THE U.S. DISTRICT HEATING INDUSTRY: A CASE STUDY OF CORPORATE STRATEGY AND PUBLIC UTILITY REGULATION

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A DISSERTATION

Submitted to
Michigan State University
in partial fulfillment of the requirements
for the degree of

DOCTOR OF PHILOSOPHY

Department of Economics

1983

ABSTRACT

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The U.S. district heating industry is in a state of decline. This dissertation examined the reasons for the industry's decline, the viability of new district heating projects, and explored whether and in what manner state regulation can be altered to change the state of the industry.

To explain the history of the industry two theories of firm behavior -- profit maximizing and strategic satisficing -- were compared. Profit maximizing theory suggests that the industry decline was caused by a decrease in the demand for steam due to the substitution of natural gas for steam. A series of demand relationships was estimated in an attempt to test this hypothesis. From these estimations it was not possible to infer that steam and gas were considered substitutes by steam customers.

Alternatively, it was possible to amass evidence that shows that electric utilities used the heating subsidiaries as part of a strategy to establish regional electric

monopolies. Steam was sold cheaply in order to discourage cogeneration by isolated producers of steam. Wherever the utility heating services expanded, isolated producers shut down. Once the heating subsidiaries accomplished their specified task, they disappeared from the planning tabloids of the electric utilities. Cost saving technologies were never exploited. Markets were never expanded. The vision of electric utility executives bounded by the rationality of the electric power process foreclosed the successful development of the heat industry.

To test the viability of heating projects a simulation model was developed. The model selected the pipe sizes and lengths, determined costs and revenue, and calculated the net present value of the project. A base case was estimated. The base case results were compared to other cases by allowing the assumed values of selected variables to change. It was found that district heating projects were viable when reasonable variable values were used.

It was recommended that state regulatory commissions encourage district heating due to the positive net present value associated with the projects. Commissions could encourage district heating by establishing an incentive rate of return scheme that would tie the allowed rate of return inversely to each utility's heat rate.

ACKNOWLEDGEMENTS

I would like to thank Professor Harry Trebing who kindled my interest in the study of public utilities. I could always count on him for an interesting suggestion and a kind word. I would also like to thank Warren Samuels and Norm Obst for their questions about the direction and purpose of this study. Ken Boyer provided valuable assistance with econometric work.

I have been fortunate to know fellow graduate students, Shashi Gupta and Donald Stabile, with whom I could talk, argue and laugh. Shashi listened to my ideas, forced me to clarify them and helped me make them more precise. Donald could always offer an instantaneous alternative explanation to every new explanation I struggled to obtain. Here at James Madison University, I have found two new friends, Russ Smith and Dave Schirm, who have given freely of their time to read and discuss various drafts.

I will never be able to repay the debt I owe my mother, father, brother and sister. Their faith in my ability kept me going through all the dark days when I thought I would never finish. Finally, I want to thank my wife, Robin Gordon, for all the moments we have spent together. Each one has been precious to me.

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INTRODUCTION

The district heating process provides heat to a number of buildings from a single source. A central boiler produces steam. The steam itself can circulate to the buildings through buried pipes, or the steam can heat water in a heat exchanger, and the heated water can then circulate through the pipe system.

The boiler that provides steam for heating can also provide the steam required for generating electricity. In this case, steam passes through a turbine or engine before it is used for heating purposes. This process is called "cogeneration." Plants which produce both outputs are called "cogenerators" or "heat and power stations." When only one output is produced, the plant is called a "single purpose station."

The district heating industry was founded in 1877. In the United States, it has passed through various stages of growth and decline. It is now stuck at a low level of activity. The number of companies providing the service dropped from 211 in 1962 to 95 in 1975,[1] and sales of the leading firms fell from 73 million pounds of steam in 1972 to 61 million pounds in 1978.[2] At present, the industry provides less than one percent of the space heating needs of the country;[3] or equivalently, it meets the space heating needs of about 2.5 million people.[4]

This stagnation stands in stark contrast to the industry's potential here and to its experience in Europe. Two studies document the industry's potential in the United States. Karkheck et al. estimated that if power plant heat were provided to district heating systems and its price set equal to the effective energy price of natural gas, then a population of 32 million individuals could be served profitably. They estimated if the price were equal to the effective energy price of imported oil, 73 million people could be served profitably.[5]

McDonald et al. estimated that the conversion of 337 power plants to dual purpose facilities could supply 2 quads of heat (15 percent of U.S. residential and commercial space heating demand) to district heating systems. The power plants studied were located within 10 miles of the service center; the population of the service area was greater than 50,000; and population densities were greater than 1,000 persons per square mile. It was estimated that district heating would be competitive with gas in such service areas.[6]

The district heating industries of several Scandanavian and Eastern European countries illustrate the industry's potential. Denmark has the highest thermal energy capacity per capita, 2000 MW/million inhabitants. Approximately forty percent of Danish households are connected to a district heating system.[7] In the Soviet Union, seventy percent of the urban heat demand is provided by district heating systems.[8]

Rationales for the existence of the gap between the U.S. industry's reality and its potential fall into two categories.

One rationale asserts that profit maximizing firms, seeing their profits erode, left the industry. Those companies that remained did so because of a perceived political constraint against a shut-down of operations. The profit erosion was caused by consumer product substitution when natural gas became available in the interstate market during the early fifties. The drop in consumption in the seventies was caused by consumer reaction to sharp rises in the price of steam. Finally the potential for expansion is non-existent, having been fabricated by researchers who made overly-optimistic assumptions about consumer response to new service and about future cost.

The other rationale states that the history of the district heating industry has been an innocent pawn used and then discarded by the electric utilities in their drive for regional monopoly control. The electrics did not take advantage of opportunities to increase the profits of district heating subsidiaries, because these opportunities did not fit into their companies' self-vision.

Instead, the electrics used district heating services as a loss leader to attract self-generators and potential self-generators of electricity. In so doing the demand for utility electricity increased and the load on the utility became more diversified. The increase load forced and enabled the electrics to invest in larger plants. The new plants that either embodied new technology or exhibited economies of scale lowered generation costs, allowing utilities to cover losses incurred by the district heating subsidiary and to attract more customers via lower prices. As soon as the electric utility established its regional monopoly it stopped promoting the district heating service. Once the service was no longer needed to fulfill an active part in the company's long-run strategy, the subsidiary fossilized. It did not take advantage of new markets. It did not actively seek rate increases needed to maintain profits. It did not adopt new cost-saving technology. It simply provided the same service to the same service area.

This idea--that business executives form a vision of reality and then acted as if that vision were real even if the vision and reality differ--is encompassed by the theory of bounded rationality.

This theory starts from the proposition that internal constraints on the decision maker are as important in the prediction of his or her behavior as external constraints.[9] Internal constraints fall into three categories. First, there is the problem of uncertainty about the external constraints. The uncertainty forces the decision maker to follow behavioral rules of thumb that will not necessarily lead to a maximization result. Second, the decision maker has only incomplete information about alternatives. It is not possible to follow a maximizing rule ala Stigler[10] because the decision maker does not know the marginal benefit schedule associated with the unknown alternatives. Third, the complexity of the problem is so great that the decision maker can not determine the best course of action.[11]

External constraints are the set of constraints on which most economists choose to focus their attention. They are demand curves, cost curves, income and legal environment. Herbert Simon's complaint against maximizing theory is that it ignores the internal constraints and uses only the external ones. He believes it is necessary to use the theory of bounded rationality because "the capacity of the human mind for formulating and solving complex problems is very small compared with the size of problems whose solution is required for objectively rational behavior in the real world";[12] or more succinctly--decision makers must "satisfice because they don't have the wits to maximize."[13]

Instead of maximizing, the theory of bounded rationality holds that business executives follow one of two behavioral modes. First the decision maker could simplify the problem until it reaches a manageable form and then maximize the simplified problem.[14] Second, the decision maker could form an aspiration level that is a satisfactory outcome, then search alternatives until the alternative that fulfills the aspiration level appears, and choose that alternative as the satisficing alternative. The decision to set the aspiration is an iterative process in which the ease and difficulty of finding the satisficing alternative influences the direction of the aspiration level. That is, if the satisficing alternative is easy to find, the aspiration level will probably rise; and if the satisficing alternative is impossible to find, the aspiration level will fall.[15]

Of course it is possible to mix the two behavioral modes. First, the decision maker can simplify the problem. Second, she can go through the process of setting aspiration levels and finding satisficing alternatives.

To reinterpret the behavior of the electric utility executives in light of the theory of bounded rationality, it can be claimed that the executives simplified the problem of running their businesses by evaluating the entire company on the basis of the relationship of each part to the goal of building an electric power and light system.[16] How and why this particular set of blinders became imbedded within the minds of the executives is beyond the scope of this paper.

For this paper it is important only that the blinders exist and that their consequences are important.

The most important consequence is that because of the choices made, there exists a large x-inefficiency. If the executives had perceived their companies to be energy transformation companies, then either prices of heat and electricity would be lower, or profits higher, or both. The gap between the reality and the potential of the district heating industry is an alternative measure of the x-inefficiency.

The x-inefficiency was ignored in the United States for a long time because technological change, economies of scale, and cheap fuels had been reducing the relative prices of electricity and heat. Now that those relative prices are rising, it is time to change the regulatory environment to provide firms with a set of incentives that if followed would eliminate the x-inefficiency.

The rest of this chapter is divided into six sections. The first section discusses the methodological problems involved in choosing between theories. The second compares the two theories. The third describes the sources of the possible x-inefficiency and its measures. The fourth details the uniqueness of this study and its applicability to major American cities. The fifth examines European practices and institutional forms. The sixth puts forth a recommendation designed to eliminate the x-inefficiency.

Methodology

Economists use a variety of criteria to evaluate theories. These criteria include simplicity,[17] elegance, internal consistency, realism on assumptions, number of assumptions, explanatory power, and predictive power. The last, predictive power, came into the forefront with Milton Friedman's Essays in Positive Economics,[18] and today still commands the greatest allegiance as the ultimate litmus test of a good theory as opposed to the other criteria.[19]

This criterion must be used with great care. Too often, economists commit the logical fallacy of affirming the consequent. For example, in the Lipsey-Steiner principles textbook, the following argument is made: One, utility theory predicts that demand curves are negatively sloped. Two, we find negatively sloped demand curves. Three, therefore utility theory is the correct description of human behavior.[20] This argument is invalid. The evidence proves only that for a theory of human behavior to be acceptable it must be consistent with negatively sloped demand curves.[21]

To use the predicative criterion correctly, it is necessary to attempt to falsify the hypothesis. For example, a statement A implies B. We find that B is not true. Therefore we can safely assume that A is not true either.

This argument is called modus tollens, and is a correct logical deduction.[22]

Of the two theories discussed above, the theory of profit maximizing is easier to test because it provides the researcher with definitive predictions. Even when the theory is broken into short-run and long-run maximizing, it is still testable. For example, while a firm that maximizes in the short run might have a different pricing strategy when compared to the firm that maximizes in the long run, neither firm would adopt a given production technique if a cheaper technique was available.

On the other hand, it is not possible to falsify the theory of bounded rationality in general. A person attempting to prove the superiority of this theory when faced by seemingly falsifying evidence can claim that the evidence compiled did not contain a true picture of the decision maker's original simplifying assumptions or search technique. Researchers claiming the superiority of the bounded rationality theory do so because the theory is more realistic in its behaviorial assumptions, it is more consistent with the evidence, and because it is possible to falsify and/or limit the applicability of profit maximization theories.[23]

Profit Maximization vs. Bounded Rationality

The theory of the profit maximizing firm predicts that a firm will always use the cheapest technique available to produce the desired output,[24] that a firm will take advantage of new cost saving technologies when they become available,[25] and that for a known demand and cost curves output will be adjusted to maximize profit.[26]

The history of the district heating industry contradicts those three predictions. First, it was always known that cogneration of electricity and steam was cheaper than producing either separately. However some firms never used cogneration facilities and others have discontinued its practice.[27]

Second, two techniques, the use of hot water as a distribution medium and the use of trash as a fuel have been demonstrated as superior techniques in Europe for a long period of time. Both techniques went through an innovation and development stage in the 1930's.[28] Since the end of World War II most new systems built in Europe use hot water transmission and distribution.[29] In the United States, there are no companies using hot water. While it is true that the use of hot water would entail expensive retrofit costs for old systems, hybrid systems (mixtures of steam and water) could have been built.[30]

The number of private systems in the United States receiving steam from trash burners is less than five. There are several public systems that burn trash. Compared to the 243 European plants, the United States' statistic is quite low.[31]

Third, opportunities to expand district heating service areas existed during the fifties and sixties in localities undergoing major urban renewal projects. In only one instance, Hartford, Connecticut, was new service provided.[32] Existing firms did not even estimate potential sales in these areas.[33] If a firm does not estimate revenue and costs for potential markets, then it cannot know that the profit maximizing behavior is to not offer the service.

Profit maximizing theory also claims that firms will leave an industry if profits drop below a normal level. Profits can fall if either revenue drops or costs rise or both. The period since World War II reveals a period of low profits and existing firms. A hypothesis that explains this phenomenon is that profits fell due to revenue loss caused by shifting to natural gas and away from steam. By implication steam customers must have considered gas to be a substitute for steam, and shifted out of steam as the price of gas fell. In an effort to substantiate this hypothesis a large number of steam demand functions were estimated. These estimations provide little to no support for this hypothesis.[34]

On the other hand, evidence consistent with the hypothesis that electric utilities acted within the framework of the theory of bounded rationality is available. First, profits were sacrificed in an attempt to attract customers.[35] Second, a large number of independent boilers were shut down and some independent steam companies were forced out of business.[36] Third, the assumption that business leaders were building electric systems can be confirmed by their statements and actions.[37] Fourth, failure to adopt new technologies or seek new markets shows that the companies did not examine all possible avenues to increased profits.[38]

To juxtapose the evidence and theory in the above fashion does not prove the correctness of the theory of bounded rationality. It merely shows that the theory is adequate to the task of explaining the history of the industry. When combined with the falsification of profit maximization theory, the evidence lends credence to the alterative theory.[39]

The Source and Measure of X-Inefficiency

Electric power can be generated in either a single purpose or dual purpose (also known as combined heat and power, CHP, or cogenerating) power plant. The single purpose plant burns fuel in a boiler to generate steam. The steam passes through a turbine and then into a condenser. The steam spins the turbine and it is this motion that generates electricity.

The fuel efficiency of this system depends on the temperature difference of the steam when it enters and leaves the turbine. In a coal burning plant under ideal conditions steam can enter at 1000° F. If these conditions are met then the plant will operate at 40 percent fuel efficiency. Two percent of the energy will be lost to mechanical inefficiencies. Ten percent will go up the stack, and 48 percent of the energy will be dissipated into the atmosphere.[40]

The dual purpose power plant attempts to capture the 48 percent that goes into the atmosphere and transform it into a saleable commodity. In order to do so the outlet temperature of the steam must be raised to at least 250° F. This change sacrifices electricity generation which drops to 30 percent of the energy consumed. However, useful heat, 58 percent of the energy input, can be captured for sale. The remaining 12 percent of the energy is lost due to the mechanical inefficiency and stack losses. The fuel efficiency of the dual purpose plant is 88 percent (30 elect, plus 58 heat).[41]

The transformation of the single purpose plant into a dual purpose does not depend on fuel efficiency alone, but it is the fuel efficiency that creates the cost saving that allows for the transformation. To make this decision it is necessary to compare the cost of alternative energy supply systems. It will be shown that, under certain conditions, the dual purpose power plant with its accompanying heat supply system is the least cost energy supply system. The cost difference between the dual purpose system and existing systems is the measure of the x-inefficiency.

Feasibility Study

The feasibility of serving a hypothetical residential community via district heating was examined. Revenues were limited to be below the cost of alternative heat delivery systems. District heat costs were estimated under a variety of different conditions. The unique features of this study were its use of pre-insulated pipe in the distribution network and the low heat density pattern of the service area.

Pre-insulated pipe has become the dominant form of pipe construction in Europe. This type of pipe was first used in the early 1960's. By 1975 it represented 50 percent of new pipe construction.[42] In only one other study evaluating United States conditions, at Piqua, Ohio, was pre-insulated pipe used in the distribution network.[43] In Piqua, conditions advantageous to successful district heating exist. First, the power plant that will provide heat to the system is located 1¼ miles from the service area.[44] Second, a hospital, industrial customers and several schools are located in the service area.[45] These customers generally have high demands and flat load curves.[46] These characteristics allow the system to take advantage of economies of scale in piping without encountering peak load problems.[47] Because of these unique conditions it is difficult to generalize from the Piqua experience. The present study eliminates these unique features. By doing so, it will be able to come to some general conclusions related to the use of prefabricated pipe.

The heat densities of the service areas examined were 13, 16, and 19 megawatts per square kilometer (mw/km^2). These densities are below the density, 20 mw/km^2, usually considered necessary for profitable district heating.[48] Figure One related heat densities to urban living patterns. Note that the densities in this study would be no higher than the level: residential area with two-family houses.

The heat densities of 13, 16 and 19 mw/km^2 are equivalent to population densities of 10,000, 20,000 and 30,000 inhabitants per square mile, respectively. Population densities of major American cities are shown in Figure Two. The cities that appear in Figure Two were considered possible candidates for new district heating systems by the Karkheck study.[49] The densities are city-wide averages. Most of the cities fall within the 10,000 to 30,000 inhabitants per square mile range. However, district heating has never been proposed as the sole heat supply source for any of these cities except for New York. One study estimated that district heating could profitably serve 33 percent of Los Angeles, 45 percent of Baton Rouge, and 83 percent of Jersey City.[50] The service areas recommended included only the most dense areas of the above cities.

Institutions and District Heating: The European Experience

The section addresses the question, does the institutional framework of a society affect the percent of any nation's heating needs met by a district heating service? The answer, according to McIntrye and Thorton, and Lucas, is yes.[51]

McIntrye and Thorton compare centralized decision-making economies (in particular the U.S.S.R.) to market economies. They argue that centralized decision-makers have the opportunity and the incentive to reduce transactions cost inherent in providing district heating;[52] and that the benefits from the reduction of environmental pollution associated with district heating will have a greater impact on centralized decision-makers than on decentralized ones.[53]

The transactions cost identified by McIntrye and Thorton includes the "need to persuade potential customers

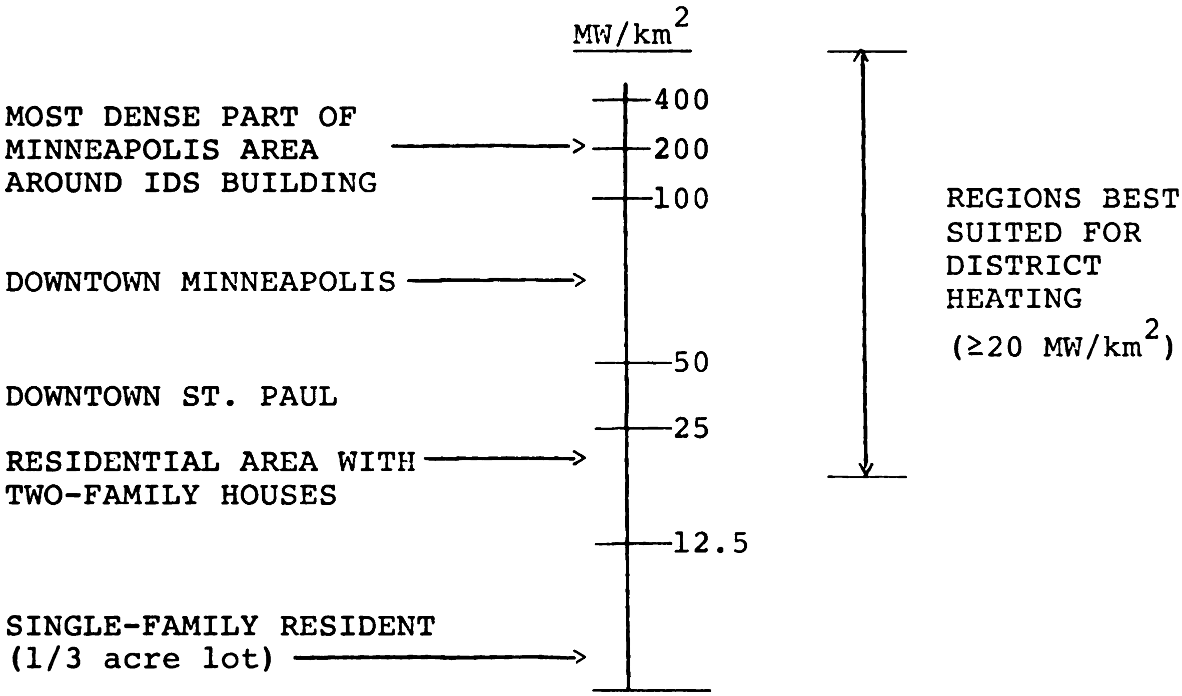

Figure 1

Comparative Urban Heat Load Density Values
[MW(t)/km²][54]

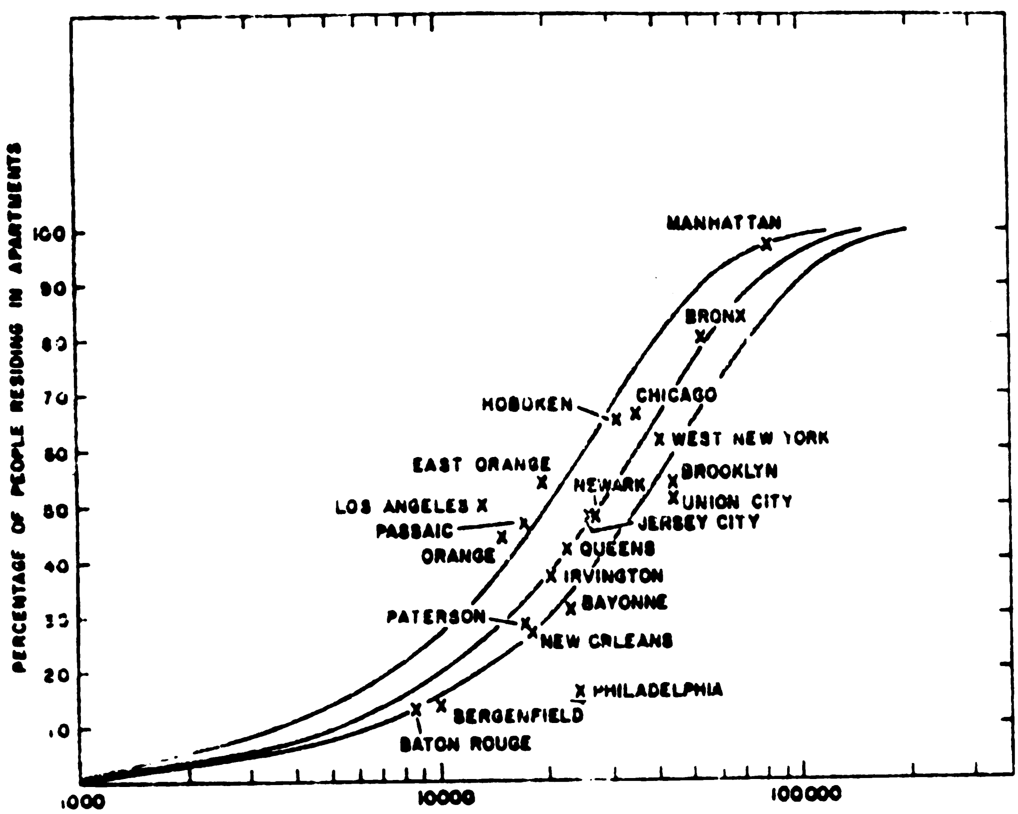

Figure 2

Population Density, People/sq mi[55]

to purchase heat from a district-heating network and to coordinate decisions with the electric utility if a heat and power station is involved."[56] The central decision maker can mandate customer hook-up to the system. This policy will reduce the average cost to each customer because it spreads the burden of the fixed cost to a larger number. A private producer cannot be assured customer acceptance of a product. The private producer must incur the costs of persuading his customers. Plus the private system will be saddled with either negative profits or high rates or both in its formative years if it cannot attract a large number of customers.[57]

The dual purpose power plant must be integrated with both the heat delivery system and the electric grid. If one organization is responsible for the integration, losses due to coordination inefficiencies can be minimized.[58]

District heating reduces air and thermal pollution because less fuel is burned, and the fuel is burned under conditions where emissions are controlled. The benefits of the reduced pollution will more likely be of concern of the central decision maker than to a private utility because total benefit is large while the benefit to any individual is small.[59]

Lucas examines district heating in several Western European countries. He concludes that "the degree of local government participation in electric supply is closely correlated with CHP (combined heat and power)."[60] When the local communities do not control electric supply then these utilities use strategies of "dynamic conservatism" to thwart the development of district heating.[61] Such strategies include excluding CHP projects from national electric grids, offering to buy power at rates below the cost of utility alternatives, and selling gas at high rates.[62] The details of these strategies and a description of other institutional factors are provided in the chapter on the European experience.[63]

Regulatory Change

A primary objective of public utility regulation is to promote efficiency. The existence of x-inefficiencies defy this regulatory standard. State Regulatory Commissions have taken steps to eliminate some x-inefficiency. A regulatory scheme similar to the Michigan plan would provide the incentive to eliminate the x-inefficiency associated with single power plants.

The Michigan plan includes a variable allowed rate of return that is triggered by a plant availability factor. If plant availability is above a certain target the allowed rate rises and if plant availability is below another target the allowed rate falls.[64] To transform this scheme so that it is relevant to the district heating case, all that needs to be done is to change the target from plant availability to fuel cycle efficiency. Firms that convert single-purpose plants into dual-purpose plants and sell the heat will increase their fuel cycle efficiency and thus be allowed to earn higher profits. A constraint that electric rates can be no higher than the rates would have been if the electric customers were served by single-purpose plants must be imposed. Otherwise utilities could set up inefficiency district heating systems, subsidize them with electric service revenues and increase company profits.

The elimination of the x-inefficiency generates a net benefit stream that can be shared by the company and its customers. Profits can rise. The prices of heat and electricity can fall.

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CHAPTER II

DISTRICT HEATING: THE U.S. EXPERIENCE

Introduction

The history of the district heating industry can be divided into three periods: innovation and development, the mature industry, and decline and possible resurrection. Each period is marked by a similar group of problems and accomplishments.

During the first period the industry's technological feasibility was proven. Economically the link between the district heating and the electric utilities was firmly established. The electric utilities used their district heating subsidiaries as pawns in their strategy to establish dominance in particular geographic service areas.

The mature period is marked by a large growth in sales and customers. Institutionally the industry remains linked to the electric utilities. The electric utilities ignored possible cost savings inherent in cogeneration as they strove to increase efficiency in electric generation rather than overall energy efficiency.

The third period, the decline and possible resurrection, is marked by a loss of customers and the bankruptcy of many companies. The decline might have been caused by the availability of natural gas. This investigator doubts that hypothesis. Evidence is provided that decline occurred while the price of natural gas was still greater than the price of steam.

An alternative explanation for decline is that the electric utilities simply ignored their small subsidiaries. The utilities failed to bring rate cases to maintain the cash flow of the subsidiary. They did not investigate possible expansion related to urban renewal projects. As the urban centers of the northeast and midwest declined the electric utilities allowed the district heating systems to shrink and disappear.

The resurrection of the industry in the late seventies was the work of the federal government. In its desire to save energy on a national level, the federal government provided the research funds to investigate the energy saving potential of the industry. These studies highlight the energy savings and possible profits ignored by the electric utilities. However, the federal involvement almost disappeared in fiscal 1982; and it is not clear how long the remaining programs will last.

Innovation and Development

Company Activity

In 1877, following experiments in which he heated his own home and his neighbors from a boiler in his basement, Birdsill Holly founded the first district heating system, Holly Steam Combination Company, in Lockport, NY. The company originally served fourteen customers. Holly's plant and equipment consisted of one boiler (7 feet in diameter and 10 feet high) and 2350 feet of iron pipe. The pipes were buried in wooden boxes with wood shavings used as insulation. The steam was distributed at a pressure of 30 PSIG. Later, the company laid additional lines to connect several factories to the system. The steam pressure in the new lines was 80 PSIG.[1]

Imitators of the Holly systems appeared immediately. Within the next ten years, district heating companies served at least 19 additional cities.[2] The imitators fell into three categories: first, companies that sold steam or hot water primarily for the profit that could be earned in the space heat and industrial heat business; second, universities that tried to reduce the cost of heating a group of buildings; third, companies that combined the sale of heat with the sale of electricity in an attempt to increase the profits of the electric business.

The most important imitator of the Holly system was the New York Steam Company, which Wallace Andrews founded in 1878. He secured permission from the state to operate in 1879, the same year in which he obtained permission to use the Holly patents.[3]

Wallace Andrews fits the stereotype of an American entrepreneur of the period, innovative and risk taking. He was on the first board of directors of the Standard Oil Company.[4] He developed the first coal slurry pipeline, securing a patent for the idea in 1891.[5] He was president of the Standard Gas Light Company, which he sold to the Consolidated Gas Company.[6] Andrews financed the fledgling New York Steam Company over its first three years by selling Standard Oil Stock at the rate of $1000 a day.[7]

New York Steam laid its first pipe in 1881. Simultaneously, a competing company, the American Steam Company, entered the picture. The rivalry grew intense with each company striving to be the first to provide steam service. However, the American Steam Company disappeared on the morning it tested its mains. A leak developed in the mains allowing the steam to mix with the insulating material. This material, 3 million tons of lampblack, blew up, creating one million Al Jolsons in black face. The New York Steam Company, on the other hand, used mineral wool as an insulating material. Mineral wool proved to be acceptable as insulation.[8]

New York Steam began service on March 3, 1882.[9] By 1886 the company had 350 customers, with 5 miles of main.[10] The company developed two separate service areas: first, a downtown area including Wall Street and most of the financial district; second, a midtown district originally serving a residential market, but later, in the 20's and 30's, when the area developed into office buildings, serving Rockefeller Center and the Empire State Building.

The company sold steam to residential customers as a premium fuel--clean, fire proof and automatic. Advertising copy included an endorsement by John D. Rockefeller: "I have had my house heated for several seasons by steam supplied by your company, and am satisfied with the service given."[11] Early customers included H. O. Armour, William Rockefeller and the Metropolitan Club.[12]

Besides selling steam for heating purposes, the New York company also sold steam for industrial uses. Its early customers included United States Illuminating Company, and Consolidated Gas. United States Illuminating was a competitor and later a subsidiary of New York Edison. Consolidated Gas used the steam in the production of town gas.[13] It is a curious footnote in history that these two customers later merge to become Consolidated Edison, and that Consolidated Edison now owns New York Steam.

Other companies or electric utility subsidiaries were formed to provide heat in Boston, Rochester, Eugene, and

Washington, D.C. The National Superheated Water Corporation, sponsored by Theodore Vail, served Boston from 1887 until it closed down in 1905. It was the first company to use water as a heat transmission vehicle, the technique of water heat transmission having been patented by E. Pratt in 1878. The water was heated to temperatures of 334°F. A plunger pump forced the water through the pipe system. At the consumer end, the water was decompressed, releasing heat. A suction pump drew the water back to the central station.[14]

Rochester Gas and Electric entered the heating business in 1889. Its initial system heated a residential district. In 1898 a second plant was built next to the Eastman Kodak plant and the Bausch and Lamp Optical Company. This heating plant, by 1920, served 84 factories with 664×10^6lbs. of steam annually.[15]

In Eugene, Oregon, in 1910, a group of sawmill operators formed the Central Heating Company, which used sawdust as its primary fuel. The company was tied to a system run by the Fruit Growers Association. The interconnect was beneficial to both entities because the canning season and heating season peaked at different times of the year.[16]

In Washington, D.C., two systems were established during this period. In 1905, Pepco contracted with the Navy to supply steam to the Navy Yard.[17] In 1910, the federal government built a system to service federal buildings on Capitol Hill including the U.S. Capital, the Library Congress, the Botanical Gardens and House and Senate office buildings.[18] Universities also entered the district heating industry at this time, producing steam for their own consumption, not for sale. In many instances, they produced steam in conjunction with electricity. Princeton produced electricity as early as 1880. Steam was exhausted from diesel engines to the heating system. By 1903 most of the academic buildings were connected to the steam system.[19] The University of Michigan began heating with steam in 1894, enlarging its system in 1915.[20]

Other electrical utilities constituted the third group interested in district heating during this period. These companies provided heat as part of a corporate strategy to eliminate self-producers of electricity within service areas, and to develop a full line of services necessitated by utility competition for customers and service area.

Detroit Edison was an example of a company facing both problems. In 1903, the Murphy Power Company, not affiliated with Detroit Edison, was established to sell steam in downtown Detroit. It also had the ability to produce electricity. Murphy's problem was that the diurnal peak for steam demand occurred in the morning while the electricity demand peaked in the late afternoon or early evening. Thus, in the morning, it had excess electricity, and in the evening it had excess steam. The solution to the morning problem was to sell electricity to Detroit Edison. This contract gave Detroit Edison control over Murphy Power Company. Murphy had no option to sell to anyone else because Detroit Edison refused to wheel Murphy's electricity to other electric companies.[21]

Detroit Edison entered into direct competition with Murphy by organizing a steam company, Central Heating. This company began operations in 1903 with 12 customers along 3000 feet of mains. Detroit Edison used the heating company to attract as customers of its electric business, self-producers and/or potential self-producers of electricity. At that time many large office buildings and commercial establishments had boilers for heating that could be converted to provide steam for the generation of electricity. By offering steam to those consumers, Detroit Edison reduced the probability of building owners' converting to self-generators. The steam service allowed building owners to reduce costs and to increase the space available for revenue-producing activities.[22]

While profit data are not available from this period, conjecture based on company announcements leads one to conclude that steam was sold below cost. Detroit Edison used below cost pricing to drive the Murphy Power Company out of business (at which time Detroit Edison purchased the assets). Detroit Edison clearly felt that additional profits earned in the electric business would more than offset steam losses.[23]

In Philadelphia, while the facts are not as clear, the trail of events was essentially the same. As of 1895 there were twenty electric companies serving Philadelphia. In that year, Pennsylvania Heat, Light and Power Company, which used Siemans-Halske patents, initiated a steam heating system.[24] Edison Electric immediately responded by founding the Philadelphia Steam Heating and Power Company. Until then Edison Electric had supplied steam to only one building adjacent to its plant and to its company offices.[25] Later, Philadelphia Electric sold steam and electricity as an integrated package to downtown stores.

