deviation of 4.26%;

SII: the share of industrial interruptible customers in the total industrial market; this share varies between 0% and 100%, with a mean of 56.30% and a standard deviation of 43.50%.

In a first step, the analysis focused on the residential market. The general features of the results are that: (1) the dichotomy of the residential market between heating and non-heating customers yields very good results in terms of the regression coefficients values; (2) the size of the heating customer becomes insignificant; and (3) the market saturation rate is significant, but its positive sign is a matter of further analysis. The best models are presented below for the two-and three-sector conventional disaggregations, and with/without the saturation rate variable RPT.

Two-Sector Models

$$RDPS = 47.926664 * RMCFH^{0.7026}_{(9.42)} * RMCFN^{0.0571}_{(2.15)} * CIMCF^{0.2802}_{(2.99)} * RCUZN^{-0.0410}_{(0.96)} * CICUZ^{-0.2478}_{(2.33)} \quad (R^2 = 0.962) \quad (3.81)$$

$$RDPS = 24.318442 * RMCFH^{0.6894}_{(9.26)} * RMCFN^{0.0587}_{(2.23)} * CIMCF^{0.2872}_{(3.08)} * RCUZN^{-0.0432}_{(1.02)} * CICUZ^{-0.2548}_{(2.41)} * RPT^{0.1837}_{(1.55)} \quad (R^2 = 0.963) \quad (3.82)$$

Three-Sector Models

$$RDPS = 62.951463 * RMCFH^{0.6338}_{(8.53)} * RMCFN^{0.0512}_{(2.00)} * CMCF^{0.2983}_{(3.16)}$$
$$* IMCF^{0.1163}_{(2.40)} * RCUZN^{-0.0399}_{(0.95)} * CCUZ^{-0.1915}_{(1.49)} * ICUZ^{-0.1289}_{(2.53)}$$
$$(R^2 = 0.965) \qquad (3.83)$$

$$RDPS = 34.282705 * RMCFH^{0.6247}_{(8.41)} * RMCFN^{0.0528}_{(2.06)} * CMCF^{0.3037}_{(3.23)}$$
$$* IMCF^{0.1104}_{(2.28)} * RCUZN^{-0.0422}_{(1.01)} * CCUZ^{-0.1946}_{(1.52)} * ICUZ^{-0.1223}_{(2.40)}$$
$$* RPT^{0.1557}_{(1.35)} \qquad (R^2 = 0.966) \qquad (3.84)$$

As expected, the sales elasticity of the non-heating residential market is much smaller (more than ten times) than the same elasticity for the heating market. Indeed, a non-heating customer has a nearly constant gas requirement, hence a very high load factor, without significant peak effects. The opposite is of course true for the heating customer. The heating/non-heating residential sales disaggregation probably accounts well for plant variations that were previously accounted for by the residential customer size variable RCUZ. Hence, in the present models the residential customer size variables have low significance, if any at all. The residential saturation rate variable improves the fit and has an acceptable significance. Its positive sign would mean that the more the market is saturated, the more expensive it is to increase this saturation. Such a result is somewhat unexpected as one would assume that the more ubiquitous mains and other equipments are the easier it is to connect new customers to the system. Possibly, opposite diseconomies of scale and agglomeration phenomena are at work, but it is impossible to say for sure without further analyses, which could not be undertaken in the framework of this study.

The next step of the analysis was to extend the previous models by adding the commercial heating customers share, SHC, and the share of industrial interruptible customers, SII. The sign of SHC always turned out to be negative. Such a result would mean that the more heating customers the lesser the plant cost, which of course is not logical in view of the peak space-heating requirements of these customers. Such a disappointing result is probably due to the overall high value of SHC and to its low variability. This variable was therefore discarded. On the other side, the variable SII turned out to have the expected negative sign: the more such interruptible customers (with generally high loads and high load factors) the lesser the plant cost. Interestingly, the significance of SII is quite acceptable when the customer size variables are not considered, with:

$$RDPS = 16.8525 * RMCFH^{0.7469}_{(12.33)} * RMCFN^{0.0316}_{(2.21)} * CMCF^{0.1915}_{(3.26)}$$
$$* IMCF^{0.0142}_{(1.17)} * SII^{-0.0384}_{(1.44)} \qquad (R^2 = 0.962) \qquad (3.85)$$

However, when SII is added to the complete model specification, it follows that:

$$RDPS = 63.898571 * RMCFH^{0.6353}_{(8.51)} * RMCFN^{0.0501}_{(1.94)} * CMCF^{0.3026}_{(3.18)}$$
$$* IMCF^{0.1092}_{(2.18)} * RCUZN^{-0.0413}_{(0.98)} * CCUZ^{-0.2006}_{(1.54)} * ICUZ^{-0.1145}_{(2.02)}$$
$$* SII^{-0.0168}_{(0.59)} \qquad (R^2 = 0.966) \qquad (3.86)$$

The lower significance of SII is most likely due to the introduction of the variable ICUZ, as the correlation coefficient between the logarithms of SII and ICUZ is equal to 0.890. This relationship is not surprising: interruptible customers are generally large customers, and therefore their increasing share pushes up the average industrial customer size. In conclusion, it is suggested, at least for PNG, to discard the variable SII from use in the cost models.

Disaggregated Distribution Plant Cost Analysis

An analysis of the historical costs of the different components (mains, services, etc.) that make up the distribution plant has been performed for Long Island Lighting Company and National Fuel Gas Distribution Corporation. The LILCO data have been obtained from the New York State Board of Equalization and Assessment (NYSBEA) and are presented in appendix A. The NFGDC data are the same as those used in the former study. For both companies, the analysis is applied only to those communities with density data (58 for LILCO and 33 for NFGDC). Also, the same model specification as used for the aggregated distribution plant is considered here, involving sales, customer size, and density variables.

Long Island Lighting Company

As the data in table A.1 (appendix A) indicate, the three major components for which cost information is available are (1) mains, (2) measuring and regulating station equipment, and (3) services. The corresponding costs are denoted DMA, DMR, and DSE. The means and standard deviations of these variables for the 58 communities are presented in table 3.18.

TABLE 3.18

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS - LILCO DISAGGREGATED ANALYSIS

Variable	Definition	Mean	Deviation
DMA	Mains in Service ($) - End of 1979	1,845,888	3,890,295
DMR	Measuring & Regulating Station Equipment in Service ($) - End of 1979	35,470	82,866
DSE	Services in Service ($) - End of 1979	359,529	779,772
DPS	Total Distribution Plant in Service ($) - End of 1979	2,219,367	4,622,761

Source: Author's calculations.

The multiplicative specification turned out to be superior in all cases.

The best fits are presented below.

a. Mains

The one- and two-sector models are:

$$DMA = 83.630978 * TMCF^{0.9681}_{(27.96)} * TCUZ^{-0.5192}_{(4.88)} * TEDN^{-0.3084}_{(4.26)} \quad (R^2 = 0.936) \qquad (3.87)$$

$$DMA = 225.00666 * RMCF^{0.6506}_{(7.95)} * CIMCF^{0.2911}_{(3.99)} * RCUZ^{-0.1493}_{(1.00)}$$
$$* CICUZ^{-0.2913}_{(2.58)} * TEDN^{-0.2926}_{(4.37)} \quad (R^2 = 0.946) \qquad (3.88)$$

The coefficients of the above models are quite close to those obtained when considering the total distribution plant (equations 3.13 and 3.14), which is not surprising in view of the fact that mains make up 83% of the total distribution plant.

b. Measuring and Regulating Station Equipment

The analysis was performed only for the 38 communities for which this variable is positive. The following results were obtained:

$$DMR = 2.4545138 * TMCF^{0.9269}_{(6.07)} * TCUZ^{-0.6592}_{(1.55)} \quad (R^2 = 0.521) \qquad (3.89)$$

$$DMR = 4.5770286 * RMCF^{0.9123}_{(6.12)} * RCUZ^{-0.7176}_{(1.64)} \quad (R^2 = 0.521) \qquad (3.90)$$

The density variable turned out to be insignificant, and the commercial/industrial variables to have the wrong signs. In the case of LILCO, it appears that this cost category is mostly dependent upon the characteristics of the residential market.

c. Services

The following models were obtained:

$$DSE = 17.440638 * TMCF^{0.9804}_{(32.17)} * TCUZ^{-0.6648}_{(7.10)} * TEDN^{-0.0668}_{(1.05)} \quad (R^2 = 0.953) \qquad (3.91)$$

$$DSE = 23.748942 * RMCF^{0.8262}_{(11.41)} * CIMCF^{0.1545}_{(2.39)} * RCUZ^{-0.3290}_{(2.49)} * CICUZ^{-0.2299}_{(2.30)} * TEDN^{-0.0659}_{(1.11)} \quad (R^2 = 0.960) \qquad (3.92)$$

The significance as well as the value of the density coefficient are rather low, pointing out the weak impact of this variable on services investments. Hence, in the case of LILCO, density mostly affects mains investments. Also, the comparison of the two-sector mains and services models shows that, in the residential sector, a higher rate of economies of scale is achieved for mains in the case of the sales variable, while the opposite is true in the case of the customer size variable. This is not surprising as mains have a rather system-wide effect whereas services are directly linked to customers.

National Fuel Gas Distribution Corporation

The variables definitions, means, and standard deviations are presented in table 3.19.

The multiplicative models turned out to be superior in all cases. The best fits are presented below.

a. Land and Land Rights

The one- and two-sector models are:

$$DLA = 0.00425631 * TMCF^{1.9328}_{(5.71)} * TCUZ^{-2.4718}_{(2.51)} \quad (R^2 = 0.523) \qquad (3.93)$$

$$DLA = 3432.503 * RMCF^{1.8519}_{(5.68)} * RCUZ^{-4.9844}_{(1.31)} \quad (R^2 = 0.529) \quad (3.94)$$

TABLE 3.19

VARIABLES DEFINITIONS, MEANS, AND STANDARD DEVIATIONS - NFGDC DISAGGREGATED ANALYSIS

Variable	Definition	Mean	Standard Deviation
DLA	Land and Land Rights ($) - End of 1979	7,963	24,760
DSI	Structure and Improvements ($) - End of 1979	18,811	58,320
DMA	Mains ($) - End of 1979	1,599,645	3,540,887
DMR	Measuring and Regulating Stations Equipment - End of 1979	43,113	107,206
DSE	Services ($) - End of 1979	337,600	731,250
DMH	Meters and House Regulators ($) - End of 1979	210,634	402,565
DPS	Total Distribution Plant ($) - End of 1979	2,217,766	4,818,647

Source: Author's calculations.

The density variable is not signficant in both models. In addition, the two-sector analysis shows that land and land rights costs depend essentially on the characteristics of the residential sector.

b. Structures and Improvements

The one- and two-sector models are:

$$DSI = 0.00460274 * TMCF^{0.8476}_{(2.60)} * TEDN^{1.3037}_{(2.05)} \quad (R^2 = 0.461) \quad (3.95)$$

$$DSI = 0.00147529 * RMCF^{0.9809}_{(2.61)} * TEDN^{1.2469}_{(1.93)} \quad (R^2 = 0.462) \quad (3.96)$$

The density coefficient turns out to be positive, indicating increasing costs with increasing density. Such a result is plausible as structures and improvements are more difficult to install in densely urbanized areas. It is also notable that cost variations are essentially due to the residential market size, the other sectors' variables having insignificant impacts.

c. Mains

The one- and two-sector models are:

$$DMA = 281.81533 * TMCF^{0.9979}_{(11.76)} * TCUZ^{-0.9439}_{(4.66)} * TEDN^{-0.2287}_{(1.61)} \quad (R^2 = 0.872) \qquad (3.97)$$

$$DMA = 134{,}217.92 * RMCF^{0.7274}_{(3.50)} * CIPMCF^{0.3151}_{(1.42)} * RCUZ^{-1.8095}_{(2.19)} * CIPCUZ^{-0.2852}_{(1.28)} * TEDN^{-0.2559}_{(1.72)} \quad (R^2 = 0.881) \qquad (3.98)$$

The above models coefficients are quite close to those obtained for the total distribution plant (equations 3.20 and 3.21), which could be expected as mains make up for 72% of the total distribution plant.

d. Measuring and Regulating Station Equipment

The one- and two-sector models are:

$$DMR = 7.471935 * TMCF^{1.0005}_{(11.50)} * TCUZ^{-0.9078}_{(4.38)} * TEDN^{-0.3511}_{(2.40)} \quad (R^2 = 0.859) \qquad (3.99)$$

$$DMR = 0.51777 * RMCF^{0.6836}_{(3.22)} * CIPMCF^{0.3202}_{(1.41)} * CIPCUZ^{-0.2486}_{(1.10)} * TEDN^{-0.2777}_{(1.93)} \quad (R^2 = 0.864) \qquad (3.100)$$

The residential customer size variable, RCUZ, was deleted from the two-sector model because its significance turned out be to very low.

e. Services

The density variable turned out to be insignificant, and so did the non-residential variables. The best one- and two-sector models are:

$$DSE = 205.72617 * TMCF^{0.8543}_{(11.76)} * TCUZ^{-0.8656}_{(4.10)} \quad (R^2 = 0.827) \quad (3.101)$$

$$DSE = 214.0458 * RMCF^{0.8411}_{(11.90)} * RCUZ^{-0.8292}_{(1.00)} \quad (R^2 = 0.826) \quad (3.102)$$

f. Meters and House Regulators

The one- and two-sector models are:

$$DMH = 20.20023 * TMCF^{1.0144}_{(10.11)} * TCUZ^{-0.8479}_{(3.54)} * TEDN^{-0.2998}_{(1.78)} * \quad (R^2 = 0.832) \quad (3.103)$$

$$DMH = 737{,}484.24 * RMCF^{0.4023}_{(1.80)} * CIPMCF^{0.7238}_{(3.03)} * RCUZ^{-2.1648}_{(2.44)} * CIPCUZ^{-0.6529}_{(2.72)} * TEDN^{-0.3224}_{(2.01)} \quad (R^2 = 0.870) \quad (3.104)$$

As a unique case, the residential sales elasticity is smaller than the sales elasticity of the non-residential sector. However, this reversal is much compensated at the customer size level, where the residential sector elasticity is very high (2.1648).

Comparison of the LILCO and NFGDC Models

The comparison of the previously presented models is necessarily limited, and restricted to mains, measuring and regulating station equipment, and services.

The comparison of the mains two-sector models (equations 3.88 and 3.98) shows that the same variables that were used in section 3 to explain the variations of the coefficients of the aggregate models, are likely to explain the differences in the coefficients of the two models, in particular those related to residential sales and customer sizes.

The models obtained for measuring and regulating station equipment are significantly different: the LILCO model includes only residential variables, whereas the NFGDC model includes non-residential variables as well as the density variable. The same differences hold for services, but in an opposite way, that is, the LILCO model includes all the explanatory variables, whereas the NFGDC model includes only residential variables. Unfortunately, given the limited data base, it is impossible to further explain these differences.

Dynamic Analysis of the Distribution Plant

The analysis presented in this section and applied to Pacific Gas and Electric Company extends a similar analysis presented in the former study by (1) improving the estimation of the new plant in service installed during the year, and (2) testing alternative model specifications.

Calculation of the New Plant in Service

The historical cost values of PG&E distribution plant in service at the end of 1979 and 1978 were made available by the company and are denoted as DPS_{79} and DPS_{78}. Two types of plant change take place during the year: (a) plant parts are retired at the end of their useful lifetimes, and (b) plant parts are added. The latter include (1) parts that are replacing those retired, and (2) parts that are necessary to serve the new customers and the new loads. The following notations are made:

$DPRET_{79}$: distribution plant retired during 1979,

$DPREP_{79}$: distribution replacement plant added during 1979,

$DPNEW_{79}$: new distribution plant added during 1979 to serve the new customers/new loads added during 1979.

The relationship between DPS_{79} and DPS_{78} is then:

$$DPS_{79} = DPS_{78} - DPRET_{79} + DPREP_{79} + DPNEW_{79} \qquad (3.105)$$

The purpose of the present analysis is to study the variations of the new plant, $DPNEW_{79}$, that is installed to serve new customers and/or the new loads corresponding to consumption increases by the existing customers. In order to estimate $DPNEW_{79}$, it is first necessary to estimate the retired and replacement plants, $DPRET_{79}$ and $DPREP_{79}$.

The historical cost values of the different components of the distribution plant retired during 1979 are indicated in table 3.20. The total value of the distribution plant retired is $4,872,546. The historical value of the total distribution plant of PG&E at the beginning of 1979 (or end of 1978) is $1,088,674,784. The retirement rate r applied to historical cost values is then defined as:

$$r = \frac{4,872,546}{1,088,674,784} = 0.00447567 \qquad (3.106)$$

It is assumed that this company-wide retirement rate can be applied uniformly to the distribution plant of all the communities in the service area. It follows that:

$$DPRET_{79} = r * DPS_{78} \qquad (3.107)$$

The next step is to estimate the replacement distribution plant $DPREP_{79}$. The proposed procedure is based on the assumption that the components are retired at the end of their average service lives, and that the Handy-Whitman index of public utility construction costs is a correct representation of price changes over the years. The estimated average service lives of the different components were drawn from the Annual Report of PG&E to the California Public Utilities Commission (CPUC). They are indicated in table 3.21, together with the values of the Handy-Whitman indices for 1979 and the year of installation of the retired plant. The natural next step would be to multiply the historical values of the plant components retired by the corresponding price multipliers (last column in table 3.21) and to sum these products to obtain the value of the plant replacing the retired plant. The Handy-Whitman index is not available for FERC accounts 385 and 386. The multiplier for account 385 was assumed equal to the multiplier of account 378 (both refer to measuring and regulating stations). The multiplier for account 386 was assumed equal to the multiplier of account 383 (house regulators). The implications of a mistake for account 386 would, in any case, be negligible because this account has a very small value. However, in addition to estimating missing values, there is the much more complicated problem of accounting for technological changes. Such changes refer to the type of material used for mains and services. Indeed, there has been a steady shift, over the years, from steel to plastic mains and services, simply because plastic pipes turn out to be cheaper, including costs of installation. Data included in PG&E 1979 Uniform Statistical Report (submitted to the American Gas Association) show that most of the pipes retired are in steel, whereas the replacement mileage is as follows:

- for mains: 73% in plastic, and 27% in steel;

- for services: 98% in plastic, and 2% in steel.

The H-W indices presented in table 3.21 for mains and services refer exclusively to steel pipes. Discussions with Columbia Gas of Ohio, Inc., engineers indicated that plastic mains are about 15% - 20% cheaper than steel mains, although this percentage varies with pipe size (5-10% for 6" pipes, 12-15% for 4" pipes, and 20% for 2"-3" pipes). A value of 18% was selected for mains. With respect to services, a very rough guess is that plastic services are about 25% cheaper than steel services. Using the

TABLE 3.20

DISTRIBUTION PLANT RETIREMENTS DURING 1979
PACIFIC GAS AND ELECTRIC COMPANY

FERC Account	Plant Component	Historical Value
376	Mains	$ 1,595,454
377	Compressor Station Equipment	5,000
378	Measuring & Regulating Station Equipment - General	90,083
380	Services	2,210,385
381	Meters	863,008
383	House Regulators	22,741
385	Industrial Measuring & Regulating Station Equipment	81,707
386	Other Property on Customer's Premises	4,168

Source: Annual Report of PG&E to the California Public Utilities Commission (CPUC) - 1979.

TABLE 3.21

DISTRIBUTION PLANT COMPONENTS AVERAGE SERVICE LIVES AND
HANDY-WHITMAN (H-W) PRICE INDICES

FERC Account	Average Service Life (Years)	1979 H-W Index (1)	H-W Index for Installation Year (2)	Price Multiplier During Service Life (1)/(2)
376	44	535	49	10.918
377	43	522	58	9.000
378	32	474	87	5.448
380	39	560	52	10.769
381	32	340	90	3.778
383	32	348	93	3.742
385	32	N.A.	N.A.	N.A.
386	35	N.A.	N.A.	N.A.

Sources: Annual Report of PG&E to CPUC (1979) and Handy-Whitman Index of Public Utility Construction Costs (Pacific Region).

above values as well as the plastic/steel shares for new mains and services, the H-W multipliers presented in table 3.21 for accounts 376 and 380 were adjusted to reflect the new technology. The finally used multipliers are:

- 9.483 for mains, and

- 8.131 for services.

The replacement value of the PG&E retired distribution plant in 1979 is $37,444,380. The replacement multiplier is then defined as:

$$k = \frac{\text{Replacement Plant}}{\text{Retired Plant}} = \frac{37{,}444{,}380}{4{,}872{,}546} = 7.6847669 \qquad (3.108)$$

The replacement multiplier is assumed applicable to the distribution plant of any community in PG&E service area. It follows that:

$$DPREP_{79} = k * DPRET_{79} = k * r * DPS_{78} \qquad (3.109)$$

Combining equations (3.105), (3.107), and (3.109) yields:

$$DPNEW_{79} = DPS_{79} - [1 + (k*r) - r] * DPS_{78} \qquad (3.110)$$

or

$$DPNEW_{79} = DPS_{79} - 1.03 * DPS_{78} \qquad (3.111)$$

Equation (3.111) is used to estimate the new plant in each of the 94 communities for which plant and market data are available. The results of the analysis applied to this new plant are presented in the next section.

Cost Models for the New Distribution Plant

The analysis was performed at the two-sector level of disaggregation, i.e., the residential and commercial/industrial sectors. Sectoral sales for 1979 and 1978 were normalized for weather according to the procedure presented in section 3 of this chapter. The normalization adjustment coefficients are presented in appendix D, table D-4. The following basic variables are defined:

DPNEW:	new distribution plant installed in 1979 (see equation 3.111);
$DRCUS = RCUS_{79} - RCUS_{78}$:	new residential customers attached in 1979;
$DCICUS = CICUS_{79} - CICUS_{78}$:	new non-residential customers attached in 1979;
$DTCUS = DRCUS + DCICUS$:	new customers (all categories) attached in 1979;
$DRMCF = ARMCF_{79} - ARMCF_{78}$:	new normalized residential load added in 1979;
$DCIMCF = ACIMCF_{79} - ACIMCF_{78}$:	new normalized non-residential load added in 1979;
$DTMCF = DRMCF + DCIMCF$:	new normalized total (all categories) load added in 1979.

All the 94 communities considered experienced a growth in the residential load ($DRMCF > 0$), and 80 of them did so for the non-residential load ($DCIMCF > 0$). One community experienced a decrease of two residential customers, and four communities did so for the non-residential customers. This seemingly paradoxical discrepancy between the changes in loads and numbers of customers is simply due to the fact that an average increase in the number of customers may be the balance between withdrawals of large-load customers and additions of small-load ones. The sample selected includes the 73 communities for which the dependent and independent variables are all positive (i.e., $DPNEW > 0$, $DRCUS > 0$, $DCICUS > 0$, $DRMCF > 0$, $DCIMCF > 0$). The means and standard deviations of all the variables considered for these 73 communities are presented in table 3.22.

TABLE 3.22

VARIABLES MEANS AND STANDARD DEVIATIONS - PG&E DYNAMIC ANALYSIS

Variable	Mean	Standard Deviation
DPNEW ($)	304,913	441,343
DRCUS (#)	545	683
DCICUS (#)	57	68
DTCUS (#)	602	738
DRMCF (MCF)	145,689	217,092
DCIMCF (MCF)	184,542	543,325
DIMCF (MCF)	330,231	616,354
ARCUZ (MCF)	97	13
ACICUZ (MCF)	1,612	4,178
ATCUZ (MCF)	190	242
TEDN (people/acre)	5.606	3.291

Source: Author's calculations.

In a first step, the new distribution plant was regressed on either the number of customers increments or the load increments, in combination with the 1970 population density and the 1979 customer size variables. The following models were obtained with the customers increments variables:

$$DPNEW = 1574.9928 * DTCUS^{0.7938}_{(11.09)} \qquad (R^2 = 0.634) \quad (3.112)$$

$$DPNEW = 3005.9562 * DRCUS^{0.5701}_{(7.08)} * DCICUS^{0.2175}_{(2.15)}$$

$$(R^2 = 0.618) \quad (3.113)$$

The density variable turned out to insignificant. The same is true for the customer size variables, which, in addition, got the wrong (positive) sign. Surprisingly, these variables turned out to be significant and with the right sign when combined with the load increments. The best models in this case are:

$$DPNEW = 1287.0602 * DTMCF^{0.9069}_{(7.36)} * ATCUZ^{-0.9956}_{(3.56)} * TEDN^{-0.6702}_{(3.14)}$$

$$(R^2 = 0.450) \quad (3.114)$$

$$DPNEW = 496{,}599.93 * DRMCF^{0.6373}_{(4.62)} * DCIMCF^{0.1249}_{(1.34)} * ARCUZ^{-1.9114}_{(2.06)} * TEDN^{-0.6584}_{(3.08)} \quad (R^2 = 0.464) \quad (3.115)$$

The non-residential customer size variable turned out to be insignificant. Notable in equations (3.114) - (3.115) is the high value of the density elasticity (0.66-0.67), much higher than the elasticity obtained in the static models (0.25 - 0.28) presented in Sections 2 and 4. This sensitivity may be linked to the fact that most growth occurs at the urban fringe, where the density factor may be very important in determining the length of main extensions and services, and hence the hook-up costs for new customers.

In a second step, the customer and load increments variables were considered simultaneously in attempting to explain the variations of the new distribution plant, DPNEW. However, the load increments defined previously were disaggregated into two components: (1) the load increment corresponding to the consumption of the new customers attached to the system, and (2) the load increment corresponding to the increased consumption by the existing customers. The latter increments are noted DREX, DCEX, and DTEX for the residential, non-residential and total markets. The reason for considering these increments separately becomes obvious when looking at the average customer sizes for 1979 and 1978, as presented in table 3.23. The data in this table include both normalized and non-normalized customer sizes. The growth rate in average consumption (or size) varies between 5% and 7%. This growth cannot be attributed to higher than average requirements by the newly attached customers. Indeed, doing so would imply, for example, that the average size of the new residential customer is, on the average, equal to 750 MCF, and varies between a minimum of 11 MCF and a maximum of 7741 MCF. Such figures are, of course, totally out of line with those corresponding to the total market, as indicated in table 3.23.

TABLE 3.23

NORMALIZED AND NON-NORMALIZED AVERAGE CUSTOMER SIZES (MCF)
FOR 1979 AND 1978 - PACIFIC GAS AND ELECTRIC COMPANY

Variable	Mean	Standard Deviation	Minimum	Maximum
Residential Market				
$RCUZ_{79}$	89.85	13.27	70.83	136.86
$RCUZ_{78}$	86.50	13.74	62.02	142.65
$ARCUZ_{79}$	98.00	14.79	74.95	156.94
$ARCUZ_{78}$	93.24	15.15	68.86	151.83
Commercial/Industrial Market				
$CICUZ_{79}$	1430.81	3,646.28	196.14	27,282.82
$CICUZ_{78}$	1364.58	3,071.88	193.84	21,008.93
$ACICUZ_{79}$	1459.16	3,693.36	197.86	27,762.32
$ACICUZ_{78}$	1390.38	3,123.96	195.37	21,282.93
Total Market				
$TCUZ_{79}$	170.94	211.53	80.09	1,718.41
$TCUZ_{78}$	162.42	175.40	77.18	1,346.80
$ATCUZ_{79}$	180.47	214.36	89.17	1,750.26
$ATCUZ_{78}$	170.42	178.89	84.47	1,388.41

Source: Author's calculations.

It was assumed that the customers newly attached in 1979 are characterized by the same 1979 average consumption (size) as those already attached to the system. The existing customers load growths are then computed as follows:

$$DREX = DRMCF - DRCUS * ARCUZ_{79} \quad (3.116)$$

$$DCEX = DCIMCF - DCICUS * ACICUZ_{79} \quad (3.117)$$

$$DTEX = DREX + DCEX \quad (3.118)$$

Whenever DREX and DCEX turned out to be negative, they were set equal to zero. Four communities turned out to have DREX negative, and 20 did so for DCEX. Two cases were then considered; (1) using all the 73 communities, (2) using the 54 communities for which DCEX > 0. The means and standard deviations of the variables DREX, DCEX, and DTEX for both cases are presented in table 3.24.

TABLE 3.24

MEANS AND STANDARD DEVIATIONS OF THE LOAD INCREMENTS OF THE EXISTING CUSTOMERS (MCF) - PACIFIC GAS AND ELECTRIC COMPANY

Variable	Mean	Standard Deviation
	54 Communities	
DREX	108,396	207,206
DCEX	156,100	491,624
DTEX	264,496	553,470
	73 Communities	
DREX	96,248	181,185
DCEX	115,471	427,399
DTEX	211,719	484,063

Source: Author's calculations.

When using the sample of 73 communities, the results turned out to be disappointing, with low significances for the load increments. The best models are:

$$DPNEW = 1209.3363 * DTCUS^{0.7877}_{(10.91)} * DTEX^{0.0275}_{(0.78)}$$

$$(R^2 = 0.637) \qquad (3.119)$$

$$DPNEW = 2472.4009 * DRCUS^{0.5704}_{(7.05)} * DCICUS^{0.2166}_{(2.13)}$$

$$* DREX^{0.0191}_{(0.56)} \qquad (R^2 = 0.620) \qquad (3.120)$$

Adding the variable DCEX leads to:

$$DPNEW = 2459.4942 * DRCUS^{0.5692}_{(7.90)} * DCICUS^{0.2190}_{(2.08)}$$

$$* DREX^{0.0179}_{(0.49)} * DCEX^{0.0021}_{(0.10)} \qquad (R^2 = 0.620) \quad (3.121)$$

Although they have the right signs, the coefficients of DREX and DCEX cannot be considered as significantly different from zero. Such a result would indicate that the growth of the load of the existing customers did not add to the distribution plant costs. This is quite possible if excess capacity is available throughout the system. Another possibility is, of course, that the procedure for calculating these load increments is incorrect.

Interestingly, better results were obtained with the 54-communities sample. The best models are:

$$DPNEW = 853.70696 * DTCUS^{0.8070}_{(9.39)} * DTEX^{0.0442}_{(0.51)}$$

$$(R^2 = 0.672) \qquad (3.122)$$

$$DPNEW = 1188.3856 * DRCUS^{0.5522}_{(6.03)} * DCICUS^{0.2101}_{(1.83)} * DCEX^{0.1020}_{(1.64)}$$

$$(R^2 = 0.688) \qquad (3.123)$$

The variable DCEX becomes significant when all the cases where DCEX = 0 are removed. On the other side, the variable DREX turns out to be insignificant and with the wrong sign.

Equation (3.123) is overall the best one obtained in this dynamic analysis. The conclusions that it enables one to draw are that: (1) new distribution plant investments depend upon the numbers of new customers attached to the system, and (2) there is excess capacity to accommodate the load growth of the existing residential customers, but additional investments are necesary to accommodate the load growth of the existing commercial/industrial customers.

Comparison of Short-Term and Long-Term Marginal Costs

PG&E equations (3.63) and (3.123) are selected to compute marginal costs functions. The method of calculation was fully discussed in the former study and is not reviewed here. The marginal cost function for long-term equilibrium costs is, for the residential sector:

$$\frac{\partial DPS}{\partial ARMCF} = 265.61456 * ARMCF^{-0.2425} * ACIMCF^{0.1593} * ARCUZ^{-0.3630} * ACICUZ^{-0.1613} * TEDN^{-0.2465} \qquad (3.124)$$

The marginal cost function for the short-term plant costs related to additional residential customers is:

$$\frac{\partial DPNEW}{\partial DRCUS} = 656.22653 * DRCUS^{-0.4478} * DCICUS^{0.2101} * DCEX^{0.1020} \qquad (3.125)$$

Equations (3.124) and (3.125) were applied to the characteristics of the community of Monterey, located in the Coast Valley division. The values of the relevant variables are, for Monterey:

ARMCF = 904,005; ACIMCF = 1,763,662; ARCUZ = 105;

ACICUZ = 2,255; TEDN = 5.202; DRCUS = 32; DCICUS = 29; DCEX = 28,875.

The long term marginal cost, based on the analysis and modeling of the historical (or book) costs and computed with equation (3.124), turns out to be 3.341 \$/MCF. The equivalent replacement marginal cost is obtained by multiplying this "historical" marginal cost by the replacement plant multiplier provided by PG&E, computed by using the Handy-Whitman index and equal to 2.79, with: LMCR = 3.341 * 2.79 = 9.321 \$/residential MCF. The short-term marginal cost incurred by an additional residential customer is computed by using equation (3.125) and turns out to be equal to \$ 804. Expressed on an MCF basis, the later cost becomes: SMCR = 804/105 = 7.657 \$/residential MCF. The additional long-term marginal cost, equal to the difference between LMCR and SMCR (or \$1.664), represents in the case of Monterey about 22% of the initial short-term marginal cost.