A different pattern developed in St. Louis. There, Union Electric did not face competition from any other electric companies. Still, it wanted to eliminate self-generators. To do so, starting in 1905, it leased and operated boilers in its service area. Each boiler served adjacent buildings. Pipes were laid to connect the boilers into a system. By 1909 it operated 23 plants serving 58 buildings. The load grew over time so that the company placed into operation a large central boiler in 1917.[26]

In 1922, at the end of this era, Boston Edison started a system. Its announced purpose was to gather in electric customers. At first it leased nine boilers from downtown department stores. These boilers were connected by a pipe system. New customers were added along the pipe system. Boston Edison also purchased the Boston and Main RR steam electric system, in which steam was used to heat railroad cars. Electricity was produced as a by-product of the steam. The railroad remained a major steam customer and its electricity demand was now served by the larger Boston Edison electric facilities.[27]

The number of steam utilities was estimated to be 150 in 1910 by the NDHA.[28] However, an industry specialist estimated that, in 1905, there existed 250 steam plants and 75 water plants.[29] This estimate may have included multi-plant firms. Another industry analyst estimated that between 300 and 400 companies existed in 1915.[30]

The profit picture is even less clear. In 1918, following sharp increases in coal prices, the largest company, New York Steam, filed for bankruptcy.[31] Most of the other companies were tied to electric companies. In those cases there are acknowledgements that steam was deliberately sold below cost, so that profit figures, even if they existed, would be meaningless.[32] Only one fact is definite: Companies were started and enlarged. Thus there must have been individuals who believed that district heat was a potentially viable industry.

Technology

Technological problems for district heating producers during this period centered on three issues: metering, distribution, and the type of transmission medium to use. Developing an accurate meter was essential. Charging customers for steam without one involved complicated formulas that sometimes contained perverse incentives. Distribution problems involved the need to effectively seal joints and to prevent steam flow blockage in pipes. The transmission medium problem involved choosing either steam or water as the preferred heat carried.

Birdsill Holly patented a steam flow meter for use in his original system. However, this meter proved to be inaccurate.[33] Instead of using a meter, district heating companies estimated energy use through a variety of techniques. The company would then charge a flat rate for the building based on the estimated energy use.

The estimation techniques used a combination of factors such as cubic feet of building space, square feet of exposed surface, square feet of windows, number of doors, and square feet of radiator surface.[34]

Perverse incentives entered this system in two ways. First, while small radiators lead to lower bills, a smaller radiator will draw more steam than a large radiator for heating the same space.[35] Second, if the rate were set for an entire season and not according to energy use, then a building owner had no incentive to conserve steam by placing controls on radiators or his heat exchanges. As long as the district heating sent steam through the line the building used it. If some occupants became hot, windows were opened.[36]

In 1904 the American District Heating Company patented a condensate meter. This meter measured the consensed water as it left the customer's heat exchanger. This device proved to be accurate. The cost of the new meter was $10 per year. Savings ran as high as a twenty-five percent reduction in steam use.[37]

Distribution problems centered on two areas, the first of which was sealing pipe connection. New York Steam started with cast iron flanges that were sealed with gaskets, then bolted together. The change was successful.[38]

The second problem in distribution centered on condensate within a steam line. If the condensate was not removed from the pipe, the water build up would eventually block the distribution system.

Early systems worked on a gravity flow principle. All pipes ran downhill from customers to the plant. The steam under pressure would flow uphill, while the water would run back to the plant. Obviously, unless highly gratuitous circumstance existed this approach led to major engineering and excavating difficulties that significantly increased the cost of the distribution system.

The introduction of the steam trap solved this problem. The trap mechanism allows water to leave the pipe system without allowing any steam to escape. It consists of a portal placed at the base of a pipe. A lever controlling the portal is attached to a flotation device. As the water in the pipe rises, the float rises, opening the portal and allowing the water to drain out. The water level drops, causing the flotation device to drop, closing the portal. In principle, the portal closes before all of the water drains so that the remaining water blocks the release of steam.[39]

Since heat can be transmitted via either water or steam each company had the choice of medium. Each fluid has its own unique properties that under a given set of circumstances would make it the preferred transmission fluid. At the beginning of the twentieth century the circumstances favoring steam were prevalent. The factors that favor steam are listed below. Later, the factors favoring water will be discussed.

First, if the condensate is not returned to the boiler plant the energy of the condensate is lost to the heat system, but this loss is much smaller for steam systems than for water systems due to the fact that the energy per pound of condensate is less than the energy per pound of water leaving a customer's heat exchanger. This factor led many early heating companies to build steam systems without return pipes, saving capital.[40] This strategy would be optimal if it coincided with two other factors: (a) the availability of a heat sink into which the condensate could be dumped. In most instances, the city sewer system was used. And (b) either the price of fuel must be low relative to the price of capital, or due to capital market imperfections which restricted the ability of heating companies to raise funds, the price of fuel must be low relative to capital to the heat companies.

Second, station equipment is lower for steam heat. Steam circulates through the pipes under its own pressure. Water systems need pumps to force circulation.[41]

Third, steam easily rises in tall buildings due to its inherent pressure. To raise water, pressure must be added.[42]

Fourth, steam can be used in a variety of industrial processes. Hot water must be converted back to steam for these processes. Many of the processes require heat ranges of greater than 250°F. Hot water distribution at these temperatures had proven to be extremely difficult. It was not until the late 20's that high hot water temperature systems were successful.[43]

Fifth, customers could control steam flow within their buildings. At the turn of the century, customer control of the water flow was expensive both to install and maintain.[44]

Regulation

This era saw the transformation of public utility regulation in the United States. Changes occurred in the substance of regulation; in the level of government responsible for regulation; and in the type of institution responsible for implementing the regulations.

Prior to this period, the substance of regulation was limited to the granting of a franchise. The franchise allowed the company to do business for a specific period of time, and to construct needed facilities along or under public thoroughfares, and sometimes granted the right of eminent domain. The new regulatory format provided the state with the right to circumscribe the business activities of the utilities on an ongoing basis. The state can set prices, determine profits and supervise the sale of corporate securities.

The authority to regulate public utilities moved from the muncipalities to the state governments. At the municipal level, elected mayors and city councils exercised regulatory authority. On the state level, the authority was delegated to an independent commission, a new institutional form, whose only task was to regulate utilities. Between 1907 and 1913, 29 states established utility commissions.[45]

Advocates of the commission system argued that these commissions, through the use of scientific expertise, would take public utilities out of the political arena and thereby lead to good government. However, when the advocates are scrutinized a little more closely, the picture grows murky.[46]

The utilities, ever wary of government control, became major advocates of state regulation. By following this policy, utility executives felt that they could obtain the right kind of regulation before the wrong kind was thrust upon them. This position was rational, given that the executives saw themselves caught between the scylla of municipal franchise and the charybdis of municipal ownership.[47]

Utility executives perceived two dangers in the municipal franchise format. First, the system was inherently corrupt. For example, in Chicago, the city councilors established dummy utility corporations. These corporations were sold to the established utilities. If the utility did not buy the dummy corporation, its franchise which was granted for only two years, might not be renewed.[48] In Philadelphia, the city councilmen granted the Pennsylvania Electric Light Company (in which the councilmen owned stock) the right to own conduit under the city streets. Edison Electric Light Company of Philadelphia was not given this right. It had to rent the right-of-way from Pennsylvania Electric.[49]

Second, the corruption which was exposed became the catalyst for public ownership. Reform mayors such as Tom Johnson of Cleveland, Samual (Golden Rule) James of Toledo, and Hazen S. (Potato Patch) Pingree of Detroit pressed hard for municipal ownership. Tom Johnson believed in:

> municipal ownership of all public service monopolies for the same reason that I believe in the municipal ownership of waterworks, of parks, of schools. I believe in the municipal ownership of these monopolies because if you do not own them they will in time own you. They will rule your politics, corrupt your institutions and finally destroy your liberties.[50]

Chicago in 1887 and Detroit in 1889 established city corporations to generate electricity for street lighting purposes.[51] These municipal corporations deprived the utilities of their largest customers. In Cleveland, Tom Johnson tried to start a municipal lighting company. Cleveland Electric Illuminating Company pressured (and bribed) the city council to vote against the bond authority Johnson needed to finance a municipal company. Next, Johnson proposed a special election on the bond issue. Cleveland Electric Illuminating Company's lawyers obtained a court injunction forbidding the election.[52]

The city of Cleveland's municipal company was finally established when Cleveland annexed South Brooklyn. This suburb already owned a plant, and its plants formed the foundation for the city's system. While Cleveland Illuminating fought the annexation, there was little it could do after the annexation passed. Court action was impossible because the courts were ruling that municipalities had the right to own and operate electricity systems.[53]

The impact of the new regulatory format on steam heating companies varied from state to state. In New York, the New York Steam Company came under the regulatory authority of the commission in 1913. The next year the Public Service Commission required the company to rebuild some of its mains.[54] In 1915, the Commission forced the company to install meters for customers. In 1918, the Commission requested that the company set promotional rates for high load customers, and in 1918, the Commission granted the company the nation's first fuel adjustment clause.[55]

In 1918, the Public Service Commission of Indiana set standards of service for hot water systems and specified a fair rate setting procedure. The standards included: first, that the company must supply hot water from October 1 through April 30, whenever the outside temperature is below 60°F; second, that the temperature of the supply of water must be at least 85°, 154°, and 184°F when the outside temperature is below 60°, 30°, 0°F respectively;[56] third, that customers pay the company in seven installments during the heating seasons; and fourth, that the customers must weather strip his doors and windows.[57]

Rates were set in proportion to heat demand. The commission provided each company with a specific formula to use in estimating heat demand. The variables in this formula were cubic feet of the building, square feet of the windows, square feet of exposed walls, and square feet of doors.[58]

The more typical situation existed in Michigan. In 1909, the Michigan Railroad Commission was given the following set of powers to regulate utilities:

1. It approved utility securities offerings.
2. It required public filing of rates.
3. Upon appeal from a city government, it could set maximum rates.[59]

During this early period of regulation, the commission's only action was to require companies to publish rates. This requirement led to a reduction in price discrimination, which in turn seemed to mollify public demand for regulation.

The Mature Industry

Company Activity

Events outside the industry, the commercial building boom in the late twenties, the depression and World War II, provided the incentives for change during this period. The district heating industry altered its course with each change in the economic environment. The industry expanded to meet the growing demand of the late twenties. It prospered early in the depression due to the lagged impact of the building boom and cost reductions. It stagnated late in the depression. Finally it supplied large increases in output during World War II.

The commercial building boom extended for the years 1926 to 1929. In each year the value of real commercial construction was greater than $3 billion in 1958 dollars. This $3 billion mark was not reached again until 1955.[60]

Simultaneously, sales of district heating companies increased rapidly. Twenty-two companies, that consistently reported sales from 1925 to 1929, sustained an 8% average annual growth rate for those years. The performance of individual companies varied. Companies that began the period with high sales volume such as Detroit, Rochester, and Milwaukee featured growth rates of 9.4, 8.6, and 7.0 percent annually respectively. Companies that began the period with low sales volumes expanded more rapidly in percentage terms. Pittsburgh sustained a 17.2 percent annual growth rate, while Boston achieved a 25 percent annual growth rate.[61]

In 1925, Rochester Gas and Electric started its downtown commercial system. That year it sold 56 million pounds of steam to 35 commercial customers. By 1929, it was selling 365 million pounds of steam to 154 commercial customers.[62]

In 1926, Boston Edison revised its business strategy. Prior to that year the sole purpose of the district heating subsidiary was to attract electric customers. Starting in 1926, Boston Edison attempted to make its district heating subsidiary profitable in its own right. It promoted the sale of steam based on three advantages steam heat would provide customers. These advantages were: first, a reduction in capital expenses; second, the elimination of jobs associated with individual building heating systems; and third, the elimination of coal handling problems.[63]

An analysis of the New York Steam Company in 1926 showed a viable company. It had lowered the price of steam from an average $1.11 per 1000 pounds in 1922 to 95 cents per 1000 pounds in 1926.[64] Increased boiler efficiency, more steam sold per pound of coal burned, was the prime cause of this reduction. The overall energy efficiency of the company was 56 percent. This efficiency was based on a 75 percent boiler efficiency, an 81 percent distribution efficiency and a 92 percent customer heating exchange efficiency.[65] The rate of return for 1926 determined as the sum of profits after tax plus interest divided by capital investment was 9.3 percent.[66]

The early years of the depression did not slow the growth of the industry. In fact to some observers it seemed that the industry was depression proof. From 1929 to 1933 an analysis of eleven cities (the cities were New York, Detroit, Milwaukee, Boston, Rochester, Dayton, Philadelphia, Pittsburgh, St. Louis, Lansing, and Baltimore. These cities were chosen because they were the only cities to complete the statistic surveys of NDHA in every year under observation. A comparison of the eleven cities to all reporting cities is given in Figure 3. This comparison shows that the eleven cities on average have customers who have high steam demands relative to all reporting cities showed: one, an increase in steam sales of 23 percent or 5.4 percent at average annual rate; two, an increase in capital invested of 20.6 percent or 4.8 percent at an average annual rate; three, an increase in maximum hourly capacity of 74 percent or 19.3 percent an average annual rate.[67] These increases were achieved in the face of an economy whose real gross national product declined by 30.5 percent.[68]

On an individual company basis the increases were equally remarkable. The New York Steam Company doubled its sales from 1927 to 1932.[69] Baltimore Gas and Electric purchased Terminal Heating and Freezing in 1927. It increased steam sales in Baltimore by 300 percent from 1928 to 1931. In its service area one hundred sixty-five independent steam generating plants shut down. No new plants were built.[70] In St. Louis Union Electric's customer load rose from 164 in 1928 to 304 in 1932. It laid 10½ miles of pipe in 1931.[71]

From 1929 to 1933 profit indicators rose. For the 11 cities previously cited, average coal cost fell by 15.4 percent from 14.98 cents per 10^6 BTUs to 12.65 cents per

10^6 BTUs while average revenue fell by only 11.0 percent from 87 cents per M lbs. to 77 cents per M lbs. Given a 13,000 BTU average per pound of coal, and that in 1929--12 pounds of steam were sold per pound of coal burned and in 1933--14 pounds of steam were sold per pound of coal burned, then the cost of coal per 1000 lbs. of steam fell from 16 cents in 1929 to 12 cents in 1933. Steam sales rose from 1690240 M lbs. to 20864552 M lbs. Thus revenue minus coal expenses rose from $12 million to $13.5 million or by 12.5 percent.[72]

Labor costs were also falling. A survey of six cities taken by the NDHA showed that total hourly labor costs dropped from $20,000 to $16,500 from 1930 to 1933. This decline was due to decreases in both the number of employees and average hourly wages.[73]

The indicators featured only the relationship between average revenue and average variable costs. They showed that cost on an average annual rate (6.6 percent for labor and 4.2 percent for coal) were declining faster than average revenue (3.0 percent).[74] Data detailing depreciation and interest costs were not available.

An additional indicator of profit, actual or potential, would be the market's willingness to purchase a company's debt. In March 1932, the New York Steam Company offered an $8.7 million bond issue. It was oversubscribed.[75]

The effects of the depression began to hit the study group cities in 1934. Steam sales leveled out and remained constant through 1939 (the drop in 1938 was due to unusually warm weather).[76]

Companies responded to the lack of growth in sales by slowing the growth in capital invested. For two years, 1938 and 1939, the value of the capital invested actually declined.[77]

Average revenue was constant from 1934 to 1937 then declined in 1938 and again in 1939. Coal costs per BTU increased but due to increased boiler efficiencies coal cost per pound of steam sold remained constant.[78] The total hourly wage bill was constant as wage increases were offset by employment reductions.[78]

This review of price and cost trends suggests that profits probably were stable from 1934 to 1937 then fell dramatically in 1938 due to both the decline in sales and average revenue. In 1939, sales returned to their previous levels but average revenue declined so that profits probably remained low.[79]

This dismal picture of the industry in the late thirties was broken by the impact of World War II. Sales jumped from 21.8×10^9 lbs. in 1939 to 30.4×10^9 lbs. in 1945. Contributing to the sales increase were increases in both the number of customers connected to steam systems and the average amount of steam purchased by each customer.[80]

The profit picture also improved. Large increases in coal cost per BTU were offset by increases in average revenue and plant efficiencies leaving revenue after coal cost constant at .67 cents per M lb. for the years 1941 to 1945. Multiplying this net revenue figure by the large increases in sales must have pushed profits up.[81]

Technology

The choice of plant type--cogeneration versus steam-only boilers--became the focus of technological decision-making in this period. The trend was away from cogeneration toward steam-only boilers. In 1925, fifty-one percent of the companies sold exhaust steam. (Cogeneration plants produce "exhaust steam"; steam-only plants, "livesteam".) This percentage dropped to 45 percent in 1932, and to 30 percent by 1945.[82]

Two reasons have been advanced to explain this switch. First, the change from generating electricity with reciprocating engines to turbo-generators carries with it a technological imperative eliminating useful exhaust steam. Therefore, the phase-out of exhaust steam follows directly from the phase-out of reciprocating engines by electric utilities. Second, due to the difference in the peak demand for electricity and steam, a cogeneration facility would, of necessity, produce either too much steam or too much electricity.[83]

Alex Dow, former president of Detroit Edison, stated:

> If you get into the idea that we ought to be able to produce a kilowatt hour of electric energy in combination with the production of steam for sale, for four thousand British Thermal Units, if you figure it that way, you figure me right out of the game...I think it is fairly well to say that the byproduct idea is abandoned.[84]

At that time, Detroit Edison was generating electricity with condensing turbines that had heat rates of 13,000 BTU/KW.[85] Dow was convinced that cogeneration of steam and electricity would waste energy due to the different demand peaks for the outputs. His policy was to sell steam for commercial reasons rather than for production savings. "We closed many a profitable electric contract," he said, "that could not have been obtained unless we had been able to furnish steam service at the same time."[86]

Support for cogeneration came from individuals closely tied to the district heating industry. In two reports, first in 1926 and second in 1948, the research committee of the National District Heating Association documented the advantages of cogeneration. These reports concluded

> as an electric utility grows a limited capacity in turbo-generators, operating non-condensing [therefore supplying steam to a district heating system] and housed in strategic locations [will result in] mutual economic advantage to the electric and heating utilities.[87]

The research committee reports focused on two key issues. First the committee demonstrated the ability of a cogeneration facility to produce more revenue per fuel input than a single purpose facility.[88] Second, the committee showed that this initial advantage could be maintained when the cogeneration facility was integrated into the steam system and electric grid.[89]

In the 1926 report, the analysis started from the conditions of steam as it enters the turbine. The steam pressure was 650 PSIG and had a temperature of 700°F.[90] At these conditions, each pound of steam contains 1165 BTU/lbs. or 1,000 lbs. contains 1,165,000 BTUs. A cogeneration facility that exhausts steam at a pressure of 85 PSIA can transform the 1,000 pounds of steam in 40 Kwh of electricity. The 1,000 pounds of exhaust steam contains 952 BTU/lb. Approximately 76,000 BTUs, 7.6 percent of the energy input, was lost in heat radiation of turbine inefficiencies. Total revenue, at 8 mills/Kwh and $1.00 per 1,000 of steam equaled $1.32 per 1,000 lbs. of steam input.[91]

A single purpose plant, operating under the same input conditions and exhausting steam into a condenser at a 29" vacuum pressure, would have generated 103 Kwh electricity, the energy equivalent of 352,000 BTUs. Conversion losses will be 21,000 BTUs. Heat loss to the condenser was 892,000 BTUs, representing 68% of the heat in the input steam. Total revenue, at 8 mills/Kwh, equaled .83 cents per 1,000 lbs. of steam input.[92]

The advantage achieved by the cogeneration plant can only be realized if the steam demand is large enough to insure base load use of the plant. To examine this problem, the 1926 report set up a hypothetical steam system. The yearly energy demand of the system was 4.25 million lbs. of steam with a peak load of 1.9 million lbs. per hour.[93]

The 1926 report compared the cost of supplying steam from a cogeneration facility with a steam-only plant/ electricity-only plant configuration to this hypothetical steam system.

The cogeneration facility not only produced steam but also had 30,000 Kwh electricity capacity. The turbines operated at an annual load factor of 48.6 percent and a 64 percent load factor during the heating system. Steam passing through the turbines provided 75 percent of the heat energy demand and 39 percent of the peak capacity. The remainder of the demand was carried by low pressure boilers. These boilers were operated at an annual load factor of 10 percent.[94]

The cost comparison made the following assumptions: First: electricity supplied from single purpose plants cost 8.90 mills per Kwh (Line 34, Table 1). Second, steam supplied from single purpose plants could be profitably sold for $1.00 m lbs. (Line 32, Table 1). The electricity generated at cogeneration facilities should be charges only for those costs needed to transform a single purpose steam plant into a cogeneration facility. For example, the cost of electricity included the difference between the cost of a high pressure boiler and a low pressure boiler, where the boiler is needed for cogeneration and the low pressure boiler could fill the steam demand needs (see Tables 2 and 3).

Cost calculations based in these assumptions show that electricity can be produced at a cost of 3.62 mills per Kwh with a heat rate of 4,530 BTU/Kwh. (There are slight differences between Tables 1 and 2 due to rounding errors.) Total savings due to cogeneration were $675,000 annually (Line 36, Table 1). If this amount was used to reduce the price of steam then that price would decline by 15.88 cents per m lbs. (Line 38, Table 1). Alternatively, the amount could be divided between steam customers, electricity customers and stockholders with each group receiving its prorationed amount.

The 1948 research committee report examined the existing Consolidated Edison system. This system included two cogeneration facilities. The cogeneration plants contain 31 percent of the steam system's capacity while providing 80.2 percent of its energy needs.[95]

The 1948 report emphasizes the relationship of the cogeneration facility to other electric generating plants. The electric system operates on the basis of economic loading or incremental heat rates. That is, plants with low heat rates carry the base load. As demand increases, additional plants are brought on line in order of ever increasing heat rates.[96] Consolidated Edison's major cogeneration facility, Waterside Station, had a heat rate, operating as a single purpose electricity generator, of 11,946 BTU/Kwh.[97]

When the Waterside Facility operates as a cogeneration facility, its output can be altered in any of three ways: first, electricity output can be held constant and steam output increased; second, both steam and electricity output can be increased; third, electricity output can decline while steam output increases (see Table 4).

If the system electric demand is such that the incremental plant has a heat rate greater than the Waterside plant (if less than Waterside, then Waterside should not be supplying electricity using this method of operation), then the steam output will be responsible for changes in the operating rates of other electric plants.

Thus the cost of steam is determined incrementally as the sum of the incremental heat needed to generate electricity at other facilities, given that the electricity generation at the cogeneration facility changes from electricity only output level plus the additional heat input needed at the cogeneration facility to produce steam.[98]

Using the above steam costing method, the cost of steam from the Waterside plant ranges from 647 to 1,117 BTUs/lb.[99]

Given that the best live steam boilers use 1,512 BTUs to produce a pound of steam, the report shows that on an incremental heat using basis, cogeneration is superior to live steam production.[100]

These two NDHA reports conflict with the conventional wisdom as expressed by Alex Dow, and implemented by many companies. Reconciliation of these conflicts can occur only on a non-economic plan. Executives of electric utilities, protected from competition by regulators, competed for honors and prestige along alternative (non-profit maximizing) routes. For instance,"in the opinion of knowledgeable observers, such rivalry for technological advance existed between AEP and Philadelphia Electric, whose Presidents, Philip Sporn and R. G. Rincliffe, both were intent on advancing plant thermal efficiencies by increasing operating pressures and temperatures."[101]

This rivalry led to a focus on large condensing plants while closing off alternative visions of plant configuration. Professional prestige prevailed over economic rationale. This particular conclusion can only be the speculation of the author. However, as John Stuart Mill observed:

> It would be a great misconception of the actual course of human affairs, to suppose that competition exercises in fact this unlimited sway. I am not speaking of monopolies, either natural or artificial, or any interference of authority with liberty of production or exchange...I speak of cases in which there is nothing to restrain competing...yet in which the result is not determined by competition, but by custom or usage.[102]

Electrical utilities have monopolies either natural or artificial. Given these monopolies, the probability must increase that action follows custom and usage rather than cost minimization.

Regulation

A 1933 NDHA survey questioned NDHA's membership on the existence and extent of regulation. Forty-two company replies were published. Of these forty-two companies, only three were privately owned and not regulated. Two companies were municipally owned. Twenty-one were regulated by state commissions only. Eleven were subject to municipal regulation only, and five were regulated by both state and municipal governments.[103]

All of the regulated companies had to file rates and submit annual reports. Most of these companies were also required to file rules and regulations pertaining to customer and/or utility obligations.[104]

However, the existence of regulation does not guarantee regulatory supervision. The review process of commissions is contingent upon the utility filing a rate case. During this period, very few utilities filed such cases. For example, from the time Sioux City, Iowa, system started, in 1918, until 1959, the only rate changes that occurred were changes triggered by a fuel adjustment clause.[105] The New York Steam Company did not file for a rate increase from 1928 to December 1946 (the increase was granted in September 1949);[106] and Rochester Gas and Electric did not file for an increase in its steam rates from 1933 until 1951.[107]

Decline and Resurrection

Company Activity

The period after World War II began optimistically. In the new District Heating Handbook the authors state that "the future looks promising and it appears that the industry has entered into a period of healthy expansion, sound operation and financial 'stability'."[108] In July 1952, an editorial in District Heating announced that "heating companies are profitable" and that "competition is not a problem."[109]

However, the industry atmosphere soon turned sour. The number of customers served by the eleven study group cities peaked in 1954. By 1978, 2271 fewer customers were being served than in 1946, representing a drop of 23 percent.[110] For the entire industry, 116 of 211 surveyed companies folded between 1962 and 1975.[111] A survey of the remaining companies showed that their profits were often low or negative.[112]

The alleged culprit responsible for the demise of the district heating is natural gas. The use of this fuel increased at an average annual rate of 9.9 percent in the first decade following World War II.[113] The rapid expansion of the gas transmission network made this increase possible. From 1945 to 1955 the length of the pipeline network grew at an average annual rate of 7.0 percent.[114] Pipeline maps (Figures 7-10) picture the extent of the pipeline growth. In 1930, pipelines existed only in the gas producing regions of the midwest and the southwest. By 1950, the southwest producing regions were connected to midwest markets, and by 1955, to the east coast markets.[115]

The impact of natural gas on district heating companies can be measured in two ways. First, an estimate of steam demand is made in which the price of natural gas is included as a determining variable. If steam and gas are substitutes then the coefficient of the price of gas should be positive. Second, the availability of cheap gas could effect steam demand in an indirect manner by reducing the number of steam customers. Both hypotheses are examined in the next section of this chapter.

Evidence refuting the role of natural gas in the demise of the industry exists. First, in the case of small companies bankruptcies evidence of management greed abounds. Depreciation funds were paid out as salaries instead of being reinvested into the companies.[116] Second, for the study group cities, the growth of steam sales while slowing down from 1945 to 1955, surpassed its historic long term growth rate in the period 1955 to 1965. The growth in sales stopped abruptly in 1973 coinciding with sharp increases in all energy prices.[117] Third, the Hartford system started operations in 1962. This system used natural gas as a boiler fuel. Yet it can provide lower cost heat than the local gas distribution system.[118]

The Hartford system was built due to the perseverence of the developer of an urban renewal site. He determined that the district heating and cooling system was the least cost method of providing those services to a group of buildings under construction. He pressured a reluctant local gas company into providing district heat. Originally, the gas company had proposed to sell gas to each building. It was persuaded to establish the district system when the service area was enlarged to include Travelers Insurance buildings and nearby Federal government office buildings. Further, the steam business was established as a nonregulated subsidiary of the gas company.[119]

The Hartford systems sells steam and chilled water. Natural gas and fuel oil are used as boiler fuel. By 1978, pipelines extended over 2 miles and the company served 23 customers. In 1978 the company ranked thirty-sixth in total sales, selling 321 million pounds of steam. Its energy efficiency, was the highest among NDHA reporting companies. This high mark was due to the return of condensate in significant amounts (only 13 of 44 1978 NDHA reporting companies do so); and the lack of losses in its pipeline system. The Hartford company lost only 5 percent of the steam it sent out while typically U.S. companies lose 15 percent.[120]

Renewed interest in the industry began in 1977 with the start of the Community Systems Program of the Department of Energy. This federal government initiative provided funds for feasibility and design studies, and performance monitoring. The federal agency attempted to build a constituency in the selected areas. This constituency would be responsible for the building or expansion of the district heating system (or using the federal jargon the integrated community energy system, ICES). The primary theme of the program was to show that a cogenerator could sell heat profitable. None of the projects were to be subsidized after the planning stage had passed.[121]

The ICES program was divided into two parts. The initial program featured small systems not affiliated with electric utilities. Each system centered around a large institution (university, state government complex or hospital group). That institution would be the primary heat market for the system. Further each system would produce and sell electricity to the local utility.[123]

Five test-sites were selected for detailed study. The feasiability analysis showed that four sites were viable. Organization problems eliminated one site from the program. The remaining three sites are at different stages of completion. The University of Minnesota system heating has been completed. The electrical units have not been put in place yet. The Clark University system has announced that it would be completed in 1982. The Trenton system has yet to sell its construction bonds. It does have its heat customers lined up and a take or pay contract with the local electric utility to purchase cogenerated electricity.[123]

The second program featured the retrofit of existing power plants, transforming the plant into a cogeneration facility. The plant would then be linked to the expansion of an existing district heating system. In most instances the planned expansion would more than double the size of the existing system.[124]

Eight test-sites were chosen. Only one, at St. Paul, Minnesota, has moved beyond the planning stage. In St. Paul, a new non-profit institution, the District Heating Corporation of St. Paul, was established. This corporation purchased the old district heating system from the local utility. It has purchased additional boilers; and has customers signed up to take the additional heat. The new pipeline system will use hot water as the heat carrier.[125]

Whether or not the other projects will be completed is problematic. The federal government has pulled out of the program. The funding level for the community system program in fiscal year 1982 budget is zero.[126]

Natural Gas Competition

The impact of natural gas on the demand for steam was estimated for twenty-one different cities. Each city was considered a separate market. For fourteen cities, the estimation includes data from the years 1946 to 1978. For the other seven cities data could be collected for only a subperiod of the above interval. Two model specifications were used. These models will be compared below. Statistical problems encountered will be analyzed. A summary of the results will be provided.

The purpose of this exercise is to estimate the size of the price elasticity of steam and the cross elasticity of steam with respect to the price of gas.

Demand Curve Estimation. Estimations of demand curves that test for interfuel substitutions fall into two categories. The first group is derived from the theory of consumer demand and second for the theory of the firm.

When consumer theory is the basis for the estimation, it is assumed that a consumer purchases fuel in order to use a given stock of equipment. The demand for fuel becomes a function of the demand for equipment and the equipment utilization rate. The demand for equipment is a function of equipment prices, income, prices of the particular fuel and its substitutes, along with other variables (usually demographic characteristics and/or housing stock data). The utilization rate is assumed to be a function of the price of the particular fuel, income, and variables related to use (for example degree days, or percent of homes that are all electric).[127] The demand curve for the fuel becomes

$$Q_i = f[P_i, P_j, P_E, Y, X] \qquad (2\text{-}1)$$

where Q_i = quantity of the particular fuel

P_i = price of the particular fuel

P_s = prices of substitute fuels

P_E = prices of equipment

Y = income

X = all other variables

When the equation is estimated equipment prices are usually ignored. Thus the estimated equation is

$$Q_i = g\ [P_i, P_s, Y, X] \qquad (2\text{-}2)$$

These models have been criticized because they did not take into consideration the process through which the equipment holdings adjusted to price changes.[128] A solution to this problem, suggested by Nerlove[129] and applied by Houthakker and Taylor,[130] is to include a specific adjustment process. In particular the desired quantity is a function of the set of variables so that

$$Q_i^* = h[P_i, P_s, Y, X] \qquad (2\text{-}3)$$

where Q_i* is the desired quantity. The desired quantity cannot be measured. The decision maker approaches the desired amount through changing existing purchases. However the actual change will not be as great as the desired change because of the time needed to make the transformation. This process can be depicted by the following equation:

$$Q_{it} - Q_{it-1} = \lambda\,(Q^*_{it} - Q_{it-1}) \qquad (2\text{-}4)$$

$$0 < \lambda \leq 1$$

where $Q_{it} - Q_{it-1}$ = actual change in the quantity

$Q^*_{it} - Q_{it-1}$ = desire change in the quantity

λ = adjustment coefficient

By combining equation (2-3) and (2-4) an equation of the form

$$Q_{it} = J[P_i, P_s, Q_{it-1}, Y, X] \qquad (2\text{-}5)$$

is arrived. This process will provide an estimation of the adjustment.[131]

An alternative solution is to develop a new dependent variable, called the quantity of new demand. This variable was suggested by Balestra and used by Balestra,[132] MacAvoy and Pindyck,[133] and Berndt and Watkins.[134] The new demand is the sum of the incremental demand plus the replacement demand. The incremental is defined as $\Delta Q_i = Q_{it} - Q_{it-1}$. To find the replacement, demand fuel use is assumed to be a function of the existing equipment stock. If the utilization rate is constant then

$$Q_{it} = \lambda E \qquad (2\text{-}6)$$

where λ is the utilization rate and E is the existing stock. If the existing stock of equipment depreciation at a constant rate (r) then a given year (t) an amount of demand will exist that could have been transferred to another fuel by the comsumer, the replacement demand, which is λrE_{t-1} or $r\ Q_{it-1}$.[135] The new demand variable, NQ_{it}, is

$$NQ_{it} = \Delta Q_i + rQ_{it-1} \qquad (2\text{-}7)$$

This variable is placed into a demand equation such as:

$$NQ_{it} = f(P_i, P_s, Y, X) \qquad (2\text{-}8)$$

The estimations, using equation (2-8), have been made for residential natural gas demand. The additional information needed to perform this task, depreciation rates, are not always available.

The alternative method of demand curve estimation is derived from the theory of firm. Recent practice starts with a translog cost function.[136] This function is transformed into a set of input cost share equations. Each cost share equation is estimated. The coefficient values estimated can be manipulated to determine the own price elasticity and the cross elasticity of demand for the inputs.[137]

This technique was recently used by Halvorsen[138] to estimate the own price elasticities and cross elasticities of demand for electricity, oil, coal and gas for each of twenty two-digit industries for the year 1971. He assumes the existence of a production function for each two-digit industry in every state. Next he assumes that the production function is weakly separable between energy inputs and all other inputs. Here separability means that the rate of technical substitution between any pair of energy inputs is not affected by the quantities of non-energy inputs used.[139] This assumption allows Halvorsen to estimate an energy cost function in terms of an energy input and the prices of the different forms of energy ("... energy cost function, $W = J(Z, P_E, P_O, P_G, P_C)$")[140] where W is total energy cost, Z is an energy input, and P_E, P_O, P_G, P_C, are the prices of all input. This method reduced the total data needs and circumvents the tricky problem of defining the price of capital.

However there are at least two problems with this short cut. First coal needs coal handling equipment and number six fuel needs to be kept warm if it is to be used. The implication of these production relationships is that the rate of technical substitution among energy inputs depends directly on the amount of capital employed. Second, energy forms have multidimensional chemical properties. Along one of these dimensions, the amount of BTUs contained per unit of account, it is possible to aggregate energy across the various forms. The purchase of energy is not made solely on the basis of BTU content. Other factors, such as sulfur content, dust content, viscousity, and volatility are important determinants of energy use. The implication of energy's multiple dimensionality is that a variable Z called energy input is not definable.