The above results indicate that the estimation of marginal distribution plant costs based on the cost of the new distribution plant added during a given year may lead to an underestimation of the real marginal costs, because the estimation procedure does not account for systemwide adjustment costs resulting from the addition of the new loads. To compute the true long-term marginal costs, the use of the static models based on total historical plant costs appears to be more appropriate.

Summary

The analysis presented in the previous sections has extended previous analyses of distribution equipment costs by (1) considering new companies, (2) improving the quality of the data, and (3) introducing new variables into the statistical cost models. The average customer size variables turned out to be highly significant in explaining some of the cost variations. The explanatory power of the population density variable was also significantly improved. The variations of the basic cost model's coefficients across the six companies were successfully explained by the variations of some company-wide parameters such as average market sales, average population densities, and load factor. The basic cost model was extended for two companies--PG&E and PNG--by introducing new variables available for these companies only. Cost analyses for the various components of the distribution plant were also conducted for two companies, LILCO and NFGDC. Finally, an alternative method for computing marginal costs was developed for PG&E, based on incremental plant and market data. The analysis points out that the resulting estimates of marginal costs are lower than those obtained with the static, long-term models, most likely because they do not account for systemwide plant adjustment costs that may be incurred much after the new customers are hooked-up to the system.

Glossary of the Most Frequently Used Symbols

DPS:	historical value of the distribution plant ($)
RDPS:	replacement value of the distribution plant ($)
RMCF:	annual residential gas sales (MCF)
CMCF:	annual commercial gas sales (MCF)
IMCF:	annual industrial gas sales (MCF)
CIMCF:	annual commercial and industrial gas sales (MCF)
TMCF:	annual total gas sales (MCF)
RCUZ:	average residential gas customer size (MCF)
CCUZ:	average commercial gas customer size (MCF)
ICUZ:	average industrial gas customer size (MCF)
CICUZ:	average commercial and industrial gas customer size (MCF)
TCUZ:	average total gas customer size (MCF)
RCUS:	number of residential gas customers
CCUS:	number of commercial gas customers
ICUS:	number of industrial gas customers
CICUS:	number of commercial and industrial gas customers
TCUS:	total number of gas customers
ARMCF:	weather-normalized residential gas sales (MCF)
ACIMCF:	weather-normalized commercial and industrial gas sales (MCF)
ATMCF:	weather-normalized total gas sales (MCF)
ARCUZ:	weather-normalized average residential gas customer size (MCF)
ACICUZ:	weather-normalized average commercial and industrial gas customer size (MCF)
ATCUZ:	weather-normalized average total gas customer size (MCF)
TEDN:	population density (people/acre)
BLS_i:	base load share for market sector i
$\overline{SLS}_i$:	space-heating load share for market sector i
$\overline{DDT}$:	normal (30-year average) annual number of degree-days
$\overline{DD}_{max}$ or DDM:	maximum value of the normal monthly number of degree-days
LFD:	1979 actual load factor for total sales
LFM:	load factor for market sector i based on monthly normalized sales
LFRM:	load factor for the residential market of PG&E based on monthly normalized sales
LFCIM:	load factor for the commercial and industrial market of PG&E based on monthly normalized sales
LFTM:	load factor for the total market of PG&E based on monthly normalized sales

DLA:	historical value of land and land rights ($)
DSI:	historical value of structure and improvements ($)
DMA:	historical value of mains ($)
DMR:	historical value of measuring and regulating station equipment ($)
DSE:	historical value of services ($)
DMH:	historical value of meters and house regulators ($)
DPNEW:	new distribution plant installed in 1979 ($)
DRCUS:	new residential customers attached in 1979
DCICUS:	new commercial and industrial customers attached in 1979
DTCUS:	new customers (all categories) attached in 1979
DREX:	normalized load increase for the existing residential customers
DCEX:	normalized load increase for the existing commercial and industrial customers
DTEX:	normalized load increase for the existing customers (all categories)

CHAPTER 4

AGGREGATE UTILITY PLANT AND OPERATING COSTS FUNCTIONS

The purpose of this chapter is to present the results of statistical analyses applied to the major plant (investment) and operating costs categories of natural gas distribution utilities. Statistical cost functions are developed for each cost category, with, as arguments, the utility's market characteristics, in particular gas sales, both in the aggregate and at the sectoral level. Such cost functions can then be used to develop marginal cost functions to calculate marginal costs for any market mix and utility size. The data used in the analysis have been gathered from 119 U.S. gas distribution utilities. The first section presents the data sources and characteristics, as well as the cost model specifications considered. The second section presents the results related to plant costs, and the third section does so for operating expenses. The last section outlines possible extensions of the analysis.

Data Characteristics and Model Specifications

All the data considered refer to the year 1979 and have been drawn from two documents:

1. The 1979 Annual Reports of the utilities to their state regulatory commissions;
2. The 1979 Uniform Statistical Reports prepared by the utilities for the American Gas Association.

A list of the major gas distribution utilities has been initially prepared, and state public utilities commissions were contacted and asked to request the above-mentioned reports from the utilities under their jurisdiction. In all, 119 utilities provided a complete or partial documentation (small utilities often do not prepare the Uniform Statistical Report, municipally-owned utilities do not submit reports to their state regulatory commissions, etc.). The names of these 119 utilities are listed in appendix E.

The data used in the analysis can be grouped into three categories:

(a) Plant in service data, characterizing the historical cost values of different plant components at the end of 1979;

(b) Operation and maintenance (O&M) costs data, characterizing the O&M cost incurred during 1979;

(c) Market sales and numbers of customers at the aggregate and sectoral levels during 1979.

The plant in service data include the following variables:

- TRANS: transmission plant, including such items as land and land rights, rights of ways, structures and improvements, mains, compressor station equipment, measuring and regulating station equipment, communication equipment, and other equipment (FERC Accounts 365 through 371);

- TDIST: distribution plant, including such items as land and land rights, structures and improvements, mains, compressor station equipment, measuring and regulating station equipment (general and city gate), services, meters, meter installations, house regulators, house regulator installations, industrial measuring and regulating station equipment, other property on customers' premises, and other equipment (FERC Accounts 374 through 387);

- TGEN: general plant, including such items as land and land rights, structures and improvements, office furniture and equipment, transportation equipment, stores equipment, tools, shop, and garage equipment, laboratory equipment, power operated equipment, communication equipment, and miscellaneous equipment (FERC Accounts 389 through 398).

The O&M costs data include the following variables:

-TROXP: transmission operation expenses, related to operation supervision and engineering, system control and load dispatching, communication system, compressor station labor, fuel gas and power, mains, measuring and regulating stations, transmission and compression of gas by others, and rents (FERC Accounts 850 through 860);

- TRMXP: transmission maintenance expenses, related to supervision and engineering, structures and improvements, mains, compressor station equipment, measuring and regulating station equipment, communication equipment, and other equipment (FERC Accounts 861 through 867);

- TDOXP: distribution operation expenses, related to operation supervision and engineering, load dispatching, compressor station labor, fuel, and power, mains and services, measuring and regulation stations (general, industrial, city gate check), meters and house regulators, customer installation, and rents (FERC Accounts 870 through 881);

- TDMXP: distribution maintenance expenses, related to supervision and engineering, structures and improvements, mains, compressor station equipment, measuring and regulating station equipment (general, industrial, city gate check), services, meters and house regulators, and other equipments (FERC Accounts 885 through 894);

- CAO: customer accounts expenses, related to supervision, meter reading, customer records and collection, uncollectible accounts, and miscellaneous expenses (FERC Accounts 901 through 905);

- CSO: customer service and informational expenses, related to supervision, customer assistance, informational and instructional activities, and miscellaneous expenses (FERC Accounts 907 through 910);

- SAO: sales expenses, related to supervision, demonstrating, selling, and advertising activities, and miscellaneous expenses (FERC Accounts 911 through 916);

- AGO: administrative and general operation expenses, related to administrative and general salaries, office supplies, outside services, property insurance, injuries and damages, employee pensions and benefits, franchise requirements, regulatory commission expenses, general advertising, and rents (FERC Accounts 920 through 931);

- AGM: administrative and general maintenance expenses, related to the maintenance of the general plant (FERC Account 932).

The market data include the following variables:

- RMCF: annual residential gas sales (MCF);

- CIMCF: annual commercial and industrial gas sales (MCF);

- RCUS: average number of residential customers during the year;
- CICUS: average number of commercial/industrial customers during the year.

The following aggregate variables are then defined:

$$TMCF = RMCF + CIMCF \tag{4.1}$$

$$TCUS = RCUS + CICUS \tag{4.2}$$

Average customer size (or consumption) variables are defined at the aggregate and sectoral levels:

RCUZ = RMCF/RCUS: residential customer size (4.3)

CICUZ = CIMCF/CICUS: commercial/industrial customer size (4.4)

TCUZ = TMCF/TCUS: total customer size (4.5)

In addition to the above variables, the utility's service territory area, measured in square miles, was considered in the analysis, as a possible determinant of transmission plant and transmission operating expenses. This variable, noted AREA, was drawn from the Uniform Statistical Report, whenever available. The sales and customer data are available in both reports, as are the plant and operating costs data.

If Y is the dependent cost variable, the model specifications were:

$$Y = F(TMCF,TCUZ) \tag{4.6}$$

$$Y = G(RMCF,CIMCF,RCUZ,CICUZ) \tag{4.7}$$

In the case of the transmission plant and operating costs, the variable AREA (service territory area) was included in the model. Also, the number of customers variables were also considered for such cost categories as the general plant (TGEN), customer accounts expenses (CAO), customer service and informational expenses (CSO), sales expenses (SAO), and administrative and general expenses (AGM and AGO), Indeed, then costs might be better predicted by the numbers of customers than by the sales magnitudes. In all cases, both additive and multiplicative specifications were tested.

Plant in Service Costs Function

The Transmission Plant

The existence of a transmission plant in a gas distribution utility is not a function of the size (in terms of sales) of the utility but rather of the location of the supply take-off points with respect to the communities where gas is distributed, hence the possible importance of the utility's service territory area. The best models, both at the aggregate and disaggregate levels, are of the additive type, with:

$$\text{TRANS} = -\ 2{,}027{,}994 + \underset{(11.52)}{0.380108} * \text{TMCF} + \underset{(3.49)}{713.7916} * \text{AREA} \qquad (4.8)$$

$$(R^2 = 0.798) \quad (N = 52)$$

$$\text{TRANS} = -\ 2{,}482{,}629 + \underset{(1.54)}{0.23968} * \text{RMCF} + \underset{(5.07)}{0.54395} * \text{CIMCF} + \underset{(2.67)}{552.69} * \text{AREA} \qquad (4.9)$$

$$(R^2 = 0.822) \quad (N = 52)$$

An interesting feature of equation (4.9) is that the transmission plant cost of a commercial/industrial MCF is larger than the same cost for a residential MCF. A possible explanation is that a large share of transmission facilities is built to serve specifically large, clustered industrial customers. The impact of the service territory area is, in all cases, significant. The means and standard deviations of the above variables for the 52 utilities for which both TRANS and AREA are different from zero are presented in table 4.1

The Distribution Plant

The best models are of the multiplicative type, with:

$$\text{TDIST} = 340.12221 * \text{TMCF}^{\underset{(47.57)}{1.0042}} * \text{TCUZ}^{\underset{(12.26)}{-0.9387}} \qquad (R^2 = 0.951) \quad (N = 119) \qquad (4.10)$$

$$\text{TDIST} = 566.91365 * \text{RMCF}^{\underset{(16.39)}{0.8777}} * \text{CIMCF}^{\underset{(2.45)}{0.1167}} * \text{RCUZ}^{\underset{(10.94)}{-0.9897}} \qquad (4.11)$$

$$(R^2 = 0.953) \quad (N = 119)$$

TABLE 4.1

MEANS AND STANDARD DEVIATIONS OF THE TRANSMISSION-PLANT-RELATED VARIABLES

Variable	Mean	Standard Deviation
TRANS ($)	47,324,622	75,624,275
TMCF (MCF)	103,075,199	156,121,556
RMCF (MCF)	37,945,016	58,540,448
CIMCF (MCF)	60,364,818	91,045,224
AREA (sq. mile)	14,252	25,228

Source: Author's calculations

The above models display very high R^2's, and all the variables are highly significant. At the aggregate level, distribution plant costs are characterized by constant costs to scale with respect to sales, and by significant economics of scale with respect to customer size. At the disaggregate level, distribution costs are characterized by economies of scale with respect to sectoral sales, as well as with respect to residential customer size. The commercial-industrial customer size variable is not significant. The cost elasticities of the sectoral sales display the expected relative values, i.e., it costs more to serve a marginal residential MCF than a commercial-industrial one. It is also interesting to note that the above results are very much in line with those obtained in chapter 3 where cost functions were developed for the distribution plant at the community level, and where it was possible to account for the impact of local features such as population density. Of course, the impacts of such localized features cannot be accounted for with aggregate utility data. The means and standard deviations of the above variables for the 119 utilities are presented in table 4.2.

The General Plant

At the aggregate level, the following models were obtained with the sales and number of customers variables:

TABLE 4.2

MEANS AND STANDARD DEVIATIONS OF THE DISTRIBUTION-PLANT-RELATED VARIABLES

Variable	Mean	Standard Deviation
TDIST ($)	147,910,478	214,883,733
TMCF (MCF)	85,235,113	135,085,072
RMCF (MCF)	33,071,717	52,989,858
CIMCF (MCF)	49,591,448	80,504,713
TCUZ (MCF)	302.492	163.748
RCUZ (MCF)	119.131	38.730
CICUZ (MCF)	3,155.489	8,744.037

Source Author's calculations

$$TGEN = 0.3352 * \underset{(14.85)}{TMCF^{0.9273}} \qquad (R^2 = 0.657) \quad (N = 117) \qquad (4.12)$$

$$TGEN = 22.4837 * \underset{(15.98)}{TCUS^{1.0131}} \qquad (R^2 = 0.689) \quad (N = 117) \qquad (4.13)$$

The performances of the above two models are quite close, although equation (4.13) has a smaller residual sum of squares (131.66) than equation (4.12) (145.31), as well as a higher R^2. Equation (4.13) points out to constant cost to scale with respect to customers, with a cost of 22.48 $/customer for the general plant.

At the disaggregate level, the following models were obtained:

$$TGEN = 0.7655 * \underset{(3.20)}{RMCF^{0.5021}} * \underset{(2.94)}{CIMCF^{0.4210}} \qquad (R^2 = 0.659) \quad (N = 117) \qquad (4.14)$$

$$TGEN = 35.3888 * \underset{(6.10)}{RCUS^{0.8782}} * \underset{(0.98)}{CICUS^{0.1317}} \qquad (R^2 = 0.689) \quad (N = 117) \qquad (4.15)$$

In view of the relatively low significance of the variable CICUS in equation (4.15), CICUS was deleted, and the following model was obtained:

$$TGEN = 27.2504 * RCUS^{1.0049} \quad (R^2 = 0.686) \quad (4.16)$$
$$(15.86) \quad (N = 117)$$

The adjusted R^2 (not shown) of equation (4.16) is higher than that of equation (4.15), and therefore equation (4.16) is to be selected. Such a result would indicate that the size of the necessary general plant is primarily a function of the size of the residential market measured in terms of numbers of customers, and that the relationship implies constant costs to scale. The means and standard deviations of the above variables are presented in table 4.3.

TABLE 4.3

MEANS AND STANDARD DEVIATIONS OF THE GENERAL-PLANT-RELATED VARIABLES

Variable	Mean	Standard Deviation
TGEN ($)	8,921,944	13,677,504
TMCF (MCF)	86,048,493	136,015,709
RMCF (MCF)	33,315,314	53,358,117
CIMCF (MCF)	50,155,775	81,051,189
TCUS (#)	289,557	490,446
RCUS (#)	267,138	459,664
CICUS (#)	22,165	32,934

Source: Author's calculations

Operation and Maintenance Cost Functions

Transmission Expenses

A general feature of the results is that for both operation (TROXP) and maintenance (TRMXP) expenses, and at both levels of aggregation, the additive specification is superior. This result is in line with the additive specification obtained for the transmission plant. The sample considered includes 47 utilities for which TROXP, TRMXP, and AREA are all different from zero. At the aggregate level, the following models were obtained:

$$TROXP = -828{,}118.2 + \underset{(10.80)}{0.02347} * TMCF + \underset{(3.06)}{41.045} * AREA \quad (R^2 = 0.788) \; (N = 47) \quad (4.17)$$

$$TRMXP = -153{,}261.5 + \underset{(10.27)}{0.004712} * TMCF + \underset{(4.60)}{13.0296} * AREA \quad (R^2 = 0.799) \; (N = 47) \quad (4.18)$$

At the disaggregate level, the following models were obtained:

$$TROXP = -\ 792{,}086.7 + \underset{(0.83)}{0.00861} * RMCF + \underset{(5.22)}{0.03741} * CIMCF + \underset{(2.08)}{28.707} * AREA$$

$$(R^2 = 0.810) \; (N = 47) \quad (4.19)$$

$$TRMXP = -168{,}325 + \underset{(3.75)}{0.009145} * RMCF + \underset{(1.27)}{0.002132} * CIMCF + \underset{(4.50)}{14.571} * AREA$$

$$(R^2 = 0.777) \; (N = 47) \quad (4.20)$$

The service territory area variable is in all cases highly significant. It is interesting to note that the marginal operating cost is four times higher for the commercial-industrial sector as compared to the residential one, whereas, the opposite relationship is true for the marginal maintenance cost. It may be that the high operating marginal cost for the commercial-industrial sector is related to huge compressor costs incurred in moving gas aimed at major industrial customers. The means and standard deviations of the above variables are presented in table 4.4

Distribution Expenses

The multiplicative specification turns out to be superior in all cases. The best models for the distribution operating expenses are:

$$TDOXP = 12.832654 * TMCF^{\underset{(50.06)}{1.0028}} * TCUZ^{\underset{(12.73)}{-0.9207}} \quad (R^2 = 0.957) \; (N = 116) \quad (4.21)$$

$$TDOXP = 13.908414 * RMCF^{\underset{(17.79)}{0.9192}} * CIMCF^{\underset{(1.63)}{0.0751}} * RCUZ^{\underset{(10.07)}{-0.8782}} \quad (4.22)$$

$$(R^2 = 0.957) \quad (N = 116)$$

TABLE 4.4

MEANS AND STANDARD DEVIATIONS OF THE
TRANSMISSION-EXPENSES-RELATED VARIABLES

Variable	Mean	Standard Deviation
TROXP ($)	2,315,651	4,804,943
TRMXP ($)	550,758	1,040,488
TMCF (MCF)	107,292,323	161,815,280
RMCF (MCF)	39,853,583	60,781,856
CIMCF (MCF)	62,213,857	94,106,303
AREA (sq. mile)	15,234	26,228

Source: Author's calculations

The above models would indicate that distribution operating costs are primarily incurred to serve the residential market. In the case of the distribution maintenance expenses, the best models are:

$$TDMXP = 3.5153883 * \underset{(14.76)}{TMCF^{1.0849}} * \underset{(4.01)}{TCUZ^{-1.0635}} \quad (R^2 = 0.659) \; (N = 116) \qquad (4.23)$$

$$TDMXP = 1.9169142 * \underset{(14.84)}{RMCF^{1.0788}} * \underset{(2.93)}{RCUZ^{-0.8878}} \quad (R^2 = 0.662) \; (N = 116) \qquad (4.24)$$

The above models indicate that distribution maintenance expenses are also essentially a function of the residential market characteristics. Overall, distribution operating expenses are related mainly to residential sales and customer size, and the impact of the commercial-industrial market on this cost category appears to be minimal. The means and standard deviations of the above variables are presented in table 4.5.

Customer Accounts Expenses

The number-of-customers variables turned out to best explain the variations of this cost category. The following models were obtained at the aggregate and disaggregate levels:

TABLE 4.5

MEANS AND STANDARD DEVIATIONS OF
THE DISTRIBUTION-EXPENSES-RELATED VARIABLES

Variable	Mean	Standard Deviation
TDOXP ($)	5,775,652	8,055,336
TDMXP ($)	3,688,733	6,143,272
TMCF (MCF)	83,089,920	133,509,246
RMCF (MCF)	32,706,088	53,335,204
CIMCF (MCF)	47,934,313	78,041,016
TCUZ (MCF)	303.745	165.147
RCUZ (MCF)	120.319	38.953
CICUZ (MCF)	3,194.052	8,852.625

Source: Author's calculations

$$CAO = 15.127904 * \underset{(55.48)}{TCUS^{1.0183}} \qquad (R^2 = 0.964) \quad (N = 116) \qquad (4.25)$$

$$CAO = 17.888606 * \underset{(55.90)}{RCUS^{1.0123}} \qquad (R^2 = 0.965) \quad (N = 116) \qquad (4.26)$$

The above results could be expected, as this cost category is linked to customer records, metering and payment collections, hence very closely to the number of customers, and as the number of residential customers is generally very much larger than the number of the other customers. As could be logically expected, the relationship displays constant cost to scale, at an average cost of 17.89 $/residential customer. The means and standard deviations of the above variables are presented in table 4.6.

Customer Service and Informational Expenses

This cost category is best explained by sales levels, and the best models turn out to be of the multiplicative form, with:

$$CSO = 0.000952 * \underset{(10.91)}{TMCF^{1.1002}} \qquad (R^2 = 0.620) \quad (N = 75) \qquad (4.27)$$

TABLE 4.6

MEANS AND STANDARD DEVIATIONS OF THE CUSTOMERS-ACCOUNTS-EXPENSES-RELATED VARIABLES

Variable	Mean	Standard Deviation
CAO ($)	5,588,923	8,803,618
TCUS (#)	286,938	492,159
RCUS (#)	264,871	461,471

Source: Author's calculations

$$CSO = 0.001908 * RMCF^{0.7291} * CIMCF^{0.3843} \quad (R^2 = 0.627) \quad (4.28)$$
$$(3.13) \qquad (1.73) \qquad (N = 75)$$

The means and standard deviations of the above variables are presented in table 4.7.

TABLE 4.7

MEANS AND STANDARD DEVIATIONS OF THE CUSTOMER-SERVICE-AND-INFORMATIONAL-EXPENSES-RELATED VARIABLES

Variable	Mean	Standard Deviation
CSO ($)	786,519	1,341,291
TMCF (MCF)	94,817,748	126,282,128
RMCF (MCF)	36,803,862	48,163,872
CIMCF (MCF)	56,535,690	82,949,432

Source: Author's calculations

Sales Expenses

The number-of-customer variables turned out to best explain the variations of this cost category. The following models were obtained at the aggregate and disaggregate levels:

$$SAO = 1.715561 * TCUS^{0.9797} \quad (R^2 = 0.364) \quad (4.29)$$
$$(7.18) \qquad (N = 92)$$

$$SAO = 2.041274 * RCUS^{0.9731} \quad (R^2 = 0.364) \quad (4.30)$$
$$(7.18) \quad (N = 92)$$

This cost category appears to be essentially related to the size of the residential market, as measured by the number of customers, with slight economies of scale. The means and standard deviations of the above variables are presented in table 4.8.

TABLE 4.8

MEANS AND STANDARD DEVIATIONS OF THE SALES-EXPENSES-RELATED VARIABLES

Variable	Mean	Standard Deviation
SAO ($)	850,034	2,210,314
TCUS (#)	271,312	465,269
RCUS (#)	249,819	436,229

Source: Author's calculations

Administrative and General Expenses

In the case of the operation costs, the best models are obtained when using market sales and customer size variables, with:

$$AGO = 20.7219 * TMCF^{0.9567} * TCUZ^{-0.7916} \quad (R^2 = 0.925) \quad (4.31)$$
$$(37.07) \quad (8.50) \quad (N = 116)$$

$$AGO = 27.6021 * RMCF^{0.8202} * CIMCF^{0.1313} * RCUZ^{-0.6922} * CICUZ^{-0.6403}$$
$$(11.31) \quad (1.95) \quad (5.46) \quad (1.00)$$
$$(R^2 = 0.924) \quad (N = 116) \quad (4.32)$$

The administrative and general operating expenses are characterized by economies of scale, both with respect to sales and customer sizes. All the market sectors have an effect on this cost category, although the impact of the residential variables is the highest. In the case of the maintenance costs, the best models are:

$$AGM = 0.48259 * TMCF^{0.9527} * TCUZ^{-0.7901} \quad (R^2 = 0.718) \quad (4.33)$$
$$(15.55) \qquad (3.37) \qquad (N = 103)$$

$$AGM = 0.323202 * RMCF^{0.9453} * RCUZ^{-0.6297} \quad (R^2 = 0.721) \quad (4.32)$$
$$(15.76) \qquad (2.61) \qquad (N = 103)$$

The above models (4.34) would indicate that the cost of maintenance of the general plant is a function of the residential market characteristics. Such a result is in line with the general plant cost function presented in the previous section (equation 4.16), where the number of residential customers appears to be the primary determinant of general plant investment costs. The means and standard deviations of the above variable for the two samples used (N = 116 for AGO and N = 113 for AGM) are presented in table 4.9.

TABLE 4.9

MEANS AND STANDARD DEVIATIONS OF THE ADMINISTRATIVE-AND-GENERAL-EXPENSES-RELATED VARIABLES

Variable	Mean	Standard Deviation
	Sample N = 116	
AGO ($)	9,409,625	16,118,279
TMCF (MCF)	83,089,920	133,509,246
RMCF (MCF)	32,706,088	53,335,204
CIMCF (MCF)	47,934,313	78,041,016
TCUZ (MCF)	303.745	165.147
RCUZ (MCF)	120.319	38.953
CICUZ (MCF)	3,194.052	8,852.625
	Sample N = 103	
AGM ($)	245,749	397,827
TMCF (MCF)	90,266,877	139,806,643
RMCF (MCF)	35,491,404	55,837,969
TCUZ (MCF)	293.890	131.952
RCUZ (MCF)	119.411	38.933

Source: Author's calculations

Extensions of the Analysis and Further Research

The analysis presented in the previous section should be viewed as a first step towards a thorough understanding of the structure of gas distribution costs. It is expected that future research will introduce into the cost models utility load characteristics measured with monthly and daily sendout data. Such data are available in the data file and were drawn from the Uniform Statistical Reports. Cost functions could be developed for each FERC account separately. Such disaggregate cost data are also available in the data file. These detailed analyses would lead to a much more precise assignment of cost responsibilities among the different customer classes.

Second, the data file could be extended to include wage-and-salaries, as well as regional indices related to economic activity, other energy sources costs, etc. Such variables could probably further explain the observed cost variations and help analyze the trade-offs between labor and other inputs to the gas distribution industry.

Third, other cost categories such as underground, LNG and local storage, natural gas production and gathering, and substitute natural gas production should be analyzed and appropriate cost functions developed. The appropriate data for such analyses are also available in the gathered documentation.

Finally, all these cost and operating data could be used to analyze the production efficiency of gas distribution utilities. Efficiency indices and frontier production functions could be developed, and might be used to rank utilities in terms of economic efficiency. Perhaps such analyses could then be used as the basis for developing incentive mechanisms for better management in the gas distribution industry.

PART III

COMPUTERIZED AND SIMPLIFIED APPROACHES TO THE CALCULATION OF GAS MARGINAL COSTS AND TO THE FORMULATION OF MARGINAL COST PRICING POLICIES

CHAPTER 5

EXTENSION OF THE GAS UTILITY MARGINAL COST PRICING MODEL

The purpose of this chapter is to present the extensions and improvements brought to the Gas Utility Marginal Cost Pricing Model (GUMCPM) and the results of some applications of this new version of the model to the East Ohio Gas Company. In the first section, the general structure of the model and the improvements brought to the former version are presented. In the second section, the results of the model applications are presented and discussed. In the final section, some possible further extensions of the model are outlined.

Structure of the Extended Gas Utility Marginal Cost Pricing Model

The purpose of this section is not to present the model in detail. For such a presentation, the reader is referred to the former study. [1] Instead, an overview of the model is presented first as a reminder, and then the specific changes brought to the former version are discussed in detail.

Overview of the Model

A general flow diagram of the model is presented in figure 5.1. The model consists of three major, interlinked blocks: (1) Exogenous data

[1] J.-M. Guldmann, Marginal Cost Pricing for Gas Distribution Utilities: Preliminary Analyses and Models, NRRI-80-12, November 1980, Chapter 4.

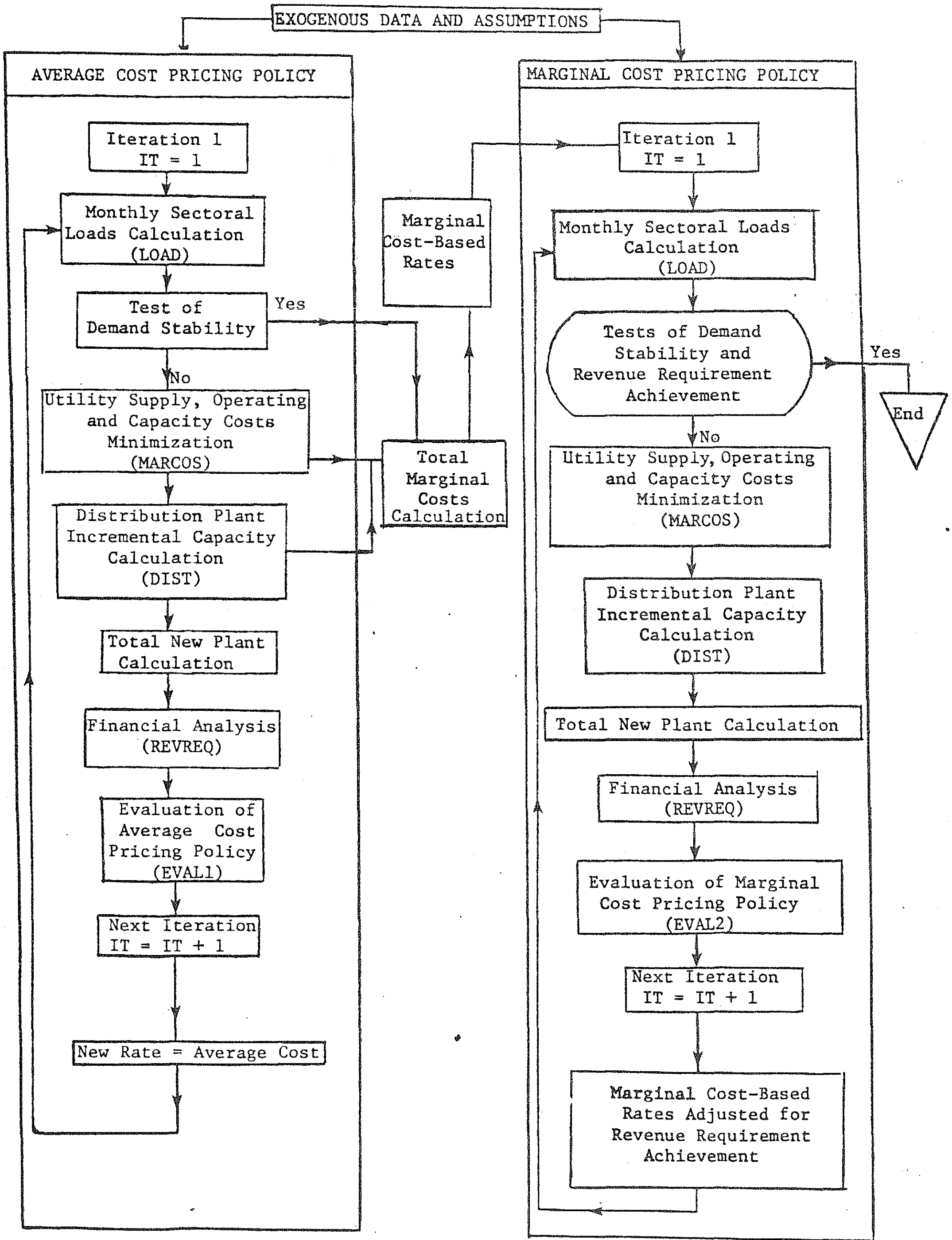

Figure 5.1 Structure of the Gas Utility Marginal Cost Pricing Model (GUMCPM)

and assumptions, (2) Average cost pricing policy, and (3) Marginal cost pricing policy. The components of the two pricing policy blocks are indicated in figure 5.1, together with the names of the corresponding computer subprograms (LOAD, MARCOS, DIST, REVREQ, EVAL1, EVAL2).

The exogenous data and assumptions include: (1) market-related parameters such as sectoral market growth, base and space-heating load coefficients, and price elasticities of monthly gas demands; (2) supply-related parameters such as maximum supplies and rates for the different available suppliers; and (3) utility-related parameters such as operating and capacity unit costs, maximum capacity expansions, the allowed rate of return, and other financial parameters (taxes, etc.).

The above data and assumptions are first used in the Average cost pricing policy block, where the monthly loads of the residential, commercial, and industrial sectors are calculated while using historically-determined base and space-heating load coefficients and an initial value of the gas rate applied uniformly to all sectors and in all months. These loads are then inputs to the utility supply, operating and capacity costs minimization submodel, which determines the optimal trade-off between supply mix and own-production, storage and transmission operations and capacity expansion decisions, subject to satisfying the above-mentioned loads and various utility-related technological constraints.

The format of this cost minimization model is a linear program, which yields automatically, as an important by-product, shadow prices for the monthly load constraints (satisfaction of demand), and these shadow prices are precisely the marginal costs incurred by marginal increases in demand. Note, however, that these marginal costs are defined only with respect to the costs considered in the linear program. Therefore, these marginal costs will have to be complemented by other marginal costs such as the distribution marginal costs computed in the next step, together with the total new distribution plant. The total new plant (production, storage, transmission, distribution) is then calculated and serves as an input to the financial analysis submodel, which closely replicates the financial analysis typically made in the context of rate cases. The utility's rate base is first calculated, and then so is the revenue from gas sales necessary to provide the allowed rate of return on this rate base. This revenue, divided by the total annual gas load, yields the appropriate average volumetric rate. This rate will be used as the new rate for the calculation of the monthly sectoral loads in the next iteration. At each iteration, the average cost pricing policy is evaluated with respect to criteria such as (1) total gas consumption, (2) peak monthly load, (3) load factor, and (4) consumers' and producer's surpluses (two measures of the overall economic efficiency of the pricing policy). This iterative procedure ends when the difference between the demands of two consecutive iterations does not exceed an exogenously prescribed small value. Note that, by virtue of the method of computing the average rate, the revenue requirement objective is always achieved.

Total monthly marginal costs are then computed. Monthly rates may either be equated to these marginal costs or be based on them, according to various possible adjustment procedures. These rates are then inputs to the Marginal cost pricing policy block, leading to the calculation of initial monthly sectoral loads. This block consists of a repetition of a calculation cycle similar to that of the Average cost pricing policy block, the major difference being that rates are now based on marginal costs and are no longer equated to the average cost. Therefore, the revenue requirement constraint is, in most cases, very unlikely to be achieved, and an additional rate adjustment mechanism is considered, based on the difference between the revenue requirement goal and the actual revenue. New rates are computed at the end of each cycle and are used to compute the monthly sectoral loads at the beginning of the next cycle. If the new loads are equal to the loads computed in the previous iteration and if the revenue requirement objective is achieved, the iterative procedure is terminated.

Extensions of the Initial Version of the Model

The changes brought to the former version of the model are:

1. The specification of the monthly gas demand functions.

2. The equilibrating procedure in the Average cost pricing policy.
3. The specification of rates based on but not necessarily equal to marginal costs.
4. The adjustment of marginal-cost-based rates to achieve the revenue requirement objective.

The monthly sectoral load functions are, as in the former study, of the forms:

$$DGMR_m = DGRMRO_m \; * \; (1+RMR) \; * \left(\frac{P_m}{PAVG} \right)^{ELR_m} \tag{5.1}$$

$$DGMC_m = DGMCO_m \; * \; (1+RMC) \; * \left(\frac{P_m}{PAVG} \right)^{ELC_m} \tag{5.2}$$

$$DGMI_m = DGMIO_m \; * \; (1+RMI) \; * \left(\frac{P_m}{PAVG} \right)^{ELI_m} \tag{5.3}$$

$DGMR_m$, $DGMC_m$, and $DGMI_m$ are the residential, commercial, and industrial loads in month m during the planning (horizon) year; $DGMRO_m$, $DGMCO_m$, and $DGMIO_m$ are the corresponding loads in the base year when rates are equal to the reference price PAVG; RMR, RMC, and RMI are the residential, commercial, and industrial sectors growth rates between the base year and the planning year; P_m is the gas rate during month m, and PAVG a parameter taken as a reference price; and ELR_m, ELC_m, ELI_m are the residential, commercial, and industrial demands price elasticities for month m. In the former study, where there was no equilibrating procedure for the Average cost pricing policy analysis, PAVG was determined at the end of this procedure, in the financial analysis submodel, as the required revenue divided by the total annual gas load, and the resulting value was used as the parameter of equations (5.1) - (5.3) in the Marginal cost pricing policy block. In the new model version, PAVG is specified from the beginning in the exogenous data and assumptions block. This prior specification leads to a complete exogenous specification of the demand functions, and hence to the possibility of conducting an equilibrating analysis in the case of the average cost pricing policy, and then of fully comparing average cost and marginal-cost-based pricing policies. PAVG was set equal to 1650 \$/MMCF in all the applications described later on. On the basis of the computer runs of the former model, this value was deemed close enough to the final equilibrium rate to avoid a large number of iterative cycles to reach the equilibrium. The elasticity assumptions used in the former study were also modified on the basis of some new results gathered from the recent literature, in particular the Gas Rate Design Study conducted by ICF, Inc., for the U.S. Department of Energy. The following values were selected:

$$ELR_m = \begin{cases} -0.20 \text{ during the summer season (April through October)}, \\ -0.24 \text{ during the winter season (November through March)}; \end{cases}$$

$$ELC_m = 0.21 \text{ during any month;}$$

$$ELI_m = 0.11 \text{ during any month.}$$

The equilibrating procedure of the Average cost pricing policy block is self-explanatory and rigorously similar to the same procedure in the Marginal cost pricing policy block. The procedure is terminated when the difference, for any month, between the demands of two consecutive years is less than 1 MMCF.

In addition to keeping the option of equating rates to marginal costs as in the former study, two marginal-cost-based rate formulations were developed, focusing on the allocation of the distribution capacity marginal cost. In the case of a pure peak-load allocation, the monthly rates are set equal to the total monthly marginal costs, TMC_m, with:

$$TMC_m = \begin{cases} MC_m + COM_2 + CMPT_2 + CMPD, \text{ if } m = m_p, \\ MC_m + COM_2, \text{ if } m \neq m_p, \end{cases} \tag{5.4}$$

where MC_m is month m marginal cost derived from the cost minimization submodel, $CMPT_2$ is the transmission component T_2 marginal capacity cost, CMPD is the distribution system marginal capacity cost, and COM_2 represents other operating marginal costs, corresponding to costs proportional to sales and not considered in the cost minimization submodel. The reader is referred to the former study for the calculation of $CMPT_2$, CMPD, and COM_2. Instead of assigning the marginal costs ($CMPT_2$ + CMPD) to the peak-load month m_p, two other assignments are considered:

(a) apportionment of these marginal costs equally over the three peak winter months: December, January, and February;

(b) apportionment of these marginal costs equally over the five months of the winter season (November through March).

The monthly rates are then defined as:

$$P_m = \begin{cases} MC_m + COM_2 + PK * (CMPT_2 + CMPD), \text{ if } m \in M_p, \\ MC_m + COM_2, \text{ if } m \notin M_p, \end{cases} \tag{5.5}$$

where M_p is the set of peak months to which the distribution-capacity-related marginal costs are assigned, and PK is the apportionment factor (PK = 1/3 in the case of the 3-month allocation, and PK = 1/5 in the case of the 5-month winter allocation).

The price adjustment procedure to achieve the revenue requirement objective is based on the comparison of the equilibrium gas sales revenues XE necessary to earn the allowed operating income with the actual gas sales revenues based on the current prices, XA. XE is computed in the financial analysis submodel, and XA is computed in the evaluation submodel (EVAL2). The revenue deficit (or surplus) is defined as:

$$DF = XA - XE \tag{5.6}$$

and the price adjustment factor is then:

$$ADJ_t = XE/XA \tag{5.7}$$

Such an adjustment factor is specific to each iteration t, hence the notation ADJ_t. The factor to be applied to the marginal-cost-based rates for iteration (t + 1) is the product $TADJ_{t+1}$ of all the previous adjustment factors, with:

$$TADJ_{t+1} = ADJ_t * ADJ_{t-1} * ADJ_{t-2} * \ldots * ADJ_1 \qquad (5.8)$$

The monthly rates to be applied at the beginning of iteration t are then:

$$P_{mt} = \begin{cases} [MC_{mt-1} + COM_2 + PK * (CMPT_2 + CMPD)] * TADJ_t, \text{ if } m \in M_p, \\ [MC_{mt-1} + COM_2] * TADJ_t, \text{ if } m \notin M_p. \end{cases} \qquad (5.9)$$

Application of the Gas Utility Marginal Cost Pricing Model

The Assumption

Besides the changes described in the previous section, the values of the different technological, cost, and financial parameters of the model have not been modified, as compared to the applications reported in the former study. The model has been applied here under only one set of assumptions related to the maximum annual supplies available from the East Ohio Gas Company's major suppliers, Consolidated Gas Supply Corporation, and Panhandle Eastern Pipeline Company. The following values were considered:

SUP1T = 500,000 MMCF for Consolidated, and
SUP2T = 200,000 MMCF for Panhandle.

The Results

The average cost pricing iterative procedure reaches an equilibrium in three iterations, while the three-and five-month allocation procedures of the marginal-cost-based pricing policy reach an equilibrium in four iterations. The equilibrium rates are presented in table 5.1, together

TABLE 5.1

TOTAL MARGINAL COSTS, INITIAL RATES, AND EQUILIBRIUM RATES ($/MMCF)

Month	Equilibrium Average Cost	Total Marginal Cost	Three-Month Allocation		Five-Month Allocation	
			Initial Rate	Final Equilibrium Rate	Initial Rate	Final Equilibrium Rate
April	1704.60	1411.88	1411.88	1318.48	1411.88	1329.72
May	1704.60	1411.88	1411.88	1318.48	1411.88	1329.72
June	1704.60	1411.88	1411.88	1318.48	1411.88	1329.72
July	1704.60	1411.88	1411.88	1318.48	1411.88	1329.72
August	1704.60	1411.88	1411.88	1318.48	1411.88	1329.72
September	1704.60	1411.88	1411.88	1318.48	1411.88	1329.72
October	1704.60	1411.88	1411.88	1318.48	1411.88	1329.72
November	1704.60	1508.78	1508.78	1408.97	1899.78	1789.22
December	1704.60	1508.78	2160.44	2017.52	1899.78	1789.22
January	1704.60	4304.10	2784.48	2600.28	2523.82	2376.94
February	1704.60	1508.78	2160.44	2017.52	1899.78	1789.22
March	1704.60	1508.78	1508.78	1408.78	1899.78	1789.22

Source: Author's calculations

with the exact total monthly marginal costs and the initially derived monthly rates based on these marginal costs. These initial rates were adjusted by factors equal to 0.934 and 0.942 in the cases of the three-month and five-month allocations to account for the revenue requirement constraint. The corresponding monthly and total annual loads for the residential, commercial, industrial, and total markets are presented in tables 5.2 through 5.4. While it is notable that the January peak gas demand is reduced by about 10% in the case of the marginal-cost-based pricing policies as compared to the average cost pricing policy, the opposite is true, although by a much smaller margin (0.3%), for the total annual gas comsumptions. This annual effect is the balance of opposite trends: the residential consumption decreases under the marginal-cost-based pricing policies, the industrial consumption increases, and the commercial one changes very little. The residential consumption decrease can be explained by (1) higher prices in winter, (2) higher monthly price elasticities in winter, and (3) significantly higher loads in winter because of the space-heating requirements. In the case of the industrial sector, the price elasticity is lower and uniform throughout the year, and the space-heating load component is less important than in the residential sector. Hence, the decrease in industrial consumption in the peak-price months is more than compensated by an increase in the other months.

The loads presented in tables 5.2 through 5.4 are part of the constraints of the cost minimization submodel solved at the last iteration of the equilibrating procedures. The corresponding minimum costs CT and their breakdown into various components are presented in table 5.5. The decrease in CT for the two marginal-cost-based pricing policies is mainly due to the decrease in the total demand and writer requirement charges, that compensate for the increases in total commodity charges due to the above-mentioned increases in total annual consumptions.

The previous results are further illustrated and clarified by the optimal values of the submodel's decision variable, as presented in tables 5.6 and 5.7. Table 5.6 shows that, in all cases, all the available

TABLE 5.2

SECTORAL MONTHLY LOADS (MMCF) WITH MARKET GROWTH RATES EQUAL TO 50% AVERAGE COST PRICING POLICY

Month	Residential Load DGMR	Commercial Load DGMR	Industrial Load DGMI	Total Load DGMT
April	22,827	9,130	17,915	49,873
May	13,619	5,626	16,538	35,782
June	6,574	2,944	15,484	25 002
July	5,166	2,409	15,273	22,848
August	5,448	2,516	15,315	23,279
September	9,068	3,894	15,857	28,819
October	18,017	7,299	17,195	42,511
November	30,129	11,924	19,013	61,067
December	42,905	16,794	20,927	80,626
January	47,749	18,639	21,653	88,042
February	42,005	16,450	20,793	79,248
March	36,531	14,364	19,973	70,868
Total	280,039	111,991	215,936	607,966

Source: Author's calculations

TABLE 5.3

SECTORAL MONTHLY LOADS (MMCF) WITH MARKET GROWTH RATES EQUAL TO 50%
MARGINAL-COST-BASED PRICING THREE-MONTH ALLOCATION POLICY

Month	Residential Load DGMR	Commercial Load DGMR	Industrial Load DGMI	Total Load DGMT
April	24,030	9,636	18,429	52,095
May	14,337	5,938	17,011	37,286
June	6,921	3,108	15,927	25,955
July	5,439	2,542	15,711	23,691
August	5,735	2,655	15,754	24,144
September	9,546	4,110	15,311	29,967
October	18,966	7,704	17,688	44,358
November	31,538	12,411	19,416	63,365
December	41,204	16,210	20,543	77,957
January	43,147	17,058	20,670	80,875
February	40,340	15,878	20,411	76,629
March	38,240	14,951	20,395	73,586
Total	279,443	112,199	218,266	609,909

Source: Author's calculations

TABLE 5.4

SECTORAL MONTHLY LOADS (MMCF) WITH MARKET GROWTH RATES EQUAL TO 50% MARGINAL-COST-BASED PRICING FIVE-MONTH ALLOCATION POLICY

Month	Residential Load DGMR	Commercial Load DGMR	Industrial Load DGMI	Total Load DGMT
April	23,990	9,619	18,411	52,020
May	14,313	5,927	16,996	37,235
June	6,909	3,102	15,912	25,923
July	5,430	2,538	15,696	23,663
August	5,725	2,650	15,739	24,115
September	9,530	4,102	16,296	29,928
October	18,934	7,690	17,672	44,296
November	29,781	11,804	18,912	60,497
December	42,409	16,624	20,816	79,849
January	44,087	17,382	20,875	82,345
February	41,519	16,284	20,682	78,485
March	36,109	14,219	19,866	70,194
Total	278,735	111,941	217,875	608,551

Source: Author's calculations

TABLE 5.5

COST STRUCTURE OF THE OPTIMUM SOLUTIONS OF THE COST MINIMIZATION SUBMODEL
(IN DOLLARS)

Cost Component	Average Cost Pricing Policy	Marginal Cost-Based Pricing Policy: Three-Month Allocation	Marginal Cost-Based Pricing Policy: Five-month Allocation
Total Cost CT	$ 751,014,287	$ 748,216,143	$ 747,361,371
Total Commodity Charge	$ 639,149,996	$ 641,411,956	$ 639,833,477
Total Demand Charge	35,105,541	32,294,139	32,871,856
Total Winter Requirement Charge	19,702,736	18,979,369	18,880,275
Wellhead Purchases	18,888,000	18,888,000	18,888,000
Field-line Purchases	0	0	0
Production Operations	18,667,121	18,726,810	18,685,139
Storage Operations	4,021,736	4,021,736	4,021,736
Total Operating Costs OMC_1	$ 735,535,097	$ 734,322,042	$ 733,180,487
Total Annualized Investment Costs PIS	$ 15,479,190	$ 13,894,102	$ 14,180,884
Total Discounted Investment Costs NEWPIS	124,731,552	111,958,880	114,269,776

Source: Author's calculations

TABLE 5.6

OPTIMAL MONTHLY PURCHASES FROM CONSOLIDATED AND PANHANDLE
AND STORAGE DELIVERIES AND WITHDRAWALS (MMCF)

Month	Average Cost Pricing Policy			Marginal-Cost-Based Pricing Policy					
				Three-Month Allocation			Five-Month Allocation		
	Consolidated SUP_1	Panhandle SUP_1	Storage Deliveries (-) and Withdrawals (+)	Consolidated SUP_1	Panhandle SUP_2	Storage Deliveries (-) and Withdrawals (+)	Consolidated SUP_1	Panhandle SUP_2	Storage Deliveries (-) and Withdrawals (+)
April	43,449.82	14,634.15	-11,900.00	45,349.66	14,634.15	-11,582.50	45,595.86	14,634.15	-11,900.00
May	19,890.72	14,634.15	- 2,431.31	29,958.04	14,634.15	-11,000.40	29,866.42	14,634.15	-10,975.74
June	17,465.85	14,634.15	-10,786.91	17,773.00	14,634.15	-10,146.02	9,841.11	14,634.15	- 2,242.47
July	14,474.14	14,634.15	- 9,949.10	14,721.13	14,634.15	- 9,357.99	15,287.62	14,634.15	- 9,949.10
August	14,132.19	14,634.15	- 9,176.39	14,447.08	14,634.15	- 8,631.17	14,966.91	14,634.15	- 9,176.37
September	18,959.66	14,634.15	- 8,463.66	19,599.65	14,634.15	- 7,960.80	20,067.57	14,634.15	- 8,463.66
October	31,994.65	14,634.15	- 7,806.30	27,864.75	14,634.15	- 1,834.76	33,777.70	14,634.15	- 7,806.30
November	21,140.55	19,512.20	+16,725.01	23,433.70	19,512.20	+16,725.01	20,569.01	19,512.20	+16,725.01
December	45,244.44	19,512.20	+12,180.54	42,569.98	19,512.20	+12,180.54	44,465.79	19,512.20	+12,180.54
January	52,521.61	19,512.20	+12,318.50	45,349.66	19,512.20	+12,318.50	46,823.43	19,512.20	+12,318.50
February	45,605.95	19,512.20	+10,440.60	42,981.59	19,512.20	+10,440.60	44,841.90	19,512.20	+10,440.60
March	38,818.07	19,512.20	+ 8,848.99	41,530.59	19,512.20	+ 8,848.99	38,142.75	19,512.20	+ 8,848.99
Total	363,697.60	200,000.00	0.00	365,578.87	200,000.00	0.00	364,226.07	200,000.00	0.00

Source: Author's calculations

TABLE 5.7

OPTIMAL MAXIMUM SUPPLIES FROM CONSOLIDATED AND PANHANDLE, WELLHEAD AND FIELD-LINE MONTHLY PURCHASES, INCREMENTAL PRODUCTION CAPACITY AND CONSTANT MONTHLY PRODUCTION, INCREMENTAL STORAGE CAPACITY AND TOTAL STORAGE DELIVERIES, AND INCREMENTAL TRANSMISSION CAPACITY

Variable	Average Cost Pricing Policy	Marginal-Cost-Based Pricing Policy	
		Three-Month Allocation	Five-Month Allocation
Consolidated's Maximum Supply:			
- Daily (MMCF)	1,750.72	1,511.66	1,560.78
-Monthly (MMCF)	52,521.61	45,349.66	56,823.43
Panhandle's Maximum Supply:			
-Daily (MMCF)	650.41	650.41	650.41
-Monthly (MMCF)	19,512.20	19,512.20	19,512.20
Monthly Wellhead Purchases (MMCF)	2,000.00	2,000.00	2,000.00
Monthly Field-line Purchases (MMCF)	0.00	0.00	0.00
Incremental Production Capacity (MMCF/month)	741.12	746.53	742.75
Monthly Production (MMCF)	1,688.79	1,694.19	1,690.42
Incremental Storage Capacity (MMCF)	0.00	0.00	0.00
Total Storage Deliveries (MMCF)	60,513.64	60,513.64	60,513.64
Transmission Component T_1 Incremental Capacity (MMCF/month)	20,722.59	13,556.05	15,026.05

Source: Author's calculations

supplies from Panhandle are purchased, and in such a way that the take-or-pay clause (75% of the contract demand) is never implemented. All the available wellhead gas is purchased because of its low cost (787 $/MMCF), whereas field-line gas is never purchased because of its high cost (1481 $/MMCF). Production is not a cost-attractive alternative, and the production capacity is expanded just enough to provide for the minimum production requirement. In all cases, no additional storage capacity is developed, while the existing capacity is used at a maximum (total annual deliveries equal to 60,513.84 MMCF). Table 5.6 shows that the storage withdrawal pattern is the same in the three pricing policies (November through March), while storage deliveries patterns display variations most likely linked to the load patterns. Table 5.7 clearly indicates the decrease in Consolidated's maximum daily supply when shifting form the average cost pricing policy to the marginal-cost-based pricing policies. A similar decrease is notable for transmission component T_1 incremental capacity, and both decreases are, of course, related to the decrease in the peak-month load.

The results of the analyses performed in the distribution and financial submodels are presented in table 5.8. The lower revenue requirements and average volumetric rates in the cases of the two marginal-cost-based pricing policies are attributable to (1) lower operating expenses (see the total cost CT in table 5.5), and (2) a lower allowed operating income. The latter is linked to a lower rate base (or net plant in service), itself related to less new plant put in service, in particular less new distribution plant highly related to the peak-month load.

The evaluation criteria are presented in table 5.9. The marginal-cost-based pricing policies are superior to the average cost pricing policy with respect to peak sales and load factors, but the reverse is true with respect to total annual comsumption, although by a much smaller margin. The superiority of the marginal-cost-based pricing policies is also clear when considering consumer's surpluses. The difference is total aggregate efficiency varies from about $14 million (three-month allocation) to about

TABLE 5.8

DISTRIBUTION PLANT, FINANCIAL VARIABLES, AND AVERAGE VOLUMETRIC RATES

Variable	Average Cost Pricing Policy	Marginal-Cost-Based Pricing policy	
		Three-Month Allocation	Five-Month Allocation
New Transmission Plant T_2($)	0	0	0
New Distribution Plant ($)	456,211,968	343,316,480	366,473,472
Total New Plant ($)	580,943,360	455,275,264	480,743,168
Net Plant in Service ($)	966,362,880	843,742,720	868,592,896
Allowed Operating Income ($)	116,543,349	101,755,351	104,752,298
Actual Operating Expenses ($)	898,769,428	894,270,600	893,593,118
Revenue Requirement ($)	1,036,321,631	1,028,274,040	1,028,240,630
Average Volumetric Rate ($/MMCF)	1,704.600	1,685.946	1,689.654

Source: Author's calculations

TABLE 5.9

EVALUATION CRITERIA

Variable	Average Cost Pricing Policy	Marginal-Cost-Based Pricing policy	
		Three-Month Allocation	Five-Month Allocation
Gas Consumption/Conservation			
Peak Sales Month	January	January	January
Peak Sales (MMCF)	88,041.09	80,874.55	82,344.55
Sales Load Factor	0.5755	0.6285	0.6159
Total Gas Consumption (MMCF)	607,963.08	609,909.15	608,551.11
Economic Efficiency			
Residential Surplus ($)	1,791,126,462	1,790,030,738	1,791,942,065
Commercial Surplus ($)	731,010,827	731,212,581	731,937,167
Industrial Surplus ($)	1,577,914,301	1,607,825,571	1,605,630,620
Total Consumer's Surplus ($)	4,100,051,590	4,129,068,890	4,129,509,852
Net Utility Income ($)	116,543,349	101,755,351	104,752,298
Aggregate Efficiency ($)	4,216,594,939	4,230,824,241	4,234,262,150

Source: Author's calculations

$ 18 million (five-month allocation).

Possible Extensions of the Model

The results of the application of the new version of the model show that:

1. A stable solution avoiding the peak-shifting phenomenon may be obtained when applying marginal-cost-based pricing policies involving the spreading of marginal distribution capacity cost over several winter months, whereas the peak-month allocation does not, in general, lead to a stable solution.

2. The two marginal-cost-based pricing policies considered in this analysis are clearly superior to the average cost pricing policy, both in terms of load structure and resource allocation efficiency.

Obviously, actual gas utility rates are not set equal to average costs but try to account for a fair allocation of costs among customer classes. Thus, it would probably be instructive, in future analyses, to replace the average cost pricing policy by current rate-making policies, and then compare these policies with the marginal-cost-based ones. Such an analysis would require some modifications of the financial analysis submodel.

Another extension of the model would involve using some of the plant and operating and maintenance statistical cost functions developed in chapter 4. Such cost functions could be used for the calculation of both total costs and marginal costs, and could ease the application of the model to any utility.

Finally, the model could be used in an incremental fashion, simulating annual decisions, year after year, instead of considering a long-term planning horizon. Such an approach would be closer to the real-world process of utility operations and expansion, and could shed a new light on the value of marginal-cost-based pricing policies.

CHAPTER 6

THE PLANNING APPROACH TO MARGINAL COSTS: A SIMPLIFIED METHOD

In this chapter, a simplified method by which the marginal cost of natural gas distribution can be calculated is outlined. The method is simple in the sense that it requires only an intense effort in gathering and organizing data, a hand-held calculator, and a statistical table. Unlike other approaches presented in this report, this method assumes that one can obtain nonpublic cost information from the distributor's planning engineers. The most important questions addressed here are the following:

(1) What elements should be measured in a marginal cost calculation?
(2) What is the proper time period in which to measure marginal costs for each element?
(3) What is the proper measure of the capacity for each element?
(4) What sources of gas supply does the utility have available?
(5) How should the annual costs of marginal capacity be allocated to the periods of the year?

This chapter has five sections. The first contains a discussion of the cost of marginal transmission capacity. This cost is a weighted average of the construction projects for new transmission pipeline the distributor is undertaking. Questions 2 and 3 above are investigated in depth in this section. In the second section, a method by which the cost of marginal distribution capacity can be calculated is presented. This cost is broken down into two parts. The first is related to the hourly volume of gas delivered. The second is the marginal customers cost. In the third section of the paper, a method by which to allocate the costs of marginal capacity to the hours, days, weeks, or months of the year is suggested. The capacity cost includes the demand charges and the cost of unused gas under the take-or-pay clause, as well as the distribution and transmission capacity charges. The fourth section of the chapter presents a method with which gas supply can be optimized manually and the marginal cost of supply tabulated. In the fifth section, a suggestion is made about how the marginal costs for each day, week, or month can be translated into time-of-use prices.

The Cost of Marginal Transmission Capacity

Distribution companies build transmission pipelines in order to transport gas from its suppliers to its distribution systems in metropolitan areas. Some distributors may route the gas through storage fields in this transmission phase. For the most part these pipelines are short transmission lines of less than 150 miles. The outlet pressure for such lines is a deciding consideration in their design. The objective of the distribution company is to design and build a pipeline to transport a given volume of gas in a specified time period between two points at minimum annual cost.

When one addresses the questions of the proper measure of capacity and the time frame for the measurement of costs, pipelines, both transmission and distribution, in general present common problems. These problems center on the lumpiness of the investment process and the difficulties in formulating reliable demand forecasts for the long term.

Problems in Measuring Capacity

Investment costs for transmission pipelines are incurred in terms of dollars per mile, dollars per ton, and dollars per inch diameter-mile. An important portion of the investment costs for a pipeline is the right-of-ways and the laying costs. Laying costs include the costs of clearing the land, ditching, laying, welding, and backfilling. These costs remain relatively stable whether a 16, 24, or 36 inch pipe is laid. The relative magnitude of the land costs and the laying costs creates incentives for the distributor to lay a pipe larger than is presently necessary in anticipation of future demand growth.

The optimal level of unused capacity to hold for future use depends primarily on the growth rate of peak-day demand and the costs of holding unused capacity relative to the present value of installing additional capacity in the future. A careful weighing of these factors will enable the distribution company to achieve all feasible economies of scale. Uncertainty of demand growth, however, greatly complicates the decision process.

Transmission lines are designed to carry the peak-day deliveries of gas from suppliers to the town-border station. This specification is called the design-day volume and is expressed as a flow of gas per day, MMCFD. The design-day volume is the proper measure of capacity for a new pipeline as long as the design-day volume corresponds to the maximum peak-day delivery reasonably expected to occur in the future.

The uncertainty surrounding a demand forecast can cause design-day volume to diverge from expected maximum peak-day deliveries. This can present problems for one wishing to use maximum peak-day deliveries as a proxy for capacity. Unused capacity is installed to enable the utility to grow into the pipeline and realize all feasible economies of scale. The time frame relevant to this decision is related closely to the useful life of the pipeline. Long-term forecasts for periods approximating the pipeline's useful life may be quite unreliable. In these circumstances, use of maximum peak-day demand expected to occur in the future is not necessarily an appropriate proxy for capacity.

One has available at least two ways to measure capacity. The reference figure for capacity is the potential maximum peak-day delivery the pipeline can transport. This can be calculated with knowledge of the length, thickness, and diameter of the pipeline, its working stress, the inlet and outlet pressures, and properties of the gas.[1] The other approach is to assume the utility's planning is optimal, and long-term forecasts are reliable. In either case, the demand forecasts and design-day volume are scrutinized, and a measure of design-day volume, MMCFD, is decided on as the proper measure for the capacity of the transmission pipeline.

Determining the Time Period

The lumpiness of the investment process in natural gas transmission presents problems for the time period over which to measure marginal costs. A distribution company installs the transmission line with the view of growing into the pipeline. The time period from the conception of the construction program until the pipeline is used to full capacity can be quite long. This time period can be divided into the lead time period and the period of unused capacity. Lead time encompasses the period from the conception of the construction project until its completion. The period of unused capacity is the time span during which the utility plans to grow into the line. These two periods vary considerably among construction projects. The foregoing considerations imply that the lumpiness of investment translates into lumpiness of time periods for each construction program.

In accounting for the lumpiness of time periods, one must examine the point in time in which one seeks to measure marginal cost relative to both the historical and projected growth of the system. One wants to measure the total cost of the project and charge it to the periods for which it is marginal. This process is very judgmental, and its use must be carefully qualified. A couple of possible scenarios will be presented below.

The easiest possible scenario is a situation where one begins examining the cost of marginal capacity in the initial stages of the project.

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[1] See Engineers Gas Handbook, chap. 4, pp. 8-92, and Hollis B. Chenery, "Engineering Production Functions," Quarterly Journal of Economics, vol. 63, 1949.

Furthermore, the growth rate of demand is such that the pipeline is planned to be fully utilized within a period of years after construction is completed. Given this time frame, one must be sure that the costs already incurred in the initial stages have been included in the total cost of the project. The time period for which the project is considered marginal will be the remaining lead time plus the anticipated period required to grow into the pipeline. It is always this full time horizon that must be examined.

Another possible scenario arises once the pipeline is completed and operational, but still has unused capacity. In this case, one cannot identify clearly a construction program and may conclude that transmission is not marginal. Such a conclusion is erroneous. It ignores the planned, unused capacity that the distribution company installed.

With qualifications added below, the following procedure is suggested in these circumstances. Any given transmission line in the period of planned, unused capacity should be considered marginal. One should use the trended annual value of the construction program as the addition to total transmission cost for added capacity. This procedure involves the use of historical information concerning the specific construction program. This historical figure must be trended to correct for price changes using an index of construction costs, such as the Handy-Whitman Index. This procedure is necessary in order to smooth the effects of lumpy investments.

This procedure is highly judgmental and must be used carefully. The rationale focuses on the lumpiness of the investment in transmission pipelines and the entailing period of unused capacity. Careful identification of this period is necessary; it is easy to confuse unused with excess capacity. Unused capacity is a planned set of circumstances. Excess capacity, on the other hand, is an unplanned under-utilization of an investment. Moreover, it is a chronic condition usually resulting from an unanticipated downward swing in demand.

Differentiating these two conditions requires that a time profile for the planned utilization of the project be developed and the market history examined. A decline in the growth rate of demand would provide evidence of excess, as opposed to unused, capacity. More details could be examined. Probably the most constraining factor in this inquiry would be the availability of the information necessary to develop a time profile. One thing is clear however: the existence of excess capacity in transmission renders the capacity non-marginal. Thus, investment costs associated with excess capacity are not part of a marginal cost calculation, while those for unused capacity are included.