Model Specification. The consumption of district heating services usually takes place in office buildings, large apartments, schools, hospitals and government buildings. Estimations of fuel demand for this group, the commercial class, have always used equations derived from the theory of consumer demand.[141] The equation forms estimate the market demand due to the inclusion of the number of customers as an independent variable. Residential fuel demand, also derived from the theory of consumer demand, is generally estimated on an individual or per capita basis. The rationale for this difference is that while residential estimates are attempts to understand the behavior of a typical consumer, there is no typical consumer in the commercial class.[142]

In particular two models, similar in form to equation 2-2, will be estimated. The first equation is

$$Q_{st} = b_o + b_1P_{st} + b_2P_{gt} + b_3NC_t + b_4DD_t + b_5YR_t \quad (2\text{-}9)$$

where Q_s = the quantity of steam sold

P_g = price of natural gas

NC = number of customers

P_{st} = price of steam

DD = degree days

YR = a time trend

These variables were chosen because:

1. price of natural gas: managers of district heating firms considered gas as their customers best alternative.
2. degree days and number of customers: the statistical reports of the International Districting Heating Association often refer to these variables when they provide reasons for changes in sales.
3. Time trend: this variable is a proxy for changes in the business conditions within the utility service area.

Both prices were deflated by the GNP deflator. This process insured that the demand curve estimates would reflect changes in relative prices rather than changes in nominal prices. If the prices had not been deflated then the estimation technique would have correlated increases in the prices of steam over time with increases in the quantity of steam purchases over time. The result would be a positive coefficient for the price of steam in all regressions. In this particular case, the GNP deflator was used to deflate the prices because neither the consumer price index nor the wholesale price index contain prices for commodities sold to commercial customers. All other prices used in this study will be adjusted using the same technique.

Further the number of customers does not necessarily have to be an exogenous variable. It could also be the conduit through which the price of gas effects the demand for steam. That is while a change in the price of gas might not effect the demand for steam a change in the expected price of gas will change the number of customers that any steam utility serves.

To test this hypothesis a two stage estimation technique was used. In the first stage the number of customers was estimated as a function of the expected prices of steam and gas and a piecewise time trend with a mode in 1955. The proxy used for the expected price was the price lagged one year. The piecewise time trend was added in this form to test the hypothesis that business activity in the utility service area declined from the mid-fifties to the present. It cannot explain why the service areas were not expanded to follow the shifting trends in business and population. Alternatively, 1955 marks the approximate completion of the interstate natural gas pipeline system. If the important variable related to natural gas is its availability and not its price then the time trend could also be responding to gas availability. The availability argument makes sense when gas is compared to coal or oil because a user of gas has lower storage, capital, and labor cost, and less pollution problems than users of other fossil fuels. However, these advantages do not exist when gas is compared to steam. In fact users' labor, capital, and insurance costs are generally assumed to be lower for steam than for gas.[143]

The equation estimated was

$$NC_t = b_0 + b_1 P_{g_{t-1}} + b_2 P_{s_{t-1}} + b_3 YR_t + b_4 (YR_t - YR^*) D_1 \qquad (2\text{-}10)$$

where

NC = the number of customers

$P_{g_{t-1}}$ = the expected price of gas

$P_{s_{t-1}}$ = the expected price of steam

YR = the time trend

YR^* = 55

$D_i = 1 \qquad YR_i \quad YR^*$

$D_i = 0 \qquad YR_i \quad YR^*$

In the second stage of the predicted value of the number of customers was inserted into the demand equation in place of the actual amount providing

$$Q_{st} = b_0 + b_1 P_{st} + b_2 P_{g_t} + b_3 \hat{NC}_t + b_4 DD_t + b_5 YR_t \qquad (2\text{-}11)$$

where

$\hat{NC}$ = the predicted number of customers, and all other variables retain the identification provided with equation (2-9).

The model specification embodied in equations (2-9) and (2-11) can be criticized along at least two lines. First, the yearly time trend is an imprecise proxy for increase in real income. Further by using the same proxy for every city, the estimation technique suggests that changes in income follow the same pattern in all cities. Second, the price of steam is not necessarily exogenous. This assumption relies on the fact that the price was set by regulation prior to the purchase decision. However, the existence of declining block rates connects the price to an endogenous variable, and with it the possibility of inconsistent estimates.[144]

Both of these criticisms have been taken into account in the second model. Here the proxy for income was retail sales of each individual city. The retail sales data were obtained from the Census of Business. Census data were available for the years 1948, 1954, 1958, 1963, 1967, 1972, and 1977. Predicted values were inserted as data points for non-Census years.

To eliminate the problem of inconsistent estimators caused by the price structure a two stage estimation technique was employed. In the first stage the price of steam is estimated as a function of the price of the fuel input to each utility and the rate of interest faced by the industry.

$$P_{st} = b_o + b_1P_{ft} + b_2r_t \qquad (2\text{-}12)$$

where

P_s = price of steam

P_f = price of fuel

r = Moody's AA bond rate for public utilities minus the percentage change in the GNP deflator.

In the second stage the quantity of steam was estimated as a function of the price of gas, the predicted price of steam, the number of customers, degree days and real retail sales.

$$Q_{st} = b_O + b_1\hat{P}_{st} + b_2P_{gt} + b_3NC_t + b_4DD_t + b_5RS_t \quad (2\text{-}13)$$

where

$\hat{P}_s$ = the predicted price of steam

RS = retail sales divided by the GNP deflator

All other variables retain the identification provided with equation (2-9).

Additional Statistical Problems. Three additional problems in regression analysis were encountered in the estimation. These were the possibility of autocorrelation of the disturbances, of contemporaneous correlation of the disturbances across equations, and of a misspecification of the model due to changes in the legal environment. Each problem has particular causes and consequences for the estimation results.

The presence of autocorrelation of disturbances implies that the error terms for a given observation is related to the error term of the preceding observation. This phenomenon is common in time series analysis because what happened last year usually effects what happens this year. The consequence of autocorrelation is that the variance of the parameters will be biased leading to the statistical acceptance (given positive autocorrelation) of parameter estimates that should be rejected.

The test for the existence of autocorrelation is imprecise. A statistic is calculated from the residuals of the regressions. This statistic is compared to a set of standardized statistics. The standardized statistics determine a three part region: occurrence, uncertain occurrence and non-occurrence of autocorrelation. The regression statistic, known as the Durbin-Watson statistic, fell into the occurrence region for most of the model one regressions, and into the uncertain region for most of the model two regressions.[145] While all of the regressions were statistically transformed via the Cochrane-Orcutt method[146] in an effort to correct for autocorrelation one is not sure if the correction of the model two regressions generated parameter estimates that are more efficient than the estimates generated by the untransformed data.[147]

Contemporaneous correlation of the disturbances occurs when the residual in one city for a given year is correlated with the residual for another city for the same year. For instance, if it is unseemingly cold in Cleveland it will probably be unseemingly cold in Akron, Detroit and Toledo also. Thus, the residuals for the individual markets that seem unrelated are actually related.[148] To correct for this correlation one can use generalized least squares technique on the seemingly unrelated equations. The technique transforms the parameter estimates by using information contained in the variance-covariance matrix. The resulting transformation will provide more efficient estimates than the ordinary least square estimates.[149]

The misspecification due a change in the legal environment was associated with a change in the air pollution laws in December 1970.[150] Following the passage of this law some heating companies switched fuel inputs from coal to gas. Thus, gas not only effects the demand for district heating, but also its supply.

If this is true then it is no longer possible to estimate the demand for steam via the two-equation model presented here. The process designed to eliminate the simultaneous equation bias adds multicollinearity to the equation due to the fact that the predicted estimators of the price of steam will be correlated with the price of natural gas. To avoid this dilemma, it might become necessary to develop a multi-equation model of energy supply.

On the other hand district heating customers and district heating companies purchase gas in different markets and pay significantly different prices for the fuel. Price changes in the commercial and industrial rates occur at different frequency and acceleration.[151] If the latter is true, then the price of fuel in equation (2-12) is not correlated to the price of gas in equation (2-13).

If the change in the legal environment had a significant impact on the variable relationships, then the demand curve for steam would be different after the new law. However, the exact date at which the law was enforced differed from state to state and industry to industry. This study divides the time period into two with 1973-78 being the period in which the law was enforced.

A Chow test was performed on each model two demand curve. If the test statistic is significant then the demand curve has been affected by the legal change.[152]

<u>Results</u>. The discussion of the results will highlight two features of the estimations. First, these will be a comparison of the expected result for each coefficient estimator to the frequency of its occurrence. Second, differences in the frequency of occurrences between models

will be noted. Model one includes estimations of equations (2-9) and (2-11). Model two includes estimations of equation (2-13). Appendix A contains the complete results of the regression estimations.

The expected sign of the price of steam is negative. If the regressions are aggregated then the expected result occurs in 71 of the 224 estimations. The sign is positive 35 times leaving it insignificant in 118 estimations.[153]

The comparison of the models reveals three differences. First, the proportion of negative significant signs is higher in model one (48 percent to 23 percent). Second, the proportion of positive significant signs is higher in model two (19 percent to 10 percent). Third, the transformation of the data to correct for autocorrelation had very little impact on model one while it made a substantial change in model two results.[154] In the latter case the number of negative significant occurrences dropped while the number of positive significant occurrences rose. Given that the Durbin-Watson statistic was in the uncertain region for most of the model two regressions the meaning of this change is unclear.

Finally, for the fourteen cities that were estimated using the generalized least squares technique, there was no change in the number of significant sign or their direction when compared to the ordinary least square estimates for these cities.[155]

The sign of the coefficient for natural gas was positive and significant in only 14 of 224 cases. This result provides little to no support for the hypothesis that steam and gas were considered substitutes. However the preverse result that steam demand is negatively related to gas is supported in 108 of 224 cases.[156] Theoretically the result implies either that steam and gas were considered compliments or that a supply curve has been estimated (given that gas is an input for some district heating companies). Alternatively the result could have been caused by unusual data correlations and an incompletely specified model. The negative sign occurs again and again across both models and all estimation configurations. The results for the generalized and ordinary were exactly the same. The transformation of the model to correct for autocorrelation had only a minor impact on the results.[157]

The expected sign of the coefficient for degree days was positive. Degree days are a measure of coldness, the higher the variable the colder it is; and when it is cold outside more steam is consumed. The regression results confirm this expectation. Of the 224 regression the sign of the coefficient was positive and significant in 129 cases while being negative and significant in only 3 cases. These results occur across both models and all estimation configurations.[158]

The expected sign for the number of customers is uncertain. In general one would expect that more customers means more demand. However, a drop in the number of customers, could mean that many small customers have been replaced by a few large customers. In the latter instance it is possible for demand to increase depending on the relative size of the large customers. The estimation result are more in harmony with the first hypothesis (87 instances) than with the second hypothesis (28 instances). The large number of insignificant cases could be caused by the off-setting influences of both trends. Model two estimations included a higher proportion of significant results than model one. Within model two the generalized least square technique included fewer significant cases than the ordinary least squares technique.[159]

In model one, results are inconsistent in respect to the hypothesis that the natural gas price affected steam demand via the number of customers. In more instances (12) the sign of the gas price coefficient was significant and negative than it was significant and positive (9).[160]

Also in the equations estimating the number of customers, the time trend followed the pattern of positively significant until 1955 and the negatively significant afterwards 15 of 42 regressions. In only three regresssions were the coefficients significant and follow an alternative pattern. In all other regressions at least one of the variables was not significant. These results are consistent with the hypothesis that the mid-fifties marks a decline in service area business activity.[161]

In model one, a time trend was used as a proxy for real income. The sign of its coefficient was positive and significant in 48 of 84 estimations. This result is consistent with the hypothesis that the time trend is an acceptable proxy for a growing real income.[162]

However, while income was growing for the nation fairly consistently over the period, this does not imply that income increased in the service area of every utility. In an attempt to make the income proxy specific to the particular city retail sales by city was substituted for year in every regression in model two. The new proxy also has limitations. For instance, if banking and government service activities increased substantially to offset a drop in retail outlets, then income of the population could increase while retail sales decreased.

The regression results for this parameter did not clearly define a trend. Out of 140 regression the coefficient was positive and significant 47 times while being negative and significant 38 times. These ambiguous results were probably due to the imprecise nature of the proxy.[163]

<u>Test for Stability</u>. Over an extended period of time the relationship between the variables could change. An

estimation procedure that ignores this possibility could register incorrect inferences. To check for this possibility the period was divided into two parts: 1946-1972 and 1973-1978. The split of 1972/73 was chosen because, by assumption, 1973 marked the year in which all companies complied with the air pollution amendments.

The importance of the legal change was that five companies responded to it by switching to a greater dependence on natural gas as an input fuel. For those companies, demand curve estimates could be inconsistent over the entire period 1946-1978 while being consistent for the subperiod 1946-1972.

A possible test for this problem would be to check for significant changes in the demand curves. If the demand curves were the same then it is possible to infer that the curves are consistent. A Chow test was used to make this test. Of the ten comparisons made only in one instance was a demand curve for one period significantly different from a demand curve for the other period.[164] Thus there is little evidence to support the hypothesis that the use of natural gas as a fuel had a significant impact on the estimation process.

<u>Elasticities</u>. The price elasticity of demand was calculated for all non-perverse (negative sign for its own price) significant coefficients. Of the 71 relevant

coefficients only in four cases did the estimates imply that the demand was elastic. For the other 67 cases the range of elasticities was from -.05 to -.83. The results indicate that for most cities an increase in price would have generated an increase in revenue.

<u>Summary</u>. This examination of the regression patterns, as presented so far, does not contain answers to two crucial questions: first, why are there so many negative significant coefficients for the price of gas; and second, why are there so many insignificant coefficients for the price of steam?

To shed light on these questions it is necessary to look a little closer at the data.

The important concern is the relative price of steam to gas. At first glance it seems that the price of gas fell below the price of steam by 1950.[165] The rational response should have been to switch from steam to gas. However there is little evidence to support that conclusion. Consumers kept on buying more steam even though its price relative to gas continually rose. The explanation for this action lies in the energy equivalent price of gas and steam. When both fuels are converted to energy equivalent prices the price of gas was below the price of steam for only five cities until 1971.[166] Those five cities do not follow the pattern of rising quantity consumed until the early 70's.

In addition, conversion costs, potential capital loss on obsolete equipment, higher labor and insurance cost associated with gas boilers would conspire against the transformation of energy supply systems even if differential energy cost had been favorable for gas.[168] Thus even if consumers in their decision making process consider steam and gas substitutes there was no reason for the substitution to take place in historical time. Whatever correlation took place between gas prices and the quantity of steam purchased (in this case a negative correlation) was probably an historical accident rather than a record of a causal relationship.

The question of the lack of significance for the coefficient of the price of steam can also be addressed from an examination of the data. For most cities, the price of steam was relatively constant in the forties and fifties, dropped slightly in the sixties and rose sharply in the seventies. Steam consumption increased steadily until the early seventies and then dropped off. Given these patterns a plausible conjecture for the regression results could be that in period prior to 1973 real income (which appears only in proxy form in these equations and thus possibly misspecified) increases lead to the increases in consumption, and in the period after 1973 increases in steam prices caused the decreases in consumption. However due to the collinearity of all energy prices in the latter period (steam price increase occurred through fuel adjustment clauses activity rather the rate case changes) the regression technique was unable to determine which fuel price increase was responsible for the decrease in steam consumption. It is this problem of multicollinearity in the crucial period when prices changed, that was responsible for the large number of insignificant results.[169]

Technology

Innovation centered on the use of hot water as a heat transmission fluid and the use of trash as an alternative low cost fuel. European utilities have adopted these two techniques in mass. Most European district heating systems built since 1945 use hot water to transmit heat. In western Europe there are at least 243 combustion units presently recovering heat from waste.[170] These units can devour 3250 metric tons per hour. 40 percent of this capacity is in West Germany. Denmark has the highest per capita capacity. 48.2 metric tons per hour per million persons (about 1 lb. per hour per person).[171]

In the United States, the two large systems built and operating since 1945, both use steam.[172] The Trenton district heating system scheduled to start in the near future, will be the first U.S. system to use hot water.[173] As of 1978, only twenty plants used trash as fuel.[174]

A hot water distribution system is preferred to steam distribution system for at least eight reasons:

1. For a given supply of heat per hour to a distribution network, more electricity can be generated. This advantage is the result of lower working temperatures in the water system. The use of lower temperatures allows steam to do more work in the turbine prior to its extraction for heating purposes and thus, to generate more electricity.[175]

2. For a given supply of heat to the final consumers, less heat needs to be supplied to the distribution network. This advantage is the result of the inherent properties of steam that cause heat loss in the distribution network.[176]

First, as the steam is sent out part of it will condense. The condensation must be removed at steam traps which are built into the line at regular intervals. All of the heat in the condensate is lost to a system that does not return condensate. In systems that do return condensate, some of the latent heat of the steam is lost.

Second, after the customer uses the steam the condensate will exist as liquid under pressure greater than 1.6 PSIG and at temperatures above 212°F. The condensate must be lowered to atmospheric pressure before returning to the boiler. In the process of reducing the pressure there is a flash loss to system. This loss has two impacts: a significant amount of the content of the condensate is vented into the atmosphere, and the heat content of the remaining condensate is reduced.

For example, assume steam is sent out at 400°F containing 1201 BTU/lb. The customer uses the latent heat of the steam 826 BTU/lb. and condensate contains the sensible heat at 375 BTU/lb. However, the condensate is still at a pressure of 247 PSIA. It must be reduced to atmospheric pressure. During the reduction the heat content of the condensate is lowered to 180 BTU/lb.; plus some of the condensate, between 5 and 20 percent is vented. The condensate is returned to boiler. Feed water (at 60°F, 28 BTU/lb.) must be added to the condensate. The mixture must be heated original send out steam conditions. The arithematic (assuming 5 percent loss to the atmosphere) of this heating process is:

1028 =	865	+	.5[375-28]	+	.95[375-180]
	latent heat		sensible heat added to feed water		sensible heat added to condensate

Thus a steam distribution system cannot be more than 80% (865/1028) efficiency. On the other hand a hot water system returns all of the heat not used by the customer to the heating plant.

3. Maintenance expenses are lower because there are no steam traps or pressure-reducing valves that need regular inspection and repair.[177]

4. For a given service area, the total length of the supply piping is shorter, because pipe length is not only a function of service area size but also pipe expansion needs.

Pipe expansion needs are a direct function of heat. Therefore, the higher steam temperatures require that steam distribution systems have longer pipes.[178]

5. Hot water has a greater storage capacity. For example, hot water systems usually send out water at 250°F. Heat storage per cubic foot at this temperature is 12,064 BTU/cu.ft. (BTU/lb. x lb./cu.ft.: 208 x 58). Steam systems send out temperatures of 400°F. Heat storage of steam at this temperature is 645 BTU/cu.ft. BTU/lb. x lb./cu.ft.: 1201 x 538). This property provides water systems with greater flexibility in meeting peak demands.[179]

6. Hot water transmission costs are cheaper than steam transmission costs. To transmit hot water greater distances requires additional pumps and power. To transmit steam greater distances requires higher outlet pressures. The higher pressures reduce plant electricity generation, and increases pipe and pressure reduction value costs. The sum of the additional steam costs is greater than the sum of the additional hot water costs.[180]

7. Hot water distribution losses due to pipe convection are less than steam pipe convection losses. Convection losses are a direct function of the difference between pipe temperature and ground temperature. Given that steam pipes are hotter than hot water pipes, it follows that steam losses are greater.[181]

8. Hot water systems can use alternative pipe materials. Compared to the standard steel and cast iron pipes the alternative pipes have a higher material cost but lower installation cost. Thus total pipe costs for alternative small diameter material pipes are below the costs of equivalent piping. When large diameter pipes are needed the hot water systems can use the steel pipes.[182]

Trash burning also has a number of cost saving advantages. First as a fuel it is free. The heat content of a ton of trash is approximately 10 million BTUs, valued at 66 dollars per ton when the price of crude oil is 34 per barrel.[183] Second burning trash reduces acreage need for land-fills;[184] and third reduces transportation costs associated with waste management.[185]

Regulation

Three trends in the regulatory arena can be identified during this period. First, a perverse regulatory lag, set in, caused by the unwillingness of companies to initiate rate cases. Second, in those rate cases that did occur, prices and cost allocation schemes were re-examined under the scrutiny of economic theory. Third, federal regulatory involvement in the industry increased as the government set air pollution standards and fuel use requirements.

Regulatory Lag. Normally, regulatory lag is caused by the regulating commission. Two characteristics of the regulation are responsible for the lag. First, the commission needs time to evaluate and authorize the change in rates. Second, the commission uses historical rather than forecast test year data. If the future is significantly different from the past, then the authorized rate change might be higher or lower than necessary depending on the change in future year costs.[186]

On the other hand, companies can cause regulatory lag when they fail to initiate rate cases. The reason for this practice is due in part to the heating companies' status as small appendages stuck onto the electric utilities. These utilities must appear before commissions to obtain rate increases for the electric business. They would prefer not to open their books again for the steam cases, nor to bear the burden of another rate case. The result of this practice is that many steam companies appear to be money losers, when in fact that might not be true. Further, when a rate case is brought the increase sought is often dramatic. In one case the increase sought was 200% plus a fuel adjustment clause.[187]

Re-examination of Steam Rates. In two recent Consolidated Edison steam cases, the New York commission used its vision of economic theory to evaluate the company's rate change requests. That vision stresses the need to provide the consumer with proper price signals, signals that present to the consumer the cost of his or her decision to society. When the consumer faces the proper prices, his decision to purchase good A or good B will lead to an efficient allocation of resources. The proper price would be one that equals the marginal cost of production.[188]

The ability to determine a unique marginal cost is a prerequisite for adapting this strategy. The commission addressed three problems involved in determining the correct marginal cost: first, it noted that it had to choose between short run and long run cost calculations.[189] Second, faced with the simultaneous production of steam and electricity, it needed to determine a scheme to allocate the common costs.[190] Third, acknowledging that steam sales have a time of day peak/off peak differential, it investigated the appropriateness of increasing the rates to peak users.[191]

The commission chose the long over the short run standard. The reason behind this choice was that the customer, when choosing a particular energy supply, must simultaneously purchase equipment that has a long life.[192] Therefore, in order to properly compare the costs of the different energy supply systems, the customer must know the long run cost of the energy component.

This rationale is flawed. It equates the customer's wish to know cost over an historical period with the analytic economic concept of the long run. The economic concept is ahistorical, out of time. It compares different plant configurations holding constant a set of prices and technology. The customer's decision is made in time with prices changing.[193]

A more generous interpretation of the use of the long run standard would be that it is the best guide available. To be the optimal guide, an additional assumption that all future price changes effecting alternative energy supply systems must not alter the relative costs of these systems must be made. However, in an era when energy prices have risen very quickly and there is a likelihood of continuing energy price increases, a belief in a constant relative price energy to capital is not plausible. When this relative price changes, then the relative costs of energy supply systems change. This reasoning suggests that long run costs today cannot be an optimal guide to the future.

The next problem the commission faced was how to allocate common cost of fuel and boiler capacity between the steam and electric service. The costs are common rather than joint because the "same equipment may be used to make products A and B, and when producing more A uses capacity that could otherwise be used to supply."[194]

In light of the common cost it is important to note that marginal cost is transformed into marginal opportunity costs.[195]

In a concurring opinion to the 1975 decision, Alfred Kahn provided these alternative definitions of marginal costs:

1. the addition to cost involved in increasing the production of one while holding the production of the other constant.
2. Value of the incremental quantities of the one sacrificed in order to increase the production of the other.
3. the incremental cost of producing the one sacrificed by alternative, single-purpose technology as might be necessary because its production is reduced in order to produce additional output of the other.[196]

However, in the body of the decision, the Commission ignored these definitions. Prior to 1975, the fuel cost attributed to the steam service was the additional fuel needed to produce steam above the fuel needed to generate the electricity at the plant that sent out the steam.[197] Under this procedure (Table 5, scheme one) the fuel charge was less than the energy in one pound of steam (800 BTU charge for approximately 950 BTU latent heat in the steam). This charge would be the marginal cost of the steam if and only if the operations of all other plants in the system were not altered due to the steam output, which is not always the case.

Further, it defines steam as the marginal output of plant. By doing so, the entire fuel savings due to cogeneration is passed through to the steam service. If on the other hand electricity was considered the marginal output, then the electricity fuel charge would be 11,300 BTU per KW [12,800 at the cogeneration facility minus 1500 for live steam] instead of 12,000 BTU per KW. Thus the right to call a service marginal becomes a grant of lower rates to that service's customers.

The justification for defining steam as the marginal output had been that the cogeneration facilities were primarily used to generate electricity with the production of steam for sale being an afterthought.[198] However, over a period of time, the cogeneration facilities had been pushed backward in the electric system's order of merit so that they were no longer on base load status. In addition the facilities began producing more steam for sale.[199]

Recognition of the above transition led Consolidated Edison to propose a new fuel cost allocation scheme when it filed for a steam rate increase on December 26, 1974.[200] The company's proposal (Table 5, scheme two) was to allocate the fuel cost based on the proportional heat input requirements of live steam and base load electricity generation. This proposal would have resulted in a dramatic increase [108% using the stylized facts in Table 5] in fuel costs allocated to the steam service.[201]

The commission agreed with the company that the allocation method needed to be changed but disagreed to the specific manner of the change. It chose to allocate the fuel cost based on the proportional heat input requirements of live steam and the system average electricity generation (Table 5, scheme three). Its scheme transferred costs to the steam service. Even though the transfer was not as large as the company's proposal it was still substantial. Further the decision was not based on marginal analysis but instead on a pro rata division.

An alternative cost allocation scheme based on marginal analysis is provided in Table 5 (Table 5, scheme four). This alternative fulfills the requirements of Mr. Kahn's marginal cost definitions 1 and 3. It defines steam as the marginal product. Then it determines the additional cost born by the electric system due to the steam production. This cost is measured by the heat rate of the peaker unit that must supply the electricity no longer generated by the cogeneration facility.

In 1978, Consolidated Edison again asked for a rate increase.[202] As part of the rate case, it proposed to undo the 1975 charge and return to prior 1975 fuel allocation scheme. Three reasons were given for its reversal. First, the cogeneration facilities were now generating electricity on a basis closer to their original rather than their latter status. Second, due to the risk of blackouts, the facilities should always be considered electricity plants first. Third, the steam system lost customers following the 1975 decision. If this drain on the system becomes a gusher then the system might be irreparably harmed and all savings from cogeneration would be lost.[203]

The commission agreed with the company and ordered the reversal.[204] Steam again became the so-called "marginal output". Yet neither decision was based on a marginal system analysis. Thus neither decision fulfills the commission's stated task of developing the proper price signal.

In its 1975 decision the commission also reviewed the rate base allocation scheme. Here the problem was what proportion of the steam boiler investment should be in the steam service rate base versus the electric service rate base. Prior to 1975, the steam service's share of the investment was determined by subtracting the capacity of live steam boilers from steam demand at the summer electric peak then dividing this difference by the capacity of the cogeneration facilities' boilers. A summer peak was used because it was the peak demand period for the Company's boilers even though it was not the peak demand period of the steam system.[205]

The company proposed to change the scheme because it did not reflect actual company practice. The live steam boilers were not used to their full capacity. Thus the amount of cogeneration capacity used by the steam service was underestimated by the above scheme. The company proposed to alter the scheme so that actual live steam boiler output, not boiler capacity, would be subtracted from steam demand. This difference would be divided by the cogeneration boiler capacity to obtain the proportion of the investment to be included in the steam service rate base.[206]

The commission accepted the company's proposal. The change increased the size of the steam service's rate base and therefore simultaneously its revenue requirement.[207]

Again it is necessary to ask what was the commission trying to do and did it accomplish that task? The commission's stated goal was to include in the steam service rate base an amount that would reflect the capacity derated from the electric service. Alternatively, the rate base could reflect how much additional capacity must the electric service have on hand due to the provision of steam for sale.

To this end the company and the commission agreed that the proper peak period was the summer electric peak. Second, the choice of actual live steam output over live steam capacity also reflects the stated goal.[208] However, when it divided the difference between demand and live steam output by a boiler capacity, it became essential to correctly define the nature of the boiler's capacity.

This problem arises because the capacity of the boiler changes with changes in the definition of the output. The examples shown in Table 6 illustrate this point. If the output of the boiler is defined as pounds of steam per hour then the steam service is responsible for 25 percent of the boiler capacity. If output is defined as the heat content of the steam then the steam service is responsible for 20.4 percent of the boiler capacity. However, if the output is the ability of the plant to generate electricity, then the steam service would be responsible for only 10.7 percent of the boiler capacity. The reason for the differences is that electricity generation converted a lower percentage of the input into a saleable output than steam production. Therefore when the steam is extracted for the turbine there is not a proportional reduction in electricity output.

For the commission to fulfill its goal of estimating capacity derated (decline in capacity) due to steam generation, it should have chosen the last scheme described above. Instead it chose the first scheme. It is not known whether the choice was made because of its administrative ease or due to ignorance of the production process. No matter what the cause, the outcome was to include a higher share of the joint investment in the steam rate base than was justified by the commission rationale.

Following the 1978 decision, if the commission had implemented its stated rationales for rate setting then the winter rate would have included a fuel charge for 800 BTUs of fuel; and the summer rate would have included a fuel charge of 1,100 BTUs of fuel, and a capital charged that was based on the inclusion of 10.7 percent of the cogeneration facilities in the steam rate base. Instead, the winter rate by accident included the same fuel charge of 800 BTUs of fuel; and the summer rate included a fuel charge of 800 BTUs of fuel and a capital charge that was based on the inclusion of 25.0 percent of the cogeneration facilities in the steam rate base.

Finally the commission addressed the time of day peak/ off peak pricing problem. The company contended that demand charges would reduce the system peak and therefore reduce system capacity requirements.[209] It proposed a demand charge based on the customers maximum hourly usage, independent of the relationship between usage and either the system's summer or winter peak. A company survey of six customers found that this charge would reduce the system peak by between 8 and 17 percent.[210]

The commission noted that the proposed charge would reduce the system peak only if the customer's peak was coincident with the system peak. The system peak usually occurred between 7 am and 9 am in the morning. However, New York City law requires that apartment buildings be heated by 6 am. Thus the apartment house demand peak was probably earlier than the system peak and that the owners of the apartment could not alter their demand in reaction to the demand charge. Because of the legal constraint on apartment owners, the commission ordered the demand charges be included in the rates of commercial buildings only.[211]

This review of the New York Commission's action highlights the problems of using economic theory as a guide to steam pricing. The theory doesn't provide a unique solution to the price problem. Decisions must be made about the determination of the so-called "marginal output", the meaning of equiproportional share, the definition of capacity, the use of system versus plant analysis and the reasonableness of alternative plant cost.

Federal Regulation. The federal regulatory involvement began with the 1970 amendments to the Clean Air Act. Those amendments mandated that pollution standards must be set and enforced upon all stationary sources of pollutants. Regulations implementing those standards were enacted by the states under the supervision of the Environmental Protection Agency.[212]

Faced with the new regulations, coal-burning district heating utilities had to choose between investments in air pollution control equipment or switching to low sulphur oil as a fuel source. A survey of twenty companies taken in 1969 revealed that eleven companies burned coal exclusively and that five others relied heavily on coal. By 1973, of the eleven coal-burning companies, five were now burning oil exclusively while two burned both coal and oil. Of the five companies burning both coal and oil in 1970, three burned only oil by 1973.[213]

An analysis of the fuel expenses of the ten companies that moved towards oil showed that, at the time of the transformations from coal to oil, the companies on average accepted 30¢ per million BTU increase in fuel expenses. By 1978, this differential had increased to 65¢ per million BTU.

Cost estimates for air pollution equipment are not available, so cost comparisons have not been made. However it is clear that decisions to burn oil have dramatically increased company fuel costs.

Table 1

Economy of High Back Pressure Turbines

1. Steam pressure at throttle, lbs. gauge	650	400	150
2. Steam temperature at throttle, deg. Fahr	700°	610°	366°
3. Saturation temp. of steam deg. Fahr .	498°	448°	366°
4. Degrees superheat, deg. Fahr	202°	162°	0°
5. Initial heat in steam at throttle BTU	1345	1309	1196
6. Heat drop, adiabatic expansion to 85 lb. abs.BTU . . .	195	147	53
7. BTU per lb. steam converted to net-work at 70% Ran-kine effeciency .	136	103	37
8. BTU per lb. taken from steam in tur-bine (including generator loss) .	145	110	40
9. BTU in exhaust steam at 85 LB. abs. pressure	1200	1199	1156
10. Steam temperature at exhaust deg. Fahr.	343°	341°	316°
11. Saturation tempera-ture at exhaust deg. Fahr	316°	316°	316°
12. Degrees superheat and quality of exhaust from turbine at 85 lb. abs.	27°	25°	96.7%
13. Water rate of tur-bine lb. per Kw.hr.	25.1	33.1	92.5
14. Steam flow lb. per hr. to 2-15,000 Kw. units full load .	753000	993000	......
15. Steam flow lb. per hr. to 2-5000 Kw. units full load .			924000

Table 1 Continued:

16. Total yearly steam available for turbine during 9 months of operation, million lbs.	3200	3500	3400
17. Average hourly steam flow to turbine during 9 months of operation (6650 hr.) lb. per hr. . . .	482000	526000	510000
18. Average load on turbine (6650 hr.) Kw.	19200	15900	5500
19. Load factor of turbines when running --per cent . . .	64	53	55
20. Load factor of turbines based on entire year--per cent	48	40	41
21. Kw.hr. sold during 9 months (million kw.hr.)	128	106	36.7
22. Yearly heat consumption of turbine including 5% for radiation, leakage, losses, etc. (1000 million BTU) . .	489	404	143
23. Coal to be charged to power generation with 85% efficiency boiler and economizer, 10,000 BTU coal, tons per year	28700	23800	8400
24. Yearly coal cost charged to power generation based on coal at $4.00 per ton . .	$ 114,800	$ 95,200	$ 33,200
25. BTU per kw.hr. including boiler losses and 5% loss turbine roon	4530	4530	4530
26. Coal cost charged to power generation, mills per kw.hr.	0.9	0.9	.93
27. Steam sold, million lbs. per annum	4250	4250	4250
28. Peak send-out on heating system thousand lb. hr.	1940	1940	1940

Table 1 Continued:

29. Per cent steam sold passing through turbine (16 + 27)	75.0	82.5	80.0
30. Per cent steam sold direct from boiler 100 -- (29) . .	25.0	17.5	20.0
31. Per cent steam peak passing through turbine (14 ÷ 28)	38.8	51.2	47.6
32. Income from steam sold at $1.00 per M	$4,250,000	$4,250,000	$4,250,000
33. Gross income from electric output based on primary charge of $21.00 per Kw. year and 0.4c per kw.hr.	$1,139,000	$1,054,000	$ 356,800
34. Gross income in mills per kw.hr. . .	8.90	9.96	9.72
35. Estimated additional investment . .	$2,280,000	$2,000,000	$ 700,000
36. Net income from electric output, after deducting 13½% on additional investment; 1.22 mills per kw.hr. for operating charge; total .	$ 675,000	$ 617,000	$ 217,000
37. Net income in mills per kw.hr.	5.27	5.82	5.92
38. Net electric income per thousand lb. steam sold, cents	15.88	14.51	5.11
39. Possible selling price of steam to yield same return as live steam heating system, with steam at $1.00 per thousand lb., cents	84.12	85.49	94.89

Source: Orr, "Report of the Research Committee," p. 95.

Table 2

Capital Costs for Dual Purpose Plant

Investment charges, 13½% of \$76.00 = \$10.25 per kw. capacity, or mills per kw. hr.	2.40
Coal charges including standby losses, mills per kw. hr.	1.00
Operation charge for boiler room, including maintenance, based on 40¢ per ton, mills per kw. hr.	.10
Operation and maintenance turbine room, (\$14,000 per year) mills per kw. hr.	.11
Total cost of power generation in heating plant including all charges, mills per kw. hr.	3.61

Source: Orr, "Report of the Research Committee," p. 93.

Table 3

Total Cost for Dual Purpose Plant

1.	Cost of 7-15000 sq. ft. boilers for 650 No. G including economizers and superheaters (not erected)	$ 840,000
2.	Cost of 7-15000 sq. ft. for 200 No. G (not erected)	510,000
3.	Additional boiler cost for same size of boilers (1)-(2)	$ 330,000
4.	Additional boiler room and boiler building cost due to 12% larger boilers when power is generated, based on actual practice, per 1000 lb. steam capacity	480,000
5.	Additional cost due to heavier superstructure in high pressure plant, boiler feed pumps and other extras	100,000
6.	Cost of H. P. header and turbine pipe . . .	50,000
7.	Total additional cost of boiler room to be charged to power generation everything included (3+4+5+6)	$ 960,000
8.	Cost of 2-15000 K.W. Turbines	$ 760,000
9.	Cost of electric equipment for 30,000 kw .	150,000
10.	Cost of turbine room building 50x70x40 with no basement	60,000
11.	Freight and erection of turbines	50,000

Table 3 Continued:

12. Total turbine room cost to be charged to power generation	$1,020,000
Total cost (7 + 12)	$1,980,000
Engineering--miscellaneous . . .	300,000
Total investment	$2,280,000
Total investment per kw.	$ 76.00

Source: Orr, "Report of the Research Committee," p. 96.

Table 4

Calculation of Steam Send-out Heat Rate
For First 400,000 lb. per hr. at 2,000,000 kw. system load

Points shown in Fig. 1	A	B	C	D
Steam send-out, 1000 lb. per hr.	0	400	400	400
Electric generation, 1000 kw.				
Waterside Station	452	473	452	425
Other stations	1,548	1,527	1,548	1,575
Total	2,000	2,000	2,000	2,000
Change in generation, 1000 kw.				
Waterside Stations	---	+21	0	-27
Other stations	---	-21	0	+27
Waterside heat-input, 10^6 BTU per hr.	5,400	6,000	5,725	5,400
Electric system incremental heat rate excluding Waterside, from Fig. 2, BTU per kw. hr.	---	16,260[a]	---	16,550[b]
Electric system heat-input change excluding Waterside, 10^6 BTU per hr.	---	-342	---	+447
Waterside heat-input change, 10^6 BTU per hr.	---	+600	+325	0
System heat-input net change, 10^6 BTU per hr.	---	+258	_325	+447
Steam send-out heat rate, BTU per hr.	---	646	¯813	1,117

[a]Average of incremental rates at 1,548 and 1,527 mw.

[b]Average of incremental rates at 1,548 and 1,575 mw.

Source: "Report of the Research Committee," Proceedings of the Thirty-ninth Annual Conference of th4 National District Heating Association, p. 188.

Table 5

Alternative Fuel Use Allocation Schemes

<u>Fuel Use Data</u>

1.	Average system heat rate:	12,000 BTU/kw
2.	Baseload heat rate:	10,000 BTU/kw
3.	Peakload heat rate:	16,500 BTU/kw
4.	Live Steam heat rate:	1,500 BTU/kw
5.	Cogeneration conditions:	12,800 BTUs generate 1 kw. and 1 lb. of steam 24,000 BTUs generage 1 kw. and 15 lbs. of steam

<u>Alternative Schemes</u>

1. Steam is the marginal output/individual plant analysis (individual plant is the average company plant):

   12,800 BTU - 12,000 BTU = <u>800 BTU fuel charge per lb. of steam</u>

   (1 kw. / 1 lb. of steam) (1 kw.)

2. Pro rata allocation using live steam and base load plant to determine allocating rates/Consolidated Edison's 1975 proposal.

   fuel use: Base load = 10,000 BTU; Live steam = 1,500 BTU; Cogeneration = 12,800 BTU

   $$\frac{10{,}000 \text{ BTU}}{10{,}000 + 1{,}500} = 87\%; \quad \frac{1{,}500}{10{,}000 + 1{,}500} = 13\%$$

   (13%) x (12,800) = <u>1664 BTU fuel charge per lb. of steam</u>

3. Pro rata allocation using live steam and company average heat rate to determine allocating ratio/Commission decision 1975.

   fuel use: Company average = 12,000 BTU; Live steam = 1,500 BTU; Cogeneration = 12,800 BTU

   $$\frac{12{,}000 \text{ BTU}}{12{,}000 + 1{,}500} = 89\%; \quad \frac{1{,}500 \text{ B}}{12{,}000 + 1{,}500} = 11\%$$

   (11%) x (12,800 BTU) = <u>1408 BTU fuel charge per lb. of steam</u>

Table 5 Continued

4. System Margin using an average plant to cogenerage and replacing electricity lost at average plant by operating a peaker plant.

fuel use: average plant generates 2 kw. or 1 kw. and 15 lbs. of steam using 24,000 BTUs, peak load plant uses 16,500 BTUs to generate 1 kw.

$$\frac{16{,}500 \text{ BTUs}}{15 \text{ lbs. of steam}} = \underline{\text{1100 BTU fuel charge per lb. of steam}}$$

Table 6

Alternative Boiler Capacity Allocation Schemes

Typical Steam Conditions for an Extracting Turbine:

	Enthalpy (BTU/lb)
Boiler outlet	1463
Turbine exhaust	990
Condenser outlet	69
Extracted steam	1192

Boiler Capacity: 800,000 lbs/hr
Steam Extracted: 200,000 lbs/hr

Analysis of Work Done:

Boiler :	1463 - 69 = 1394 BTU/lb:	energy added
Turbine :	1463 - 990 = 473 BTU/lb:	energy transformed into electricity
Condenser:	990 - 69 = 921 BTU/lb:	dissipated into heat sink

Electricity Efficiency Analysis:

$$\frac{473 \text{ BTU/lb}}{1394 \text{ BTU/lb}} = \frac{\text{Turbine Work}}{\text{Boiler Work}} = 33.9\%$$

$$\frac{3413 \text{ BTU/kw}}{.339} = 10{,}068 \text{ BTU/kw heat rate}$$

Analysis of Boiler Capacity Used by Steam Service:

1. output is the number of pounds of steam:

$$\frac{200{,}000 \text{ lb/hr steam extracted}}{800{,}000 \text{ lb/hr boiler output}} = 25.0\%$$

2. output is the energy in steam:

$$\frac{1192 \text{ BTU/lb} \times 200{,}000 \text{ lb/hr}}{1463 \text{ BTU/lb} \times 800{,}000 \text{ lb/hr}} = 20.4\%$$

3. output is the ability to generate electricity:

$$\frac{(1192 \text{ BTU/lb} - 990 \text{ BTU/lb}) \times 200{,}000 \text{ lb/hr}}{(1463 \text{ BTU/lb} - 990 \text{ BTU/lb}) \times 800{,}000 \text{ lb/hr}} = 10.7\%$$

Table 7

Total Gas Utility Sales

Year	Millions of Therms	Percent Change (Avg. Annual Rate)
1935	12,923	
1945	25,867	7.2
1955	66,586	9.9
1965	119,803	6.0
1975	148,629	2.2

Source: American Gas Association, Gas Facts (Arlington, Virginia: American Gas Association, 1976), p. 15.

Table 8

Natural Gas Transmission Pipeline

Year	Length	Percent Change (Avg. Annual Rate)
1945	72,280	
1955	142,490	7.0
1965	210,780	4.0
1975	262,600	2.2

Source: American Gas Association, Gas Facts, (Arlington, Virginia: American Gas Association, 1976), p. 23.

Table 9

List of Cities

1.	Cambridge, Mass.	14.	Baltimore, Md.
2.	Concord, N.H.	15.	Milwaukee, Wis.
3.	Piqua, Ohio	16.	Cleveland, Ohio
4.	Cheyenne, Wyo.	17.	St. Louis, Mo.
5.	Philadelphia, Pa.	18.	Dayton, Ohio
6.	New York, N.Y.	19.	Pittsburg, Pa.
7.	Toledo, Ohio	20.	Denver, Colo.
8.	Akron, Ohio	21.	Seattle, Wash.
9.	San Diego, Calif.	22.	Harrisburg, Pa.
10.	Detroit, Mich.	23.	Lansing, Mich.
11.	Boston, Mass.	24.	Atlanta, Ga.
12.	Indianapolis, Ind.	25.	Grand Rapids, Mich.
13.	Rochester, N.J.	26.	Spokane, Wash.

Table 10

Study Group Cities

1.	New York
2.	Detroit
3.	Milwaukee
4.	Boston
5.	Rochester
6.	Dayton
7.	Philadelphia
8.	Pittsburg
9.	St. Louis
10.	Lansing
11.	Baltimore

Table 11

Statistics for Study Group Cities 1929-1945

Year	Steam Sales (M lbs)	Customers Served	Capital Invested ($)	Max. Hourly Cap. (M lbs)	Average Revenue (cents)	Steam Sold Per Coal Burned lbs/lbs	Revenue After Fuel Cost ($M)	Aver. Rev. Minus Coal Cost (cents)
1929	1,690,240	7,619	74,560	8,651	87	12.47	12.0	71
1932	20,844,959	7,598	88,384	15,052	80			
1933	20,864,552	7,295	89,953	16,575	77	14.14	13.5	65
1934	21,951,948	7,380	91,533	17,509	80	14.29	14.7	67
1935	21,720,667	7,430	92,108	18,101	80	12.56	14.1	65
1936	21,811,460	7,534	93,128	17,453	80	14.59	14.6	67
1937	21,719,557	7,791	94,265	17,383	80	14.80	14.6	67
1938	20,635,382	7,780	93,855	17,525	78	14.84	13.0	63
1939	21,814,410	7,720	90,177	18,278	75	14.83	13.5	62
1940	24,056,730	7,805	94,828	20,350	79	14.94	15.9	66
1941	24,337,100	7,917	97,199	20,711	80	16.55	16.3	67
1942	24,295,006	8,200	98,030	20,741	82	15.63	16.3	67
1943	28,804,162	8,609	98,650	21,206	84	14.71	19.3	67
1944	30,804,162	8,954	99,435	21,915	85	15.22	20.6	67
1945	30,425,690	9,325	100,218	22,148	86	15.27	20.7	67

Source: "Report of the Statistics Committee," Proceedings of the Thirty-sixth Annual Conference of the National District Heating Association (Pittsburgh: National District Heating Association, 1945), pp. 145-157.

Table 12

Steam Sales of Study Group Cities

Year	Steam Sales (mm lbs)	Percent Change (Avg. Annual Rate)
1935	21,720	---
1945	30,425	3.4
1955	38,154	2.2
1965	54,976	3.7
1975	66,197	1.8

Table 13

Data Sources

	Item	Title Used in the Source	Source
1.	Quantity of Steam Sold	Total steam sales	IDHA annual proceedings
2.	Price of Steam	Average gross revenue	IDHA annual proceedings
3.	Degree Days	Actual degree days	IDHA annual proceedings
4.	Number of Customers	Number of customers served	IDHA annual proceedings
5.	Price of Gas	Gas utility revenue divided by gas utility sales for commercial class by state	American Gas Association
6.	GNP Deflator	GNP deflator	Survey of Current Business
7.	Pipeline Length (steam)	Total length supply piping	IDHA annual proceedings
8.	Capital Investment	Capital investment	IDHA annual proceedings
9.	Maximum Hourly Capacity	Maximum hourly send-out capacity	IDHA annual proceedings

IDHA: International District Heating Association

Table 14

Variables of the Model

1. The price of steam is the average gross revenue received by steam heating companies. The price is divided by the GNP deflator to transform it into a relative price.

2. The price of gas was calculated by dividing gas utility revenues by gas utility sales for commercial class customers. These statistics are only available by state. The state-wide price was adopted as the price for every city in that state. The price is divided by the GNP deflator to transform it into a relative price. This price was chosen over prices available from the Bureau of Labor Statistics' consumer price index for two reasons. First, the consumer price index does not survey many of the cities in the data set. Second, the price used by the consumer price index is the price to single-family residential dwellings. Steam companies, usually, do not service that type of residential market.

3. The number of customers served is recorded on December 31 of the given year.

4. The number of degree days, annually, is calculated by first subtracting for each calendar day, the difference between 65 degrees and the average daily temperature.

Table 14 Continued

Second, these differences are summed to arrive at the annual figure. Only calendar days with an average temperature of below 65 degrees are included in the calculation.

Table 15

Demand Relationship: Single Equation Model

number of cities: 21
dependent variables: quantity of steam sold
variables: untransformed

Independent Variables	Negative	Coefficient	Positive	Coefficient
	$95 \leq S$	$95 > S \leq 90$	$95 \leq S$	$95 > S \leq 90$
1. Price of Steam	10	1	2	0
2. Price of Gas	8	0	2	1
3. Number of Customers	1	1	7	1
4. Year	2	0	12	0
5. Degree Days	0	0	9	0

R^2 results

$90 \leq$	$90 > \leq 80$	$80 > \leq 70$	$70 >$
8	8	2	3

Table 16

Demand Relationship: Single Equation Model

number of cities: 21
dependent variable: quantity of steam sold
variables: transformed via Cochrane-Orcutt Procedure

Independent Variables	Negative	Coefficient	Positive	Coefficient
	$95 \leq S$	$95 > S \leq 90$	$95 \leq S$	$95 > S \leq 90$
1. Price of Steam	9	1	2	0
2. Price of Gas	7	2	0	0
3. Number of Customers	1	0	4	2
4. Year	3	0	12	1
5. Degree Days	0	0	10	2

R^2 results

$90 \leq$	$90 > \leq 80$	$80 > \leq 70$	$70 >$
6	6	2	7

Table 17

Demand Relationship: Two-Stage Estimation

number of cities: 21
dependent variable: quantity of steam sold
variables: untransformed

Independent Variables	Negative Coefficient		Positive Coefficient	
	$95 \leq S$	$95 > S \leq 90$	$95 \leq S$	$95 > S \leq 90$
1. Price of Steam	9	1	2	0
2. Price of Gas	8	1	0	1
3. Degree Days	0	0	8	1
4. Year	3	0	9	1
5. Predicted Number of Customers	1	1	5	1

R^2 results

$90 \leq$	$90 > \leq 80$	$80 > \leq 70$	$70 >$
8	6	3	4

Table 18

Demand Relationship: Two-Stage Estimation

number of cities: 19
dependent variable: quantity of steam sold
variables: transformed via Cochrane-Orcutt Procedure

	Negative	Coefficient	Positive	Coefficient
	$95 \leq S$	$95 > S \leq 90$	$95 \leq S$	$95 > S \leq 90$
1. Price of Steam	6	1	2	0
2. Price of Gas	5	2	0	0
3. Degree Days	0	0	6	3
4. Year	0	0	9	3
5. Predicted Number of Customers	0	0	4	0

R^2 results

$90 \leq$	$90 > \leq 80$	$80 > \leq 70$	$70 >$
7	4	2	6

Table 19

Estimation of the Number of Customers

number of cities: 21
dependent variable: number of customers
variables: untransformed

Independent Variables	Negative	Coefficient	Positive	Coefficient
	$95 \leq S$	$95 > S \leq 90$	$95 \leq S$	$95 > S \leq 90$
1. Lagged Price of Steam	6	1	3	0
2. Lagged Price of Gas	6	3	4	0
3. Year	2	1	10	0
4. Year minus 1955	16	1	1	0

R^2 results

$90 \leq$	$90 > \leq 80$	$80 > \leq 70$	$70 >$
14	4	2	1

Table 20

Estimation of the Number of Customers
Transformed

number of cities: 21
dependent variable: number of customers
variables: transformed via Cochrane-Orcutt Procedure

Independent Variables	Negative Coefficient		Positive Coefficient	
	$95 \leq S$	$95 > S \leq 90$	$95 \leq S$	$95 > S \leq 90$
1. Lagged Price of Steam	7	4	3	0
2. Lagged Price of Gas	2	1	3	2
3. Year	2	0	5	0
4. Year minus 1955	7	2	1	1

R^2 results

$90 \leq$	$90 > \leq 80$	$80 > \leq 70$	$70 >$
10	4	1	6

Table 21

Summary of Significant* Results for the Price of Steam

	1	2	3	4	5	6	7	8	9
Positive	4	4	11	11	12	15	12	15	35
Negative	21	18	12	12	23	9	11	21	71
Insignificant	17	20	33	33	35	46	47	34	118
Total	42	42	56	56	70	70	70	70	224

*To be counted as significant an estimate had to be significant at the 10% confidence level

Column one: results from model one, original data estimations

Column two: results from model one, transformed data estimations

Column three: results from model two, ordinary least squares estimations, 14 cities only

Column four: results from model two, generalized least squares estimations

Column five: results from model two, untransformed data

Column six: results from model two, transformed data

Column seven: results from model two, time period truncated in 1972

Column eight: results from model two, all years

Column nine: Total, sum of 1, 2, 5, 6 or 1, 2, 7, 8

Table 22

Summary of Significant* Results for the Price of Gas

	1	2	3	4	5	6	7	8	9
Positive	3	0	5	5	7	4	9	2	14
Negative	17	16	32	32	41	34	30	45	108
Insignificant	22	26	19	19	22	32	31	23	102
Total	42	42	56	56	70	70	70	70	224

*To be counted as significant an estimate had to be significant at the 10% confidence level

Column one: results from model one; original data estimates

Column two: results from model one; transformed data

Column three: results from model two; ordinary least squares, 14 cities only

Column four: results from model two; generalized least squares

Column five: results from model two; original data estimates

Column six: results from model two; transformed data

Column seven: results from model two; time period truncated in 1972

Column eight: results from model two; all years

Column nine: Total; sum of 1, 2, 5, 6 or 1, 2, 7, 8

Table 23

Summary of Significant* Results
for the Number of Customers

	1	2	3	4	5	6	7	8	9
Positive	14	10	29	23	30	33	32	31	87
Negative	4	1	12	8	9	14	11	12	28
Insignificant	24	31	15	35	31	23	27	27	109
Total	42	42	56	56	70	70	70	70	224

*To be counted as significant an estimate had to be significant at the 10% confidence level

Column one: results from model one; original data estimates

Column two: results from model one; transformed data

Column three: results from model two; ordinary least squares, 14 cities only

Column four: results from model two; generalized least squares

Column five: results from model two; original data estimates

Column six: results from model two; transformed data

Column seven: results from model two; time period truncated in 1972

Column eight: results from model two; all years

Column nine: Total; sum of 1, 2, 5, 6 or 1, 2, 7, 8

Table 24

Summary of Significant* Results for Degree Days

	1	2	3	4	5	6	7	8	9
Positive	18	22	33	35	32	57	42	47	129
Negative	0	0	0	3	2	1	1	2	3
Insignificant	24	20	23	18	36	12	27	21	92
Total	42	42	56	56	70	70	70	70	224

*To be counted as significant an estimate had to be significant at the 10% confidence level

Column one: results from model one; original data estimates

Column two: results from model one; transformed data

Column three: results from model two; ordinary least squares, 14 cities only

Column four: results from model two; generalized least squares

Column five: results from model two; original data estimates

Column six: results from model two; transformed data

Column seven: results from model two; time period truncated in 1972

Column eight: results from model two; all years

Column nine: Total; sum of 1, 2, 5, 6 or 1, 2, 7, 8

Table 25

Summary of Significant* Results for Retail Sales

	1	2	3	4	5	6	7
Positive	18	19	17	30	20	27	47
Negative	20	15	23	15	23	15	38
Insignificant	18	22	30	25	27	28	55
Total	56	56	70	70	70	70	140

*To be counted as significant an estimate had to be significant at the 10% confidence level

Column one: results from model two; ordinary least squares, 14 cities only

Column two: results from model two; generalized least squares

Column three: results from model two; original data estimates

Column four: results from model two; transformed data

Column five: results from model two; time period truncated in 1972

Column six: results from model two; all years

Column seven: Total; sum of 5, 6 or 3, 4

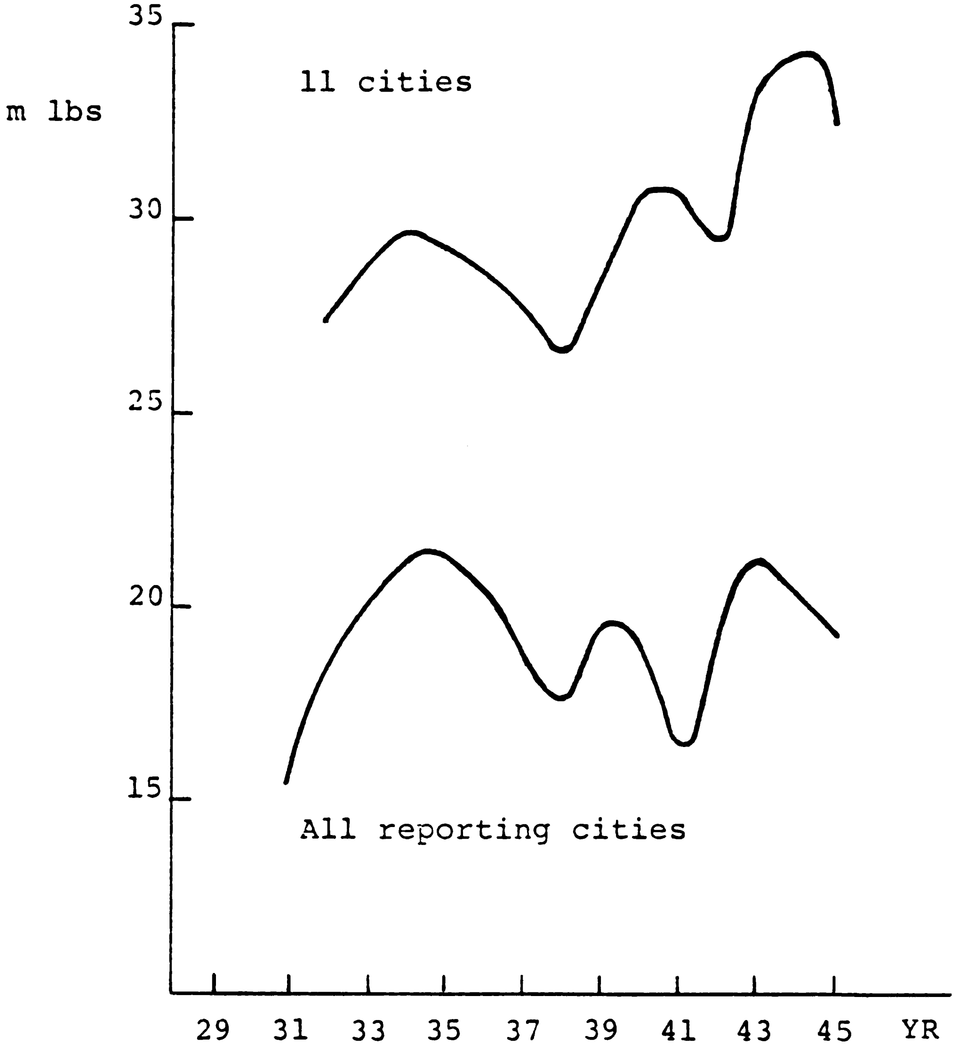

Figure 3

Steam Sales per Customer

- 11 cities

- all reporting cities

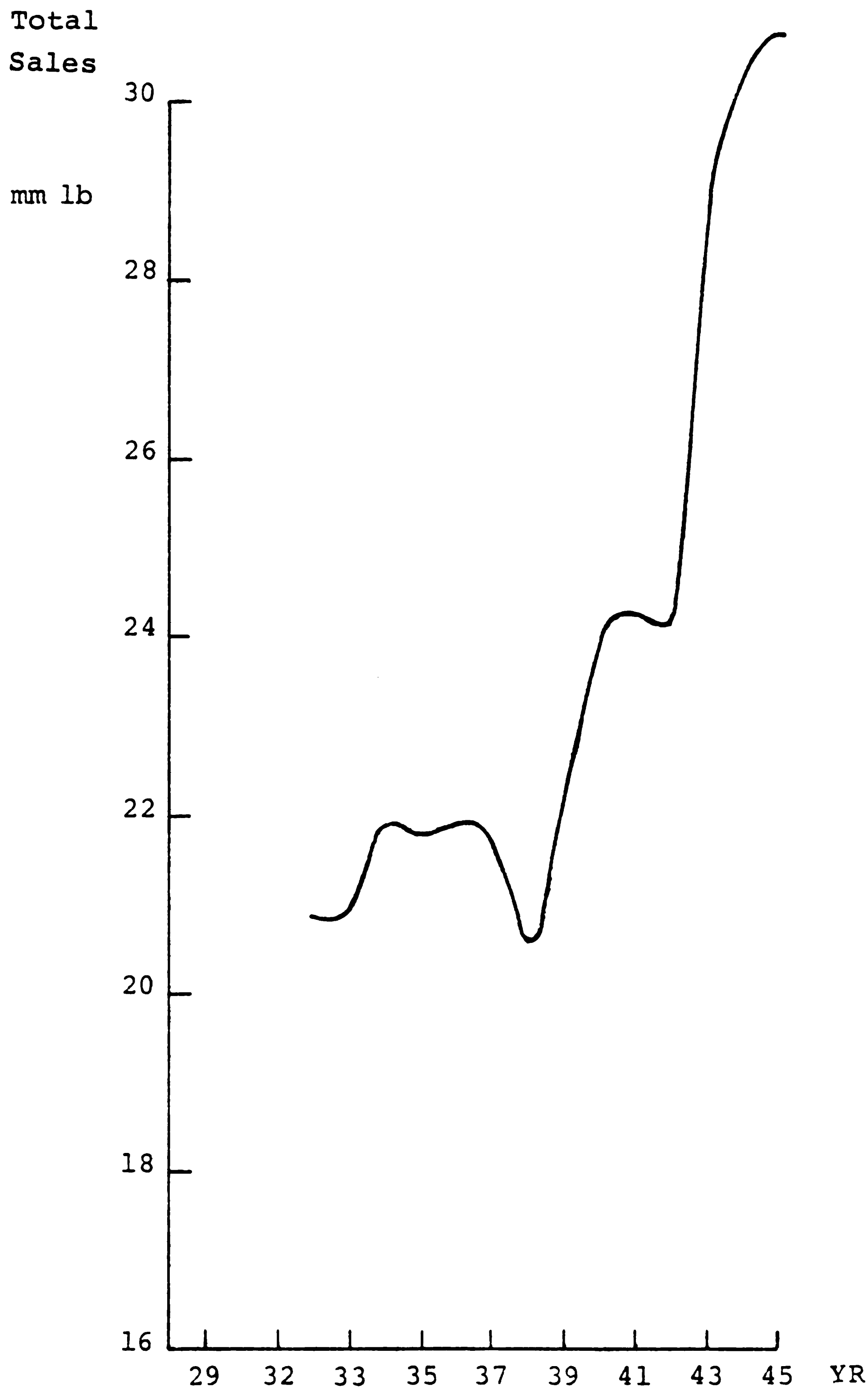

Figure 4

Steam Sales

11 cities

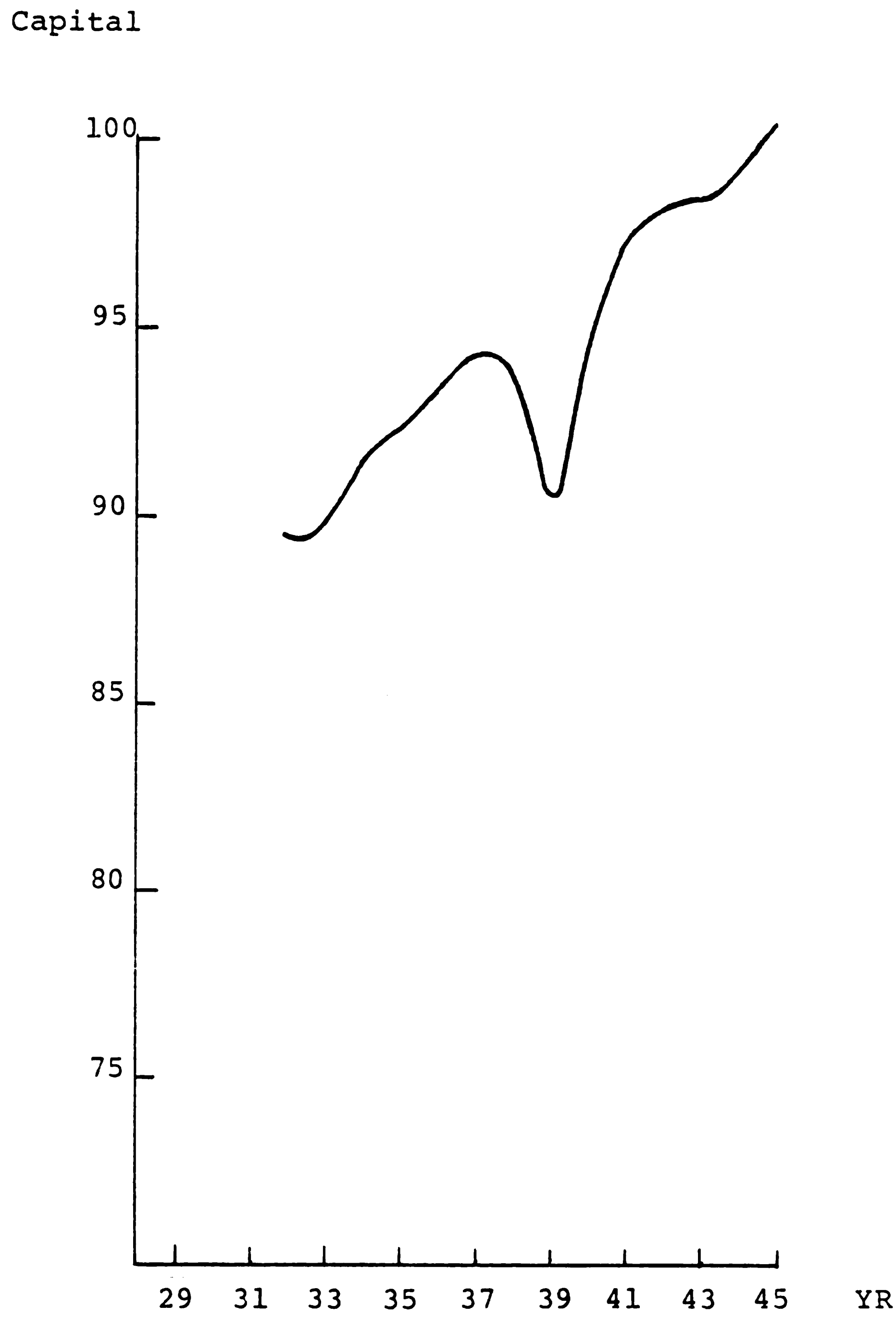

Figure 5

Capital Invested

11 Cities

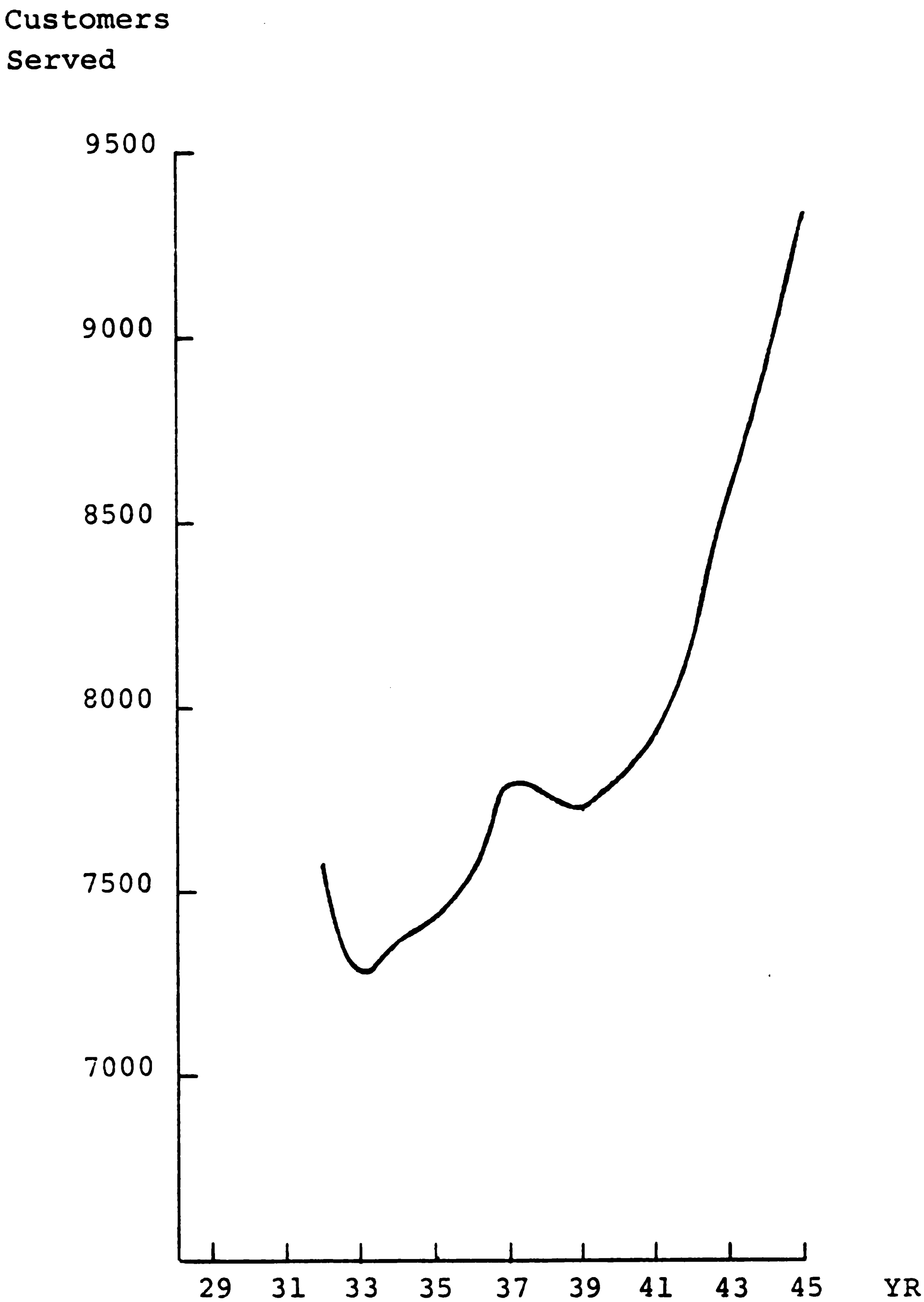

Figure 6

Customers Served

11 Cities

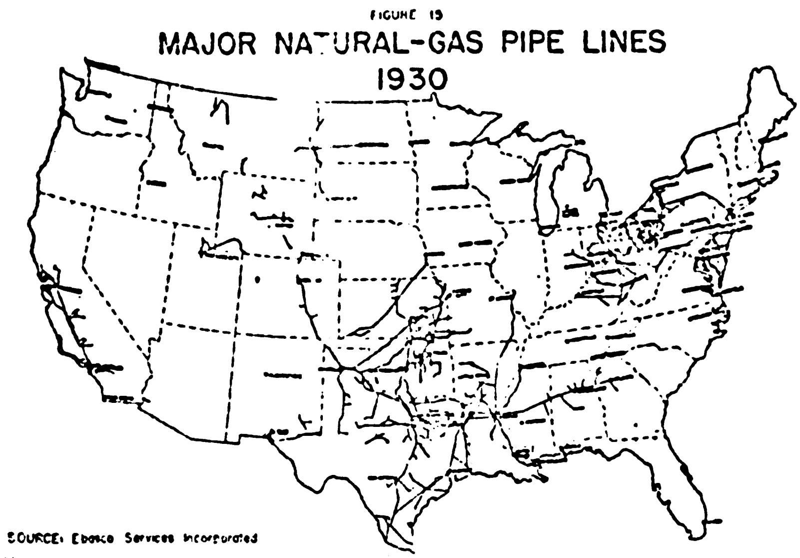

Figure 7

Natural-Gas Statistics 1930[214]