The Problem of Lumpiness: Some Concluding Remarks

Lumpiness of the investment has three main consequences for the quantification of the cost of marginal transmission capacity. First, the proper measure of capacity in terms of design-day volume is complicated by the planned installation of unused capacity into which the demand can grow. Second, the existence of unused capacity extends the period for which transmission capacity is marginal beyond the construction period. Finally, one must carefully distinguish between unused and excess capacity. For this last consequence, one should examine the actual demands for downward swings relative to the demands forecasted. Each of these complications requires careful investigation and judgment.

Calculating the Cost of Marginal Transmission Capacity

The actual calculation of the cost of marginal transmission capacity for new pipeline is relatively straightforward once the foregoing issues have been resolved. For each construction program, the utility has calculated the first investment cost. This cost is incurred with respect to both design-day volume and the length of the pipeline. The cost per unit of marginal capacity will vary considerably with pipeline length. If comparisons of marginal costs between projects is attempted, the cost per unit of marginal capacity per mile should be the basis of the comparison.

For a given construction project installing new pipeline capacity, the cost of marginal transmission capacity is calculated in two basic steps. First, the annual cost of the construction project is calculated. This involves determining the capital recovery factor[2], CRF, for the utility, and then multiplying it by the first investment cost of the i-th new project, or IT_i^n.[3] This annual cost is divided by the design-day volume for the i-th new project, or KT_i^n. If MCT_i^n is the cost of marginal transmission capacity for the i-th new construction project, this calculation is formalized as:

$$MCT_i^n = \frac{CRF * IT_i^n}{KT_i^n} \tag{6.1}$$

$$= \frac{\text{the annual cost of the i-th construction project}}{\text{the design-day volume for the i-th construction project}}$$

In order to calculate the overall or total cost of marginal transmission capacity, a weighted average of all projects must be calculated. The weight for the i-th project, or WT_i^n, is the design-day volume for the i-th construction project divided by the sum of the design-day volumes for all projects, with:

$$WT_i^n = \frac{KT_i^n}{\sum_i KT_i^n} = \frac{\text{design-day volume for the i-th project}}{\text{sum of all projects' design-day volumes}} \tag{6.2}$$

The total cost of marginal transmission capacity is:

$$MCT^n = \sum_i WT_i^n * MCT_i^n \tag{6.3}$$

or

$$MCT^n = \frac{\sum_i CRF * IT_i^n}{\sum_i KT_i^n} \tag{6.4}$$

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[2] See chapter 2, equation (2.23)

[3] As previously noted, the first investment cost can be a historic figure. In this case the IT_i is the historic cost times a replacement multiplier based on an index of utility construction costs. The superscript n refers to new construction projects.

The value of MCT^n represents the addition to the cost of transmission capacity per unit of design-day volume added to the system.

When existing transmission pipelines have their capacity augmented, the procedure for calculating the cost of marginal capacity is basically the same. There is one change, however. The denominator for the i-th project's cost of marginal transmission capacity becomes the change in design-day volume, or ΔKT_i^e.[4] This volume can be increased by installing additional compressors to increase the compression ratio and by reinforcing the pipeline to operate at this higher pressure. Another method is looping. This involves laying a parallel line. In these circumstances the cost of marginal transmission capacity is:

$$MCT_i^e = \frac{CRF * IT_i^e}{\Delta KT_i^e} , \qquad (6.5)$$

where MCT_i^e is the cost of marginal transmission capacity when the capacity of an existing pipeline is increased, and IT_i^e the first investment cost of this extension.

The total cost of marginal transmission capacity for existing lines is a weighted average of the relevant construction programs. The weight is calculated as:

$$WT_i^e = \frac{\Delta KT_i^e}{\sum_i \Delta KT_i^e} . \qquad (6.6)$$

The total cost of marginal transmission capacity for existing lines is finally:

$$MCT^e = \sum_i WT_i^e * MCT_i^e \qquad (6.7)$$

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[4] The superscript e refers to the extension of existing pipelines.

This figure is combined with the cost of marginal transmission capacity for completely new lines.

The previous procedures are used to calculate the marginal cost of transmission capacity for totally new projects and for expansion of existing capacity when taken separately. When both kinds of projects are undertaken, a new weighting procedure is necessary. A weighted average of all of the MCT^n_i and MCT^e_i is the appropriate way to combine these costs of marginal transmission capacity. The weights for the i-th project when completely new capacity is added are given by:

$$WT_i = \frac{KT_i}{\sum_i (KT_i + \Delta KT_i)} \qquad (6.8)$$

When the i-th project augments existing capacity the weights are:

$$WT'_i = \frac{\Delta KT_i}{\sum_i (KT_i + \Delta KT_i)} \qquad (6.9)$$

The system's cost of marginal transmission capacity is finally given by:

$$MCT = \sum_i WT_i * MCT^n_i + \sum_i WT'_i * MCT^e_i \qquad (6.10)$$

The addition of transmission capacity to the system impacts on the operating costs to be incurred. Theory suggests that the change that occurs in operating costs is an integral part of the cost of marginal capacity. This change in operating costs presents problems in designing simplified methods for quantifying the cost of marginal transmission capacity.[5]

[5] See R.E. Dansby, "Capacity Constrained Peak Load Pricing," Quarterly Journal of Economics, August 1978, pp. 387-398.

Ideally, one would like to be able to simulate the operation of the transmission system without the additional capacity and then with it. The difference in the operating cost under these two circumstances would provide the information necessary to calculate the change in operating costs. In considering this change, one would examine the costs of operation for the new segment of transmission line, as well as the lower utilization of less efficient transmission capacity. Adding this change to the total cost of marginal transmission capacity calculated above, would yield the best possible estimate for the costs of marginal transmission capacity.

The simplified method assumes that the sophisticated optimization models are not available. Therefore, one must rely on estimates of changes in operating cost from adding capacity. Such calculations should examine the addition to operating, labor, and maintenance costs directly attributable to the additional capacity. More elusive, however, is quantifying the change in operating costs attributable to lower utilization of less efficient technologies; that is, older pipelines. This element of the costs of marginal transmission capacity may prove impossible to calculate. One must look for associated retirements of capacity and shorter hours of utilization for specific pieces of equipment in the system. This task requires detailed operating information which may be impossible to obtain. In any case, one must consider this element in quantifying the costs of marginal transmission capacity.

The change in operating costs attributable to marginal transmission capacity is unitized by the design-day volume for new capacity and the change in design-day volume for improvement and looping of existing capacity. This change in operating costs can be positive, negative, or zero. It is added to the cost of marginal transmission capacity, MCT, calculated above.

To be realistic, the actual calculation of the change in operating costs may be impossible to assess. In these circumstances, some error may be introduced into the cost of marginal transmission capacity. One must accept this error as one of the costs of foregoing computerized techniques in calculating the cost of marginal transmission capacity.

The Cost of Marginal Distribution Capacity

Distribution capacity is installed to deliver hourly volumes of gas from the town-border station to the customer's premises. For analytical purposes, this process can be divided into a transport function and a customer-related component. The transport function designates a system of mains that distributes gas throughout a metropolitan area. The customer related component identifies a service line and some equipment dedicated to delivering gas from a main to a customer's end-use appliances. This latter component varies with the number of customers. The costs of marginal distribution capacity are those costs associated with an increase in the capacity of the system of mains. The marginal customer cost are the costs associated with adding a customer to the system. Each of the costs is treated below.

Planning Considerations

The function of a distribution system is to deliver gas from the town-border station to the consumer's premises. This system is a complex of mains of varying diameters, working stresses, and operating pressures. The adequacy of the system is measured in terms of its ability to meet the hourly peak demands with adequate line pressure.

Planning engineers can anticipate severe pressure drops at different locations in the distribution system. They need information concerning the expected pattern and magnitude of geographic growth, the anticipated customer mix, and the estimated demand diversity along a given segment of lines. Computerized-simulation models allow distribution planners to simulate pressures and flows in the system as they work their way from a given location back toward the town-border station. This simulation identifies segments of the main where severe pressure drops occur. With this information, remedial construction programs are analyzed with the simulation model to pick the best program to restore adequate pressure to deliver the required flow.

The Gas Engineer's Handbook lists six possible ways the capacity of the distribution system can be augmented.[6] Two reasonable and often used choices emerge from this list. The distributor can either upgrade the existing system to operate at higher pressures or replace existing mains with larger mains. Upgrade of existing mains is undertaken because the increment in the expected hourly peak volume of gas cannot be delivered at an adequate pressure. Existing mains are improved and regulators strategically placed to safely augment the pressure in that segment. In circumstances where the mains cannot be safely upgraded to operate at higher pressures, new mains of a larger diameter and/or higher working stress are installed. Either method enables the distributor to meet the increment of hourly peak load along a segment of the system at adequate operating pressure.

These planning considerations provide the basis for calculating the cost of marginal distribution capacity. Computer-simulation models enable the distribution planning engineer to analyze the effect of various construction scenarios. He is able to select the least-cost construction program that adequately and safely augments the capacity of the system. From this simulation, one can obtain the increase in hourly volume along a given segment of main and the cost of the associated construction project. One can then use this information to calculate the cost of marginal distribution capacity for a particular segment of the system, or aggregate it to obtain the cost of marginal capacity of the entire distribution system.

Lumpy Investment for Distribution

The lumpiness of the investment process complicates the calculation of the cost of marginal distribution capacity in the same way it affects

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[6] (pp. 9-68).

transmission. Both the measure for capacity and the time period over which the measurement is made require careful consideration of the accuracy of demand forecasts and the amount of unused capacity. Installation of unused capacity will be treated in the same manner for calculating the cost of marginal distribution capacity as it was for transmission. The reader is referred to the relevant sections above.

A Note on Demand Growth

Installation of new mains or the upgrade of an existing segment of line is usually required in response to growth in the hourly peak demand. Demand growth occurs for one or more of the following three reasons:

1. Existing customers increase their coincident hourly demands.
2. New residential, commercial, and industrial customers locate within the existing system of mains.
3. New residential, commercial, and industrial customers locate beyond the existing system of mains.

The first two types of growth have similar analytical characteristics. The first type of growth can result from a change in the end-use appliance mix or an increase in end-use appliances. The second type of growth adds new end-use appliances which can alter demand diversity and customer mix. These two types of growth only impact on the existing system of mains.

The third type of growth, on the other hand, requires the installation of a completely new segment of mains and may have an impact on the existing system. Extension of mains beyond the existing system can render segments of the existing system inadequate. The planning engineer, in tracing the consequences of the extension of mains and of delivering the required volume to new service areas, may identify severe pressure drops along segments of the existing system of mains. This impact, attributable to the extension of mains, should be treated as a separate construction project for purpose of determining marginal cost. The rationale for this approach focuses on the idea that the cost of construction along any segment should be attributed to those customers who benefit. In this case the upgrade or replacement of existing mains benefits both the new customers beyond the system and the existing customers along the segment of main affected. This is true because the existing customers could cut back their demands for gas and the upgrade or replacement would be unnecessary.

Calculating the Cost of Marginal Distribution Capacity

The calculation of the cost of marginal distribution capacity treats each construction project independently. Separate formulas are developed for the addition of totally new capacity and additions to existing capacity. This approach allows a wide latitude in translating the marginal cost into a system of prices.

Several issues must be resolved in order to calculate the cost of marginal distribution capacity. Among the most important are:

1. The proper measure of capacity for both new capacity and increases in existing capacity. This measure is stated in terms of a volume of gas per hour (MMCFH).

2. The relevant time period during which capacity is marginal. This period will vary among construction projects.

The information from the simulation models is an important input for resolving the first issue. A clear understanding of the implications of the lumpy investment process is important to resolving both issues. The procedure outlined in this subsection assumes that these issues have been resolved satisfactorily.

The extension of distribution mains into a new area has associated with it a first investment cost, ID_i^n, and a capacity, KD_i^n. The cost of marginal distribution capacity for this type project is:

$$MCD_i = \frac{CRF * ID_i^n}{KD_i^n} \tag{6.11}$$

where CRF is the capital recovery factor and MCD_i^n the cost of marginal capacity for the i-th project. The cost of marginal capacity for all projects that extend the system into new areas is a weighted average of all such construction projects in the utility's jurisdictional area. The weight is:

$$WD_i^n = \frac{KD_i^n}{\sum_i KD_i^n} \tag{6.12}$$

This weight yields the percentage of the total marginal capacity for this type project that is represented by the i-th project. The total cost of marginal distribution capacity for extension of mains is given by:

$$MCD^n = \sum_i WD_i^n * MCD_i^n \tag{6.13}$$

This yields a marginal cost for this type of project for the distributor's entire distribution area.

The calculation of the cost of marginal distribution capacity differs somewhat when existing mains are upgraded and reinforced or replaced. In this case, the utility planners have formulated a construction project to correct a severe pressure drop along a segment of line. The cost of this project is ID_j^e, and the associated increase in capacity is ΔKD_j^e. The cost of marginal distribution capacity for increases in existing lines is then:

$$MCD_j^e = \frac{CRF * ID_j^e}{\Delta KD_j^e} \tag{6.14}$$

The total cost of marginal distribution capacity for improvements of existing mains is a weighted average of all such projects in the utility's jurisdictional area. The weight is:

$$WD_j^e = \frac{\Delta KD_j^e}{\sum_j \Delta KD_j^e} \tag{6.15}$$

The total cost of marginal distribution capacity for increases in existing mains is finally:

$$MCD^{e} = \sum_{j} WD^{e}_{j} * MCD^{e}_{j} \qquad (6.16)$$

The cost of marginal distribution capacity for the entire system is a weighted average of the marginal costs MCD^{n}_{i} and MCD^{e}_{j}.[7] The weight for the costs of new projects is:

$$WD_{i} = \frac{KD_{i}}{\sum_{i} KD_{i} + \sum_{j} \Delta KD_{j}} \qquad (6.17)$$

The weight for the cost of projects which upgrade existing mains is given by:

$$WD'_{i} = \frac{\Delta KD_{j}}{\sum_{i} KD_{i} + \sum_{j} \Delta KD_{j}} \qquad (6.18)$$

The cost of marginal distribution for the entire system in a jurisdictional area is given by:

$$MCD = \sum_{i} WD_{i} * MCD^{n}_{i} + \sum_{j} WD'_{j} * MCD^{e}_{j} \qquad (6.19)$$

Marginal Customer Costs

Certain costs incurred by a distribution company are related to the number of customers. These costs are related to the provision of the

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[7] This procedure is strictly similar to that developed in the previous section for transmission capacity.

service pipes, metering of usage, and billing services. The physical connection between the producer's facilities and the consumers' premises render the utility the most efficient and convenient supplier of these services.

In calculating the marginal customer costs, one must recognize the distinction between customer classes. This distinction is integrated into the calculation by developing a typical customer for each class. The characteristics of interest for each classification are:

1. Length, diameter, and working stress of the service.
2. Type and size of regulator.
3. Type and size of valve.
4. Type of meter.

The current market prices for the above components should be gathered. The sum of these costs is the marginal customer cost. This cost figure is calculated on a per customer basis. One might add to this basic cost the change in administrative cost from adding a customer.

The Cost of Marginal Distribution Capacity: Some Concluding Remarks

The cost of marginal distribution capacity is two-part. The first part is related to the maximum hourly load placed on the segments of the system. The system-wide cost of marginal distribution capacity is a weighted average of the costs of construction programs per unit of added hourly capacity. The second part is marginal customer cost. This cost is related to the number of customers. Additional customers require a service, valve, regulator, metering, and monthly billing, the costs of which are expressed on a per customer basis.

A Factor for Assigning Capacity Costs to Time Periods

Capacity costs are expressed on an annual basis for marginal transmission or distribution capacity. Similarly, the capacity-related charge for purchased gas is usually expressed in terms of annual measures. A problem arises when one wishes to assign these costs to intra-annual time periods. For instance, the cost of marginal transmission capacity is incurred because the pipeline must have sufficient capacity to carry the maximum daily load. This implies that the cost of marginal transmission capacity should be assigned to days according to the probability that demand will exceed capacity.

This section will develop an allocation factor based on the probability distribution of degree-day temperatures. This factor

a. Allocates costs to time periods relevant to planning decisions rather than pricing periods.
b. Is based on planning decisions to expand or contract capacity.
c. Reasonably reflects the probability the distributor will be unable to meet any given demand in a specified time period.

The probability of a given occurring degree-day value meets these criteria. First, design-day or design-hour capacity specifications are closely correlated to temperature sensitive loads. Maximum hourly and daily demands can be expressed in terms of a temperature. Second, capacity is designed to meet the maximum load. As a result, the probability of a temperature greater than the design temperature reflects the probability that the distributor will be unable to meet the demand. Finally, planning considerations should guide the selection of the time periods to which costs are assigned. These periods are those for which probabilities are calculated. For instance, the transmission pipeline is planned to meet maximum daily loads, while the distribution system is designed to serve hourly loads.

Distribution companies usually develop a daily probability distribution to carefully plan the purchases of gas as well as curtailment of gas to interruptible customers. This data base along with the utility's design-temperature provides the basis for the development of an allocation factor.

Theoretical Considerations

The theory of peak-load pricing with capacity constraints indicates that the costs of marginal capacity are incurred according to the relative shortage of capacity. Increased demands during the peak periods lead the producer to weigh the costs and benefits of adding capacity rather than leaving the demand unsatisfied. Theory offers the producer a guide in the expansion decision. Capacity is optimal when the sum of the scarcity (or rationing) costs in each of the peak periods just recovers the annual cost of marginal capacity.

Demand, of course, is stochastic. Any given point in time is a potential peak period with a given probability. This stochastic element of demand complicates capacity planning. The producer wishes to meet consumer demands with a given degree of reliability. This criterion can be expressed in terms of meeting a given level of demand with a specified probability. Optimal capacity is installed in a stochastic sense by aligning actual with desired reliability. The scarcity costs (or rationing costs) incurred in any given time period is interpreted as the marginal contribution of capacity to reliability during that period. The sum of these marginal contributions to reliability over a year should recover exactly the annual cost of marginal capacity for an optimally designed system.

Developing the Factor

The information necessary for computing the allocation factor can be obtained from one of two sources. The easiest method is to obtain the probability of a given degree-day occurrence for each day from the distributor. This information is used directly in computing the allocation factor. Another more involved method requires a data bank of hourly temperature readings for an historical period and the distributor's design temperature. One must develop a probability distribution for each day of the year based on the assumption that degree-days are normally or lognormally distributed. This enables one to estimate the probability of the occurrence of a temperature greater than the design-day temperature.

The factor uses this probability as its basis. Let $PR^t(\circ)$ represent a probability function for the t-th day. The probability of a degree-day DD exceeding the design degree-day DD^* on the t-th day is given by:

$$PR^t\ (DD > DD^*) = 1 - PR^t\ (DD \leq DD^*) = \alpha^t \tag{6.20}$$

There is one probability α^t for each day of the year. This number will range between zero and one (That is: $0 \leq \alpha^t \leq 1$).

Theory suggests that the allocation factor should assign the cost of marginal capacity to the days of the year such that a one MMCF of gas demand for the entire year would be sufficient to recover the cost of marginal capacity. To assure this occurrence, the allocation factor is developed as a relative probability. It is given by:

$$A^t = \frac{\alpha^t}{\sum_{t=1}^{365} \alpha_t} \tag{6.21}$$

where A^t is the relative probability of the actual degree-day exceeding the design degree-day. This allocation factor is such that:

$$\sum_{t=1}^{365} A^t = 1 \tag{6.22}$$

Capacity-related costs such as

a. the cost of marginal transmission capacity,
b. the cost of marginal distribution capacity,
c. the demand charge for purchased gas, and
d. the cost of unused gas under take-or-pay clauses,

are assigned to the days of the year by multiplying the allocation factor A^t by the relevant cost of marginal capacity.

The allocation factor can be developed for hours, weeks, and months. The choice of this time period should be dictated by planning considerations. Data and personnel limitations may be a real constraint on this choice. One must weigh carefully the costs and benefits of using rough approximations.

The Marginal Cost of Supply

The marginal cost of natural gas supply is the cost of one more or one less million cubic feet per day (MMCFD) once the optimal mix of suppliers has been determined. The calculation of this marginal cost involves three basic steps. First, the optimal mix of gas suppliers necessary to meet the expected demands, accounting for gas deliveries and withdrawals from storage, must be determined. This optimal mix of suppliers is the mix that minimizes the annual cost of meeting customer demands. The second step is to identify the marginal supplier for each day, week, or month of the year and the prices it charges to the distributor. The final step is to compute the marginal cost for each time period used in step two above. This marginal cost spreads the demand charge of the marginal supplier and the cost of unused gas per MMCF under take-or-pay charges, if any, according to the allocation factor, A^t, developed in the last section. The marginal costs of supply for each day, week, or month of the year can be aggregated over various pricing periods, including the entire year.

This section is divided into four subsections. The first subsection is a brief discussion of the rate structure a distributor faces when purchasing natural gas from interstate pipelines. The focus of this discussion is the role the load factor plays in this rate structure. In the second subsection, a method for determining the least cost supply mix for a distributor is presented. This method is based on the general discussion on simplified methods in chapter 2. A technique for identifying the marginal supplier and computing the marginal cost for each costing period is delineated in the third subsection. The final subsection is an example computation of the marginal cost of supply using data from the East Ohio Gas Company.

Rate Structures and the Distributor's Load Factor

A distributor must obtain adequate supplies of natural gas to meet the demands of its customers. Gas supplies are available from interstate transmission pipelines, independent producers within the state, production by the distribution company or its subsidiaries, and synthetic gas sources. The most commonly used source of gas is the interstate pipeline.

The rates at which distributors purchase natural gas from interstate pipelines are regulated by the Federal Energy Regulatory Commission (FERC). Average rates primarily vary according to the load factor of the purchaser and the volume purchased. Distribution companies for the most part tend to have low load factors, and usually confront a multipart tariff. These parts are most likely to be:

Demand Charges,
Winter Requirement Charges,
Take-or-Pay Clauses,
Commodity Charges.

A low load factor suggests that the pipeline has an investment that lies idle a good part of the year, and therefore fails to earn a return. The demand charge, winter-requirements charge, and the take-or-pay clause are instituted to help assure that the interstate pipeline will recover its investment. The demand charge is related to the distributor's maximum daily demand. This maximum provides a measure of the capacity a transmission pipeline must install to serve this customer. The winter-requirements charge is a charge added to the commodity charge during the winter months. The assumption, in applying this winter rate, is that a low load factor is due to temperature sensitive loads. The take-or-pay clause places a floor on the revenues a transmission pipeline receives from a distributor. This clause specifies that a distributor must purchase some percentage of his maximum day demand all the other days of the year, or at least pay for it as if he used it. Each of these charges aid the transmission pipeline in recovering the cost of its investment.

This discussion of the load factor and its relation to rate structure suggests that the demand charge and the cost of unused gas paid for under a take-or-pay charge are capacity-related charges. The expected maximum daily demand the interstate pipeline must serve determines the minimum capacity for this pipeline. Both of these charges are linked to a distributor's maximum demand. Thus, the cost of the distributor incurs under both the demand charge and the take-or-pay charge per MMCFD are properly assigned to periods in which the probability of the maximum demand occurring is positive. This procedure is utilized below.

Assigning the cost of unused gas per MMCFD under a take-or-pay charge to peak periods is not without dispute. It may be argued that, although one expects that peak consumers are often responsible for circumstances leading to the activation of a take-or-pay clause, it could also be a decline in off-peak as easily as an increase in on-peak demand that leads to the result. However, if off-peak demand declines, the total cost of supply for the year will be unchanged. What does change is the amount of unused gas. Now consider an increase in the maximum daily demand. This increase requires the distributor to pay for an additional MMCFD in the off-peak periods whether it is used or not. The total cost of the supply for the year increases by the amount paid for the additional consumption on peak as well as the amount paid for the additional unused gas.

Thus, changes in the maximum daily demand have an effect on the cost of supply in the off-peak period. As previously noted, changes in the off-peak demand do not have a similar effect on the costs in the on-peak period. The change in total cost over and above the cost of on-peak consumption is the cost of unused gas. This cost of unused gas per MMCFD should be properly attributed to on-peak demands with the allocation factor developed above.

Optimizing the Supply Mix of a Distributor

As previously noted, a distributor must sign contracts in order to assure he has adequate supplies of natural gas to meet the demands of his customers. In deciding from which of the available suppliers to purchase gas and in what quantities, the distributor faces a trade-off between demand charges and commodity costs. This aspect of the optimization of supply was discussed in chapter 2. In this subsection, a method to determine from which supplier to purchase gas and in what quantities is suggested. The distributor's objective is to minimize the annual cost of meeting his expected load.

The discussion of this subsection proceeds from a simple case in which one supplier satisfies the distributor's entire demands to cases in which a supplier will limit maximum daily requirements and/or impose take-or-pay charges.

The basic consideration underlying the optimization of supply is the cost of acquiring gas from a supplier based on the distributor's load factor for a typical day. The information one must have available is

a. Hourly, daily, weekly, or monthly loads for the distributor's planning horizon. The daily loads would be best.
b. Expected deliveries to and withdrawals from storage on a hourly, daily, weekly, or monthly bases. The time frame should be the same as that chosen for (a) above.
c. The rate schedules for all feasible sources of supply to the distributor.

This information is used to construct the distributor's load-duration curve, compute his load factor for a typical day, and calculate his cost-decision function. For a given supplier, this function yields the total cost of gas per unit of the distributor's annual maximum daily demand.

The distributor's load factor for a typical day is computed by dividing the average daily demand by the annual maximum daily demand, with:

$$LF = \frac{(MMCFY/365)}{MAXDAY} \tag{6.23}$$

where:

MMCFY = the annual consumption in millions of cubic feet of gas,

MAXDAY = the annual maximum daily demand.

The load factor is a fraction between zero and one. It can be interpreted as hours use of maximum demand, or, in other words, the number of days of the year during which the distributor can purchase gas at the level of his annual maximum daily demand and then purchase nothing for the rest of the year. For instance, a load factor of .4931 tells a distributor he can purchase gas at the level of his maximum demand for 180 days. For the remaining 185 days, he purchases no gas at all. The load factor is a variable of the distributor's cost-decision function.

In chapter 2, table 2.1, the cost of purchasing gas from a supplier based on the distributor's load factor is evaluated. The basic formula is:

$$TC_i = DC_i + 365*LF*CC_i, \qquad (6.24)$$

where:

DC_i = the demand charge for the i-th supplier,

CC_i = the commodity charge for the i-th supplier.

This formula is the distributor's cost-decision function when a winter-requirements charge does not apply. When it does apply, the formula becomes:

$$TC_i = DC_i + 365*LF*CC_i + WRCDAYS_i*WRCLF*WRC_i, \qquad (6.25)$$

where:

$WRCDAYS_i$ = the number of days during which the winter-requirements charge is applied,

WRCLF = the load factor for the winter-requirement charge period,

WRC_i = the winter-requirements charge imposed by the i-th supplier.

The load factor for the winter-requirements charge period is computed as:

$$WRCLF = \frac{\begin{bmatrix}\text{average daily demand} \\ \text{during the winter-requirements} \\ \text{charge period}\end{bmatrix}}{MAXDAY} \qquad (6.26)$$

Both of these cost-decision functions allow the distributor to evaluate his trade-off between demand charges and commodity charges. The cost-decision function yields the cost of purchasing one MMCFD on the maximum daily demand day and of purchasing a fraction of this amount (as indicated by the load factor) all other days of the year. By purchasing gas from the supplier yielding the lowest value of the cost-decision function, the distributor can minimize the cost of meeting his annual load. This is the basic decision rule.

The procedure outlined above assumes that the distributor does not have storage facilities and the supplier does not impose limits on the maximum daily purchase or impose a take-or-pay charge. These complications do not change the cost-decision function, but requires more computation and changes the load factor that enters the formula. These procedures are discussed below.

Storage Storage alters the time pattern of purchases relative to demands. The necessary purchase for periods in which gas is withdrawn from storage is lowered, while deliveries to storage raise the necessary purchases during those deliveries periods. The effect of these changes is to increase the distributor's load factor used in the cost-decision function. This change can alter the relative ordering of suppliers for the decision rule.

In order to introduce storage into the decision process, the following procedure is appropriate. For days on which deliveries are made to storage, the delivery for a day should be added to the customers' demands for that day. On days which gas is withdrawn from storage, the withdrawal for a day should be subtracted from the customers' demands for that day. This new time pattern of purchases becomes the basis for subsequent computations. The resulting average daily purchase and maximum daily purchase are used to calculate the load factor for the cost-decision function. The new time pattern of demand is also used to construct the load-duration curve.[8]

Limits on the Maximum Daily Purchase If a distributor cannot purchase all of the gas he desires from a supplier, two or more steps are required to optimize supply. A supplier imposes limits on the maximum daily purchase when there exists insufficient capacity to deliver the desired purchase. The optimization in this circumstance is a step-by-step iteration of calculating cost-decision functions for suppliers with gas still available. This iterative process is outlined below.

One begins by calculating the cost-decision function for each supplier using the load factor calculated from the desired time pattern of purchases. The decision rule is applied and the least-cost supplier chosen. Now suppose that this supplier imposes a limit on daily purchases. As a result, all of the distributor's requirements cannot be purchased. The distributor must now evaluate from which of the remaining suppliers he should purchase his unsatisfied demand. In these circumstances, the following procedure should be followed.

The daily purchases from the preferred supplier that imposes the limit should be subtracted from the total purchase the distributor has to make

[8] The load-duration curve might be better labelled as purchase-duration curve after this computation. This would differentiate the change in the time pattern of purchases relative to demands.

for that day. This computation will yield the remaining unsatisfied demand for each day. Using this new time pattern of purchases, the load factor for the unsatisfied demand and the cost-decision function for each of the remaining suppliers should be computed. Applying the decision rule, the least-cost supplier for this step is chosen to supply the unsatisfied demand.

It is possible that the least-cost supplier in this second step may also impose a limit on the maximum daily purchase. In this case, the procedure above is repeated by subtracting the purchase from this supplier for each day from the unsatisfied demand determined in the previous step. This yields the distributor's demand yet to be satisfied. This newest time pattern of demand is used to calculate the load factor of a new set of cost-decision functions. This procedure is repeated until the supplier meets his daily load requirements.

Take-or-Pay Charges Take-or-pay charges require a distributor to purchase some fraction of the maximum daily purchase each day or at least pay for it. This type of charge can alter a distributor's optimal supply mix. The prospect of paying for unused gas can lead a distributor to limit his purchases from this supplier. When this occurs, the following procedure should be followed.

As in all cases, the relative merit of purchasing gas from each supplier should be evaluated by using the cost-decision function and ignoring all constraints on supply and the take-or-pay charges. If the preferred supplier from this initial step imposes a take-or-pay charge on the distributor, and if the entire load curve cannot be met without purchasing unused gas, further computation is required.

The next step is to eliminate the unused gas the distributor is required to purchase. This is done by computing the maximum allowable daily purchase from this supplier. Since there is unused gas, the minimum purchase required under the take-or-pay clause exceeds the smallest demand the distributor places on the supplier. Identify this smallest daily demand of the distributor. Dividing this demand by the take-or-pay fraction yields the maximum allowable daily purchase, with:

$$MAXAP_i = \frac{MINMMCFD}{TP^i} \qquad (6.27)$$

where:

$MAXAP_i$ = the maximum allowable daily purchase from the i-th supplier,

MINMMCFD = the smallest daily demand the distributor places on all the suppliers,

TP_i = the take-or-pay fraction for the ith supplier.

As long as the distributor never purchases more than the maximum allowable purchase on any given day, he never has to purchase any unused gas. Thus, this self-imposed limit on the distributor's purchase is the most gas he will purchase. When his demand is less than this limit, he only purchases the gas he requires.

Having computed the maximum allowable purchase, the next step is to compute the unsatisfied demand. This is accomplished by subtracting the daily purchases of the preferred supplier with the take-or-pay charge from the distributor's required purchase on the respective days. For the day on which the smallest daily demand occurs, there will be no unsatisfied demand; the same is true for all days on which this demand does not exceed the maximum allowable purchase. This new time pattern of demand is used to compute a load factor for the calculation of a new set of cost-decision functions for the remaining suppliers. The decision rule is applied to choose the next suppliers to meet this remaining unsatisfied demand.