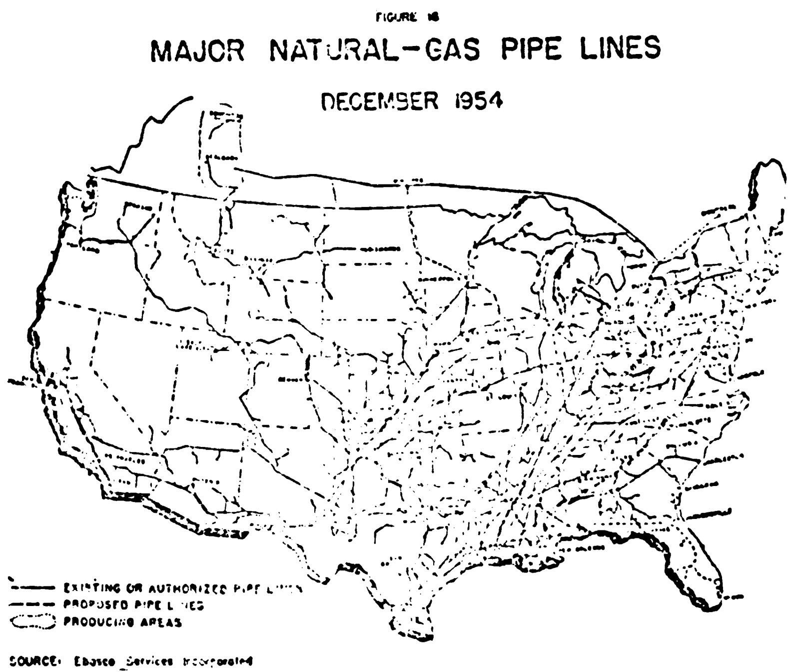

Figure 8

Natural-Gas Statistics[215]
December 1954

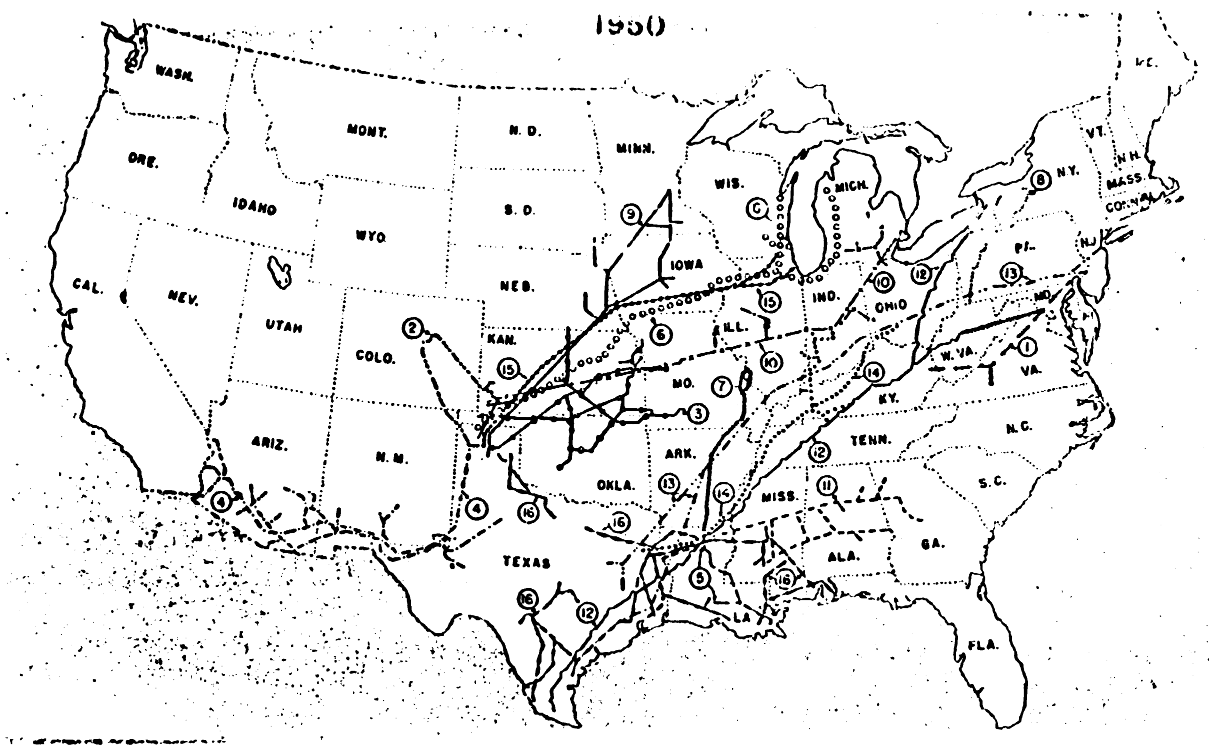

Figure 9

Natural Gas Pipelines - 1950

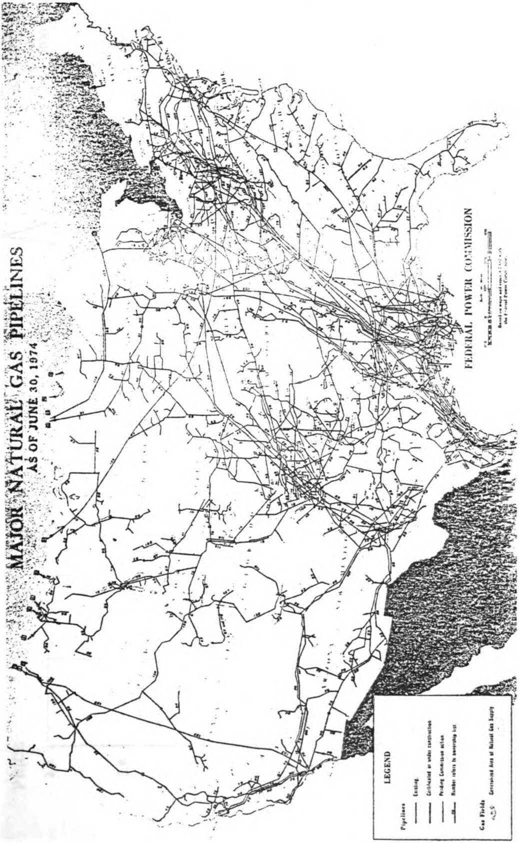
MAJOR NATURAL GAS PIPELINES
AS OF JUNE 30, 1974
FEDERAL POWER COMMISSION
LEGEND
Pipelines
Existing.
Certificated or under construction.
Pending Commission action.
Number refers to ownership list.
Gas Fields
Generalized Area of Natural Gas Supply

Figure 10

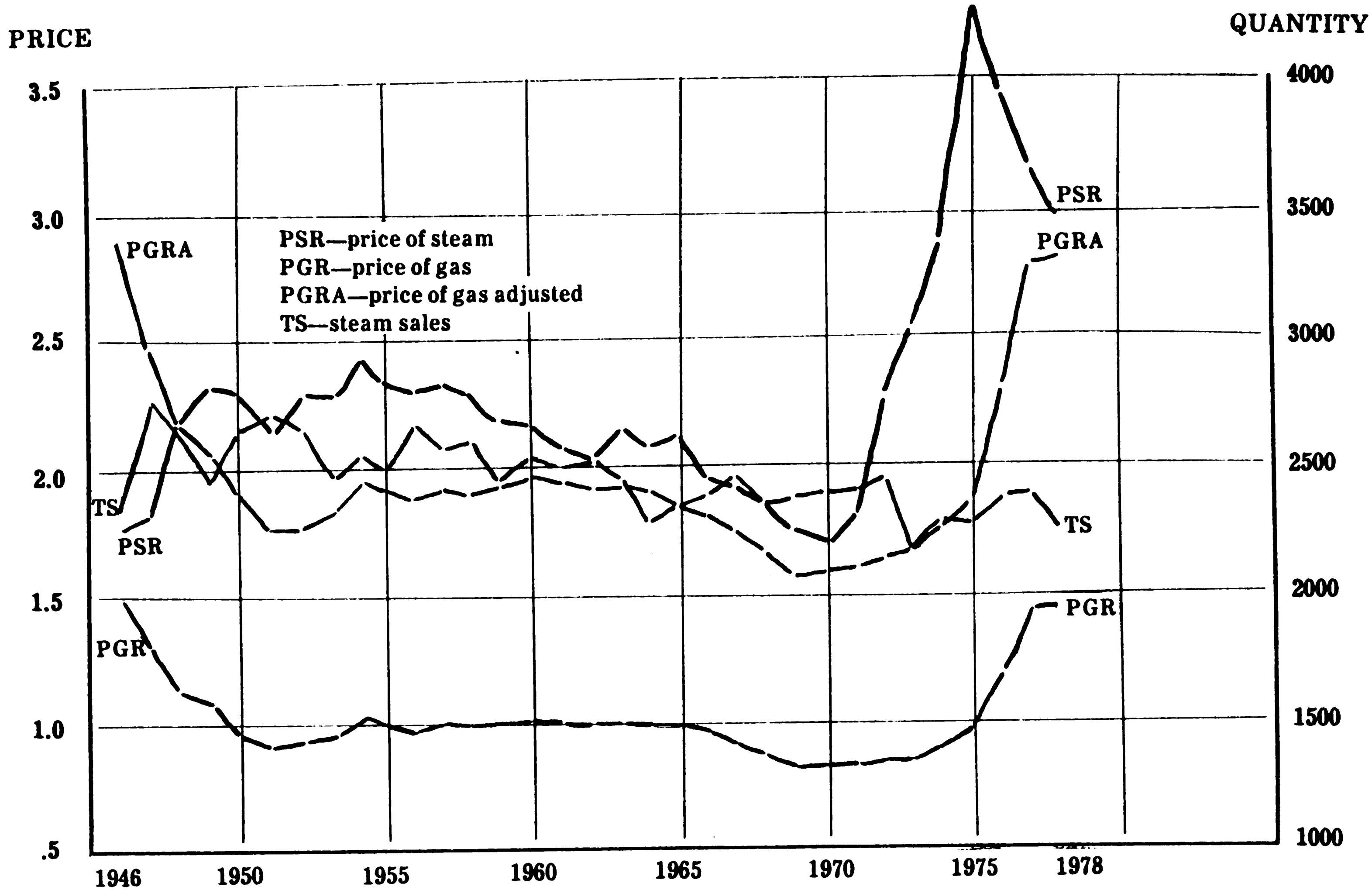

Figure 11

Cleveland

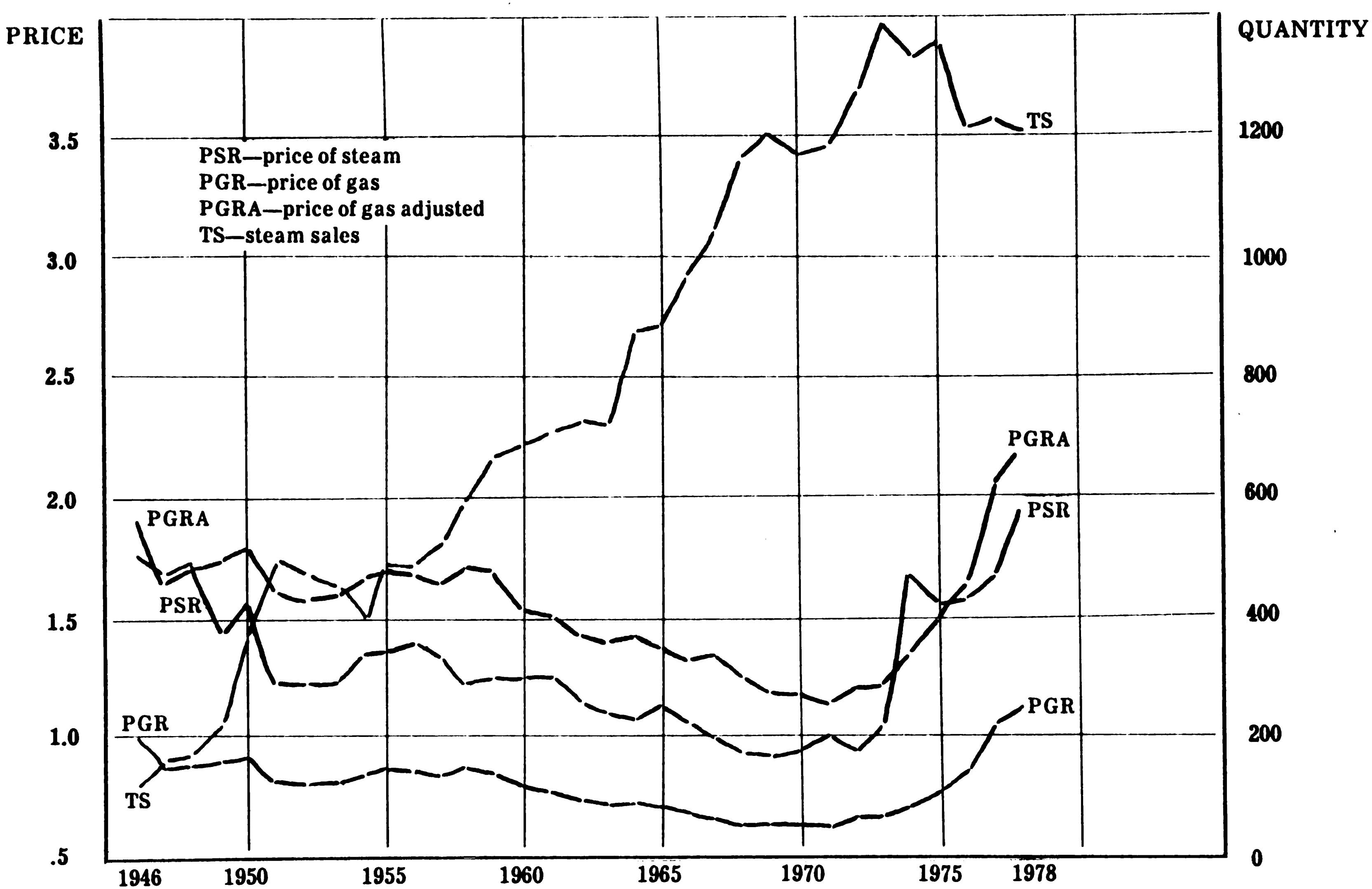

Figure 12

Denver

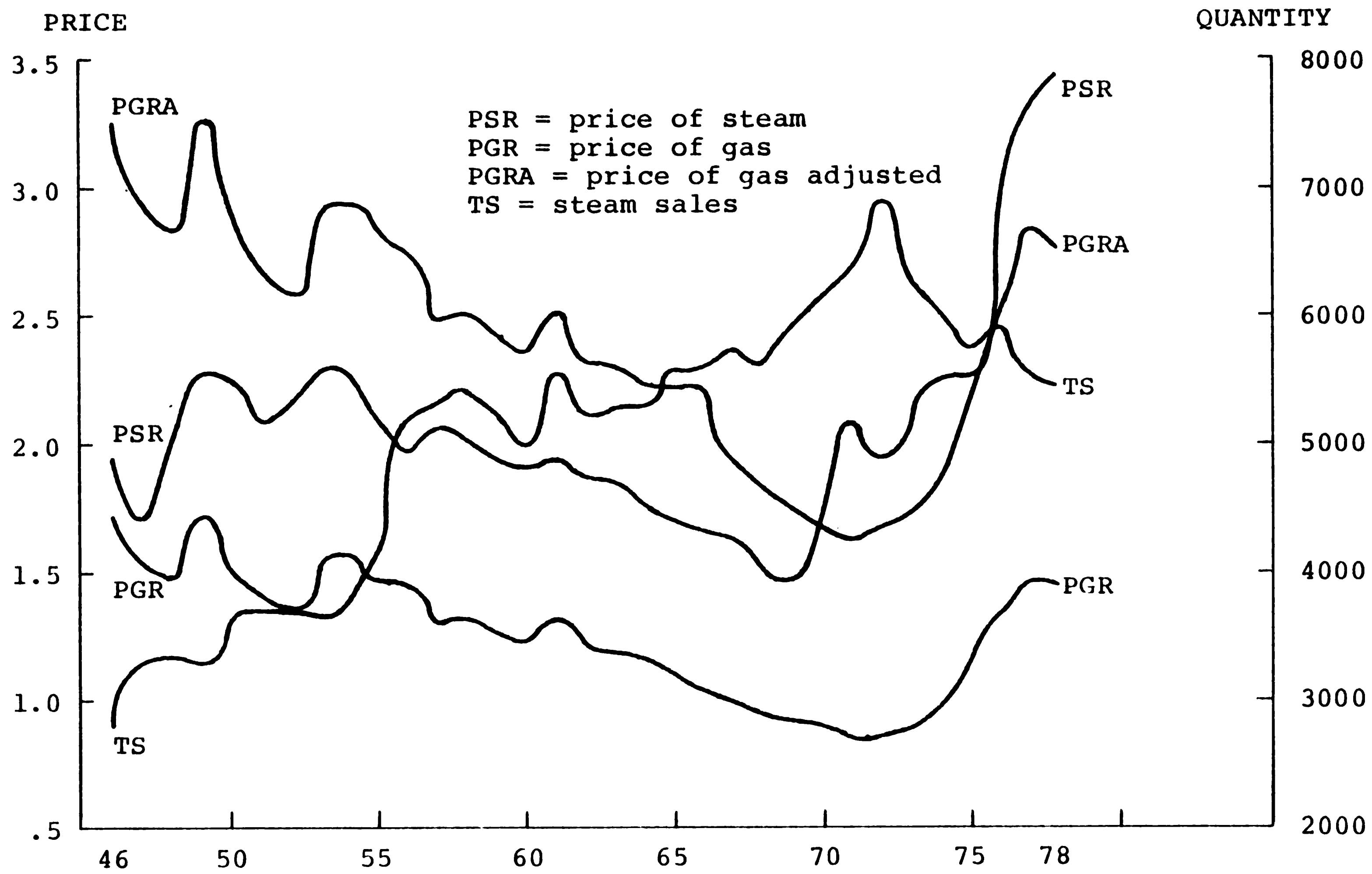

Figure 13

Detroit

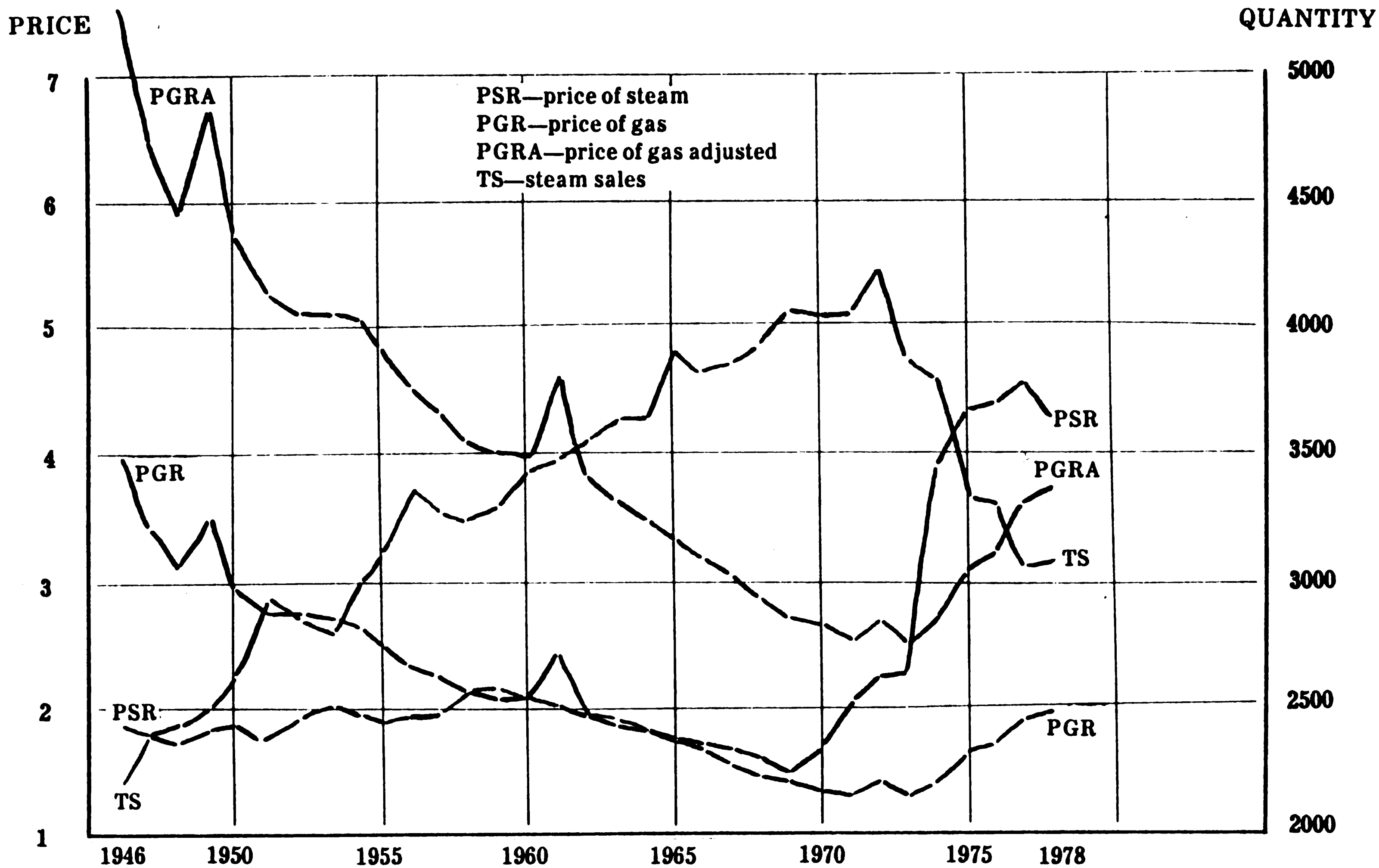

Figure 14

Rochester

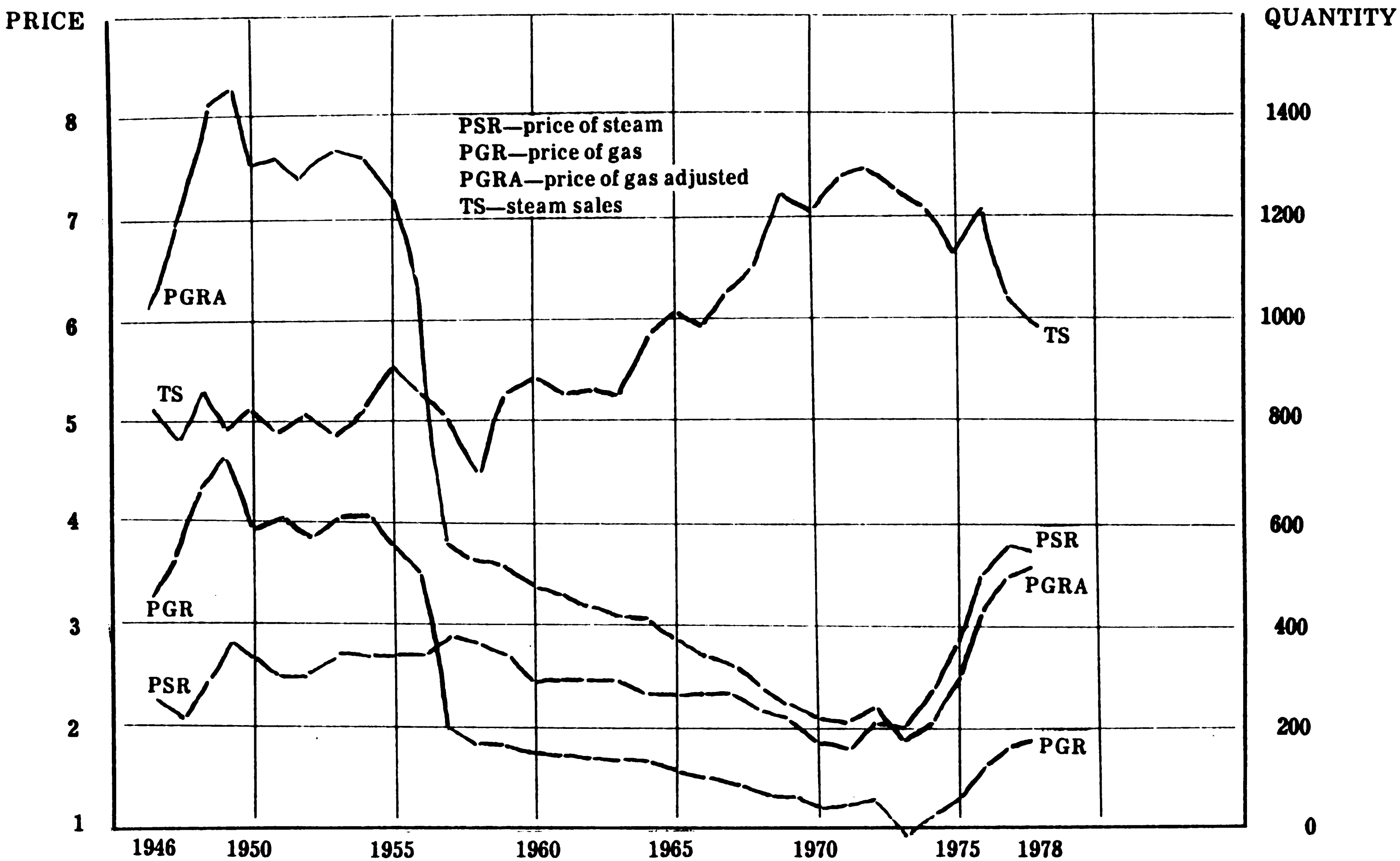

Figure 15

Seattle

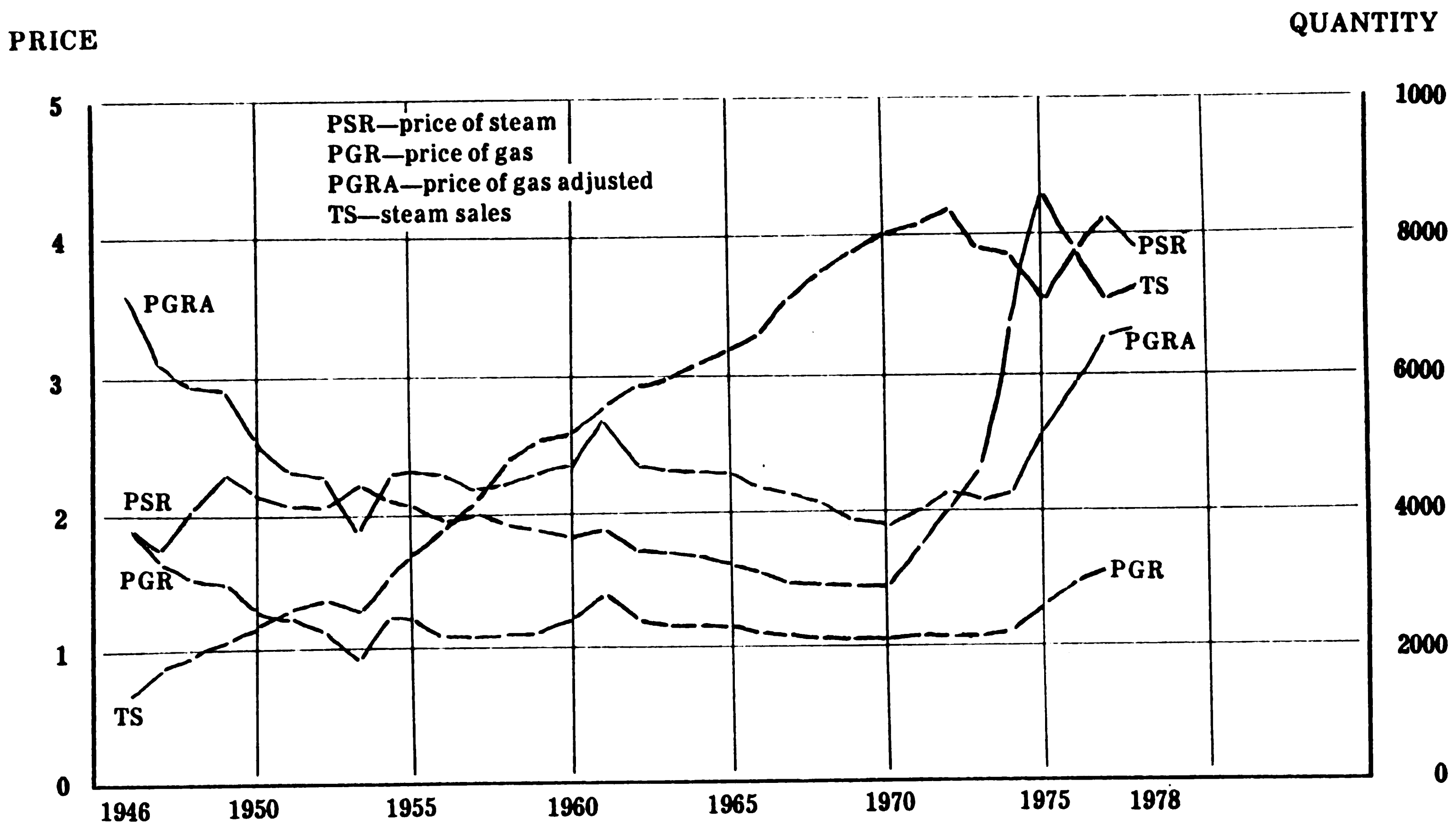

Figure 16

Philadelphia

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CHAPTER II

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The energy in natural gas is usually assumed to be at 1000 BTU/CF. Boiler efficiencies range from 40 to 60 percent. Using the mid-point of this range as a rule of thumb the customer obtains 500,000 BTU/MCF. The ratio of 952,000 BTU/mlb. to 500,000 BTU/MCF determines the factor 1.9. The price of gas is multiplied by 1.9 to obtain the energy-equivalent or adjusted price of gas that appears in Table 26 and Charts 18-23.

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CHAPTER III

DISTRICT HEATING: THE EUROPEAN EXPERIENCE

Introduction

District Heating is a viable and growing industry in Europe. Three reasons are usually given for the industry's success. First, the rebuilding following the destruction in World War II provided utilities with the opportunity to install pipe distribution networks cheaply. Second, high fuel costs have an incentive for consumers to purchase heat through a fuel saving energy supply system. Third, the use of hot water as a distribution fluid instead of steam has led to significantly lower costs for newer systems.

While all these reasons have made a contribution to the industry, it is interesting to note that application of these causal factors will not lead to consistent predictions about the development of district heating. First, if rebuilding is important, why has England lagged behind all other countries, and why, on a per capita basis, are the Scandinavian countries leaders in Europe. Second, European fuel prices prior to 1973 were not significantly different from U.S. prices. The illusion of high prices exists due to the fact that gasoline has always been taxed at a high rate in Europe.[1] Third, Czechoslovakia, the USSR, and Germany (nations with well-developed district heating systems) started the development of district heating systems in the era when steam was the preferred transmission fluid.[2] Further, the technology of hot water distribution was developed in the late twenties and early thirties, yet not one system in the United States attempted to integrate this development into their systems.[3]

The only common characteristic that exists in countries with dynamic district heating industries is local government involvement in heat supply.[4] This factor even exists in Eastern Block countries where the city authority is responsible for heat supply. The Moscow Power System is run by city bureaucrats. It is the world's largest system. The system has 13 combined heat and power stations with a heating capacity of 23,260 MW and district boiler plants with a capacity of 4652 MW.[5]

Sweden

The Development of District Heating

District Heating began in Sweden in 1948 in the city of Karlstad. The original connected load was 2000 Kw and energy supplied in the first year was 2100 MWH. The next two cities to establish systems were Malmo and Norrkoping. Both started operations in 1951. Vasteras, the most publicized system, was started in 1954.[6]

The recent history of the industry is shown in Tables 26 and 27. The summary statistics are defined in the following manner: first, connected load is the sum of the connected load of all customers. The connected load for a customer is the estimated demand during the coldest two consecutive days in 30 years. Second, delivered heat is the amount of heat consumed. It is <u>not</u> the amount of heat delivered to the distribution systems.[7] Third, back-pressure capacity is an ambiguous term. It is not clear whether it is the capacity of plants connected to district heating systems to produce electricity or whether it is the capacity of those plants to produce electricity while the plants are operating in the back pressure mode. The difference in the definitions is due to the fact that some plants can be operated as condensing plants. This latter type of operation would not be economically viable but is available for emergency periods. The final statistic, electricity production, includes all electricity produced at combined heat and power plants, irregardless of the operating mode of the plant.[8]

The total connected load, for the fiscal year ending June 30, 1977, was 11.5 GW and the quantity of heat delivered was 21.8 TWh. Heat supplied by the district heating system represented approximately 20 percent of the space heat and hot water energy use of commercial and residential buildings.[9]

In the fiscal year ending June 30, 1977, back pressure capacity was 1600 MW and electricity produced was 4600 GWH. Total electricity consumed in Sweden was 85,619 GWH in 1977, so that electricity generated by district heating utilities represented about 5% of national electricity consumption.[10]

The growth rate of district heating systems, as measured by increases in the summary statistics, is lower for the mid-seventies than in earlier periods. However, the growth rates for these variables in the mid-seventies, rates of between 5 and 14.4 percent annually, are still quite high in absolute terms. Second, when compared to the growth rate for the Swedish economy, the district heating industry achieved remarkable rates of increase. The Swedish economy, as measured by gross domestic product valued at 1975 prices, shrank from 285.44 billion Kroner in 1974 to 283.5 billion Kroner in 1977. This represents an average annual growth rate of -.2 percent.[11]

Variations across district heating systems are depicted in Figures 17 through 19. Percentage distributions shown are based on data for fifty systems.