Once the next preferred supplier has been selected by applying the decision rule, one must check if the purchase of unused gas is advisable. To do this, the cost of purchasing one more MMCFD to meet the maximum daily unsatisfied demand from the supplier imposing the take-or-pay provision is compared to the same cost for the next preferred supplier. On the maximum day, the purchase of an MMCFD from the supplier with the take-or-pay clause will cause a distributor to incur the demand charge, the commodity cost, the winter-requirements charge, if any, and the cost of one MMCFD for each day he must purchase unused gas. This cost should be calculated. Compare this to the cost of an MMCFD purchased on the maximum day from the next preferred supplier. If the cost of one MMCFD on the maximum day purchased from the supplier with the take-or-pay charge is less than the next preferred supplier, then the purchase of unused gas will minimize the cost of supply.

If other suppliers have take-or-pay charges, the purchase of unused gas may be unavoidable. This situation requires a comparison of the total cost of gas supplies for two possible scenarios. First, compare the cost of purchasing all of the distributor's gas from the initially preferred supplier to the total cost using both suppliers. Second, purchase gas to meet the unsatisfied demand from the next lowest cost supplier. This supplier ranks second in the set of cost-decision functions calculated above. Compute the total cost of meeting the entire annual demand under these circumstances. This figure should be compared to the lowest cost solution from the first comparison above. The least-cost mix of suppliers is the lowest of these two total costs.

This iterative procedure is repeated until there is enough gas supply to meet each day's demand at the lowest feasible cost. If any limits on maximum daily purchases are encountered when dealing with take-or-pay charges, the procedure of the last subsection is used in conjunction with the procedure in this subsection.

Required Purchases From a Supplier Sometimes a state commission or legislature may require a distributor to purchase a certain amount of gas each day from an in-state supplier. When this requirement is imposed, the required daily purchase from this supplier should be subtracted from the time pattern of demands. This is done before any load factors or decision functions are calculated. Although the gas is purchased, the decision by the distributor is not an optimizing decision. The unsatisfied demand is then calculated using the procedure and decision rule discussed above.

The Marginal Supplier and the Marginal Cost of Supply

Once the optimal mix of suppliers has been determined, the marginal supplier for each day must be identified, and the marginal cost of supply for each day calculated. In this subsection, the procedure for accomplishing these tasks is outlined. One must have at hand the ordering of purchases from each supplier for each day, the rate schedules for each of these suppliers, and the allocation factor, A^t, for each day of the year. This information is used in computing the marginal cost of supply.

The identification of the marginal supplier for each day is a relatively straightforward procedure. One must determine, for each day, from which supplier would one more MMCFD be purchased. The supplier so identified is the marginal supplier for that day. This supplier's demand charge, winter-requirements charge, and commodity charge are the relevant prices for computing the marginal cost of supply for that day.

The general formula for calculating the marginal cost of supply for a day is given by:

$$MCS^t = A^t * DC^t_m + WRC^t_m + CC^t_m + A^t * UG \tag{6.28}$$

where:

MCS^t = the marginal cost of supply for day t,

A^t = the allocation factor for day t,

DC^t_m = the demand charge for the marginal supplier m and for day t,

WRC^t_m = the winter requirements charge for the marginal supplier m on day t (if any),

CC^t_m = the commodity charge for the marginal supplier m on day t,

UG = the cost of unused gas per MMCFD of unused gas (if any) for supplier imposing a take-or-pay clause.

Equation (6.28) yields the marginal cost of supply for each day of the year. Four cases can be considered:

(1) The probability of the maximum demand occurring is positive ($A^t > 0$) and the winter-requirements charge applies. In this case, the marginal cost of supply for this type of day is:

$$MCS^t = A^t * DC_m^t + WRC_m^t + CC_m^t + A^t * UG \quad (6.29)$$

(2) The probability of the maximum demand occurring is positive, but there is no winter requirements charge applicable. In this case, the marginal cost of supply for this type of day is:

$$MCS^t = A^t * DC_m^t + CC_m^t + A^t * UG \quad (6.30)$$

(3) The probability of the maximum demand occurring is zero ($A^t = 0$) and the winter-requirements charge is applicable. In this case, the marginal cost of supply for this type of day is:

$$MCS^t = WRC_m^t + CC_m^t \quad (6.31)$$

(4) The probability of the maximum demand occurring is zero, and the winter-requirements charge is not applicable. In this case, the marginal cost of supply for this type of day is:

$$MCS^t = CC_m^t \quad (6.32)$$

In the first two cases above, if there is no unused gas, the term UG drops out of the formula. These four cases should encompass all of the possible forms that might possibly occur. The last section of this chapter, contains some suggestions about how one might aggregate these daily marginal costs into pricing periods.

An Example: The Case of the East Ohio Gas Company

The foregoing optimization technique and marginal cost of supply calculation are applied to data for the East Ohio Gas Company (EOGC) in this subsection. Data for this company are used in chapter 5 as inputs to the linear programming model called the Gas Utility Marginal Cost Pricing Model (GUMCPM). There are however certain differences between the simplified method and GUMCPM that will alter the results somewhat. In particular, the GUMCPM program assigns the demand charge to the peak month only; it is a deterministic model. This simplified method, on the other hand, introduces a stochastic element with the allocation factor, A^t.

The demand data for the East Ohio Gas Company are only available by months. Thus, demand charges and the allocation factor are computed on a monthly basis. This also requires the marginal cost of supply to be computed on a monthly basis. This form of data availability is of course not optimal, while, ideally, daily demands should be used to capture the time variations in cost occurrence.

The demand data are presented in column 1 of table 6.1. These data are the output of the GUMCPM program under an average cost pricing policy assumption.[9] Column 2 of table 6.1 presents the optimal deliveries to and withdrawals from storage as determined by the GUMCPM model. In the simplified method it is assumed that the distributor has optimized his storage deliveries and withdrawals. The GUMCPM data for storage are used as a proxy. Finally, column (3) of table 6.1 presents the monthly loads that the distributor must satisfy. The total annual consumption is the total for columns 1 or 3. These do not match exactly because of rounding errors.

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[9] See Chapter 5

EOGC has several suppliers with various rate schedules and restrictions. They are the Panhandle Eastern Pipeline Company, Consolidated Gas Supply Corporation, wellhead and field-line sources as well as EOGC's own production. Table 6.2 presents this information. The demand charges are computed on a monthly basis.

The restrictions vary considerably. Panhandle has a take-or-pay charge, while Consolidated has no restrictions. The wellhead and field-line purchases are limited by maximum purchases each month. The Public

TABLE 6.1

MONTHLY LOADS (MMCF) AND OPTIMAL DELIVERIES TO AND WITHDRAWALS FROM STORAGE (MMCF) WITH MARKET GROWTH RATES EQUAL TO 50% AVERAGE COST PRICING POLICY

Month	(1) Total Load DGMT	(2) Storage Deliveries and Withdrawals	(3) Required Monthly Purchases
April	49,873	-11,900.00	-71,773.00
May	35,782	- 2,431.31	-38,243.31
June	25,002	-10,786.91	-35,788.91
July	22,848	- 9,949.10	-32,797.10
August	23,279	- 9,176.39	-32,455.39
September	28,819	- 8,463.66	-37,282.66
October	42,511	- 7,806.30	-50,317.30
November	61,067	+16,725.01	-44,341.99
December	80,626	+12,180.54	-68,445.46
January	88,042	+12,318.50	-75,723.50
February	79,248	+10,440.60	-68,807.40
March	70,868	+ 8,848.99	-62,019.01
Total	607,966	0.00	607,965.01

Source: J-M Guldmann's GUMCPM model chapter 5, tables 5.2 and 5.6, columns 1 and 2. Column 3 is the author's calculation.

Utilities Commission of Ohio requires EOGC to purchase its own production to meet 10% of the demands from new customers. Load grows by approximately 202,660 MMCF during the planning horizon. Computing 10% of this amount and spreading it over the months of the year equally yields a minimum own production of 1689 MMCF/month. Finally, the winter-requirement charge for Consolidated is imposed during the months of November through March.

In order to optimize the supply mix for EOGC, the cost-decision function must be calculated. The general form, on a monthly basis, is:

$$TC_i = DC_i + 12*LF*CC_i + 5*WRCLF*WRC_i \qquad (6.33)$$

TABLE 6.2

EOGC'S POTENTIAL SUPPLIERS' RATE SCHEDULES AND RESTRICTIONS

Supplier	Demand Charge ($/MMCF)	Commodity Charge ($/MMCF)	Winter Requirements Charge ($/MMCF)	Restrictions
Panhandle	1,860	1009.2	0	Take-or-pay = .75
Consolidated	980	1202.4	96.90	-
Wellhead	0	787.0	0	Maximum 2000 MMCF/month
Fieldline	0	1481.0	0	Maximum 2500 MMCF/month
Own Production*	14,398.11	921.13	0	Minimum 1689

*EOGC is required by the Public Utilities Commission of Ohio to purchase 10% of its new customers' demands from its own production. This minimum is assumed to be 20266 MMCF per year. This is spread equally over the year.

Source: J-M Guldmann, MARGINAL COST PRICING FOR GAS DISTRIBUTION UTILITIES, NRRI, 1980.

The first step is to compute the unsatisfied demand after making the required monthly "purchases" from EOGC's own production. The new time pattern of required monthly purchases is given in table 6.3.

The next step is to compute the load factor for the new time pattern of monthly purchases (or unsatisfied demands). The average monthly demand is 48,974.83 MMCF/month. The maximum monthly demand occurs in January and is 74,034.5 MMCF/month. This yields the following load factor:

$$LF = \frac{48,974.83}{74,034.5} = .662 \tag{6.34}$$

The load factor for the winter-requirements charge period (WRCLF) is computed as follows (a total of 310,892.36 MMCF are consumed from November through March or for 5 months):

$$WRCLF = \frac{\frac{310,892.36}{5}}{74,034.5} = .8399 \tag{6.35}$$

This 84% load factor is used in the cost-decision variable for Consolidated.

TABLE 6.3

UNSATISFIED DEMAND AFTER "PURCHASES" ARE MADE FROM EOGC'S OWN PRODUCTION

Month	Required Monthly Purchase (MMCF/month)
April	60,084.00
May	36,524.31
June	34,099.91
July	31,108.10
August	30,766.39
September	35,593.66
October	48,628.30
November	42,652.99
December	66,756.46
January	74,034.50
February	67,118.40
March	60,330.01
Total	587,698.00

Source: Author's calculations

The cost-decision function for each supplier, including own production, is given in table 6.4. Own production is included because the restriction did not place an upper bound on purchases from this source.

TABLE 6.4

COST-DECISION FUNCTION VALUES FOR EOGC'S POTENTIAL SUPPLIERS - STEP 1

Supplier	Cost-Decision Function Value ($)
Panhandle	9,877.08
Consolidated	10,938.89
Wellhead	6,251.93
Field Line	11,765.06
Own Production	21,715.57

Source: Author's calculations

The preferred supplier in these circumstances includes all the wellhead sources. Unfortunately, EOGC can only purchase a maximum of 2000 MMCF/month from these sources, and will do so, of course.

The unsatisfied demand has to be calculated again. The new time pattern of demand is given in table 6.5.

TABLE 6.5

UNSATISFIED DEMAND AFTER PURCHASES FROM WELLHEAD SOURCES

Month	Unsatisfied Demand (MMCF/Month)
April	58,084.00
May	34,524.31
June	32,099.91
July	29,108.10
August	28,766.39
September	33,593.66
October	46,628.30
November	40,652.99
December	64,756.46
January	72,034.50
February	65,118.40
March	58,330.01
Total	563,698

Source: Author's calculations

These load data are used to compute the load factor for the next iteration. This load factor is:

$$LF = \frac{46,974.83}{72,034.50} = .652 \tag{6.36}$$

The load factor for the winter requirements charge period is:

$$WRCLF = \left(\frac{\frac{300,892.36}{5}}{72,034.5}\right) = .8354 \tag{6.37}$$

The cost-decision functions values for each supplier are presented in table 6.6. Wellhead production is excluded from this table since it is no longer available.

TABLE 6.6

COST-DECISION FUNCTION VALUES FOR EOGC'S REMAINING POTENTIAL SUPPLIERS - STEP 2

Supplier	Cost-Decision Function Values ($)
Panhandle	9,757.38
Consolidated	10,792.33
Field Line	11,589.40
Own Production	21,606.31

Source: Author's calculations

In these circumstances, Panhandle is EOGC's preferred supplier for the unsatisfied demand. Since Panhandle imposes a take-or-pay charge, one must compute the amount of unused gas, if any. If Panhandle is to supply the rest of EOGC's needs, the maximum monthly purchase from Panhandle will be 72,034.5 MMCF in January. With a take-or-pay fraction of .75, EOGC will have to purchase at least 54,025.88 MMCF each month or pay for unused gas. The minimum monthly purchase is 28,766.39 MMCF/month in August. Obviously, EOGC would have to pay for unused gas if it purchased its remaining requirements from Panhandle.

The next step is to calculate the maximum allowable monthly purchase from Panhandle. This is given by applying formula (6.27), with:

$$MAXAP = \frac{28,766.39}{.75} = 38,355.19 \tag{6.38}$$

In any month, EOGC limits itself to this purchase; otherwise, it would have to pay for unused gas. For months in which the unsatisfied demand is less than this maximum allowable month purchase, EOGC acquires all the necessary gas from Panhandle.

Table 6.7 presents the remaining unsatisfied demand after purchases are made from Panhandle. This new time pattern of unsatisfied demands is used to compute a load factor and the cost-decision variables for the remaining potential suppliers. The load factor is:

$$LF = \frac{11,426.53}{33,679.31} = .339 \tag{6.39}$$

The load factor for the winter-requirements charge period is:

$$WRCLF = \left(\frac{\frac{109,116.41}{5}}{33,679.31}\right) = .6479 \tag{6.40}$$

The resulting cost-decision function values are given in table 6.8. Field-line purchases just edge out a supply from Consolidated. Field-line purchases are restricted to be no greater than 2500 MMCF/month.

Table 6.9 presents the remaining unsatisfied demands after purchases are made from the field-line source. This set of monthly unsatisfied demands is used to compute another load factor and set of cost-decision function values for the remaining two suppliers. The load factor is:

TABLE 6.7

UNSATISFIED DEMAND AFTER PURCHASES FROM PANHANDLE

Month	Unsatisfied Demand (MMCF/Month)
April	19,728.81
May	-0-
June	-0-
July	-0-
August	-0-
September	-0-
October	8,273.11
November	2,297.80
December	26,401.27
January	33,679.31
February	26,763.21
March	19,974.82
Total	137,118.33

Source: Author's calculations

TABLE 6.8

COST-DECISION FUNCTION VALUES FOR EOGC'S REMAINING POTENTIAL SUPPLIERS - STEP 3

Supplier	Cost-Decision Function Values ($)
Consolidated	6,185.30
Field Line	6,024.71
Own Production	18,145.27

Source: Author's calculations

TABLE 6.9

UNSATISFIED DEMAND AFTER PURCHASES FROM FIELD-LINE SOURCES

Month	Unsatisfied Demand (MMCF/Month)
April	17,228.81
May	-0-
June	-0-
July	-0-
August	-0-
September	-0-
October	5,773.11
November	-0-
December	23,901.27
January	31,179.31
February	24,263.21
March	17,474.82
Total	119,820.53

Source: Author's calculations

The load factor for the winter-requirements charge period is:

$$\text{WRCLF} = \left(\frac{\frac{96,818.61}{5}}{31,179.31} \right) = .6210 \tag{6.42}$$

The cost-decision function values are given in table 6.10.

TABLE 6.10

COST DECISION FUNCTION VALUES AFTER PURCHASES FROM FIELD-LINE SOURCES STEP 4

Supplier	Cost-Decision Function Values ($)
Consolidated	5,898.11
Own Production	17,935.25

Source: Author's calculations.

Since Consolidated does not impose any restriction on its supply, EOGC's remaining unsatisfied demand can be completely acquired from this source. It is interesting to note that EOGC's own production is not used except for the legal restriction imposed by the Public Utilities Commission of Ohio.[10]

Once the optimization of supply mix is completed, one must gather the monthly purchases from each supplier in a single table. Table 6.11 presents the purchases from each supplier by month. The suppliers are arranged in the table from left to right according to EOGC's preference ordering; that is, according to the order in which purchases were made. This arrangement of suppliers facilitates the identification of the marginal supplier for each month.

[10] This production capacity was installed to meet its customers' demand during the severe gas shortage of the 1970s.

TABLE 6.11

MONTHLY PURCHASES FROM EACH SUPPLIER
LEFT TO RIGHT RANKING ACCORDING TO COST PREFERENCE
(MMCF/MONTH)

	Supplier				
Month	Own Production	Wellhead	Panhandle	Fieldline	Consolidated
April	1689	2000	38,355.19	2,500	17,228.81
May	1689	2000	34,524.31	-0-	-0-
June	1689	2000	32,099.91	-0-	-0-
July	1689	2000	29,108.10	-0-	-0-
August	1689	2000	28,766.39	-0-	-0-
September	1689	2000	33,593.66	-0-	-0-
October	1689	2000	38,355.19	2,500	5,773.11
November	1689	2000	38,355.19	2,297	-0-
December	1689	2000	38,355.19	2,500	23,901.27
January	1689	2000	38,355.19	2,500	31,179.31
February	1689	2000	38,355.19	2,500	24,263.21
March	1689	2000	38,355.19	2,500	17,474.82
Total	20,268	24,000	426,578.70	17,297.8	119,820.53

Source: Author's calculations

The total purchases from each supplier in table 6.11 adds up to the total purchases that EOGC has to meet, equal to 607,966 MMCF per year.

Before calculating the marginal cost of supply, the allocation factor, A^t, needs to be calculated for each month. The first step is to obtain the design-day degree-days for EOGC's system or a proxy for it. EOGC's design-day degree-days is 69 degree-days.[11] However, this figure is of little use for monthly load data. EOGC's maximum monthly demand occurred in January 1972. 1173 degree-days were recorded in that month. This degree-day figure is used as a proxy for the design-day degree-days.

[11]This figure is the standard degree-day for Ohio used by natural gas distributors operating in the state. The figure was obtained from a spokesman for Columbia Gas Distribution Companies.

The means and standard deviations for degree-days for each month are presented in the first two columns of table 6.12. These statistics were calculated from a 47-year history of weather data for Ohio.

TABLE 6.12

WEATHER DATA, PROBABILITY DATA, AND THE ALLOCATION FACTOR

Month	Monthly Average Degree-Days	Standard Deviation of Degree-Days	Z Statistic	Pr(DD> 1173)	Allocation Factor A_t
April	463	85	8.35	0	0
May	187	69	14.29	0	0
June	29	23	49.74	0	0
July	3	5	234.00	0	0
August	9	11	105.82	0	0
September	91	41	26.39	0	0
October	340	92	9.05	0	0
November	720	94	4.82	.000003	.000004
December	1047	142	.89	.1867	.259449
January	1150	184	.13	.4483	.622982
February	1002	120	1.43	.0764	.10617
March	822	146	2.40	.0082	.011395

Source: Author's calculations

The statistic for calculating the probability of a degree-day greater than the design-day 1173 degree-days is the Z-statistics (or normal variate). The Z-statistic, the relevant probability, and the allocation factor, A^t, for each month are presented in the last three columns of table 6.12.

Once the allocation factor is computed for each month, the marginal supplier for each month can be identified and the marginal cost of supply for each month computed. Table 6.11 enables one to identify the marginal supplier. This is accomplished by asking where one more MMCF per month would be acquired. The second column of table 6.13 lists each month's marginal supplier.

Tables 6.2 and 6.12 enable one to compute the marginal cost of supply for each month. The general formula is:

$$MCS^t = A^t * DC_m + WRC_m^t + CC_m^t + A^t * UG \tag{6.43}$$

where the subscript m denotes the marginal supplier. Since EOGC does not purchase any unused gas, the term associated with the take-or-pay clause drops out.

The third column of table 6.13 gives the marginal cost of supply for each month. The monthly marginal capacity costs for transmission and distribution are added to the monthly marginal costs of supply. This monthly total marginal cost of natural gas distribution is used in ratemaking and/or analysis.

TABLE 6.13

THE MARGINAL SUPPLIER AND MARGINAL COST OF SUPPLY FOR EACH MONTH

Month	Marginal Supplier	Marginal Cost of Supply ($/MMCF/month)
April	Consolidated	1299.30
May	Panhandle	1009.20
June	Panhandle	1009.20
July	Panhandle	1009.20
August	Panhandle	1009.20
September	Panhandle	1009.20
October	Consolidated	1299.30
November	Field Line	1481.00
December	Consolidated	1553.56
January	Consolidated	1909.82
February	Consolidated	1403.35
March	Consolidated	1310.47

Source: Author's calculations.

A Pricing Strategy Based on Marginal Cost

The simplified method for quantifying the marginal costs of natural gas distribution that is presented in this chapter can be a basis for the pricing of natural gas. In this section, an approach for translating the hourly, daily, weekly, or monthly marginal cost and the marginal customer costs into prices is suggested. Although the above method advocates calculating the marginal cost on a daily basis, it is not suggested nor advisable to have the price of natural gas fluctuate daily or even monthly. Instead, it is appropriate to develop a schedule of seasonal rates which has a single on-peak period and a single off-peak one. To accomplish this, one must have a method by which these pricing periods can be determined and for which the daily marginal costs can be aggregated.

The general form of the marginal cost for a day is given by:

$$TMC^t = A^t{*}MCT + A^t{*}MCD + A^t{*}DC_m^t + WRC_m^t + CC_m^t + A^t{*}UG_m \qquad (6.44)$$

where TMC^t is the total marginal cost of distribution for day t and the subscript m denotes the marginal supplier. The allocation factor A^t is used to assign the cost of marginal transmission (MCT) and distribution (MCD) capacity to the days of the year. TMC^t can be aggregated over appropriate pricing periods and this aggregate value can be used as a basis for marginal cost pricing.

Pricing periods can be determined in many ways. An on-peak period is one in which there exists a positive probability that demand will exceed the capacity of the system. An off-peak period is one in which this probability is zero. One approach to determine pricing periods is suggested here. The literature on marginal cost of electric power may offer alternative approaches.

The allocation factor is the basis for determining the on-peak and off-peak seasons. As discussed previously, the capacity of a distribution and transmission system can be stated in terms of a design-day temperature which is usually specified in degree-days. The development and use of the allocation factor A^t was premised on the assumption that temperature-sensitive loads are responsible for the time-variation in demand. Thus, the probability that an occurring degree-day exceeds the design-degree day reflects the probability that demand would exceed capacity. Since the on-peak period can be defined as the period in which there exists a positive probability that demand will exceed capacity, it is also that period during which the allocation factor has a positive value. Correspondingly, the off-peak period is that period during which the allocation factor has a value of zero. Thus, the value of the allocation factor A^t provides one basis for determining the on-peak and off-peak seasons of the year.

This method of determining the on-peak and off-peak periods for pricing purposes results in two general forms for the daily marginal cost. For the on-peak period it is:

$$TMC^t = A^t*MCT + A^t*MCD + A^t*DC_m^t + WRC_m^t + CC_m^t + A^t*UG_m \tag{6.45}$$

For the off-peak period, it is:

$$TCM^t = WRC_m^t + CC_m^t \tag{6.46}$$

The on-peak days will recover the capacity related marginal costs for transmission and distribution as well as the demand charges and the cost of unused gas paid to the marginal supplier. The off-peak days have no capacity-related marginal costs. In fact, the off-peak days are most likely to be those days in which the winter-requirements charge does not apply. If this is the case, each day's marginal cost for the off-peak period will be the commodity cost paid to the marginal supplier on that day; that is:

$$TMC^t = CC_m^t \tag{6.47}$$

The marginal costs used as a basis for formulating prices are weighted averages of the marginal costs for each day in each period. The weight suggested here is the fraction of the period's total consumption that is consumed on day t, with:

$$W_t = \frac{MMCFD_t}{\sum_t MMCFD_t} \tag{6.48}$$

where $MMCFD_t$ is the consumption on day t.

Weights are calculated for each day of the year. The summation in the denominator of the weight W_t is over the days in the on-peak period. If off-peak marginal costs are aggregated, the summation is over the days in the off-peak period. The on-peak marginal cost of natural gas distribution is given by:

$$TMC^{on} = \sum_t W_t * TMC_t \tag{6.49}$$

where the t are days in which the allocation factor A^t is positive. The off-peak marginal cost is given by:

$$TMC^{off} = W_t * TMC_t \tag{6.50}$$

where the t are days in which the allocation factor is equal to zero. These two marginal costs, TMC^{on} and TMC^{off}, are used in formulating prices.

In setting the prices to be charged during each period, two considerations are among the most important:

1. How much should a price deviate from marginal cost in each period so that revenue requirements are just recovered?
2. How is each period's price determined so that the deviation from marginal cost does the least harm to consumers' welfare?

These issues were addressed in chapter 2 of this report, and the Baumol-Bradford inverse elasticity rule was deemed an appropriate method to determine this deviation.

One also has calculated a marginal customer cost for each customer class. This cost suggests that a two-part rate for each pricing period might be appropriate. The first part of this rate is a fixed charge paid by a customer in a class irrespective of his consumption. This fixed charge is based on the marginal customer cost. The second part of the rate is a charge per unit of natural gas consumed in the on-peak period or the off-peak period. It is determined by applying the inverse elasticity rule to both TMC^{on} and TMC^{off}.

CHAPTER 7

SUMMARY

The purpose of this research effort, building upon previous related research by The National Regulatory Research Institute, was to further develop methods for the calculation of the marginal costs of gas distribution utilities and for the evaluation of gas pricing policies based on marginal costs.

A thorough analysis of the basic issues in gas marginal cost pricing, based upon an extensive review of the most recent literature on public utilities marginal cost pricing and upon the specific characteristics of natural gas supply and distribution, provides a general framework for the specific analyses and applications described in the remainder of the report.

Several empirical investigations of the structure of various cost categories of gas distribution utilities, with the exception of gas supply costs, are presented in chapters 3 and 4. Chapter 3 focuses on distribution plant (investment) costs at the urban/community level, using data gathered from six different distribution utilities. A new specification for the cost model was used, significantly improving the regression fits obtained in previous research, and the variations of the basic cost model's coefficients across the six companies were successfully explained by the variations of some company-wide parameters such as average sales, densities, and load factor. More detailed analyses were performed for some companies because of additional data availability. All the results confirm the joint character of gas distribution plant costs, and provide ready means to estimate the corresponding marginal costs for the different sectoral markets at the community/local level. In contrast, the analyses presented in chapter 4 provide cost models based on data characterizing the whole utility, and gathered from 119 U.S. gas distribution companies. Cost models have been developed for the major plant and operating costs categories, with, as arguments, the utility's market characteristics, such as sectoral sales and average customer sizes. Such cost functions can then be used to develop marginal cost functions to calculate marginal costs for any market mix and utility size.

Computerized and simplified approaches to the calculation of gas marginal costs and to the formulation of marginal cost pricing policies are presented in chapters 5 and 6. A major emphasis of these approaches is on the calculation of gas supply marginal costs, accounting for the usual pipeline rate schedules that involve demand charges and take-or-pay clauses in addition to commodity charges. Chapter 5 presents the extensions and improvements brought to the Gas Utility Marginal Cost Pricing Model (GUMCPM) developed in previous research, and the results of some applications of this new version to the East Ohio Gas Company. It is shown that a stable solution avoiding the peak-shifting phenomenon may be obtained when applying marginal-cost-based pricing policies involving the spreading of marginal distribution capacity cost over several winter months, and that these pricing policies are clearly superior to the average cost pricing policy, both in terms of load structure and resource allocation efficiency. Finally, chapter 6 presents a simplified approach to the calculation of marginal costs, that can be implemented with a hand calculator. The calculation of transmission and distribution capacity marginal costs is based on the assumed knowledge of the utility's expansion plans. Probabilistic concepts are used to account for peak-load occurrences, and a heuristic iterative procedure is applied with data pertaining to the East Ohio Gas Company to approximately calculate monthly supply marginal costs. A pricing strategy based on aggregated on-peak and off-peak marginal costs is outlined.

The previous analyses can be improved and developed in a number of ways. The utility cost models presented in chapter 4 can be extended by introducing new explanatory variables, such as unit labor costs, and by performing the analyses at a more disaggregated level, for each FERC account separately. Such improved cost functions could then be integrated into the computerized and simplified approaches to estimate marginal costs. Finally, improved and more comprehensive ratemaking procedures using these estimated marginal costs could be developed.

APPENDIX A

LONG ISLAND LIGHTING COMPANY DATA

The purpose of this appendix is to present the new community-level plant data used in the statistical analyses of Long Island Lighting Company, as reported in chapter 3, sections 2 and 5. Distribution plant disaggregated and aggregated data are presented in table A-1 for the 58 communities for which density data are available.

TABLE A-1

DISAGGREGATED AND TOTAL DISTRIBUTION PLANT IN SERVICE ($) - END OF 1979 - LONG ISLAND LIGHTING COMPANY

	Community	Structures & Improvements	Mains	Compressor Station Equipment	Measuring & Regulating Station Equipment	Services	Total Distribution Plant
1.	Hempstead	179,752	21,649,344	0	452,028	4,720,379	25,801,504
2.	Cedarhurst	0	293,086	0	14,402	71,222	378,710
3.	East Rockway	0	336,008	0	14,487	86,950	447,545
4.	Floral Park	0	513,276	0	0	217,241	730,517
5.	Free Port	0	2,304,601	0	104,984	443,202	2,852,787
6.	Garden City	0	1,347,991	0	67,467	242,559	1,658,017
7.	Hemstead Vill.	0	1,626,114	0	55,637	393,150	2,074,901
8.	Island Park	0	494,000	0	62,250	126,050	682,300
9.	Lawrence	0	496,034	0	25,211	118,470	639,715
10.	Long Beach	0	1,888,725	500	102,316	355,257	2,346,818
11.	Lynbrook	0	644,668	0	30,023	181,751	856,442
12.	Malverne	0	364,557	0	21,507	79,980	466,044
13.	New Hyde Park	0	144,441	0	0	38,590	183,031
14.	Rockville Ctr.	0	1,208,976	0	42,474	228,575	1,480,025
15.	S. Floral Park	0	51,371	0	0	30,807	82,178
16.	Valley Stream	0	1,839,153	0	84,638	389,530	2,313,321
17.	N. Hempstead	0	5,134,843	0	54,536	1,291,541	6,480,920
18.	East Hills	0	167,709	0	0	29,709	197,418
19.	E. Williston	0	134,581	0	7,572	29,546	171,699
20.	Flower Hill	0	306,892	0	0	38,693	345,585
21.	Great Neck	0	555,654	0	0	129,436	685,090
22.	Gr. Neck Estate	0	155,397	0	0	44,350	199,747
23.	Gr. Neck Plaza	0	175,395	0	1,093	35,674	212,162
24.	Kensington	0	45,418	0	4,111	13,543	63,072
25.	Kingspoint	0	513,750	0	5,447	68,646	587,843
26.	Lake Success	0	318,932	0	0	37,122	356,054

TABLE A-1

DISAGGREGATED AND TOTAL DISTRIBUTION PLANT IN SERVICE ($) - END OF 1979 - LONG ISLAND LIGHTING COMPANY
(Continued)

	Community	Structures & Improvements	Mains	Compressor Station Equipment	Measuring & Regulating Station Equipment	Services	Total Distribution Plant
27.	Manorhaven	0	240,349	0	451	49,540	290,340
28.	Mineola	0	659,756	0	95,530	208,027	963,313
29.	Munsey Park	0	133,492	0	0	25,832	159,315
30.	New Hyde Park	0	204,527	0	0	76,150	280,677
31.	Old Westbury	0	223,826	0	0	11,406	235,232
32.	Port Wash. N.	0	188,558	0	0	59,805	248,363
33.	Roslyn	0	135,890	0	10,463	24,442	170,975
34.	Sands Point	0	70,597	0	0	7,466	78,063
35.	Westbury	0	839,354	0	0	231,857	1,071,211
36.	Williston Park	0	230,382	0	32,323	67,695	330,400
37.	Oyster Bay	0	10,996,323	0	105,597	2,419,603	13,521,523
38.	Bayville	0	263,521	0	183	88,651	352,355
39.	Brookville	0	144,369	0	900	17,383	162,652
40.	Farmingdale	0	433,585	0	0	111,271	544,856
41.	Glencove City	0	1,779,009	0	20,315	267,153	2,066,477
42.	Massapequa Park	0	571,369	0	0	160,990	732,359
43.	Sea Cliff	0	727,915	0	10,314	93,626	831,855
44.	Babylon	0	7,601,382	0	1,827	1,347,421	8,950,630
45.	Amityville	0	743,856	0	0	133,813	877,669
46.	Babylon Vill.	0	989,449	0	26,132	165,065	1,180,646
47.	Lindenhurst	0	1,408,370	0	10,470	287,976	1,706,816
48.	Brookhaven	0	10,023,832	0	112,224	1,347,160	11,123,216
49.	Bellport	0	63,369	0	154	10,748	74,269
50.	Patchogue	2143	576,593	0	41,475	95,580	715,791
51.	Port Jefferson	0	357,942	0	0	45,900	403,842
52.	Lake Grove	0	389,598	0	0	30,778	420,376

TABLE A-1

DISAGGREGATED AND TOTAL DISTRIBUTION PLANT IN SERVICE ($) - END OF 1979 - LONG ISLAND LIGHTING COMPANY
(Continued)

	Community	Structures & Improvements	Mains	Compressor Station Equipment	Measuring & Regulating Station Equipment	Services	Total Distribution Plant
53.	Huntington	0	10,083,830	0	18,769	1,524,956	11,627,555
54.	Lloyd Harbor	0	21,035	0	587	1,761	23,383
55.	North Port	0	383,676	0	338	65,590	449,604
56.	Islip	0	12,332,819	0	418,521	2,255,630	15,006,970
57.	Brightwaters	119,453	260,177	0	486	42,980	423,096
58.	Riverhead	0	1,271,860	0	0	134,132	1,405,992

Source: New York State Board of Equalization and Assessment

APPENDIX B

EAST OHIO GAS COMPANY DATA

The purpose of this appendix is to present the community-level data used in the statistical analysis of East Ohio Gas Company, as reported in chapter 3, section 2. The data are indicated for 85 communities and include the distribution plant in service at the end of 1979, the 1979 sectoral sales and numbers of customers, and 1970 Census data used to compute population density. All these data are presented in table B-1.