Figure 17 shows the variation in utilization time. This variable is defined as the total heat delivered divided by the total connected load. To convert the utilization time into a percentage of capacity utilized, it is necessary to divide the utilization time by 8760 hours/per year. Seventy-four percent of the Swedish systems operate within the span of 1700 to 2300 hour/year utilization time. This is equivalent to operating between 19.4 to 23.9 percent capacity utilization.[12]

This capacity utilization range seems low when compared to the annual systems load factors reported by U.S. district heating utilities. In 1978, the ten largest systems in the United States reported annual system load factors ranging from 26 to 43 percent.[13] However, the U.S. statistic is determined using actual plant sendout data as opposed to customer usage data. It is possible to convert the U.S. data to a form compatible with the Swedish data, if the assumption that system losses are constant in percentage terms as American systems approach capacity is used. Under this case the annual system load factors of the ten largest U.S. systems fall into the range of 17 to 33 percent, with the median system at 25 percent. Thus the American systems appear to have a slightly higher load factor, but that the range of load factors is larger in the U.S. than it is in Sweden. The higher load factor is consistent with the facts that U.S. systems have proportionately more industrial customers and service an off-peak air conditioning load.

Figure 18 shows the variation in the specific length of the distribution systems. This variable measures the length of pipe needed to supply one GWh of heat. The variable is small in areas with high heat loads; and large in areas with low heat loads, i.e., in neighborhoods of single family dwellings or areas where the penetration ratio is low. Approximately 70 percent of the Swedish systems operate within the range 76 to 150 m/GWH/year. For the ten smallest systems in the United States the range runs from 29.1 to 270 m/GWH/year. However this range is stretched out by the extreme case of Ricelake, Minn., the system with the specific length of 270. Eight of the small systems have specific lengths of less than 110 m/GWH/year.[15]

Further the U.S. statistics are biased towards longer specific lengths because the U.S. data include the length of service pipe while the Swedish data include only the length of truck mains.

Figure 19 shows the variation in efficiency of the Swedish system. Efficiency is defined as the sum of all electricity produced at combined heat and power plants plus heat delivered to district heating customers divided by the net caloric value of fuels used at combined heat and power plants plus fuel used at single purpose hot water boilers. Thus transmission losses in the heat delivery system will effect efficiency while transmission losses in the electric grid will not.

The typically Swedish utility runs at between 75 and 85 percent energy efficiency levels.[16] Direct comparisons to U.S. systems are hard to make because data for electricity produced at combined heat and power plants are not available. For those systems that produce only heat (which includes six of the ten largest and seven of the ten smallest) the typically U.S. utility achieves an energy efficiency ratio of between 45 to 55 percent in 1978. The Hartford system, one of the newest systems built in the U.S., achieved an efficiency ratio of 64 percent, which is significantly higher than the U.S. average, but below 95 percent of the Swedish utilities.[17]

The success of the Swedish systems in achieving higher energy efficiencies lies in three factors: 1) the use of hot water instead of steam as a heat transmission fluid. This choice allows for less energy input into the system, and also reduces distribution losses; 2) the use of combined heat and power plants (however only twelve of fifty systems have combined heat and power plants); 3) the lack of an air conditioning load that requires high heat values in the transmission fluid during summer operations.

Data on individual Swedish systems are presented in Tables 28 and 29. The size variation of the systems according to any variable is large. Systems serve cities with populations as small as 3,000 to as large as 724,000. The connected load (excluding systems starting in 1971) varies from 5.4 MW to 875.6 MW. Energy supplied varies from

12,520 MWh to 1,748,980 MWh. Truck line main lengths varies from 1.4 Km to 292 Km.[18]

Twelve systems have combined heat and power plants. The economic viability of combined heat and power plants is a function of a variety of parameters. Systems that exceed the lower bound set for each parameter listed below can successfully support a plant. Suggested lower bounds are:

1. city population of 30,000
2. Heat density of the service area to be at least 200 MJ/M^2 (60 MW/KM^2)
3. a service area of 50,000 M^2
4. energy demand of 555 GWh per year
5. peak demand of 200 MW[19]

Nine cities meet these recommended standards and three do not. While it is not possible to determine from the available data why the three small cities have combined heat and power plants, it would be interesting to find why they decided to build such plants. Determination of the minimum efficient scale of operations is an important but elusive finding.

Impact of District Heating on Sweden

The major components of a benefit-cost analysis of district heating would include as benefits energy saved and air pollution reduced, and as costs the additional capital expenditures made by district heating systems compared to alternative heat delivery systems. Of these three components, the easiest to estimate is energy saved. Two estimates have been made by Swedish experts. The estimations place the savings to be between 32 and 38 percent of the energy that would have been consumed if the district heating systems had not been in place. Difference between the estimates can be explained by the difference in the assumed efficiencies in the alternative heat delivery systems, the increased reliance on trash burning, and the decommissioning of an experimental nuclear reactor.[20]

The impact on air pollution is shown in Figure 20. District heating seems to be responsible for dramatic reductions in the level of air pollution. However, no information is given about other factors that might effect the level of air pollution. If these factors vary significantly then the figures shown would be misleading.

Institutional Setting

The district heating utilities are embedded in a framework of institutional relationships. These relationships can be divided into two areas: first, what entity owns and controls the heat supply facilities, and second, the division of responsibility for electricity supply between the municipalities and the national electric grid.

Each municipality owns and operates heat and electric distribution networks. In fulfilling these responsibilities the municipality can create a variety of organizational structures. Usually a separate corporation, whose stock is wholly owned by the municipality, is established to fulfill each responsibility. In this case the district heating corporation owns and operates the distribution network and the hot water generation facilities. Alternatively, the heating system can be a subsidiary of a prior established electric corporation. A third alternative is that the district heating company owns and operates the distribution system while the heat production facilities are jointly owned with either the city electric corporation or the State Power Board. The fourth alternative is that the district heating company owns and operates the distribution system and purchases heat from others.[21]

The choice between the alternatives listed above seems to have been made by historical accident and local preference. The choice had little importance on the end result, and the decision was made by one actor: the municipality.

On the other hand, the division of responsibility for electricity supply has had important consequences on the development of district heating. In particular, the size, number, and profitability of combined heat and power plants is directly related to the rules and rates established by the State Power Board, the body that owns and controls the national grid. To understand why a particular division of responsibility exists today it is necessary to provide some details of the historical development of the electrical supply industry.

This development can be broken into four stages. First, local governments set up distribution networks and built coal-fired generation facilities. Second, hydropower was developed in northern Sweden. This development occurred after the national government passed two water acts. These acts allowed developers to construct transmission lines across land owned by others and to allow for private expropriation of land along the rivers. The hydropower sites were developed by both private and public entities. Hydropower undersold the coal plants. Eventually, the coal plants were shut down. The municipalities held on to the distribution networks and purchased electricity from the national grid.[22] These purchases led to a fight over control of national grid. This fight ended when the government granted the State Power Board sole ownership and control of the national grid in 1946. That year marked the beginning of the third stage. In this stage, the State Power Board expanded its control over the entire system. Ownership of producing facilities remained split between the State Power Board and private producers.[23] The operations of the system was controlled by the State Power Board. During this stage, it became clear that expansion of electricity demand would soon outrun the supply potential of hydrosites.

Two alternatives to hydropower developed. First, nuclear power was initiated by the large producers in combined projects with the State Power Board. Second, the cities led by Vasteras started building combined heat and power stations. The cities formed a distributors cartel. Its objectives were to use the national grid as means to obtain stand-by power, reduce peaking problems, or to wheel power between the cities. The implication of municipals' program for the private producers was a dramatic change in function. The private producers would become providers of stand-by and peak power.[24]

The choice between these alternatives was made by the State Power Board. In 1963, it initiated a series of tariff reforms that destroyed the distributor's cartel. The policy brought the Swedish electric system into its fourth stage. This stage is characterized by one, base load electricity is generated at hydro- and nuclear facilities. These facilities are owned either separately or jointly by private producers and the State Power Board. Two, municipalities provide a significant amount of peaking power in relatively small combined heat and power facilities. Three, the State Power Board has hegemony over the entire system through its control of the national grid.[25]

Rates

While the cost of district heating varies from city to city, maximum price is agreed upon by the utilities. The maximum price is set through the District Heating Association. The price of oil heat is used as a reference point. The maximum price of district heating is always kept immediately below the price of oil heat.[26]

The general pattern used in pricing district heating is to divide the costs into three parts: a connection charge, an annual fixed charge, and an energy charge.

The connection charge is dedicated to cover the cost of hooking up the building to the pipeline network. In practice, this charge is set on the basis of the size of the dwelling or of the heat demanded when the outdoor temperature reaches a certain negative temperature. Thus implicitly, the connection charge includes a charge for the sizing of the entire distribution network and not just the marginal cost of connecting the additional customer.

Some utilities used a system of rebates of the connection charge as an incentive to hook up with the system. For instance, the connection charge is forgiven if the owner agrees to hook up to the system while the main is being installed. Alternatively, when a house is sold the new owner is given a 75% rebate if the new owner joins the system immediately after the purchase of the property.[27]

The annual charge is based on the peak load of the customer. Block rates and customer classifications are used in devising the annual charge. It was not possible to ascertain if declining block rates prevailed over increasing block rates. The declining block rates would reflect the generally recognized economies of scale in pipeline distribution; while the increasing block rates could reflect an historic pattern of inflation in construction cost, or the additional cost of maintaining peak equipment.

The energy charge is dependent on the type of meter installed. If the meter records both water flow and temperature drop, then the energy charge is based on therms used. If the meter records only water flow, then the energy is based on the water flow. In the second case, the customer can reduce the variable costs of home heating by installing a better heat exchanger.

Finances

A typical district heating corporation might have the following financial structure.

Loans from subscribers	35%
Self-financing	15
External loans	50
	100%

Loans from subscribers are obtained when a residential customer connects to a system. At that time, the residential customer obtains a loan from the State via the National

Housing Board. The residential customer then reloans 75% of the housing loan to the utility. The loans have a 30-year term. In 1977, the interest rate on these loans was 8.75%.[28]

Self-financing refers to the use of retained earnings. This method is more often used when the heating company is a subsidiary of the electric utility. Profits of the electric utility are used to build the district heating company, the latter generally does not generate profits in the first five to ten years of operations.

Outside funding can be provided by loans from town councils, or bonds sold on national or international markets. Combined heat and power facilities built jointly with the State Power Board are usually financed by the State Power Board which has superior access to bond markets.[29]

Energy Planning

The Swedish government has implemented two energy plans since the first oil crisis in 1973/74. The goal of these plans is to separate the growth of the economy from the growth in energy demand. Specifically, the government wishes to hold the energy growth in demand to 2% annually in the 1980s and to move to a zero-growth rate in the 1990s.[30]

The major points of the program are:

-conservation of energy

-minimize the pollution and security problems associated with energy conversion

-increase the security of supply by reducing the dependence on oil

-international cooperation in the energy field

-pursue an energy policy which will provide for freedom of action in the future[31]

These plans as applied to the district heating industry include the following points:

1. Community owned enterprises can demand compulsory hook up within specified areas. The enterprise must pay the customer a fair market price for heating equipment made obsolete by this action.

2. The plans require all communities to consider energy activities in their planning activities.

3. The government will increase the funding for loan associations that finance district heating schemes.

4. The National Board of Industry is authorized to use its funds for grants to support connection of new customers to district heating systems. An individual grant may cover up to 35% of the internal costs of connection.[32]

Denmark

Development

The district heating in Denmark can be divided into two groups, small systems supplied by heat only with hot water boilers, and large systems supplied by combined heat and power plants.

As of 1978, there were 400 small systems in operation. This number represented a growth of approximately 150 systems since 1962. The primary fuel used to fire the hot water boilers was oil. Refuse represented approximately 2% of the fuel input into these systems.[33]

A sample survey of Danish systems is shown in Table 30. The survey was taken in 1962. It included 55 small systems and three large ones (Esberg, Randers, and Aalborg).[34]

Two significant points can be made by analyzing the table. First, there has been a steady expansion of the industry in the post World War II period. Second, by world standards, the Danish systems are tiny. Almost two-thirds of the systems have a capacity of 11.6 MW or less. Approximately 75 percent of the capacity of the district heating schemes is in systems that have a capacity of 23.2 MWs or less.

Six sites have been served by power plants for many years. Three additional sites have recently hooked up district heating systems to power plants. A tenth city, Hernig, is in the process of hooking up to a power plant.[35]

Following the completion of the Hernig project, eleven of eighteen major electrical facilities will be operated as combined heat and power plants. As of 1978, the thermal efficiencies of the eighteen plants was 45.5%. Heat sales increased the thermal efficiency of the electric supply industry by ten percentage points.[36]

The electric supply industry is in the process of transforming oil burning units into coal burners. As of 1978, 52 percent of the fuel used to generate electricity was coal. This percentage is expected to rise to 80 percent by the mid-eighties. By supplying heat from these electric plants, Denmark will be able to meet a significant portion of its domestic heating demand by burning coal instead of oil.[37]

At present, combined heat and power stations supply ten percent of the Danish heat load. Another 20 percent of the heat load is supplied by the small systems. These exist a capacity equivalent of 2000 MW thermal per capita. This per capita capacity is the highest capacity figure in Western Europe.[38]

Rates

The rates are set by the town councils. The councils' rate making activities are supervised by the national Gas and Heat Price Committee. This committee sets guidelines for the town councils. Each town council must submit its prices to the committee. However, the committee has the power to order town councils to change their rates.[39]

The Gas and Heat Price Committee is appointed by the Minister of Commerce. It has a chairman and 13 other members. The chair and seven members of the Committee are to be independent of the supply industry and the municipal governments. They should represent consumer interests and provide expert opinion. The remaining six members of the committee represent organizations with a vested interest in heat supply.[40] One person is selected to represent each of the following groups:

-Danish Association of Electric Supply Undertakings

-Association of Danish District Heating Undertakings

-Dansk Olie and Naturgas A/S

-Natural gas distribution companies

-National Association of Local Governments

-Municipalities of Copenhagen and Frederiksburg[41]

In general, the district heating utilities are suppose to be run on a non-profit basis yet at the same time be self-sustaining. Rates should cover legitimate costs. These costs include: expenditures on fuel, wages and other running costs, administration and marketing, payment of interest on foreign debt, other interest payments, depreciation, and payments to reserves for new investment. Only the last item would be considered profits. Notice that excluded from costs are payments to town councils over and above interest on debt. Thus, the utilities cannot be used as a second-hand tax gathering institution.[42]

The rates have not been set in terms of the oil equivalent prices. To do so would generate large profits for most systems. For 1979, in Odense, the average single family dwelling paid an annual heat charge of $341 US. For equivalent heat provided by an individual oil boiler, the customer's annual cost would have been $1188 US.[43]

Each customer must pay a connection charge at the time he joins the system. The connection charge is based on the volume of the dwelling and the length of pipe needed to connect the house to the system. This charge can be financed over a 15 year period via a loan secured from the utility.[44]

The annual charge is based on a three-part rate scheme. These parts are a meter charge, a fixed charge, and a water charge. For dwellings, the fixed charge is based on the volume of space heated. For industries, the maximum demand for any one-half hour period is used to determine the fixed rate.[45]

The water charge is based on the amount of water that passes through the customer's heat exchanger. For most dwellings, temperature drop is not recorded. Thus, there is no exact measure of energy use per dwelling. To obtain the energy measure would entail a large increase in metering costs. It was decided that the additional cost is not worth the benefits that could be obtained from instituting more precise rates.[46]

Institutional Setting

District heating utilities are a branch of the local governments similar in organization to the typical water and sewage system in the United States.

Relationships between the heating utilities and the electric utilities follow a formal pattern. The electric utilities (these utilities are usually co-ops owned by several cities) charge the heat utilities for heat on the basis of KWH of electricity not generated due to the plant being operated in either the extracting or back-pressure mode.

For example, a given plant that produces 1000 MWHe in the condensing mode switches to the extracting mode where it produces 800 MWHe and 800 MWHt. Further, the price of electricity at the plant is $10 US per MWHe. Then the heat utility would pay the electric utility $2000 US for the 800 MWHt or $2.5 US per MWHt.[47]

Finances

The district heating systems are financed through the town councils. As of 1978, 11,000 mill kr had been invested in districting heating schemes. Investments in distribution networks are increasing by approximately 500 mill kr per year.[48]

Combined heat and power plants are built by the electric co-ops. These co-ops rely on the towns for financial aid. Also, these projects receive grants from the national government.

Energy Planning

In the Act on Measures and Energy Policy, April 1976, the Minister of Commerce was directed to prepare reports on energy policy. To comply with the act, the Minister of Commerce produced a report called the "Danish Energy Policy 1976," The report contained three broad-range goals:

-to reduce our vulnerability to energy supplies and in particular our dependence on oil supplies as quickly as possible

-to establish a versatile energy supply, under which energy efforts can be made to utilize indigenous sources of energy

-to cut the growth in energy consumption.[49]

As performance criterion to measure the effectiveness of energy policies, the plan set out the following two specific goals: first, to reduce annual oil consumption by 22 percent by 1985 from its 1975 level; and second, to reduce the oil share of total energy consumption from 87 percent in 1975 to 48 percent by 1995.[50]

To further specify the energy plan, the Minister of Commerce set up a Heat Plan Committee on April 1, 1977. The objective of the committee was to devise a plan that would reduce Denmark's dependence on oil for home heating.[51]

The first report of the committee appeared in October 1977. The report stressed the need to develop pipeline heat as a substitute for oil. Pipeline heat would appear in the form of hot water from combined heat and power plants and natural gas from North Sea wells. It was envisioned that power plant heat would supply between 35 and 40 percent of the heat requirement, and natural gas would supply 20 to 25 percent of the heat required by 1995. Compared to the 1977 situation, where eight percent of the heat requirement was met by power plant heat and natural gas was almost non-existent, this plan would require a high investment in distribution networks. To implement this development strategy, the Heat Plan Committee made a series of subsidiary recommendations. Many of these recommendations were incorporated in the 1979 Act on Heat Supply.[52]

The 1979 Act on Heat Supply mandates that there be a comprehensive heat plan for the entire nation. The plan will be developed by the local and county governments under the supervision of the Ministry of Commerce.[53]

Each local authority is directed to develop a heat map. The map should include existing heat requirements, the present method of meeting those requirements, and the amounts of waste or surplus heat available in the area.[54]

Each local authority must establish a heat plan. The plan should specify the preferred heat supply method in each area of the locality. Plants needed to supply heat must be sited within the area and tentative pipeline networks must be outlined. A timetable for building the distribution network is also part of each plan.[55]

Local authorities are authorized to force compliance with the plan on building owners. That is, there can be mandatory connections to a distribution network. All new buildings must be built with heating systems that are compatible with the designated heat supply network for the area. If the construction of a new building is completed prior to the extension of the distribution network to the building site, then the municipality is responsible for any temporary increase in heating costs that occur.[56]

Existing buildings can also be forced to join a particular heat system. The municipality can either provide a timeframe to the building's owner designating when the building must be connected, or it can demand immediate connection. If a timeframe is specified, it should be related to the remaining useful life of the existing heating equipment within the building. If the municipality demands immediate connection, it can subsidize the building's owners heat system transformation and connection costs.[57]

Finally, the municipality has the right to expropriate property for the purpose of building distribution networks. Compensation for expropriated property shall be determined in accordance with rules established for this activity in the Act on Public Roads.[58]

United Kingdom

Development

In the United Kingdom, less than one percent of the space heating load is supplied by district heating schemes. There are 1701 heating schemes, composed of two combined heat and power schemes, 1522 heat only schemes and 177 industrial cogeneration schemes. Most of the housing schemes are small. The typical project serves 100-200 dwellings with a heat load of less than .3 MW.[59]

The two combined heat and power schemes are owned and operated by the electric board. One scheme, at Aldershot, serves a military base. The other scheme, at Pimlico, serves two housing estates.[60] The Pimlico scheme started operations in 1951. It has not been a financial success. Its problems are two-fold. First, long-term heat contracts were signed with major customers that did not include escalator clauses. As fuel prices rose, the project began to lose money. Second, the capacity of the boilers were large compared to the distribution system. Thus, there was always excess boiler capacity. No explanation was ever given for the mismatch. No attempts were made to extend the distribution system to connect to the Whitehall heat only scheme.[61]

Recently, the South of Scotland Electric Board (SSEB) retired a plant in Glasglow. At the time, the SSEB conducted a feasibility study to ascertain if the plant could be converted to a combined heat and power station. The conclusion of the study was the conversion would not be feasible.[62]

This conclusion was the catalyst for a debate between proponents of district heating and the SSEB. The proponents of district heating pointed out six places in the study where the professional judgments made were detrimental to district heating.

These points were that the study:

1. ignored alternative technologies such as gas turbines (successfully established in Searbucken, Germany)

2. used steam turbines that were oversized for the heat load

3. credited the entire electric output of the plant at the bulk electric rate even though the plant will operate at peak and off-peak hours

4. assumed turbine efficiencies significantly lower than those achieved by similar turbines presently operating in Sweden

5. used a price for heat sales of 29.3 p/therm while heat presently sells for 33.5 p/therm

6. did not credit the district heating scheme for its ability to use cheaper fuels.

Energy feasibility studies must start from a set of assumptions. The question of why the SSEB chose to make its decision on the basis of this particular set of assumptions cannot be answered here. Not enough information is known about the decision making process of the SSEB.[63]

Finance

It is generally presumed that all future district heating schemes will be financed through a government agency. At present, nationalized industries are required to show an estimated real rate of return of five percent on future investment projects in order to obtain Treasury financing. This rate is a change from the recent past when a ten percent nominal rate had been used. One would expect that future district heating projects that meet this criterion will be able to obtain Treasury financing.[64]

Rates

The Midlands Electric Board recently built a combined heat and power project in Hereford. It chose to price heat at a level ten percent below the industrialists' own costs. This rate was chosen because of the belief that the industrialists must receive some compensation for the loss of freedom due to the fact that they will no longer be operating their own plants before the industrialists will switch to a joint system.[65]

Institutional Setting

At present, the electricity boards have the responsibility to promote district heating from combined heat and power plants. The Electricity Act of 1947 authorized the boards to sell heat that is produced jointly with electricity.[66]

The Electricity Act of 1957 gave the industry its present structure. There exists the central electricity generating board (CEGB), 12 Area boards, and the Electricity Council. The CEGB generates the electricity; maintains the transmission grid and determines bulk power rates. The area boards purchase electricity from the CEGB, resale electricity to final customers, and build and maintain the distribution. The Electricity Council is an advisory and a research group. The Secretary of State has the responsibility of supervising the electric supply industry.[67]

The Electricity Act of 1957 also allows area boards to generate electricity. The first board to do so for the purpose of combined heat and power was the Midlands Board; construction started on this project in 1978. This project will supply process steam to food processors. The planners of this project were not interested in providing residential space heating.[68]

Local authorities that have attempted to build combined heat and power systems have their projects develop financial difficulties due to the policies of the electric supply industry and the National Gas Corporation. First, the electric supply industry by exerting its monopsony buying power purchases electricity from these schemes at prices below its alternative costs.[69] Second, if the combined heat and power station is a gas turbine, then the Gas Corporation will charge that station a higher than normal interruptible rate. This Corporation is able to charge the higher rate because for the turbine the only substitute fuel is gas oil, and gas oil is a relatively high priced fuel.[70]

The Gas Corporation follows this policy for two reasons. First, price discrimination will increase its profits. Second, if it destroys existing projects or discourages new projects with the high rate, then it maintains its grip on the residential heat market.[71]

Energy Planning

At the end of 1974, the Secretary of State set up the Combined Heat and Power Group. The Group's task was "to consider the economic sale of combined heat and power in the United Kingdom and to identify technological, institutional, planning, legal or other obstacles to the fulfillment of the role and to make recommendations."[72]

In 1979, the study group published its final report: Energy Paper No. 35, Combined Heat and Electrical Power Generation in the United Kingdom.

The study group used the following methodology to analyze the feasibility of district heating in the UK.[73]

1. It divided the future into three time periods:

    a. The short-term. This period is characterized by relatively cheap and abundant natural gas and oil.

    b. The medium-term. This period is characterized by the growing scarcity of gas and oil. Specific dates for this period are approximately from the mid eighties through the year 2000.

    c. The long-term. In this period, the only two dependable fuel sources will be coal and uranium.

2. Head demand was estimated for a typical small city and a typical large city. Demand characteristics such as density and peak were included in the estimates.

3. Cost comparisons were made for the two typical cities for the three time periods across a variety of heat supply systems.

4. Cost comparisons were subjected to sensitivity analysis. The three variables that were allowed to change during the analysis were:

    a. the fuel price

    b. the interest rate

    c. the heat load density.

A summary of the study group's conclusion would include the following positions. First, in the short-term, natural gas is the preferred fuel to be used for space heating. Second, in the medium-term, combined heat and power stations would be the preferred method of supplying heat to the dense areas of large cities. Third, in the long-term, combined heat and power stations should carry a significant portion (approximately 30 percent) of the UK space heating load. Fourth, if district heating through combined heat and power station is to be an integral part of the future energy supply system, then it is necessary to start building the schemes today. This process should take place in designated lead-cities even if it is necessary to subsidize the schemes in the short-term. Fifth, a National Heat Board should be established. Its tasks would be to identify lead-cities, set up local boards, carry out detailed studies of other cities and work with the government to coordinate a national energy policy. The task of the local heat boards will be to build, own, and operate the district heating schemes.[74]

West Germany

District heating systems have existed in Germany since the turn of the century. Prior to WW II, there were at least 35 systems in operation. By 1975, 112 utility companies were operating, 104 combined heat and power plants, and 363 heat only boilers. The total connected load was 24,000 MW. By 1978, total heat sales were greater than 60 TWH.[75]

Hamburg has the largest system with a connected load of over 3000 MW. It is interesting that Hamburg is one of the few cities in the world with competing district heating companies.[76]

Comparative size data for the United States shows that the largest three systems, New York, Philadelphia, and Detroit have capacities of 4390, 1130, and 858 MW respectively. The largest system in the UK, Nottingham, has a capacity of 85 MW, and the largest system in France, Paris, has a capacity of 1821 MW.

District heating systems received financial aid from Federal and local governments. For the years 1977 through 1980, these governments have allocated 680 million marks as investment incentives for the systems.[77]

The German governments (federal and state) have influenced the development of district heating in two other areas. First, the governments tie subsidies to the use of German coal as the primary fuel. One company claims to use local coal to cover 90% of its fuel use in district heating plants. Second, in the Ruhr valley, the Federal Governments and the State Government of North Rhine-Westphalia subsidized the building and a heat grid. The purpose of the grid is to connect small service areas with each other, and to large combined heat and power stations. The first phase of the heat grid was completed in 1978. Ten service areas in Essen, Bottrop and Gelsenkirchen were interconnected. A single chp plant now provides 75% of the energy needs of the service areas. The local plants meet the peak demand and provide reserve capacity.[77]

France

The capacity of French district heating systems is 10,000 MW. For 1978, total sales were approximately 12 TWH. The Paris system is supplied by three trash incenerators, and a back pressure turbine. The trash burners supply approximately one-third of the steam sold.[78]

One other system produces heat with a combined heat and power plant. It is in Metz. The system was built in 1957. The Metz is operated by a regies, the local electric board. It is one of a small number of local electric boards still in existence. Most of the other boards were either dissolved or are non-functioning. It is interesting to note that the only combined heat and power plant built since the nationalization of the electricity system (the Paris plants pre-date the nationalization) is connected to an institution which is under local control.[79]

Table 26

Development of the Swedish District Heating Industry

	1965/66	1973/74	1976/77
Connected Load (MW)	2280	8630	11500
Delivered heat (GWH)	5050	15512	21800
Installed back-pressure capacity	381	1380	1600
Production of Back-pressure electricity (GWH)	842	3066	4600

Source: United Nations, Economic Commission for Europe, _Energy Saving with Combined Production of Electric Power and Heat - A Question of Proper Use of Heat_ (Seminar on Combined Production of Electric Power and Heat), p. 6; Carl-Erik Lind, "District Heating in Sweden, 1972-77, _Energy Policy_, March 1979, p. 74.

Table 27

Average Annual Percentage Growth Rates for the Summary Statistics of the Swedish District Heating Industry

	1965/66 to 1976/77	1965/66 to 1973/74	1973/74 to 1976/77
Connected Load	15.8	18.1	10.0
Delivered Heat	14.2	15.1	12.0
Installed back-pressure capacity	13.9	17.5	5.0
Production of back-pressure electricity	16.7	17.5	14.4

Source: United Nations, Economic Commission for Europe, _Energy Saving with Combined Production of Electric Power and Heat - A Question of Proper Use of Heat_ (Seminar on Combined Production of Electric Power and Heat), p. 6; Carl-Erik Lind, "District Heating in Sweden, 1972-77, _Energy Policy_, March 1979, p. 74.

Table 28

Statistical Data on Some Member Towns of the Swedish District Heating Association for the Operating Year 1971-72

Place	Inhabitants in Urban Area	Start-up	Connected load MW	Energy Supplied MWh	Back Pressure Power MW	Trunk Mains Length km	Fuel
Borlange	20 000	1969	32.4	46 820	-	6.2	Eo 3
Boras	73 483	1959	191.3	431 072	26	45	Eo 5, Refuse
Enkoping	20 300	1969	24.0	40 309	-	3.5	Eo 4 LS
Gothenburg	175 000	1953	836.5	1 748 980	52	101	Eo 4 LS Refuse
Helsingborg	35 000	1964	190	418 428	-	70	Eo 1
Karlstad	11 700	1948	34.8	62 038	15.5	5	Eo 4
Koping	8 000	1969	26.6	55 151	-	6.3	Eo 4
Lidingo	35 500	1971	1	2 000	-		Eo 1
Linkoping	77 000	1954	394.2	774 930	82.5	100	Eo 5, Refuse
Lulea	60 000	1971	7.8	9 530	- 1)	2.5	Eo 3
Malmo	263 829	1951	875.6	1 681 376	170	96.6	Eo 5
Nora	8 945	1965	5.4	12 520	-	1.4	Eo 4
Norrkoping	74 000	1951	345.4	733 100	26 2)	88	Eo 5

1) 100 MW prel. planning   2) 1972/73: 233 MW   LS = Low Sulphur

Table 28 Continued:

Place	Inhabitants in Urban Area	Start-up	Connected load MW	Energy Supplied MWh	Back Pressure Power MW	Trunk Mains Length km	Fuel
Sandviken	27 499	1970	11.3	12 660	-	3.8	Eo 4
Skovde	30 078	1970	12.6	12 816	-	1.7	Eo 3
Sollentuna	8 000	1969	35.6	55 460	-	2.7	Eo 4 LS
Solna	33 500	1963	154.8	313 955	-	17.9	Eo 4 LS Refuse
Stockholm	723 688	1953	319.2	679 521	80 3)	35	Eo 4 LS
		1959	376	674 764	-	67	Eo 1
		1957	134.1	299 500	10	22	Nuclear
Sundbyberg	17 100	1953	115.1	211 745	6	16.4	Eo 4 LS Refuse
Soderhamn	3 100	1970	11	21 240	-	3.4	Eo 1
Sodertalje	76 881	1970	18.5	22 726	- 4)	4	Eo 1
Tranas	19 016	1968	7.7	14 267	-	3	Eo 3
Umea	12 000	1966	50	95 977	-	7	Eo 4, Refuse
Uppsala	80 000	1961	477	1 066 111	- 5)	114.5	Eo 4, Refuse
Vasteras	110 000	1954	715	1 665 400	316 6)	292	Eo 5
Vaxjo	39 000	1970	27.9	42 991	-	6.2	Eo 1
Orebro	92 795	1956	441.4	879 471	45 7)	69.8	Eo 5

Table 28 Continued:

3)	207 MW on order	4)	2 x 106 MW planned	5)	1972/3: 207 MW
6)	+ 207 MW commissioning	7)	+ 106 MW under manufacture		

Source: Neil Muir, "District Heating in Sweden," pp. 55-56.

Table 29

Existing Combined Power and Heating Plants 1975-07-01

	1974/75 el			1974/75 heat		
	MW	CWh	hrs/year	MW	CWh	hrs/year
Borda	26.0	109.4	4 210	227.6	464.3	2 040
Goteborg	52.0	36.2	700	1 098.3	1 906.5	1 740
Karlstad	6.5	13.8	2 120	52.3	82.1	1 570
Linkoping	83.0	269.0	3 240	463.8	772.8	1 670
Malmo	170.0	587.1	3 450	1 037.8	1 770.1	1 710
Worrkoping	228.0	362.1	1 590	436.2	829.2	1 820
Stockholm	95.0	226.3	2 380	1 180.0	1 945.6	1 650
Sundbyberg	10.0	54.6	5 460	149.9	241.2	1 610
Uppsala	200.0	505.8	2 530	696.7	1 224.1	1 760
Vasteras	550.0	870.5	1 580	832.0	1 656.8	1 990
Vaxjo	28.4	13.5	480	93.7	164.1	1 750
Orabro	155.0	369.6	2 380	513.0	862.1	1 680
Total	1 603.9	3 418.1	2 130	6 801.3	11 918.9	1 730

Source: United Nations, Energy Savings with Combined Production of Electric Power and Heat - A Question of Proper Use of Heat, p. 6.

Table 30

Survey of Danish Heating Supply Systems

Country	Town	Capacity therms/h	Length of mains miles	Capital cost (1963) £ sterling	Date of inst'l'n year
Denmark	Brunderslev	590	8.1	204,000	1921
"	Esbjerg	7,280	49.4	1,017,000	1927
"	Varde	160	2.1	34,000	1927
"	Randers	5,600	28.1	933,000	1931
"	Slagelse	680	6.0	236,000	1936
"	Herning	2,670	64.0	1,163,000	1950
"	Grindsted	180	1.6	45,000	1950
"	Kildong	1,740	17.5	608,000	1951
"	Rodding	280	3.2	54,000	1951
"	Silkeborg	1,780	14.7	550,000	1953
"	Sunby-Hvorup	620	n.k.	200,000	1953
"	Kristrup	260	"	157,000	1953
"	Svendborg	290	3.35	192,000	1953
"	Vordingborg	n.k.	0.3	14,000	1953
"	Jiborg	1,600	14.7	551,000	1954
"	Aalborg	8,000	50.5	898,000	1954
"	Frederica	760	8.7	158,000	1955
"	Aarhus	400	6.95	119,000	1955
"	Graasten	360	4.66	128,000	1955
"	Ranum	120	2.2	36,000	1955
"	Hovbjerg	880	12.1	390,000	1956
"	Faaborg	420	7.15	210,000	1956
"	Logstor	380	6.2	116,000	1956
"	Brande	240	3.4	72,000	1956
"	Vording Borg.	28	0.2	12,000	1956
"	Odder	600	14.7	219,000	1957
"	Kjellerup	360	5.6	131,000	1957
"	Hammel	260	4.0	96,000	1957
"	Norresundby	800	6.2	341,000	1958
"	Aalestrup	220	4.35	94,000	1958
"	Struer	450	6.6	178,000	1959
"	Bjerringbro	420	8.4	202,000	1959
"	Hammerlom	260	7.1	117,000	1959
"	Uraa	272	6.8	94,000	1959
"	Lokken	200	5.5	68,000	1959
"	Vodskov	180	10.1	99,000	1959
"	Vamdrup	140	1.9	65,000	1959

Table 30 Continued:

Country	Town	Capacity therms/h	Length of mains miles	Capital cost (1963) £ sterling	Date of inst'l'n year
Denmark	Naesby	680	10.6	350,000	1960
"	Hadsten	260	4.85	115,000	1960
"	Assens	510	7.1	159,000	1960
"	Dronnlaglund	200	4.7	100,000	1960
"	Padborg	120	4.5	111,000	1960
"	Ejby	136	3.5	60,000	1960
"	Jelling	168	3.85	59,000	1960
"	Sondenagreda	n.k.	1.0	41,000	1960
"	Nykohingf	n.k.	1.83	101,000	1960
"	Dalum	960	20.2	680,000	1961
"	Hjorring	580	12.1	305,000	1961
"	Vejen	260	5.85	157,000	1961
"	Frederikshavn	416	4.85	169,000	1961
"	Hedensted	240	5.0	101,000	1961
"	Sore	168	2.2	85,000	1961
"	Glamsbjerg	96	n.k.	81,000	1961
"	Vejlby-Risskon	280	6.9	61,000	1961
"	Nibe	220	5.7	121,000	1962
"	Hillerod	368	3.35	140,000	1962
"	Gentofte	100	0.95	31,000	n.k.
"	Rabk Mowe	48	0.56	10,000	n.k.

Source: Heating and Ventilating Research Association, <u>District Heating: A Survey of Current Practice in Europe and America</u>, p. 95.

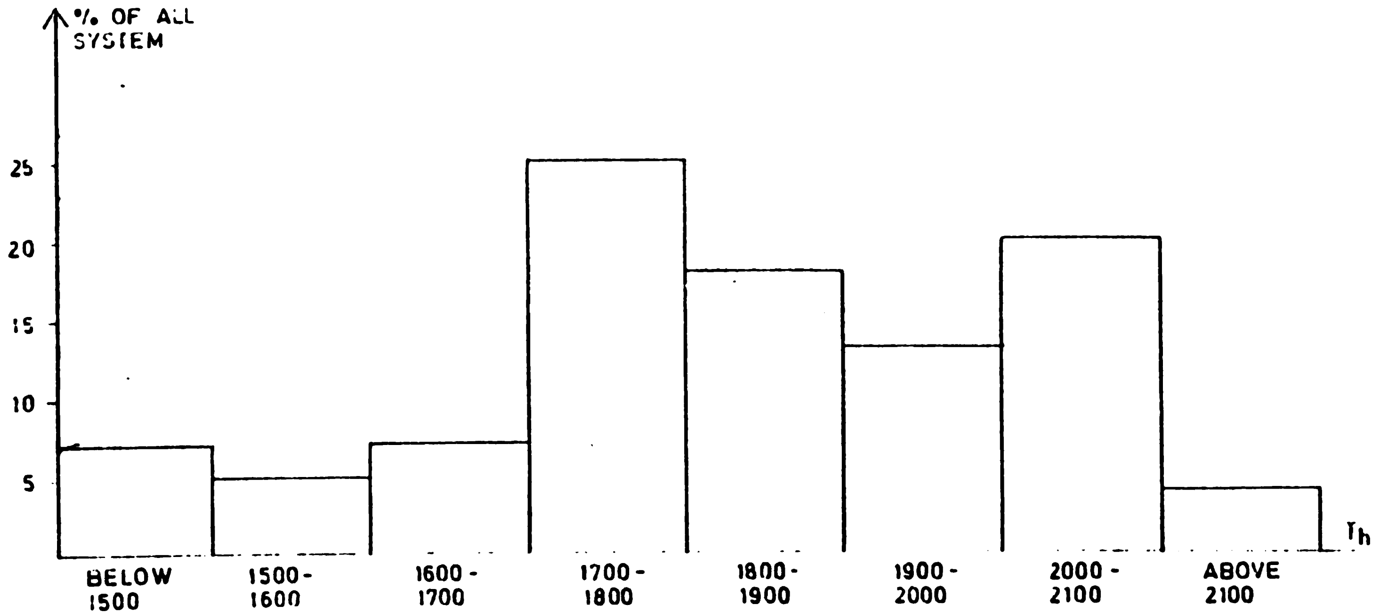

Figure 17

Utilization Time T_v 80
in Hours/Year

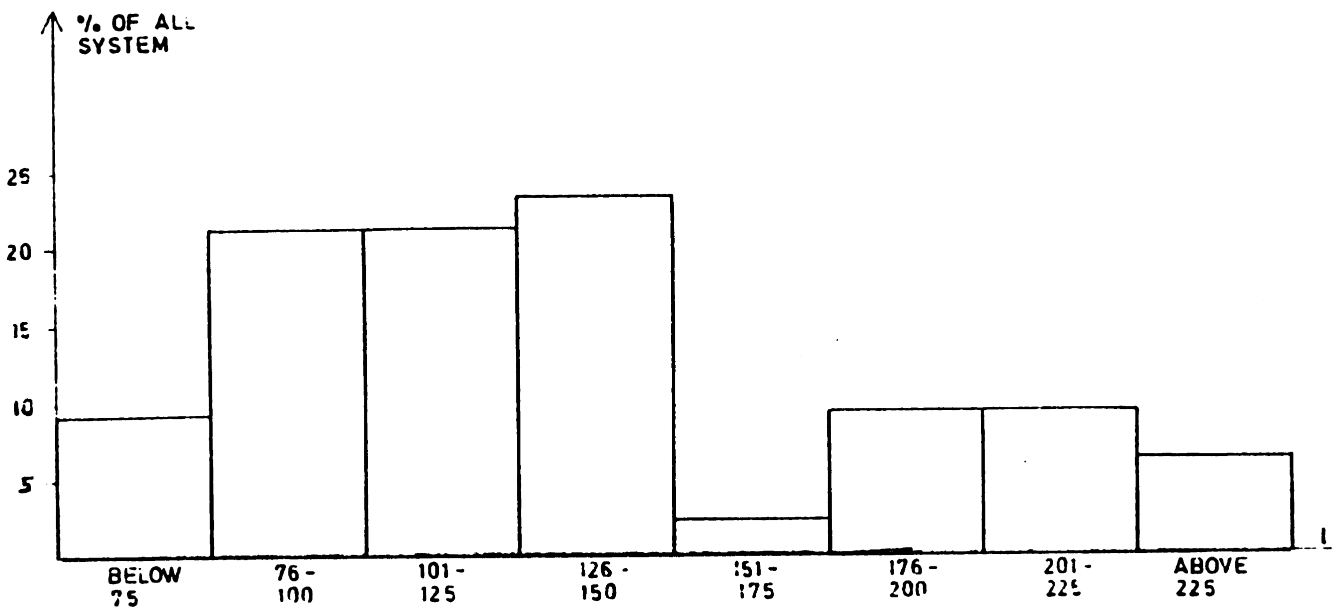

Figure 18

Specific Length 1[81]

M/GWh/year

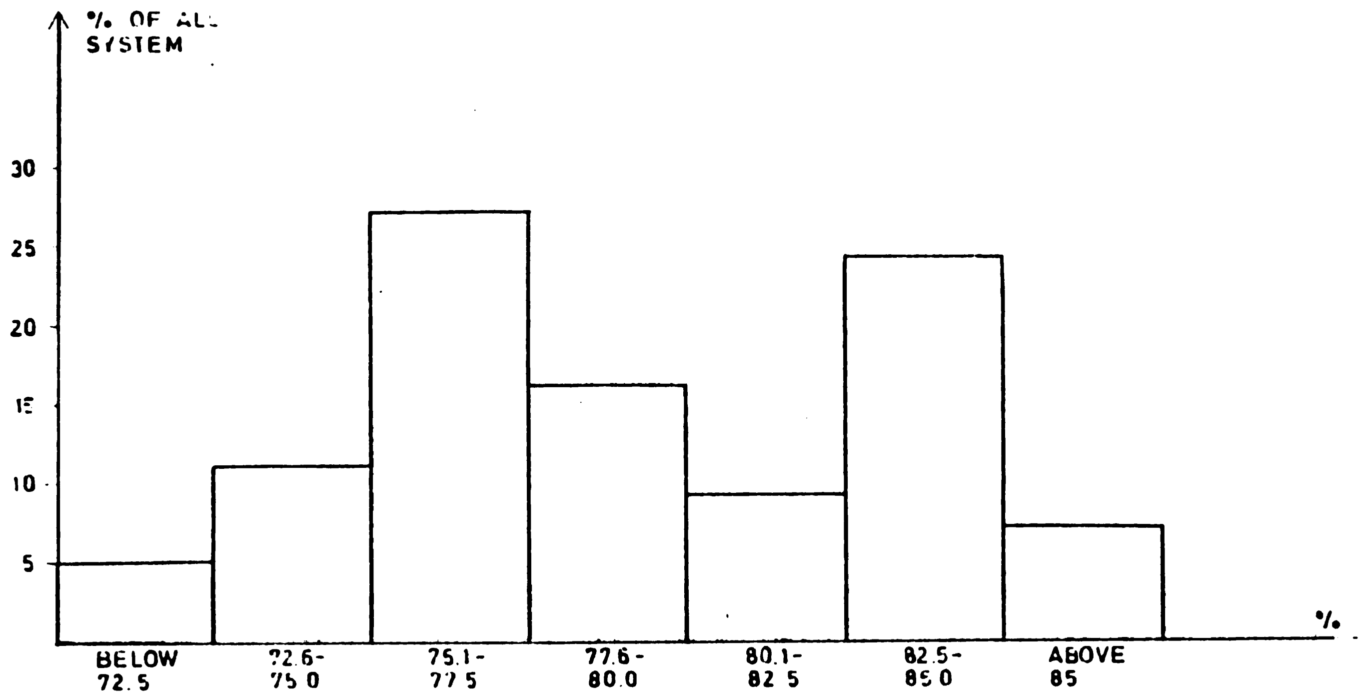

Figure 19

Efficiency n^{82}

in %

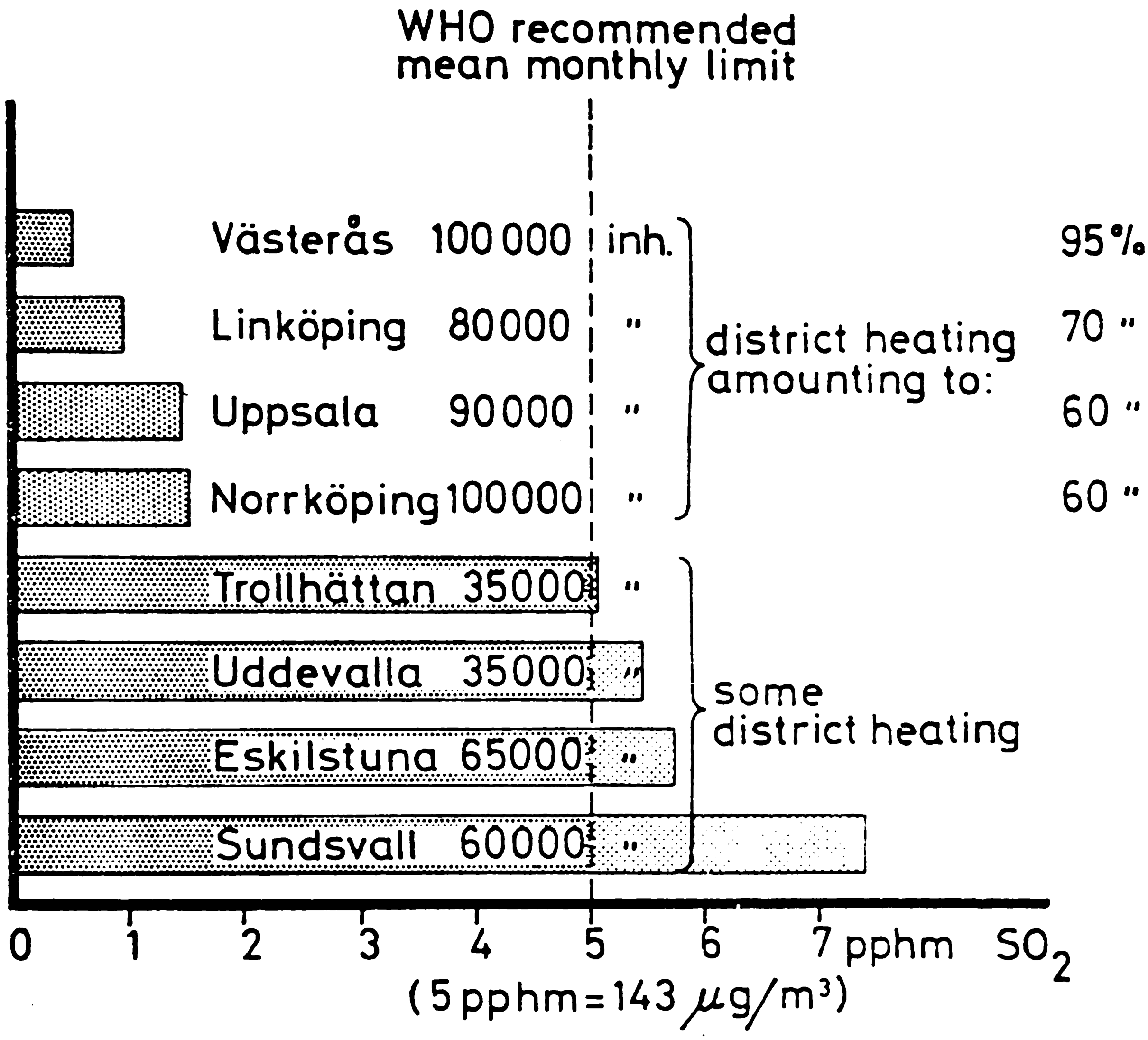

Figure 20

Concentration of SO_2 in the Air in some Swedish Towns. February 1971.[83]

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CHAPTER IV

THE VIABILITY OF DISTRICT HEATING IN THE UNITED STATES

This chapter answers two questions: first, can a viable district heating system be built in the United States, and second, will such a system be built here? To answer the first question, a hypothetical system is simulated. This system is operated under a variety of test conditions. Comparative results are examined using the net present value of the project as the criterion of evaluation. To answer the second question, the present utility regulation framework is compared to an alternative framework. It will be argued that the present framework impedes the growth of district heating while the alternative would promote growth.

The simulation model works in two stages. The first stage determines optimal pipe diameter sizes, given cost, technical and demand information. The second stage determines the net present value of the project using investment cost based on the optimal pipeline network determined in stage one plus demand and cost information, a stylized construction program, and a specified project life.

Pipe Size Determination

To determine the optimal pipe size of each section of a distribution network, the total cost of the network must be minimized. Total costs are the sum of capital costs and pumping costs.[1]

Capital costs are

$$C_k = aDL \qquad (1)$$

where a = the cost of one foot of pipeline of a given diameter. (It is a function of the diameter) times a capital recovery factor.

D =pipe diameter

L =pipeline length

The annual pumping cost is calculated in the following manner.

First, pumping power is

$$Wp = \frac{\ }{4} frlDv^3 \qquad (2)$$

where f = the friction factor for the pipe material

r = density of water

v = the velocity of circulation of working fluid

Second, the rate of heat transport is

$$H = D^2 vrc\Delta T \qquad (3)$$

where c = the specific heat of water

ΔT = the difference between the supply and return temperature of the working fluid

Solving equation three for v and substituting in equation two

$$Wp = \frac{16fl}{\Pi^2 r^2 c^3} D^{-5} \left[\frac{H}{\Delta T}\right] \quad (4)$$

Let $\frac{16fl}{\Pi^2 r^2 c^3}$ = z, then energy cost of pumping is

$$Cp = ubzD^{-5} \left[\frac{H}{\Delta T}\right]^3 \quad (5)$$

where u=the annual capacity factor

b=cost of electricity used for pumping

Total cost becomes

$$C_t = C_k + C_p = aDL + ubzD^{-5} \left[\frac{H}{\Delta T}\right]^3 \quad (6)$$

To minimize total cost, the derivative of cost with respect to the diameter is set equal to zero. All the other variables are assumed constant. The rationale for that assumption is explained below.

Therefore the cost minimizing diameter is

$$D = \left[\frac{5uzb}{aL}\right]^{1/6} \left[\frac{H}{\Delta T}\right]^{1/2} \quad (7)$$

Let $\left[\frac{5uzb}{aL}\right]^{1/6}$ = S. Then the fluid velocity can be obtained by substituting (7) into (3).

$$v = \frac{4}{\Pi} s^{-2} c^{-1} r^{-1}$$

Given v, D the pressure drop along any pipe line is

$$\Delta p = \frac{f}{2} LD^{-1} rv^2 \quad (8)$$

However, the pressure drop is constrained by the availability of pumping equipment. In this program the largest allowable pressure drop was set at 75 PSI. Faced with this constraint, the minimum cost pipe was determined in an iterative manner that searched through that cheapest pipe until it found the pipe diameter that was compatible with the constraint.

The next five sections (heat demand, pipeline length, change in temperature, capital cost, and electricity cost) will provide the assumptions made in specifying the other variables that appeared in equation 5.

The Rate of Heat Transport (H)

The rate of heat transport is dependent on the heat demand in the different sections of the service area. Heat demand is a function of the outside temperature, design temperature, inside design temperature, building structure, and the demand for hot water for direct consumption (sanitation, etc.).

In particular, heat demand is the heat needed to raise the indoor temperature to 62°F when the outside temperature is at the design temperature. For this study the design temperature was set at 21°F. It was assumed that internal sources are capable of raising the temperature the final 10 degrees to the indoor design temperature of 72°F.[2] The design temperature was set relative to the typical winter climate. This study used the New York City weather pattern as the typical climate. In that climate there are normally only 133 hours in which the temperature drops below 21°F. (One would hope these hours occur at night with everyone under blankets.) At outside temperatures above 21°F, heat demand was assumed to vary proportionately to the ratio of the difference between 62° and the outside temperature to the difference between 62° and 21°F.

The housing stock was assumed to be two story and four story apartment buildings. Each two story building contained 18 apartments. Its peak heat demand was 259,000 BTU/hour, and its annual heat load was 1080 x 10^6 BTU. The four story building heat demand and load was calculated by doubling the two story building estimates.[4]

Hot water demand for consumption purposes was set at 58 gallons per person. The water temperature was raised by 80°F. These parameters translated into a building (for the two story apartment house) peak demand of 58,000 BTU/hour and an annual load of 50.8 x 10^6 BTU.[5]

Pipeline Length

Population density and the housing pattern determine pipeline length. Three population densities, (10,000, 20,000, and 30,000 people per square mile) were chosen for study. The apartment houses were set in a rectangular grid. Increases (decreases) in density were achieved by moving the buildings closer together (farther apart). As the location of the buildings was moved, pipe lengths were changed accordingly.

Translated into thermal loads the above-mentioned heat demand became 13.5, 27, and 40.5 megawatts (mw) per square mile respectively. The Pine Study, from which the standard building heat demands were taken, used density patterns of up to 15,000 persons per square mile or equivalently 20 mw per square. The Pine Study stands alone as the only study to show that district heating is feasible at those densities.[6] Other studies state that below 52 mw per square mile district heating is not feasible.[7] However, many of these studies used obsolete pipe construction techniques. New techniques incorporating different materials and construction practices reduce the pipeline costs, might allow district heating to become feasible in areas previously ignored. To investigate this possibility, this study uses densities below the old rule of thumb standard of 52 mw per square mile.

Change in Temperature

The difference between a supply temperature of 300°F and a return of 210°F set the change of temperature at 90°F.

These temperatures are significantly higher than the typical European temperatures of 250°D supply and 160°F return. The need for the higher temperatures is twofold. First, higher temperatures are needed in the U.S. to run absorption cooling equipment; the Europeans do not provide air cooling services. Second, the higher temperature is needed to run steam generators. These generators provide low pressure steam that is used in older buildings with antiquated heat systems. Providing the higher temperature will allow these customers to purchase the heating service without incurring major retrofit costs.[8]

Once the temperature parameters are set it is possible to obtain estimates of two other variables observed in equation six above. These variables are the specific heat and density of water.

Capital Cost

Capital cost per foot is the product of a capital recovery factor and the original cost of the pipeline. The capital recovery factor, in turn, depends on the project life and the interest rate. The project life was set at 30 years. Three interest rates, 5, 10, and 15 percent were used in the calculations. The optimal pipe size was found to be independent of the interest rate.

Estimates of pipeline cost vary by large amounts (see Table 31). The cause of the variance can partially be explained by construction technique and pipe materials. However, even when these factors are held constant, the data still show sharp differences. For example, in Table 31, construction technique and pipe materials are the same for columns 1 and 4, for 2 and 7, and for 3, 5, and 8.

There are two standard construction techniques, field fabricated, and pre-fabricated. The field fabricated technique can be subdivided into those methods that construct concrete ducts, and those that pour concrete into the trench.

The concrete duct field fabrication technique involves at least ten different construction steps: excavation, laying a concrete base, forming the walls, placing the pipe in the form, insulating the pipe, waterproofing, placing the drainage pipe in the duct, and a three-step covering process. (The finished product is shown in Figure 21.) The poured concrete technique, shown in Figure 22, is slightly easier to construct because it eliminates the drainage pipe, the waterproofing, and the need to place a roof over the duct.[9] In both cases a steel service pipe is used. Traditionally, mineral wool has been used as the insulator. The temperature of the heating medium can be raised to 2192°F without damaging the system.[10] (Steam systems operate at 400°-450°F and hot water systems operate at 200°-300°F.)

The pre-fabricated techniques involve only six construction steps: excavation (usually the trench width is only 60 percent of the width needed for field fabricated pipelines for the same size service pipe), assembly of pipes, insulation of joints, laying sand around the pipes, back-filling, and replacing the surface.[11]

The pre-fabricated pipe can be either steel-in-steel pipe or steel-in-plastic. The steel-in-steel pipe consists of steel service pipe wrapped with insulation of either calcium silicate or polyurethane. The outer mantle is 10-gage steel protected by glass fibre reinforced bitumen. The temperature range of the insulation is up to 1200°F[12], (see Figure 23). The steel-in-plastic pipe consists of a steel service pipe wrapped in polyurethane. The mantle pipe is a polyethylene protective sleeve. The insulation package can be altered to be viable at temperatures of up to 248°F or 338°F[13], (see Figures 24 and 25).

The decision to use field fabrication versus pre-fabricated depends on the relative price of labor and materials. The field-fabricated technique uses more labor during construction while the pre-fabricated service pipe is more expensive. (Also, the speed of construction is faster with pre-fabricated systems, and the inconvenience of and the third party expenses related to the construction project are smaller.) As the pipe size increases, service pipe cost as a percent of pipeline cost increases. This fact has led several European experts to recommend pre-fabricated pipelines where the service pipe is 8" or less; and field fabricated pipe when the service pipe is 10" or more; with the 8"-10" range to be zone of indeterminancy depending on local conditions.[14]

Historically, in the United States, the concrete duct field fabrication was the most important method. The New York Steam Company perfected this method in the early 1900's. Almost all the pipelines in use today were constructed in that manner. The alternative techniques have been used in Europe since the early 1960's.[15] Data recording the proportion of recent pipelines completed by construction technique in the United States are not available. However, given that the several feasability studies of district heating written in the late 1970's did not even price the alternate techniques, it seems reasonable to conclude that pre-fabricated pipelines have not been used in large numbers in the United States.

For the purposes of this study, the pipeline cost estimates provided in the Piqua study were adopted. These pipelines were pre-fabricated, using steel-in-plastic pipes. This adoption provided the study with a reasonable estimate of the cheapest pipeline. Later, the cost will be inflated by a factor of 1.2 and 1.4 to see the impact of higher pipeline cost on project feasibility.

Electricity Cost

The cost of electricity used to pump the hot water through the system was set equal to the average price of electricity to industrial concerns in the United States in 1980. This price was 3.4¢ per kilowatt hour.[16] This price was adjusted in every year for inflation. In the base case the inflation rate was set at 7 percent.

Total Pipeline Cost

Given the above inputs it is then possible to determine the optimal pipe sizes for each section of the service area. Summing across sections provides an estimate of pipe needs by pipe size. Table 32 shows the results of the optimal pipe model by density classification. The transmission pipe was extended or shortened depending on designated plant location site. Origin cost of the pipeline was then determined in 1980 prices by multiplying the price per foot by the number of feet of each pipe size, and then summing across pipe size.

Distribution network pipe size varied from 2" to 10" diameter. In this size range the European practice is to use pre-insulated pipe. This study followed the European practice in that range. The transmission pipe was 12" and 13" in diameter. For these sizes, the European practice is to use field fabricated concrete duct pipelines.[17] This study continued to use pre-fabricated pipe for the larger pipe sizes. The latter practice allowed the use of one source for all pipeline cost estimates.

Net Present Value Determination

District heating projects entail multi-year construction programs. Revenues and operating costs can begin only after the construction program has advanced to allow the system to go into partial operation. Because of this extended time dimension, the net present value criterion was chosen to evaluate the success or failure of the projects.

In this study, the pipeline system was built in four phases over a ten year period. Each section serves a population of 54,000 individuals. Peak heat demand is 3.04×10^{8} BTU/hour and annual load is 8.2×10^{11} BTU. This construction schedule implies that revenues and operation costs began for sections 1 through 4 in years five, seven, nine and eleven, respectively. A phase or section took four years to complete, one-fourth of the phase built per year.

Revenue

Revenue received by the project is a function of three factors: the annual heat load given one hundred percent participation in the system, an attraction rate that allows for less than one hundred percent participation in the systems, and the price of a competitive fuel.

The annual heat load was determined previously in the pipeline size model. It is based on the average temperatures for the New York City climate. It will be assumed that the climate for each year of the next thirty years will be identical to the average climate.

The attraction rate is the percent of the potential customers who are connected to the system. The rate is allowed to move through time. An initial rate is set in the year the system starts to operate. Every year thereafter, the rate is increased until it hits a final attraction rate in the 30th year.

The price of heat was set at ninety percent of the energy equivalent price of natural gas. The latter price was determined by assuming that the average boiler operates at a seventy percent efficiency rate, and that the average customer purchases gas at the national average gas price for commercial customers.[18]

Total revenue for any given year is the product of the maximum load times an attraction rate times the energy equivalent price of gas times ninety percent.

Other studies have used boiler efficiency rates of between sixty and seventy percent, attraction rates of between seventy and one hundred percent, and used the price of fuel oil instead of the price of gas.[19] The reason for multiplying the energy equivalent price by ninety percent was to provide an incentive for customers to join the system. The ninety percent rate was used in the Detroit, Michigan and Hereford, England studies.[20]

Costs

Total costs are the sum of investments; heating costs, pumping costs, maintenance. Each cost was first estimated for 1980. For all other years costs were increased by an inflation factor.

Investments cost determined by the original cost estimate for a pipeline section, the construction schedule and the construction inflation rate. Original cost estimate is shown in Table 2 and the pipeline construction program is shown in Table 4.

Heating costs are set equal to the loss of revenue received by the electric utility due to the reduction of electricity output caused by the sale of steam. The loss of electricity output is the result of removing the steam from the turbine prior to the completion of the turbine cycle.

This removal of steam causes a loss of electricity because the steam still contains energy that could have been transformed into electricity. A measure of this energy is the temperature of the steam. Further, the efficiency of a heat engine depends on the difference between the temperature as it enters the turbine compared to the temperature as it leaves. A very efficient system would have the sun at one end to heat the fluid, and Lake Superior at the other end to cool it. To be more precise the thermodynamic efficiency of a heat engine is given by the following equation:[21]

$$N = \frac{T_1 - T_2}{T_1}$$

where N = efficiency

T_1 = temperature of the entering steam, degrees Kelvin (°K)

T_2 = temperature of the exhaust steam, degrees Kelvin

The efficiency of the steam plant is dependent on not only the thermodynamic efficiency but also the boiler, turbine, and generator efficiencies. The efficiency of the plant is approximately 55 percent of the thermodynamic efficiency.[22]

In a typical 800 MWe turbo-generator, steam leaves the boiler at 2400 PSIG and 1000°F. It enters the condenser at 1.5 in HgA backpressure and at approximately 70°F. The thermodynamic efficiency of this system is 64 percent (811°K - 294°K/811°K), and the plant efficiency is 35 percent. In order to raise the temperature of the heat supply water from its return temperature of 210°F to its send out temperature of 300°F it is necessary to remove steam from the turbine at 320°F and 91.1PSIG. This process reduces the thermodynamic efficiency to 47 percent (811°K - 433°K/811°K) and the plant efficiency to 26 percent.[23]

The additional electricity that the removed steam would have generated by continuing through the turbine to the condensers is the electricity loss charged to the district heating system. This loss can be reduced if the heating fluid is heated in multiple stages. By using the multiple stage process a portion of the steam is allowed to progress further through the turbine before it is removed for heating purposes, and in turn the steam will generate more electricity. A two stage heating system was used in this study because a majority of the savings due to multiple-stage heating are saved in the second stage.[24]

Heat cost, which is equivalent to revenue loss, is obtained by multiplying the output loss times the electricity price. The choice of electricity price has varied across studies. Some studies use the busbar cost of the plant producing the heat. Others use typical baseload busbar costs.

The proper price to use depends on the particular pricing philosophy. Alternative pricing strategies were discussed above in reference to the Consolidated Edison Steam Cases. In the simulation model a price is quoted and compared to alternative prices.

Pumping costs are a function of pumping energy requirement and the cost of electricity. The pumping energy requirements were determined in the pipeline size model. The cost of electricity was set at the average national rate for industrial customers.

Maintenance costs were estimated at 3 percent of pipeline replacement costs. For the first ten years, these latter costs were set equal to the total actual pipeline investments. Starting in year eleven replacement costs were set equal to the actual costs as of the tenth year times the construction inflation factor.

This practice results in high maintenance cost relative to other studies that set maintenance costs at 2 to 5 percent of the initial investment costs.[25] The consequence of this assumption is that any underestimation that may have occurred in other cost figures will be compensated for by an overestimation here.

Results

A base case analysis was determined for service areas with population densities of 10,000, 20,000, and 30,000 inhabitants per square mile. The following assumptions were made:

- -The transmission distance from the plant to the service area was five miles.
- -The attraction rate was set at .75 + .008(I-5). This rate implies that at the start of operations seventy-five percent of the customers signed up; and by the 30th year of operations ninety-five percent of the potential customers had joined the system.
- -The construction inflation rate was 5 percent.
- -All energy cost inflation rates were 7 percent.
- -Industrial customer electric cost was $.034/ Kilowatt hours.
- -The busbar cost was $.024/Kilowatt hours.
- -Natural gas energy equivalent price was 4.77E-6 dollars/BTU.[26]

The results of these trials are shown on Tables 33, 34, and 35. The net present value of the trials was 3.15×10^7, 6.52×10^7, and 7.39×10^7 for densities of 10,000, 20,000, and 30,000 inhabitants per square mile respectively. The trend that benefits will increase as density increased was expected. The fall in capital, pumping and maintenance cost as a function of density are responsible for the trend. The positive results indicate that the project should be adopted. However, these results are obviously dependent on the reasonableness of the assumptions. The next seven sections will test that reasonableness through a sensitivity analysis on the selected variables.

Transmission Distance

The distance from the dual purpose plant to the heat service area is the transmission distance. The pipeline connecting the two principal components of the system carries the entire heat load. Consequently it is the largest and most expensive pipe in the system.

Three alternative plant locations, 1, 5, and 10 miles from the service area, are compared for each population density. A distance of ten miles was considered the maximum feasible distance in the Battelle and Pine studies.[27]

As anticipated, the net present value of project declined as the distance increased. In only one instance did the net present value turn negative (10 miles and 10,000 inhabitants per square mile). For the higher two density cases the magnitude of the change was large, increasing by more than 140 percent as the plant moved from 10 miles to one mile away from the service area.

Interest Rate

Changes in the interest rate, holding all other variables constant, had a larger impact on project feasibility than changes in any other variable. The range of results (see Table 37) stretches from 2.31×10^8 to -1.28×10^7.

This impact is caused by the length of project, 30 years, and the timing of revenue and costs. Revenue increases in the latter years of the project due to the increase in the attraction rate and the natural gas inflation rate. Capital costs cease after the first ten years. Maintenance costs increase at a slower rate than energy costs. The confluence of these trends produce high nominal profits in the latter years of the project. A high interest rate would reduce to a great extent the present value of the large nominal profits earned in the final years of the project life as compared to a low interest rate. For example, a profit of 7.3×10^7 earned in the 30th year has a present value of 1.78×10^7 with a 5 percent interest rate but only a $.128 \times 10^7$ present value with a 15 percent interest rate.

Changing the interest rate by itself entails changing the real interest rate. The base case contains a real interest rate of 3 to 5 percent (the nominal interest rate, 10 percent to either the energy inflation rate of 7 percent or the construction inflation rate of 5 percent). This real rate of interest is equal or slightly higher than the approximately 3 percent real interest rate that existed on corporate AAA bonds over the period 1960-1980.[28] The comparisons shown on Table 37 change the project interest rate to 5 and 15 percent or equivalently to real rates of interest of -2 to 0, and 8 to 10 percent respectively. A range of -2 to 0 real interest rate existed in the 1970's for Treasury Bills but not for any long term bonds.[29] In 1982, the real interest rate for corporate bands has hovered around 7 percent.[30] Therefore, the comparative interest rates shown capture the range of real interest rates encountered in recent history. The fact that net present value of project for the higher two density cases was positive even when the interest rate was 15 percent demonstrates that high interest will not cause project cancellation even though they will reduce the project's value.

Energy Inflation Rate

The energy inflation rate adjusts the price of natural gas, the busbar cost, and the pumping costs. The adjustment to natural gas prices changes revenues. The adjustment to busbar cost and pumping cost changes total cost. Because natural gas price is the sole basis for revenue calculation, and total costs include other factors beside busbar and pumping costs, increases in the energy inflation rates will increase the net present value of the project (see Table 38).