TABLE B-1

DISTRIBUTION PLANT, GAS SALES, NUMBERS OF CUSTOMERS, POPULATION AND ACREAGE - THE EAST OHIO GAS COMPANY

	Community	Distribution Plant in Service ($) End of 1979	Gas Sales in 1979 (MCF)			Average Number of Customers in 1979			Population in (1970)	Land Area in 1970 (sq. mi.)
			Residential	Commercial	Industrial	Residential	Commercial	Industrial		
1	Ashtabula	6,554,005	2,025,883	985,497	5,299,839	11,426.1	885.8	30.2	24,313	7.1
2	Conneaut	2,026,722	761,647	297,528	319,294	4,314.7	270.2	7.9	14,552	27.5
3	Geneva	1,573,021	453,472	238,331	125,639	2,797.6	268.3	6.0	6,449	3.2
4	Geneva on the Lake	299,867	81,768	14,039	0	662.9	45.0	0.0	NA	NA
5	Jefferson	680,171	156,831	131,984	51,164	967.8	124.1	2.1	3,664	1.9
6	Madison	2,146,989	558,379	204,817	1,498	3,732.2	219.9	0.2	6,882	4.6
7	North Kingsville	753,958	157,183	86,047	2,768	948.7	71.3	0.2	NA	NA
8	North Perry	630,451	41,073	5,810	0	227.8	9.2	0.0	NA	NA
9	Perry	2,252,860	430,963	165,509	571,170	2,719.3	182.4	7.0	NA	NA
10	Painesville	2,244,959	715,874	384,181	321,997	4,362.6	347.8	11.6	16,536	4.7
11	Akron	29,910,879	15,026,566	5,294,141	3,159,718	77,395.0	4,266.8	78.8	275,425	54.2
12	Cuyahoga Falls	4,449,177	2,374,227	664,338	150,774	14,865.5	761.4	6.0	49,678	8.7
13	Silver Lake	423,248	221,132	12,484	0	985.2	9.0	0.0	3,637	1.4
14	Turkeyfoot Lake	22,465	23,992	443	0	156.3	1.0	0.0	NA	NA
15	Stow	2,706,116	1,030,392	273,967	57,334	6,778.8	232.8	10.5	19,847	17.2
16	Barberton	3,645,098	1,606,793	790,140	2,574,087	9,714.1	612.3	18.0	33,052	7.6
17	Wadsworth	2,445,942	732,778	254,565	637,787	4,559.9	241.7	8.7	13,142	6.2
18	Doylestown	441,855	157,713	38,123	5,593	946.3	62.3	1.0	NA	NA
19	Canal Fulton	574,632	163,255	46,575	4,706	1,094.2	94.8	1.0	NA	NA
20	Clinton	189,189	51,441	10,231	0	330.9	25.9	0.0	NA	NA
21	Manchester	358,515	171,734	32,952	0	983.3	37.8	0.0	NA	NA
22	Tallmadge	1,779,968	701,160	257,097	112,266	4,093.8	254.9	8.6	15,274	13.3
23	Mogadore	1,517,532	473,096	435,330	268,438	3,169.2	170.6	7.0	3,858	1.8
24	Lakemore	1,340,227	397,348	153,640	0	2,679.7	141.5	0.0	2,708	0.8
25	Monroe Falls	514,753	183,092	20,008	0	1,146.6	36.9	0.0	3,794	2.8
26	Hudson	1,171,185	386,508	247,816	277,701	1,927.1	164.9	3.5	3,933	3.7
27	Boston Heights	713,130	122,486	96,923	0	612.2	21.1	0.0	NA	NA
28	Fairlawn Village	863,851	379,297	213,228	0	2,049.8	307.6	0.0	6,102	4.0
29	Norton Village	1,845,676	486,420	145,201	72,548	3,073.0	139.3	4.9	12,308	19.9
30	Mantua Village	166,475	50,365	49,788	2,390	268.8	46.4	0.4	NA	NA
31	Penninsula	169,074	27,417	13,903	48,259	152.3	18.5	2.7	NA	NA
32	Streetsboro	849,075	266,265	94,450	14,929	1,768.3	106.9	2.5	7,966	25.0

TABLE B-1

DISTRIBUTION PLANT, GAS SALES, NUMBERS OF CUSTOMERS, POPULATION AND ACREAGE - THE EAST OHIO GAS COMPANY (Continued)

	Community	Distribution Plant in Service ($) End of 1979	Gas Sales in 1979 (MCF)			Average Number of Customers in 1979			Population in (1970)	Land Area in 1970 (sq. mi.)
			Residential	Commercial	Industrial	Residential	Commercial	Industrial		
33	Canton	16,177,772	7,266,380	2,828,392	15,185,272	38,295.3	2,530.8	59.7	110,053	19.0
34	East Canton	355,760	73,581	38,377	283,840	486.9	49.2	2.0	NA	NA
35	North Canton	2,028,195	746,491	296,468	310,757	4,267.3	299.3	3.3	NA	NA
36	Louisville	929,430	280,535	106,396	1,020,176	1,787.0	121.4	3.0	6,298	3.4
37	Hills & Dale	82,043	49,062	1,322	0	144.3	4.6	0.0	NA	NA
38	Lake Cable	236,010	103,535	14,324	0	589.1	37.0	0.0	NA	NA
39	Meyers Lake	39,512	12,320	954	0	81.1	1.0	0.0	NA	NA
40	Hartville	931,274	226,624	113,570	187,179	1,375.1	118.2	3.0	NA	NA
41	Baltic Village	257,938	23,534	20,876	167,692	154.1	37.6	2.0	NA	NA
42	Limaville Village	29,742	14,790	501	0	89.5	3.0	0.0	NA	NA
43	Youngstown	21,374,705	9,870,464	3,742,219	12,738,201	47,920.3	3,215.2	47.4	139,788	33.6
44	Campbell	1,388,014	711,067	94,108	176,596	3,900.3	137.6	2.0	12,577	3.5
45	Girard	1,700,798	742,970	194,819	139,654	3,914.0	259.4	5.0	14,119	3.9
46	Hubbard	1,305,847	479,092	187,785	100,251	2,598.1	170.3	2.0	8,583	2.7
47	Struthers	1,892,453	792,033	165,069	2,607,307	4,584.4	278.8	1.0	15,343	3.7
48	Lowellville	304,900	94,990	21,502	30,115	485.2	41.8	2.8	NA	NA
49	East Palestine	1,079,571	322,405	112,048	146,672	1,731.1	153.9	7.7	5,604	2.0
50	Poland	1,200,838	574,419	57,184	0	2,929.7	62.8	0.0	3,097	1.5
51	New Middletown	257,968	96,506	17,337	0	565.8	27.0	0.0	NA	NA
52	Petersburg	257,155	21,996	9,014	40,391	112.7	11.0	2.0	NA	NA
53	Massillon	4,657,082	2,254,301	699,721	3,895,773	12,607.0	763.3	24.1	32,539	8.9
54	Dover	1,926,625	621,175	258,587	1,064,179	3,771.4	337.3	13.5	11,516	5.0
55	Sugar Creek- Shaneville	365,275	79,030	52,464	653,182	511.7	81.1	4.0	NA	NA
56	Mineral City	285,075	63,649	11,071	66,499	437.3	29.1	2.0	NA	NA
57	Parral	40,295	9,516	2,348	0	64.8	7.3	0.0	NA	NA
58	Dellroy	54,767	15,301	8,912	0	101.9	23.3	0.0	NA	NA

TABLE B-1

DISTRIBUTION PLANT, GAS SALES, NUMBERS OF CUSTOMERS, POPULATION AND ACREAGE - THE EAST OHIO GAS COMPANY (Continued)

	Community	Distribution Plant in Service ($) End of 1979	Gas Sales in 1979 (MCF)			Average Number of Customers in 1979			Population in (1970)	Land Area in 1970 (sq. mi.)
			Residential	Commercial	Industrial	Residential	Commercial	Industrial		
59	New Philadelphia	2,280,491	873,492	343,838	86,979	5,351.4	472.8	5.4	15,184	4.4
60	Stone Creek	53,403	10,333	5,168	311,574	59.7	14.2	2.0	NA	NA
61	Midvale	336,807	46,505	40,704	327,206	283.0	45.1	2.0	NA	NA
62	Uhrichsville & Dennison	1,972,690	599,662	152,805	746,391	3,129.6	249.4	5.0	9,237	2.7
63	Tuscarawas	185,053	51,153	10,706	0	307.5	28.0	0.0	NA	NA
64	Kent	2,527,806	960,827	908,461	251,347	4,895.4	443.6	9.9	28,183	7.3
65	Brady Lake	250,116	47,263	12,869	0	332.7	15.0	0.0	NA	NA
66	Ravenna	1,611,613	651,003	360,956	407,595	3,505.1	339.6	18.3	11,780	5.0
67	Warren	8,692,329	3,219,903	1,584,355	9,562,409	17,914.1	1,250.1	22.5	63,494	12.0
68	Windham	583,935	186,435	37,652	264,572	1,242.5	47.8	1.0	3,360	2.0
69	Newton Falls	1,024,725	255,591	184,307	2,806,243	1,579.4	159.8	4.8	5,378	1.6
70	Cortland	643,984	182,009	75,391	1,168	1,168.9	95.1	2.0	2,525	2.0
71	Craig Beach	358,596	75,201	16,641	0	527.4	30.9	0.0	NA	NA
72	Hiram	270,157	27,529	67,867	95	170.1	15.0	0.1	NA	NA
73	Garrettsville	379,175	66,355	50,718	14,293	385.3	70.3	1.0	NA	NA
74	Lordstown	332,404	18,879	5,895	0	128.8	6.5	0.0	NA	NA
75	Niles	3,416,521	1,323,318	373,382	1,791,457	6,781.7	380.8	11.0	21,581	7.6
76	McDonald	644,058	149,350	36,721	1,982,916	911.3	35.6	1.0	NA	NA
77	Wooster	3,453,548	987,648	682,449	899,310	5,475.4	563.8	15.7	18,703	9.3
78	Orrville	1,644,167	407,782	252,101	837,512	2,527.6	254.1	18.9	7,408	6.0
79	Loudonville	524,135	172,461	94,129	22,219	1,059.8	133.8	2.0	2,865	1.6
80	Shreve	213,698	80,275	24,163	48,754	483.4	47.6	1.0	NA	NA
81	Gann	39,723	14,946	740	755	91.3	4.8	1.0	NA	NA
82	Danville	312,611	55,430	36,148	0	346.0	58.1	0.0	NA	NA
83	Smithville	190,325	62,693	63,579	10,790	388.9	48.5	2.0	NA	NA
84	Marshallville	111,482	42,086	15,415	305	257.4	21.3	1.0	NA	NA
85	Applecreek	284,337	44,771	37,039	429	285.4	36.1	0.5	NA	NA

Source: The East Ohio Gas Company

APPENDIX C

PEOPLES NATURAL GAS DATA

The purpose of this appendix is to present the community-level data used in the statistical analyses of Peoples Natural Gas, as reported in chapter 3, sections 2 and 4. The data are indicated for 109 communities. The residential data are presented in table C-1, and the commercial/industrial ones in table C-2. Population, acreage, maximum daily sendout and production/purchase capacity data are presented in table C-3. Degree-day data are presented in table C-4, and plant data in tables C-5 and C-6.

TABLE C-1

RESIDENTIAL GAS SALES, NUMBERS OF CUSTOMERS, AND SERVICE SATURATION - 1979 - PEOPLES NATURAL GAS

Community	Residential Gas Sales			Residential Gas Customers			Gas Service Saturation of the Residential Sector (%)
	Heating	Non-Heating	Total	Heating	Non-Heating	Total	
1. Ackley	93	2	95	551	46	597	76
2. Adair	40	0	40	297	10	307	77
3. Anamosa	180	1	181	1181	34	1215	87
4. Andrew	15	0	15	97	5	102	96
5. Anita	57	0	57	391	10	401	78
6. Arlington	25	0	25	168	10	178	62
7. Arnolds Park	52	0	52	422	13	435	53
8. Bellevue	73	2	75	536	81	617	70
9. Boxholm	17	0	17	90	2	92	45
10. Calmar	43	1	44	274	22	296	80
11. Carter Lake	128	0	128	946	6	952	84
12. Council, Bluffs	2772	7	2779	18526	162	18688	78
13. Council Bluffs - Crescent	32	0	32	218	0	218	100
14. Cresco	161	3	164	1063	105	1168	73
15. Cumberland	18	0	18	127	5	132	100
16. Dayton	55	0	55	323	2	325	63
17. Decorah	250	9	259	1547	264	1811	66
18. Delhi	26	0	26	160	2	162	48
19. Denison	240	2	242	1634	57	1691	68
20. Dike	39	1	40	258	30	288	90
21. Dubuque	2190	59	2249	14582	1769	16351	64
22. Dyersville	154	1	155	942	26	968	62
23. Earlville	42	0	42	252	10	262	53
24. Edgewood	32	1	33	248	21	269	78
25. Elkader	63	1	64	394	36	430	58
26. Elkader-St. Olaf	5	0	5	35	7	42	100
27. Emmons	1	0	1	9	0	9	100

TABLE C-1

RESIDENTIAL GAS SALES, NUMBERS OF CUSTOMERS, AND SERVICE SATURATION - 1979 - PEOPLES NATURAL GAS
(Continued)

Community	Residential Gas Sales			Residential Gas Customers			Gas Service Saturation of the Residential Sector (%)
	Heating	Non-Heating	Total	Heating	Non-Heating	Total	
28. Epworth	42	0	42	276	3	279	50
29. Estherville	434	0	434	2654	8	2662	92
30. Everly	46	0	46	278	1	279	71
31. Farley	45	0	45	280	8	288	55
32. Farnhamville	28	0	28	170	0	170	63
33. Fayette	65	1	66	397	16	413	59
34. Fertile	21	0	21	131	1	132	84
35. Forest City	235	0	235	1442	2	1444	91
36. Fostoria	13	0	13	83	0	83	43
37. Fredericksburg	39	1	40	261	33	294	83
38. Glenwood	188	0	188	1345	10	1355	87
39. Glidden	59	0	59	372	10	382	82
40. Gowrie	69	0	69	394	0	394	78
41. Grand Junction	62	0	62	376	4	380	64
42. Granger	30	0	30	189	2	191	60
43. Greene	52	1	53	341	42	383	68
44. Grimes	65	0	65	448	2	450	80
45. Grundy Center	130	1	131	838	19	857	73
46. Guttenberg	93	1	94	676	28	704	79
47. Hamburg	62	0	62	464	18	482	100
48. Hanlontown	13	0	13	80	0	80	55
49. Harcourt	21	0	21	124	0	124	60
50. Hartley	105	0	105	677	5	682	83
51. Hawkeye	24	0	24	155	9	164	83
52. Hopkinton	39	0	39	231	5	236	83
53. Ionia	13	0	13	90	11	101	64
54. Joice	14	0	14	92	0	92	51

TABLE C-1

RESIDENTIAL GAS SALES, NUMBERS OF CUSTOMERS, AND SERVICE SATURATION - 1979 - PEOPLES NATURAL GAS
(Continued)

Community	Residential Gas Sales			Residential Gas Customers			Gas Service Saturation of the Residential Sector (%)
	Heating	Non-Heating	Total	Heating	Non-Heating	Total	
55. Kellog	29	0	29	193	8	201	86
56. Klemme	37	0	37	236	3	239	78
57. Lake Mills	124	0	124	788	0	788	86
58. Lake Park	49	0	49	334	13	347	72
59. Lamont	27	0	27	184	7	191	62
60. Langworthy	2	0	2	14	3	17	68
61. Laporte City	111	1	112	711	18	729	80
62. Lehigh	34	0	34	224	1	225	83
63. Luana	9	0	9	62	3	65	88
64. Madrid	125	1	126	814	13	827	84
65. Manchester	264	2	266	1637	72	1709	93
66. Maquoketa	210	2	212	1508	52	1560	76
67. Marble Rock	18	0	18	117	11	128	72
68. Massena	21	0	21	152	6	158	100
69. Miles	14	0	14	78	10	88	61
70. Millford	93	0	93	602	1	603	83
71. Mitchell	12	1	12	71	1	72	83
72. Monana	68	1	69	447	27	474	76
73. Monticello	156	1	157	1032	37	1069	77
74. New Hampton	203	1	204	1169	38	1207	89
75. Newton	783	13	796	5135	320	5455	88
76. Ogden	118	0	118	723	4	727	74
77. Onawa	109	3	112	776	92	868	67
78. Ossian	38	1	39	231	17	248	81
79. Paullina	86	0	86	500	5	505	83
80. Pilot Mound	12	0	12	72	0	72	78
81. Pocahantas	96	2	98	651	52	703	70

TABLE C-1

RESIDENTIAL GAS SALES, NUMBERS OF CUSTOMERS, AND SERVICE SATURATION - 1979 - PEOPLES NATURAL GAS (Continued)

Community	Residential Gas Sales (MMCF)			Residential Gas Customers			Gas Service Saturation of the Residential Sector (%)
	Heating	Non-Heating	Total	Heating	Non-Heating	Total	
82. Postville	52	1	53	356	43	399	61
83. Primghar	63	0	63	362	6	368	79
84. Ralston	6	0	6	38	1	39	42
85. Readlyn	35	2	37	222	43	265	54
86. Ridgeway	9	0	9	62	11	73	68
87. Rippey	19	0	19	121	0	121	55
88. Rockford	56	0	56	348	4	352	78
89. Royal	26	0	26	178	7	185	59
90. Scranton	38	0	38	254	15	269	76
91. Sidney	50	1	51	394	21	415	100
92. Spencer	520	1	521	3199	28	3227	77
93. Spirit Lake	183	1	184	1202	12	1214	76
94. Spirit Lake-Orleans	40	0	40	317	1	318	100
95. St. Ansgar	37	1	38	243	21	264	77
96. Story City	146	0	146	884	8	892	76
97. Strawberry Point	65	1	66	415	25	440	89
98. Sumner	81	0	81	553	22	575	63
99. Superior	12	0	12	70	0	70	66
100. Tabor	44	0	44	300	10	310	100
101. Terril	24	0	24	152	4	156	64
102. Triploi	47	1	48	319	46	365	62
103. Vincent	11	0	11	65	1	66	80
104. Wallingford	11	0	11	79	1	80	85
105. Waukon	160	2	162	1092	64	1156	75
106. Webster City	506	3	509	2993	67	3060	90
107. West Union	128	1	129	808	31	839	81
108. Woodward	63	0	63	410	3	413	70
109. Worthington	14	0	14	89	8	97	27

Source: Peoples Natural Gas

TABLE C-2

COMMERCIAL AND INDUSTRIAL GAS SALES AND NUMBERS OF CUSTOMERS - 1979 - PEOPLES NATURAL GAS

Community	Total Commercial Gas Sales (MMCF)	Commercial Gas Customers			Total Industrial Gas Sales (MMCF)	Total Industrial Customers	Industrial Interruptible Customers
		Heating	Non-Heating	Total			
1. Ackley	46	99	7	106	63	4	4
2. Adair	19	55	0	55	10	2	2
3. Anamosa	68	162	2	164	106	6	3
4. Andrew	10	17	0	17	0	0	0
5. Anita	25	71	1	72	2	1	1
6. Arlington	9	31	0	31	0	0	0
7. Arnolds Park	17	38	5	43	0	0	0
8. Bellevue	27	80	0	80	5	2	2
9. Boxholm	16	24	2	26	0	0	0
10. Calmar	42	70	5	75	1	2	0
11. Carter Lake	23	39	0	39	0	0	0
12. Council, Bluffs	1234	1358	13	1371	616	26	10
13. Council Bluffs - Crescent	4	13	1	14	0	0	0
14. Cresco	114	164	6	170	89	4	2
15. Cumberland	5	30	0	30	0	0	0
16. Dayton	33	71	1	72	0	1	1
17. Decorah	309	261	31	292	111	2	1
18. Delhi	24	41	0	41	0	0	0
19. Denison	163	260	4	264	444	7	3
20. Dike	20	39	1	40	4	1	1
21. Dubuque	1589	1277	121	1398	3568	43	19
22. Dyersville	101	165	0	165	78	4	2
23. Earlville	10	34	1	35	0	0	0
24. Edgewood	17	31	0	31	0	1	1
25. Elkader	58	109	8	117	11	3	3
26. Elkader-St. Olaf	4	10	1	11	0	0	0
27. Emmons	1	2	0	2	0	0	0
28. Epworth	24	23	4	27	0	0	0

TABLE C-2

COMMERCIAL AND INDUSTRIAL GAS SALES AND NUMBERS OF CUSTOMERS - 1979 - PEOPLES NATURAL GAS (Continued)

Community	Total Commercial Gas Sales (MMCF)	Commercial Gas Customers: Heating	Commercial Gas Customers: Non-Heating	Commercial Gas Customers: Total	Total Industrial Gas Sales (MMCF)	Total Industrial Customers	Industrial Interruptible Customers
29. Estherville	202	296	1	297	237	13	9
30. Everly	33	47	3	50	5	1	1
31. Farley	21	39	0	39	2	1	1
32. Farnhamville	13	39	3	42	17	2	2
33. Fayette	56	69	14	83	9	1	1
34. Fertile	8	23	1	24	1	1	1
35. Forest City	179	224	0	224	127	7	4
36. Fostoria	3	16	0	16	3	1	1
37. Fredericksburg	33	53	4	57	328	2	1
38. Glenwood	156	179	0	179	159	2	1
39. Glidden	28	57	5	62	0	0	0
40. Gowrie	40	80	0	80	0	2	2
41. Grand Junction	43	72	4	76	0	0	0
42. Granger	19	29	4	33	0	0	0
43. Greene	38	61	9	70	24	1	1
44. Grimes	16	41	0	41	58	1	1
45. Grundy Center	84	119	5	124	18	6	4
46. Guttenberg	62	110	6	116	0	0	0
47. Hamburg	75	76	11	87	0	0	0
48. Hanlontown	12	17	2	19	6	1	1
49. Harcourt	4	20	0	20	1	1	1
50. Hartley	51	100	2	102	14	2	2
51. Hawkeye	15	23	1	24	0	0	0
52. Hopkinton	11	42	1	43	159	2	2
53. Ionia	4	18	0	18	3	2	2
54. Joice	6	22	1	23	2	1	1
55. Kellog	17	19	3	22	40	1	0
56. Klemme	17	43	0	43	4	1	1

TABLE C-2

COMMERCIAL AND INDUSTRIAL GAS SALES AND NUMBERS OF CUSTOMERS - 1979 - PEOPLES NATURAL GAS (Continued)

Community	Total Commercial Gas Sales (MMCF)	Commercial Gas Customers			Total Industrial Gas Sales (MMCF)	Total Industrial Customers	Industrial Interruptible Customers
		Heating	Non-Heating	Total			
57. Lake Mills	70	122	0	122	69	7	5
58. Lake Park	40	66	1	67	70	4	4
59. Lamont	11	38	0	38	0	0	0
60. Langworthy	2	3	1	4	0	0	0
61. Laporte City	43	83	10	93	0	0	0
62. Lehigh	12	43	2	45	0	0	0
63. Luana	7	18	0	18	165	2	1
64. Madrid	48	82	0	82	0	0	0
65. Manchester	225	236	0	236	27	2	1
66. Maquoketa	122	245	1	246	120	10	8
67. Marble Rock	8	26	0	26	7	1	1
68. Massena	7	38	1	39	0	0	0
69. Miles	5	20	1	21	0	0	0
70. Millford	41	92	0	92	13	5	3
71. Mitchell	1	6	0	6	0	0	0
72. Monana	52	78	5	83	0	0	0
73. Monticello	98	172	0	172	33	8	3
74. New Hampton	153	201	7	208	150	6	5
75. Newton	332	437	0	437	610	17	10
76. Ogden	43	95	4	99	7	3	3
77. Onawa	78	132	0	132	6	1	1
78. Ossian	36	69	2	71	3	1	1
79. Paullina	34	77	0	77	16	6	5
80. Pilot Mound	7	20	0	20	0	0	0
81. Pocahantas	80	123	1	124	0	0	0
82. Postville	42	70	10	80	154	3	3
83. Primghar	37	86	1	87	3	1	1
84. Ralston	3	12	0	12	49	1	1

TABLE C-2

COMMERCIAL AND INDUSTRIAL GAS SALES AND NUMBERS OF CUSTOMERS - 1979 - PEOPLES NATURAL GAS (Continued)

	Community	Total Commercial Gas Sales (MMCF)	Commercial Gas Customers			Total Industrial Gas Sales (MMCF)	Total Industrial Customers	Industrial Interruptible Customers
			Heating	Non-Heating	Total			
85.	Readlyn	14	46	0	46	3	2	2
86.	Ridgeway	10	14	2	16	0	0	0
87.	Rippey	10	28	0	28	0	0	0
88.	Rockford	31	64	0	64	8	2	2
89.	Royal	14	32	1	33	22	1	1
90.	Scranton	18	46	4	50	14	1	1
91.	Sidney	34	71	0	71	0	0	0
92.	Spencer	376	405	5	410	194	14	9
93.	Spirit Lake	165	169	5	174	28	3	3
94.	Spirit Lake-Orleans	4	11	1	12	0	0	0
95.	St. Ansgar	18	61	0	61	16	4	4
96.	Story City	77	109	0	109	16	4	3
97.	Strawberry Point	33	68	5	73	1	1	1
98.	Sumner	52	117	0	117	8	3	2
99.	Superior	2	9	0	9	25	1	1
100.	Tabor	18	54	4	58	0	0	0
101.	Terril	14	26	0	26	5	1	1
102.	Triploi	23	49	7	56	2	1	1
103.	Vincent	6	19	0	19	32	1	1
104.	Wallingford	3	12	1	13	0	1	1
105.	Waukon	81	152	0	152	127	3	1
106.	Webster City	233	338	7	345	127	12	5
107.	West Union	81	144	6	150	8	2	2
108.	Woodward	23	45	0	45	13	1	1
109.	Worthington	7	20	2	22	0	0	0

Source: Peoples Natural Gas

TABLE C-3

POPULATION, ACREAGE, MAXIMUM DAY SENDOUT AND MAXIMUM PRODUCTION AND PURCHASE CAPACITY
PEOPLES NATURAL GAS

Community	Population in 1970	Population in 1979	Acreage in 1970 (sq. mi.)	Maximum Day Sendout in 1979 (MMCF)	Total Maximum Daily Production & Purchase Capacity (MMCF)
1. Ackley	N.A.	1,820	N.A.	1.3	1.0
2. Adair	N.A.	932	N.A.	0.5	0.4
3. Anamosa	4,389	4,148	1	2.3	1.8
4. Andrew	N.A.	307	N.A.	0.2	0.2
5. Anita	N.A.	1,262	N.A.	0.6	0.6
6. Arlington	N.A.	723	N.A.	0.3	0.2
7. Arnolds Park	N.A.	1,674	N.A.	1.1	0.4
8. Bellevue	N.A.	2,362	N.A.	0.8	0.7
9. Boxholm	N.A	505	N.A.	0.4	0.2
10. Calmar	N.A.	1,066	N.A.	0.6	0.6
11. Carter Lake	3,268	3,950	4	1.3	1.0
12. Council, Bluffs	60,348	68,120	40	29.9	31.3
13. Council Bluffs - Crescent	N.A.	294	N.A.	N.A.	N.A.
14. Cresco	3,927	4,012	3	2.2	2.0
15. Cumberland	N.A.	385	N.A.	N.A.	N.A.
16. Dayton	N.A.	1,344	N.A.	0.7	0.6
17. Decorah	7,458	8,391	4	3.6	3.1
18. Delhi	N.A.	1,186	N.A.	0.3	0.3
19. Denison	5,882	6,685	6	4.3	3.2
20. Dike	N.A.	847	N.A.	0.5	0.3
21. Dubuque	62,309	83,611	16	35.6	32.3
22. Dyersville	3,437	5,133	3	2.0	1.8
23. Earlville	N.A.	1,590	N.A.	0.4	0.4
24. Edgewood	N.A.	1,015	N.A.	0.4	0.3
25. Elkader	N.A.	1,607	N.A.	1.1	0.9
26. Elkader-St. Olaf	N.A.	147	N.A.	N.A.	N.A.
27. Emmons	N.A.	26	N.A.	N.A.	N.A.
28. Epworth	N.A.	2,319	N.A.	0.5	0.4

TABLE C-3

POPULATION, ACREAGE, MAXIMUM DAY SENDOUT AND MAXIMUM PRODUCTION AND PURCHASE CAPACITY
PEOPLES NATURAL GAS
(Continued)

Community	Population in 1970	Population in 1979	Acreage in 1970 (sq. mi.)	Maximum Day Sendout in 1979 (MMCF)	Total Maximum Daily Production & Purchase Capacity (MMCF)
29. Estherville	8,108	8,223	4	5.0	4.7
30. Everly	N.A.	1,101	N.A.	0.8	0.4
31. Farley	N.A.	1,990	N.A.	0.5	0.5
32. Farnhamville	N.A.	676	N.A.	0.9	0.3
33. Fayette	N.A.	2,306	N.A.	0.9	0.7
34. Fertile	N.A.	409	N.A.	0.3	0.2
35. Forest City	3,841	4,422	3	3.5	2.3
36. Fostoria	N.A.	550	N.A.	0.3	0.1
37. Fredericksburg	N.A.	1,004	N.A.	2.0	0.8
38. Glenwood	4,195	5,013	12	2.9	2.3
39. Glidden	N.A.	1,131	N.A.	0.7	0.6
40. Gowrie	N.A.	1,274	N.A.	0.9	0.9
41. Grand Junction	N.A.	1,452	N.A.	0.8	0.8
42. Granger	N.A.	841	N.A.	0.4	0.3
43. Greene	N.A.	1,298	N.A.	0.8	0.6
44. Grimes	N.A.	956	N.A.	0.9	0.6
45. Grundy Center	N.A.	2,803	N.A.	1.7	1.6
46. Guttenberg	N.A.	2,247	N.A.	1.2	1.1
47. Hamburg	N.A.	1,649	N.A.	N.A.	N.A.
48. Hanlontown	N.A.	428	N.A.	0.3	0.1
49. Harcourt	N.A.	542	N.A.	0.2	0.2
50. Hartley	N.A.	1,959	N.A.	1.3	1.4
51. Hawkeye	N.A.	536	N.A.	0.4	0.2
52. Hopkinton	N.A.	799	N.A.	1.0	0.4
53. Ionia	N.A.	487	N.A.	0.2	0.1
54. Joice	N.A.	453	N.A.	0.4	0.1
55. Kellog	N.A.	596	N.A.	0.6	0.3
56. Klemme	N.A.	773	N.A.	0.4	0.4

TABLE C-3

POPULATION, ACREAGE, MAXIMUM DAY SENDOUT AND MAXIMUM PRODUCTION AND PURCHASE CAPACITY
PEOPLES NATURAL GAS
(Continued)

Community	Population in 1970	Population in 1979	Acreage in 1970 (sq. mi.)	Maximum Day Sendout in 1979 (MMCF)	Total Maximum Daily Production & Purchase Capacity (MMCF)
57. Lake Mills	N.A.	2,246	N.A.	2.0	1.3
58. Lake Park	N.A.	1,161	N.A.	1.4	0.5
59. Lamont	N.A.	845	N.A.	0.3	0.2
60. Langworthy	N.A.	69	N.A.	0.1	0.1
61. Laporte City	N.A.	2,526	N.A.	1.2	1.2
62. Lehigh	N.A.	650	N.A.	0.4	0.3
63. Luana	N.A.	186	N.A.	0.7	0.6
64. Madrid	N.A.	2,670	N.A.	1.5	1.3
65. Manchester	4,641	4,688	3	3.2	3.0
66. Maquoketa	5,677	5,204	3	3.0	2.7
67. Marble Rock	N.A.	476	N.A.	0.4	0.2
68. Massena	N.A.	433	N.A.	N.A.	N.A.
69. Miles	N.A.	419	N.A.	0.2	0.1
70. Millford	N.A.	1,765	N.A.	1.1	1.2
71. Mitchell	N.A.	224	N.A.	0.1	0.1
72. Monana	N.A.	1,431	N.A.	0.9	0.7
73. Monticello	N.A.	3,781	N.A.	2.1	1.8
74. New Hampton	3,621	3,681	2	2.8	2.6
75. Newton	15,619	15,802	7	11.2	9.1
76. Ogden	N.A.	2,372	N.A.	1.3	1.2
77. Onawa	3,154	3,185	5	1.7	1.1
78. Ossian	N.A.	879	N.A.	0.7	0.5
79. Paullina	N.A.	1,511	N.A.	1.0	1.0
80. Pilot Mound	N.A.	237	N.A.	0.2	0.1
81. Pocahantas	N.A.	2,622	N.A.	1.3	1.0
82. Postville	N.A.	1,506	N.A.	1.6	0.5
83. Primghar	N.A.	1,283	N.A.	0.8	0.8
84. Ralston	N.A.	248	N.A.	0.9	

TABLE C-3

POPULATION, ACREAGE, MAXIMUM DAY SENDOUT AND MAXIMUM PRODUCTION AND PURCHASE CAPACITY
PEOPLES NATURAL GAS
(Continued)

Community	Population in 1970	Population in 1979	Acreage in 1970 (sq. mi.)	Maximum Day Sendout in 1979 (MMCF)	Total Maximum Daily Production & Purchase Capacity (MMCF)
85. Readlyn	N.A.	1,446	N.A.	0.4	0.3
86. Ridgeway	N.A.	264	N.A.	0.2	0.1
87. Rippey	N.A.	522	N.A.	0.2	0.2
88. Rockford	N.A.	1,225	N.A.	0.7	0.7
89. Royal	N.A.	869	N.A.	0.7	0.3
90. Scranton	N.A.	886	N.A.	0.7	0.4
91. Sidney	N.A.	1,061	N.A.	N.A.	N.A.
92. Spencer	10,278	10,703	8	7.4	5.8
93. Spirit Lake	3,014	4,163	2	2.9	2.0
94. Spirit Lake-Orleans	N.A.	405	N.A.	N.A.	0
95. St. Ansgar	N.A.	954	2	0.6	0.4
96. Story City	N.A.	2,962	N.A.	1.7	1.4
97. Strawberry Point	N.A.	1,253	N.A.	0.8	0.7
98. Sumner	N.A.	2,195	N.A.	1.0	1.0
99. Superior	N.A.	300	N.A.	0.9	0.1
100. Tabor	N.A.	957	N.A.	0	N.A.
101. Terril	N.A.	646	N.A.	0.4	0.2
102. Triploi	N.A.	1,504	N.A.	0.5	0.5
103. Vincent	N.A.	226	N.A.	1.1	0.1
104. Wallingford	N.A.	260	N.A.	0.4	0.1
105. Waukon	3,883	4,029	1	2.0	1.9
106. Webster City	8,488	8,766	6	6.1	6.1
107. West Union	2,624	2,668	2	1.6	1.4
108. Woodward	N.A.	1,576	N.A.	0.8	0.7
109. Worthington	N.A.	1,372	N.A.	0.2	0.1

Source: Peoples Natural Gas

TABLE C-4

ANNUAL AND MONTHLY DEGREE-DAY DATA - PEOPLES NATURAL GAS

Community	Total Annual Degree-Days in 1980	Normal Annual Degree-Days	Maximum Monthly Degree-Days in 1980	Maximum Monthly Normal Degree-Days
1. Ackley	7,231	7,415	1,424	1,510
2. Adair	6,288	6,710	1,320	1,414
3. Anamosa	6,860	6,601	1,343	1,383
4. Andrew	7,074	7,277	1,395	1,466
5. Anita	6,288	6,710	1,320	1,414
6. Arlington	7,074	7,277	1,395	1,466
7. Arnolds Park	7,357	7,770	1,458	1,559
8. Bellevue	7,074	7,277	1,395	1,466
9. Boxholm	6,288	6,710	1,320	1,414
10. Calmar	7,574	7,667	1,515	1,547
11. Carter Lake	6,534	6,563	1,310	1,398
12. Council, Bluffs	6,534	6,563	1,310	1,398
13. Council Bluffs-Crescent	6,534	6,563	1,310	1,398
14. Cresco	7,574	7,667	1,515	1,547
15. Cumberland	6,288	6,710	1,320	1,414
16. Dayton	7,574	6,710	1,320	1,414
17. Decorah	7,574	7,667	1,515	1,547
18. Delhi	7,231	7,415	1,424	1,510
19. Denison	6,288	6,710	1,320	1,414
20. Dike	7,231	7,415	1,424	1,510
21. Dubuque	7,074	7,277	1,395	1,466
22. Dyersville	7,231	7,415	1,424	1,510
23. Earlville	7,321	7,415	1,424	1,510
24. Edgewood	7,074	7,277	1,395	1,466
25. Elkader	7,074	7,277	1,395	1,466
26. Elkader-St. Olaf	7,074	7,277	1,395	1,466
27. Emmons	7,574	7,667	1,515	1,547
28. Epworth	7,231	7,415	1,424	1,510
29. Estherville	7,357	7,770	1,458	1,559
30. Everly	7,357	7,770	1,458	1,559
31. Farley	7,231	7,415	1,424	1,510
32. Farmhamville	6,288	6,710	1,320	1,414
33. Fayette	7,074	7,277	1,395	1,466
34. Fertile	7,574	7,667	1,515	1,547
35. Forest City	7,574	7,667	1,515	1,547
36. Fostoria	7,357	7,770	1,458	1,559

TABLE C-4

ANNUAL AND MONTHLY DEGREE-DAY DATA - PEOPLES NATURAL GAS
(Continued)

Community	Total Annual Degree-Days in 1980	Normal Annual Degree-Days	Maximum Monthly Degree-Days in 1980	Maximum Monthly Normal Degree-Days
37. Fredericksburg	7574	7667	1515	1547
38. Glenwood	6021	6218	1263	1327
39. Glidden	6288	6710	1320	1414
40. Gowrie	6288	6710	1320	1414
41. Grand Junction	6288	6710	1320	1414
42. Granger	6288	6710	1320	1414
43. Green	7574	7667	1515	1547
44. Grimes	6288	6710	1320	1414
45. Grundy Center	7231	7415	1424	1510
46. Guttenberg	7074	7277	1395	1466
47. Hamburg	6021	6218	1263	1327
48. Hanlon town	7574	7667	1515	1547
49. Harcourt	6288	6710	1320	1414
50. Hartley	7357	7770	1458	1559
51. Hawkeye	7074	7277	1395	1466
52. Hopkinton	6860	6601	1343	1383
53. Ionia	7574	7667	1515	1547
54. Joice	7574	7667	1515	1547
55. Kellogg	6288	6710	1320	1414
56. Klemme	7574	7667	1515	1547
57. Lake Mills	7574	7667	1515	1547
58. Lake Park	7357	7770	1458	1559
59. Lamont	7074	7277	1395	1466
60. Langworthy	6860	6601	1343	1383
61. Laporte City	7231	7415	1424	1510
62. Hehigh	6288	6710	1320	1414
63. Luana	7074	7277	1395	1466
64. Madrid	6288	6710	1320	1414
65. Manchester	7231	7415	1424	1510
66. Maquoketa	7074	7277	1395	1466
67. Marble Rock	7574	7667	1515	1547
68. Massena	6288	6710	1320	1414
69. Miles	7074	7277	1395	1466
70. Millford	7357	7770	1458	1559
71. Mitchell	7574	7667	1515	1547
72. Monana	7074	7277	1395	1466
73. Monticello	6860	6601	1343	1383
74. New Hampton	7574	7667	1515	1547
75. Newton	6288	6710	1320	1414

TABLE C-4

ANNUAL AND MONTHLY DEGREE-DAY DATA - PEOPLES NATURAL GAS
(Continued)

Community	Total Annual Degree-Days in 1980	Normal Annual Degree-Days	Maximum Monthly Degree-Days in 1980	Maximum Monthly Normal Degree-Days
76. Ogden	6288	6710	1320	1414
77. Onawa	6288	6710	1320	1414
78. Ossian	7574	7667	1515	1547
79. Paullina	7357	7770	1458	1559
80. Pilot Mound	6288	6710	1320	1414
81. Pocahantas	7357	7770	1458	1559
82. Postville	7074	7277	1395	1466
83. Primghar	7357	7770	1458	1559
84. Ralston	6288	6710	1320	1414
85. Readlyn	7574	7667	1515	1547
86. Ridgeway	7574	7667	1515	1547
87. Rippey	6288	6710	1320	1414
88. Rockford	7574	7667	1515	1547
89. Royal	7357	7770	1458	1559
90. Scranton	6288	6710	1320	1414
91. Sidney	8021	6218	1263	1327
92. Spencer	7357	7770	1458	1559
93. Spirit Lake	7357	7357	1458	1559
94. Spirit Lake-Orleans	7357	7357	1458	1559
95. St. Ansgar	7574	7667	1515	1547
96. Story City	6288	6710	1320	1414
97. Strawberry Point	7074	7277	1395	1466
98. Sumner	7574	7667	1515	1547
99. Superior	7357	7770	1458	1559
100. Tabor	6021	6218	1263	1327
101. Terril	7357	7770	1458	1559
102. Tripoli	7574	7667	1515	1547
103. Vincent	6288	6710	1320	1414
104. Wallingford	7357	7770	1458	1559
105. Waukon	7074	7277	1395	1466
106. Webster City	6288	6710	1320	1414
107. West Union	7074	7277	1395	1466
108. Woodward	6288	6710	1320	1414
109. Worthington	7231	7415	1424	1510

Source: Peoples Natural Gas

TABLE C-5

DISAGGREGATED DISTRIBUTION PLANT IN SERVICE ($) - END OF 1979 - PEOPLES NATURAL GAS

Case	Community	Land and Land Rights	Structures & Improvements	Mains	Measuring and Regulating Station Equipment	Services	Meters	Meter Installations	House Regulators	House Regulators Installations	Industrial Measuring & Reg. Station Equipment
1	Ackley	0	121	125,746	11,326	74,253	35,600	5,166	6,996	3,010	4,930
2	Adair	0	21	62,594	7,391	43,878	18,443	2,225	5,351	2,399	2,909
3	Anamosa	0	0	273,540	6,310	188,804	69,945	10,336	10,856	5,737	6,601
4	Andrew	0	0	20,484	3,057	15,012	5,983	1,053	1,563	879	956
5	Anita	0	314	91,713	9,139	55,006	23,338	2,421	5,933	2,976	11,158
6	Arlington	0	0	33,140	3,616	32,795	10,631	2,304	1,926	676	0
7	Arnolds Park	0	0	46,605	10,290	41,180	23,931	3,554	5,136	2,067	815
8	Bellevue	0	0	172,711	7,898	129,503	36,490	5,398	10,290	3,791	2,899
9	Boxholm	42	188	49,125	5,797	22,413	5,785	2,191	1,930	793	1,751
10	Calmar	0	0	92,263	6,230	45,788	18,393	2,646	3,274	1,146	3,011
11	Carter Lake	2	1,277	157,307	3,372	98,185	50,532	18,216	7,951	2,893	2,861
12	Council Bluffs	30,388	472,701	4,236,233	134,853	2,854,388	992,115	164,852	192,472	65,395	314,909
13	Council Bluffs - Crescent	0	0	125,766	1,475	32,225	11,768	1,047	3,987	1,535	0
14	Cresco	77	0	380,062	7,207	195,383	67,393	8,287	11,478	5,346	19,288
15	Cumberland	0	0	26,373	8,410	18,012	8,010	400	2,010	991	0
16	Dayton	300	621	59,533	9,813	50,676	19,679	2,937	584	228	2,943
17	Decorah	7,171	36,074	584,592	15,420	428,813	105,465	17,034	21,565	9,491	22,930
18	Delhi	0	0	34,539	5,329	29,610	10,037	1,029	1,856	564	488
19	Denison	5,747	26,818	552,353	30,828	265,067	100,026	21,773	21,111	9,170	21,539
20	Dike	0	0	61,726	5,738	43,037	17,058	1,941	2,981	1,378	2,539
21	Dubuque	12,510	178,380	5,658,297	150,565	4,768,067	883,485	203,405	114,504	50,396	462,089
22	Dyersville	248	1,187	244,030	3,682	150,643	56,861	9,660	12,232	5,091	15,301
23	Earlville	0	0	58,777	6,090	37,220	14,685	1,834	2,626	954	490
24	Edgewood	0	0	66,553	5,256	40,643	15,575	2,113	3,560	1,072	2,240
25	Elkader	194	0	157,638	4,203	64,589	26,848	6,850	4,183	1,523	8,313
26	Elkader-St. Olaf	0	0	30,168	0	8,374	2,621	658	882	193	1,421
27	Emmons	0	0	2,483	542	885	494	11	31	18	257
28	Epworth	0	0	46,968	5,578	41,326	15,229	2,334	2,610	1,041	2,494

TABLE C-5

DISAGGREGATED DISTRIBUTION PLANT IN SERVICE ($) - END OF 1979 - PEOPLES NATURAL GAS (Continued)

Case	Community	Land and Land Rights	Structures & Improvements	Mains	Measuring and Regulating Station Equipment	Services	Meters	Meter Installations	House Regulators	House Regulators Installations	Industrial Measuring & Reg. Station Equipment
29	Estherville	435	3,689	416,639	31,110	246,861	145,169	22,159	28,671	11,066	25,140
30	Everly	0	0	25,580	6,119	15,355	16,317	2,703	2,896	1,133	1,607
31	Farley	0	0	62,724	5,367	43,825	16,465	1,204	2,804	1,236	1,940
32	Farmhamville	63	195	32,389	6,916	33,567	10,433	1,942	2,429	1,173	182
33	Fayette	0	0	122,902	5,602	62,470	24,772	3,094	3,878	1,928	8,757
34	Fertile	0	0	14,421	5,810	12,508	7,713	938	1,137	757	983
35	Forest City	418	490	278,398	7,828	152,313	80,347	16,322	16,991	8,388	41,856
36	Fostoria	0	0	9,958	1,169	6,375	4,944	580	1,052	532	130
37	Fredericksburg	647	53	64,468	7,833	70,995	17,701	2,028	4,629	1,769	4,171
38	Glenwood	333	2,542	399,298	13,336	213,475	76,392	12,776	4,990	2,073	17,088
39	Glodden	109	475	56,696	13,510	52,590	22,151	4,257	4,202	1,983	1,542
40	Gowrie	945	3,899	138,089	15,770	80,009	23,338	4,976	1,001	497	2,853
41	Grand Junction	154	551	51,702	6,624	35,983	22,497	3,038	4,373	1,850	2,935
42	Granger	0	0	28,513	7,300	19,257	10,977	1,653	2,094	984	2,113
43	Greene	0	0	128,411	6,195	59,351	23,090	1,792	7,947	2,227	2,666
44	Grimes	0	356	139,125	23,735	70,309	24,920	3,668	6,796	2,629	2,305
45	Grundy Center	7,535	26,132	195,042	8,500	121,532	49,840	10,091	10,179	4,891	20,747
46	Guttenberg	190	0	137,878	5,578	87,832	40,940	6,327	6,878	2,607	7,334
47	Hamburg	0	0	125,573	8,049	98,035	28,183	10,036	6,266	3,638	2,575
48	Hanlontown	0	0	20,930	5,156	15,890	4,944	790	845	669	937
49	Harcourt	207	202	39,962	5,877	24,241	7,071	1,625	2,334	432	1,482
50	Hartley	0	0	83,020	3,710	43,933	38,764	5,213	7,937	2,524	6,925
51	Hawkeye	479	0	37,286	3,702	27,706	9,345	1,308	1,932	743	816
52	Hopkinton	0	0	90,611	6,388	44,634	14,191	1,755	2,418	1,191	224
53	Ionia	0	0	21,060	3,755	14,146	6,181	1,234	1,087	498	260
54	Joice	154	0	10,071	6,868	6,775	5,686	2,947	1,235	539	309
55	Kellogg	0	433	34,422	4,793	17,947	11,125	2,487	1,599	663	2,993
56	Klemme	0	450	34,603	5,130	23,916	14,092	2,053	2,247	1,154	2,978

TABLE C-5

DISAGGREGATED DISTRIBUTION PLANT IN SERVICE ($) - END OF 1979 - PEOPLES NATURAL GAS (Continued)

Case	Community	Land and Land Rights	Structures & Improvements	Mains	Measuring and Regulating Station Equipment	Services	Meters	Meter Installations	House Regulators	House Regulators Installations	Industrial Measuring & Reg. Station Equipment
57	Lake Mills	1,300	15,750	88,366	4,340	56,165	44,895	7,022	8,619	3,817	10,311
58	Lake Park	0	827	80,941	7,241	42,382	20,618	1,385	5,436	2,487	4,878
59	Lamont	0	0	26,230	5,823	28,112	11,422	2,602	2,126	748	637
60	Langworthy	0	19	7,215	1,148	2,317	939	152	133	76	55
61	Laporte City	105	73	135,881	18,809	78,068	41,385	5,726	6,947	2,906	1,778
62	Lehigh	211	130	60,436	11,286	42,418	13,350	3,181	2,195	1,054	365
63	Luana	0	0	21,693	3,799	10,963	4,153	73	876	681	1,012
64	Madrid	103	618	109,582	8,325	90,319	45,588	7,280	9,861	3,645	8,842
65	Manchester	519	1,864	389,738	12,835	273,401	96,268	18,297	16,338	7,544	35,254
66	Maquoketa	5,055	42,901	562,208	13,259	395,323	92,560	21,162	19,948	6,896	24,978
67	Marble Rock	0	0	29,485	5,990	22,038	8,010	355	2,436	1,022	1,245
68	Massena	0	0	27,625	8,519	24,373	9,988	1,165	2,631	1,290	999
69	Miles	0	0	37,153	6,368	21,237	5,439	634	1,295	447	0
70	Millford	0	548	58,657	11,166	38,832	34,611	4,484	7,283	3,373	5,493
71	Mitchell	0	0	22,398	5,423	14,448	4,005	274	1,398	158	0
72	Monana	140	0	114,451	4,351	65,476	27,738	3,599	5,441	1,985	8,704
73	Monticello	231	0	255,731	3,180	168,712	61,855	7,869	11,224	4,969	20,230
74	New Hampton	5,137	17,089	291,464	14,770	204,278	71,744	17,879	12,878	8,963	22,849
75	Newton	1,651	45,199	1,132,509	52,605	578,857	291,129	56,393	52,345	33,021	63,937
76	Ogden	3,390	32,226	153,020	24,089	109,403	40,000	6,343	4,325	3,596	15,740
77	Onawa	0	0	209,749	12,087	157,481	51,027	8,928	13,865	4,109	5,076
78	Ossian	0	0	70,483	2,890	42,216	15,921	2,188	2,871	815	1,082
79	Paullina	154	0	46,576	1,682	34,258	28,875	4,076	5,624	2,191	8,439
80	Pilot Mound	32	168	25,831	9,161	15,802	4,549	691	470	90	682
81	Pochantas	2,224	16,437	178,747	2,514	74,979	41,237	2,714	12,894	4,579	4,376
82	Postville	77	0	132,750	5,785	74,451	24,327	3,533	4,783	1,589	5,809
83	Primghar	0	434	70,548	9,329	26,137	22,695	3,395	5,855	1,887	4,881
84	Ralston	234	452	13,734	7,256	5,811	2,522	371	374	182	1,384

TABLE C-5

DISAGGREGATED DISTRIBUTION PLANT IN SERVICE ($) - END OF 1979 - PEOPLES NATURAL GAS (Continued)

Case	Community	Land and Land Rights	Structures & Improvements	Mains	Measuring and Regulating Station Equipment	Services	Meters	Meter Installations	House Regulators	House Regulators Installations	Industrial Measuring & Reg. Station Equipment
85	Readlyn	0	0	49,493	4,623	39,910	15,872	1,429	4,402	2,069	1,435
86	Ridgeway	0	0	19,873	3,872	15,103	4,351	273	1,237	601	859
87	Rippey	0	0	7,662	6,724	15,123	7,367	922	1,548	679	1,302
88	Rockford	233	1,124	78,899	5,368	33,445	21,014	2,487	3,481	1,617	5,192
89	Royal	0	0	28,873	2,930	17,745	10,878	761	2,964	1,352	562
90	Scranton	242	421	41,410	8,784	29,089	15,674	2,244	2,960	1,521	1,955
91	Sidney	0	0	88,168	0	74,821	23,832	5,366	4,806	2,506	9,348
92	Spencer	974	22,441	616,438	47,868	309,521	177,950	30,961	38,063	15,026	85,057
93	Spirit Lake	3,233	29,539	291,100	16,262	112,935	68,233	12,959	16,426	7,601	21,284
94	Spirit Lake-Orleans	0	0	45,984	3,551	33,962	16,020	769	5,501	2,359	0
95	St. Ansgar	0	0	80,685	7,117	30,916	17,454	1,891	5,638	1,969	1,175
96	Story City	124	513	164,688	4,733	100,113	49,889	9,572	10,589	5,578	6,830
97	Strawberry Pnt.	0	11	108,436	16,503	84,354	25,464	3,478	4,772	2,058	3,277
98	Sumner	177	0	166,118	6,449	107,069	35,798	5,944	7,691	3,950	18,020
99	Superior	0	0	13,611	1,991	5,068	3,906	457	873	218	776
100	Tabor	53	204	81,021	2,287	58,122	18,640	3,901	3,532	1,920	1,101
101	Terril	0	0	31,327	1,607	11,441	9,197	771	1,523	768	611
102	Tripoli	0	0	103,576	4,402	66,875	21,063	2,934	4,300	1,749	2,346
103	Vincent	0	0	20,808	1,929	7,835	4,351	882	1,338	312	475
104	Wallingford	0	0	10,240	2,059	7,642	4,697	588	1,101	370	779
105	Waukon	480	0	311,119	9,216	182,892	66,305	8,883	13,731	6,023	15,026
106	Webster City	604	148,147	676,649	34,066	446,070	168,952	32,250	34,813	24,695	43,463
107	West Union	50	0	203,949	5,669	150,066	49,692	6,010	9,153	2,810	17,161
108	Woodward	0	45	36,288	7,118	47,849	22,744	3,308	4,662	1,962	1,369
109	Worthington	0	0	26,870	5,714	19,418	5,983	422	1,711	801	866

Source: Peoples Natural Gas

TABLE C-6

DISTRIBUTION PLANT HISTORICAL AND REPLACEMENT VALUES ($) - END OF 1979 - PEOPLES NATURAL GAS

Community	Other Equipment	Book Value of Distribution Plant	Replacement Value of Distribution Plant	Replacement Multiplier
1. Ackley	970	268,118	666,863	2.487
2. Adair	0	145,211	326,812	2.251
3. Anamosa	10,864	582,993	1,539,742	2.641
4. Andrew	0	48,987	93,986	1.919
5. Anita	0	201,998	488,532	2.418
6. Arlington	0	85,088	197,719	2.324
7. Arnolds Park	0	133,578	263,082	1.969
8. Bellevue	0	368,980	801,314	2.172
9. Boxholm	0	90,015	217,782	2.419
10. Calmar	991	173,742	466,045	2.682
11. Carter Lake	0	342,596	993,323	2.899
12. Council, Bluffs	56,164	9,514,470	26,964,000	2.834
13. Council Bluffs - Crescent	0	177,803	N.A.	N.A.
14. Cresco	5,787	700,308	1,751,190	2.501
15. Cumberland	0	64,206	154,441	2.405
16. Dayton	0	147,314	N.A.	N.A.
17. Decorah	55,336	1,303,891	2,837,396	2.176
18. Delhi	0	83,452	217,751	2.609
19. Denison	20,833	1,075,265	2,425,152	2.255
20. Dike	0	136,398	N.A.	N.A.
21. Dubuque	46,678	12,528,376	31,847,120	2.542
22. Dyersville	14,692	513,627	1,169,579	2.277
23. Earlville	0	122,676	311,229	2.537
24. Edgewood	0	137,012	310,250	2.264
25. Elkader	991	275,332	744,883	2.705
26. Elkader-St. Olaf	0	44,317	131,032	2.957
27. Emmons		4,721	14,093	2.985

TABLE C-6

DISTRIBUTION PLANT HISTORICAL AND REPLACEMENT VALUES ($) - END OF 1979 - PEOPLES NATURAL GAS
(Continued)

Community	Other Equipment	Book Value of Distribution Plant	Replacement Value of Distribution Plant	Replacement Multiplier
28. Epworth	0	117,580	261,380	2.223
29. Estherville	12,698	943,637	3,417,192	3.621
30. Everly	0	71,710	338,464	4.720
31. Farley	0	135,565	297,050	2.191
32. Farnhamville	0	89,289	222,321	2.490
33. Fayette	976	234,379	681,551	2.908
34. Fertile	0	44,267	76,710	1.733
35. Forest City	45,617	648,968	1,822,626	2.808
36. Fostoria	0	24,74	47,397	1.916
37. Fredericksburg	0	0	395,456	2.269
38. Glenwood	7,158	749,461	1,878,448	2.506
39. Glidden	1,215	158,730	N.A.	N.A.
40. Gowrie	0	271,377	691,116	2.547
41. Grand Junction	0	129,707	573,409	4.421
42. Granger	0	72,891	181,433	2.489
43. Greene	0	231,679	540,600	2.333
44. Grimes	0	273,843	542,483	1.981
45. Grundy Center	4,803	459,292	1,249,779	2.721
46. Guttenberg	5,806	301,370	709,033	2.353
47. Hamburg	0	282,355	731,864	2.592
48. Hanlontown	0	50,161	107,244	2.138
49. Harcourt	0	83,433	179,706	2.154
50. Hartley	0	192,026	1,016,912	5.296
51. Hawkeye	0	83,317	225,722	2.709
52. Hopkinton	0	161,412	453,358	2.809
53. Ionia	0	48,221	N.A.	N.A.
54. Joice	0	34,584	N.A.	N.A.
55. Kellog	0	76,462	N.A.	N.A.
56. Klemme	0	86,623	N.A.	N.A.

TABLE C-6

DISTRIBUTION PLANT HISTORICAL AND REPLACEMENT VALUES ($) - END OF 1979 - PEOPLES NATURAL GAS (Continued)

Community	Other Equipment	Book Value of Distribution Plant	Replacement Value of Distribution Plant	Replacement Multiplier
57. Lake Mills	1,950	242,535	N.A.	N.A.
58. Lake Park	0	166,195	N.A.	N.A.
59. Lamont	0	77,700	N.A.	N.A.
60. Langworthy	0	12,054	N.A.	N.A.
61. Laporte City	0	219,678	N.A.	N.A.
62. Lehigh	0	134,626	391,317	2.907
63. Luana	0	43,250	95,557	2.209
64. Madrid	0	248,163	904,747	3.184
65. Manchester	53,246	905,304	2,312,780	2.555
66. Maquoketa	28,509	1,213,799	2,482,460	2.045
67. Marble Rock	0	70,581	160,918	2.280
68. Massena	0	76,590	165,051	2.155
69. Miles	0	72,573	165,089	2.275
70. Millford	0	164,447	758,101	4.610
71. Mitchell	0	48,104	109,615	2.279
72. Monana	921	232,806	593,166	2.548
73. Monticello	11,616	545,617	1,383,629	2.536
74. New Hampton	5,836	672,887	1,678,785	2.495
75. Newton	44,594	2,352,240	6,437,608	2.737
76. Ogden	10,230	402,362	1,063,523	2.643
77. Onawa	0	462,322	1,007,492	2.179
78. Ossian	0	138,466	383,246	2.768
79. Paullina	1,337	133,212	787,589	5.912
80. Pilot Mound	0	57,476	151,512	2.636
81. Pocahantas	0	340,701	776,491	2.279
82. Postville	921	254,025	621,066	2.445
83. Primghar	1,337	146,498	456,561	3.116
84. Ralston	0	32,320	94,859	2.935

TABLE C-6

DISTRIBUTION PLANT HISTORICAL AND REPLACEMENT VALUES ($) - END OF 1979 - PEOPLES NATURAL GAS
(Continued)

	Community	Other Equipment	Book Value of Distribution Plant	Replacement Value of Distribution Plant	Replacement Multiplier
85.	Readlyn	0	119,233	273,377	2.293
86.	Ridgeway	0	46,169	95,584	2.070
87.	Rippey	0	41,327	170,036	4.114
88.	Rockford	0	152,860	501,503	3.281
89.	Royal	0	66,065	141,280	2.138
90.	Scranton	0	104,300	326,636	3.132
91.	Sidney	4,540	213,387	502,356	2.354
92.	Spencer	33,375	1,377,674	4,345,596	3.154
93.	Spirit Lake	11,437	591,009	1,517,119	2.567
94.	Spirit Lake-Orleans	0	108,146	242,993	2.247
95.	St. Ansgar	0	146,845	323,132	2.200
96.	Story City	2,843	355,472	943,849	2.655
97.	Strawberry Point	0	248,353	617,033	2.484
98.	Sumner	5,989	357,205	832,288	2.330
99.	Superior	0	26,900	52,458	1.950
100.	Tabor	0	170,781	430,761	2.522
101.	Terril	0	57,245	152,443	2.663
102.	Triploi	0	207,245	506,175	2.442
103.	Vincent	0	37,930	97,275	2.565
104.	Wallingford	0	27,476	46,712	1.700
105.	Waukon	5,261	618,936	1,615,236	2.610
106.	Webster City	78,990	1,688,699	3,897,854	2.308
107.	West Union	79,252	523,922	1,275,749	2.435
108.	Woodward	0	125,345	421,385	3.362
109.	Worthington	0	61,785	130,675	2.115

Source: Peoples Natural Gas

APPENDIX D

PACIFIC GAS AND ELECTRIC COMPANY DIVISIONS DATA

The purpose of this appendix is to present the division-level equations, data and computed parameters that are used in PG&E models extensions developed in chapter 3, section 4, and in PG&E dynamic models presented in chapter 3, section 6. After the listing of the divisions monthly load equations, the 1979, 1978 and normal (30-year average) degree-day data used are presented in tables D-1 through D-3. The load shares, sales normalization coefficients for 1979 and 1978, and the normal load factors are presented in tables D-4 through D-6. A map, delineating the 13 divisons, is presented in figure D-1.

Monthly Load Equations for PG&E Thirteen Divisions

Notations

RMCF: monthly residential sales (MCF)

CMCF: monthly commercial sales (MCF)

IMCF: monthly industrial sales (MCF)

CIMCF: monthly commercial/industrial sales (MCF)

TMCF: monthly total sales (MCF)

DD: monthly heating degree-days (70°F basis)

Coast Valley

$$RMCF = 104{,}330.8 + \underset{(9.27)}{1410.159} * DD \qquad (R^2 = 0.896) \tag{D.1}$$

$$CMCF = 227{,}581.9 + \underset{(3.14)}{276.404} * DD \qquad (R^2 = 0.496) \tag{D.2}$$

$$IMCF = 32{,}614.3 + \underset{(3.68)}{85.285} * DD \qquad (R^2 = 0.575) \tag{D.3}$$

$$CIMCF = 260{,}196.1 + \underset{(4.32)}{361.689} * DD \qquad (R^2 = 0.651) \tag{D.4}$$

$$TMCF = 364{,}487.0 + \underset{(7.79)}{1{,}772.269} * DD \qquad (R^2 = 0.858) \tag{D.5}$$

Colgate

$$RMCF = 107{,}542.0 + \underset{(8.11)}{660.771} * DD \qquad (R^2 = 0.868) \tag{D.6}$$

CMCF: tolerance level insufficient for further computations

$$IMCF = 25{,}635.2 + \underset{(0.14)}{3.674} * DD \qquad (R^2 = 0.002) \tag{D.7}$$

CIMCF: tolerance level insuffficent for further computations

$$TMCF = 383{,}398.9 + \underset{(3.73)}{666.097} * DD \qquad (R^2 = 0.581) \tag{D.8}$$

De Salba

$$RMCF = 81{,}881.8 + 484.099 * DD \quad (R^2 = 0.885) \qquad (D.9)$$
$$(8.76)$$

$$CMCF = 135{,}030.1 + 121.646 * DD \quad (R^2 = 0.744) \qquad (D.10)$$
$$(5.45)$$

$$IMCF = 18{,}800.2 + 5.872 * DD \quad (R^2 = 0.184) \qquad (D.11)$$
$$(1.50)$$

$$CIMCF = 153{,}830.2 + 127.518 * DD \quad (R^2 = 0.740) \qquad (D.12)$$
$$(5.33)$$

$$TMCF = 235{,}723.6 + 611.757 * DD \quad (R^2 = 0.885) \qquad (D.13)$$
$$(8.77)$$

Drum

$$RMCF = 109{,}605.2 + 664.752 * DD \quad (R^2 = 0.812) \qquad (D.14)$$
$$(6.57)$$

$$CMCF = 40{,}632.6 + 150.087 * DD \quad (R^2 = 0.772) \qquad (D.15)$$
$$(5.83)$$

$$IMCF = 9{,}647.2 + 9.987 * DD \quad (R^2 = 0.586) \qquad (D.16)$$
$$(3.76)$$

$$CIMCF = 50{,}279.8 + 160.074 * DD \quad (R^2 = 0.769) \qquad (D.17)$$
$$(5.76)$$

$$TMCF = 159{,}900.7 + 824.926 * DD \quad (R^2 = 0.806) \qquad (D.18)$$
$$(6.44)$$

East Bay

$$RMCF = 359{,}060.8 + 12{,}176.620 * DD \quad (R^2 = 0.863) \qquad (D.19)$$
$$(7.94)$$

$$CMCF = 4{,}664{,}832.0 + 820.656 * DD \quad (R^2 = 0.031) \qquad (D.20)$$
$$(0.56)$$

$$IMCF = 532{,}244.2 + 49.035 * DD \quad (R^2 = 0.013) \qquad (D.21)$$
$$(0.36)$$

$$CIMCF = 5{,}188{,}076.2 + 869.691 * DD \quad (R^2 = 0.031) \qquad (D.22)$$
$$(0.57)$$

$$TMCF = 5{,}547{,}759.0 + 13{,}050.790 * DD \quad (R^2 = 0.891) \qquad (D.23)$$
$$(9.06)$$

Humboldt

$$RMCF = -90{,}127.7 + 599.123 * DD \quad (R^2 = 0.869) \quad (D.24)$$
(8.13)

$$CMCF = -20{,}051.4 + 242.835 * DD \quad (R^2 = 0.861) \quad (D.25)$$
(7.86)

$$IMCF = 1{,}815.3 + 40.698 * DD \quad (R^2 = 0.398) \quad (D.26)$$
(2.57)

$$CIMCF = -18{,}236.1 + 283.532 * DD \quad (R^2 = 0.829) \quad (D.27)$$
(6.97)

$$TMCF = -108{,}443.4 + 882.983 * DD \quad (R^2 = 0.869) \quad (D.28)$$
(8.16)

North Bay

$$RMCF = 561{,}160.9 + 3{,}417.718 * DD \quad (R^2 = 0.809) \quad (D.29)$$
(6.51)

$$CMCF = 844{,}575.5 + 882.636 * DD \quad (R^2 = 0.765) \quad (D.30)$$
(5.70)

$$IMCF = 64{,}058.7 + 47.484 * DD \quad (R^2 = 0.714) \quad (D.31)$$
(5.00)

$$CIMCF = 908{,}633.9 + 930.120 * DD \quad (R^2 = 0.787) \quad (D.32)$$
(6.08)

$$TMCF = 1{,}469{,}946.0 + 4{,}348.580 * DD \quad (R^2 = 0.839) \quad (D.33)$$
(7.23)

Sacramento

$$RMCF = 773{,}161.1 + 4{,}635.408 * DD \quad (R^2 = 0.833) \quad (D.34)$$
(7.08)

$$CMCF = 482{,}442.0 + 965.352 * DD \quad (R^2 = 0.765) \quad (D.35)$$
(5.70)

$$IMCF = 65{,}529.3 + 60.694 * DD \quad (R^2 = 0.863) \quad (D.36)$$
(7.93)

$$CIMCF = 547{,}971.4 + 1{,}026.046 * DD \quad (R^2 = 0.789) \quad (D.37)$$
(6.11)

$$TMCF = 1{,}321{,}398.0 + 5{,}664.709 * DD \quad (R^2 = 0.827) \quad (D.38)$$
(6.91)

San Francisco

$$RMCF = 347{,}879.8 + 5{,}483.548 * DD \quad (R^2 = 0.810) \quad (D.39)$$
$$(6.52)$$

$$CMCF = 331{,}572.8 + 1{,}689.371 * DD \quad (R^2 = 0.738) \quad (D.40)$$
$$(5.31)$$

$$IMCF = 97{,}140.8 + 88.515 * DD \quad (R^2 = 0.546) \quad (D.41)$$
$$(3.47)$$

$$CIMCF = 428{,}713.8 + 1{,}777.884 * DD \quad (R^2 = 0.733) \quad (D.42)$$
$$(5.24)$$

$$TMCF = 776{,}932.7 + 7{,}262.509 * DD \quad (R^2 = 0.793) \quad (D.43)$$
$$(6.02)$$

San Joaquin

$$RMCF = 640{,}835.2 + 4{,}028.866 * DD \quad (R^2 = 0.867) \quad (D.44)$$
$$(8.07)$$

$$CMCF = 740{,}407.7 + 1{,}065.410 * DD \quad (R^2 = 0.723) \quad (D.45)$$
$$(5.11)$$

$$IMCF = 185{,}762.0 + 123.559 * DD \quad (R^2 = 0.524) \quad (D.46)$$
$$(3.32)$$

$$CIMCF = 926{,}169.5 + 1{,}188.969 * DD \quad (R^2 = 0.719) \quad (D.47)$$
$$(5.06)$$

$$TMCF = 1{,}710{,}416.0 + 6{,}390.646 * DD \quad (R^2 = 0.879) \quad (D.48)$$
$$(8.53)$$

San Jose

$$RMCF = 1{,}306{,}396.0 + 9{,}599.366 * DD \quad (R^2 = 0.839) \quad (D.49)$$
$$(7.20)$$

$$CMCF = 802{,}379.7 + 2{,}114.638 * DD \quad (R^2 = 0.768) \quad (D.50)$$
$$(5.80)$$

$$IMCF = 356{,}209.1 + 186.273 * DD \quad (R^2 = 0.048) \quad (D.51)$$
$$(0.71)$$

$$CIMCF = 1{,}158{,}588.0 + 2{,}300.911 * DD \quad (R^2 = 0.706) \quad (D.52)$$
$$(4.90)$$

$$TMCF = 2{,}571{,}005.0 + 12{,}508.420 * DD \quad (R^2 = 0.834) \quad (D.53)$$
$$(7.10)$$

Shasta

$$RMCF = 49,832.0 + 357.350 * DD \quad (R^2 = 0.870) \quad (D.54)$$
$$(8.19)$$

$$CMCF = 96,886.3 + 105.634 * DD \quad (R^2 = 0.530) \quad (D.55)$$
$$(3.36)$$

$$IMCF = 7,744.8 + 0.275 * DD \quad (R^2 = 0.006) \quad (D.56)$$
$$(0.26)$$

$$CIMCF = 104,631.1 + 105.909 * DD \quad (R^2 = 0.529) \quad (D.57)$$
$$(3.36)$$

$$TMCF = 154,473.8 + 463.506 * DD \quad (R^2 = 0.835) \quad (D.58)$$
$$(7.12)$$

Stockton

$$RMCF = 559,952.7 + 2,117.653 * DD \quad (R^2 = 0.593) \quad (D.59)$$
$$(3.82)$$

$$CMCF = 442,237.7 + 666.174 * DD \quad (R^2 = 0.322) \quad (D.60)$$
$$(2.18)$$

$$IMCF = 161,760.5 + 75.705 * DD \quad (R^2 = 0.532) \quad (D.61)$$
$$(3.37)$$

$$CIMCF = 603,998.1 + 741.879 * DD \quad (R^2 = 0.346) \quad (D.62)$$
$$(2.30)$$

$$TMCF = 1,164,066.0 + 2,859.784 * DD \quad (R^2 = 0.537) \quad (D.63)$$
$$(3.41)$$

TABLE D-1

MONTHLY AND ANNUAL DEGREE-DAYS FOR 1979 - METEOROLOGICAL STATIONS IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual
COAST VALLEY DIVISION													
Salinas	648	545	464	391	266	242	174	160	85	209	423	516	4,123
Santa Maria	655	569	506	469	325	262	199	175	129	234	443	473	4,439
Average	562	557	485	430	296	252	186	167	102	221	433	495	4,281
COLGATE DIVISION													
Marysville	753	568	454	376	114	15	3	2	0	158	493	656	3,592
DE SABLA DIVISION													
Red Bluff	685	551	392	314	84	1	0	2	0	167	496	613	3,305
Marysville	753	568	454	376	114	15	3	2	0	158	493	656	3,592
Average	719	560	423	345	99	8	2	2	0	163	495	635	3,449
DRUM DIVISION													
Sacramento	752	580	465	384	135	33	13	7	6	192	539	700	3,806
EAST BAY DIVISION													
Oakland	645	520	445	390	254	236	152	146	60	171	406	544	3,969
HUMBOLDT DIVISION													
Eureka	707	600	620	560	514	470	359	316	221	385	515	503	5,830

TABLE D-1

MONTHLY AND ANNUAL DEGREE-DAYS FOR 1979 - METEOROLOGICAL STATIONS IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA (Continued)

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual
NORTH BAY DIVISION													
Santa Rosa	716	572	491	389	203	111	73	59	46	225	528	652	4,065
Ukiah	793	642	536	442	198	63	27	27	32	279	589	694	4,322
Average	755	607	514	416	231	87	50	43	39	252	564	673	4,194
SACRAMENTO DIVISION													
Sacramento	752	580	465	384	135	33	13	7	6	192	539	700	3,806
SAN FRANCISCO DIVISION													
S/F City	586	471	435	402	325	339	289	276	120	200	365	444	4,252
S/F Airport	690	539	474	428	287	268	182	190	102	216	466	588	4,430
Average	638	505	455	415	306	304	236	233	111	208	416	516	4,341
SAN JOAQUIN DIVISION													
Fresno	700	505	382	216	75	7	0	0	0	119	460	707	3,171
Bakersfield	556	480	343	200	40	2	0	0	0	65	338	476	2,500
Average	628	493	363	208	58	5	0	0	0	92	399	592	2,836
SAN JOSE DIVISION													
San Jose (City Hall)	659	526	428	365	162	122	53	66	23	157	439	568	3,563

TABLE D-1
MONTHLY AND ANNUAL DEGREE-DAYS FOR 1979 - METEOROLOGICAL STATIONS IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA (Continued)

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual
						SHASTA DIVISION							
Red Bluff	685	551	392	314	84	1	0	2	0	167	496	613	3,305
						STOCKTON DIVISION							
Stockton	748	517	412	272	77	11	3	0	1	140	484	668	3,333

Source: Pacific Gas and Electric Company

TABLE D-2

MONTHLY AND ANNUAL DEGREE-DAYS FOR 1978 - METEOROLOGICAL STATIONS IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual
						COAST VALLEY DIVISION							
Salinas	495	436	354	436	273	242	212	177	153	281	501	686	4,244
Santa Maria	485	451	380	483	330	319	277	185	177	300	535	707	4,625
Average	490	444	367	460	302	281	245	181	165	291	518	697	4,435
						COLGATE DIVISION							
Marysville	582	493	326	344	95	1	3	9	63	98	550	853	3,414
						DE SABLA DIVISION							
Red Bluff	584	488	348	362	87	0	1	4	29	65	506	776	3,248
Marysville	582	493	326	344	95	1	3	9	63	98	550	853	3,414
Average	583	490	337	353	91	1	2	6	46	81	528	814	3,331
						DRUM DIVISION							
Sacramento	613	509	399	428	141	48	16	13	67	151	608	879	3,870
						EAST BAY DIVISION							
Oakland	496	449	346	372	217	210	197	146	99	242	508	756	4,035
						HUMBOLDT DIVISION							
Eureka	565	552	512	570	520	422	438	404	374	468	661	829	6,312

TABLE D-2

MONTHLY ANNUAL DEGREE-DAYS FOR 1978 - METEOROLOGICAL STATIONS IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA (Continued)

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual
NORTH BAY DIVISION													
Santa Rosa	591	489	561	440	179	108	70	61	58	151	505	740	3,951
Ukiah	628	522	430	501	242	123	34	48	98	177	578	774	4,153
Average	609	505	496	470	210	116	52	55	78	164	542	757	4,052
SACRAMENTO DIVISION													
Sacramento	613	509	399	428	141	48	16	13	67	151	608	879	3,870
SAN FRANCISCO DIVISION													
S/F City	459	409	335	402	284	327	351	286	151	266	415	626	4,311
S/F Airport	544	483	403	453	301	291	268	210	144	284	528	744	4,651
Average	501	446	369	428	292	309	310	248	148	275	472	685	4,481
SAN JOAQUIN DIVISION													
Fresno	577	490	302	334	80	0	0	0	30	88	539	844	3,282
Bakersfield	473	387	232	261	55	0	0	0	10	35	384	740	2,575
Average	501	438	267	297	67	0	0	0	20	62	461	792	2,929
SAN JOSE DIVISION													
San Jose (City Hall)	527	462	345	394	154	127	58	54	67	174	505	752	3,618

TABLE D-2

MONTHLY AND ANNUAL DEGREE-DAYS FOR 1978 - METEOROLOGICAL STATIONS IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA
(Continued)

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual
							SHASTA DIVISION						
Red Bluff	584	488	348	362	87	0	1	4	29	65	506	776	3,248
							STOCKTON DIVISION						
Stockton	610	507	354	369	86	5	4	4	39	107	558	877	3,516

Source: Pacific Gas and electric Company

TABLE D-3

NORMAL DEGREE-DAYS (30-YEAR AVERAGES) - METEOROLOGICAL STATIONS IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual	Peak Month
							COAST VALLEY DIVISION							
Salinas	627	501	533	452	372	285	250	223	189	281	433	597	4,743	627
Santa Maria	606	501	545	475	410	310	240	219	216	302	432	577	4,833	606
Average	617	501	539	464	391	298	245	221	203	292	433	587	4,788	617
							COLGATE DIVISION							
Marysville	758	536	477	302	136	32	3	8	29	183	486	734	3,684	758
							DE SABLA DIVISION							
Red Bluff	771	553	521	335	138	27	2	5	24	186	499	730	3,791	771
Marysville	758	536	477	302	136	32	3	8	29	183	486	734	3,684	758
Average	765	545	500	319	137	30	3	7	27	185	493	732	3,743	765
							DRUM DIVISION							
Sacramento	774	554	521	357	183	60	9	13	41	204	507	752	3,974	774
							EAST BAY DIVISION							
Oakland	668	507	510	420	341	248	211	184	162	267	449	637	4,603	668
							HUMBOLDT DIVISION							
Eureka	708	604	675	622	557	461	433	402	397	484	556	670	6,568	708

TABLE D-3

NORMAL DEGREE-DAYS (30-YEAR AVERAGES) - METEOROLOGICAL STATION IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA (Continued)

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual	Peak Month
NORTH BAY DIVISION														
Santa Rosa	730	545	561	436	308	171	103	95	119	267	505	700	4,540	730
Ukiah	739	560	565	427	264	109	24	30	72	269	528	714	4,301	739
Average	735	553	563	432	286	140	64	63	96	268	517	707	4,424	735
SACRAMENTO DIVISION														
Sacramento	774	554	521	357	183	60	9	13	41	204	507	752	3,974	774
SAN FRANCISCO DIVISION														
S/F City	577	448	479	437	409	344	349	316	235	262	377	550	4,782	577
S/F Airport	672	520	537	457	381	283	248	218	194	293	461	641	4,908	672
Average	625	484	508	447	395	314	294	267	215	278	419	584	4,845	625
SAN JOAQUIN DIVISION														
Fresno	766	550	489	300	127	28	1	4	23	188	501	761	3,739	766
Bakersfield	685	471	402	235	86	13	0	1	11	123	411	674	3,113	685
Average	726	511	446	268	107	21	1	3	17	156	456	718	3,430	726
SAN JOSE DIVISION														
San Jose (City Hall)	642	487	477	371	256	143	73	69	93	230	439	624	3,905	642

TABLE D-3

NORMAL DEGREE-DAYS (30-YEAR AVERAGES) - METEOROLOGICAL STATIONS IN THE PACIFIC GAS AND ELECTRIC COMPANY'S SERVICE AREA (Continued)

Meteor. Stat.	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total Annual	Peak Month
							SHASTA DIVISION							
Red Bluff	771	553	521	335	138	27	2	5	24	186	499	730	3,791	771
							STOCKTON DIVISION							
Stockton	770	558	512	337	161	46	5	9	33	195	508	758	3,893	770

Source: Pacific Gas and Electric Company

TABLE D-4

NORMAL ANNUAL DEGREE-DAYS AND NORMALIZED BASE LOAD AND SPACE-HEATING LOAD SHARES AT THE DIVISION LEVEL
PACIFIC GAS AND ELECTRIC COMPANY

Division	Number of Communities	Normal Annual Degree-Days[1] DDT (Base = 70°F)	Residential Sector		Commercial Sector		Industrial Sector		Commercial/Industrial Sector		Total Market	
			Base	Space-Heating	Base	Space-Heating	Base	Space-Heating	Base	Space-Heating	Base	Space-Heating
Coast Valley	4	4788	0.1564	0.8436	0.6736	0.3264	0.4894	0.5106	0.6432	0.3568	0.3401	0.6599
Colgate	1	3684	0.3465	0.6535	1.0000	0.0000	0.9579	0.0421	0.9747	0.0253	0.6522	0.3478
De Sabla	1	3743	0.3516	0.6484	0.7806	0.2194	0.9112	0.0888	0.7945	0.2055	0.5526	0.4474
Drum	1	3974	0.3324	0.6676	0.4498	0.5502	0.7447	0.2553	0.4868	0.5132	0.3692	0.6308
East Bay	24	4603	0.0714	0.9286	0.9368	0.0632	0.9653	0.0347	0.9396	0.0604	0.5256	0.4744
Humboldt	2	6568	0.0000	1.0000	0.0000	1.0000	0.0754	0.9246	0.0000	1.0000	0.0000	1.0000
North Bay	12	4424	0.3081	0.6919	0.7218	0.2782	0.2146	0.7854	0.7260	0.2740	0.4783	0.5217
Sacramento	5	3974	0.3350	0.6650	0.6015	0.3985	0.7653	0.2347	0.6173	0.3827	0.4133	0.5867
San Francisco	6	4845	0.1358	0.8642	0.3271	0.6729	0.7310	0.2690	0.3739	0.6261	0.2095	0.7905
San Joaquin	9	3430	0.3375	0.6425	0.7086	0.2914	0.8403	0.1597	0.7316	0.2684	0.4836	0.5164
San Jose	21	3905	0.3358	0.6642	0.5339	0.4661	0.8414	0.1586	0.6074	0.3926	0.4095	0.5905
Shasta	1	3791	0.3062	0.6938	0.7438	0.2562	0.9889	0.0111	0.7577	0.2423	0.5134	0.4866
Stockton	7	3893	0.4491	0.5509	0.6717	0.3283	0.8682	0.1318	0.7151	0.2849	0.5565	0.4435

Source: Author's calculations

TABLE D-5

ANNUAL DEGREE-DAYS AND SALES NORMALIZATION ADJUSTMENT FACTORS FOR 1978 AND 1979 AT THE DIVISION LEVEL
PACIFIC GAS AND ELECTRIC COMPANY

Division	Annual Degree-Days 1979	Annual Degree-Days 1978	Adjustment Factors for 1979				Adjustment Factors for 1978			
			Residential Sector	Commercial Sector	Industrial Sector	Total Market	Residential Sector	Commercial Sector	Industrial Sector	Total Market
Coast Valley	4281	4435	1.0981	1.0358	1.0572	1.0751	1.0663	1.0247	1.0391	1.0511
Colgate	3592	3414	1.0166	1.0000	1.0011	1.0088	1.0503	1.0000	1.0031	1.0262
De Sabla	3449	3331	1.0537	1.0175	1.0070	1.0364	1.0769	1.0247	1.0099	1.0518
Drum	3806	3870	1.0290	1.0238	1.0109	1.0274	1.0178	1.0146	1.0067	1.0168
East Bay	3969	4035	1.1467	1.0088	1.0048	1.0699	1.1294	1.0079	1.0043	1.0622
Humboldt	5830	6312	1.1266	1.1266	1.1159	1.1266	1.0406	1.0406	1.0374	1.0406
North Bay	4194	4052	1.0373	1.0147	1.0426	1.0279	1.0618	1.0239	1.0707	1.0459
Sacramento	3806	3870	1.0289	1.0171	1.0100	1.0254	1.0177	1.0105	1.0062	1.0156
San Francisco	4341	4481	1.0988	1.0753	1.0288	1.0896	1.0694	1.0532	1.0206	1.0631
San Joaquin	2836	2929	1.1252	1.0531	1.0284	1.1080	1.1036	1.0445	1.0239	1.0816
San Jose	3563	3681	1.0618	1.0426	1.0141	1.0545	1.0513	1.0355	1.0118	1.0454
Shasta	3305	3248	1.0976	1.0340	1.0014	1.0665	1.1103	1.0381	1.0016	1.0749
Stockton	3333	3516	1.0861	1.0496	1.0193	1.0681	1.0564	1.0328	1.0129	1.0449

Source: Author's calculations

TABLE D-6

NORMAL MAXIMUM MONTHLY DEGREE-DAYS AND NORMAL MONTHLY LOAD FACTORS AT THE DIVISION LEVEL
PACIFIC GAS AND ELECTRIC COMPANY

Division	Normal Maximum Monthly Degree-Days $\overline{DD}_{max}$	Residential Sector Load Factor	Commercial Sector Load Factor	Industrial Sector Load Factor	Commercial/ Industrial Sector Load Factor	Total Market Load Factor
Coast Valley	617	0.6845	0.8487	0.7819	0.8369	0.7350
Colgate	758	0.5102	1.0000	0.9418	0.9651	0.6618
De Sabla	765	0.5150	0.7583	0.8857	0.7701	0.6061
Drum	774	0.5283	0.5761	0.7455	0.5930	0.5424
East Bay	668	0.5922	0.9552	0.9749	0.9571	0.7400
Humboldt	708	0.7752	0.7752	0.7865	0.7731	0.7752
North Bay	735	0.5926	0.7834	0.5617	0.7860	0.6586
Sacramento	774	0.5293	0.6524	0.7611	0.6615	0.5604
San Francisco	625	0.6786	0.7306	0.8715	0.7445	0.6977
San Joaquin	726	0.5026	0.6902	0.8026	0.7076	0.5570
San Jose	642	0.6075	0.6880	0.8663	0.7236	0.6351
Shasta	771	0.5001	0.7304	0.9843	0.7413	0.5879
Stockton	770	0.5693	0.6892	0.8467	0.7187	0.6214

Source: Author's calculations

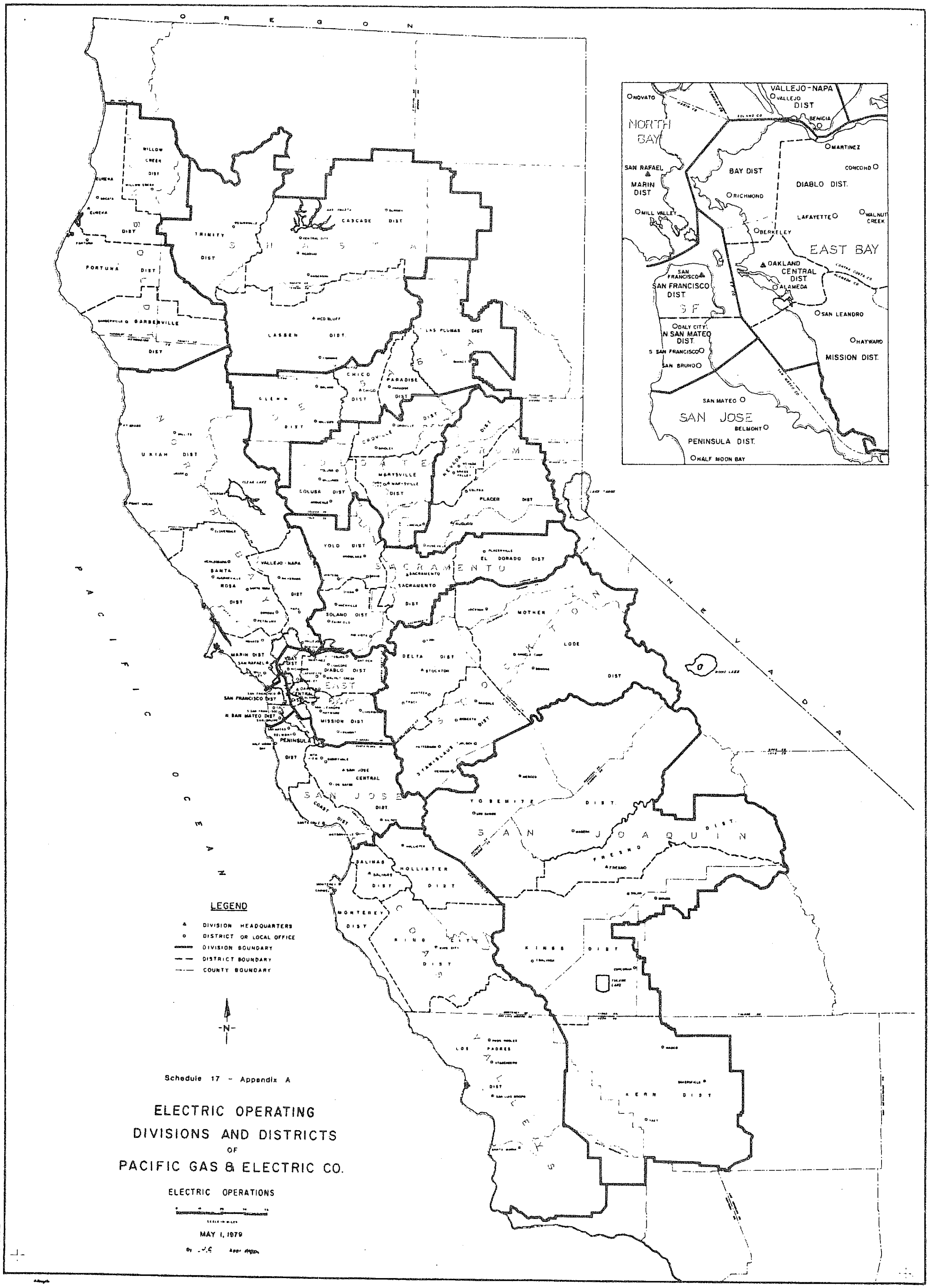

Figure D-1 Divisions of Pacific Gas and Electric Company's Service Area
Source: Pacific Gas and Electric Company

APPENDIX E

GAS DISTRIBUTION UTILITIES WITH DATA IN THE PLANT AND OMEXP FILES

The purpose of this appendix is to present the list of the 119 gas distribution utilities that provided their 1979 Annual Reports submitted to their state commission and/or their 1979 Uniform Statistical Reports submitted to the American Gas Association. Part of the data included in these documents has been used, as detailed in chapter 4, for building the PLANT and OMEXP data files.

ALABAMA

Mobile Gas Service Corporation

Alabama Gas Corporation

CALIFORNIA

Pacific Gas and Electric Company

San Diego Gas and Electric Company

Southern California Gas Company

COLORADO

Public Service Company of Colorado

Northern Natural Gas Company (Peoples Natural Gas Division)

CONNECTICUT

Connecticut Natural Gas Corporation

The Southern Connecticut Gas Company

The Hartford Electric Light Company

The Connecticut Light and Power Company

DELAWARE

Chesapeake Utilities Corporation

Delmarva Power and Light Company

FLORIDA

City Gas Company of Florida

Peoples Gas System, Inc.

GEORGIA

Atlanta Gas Light Company

IDAHO

Intermountain Gas Company

ILLINOIS

Gas Utilities Company
Illinois Gas Company
Illinois Power Company
Interstate Power Company
South Beloit Water, Gas and Electric Company
The Peoples Gas Light and Coke Company
Monarch Gas Company
Northern Illinois Gas Company
North Shore Gas Company
Kaskaskia Gas Company
Mt. Carmel Public Utility Company
Town Gas Company of Illinois
Union Electric Company
Central Illinois Light Company
Central Illinois Public Service Company
Consumers Gas Company
United Cities Gas Company
Eastern Illinois Gas and Securities Company

INDIANA

Indiana Gas Company, Inc.
Northern Indiana Public Service Company

IOWA

Iowa - Illinois Gas and Electric Company
Iowa Power and Light Company
Iowa Public Service Company
Northern Natural Gas Company (Peoples Natural Gas Division)
Iowa Electric Light and Power Company

KANSAS

The Gas Service Company
Kansas Nebraska Natural Gas Company, Inc.
The Kansas Power and Light Company
Northern Natural Gas Company

KENTUCKY

Louisville Gas and Electric Company

LOUISIANA

Louisiana Gas Service Company

MAINE

Northern Utilities, Inc.

MASSACHUSETTS

Bay State Gas Company

Boston Gas Company

Commonwealth Gas Company

MICHIGAN

Consumers Power Company

Michigan Consolidated Gas Company

Michigan Utilities Company

MINNESOTA

Minnesota Gas Company

Northern States Power Company

Northern Natural Gas Company (Peoples Natural Gas Division)

MISSISSIPPI

Entex, Inc.

Mississippi Valley Gas Company

Willmut Gas and Oil Company

MISSOURI

Missouri Utilities Company

MONTANA

Great Falls Gas Company

The Montana Power Company

NEBRASKA

Metropolitan Utilities District of Omaha

NEVADA

Sierra Pacific Power Company

Southwest Gas Corporation

NEW HAMPSHIRE

Gas Service, Inc.

Manchester Gas Company

NEW JERSEY

New Jersey Natural Gas Company

Public Service Electric and Gas Company

South Jersey Gas Company

Elizabethtown Gas Company

NEW MEXICO

Hobbs Gas Company

NEW YORK

Central Hudson Gas and Electric Corporation

Consolidated Edison Company of New York

Long Island Lighting Company

National Fuel Gas Company

Niagara Mohawk Power Corporation

New York State Electric and Gas Corporation

Rochester Gas and Electric Corporation

NORTH CAROLINA

Piedmont Natural Gas Company, Inc.

Public Service Company of North Carolina, Inc.

North Carolina Natural Gas Corporation

NORTH DAKOTA

Montana - Dakota Utilities Co.

OHIO

Columbia Gas of Ohio, Inc.

Cincinnati Gas and Electric Company

Dayton Power and Light Company

East Ohio Gas Company

National Gas and Oil Corporation

Ohio Gas Company

Toledo Edison Company

West Ohio Gas Company

OKLAHOMA

Arkansas-Louisiana Gas Company

Oklahoma Natural Gas Company

OREGON

Northwest Natural Gas Company

PENNSYLVANIA

Philadelphia Electric Company

UGI Corporation

The Peoples Natural Gas Company

Equitable Gas Company

Pennsylvania Gas and Water Company

Columbia Gas of Pennsylvania, Inc.

RHODE ISLAND

The Providence Gas Company

Valley Gas Company

SOUTH CAROLINA

South Carolina Electric and Gas Company

SOUTH DAKOTA

Northwestern Public Service Company

TEXAS

The Pioneer Corporation

Lone Star Gas Company

Southern Union Company

UTAH

Mountain Fuel Supply Company

VERMONT

Vermont Gas Systems, Inc.

VIRGINIA

Columbia Gas of Virginia, Inc.

Commonwealth Gas Distribution Corporation

Portsmouth Gas Company

Virginia Electric and Power Company

WASHINGTON

Cascade Natural Gas Corporation

Washington Natural Gas Company

The Washington Water Power Company

WYOMING

Cheyenne Light, Fuel and Power Company