The assumption that all energy prices increase at the same rate has a conservative impact on the results as compared to other studies that allow gas prices to increase faster than coal prices.[31] Increases in coal prices have a greater impact on the price of electricity than increases in natural gas prices due to the fact that coal is responsible for 51 percent of electricity generation while gas is responsible for 15 percent.[32] The price of electricity determines the energy costs of district heating. Therefore lower coal inflation rates will lower the energy costs and increase the difference between revenue and costs compared to other inflation scenarios.

To assume that all energy costs increase at the same rate implies that not only coal and gas prices increase at the same rate but that all other inputs into electricity production increase at the same rate. While the latter assumption might seem to be heroic it was made to erase any impression that assumptions have been made for the purpose of insuring project feasibility.

Busbar Cost

Busbar cost is the cost of electricity at the plant. It is used to determine the revenue loss to the electricity subsidiary when a plant simultaneously produces electricity and heat. The base results case used a busbar cost of .024 cents per kwh for 1980. This is the cost of electricity at large base load plants.[33] This price is equivalent to a short-run fully distributed (or actual average cost or account cost) off-peak cost. The simulation model was run using two alternative busbar prices, .030 and .036 cents per kwh for 1980. The price of .036 cents was considered reasonable for a high price because it was above the 1980 average kwh price for industrial customers.[34] The results of these alternative cases are shown on Table 39. As expected higher busbar costs are associated with lower net present values.

Pipeline Cost

Pipeline costs are the sum of the costs of the transmission pipeline and the distribution network. It was first estimated as if it were installed instantaneously in year one of the project. Then the cost was adjusted to accomodate historical construction time and inflation in construction costs.

Base case results are compared to two higher cost estimates. These estimates were obtained by multiplying the instantaneous installed cost by factors of 1.2 and 1.4

and then adjusting the new initial costs for inflation incurred during construction.

The alternate cost estimates approximate the relationship between columns one and four in Table 31 (except at the 2-inch pipe diameter size). Column four costs are the costs used to determine the base case estimates. Column one costs represent an alternative estimate of the steel-in-plastic construction technique.

The increase in pipeline costs, as expected, reduced the net present value of the project for each density level (see Table 40). However, only in one case, at a 1.4 cost factor for 10,000 inhabitants per square mile, did the net present value turn negative.

Nominal Rates

Changes in nominal rates refer to changes in the underlying inflation rate. The catalyst for these changes is usually a change in federal government policy, rather than a change in a particular industry. For example, the large increases in defense spending could cause the aggregate demand curve to shift or the aggregate supply curve could shift given a reduction in the dead weight loss following the death of the disabled who have been removed from the Medicaid rolls. The consequence of such a change on the simulation model would be to increase or decrease construction costs, energy costs and interest rates simultaneously.

The comparative results for three different sets of nominal rates are shown on Table 41. As the rates increased, the net present value decreased by small amounts. This pattern is the result of the relative increased costs in the early years leading to larger negative surpluses in the first eight years of the project, and higher relative revenues in the later years leading to higher positive surplus in last years of the project. When the new pattern of surpluses was discounted back to the initial year at the new higher discount rates, the impact of the increased costs was greater than the impact of the increased revenues, so the new present value fell.

Attraction Rate

The attraction rate specifies the percent of the service area heat load that is connected to the system. In the base case the percent started at 75 percent in first year of operation (the fifth year of the project life) and increased at a constant rate until it hit 95 percent in the 30th year. In the two alternative cases, the attraction rate started lower, at 65 and 70 percent, and ended up at the same rate, 95 percent.

The high final attraction rates are consistent with the low relative price of steam. Steam heat is always priced at 90 percent of the cheapest alternative fuel. Therefore, it would be rational for all new buildings and old buildings that have heating systems that need major renovation to join the system. A period of thirty years is probably long enough for most buildings in a service area to fall into one of the two categories. Further, the high delivery temperature of the water allows for the retrofit of old buildings at minimum cost.

Setting the starting attraction rates calls for professional judgment, marketing expertise and a lucky guess. The three starting attraction rates compared in this study are below attraction rates used in other studies.[35]

Comparative results are shown in Table 42. For each density level, the net present value decreased as the starting participation rate decreased. These results were expected because capital and maintenance costs do not decline with the decline in customers, while revenues do.

Summary

The simulation model was run 45 times. In 40 cases (89 percent) the net present value of the project was positive. All of the negative cases occurred at the density level of 10,000 inhabitants per square mile. In

27 cases (60 percent) the value was positive by the twentieth year of the project life. This cut off date was important because first, the estimate became more uncertain the longer the time horizon, and, second, several other studies of district heating feasibility stopped in the twentieth year. In 13 cases that turned from positive to negative with the shortened project life, seven were associated with 10,000 inhabitants per square mile density level, and two of the others were associated with a 10-mile transmission distance.

Three conclusions can be drawn from this feasibility study. First, district heating is feasible for service areas with a density level of 30,000 inhabitants per square mile. Second, district heating is not feasible for service areas with a density level of 10,000 inhabitants per square mile. Third, district heating may or may not be feasible for service areas with a density level of 20,000 inhabitants per square mile.

The information needed to translate these conclusions into practical policy guidelines for real American Cities is not readily available. It is possible to obtain population densities on a city-wide basis. Table 19 lists the population densities of nineteen American cities. The first fifteen cities were chosen from the largest 75 American cities by choosing every fifth city. The last four cities were chosen because additional information is known about them.[36] If the densities shown in Table 43 were used as a policy guideline then this study would conclude that district heat is definitely feasible only in New York City, is worthy of investigation in Newark and San Francisco, and is not feasible any place else. However, very few district heating systems serve entire cities. Instead the service areas usually contain only parts of each city. Due to the fact that heat density vary within each city (for example Figure 1 shows a variance from 5 to 200 megawatts per square kilometer in the Minneapolis-St. Paul metropolitan area) city-wide averages cannot be used a policy guidelines.

An alternative is to examine other feasibility studies performed on real cities to obtain data for densities in possible future service areas. Here the data are only suggestive because of the limited ability to translate the figures provided into a single framework of analysis. Many studies do not provide data on design temperatures, size of service areas in terms of land mass, distribution of customer types, or population densities. Without that data it is impossible to make accurate comparisons.

In three studies it was possible to make some rough estimates. Returning to Figure 1, heat load densities for downtown St. Paul and downtown Minneapolis are approximately 40 and 70 megawatts per square kilometer respectively. These numbers translate roughly into population densities of

50,000 and 87,000 inhabitants per square mile. These densities are significantly higher than city-wide averages for St. Paul and Minneapolis reported in Table 19. Further, they are above the test densities used in this study so that one could conclude that district heating would be profitable in these areas.

Second, the Detroit study provided heat demand and acreage by census tract. Summing across census tracts provided an estimated 16 megawatts per square kilometer for the proposed service area. This heat demand is equivalent to the heat demand for 20,000 inhabitants per square mile used in this study.[37] Three other characteristics of the Detroit study are worth noting. First the distribution network was to be constructed using field-fabrication techniques.[38] Second a large proportion of the pipe would have been less than 8" in diameter.[39] Current practices in Europe dictates the use of pre-fabricated pipe for those sizes. Third the plant providing heat for the service area at Conners Creek is within the borders of the service area.[40] Therefore a transmission pipe connecting the plant to the service area does not have to be built.

Under these conditions this study would have recommended that Detroit Edison build the new system. However, the conclusion of the Detroit Edison study was to abandon construction plans unless the city of Detroit subsidized the project.

A second proposal of the Detroit study was to examine the feasibility of a smaller service area. The heat density of the smaller area was 19 megawatts per square kilometer or the equivalent of 30,000 inhabitants per square mile. Again this study would recommend construction of the system. It is not known if Detroit Edison ever completed the analysis on the second service area.[41]

The major cause of the different recommendations was pipeline costs. For pipes with an 8" diameter or smaller Detroit's costs were higher by a factor of 1.6 to 2.2 than costs used in this study.

Third, the Piqua study divided the city into 52 heat zones. Heat demand and acreage was provided for each zone. It was decided to study the feasibility of district heating for a service area containing 12 zones. The heat density for the proposed service area was 54 megawatts per square kilometer.[42]

It is difficult to generalize for the entire country from a sample of three cities. However, the examples provided show that in both large and small cities there are regions where district heating could be profitable.

A comparison of nine other feasibility studies is shown in Table 44. Two curious correlations appear in that table. First, the closer to a privately-owned public utility is the performing agent (that person(s) who actually prepared the study) or sponsoring agent (that person(s) who can hire or fire the performing agent; the sponsoring agent is not necessarily the agent who pays for the work) the more likely the project will be found to be not feasible. Second, the closer to either the European district heating industry or the American nuclear power establishment the performing agent or sponsoring agent is, the more likely the project will be forced to be feasible.

The above comparisons imply that the self interest of the person conducting the study determines the outcome. The recent history of existing privately-owned U.S. district heating utilities has led to a disenchantment with the industry. An analysis of Federal Energy Regulatory Commission data for 31 firms demonstrates the current situation. Only 15 firms earned a positive return on net fixed assets dedicated to the heating subsidiary. Their average return was 6.6 percent. For the remaining 16 firms, the average loss was 9.9 percent. Further, the steam revenues represented less than 2 percent of average companies' gross revenue.[43] Thus, from a company perspective, the conclusion becomes "why bother with a tiny business that will probably lose money anyway?".

On the other hand, agencies and individuals tied to the nuclear power business would have an incentive to promote anything that increases the economic viability of nuclear power. Given that a nuclear plant does not have stack losses (one would hope), heat from a nuclear plant has a lower cost than heat from a fossil fuel plant. Therefore, a district heating business that buys heat from a nuclear plant rather than from a coal plant potentially will be more profitable. This logic appears to this author to be the only reasonable explanation for the long and extensive research into district heating sponsored by Oak Ridge National Laboratory.

Regulatory Practices

Given that new district heating systems are economically feasible, it is incumbent upon the investigator to explain the general lack of interest in building one. Invariably, the answer is to blame the present regulatory system. I. Oker, for example, states that while economic, technological and environmental aspects of district heating are favorable, institutional barriers remain a major deterrent to implementation.[44]

Peter Donnelly and Isiah Sowell state that "profitable investment in such facilities hinges on resolving regulatory treatment of issue such as: (1) joint cost allocation, (2) use of innovative financing techniques; . . . (Uncertain) Regulatory treatment of each of these issues . . . has a chilling effect on attempts to promote district heating."[45]

These issues focus the controversy on a single question: can a district heating entity stand by itself (earn the allowed rate of return without a subsidy from the electric utility)? To answer this question it is first necessary to determine the allocation of joint costs of heat and electricity generation. This allocation simultaneously sets the legitimate costs and profits of each subsidiary. The regulatory commission must approve a particular allocation scheme. Different approved schemes could make or break a district heating project.

Second, each district heating project is a multi-year endeavor that will lose money in the early years of its life and earn money in the latter years. It is therefore necessary to borrow in order to finance the early years' losses. If an electric company finances a district heating subsidiary's losses through higher than otherwise electric rates or lower than otherwise rates of return to owners, is this flow of funds automatically a subsidy?

That depends on how subsidy is defined. If a subsidy occurs in any year in which a district heating subsidiary does not stand by itself, then a subsidy must be paid. However, when other definitions are used, the answer is not quite so clear.

Gerald Faulhaber presented two definitions:

1. informally a subsidy does not occur "if the provision of any commodity (or group of commodities) by a multicommodity enterprise subject to a profit constraint

leads to prices for the other commodities no higher than they would pay by themselves;"[46] or

2. (formally) "Price for which the resulting revenue vector lies in the core of the game."[47]

The two definitions are identical because a revenue vector which is outside of the core leads to prices that are higher than would be paid if each commodity were supplied by a separate enterprise.

Faulhaber also quotes a definition of a subsidy provided by Harry Trebing:

> A more meaningful standard might relate maximum rates to the cost of a single purpose facility or system built to serve the user requirements of the particular group most affected by the upper price limit. If this group paid a rate in excess of the cost of the single purpose facility, it would be subsidizing other user groups as well as failing to participate in any of the economics of the joint cost inherent in the public utility operation.[48]

While the Trebing definition emphasizes the losses incurred by the subsidizer, and the Faulhaber definitions emphasize individuals' decision to play with the group (according to Faulhaber a person receiving a subsidy inside the group might remain outside if there are potential gains from doing so), neither definition directly tackles the issue of multi-year multi-commodity projects.

To do so, a corollary to the above definitions must be given. First, the net present value of the revenue requirement decreases (increases), then the wealth of the customers increases (decreases). A subsidy will occur, "given a utility with two or more subsidiaries, if a flow of funds between these subsidiaries leads to the net present value of the revenue requirement for the customers of one subsidiary being higher than it would have been had the subsidiary been an independent entity."[49]

The implication of the corollary, given the problems of joint cost allocation and financing, can be demonstrated through an example. The example will compare a single-purpose electric utility and gas service for heat demand group to two alternative cogenerating electric and district heating systems. The difference between the alternatives centers on the joint cost allocation scheme.

The technical choices available to the electric utility are shown in Figure 26. Part I details the energy cycle efficiencies for an electric plant operating either in single-purpose or dual-purpose mode. It shows that 14 kilowatt hours (kwh) of electricity must be sacrificed to obtain 62 kwh of useful heat per every 100 kwh of energy consumed. Part II illustrates the alternatives given that a boiler can instantaneously burn 3080 kw of energy. Part II alternatives 1 and 4 are based on Part I-a fuel efficiencies. Part II alternative 2 is based on Part I-b fuel efficiencies. Part II alternative 3 is a hybrid. Steam containing 1000 kwh is allowed to expand through turbine to the condenser, producing 400 kwh of electricity, and steam containing 1540 kwh is extracted at 300 degrees F, generating the additional 400 kwh of electricity and 955 kwh of useful heat.[50]

The demand for electricity is divided into a summer peak and winter off-peak seasons of 4380 hours each. Summer demand level is constant at 1232 kw and the winter demand level is constant at 800 kw. The single purpose electric utility would meet those loads operating at Figure 6 Part II and 4 levels. Given a price of electricity $.024/kwh, annual revenue is $213,604. It is assumed that the company is run efficiently and regulated properly so that it is earning equal its allowed rate of return, which is the true cost of capital. Therefore economic profits are zero.

Gas sales occur only in the winter meeting the heat demand. This demand is set equal to the maximum heat sales that could be serviced by the electric utility's boiler. This amount to an annual sale of 38,739 MCF (see Table 46 for a listing of assumptions and definitions that generate this number). Given a price of natural gas of $3.34, per MCF annual revenue is $129,388.

From this position the electric utility decides to start a district heating subsidiary. The project life is collapsed into two years. Year one represents the time period over which the subsidiary's profits are expected to be negative, while in year two, profits are expected to be positive. An increase in the heat attraction rate from 50 percent to 100 percent is the cause of the change in expectations.

District heating revenue is set at 90 percent of gas revenue for the relevant heat sales (50 or 100 percent of gas sales). Non-fuel costs are set at $50,000 annually. Full costs are set at $.01 kwh. The number of kwh charged to the district heating subsidiary depends on the joint cost allocation scheme. An incremental scheme charges the heat customers only for that energy used above the energy needed to serve the electric customers. A proportional scheme charges the heat customers in proportion to the energy in steam sales relative to electric sales (see Table 47 for calculations).

Alternative profits of the district heating subsidiary are shown on Table 48. Using the incremental joint cost allocation scheme, the subsidiary loses money in year one but earns a positive profit in year two. Using the proportional joint cost allocation scheme, the subsidiary earns negative profits in both years.

Alternative profits of the electric subsidiary are shown on Table 49. Its profits are the sum of profits earned on electric sales, profits earned on sales to the heating subsidiary and (the flow of funds to or from the heating subsidiary). The electric business, being perfectly regulated, earns zero economic profits. Profits from heat sales are zero under the incremental joint cost scheme and are positive under the proportional scheme (heat revenue is greater than additional costs). The flow of funds to the heating subsidiary are the reverse of heating subsidiary profits.

Total profits of the electric subsidiary do not vary given the different allocative schemes; only the source of the profits varies. Assuming a 10 percent discount rate, the net present value of the project in year one dollars is $1976 to the electric utility.

Given these facts, should the electric utility be allowed to operate the district heating subsidiary? The answer given by a public utility commission charged with establishing just, reasonable, non-discriminatory rates must be "no" if a subsidy exists.

Has a subsidy been paid in this example? The answer obviously depends on the definition of "subsidy." If a subsidy occurs when in any year funds flow from a subsidiary to another, then there has been a subsidy. If a subsidy occurs when the sum of the discounted profits of any subsidiary are negative, then the occurrence of a subsidy depends on the choice of joint cost allocation schemes. The proportional scheme insures negative profits for the district heating subsidiary in both years; thus there is no discount rate that would allow its discounted profits to be positive, so a subsidy did occur. However, if a subsidy occurs only when the net present value of revenue requirements has increased, then the project is subsidy free. The net present value of heat customers' payment must decline because heat payments drop in both years (5 percent in year one and 10 percent in year two). The net present value of the revenue requirement of electric customers drops if any discount rate less than or equal to 24 percent is used. Given that discount rates of greater than 24 have not been used by public utility commissions (to this author's knowledge), the electric customers could gain even if rates increased by the full amount of the electric subsidiary's loss in year one.

Regulatory Reform

A utility commission that accepts the net present value definition of subsidy and is aware of a district heating project that has a positive net present value still has one more task: it must persuade a reluctant, skeptical utility to undertake the project.

A possible solution is to institute an incentive scheme. The incentive schemes must meet three criteria: first, there must be a direct link between the incentive offered and the performance desired. Second, the size of the incentive must be set high enough to promote the project but not so high that the owners benefit at the expense of the customers. Third, the incentive can produce counter-productive tendencies. The commission must have the ability to recognize and eliminate these tendencies.

A scheme that increases (decreases) the utility's allowed rate of return as the BTU conversion of the steam electric plants rises (falls) will meet the first criterion. The BTU conversion rate is defined as the BTUs contained in output divided by the BTUs in the inputs. This rate is the inverse of the heat rate presently used to measure utility plant performance, given the kwh are converted into BTUs. (For example, a plant with a heat rate of 10,000 BTU/kwh will have a BTU conversion rate of 3413/10,000 or 34 percent; note: 1 kwh = 3413 BTUs.) An electric utility that converts its plant from a single purpose electric facility to a dual purpose facility will automatically increase its BTU conversion rate. Using the stylized facts presented in Figure 6, the conversion rate rises from 40 percent to 88 percent.

The size of the incentive, the increase in the allowed rate per increase in BTU conversion rate, must be project specific. It will be a function of the potential net benefits and the size of the project relative to the utility's normal generation. If the net benefits are larger, the incentive can be small. If the project is large relative to the utility, it will have a large impact on the utility's fuel efficiency so, again, the incentive can be small.

The potential counter-productive tendency that this program might encounter would be the ability of the utility companies to over estimate future benefits. In this case, the electric customer pays for the incentive and the losses in stylized year one but never receives the benefits in stylized year two because year two never appears. Given today's environment, which includes the reluctance of electric utilities to expand district heating subsidiaries and so-called finance hardship of the electrics, the probability of a electric utility starting a project that could cause it financial damage from irate electric customers and commissioners who feel dupped seems small. Further, commissions are called on every day to evaluate projects whose benefits will occur in some future time period. A commission staff that has the ability to evaluate the future benefits of a nuclear power plant should be able to evaluate the future benefits of a district heating system.

Commissions have the power to instigate an incentive scheme and several are ongoing today. For example, the Michigan plan includes an incentive that rises (lowers) the utility's allowed rate of return depending on the plant availability. Availability is defined as the percentage of hours that a unit would be available for generation. The goal of the plan was to increase the availability of Detroit

Edison and Consumer's Power plants. The desired result would be a decrease in fuel and purchased power costs. The counter-productive tendency to be monitored would be an increase in production maintenance costs.[51]

The plan originally established four availability ranges. Each range is associated with a particular allowed rate of return. A neutral zone between 70 and 80 percent was established. In this range the utility received its cost of capital. If availability fell below 70 percent, the allowed return dropped by 25 basis points. If the availability rate was between 80 and 85 percent, the allowed rate rose by 25 basis points; and if the availability rate was 85.1 or higher, the allowed rate rose by 50 basis points.[52]

Michigan Public Service Commission change the plan in 1980. It established a separate set of ranges for Detroit Edison and Consumers Power. The number of ranges increased and the size of each range was shortened. The measure of availability was altered. The new measure was set equal to the old measure plus the periodic factor. The periodic factor measures the time the plant is not available due to planned ontages. The new ranges for Detroit Edison are shown on Table 50.[53]

In the case of Detroit Edison, the scheme worked as planned. For the years 1977-1981, 110 million dollars of fuel and purchased power costs were saved. Profits increased by 32 million dollars, and rates reduced by 78 million. Further production maintenance costs increased only according to their long run trend. One possible explanation for these results is that management, responding to incentive, paid closer attention to costs. Therefore, this example shows that x-inefficiencies can be eliminated by refocusing management attention.[54]

Summary

The feasibility of district heating for an experimental city was studied. The criterion used to judge the feasibility of the project was a positive net present value. The project was found to be feasible in 40 of 45 comparisons of the simulation model.

The five nonfeasible cases had the following characteristic: Each occurred at the lowest density level (10,000 inhabitants per square mile).[55]

Other feasibility studies were examined. Only in cases where the study sponsor was a privately-owned public utility were district heating projects found to be not feasible. It suggested that these negative results were a function of current utility experience with district heating, rather than the real potential losses of the project.

To overcome utility inertia and trepidation, and to allow the benefits of the project to be reaped, an incentive scheme was proposed. This scheme would allow the benefits to be shared by both the customers and the owners of the electric utility and its heating subsidiary. For it has been found that "unless every major player in this game who has a veto power over the realization of district heating and cooling will at least not lose, it is not going to fly."[56]

Table 31

Pipeline Cost Per Foot of Dual Pipe (1980 Dollars)*

Pipe Diameter	1	2	3	4	5	6	7	8
2	60	139	25	43	93			
4	97	186	34	75	131			
6	133	222	41	109	167			
8	172	305	57	143	232			
10	216	360	74	181	256			
12	263	415	91	203	296	686	696	641
14			108	245				
16	346	523		252	374		872	771
20						1031	1126	901
24						1142	1347	946

Sources for Columns:

1. Oliker, "Economic Feasibility of District Heat Supply from Coal-fired Power Plants," p. 1064.
2. Ibid.
3. Pine, "Assessment of Integrated Urban Energy Options," p. 212.
4. City of Piqua, Power Plant Retrofit, pp. 337-338.
5. Detroit Edison Company, Power Plant Retrofit, p. 224.
6. Wisconsin Energy Office, Power Plant Retrofit, p. 4:40.
7. Ibid.
8. Ibid.

*All estimates were transformed into 1980 dollars using the Environmental Protection Agency's Sewer Construction Cost Index.

Table 32

Original Pipeline Cost (1980 Dollars)

Transmission Distance	Density (in habitants per sq. mile)	30,000	20,000	10,000
1 mile	Distribution	8,014,980	9,724,374	15,952,100
	Transmission	1,288,320	1,288,320	1,346,400
	Total	9,303,300	11,012,694	17,298,500
5 miles	Distribution	8,014,980	9,724,374	15,952,100
	Transmission	6,441,600	6,441,600	6,732,000
	Total	14,456,580	16,165,974	22,684,100
10 miles	Distribution	8,014,089	9,724,374	15,952,100
	Transmission	12,883,200	12,883,200	1,346,400
	Total	20,898,180	22,607,574	29,416,100

Table 33

Population Density 30,000 Per Sq. Mile

Year	Revenue	Heat Cost	Main- tenance	Capital	Total Cost	Surplus	NPV
1	0.00E+00	0.00E+00	1.08E+05	3.62E+06	3.73E+06	-3.73E+06	-3.73E+06
2	0.00E+00	0.00E+00	2.22E+05	3.80E+06	4.02E+06	-4.02E+06	-7.39E+06
3	0.00E+00	0.00E+00	4.62E+05	7.99E+06	8.45E+06	-8.45E+06	-1.43E+07
4	0.00E+00	0.00E+00	7.14E+05	8.39E+06	9.10E+06	-9.10E+06	-2.12E+07
5	3.25E+06	8.17E+05	9.78E+05	8.81E+06	1.08E+07	-7.59E+06	-2.64E+07
6	3.51E+06	8.84E+05	1.25E+06	9.25E+06	1.16E+07	-8.13E+06	-3.14E+07
7	7.60E+06	9.56E+05	1.54E+06	9.71E+06	1.24E+07	-4.88E+06	-3.42E+07
8	8.21E+06	1.03E+06	1.85E+06	1.02E+07	1.33E+07	-5.16E+06	-3.68E+07
9	1.33E+07	1.11E+06	2.01E+06	5.35E+06	8.79E+06	4.52E+06	-3.47E+07
10	1.44E+07	1.20E+06	2.18E+06	0.00E+00	9.34E+06	5.05E+06	-3.26E+07
11	2.07E+07	1.30E+06	3.55E+06	0.00E+00	5.21E+06	1.55E+07	-2.66E+07
12	2.24E+07	1.41E+06	3.73E+06	0.00E+00	5.52E+06	1.69E+07	-2.07E+07
13	2.42E+07	1.52E+06	3.92E+06	0.00E+00	5.85E+06	1.83E+07	-1.48E+07
14	2.61E+07	1.64E+06	4.11E+06	0.00E+00	6.19E+06	2.00E+07	-9.04E+06
15	2.83E+07	1.78E+06	4.32E+06	0.00E+00	6.56E+06	2.17E+07	-3.32E+06
16	3.05E+07	1.92E+06	4.53E+06	0.00E+00	6.95E+06	2.36E+07	2.33E+06
17	3.30E+07	2.07E+06	4.76E+06	0.00E+00	7.37E+06	2.56E+07	7.91E+06

Table 33 Continued:

Year	Revenue	Heat Cost	Main-tenance	Capital	Total Cost	Surplus	NPV
18	3.56E+07	2.24E+06	5.00E+06	0.00E+00	7.81E+06	2.78E+07	1.34E+07
19	3.85E+07	2.42E+06	5.25E+06	0.00E+00	8.28E+06	3.02E+07	1.88E+07
20	4.16E+07	2.61E+06	5.51E+06	0.00E+00	8.78E+06	3.28E+07	2.42E+07
21	4.49E+07	2.82E+06	5.79E+06	0.00E+00	9.31E+06	3.56E+07	2.95E+07
22	4.85E+07	3.05E+06	6.08E+06	0.00E+00	9.87E+06	3.86E+07	3.47E+07
23	5.23E+07	3.29E+06	6.38E+06	0.00E+00	1.04E+07	4.18E+07	3.98E+07
24	5.65E+07	3.55E+06	6.70E+06	0.00E+00	1.11E+07	4.54E+07	4.49E+07
25	6.10E+07	3.83E+06	7.04E+06	0.00E+00	1.17E+07	4.92E+07	4.99E+07
26	6.58E+07	4.14E+06	7.39E+06	0.00E+00	1.25E+07	5.33E+07	5.48E+07
27	7.11E+07	4.47E+06	7.76E+06	0.00E+00	1.32E+07	5.78E+07	5.97E+07
28	7.67E+07	4.82E+06	8.15E+06	0.00E+00	1.40E+07	6.26E+07	6.45E+07
29	8.28E+07	5.20E+06	8.55E+06	0.00E+00	1.49E+07	6.78E+07	6.92E+07
30	8.93E+07	5.62E+06	8.98E+06	0.00E+00	1.58E+07	7.34E+07	7.38E+07

Table 34

Population Density 20,000 Per Sq. Mile

Year	Revenue	Heat Cost	Main-tenance	Capital	Total Cost	Surplus	NPV
1	0.00E+00	0.00E+00	1.21E+05	4.05E+06	4.17E+06	-4.17E+06	-4.17E+06
2	0.00E+00	0.00E+00	2.49E+05	4.25E+06	4.50E+06	-4.50E+06	-8.26E+06
3	0.00E+00	0.00E+00	5.17E+05	8.93E+06	9.44E+06	-9.44E+06	-1.60E+07
4	0.00E+00	0.00E+00	7.98E+05	9.37E+06	1.01E+07	-1.01E+07	-2.37E+07
5	3.25E+06	8.17E+05	1.09E+06	9.84E+06	1.20E+07	-8.76E+06	-2.97E+07
6	3.51E+06	8.84E+05	1.40E+06	1.03E+07	1.29E+07	-9.38E+06	-3.55E+07
7	7.60E+06	9.56E+05	1.72E+06	1.85E+07	1.38E+07	-6.23E+06	-3.90E+07
8	8.21E+06	1.03E+06	2.07E+06	1.14E+07	1.48E+07	-6.59E+06	-4.24E+07
9	1.33E+07	1.11E+06	2.25E+06	5.98E+06	9.68E+06	3.64E+06	-4.07E+07
10	1.44E+07	1.20E+06	2.43E+06	6.28E+06	1.02E+07	4.11E+06	-3.89E+07
11	2.07E+07	1.30E+06	3.97E+06	0.00E+00	5.66E+06	1.51E+07	-3.31E+07
12	2.24E+07	1.41E+06	4.17E+06	0.00E+00	5.99E+06	1.64E+07	-2.74E+07
13	2.42E+07	1.52E+06	4.38E+06	0.00E+00	6.34E+06	1.79E+07	-2.17E+07
14	2.61E+07	1.64E+06	4.60E+06	0.00E+00	6.71E+06	1.94E+07	-1.60E+07
15	2.83E+07	1.78E+06	4.83E+06	0.00E+00	7.10E+06	2.11E+07	-1.04E+07
16	3.05E+07	1.92E+06	5.07E+06	0.00E+00	7.52E+06	2.30E+07	-4.95E+06
17	3.30E+07	2.07E+06	5.32E+06	0.00E+00	7.97E+06	2.50E+07	4.93E+05

Table 34 Continued:

Year	Revenue	Heat Cost	Main-tenance	Capital	Total Cost	Surplus	NPV
18	3.56E+07	2.24E+06	5.59E+06	0.00E+00	8.44E+06	2.72E+07	5.87E+06
19	3.85E+07	2.42E+06	5.87E+06	0.00E+00	8.94E+06	2.95E+07	1.12E+07
20	4.16E+07	2.61E+06	6.16E+06	0.00E+00	9.48E+06	3.21E+07	1.64E+07
21	4.49E+07	2.82E+06	6.47E+06	0.00E+00	1.00E+07	3.48E+07	2.16E+07
22	4.85E+07	3.05E+06	6.79E+06	0.00E+00	1.06E+07	3.78E+07	2.67E+07
23	5.23E+07	3.29E+06	7.13E+06	0.00E+00	1.12E+07	4.10E+07	3.18E+07
24	5.65E+07	3.55E+06	7.49E+06	0.00E+00	1.19E+07	4.45E+07	3.67E+07
25	6.10E+07	3.83E+06	7.86E+06	0.00E+00	1.26E+07	4.83E+07	4.16E+07
26	6.58E+07	4.14E+06	8.26E+06	0.00E+00	1.34E+07	5.24E+07	4.65E+07
27	7.11E+07	4.47E+06	8.67E+06	0.00E+00	1.42E+07	5.68E+07	5.12E+07
28	7.67E+07	4.82E+06	9.10E+06	0.00E+00	1.51E+07	6.16E+07	5.59E+07
29	8.28E+07	5.20E+06	9.56E+06	0.00E+00	1.60E+07	6.67E+07	6.06E+07
30	8.93E+07	5.62E+06	1.00E+07	0.00E+00	1.70E+07	7.23E+07	6.51E+07

Table 35

Population Density 10,000 Per Sq. Mile

Year	Revenue	Heat Cost	Main-tenance	Capital	Total Cost	Surplus	NPV
1	0.00E+00	0.00E+00	1.70E+05	5.67E+06	5.84E+06	-5.84E+06	-5.84E+06
2	0.00E+00	0.00E+00	3.49E+05	5.95E+06	6.30E+06	-6.30E+06	-1.15E+07
3	0.00E+00	0.00E+00	7.24E+05	1.25E+07	1.32E+07	-1.32E+07	-2.25E+07
4	0.00E+00	0.00E+00	1.11E+06	1.31E+07	1.42E+07	-1.42E+07	-3.32E+07
5	3.25E+06	8.17E+05	1.53E+06	1.38E+07	1.65E+07	-1.32E+07	-4.22E+07
6	3.51E+06	8.84E+05	1.96E+06	1.44E+07	1.77E+07	-1.42E+07	-5.11E+07
7	7.60E+06	9.56E+05	2.42E+06	1.52E+07	1.90E+07	-1.14E+07	-5.75E+07
8	8.21E+06	1.03E+06	2.90E+06	1.59E+07	2.03E+07	-1.21E+07	-6.37E+07
9	1.33E+07	1.11E+06	3.15E+06	8.38E+06	1.31E+07	1.94E+05	-6.36E+07
10	1.44E+07	1.20E+06	3.41E+06	8.80E+06	1.39E+07	4.65E+05	-6.34E+07
11	2.07E+07	1.30E+06	5.56E+06	0.00E+00	7.41E+06	1.33E+07	-5.83E+07
12	2.24E+07	1.41E+06	5.84E+06	0.00E+00	7.83E+06	1.45E+07	-5.32E+07
13	2.42E+07	1.52E+06	6.13E+06	0.00E+00	8.28E+06	1.59E+07	-4.81E+07
14	2.61E+07	1.64E+06	6.44E+06	0.00E+00	8.75E+06	1.74E+07	-4.30E+07
15	2.83E+07	1.78E+06	6.76E+06	0.00E+00	9.25E+06	1.90E+07	-3.80E+07
16	3.05E+07	1.92E+06	7.10E+06	0.00E+00	9.79E+06	2.07E+07	-3.31E+07
17	3.30E+07	2.07E+06	7.46E+06	0.00E+00	1.03E+07	2.26E+07	-2.81E+07

Table 35 Continued:

Year	Revenue	Heat Cost	Main- tenance	Capital	Total Cost	Surplus	NPV
18	3.56E+07	2.24E+06	7.83E+06	0.00E+00	1.09E+07	2.47E+07	-2.32E+07
19	3.85E+07	2.42E+06	8.22E+06	0.00E+00	1.15E+07	2.69E+07	-1.84E+07
20	4.16E+07	2.61E+06	8.63E+06	0.00E+00	1.22E+07	2.93E+07	-1.36E+07
21	4.49E+07	2.82E+06	9.06E+06	0.00E+00	1.29E+07	3.19E+07	-8.88E+06
22	4.85E+07	3.05E+06	9.52E+06	0.00E+00	1.37E+07	3.47E+07	-4.18E+06
23	5.23E+07	3.29E+06	9.99E+06	0.00E+00	1.45E+07	3.78E+07	4.66E+05
24	5.65E+07	3.55E+06	1.05E+07	0.00E+00	1.53E+07	4.11E+07	5.06E+06
25	6.10E+07	3.83E+06	1.10E+07	0.00E+00	1.62E+07	4.47E+07	9.61E+06
26	6.58E+07	4.14E+06	1.15E+07	0.00E+00	1.72E+07	4.86E+07	1.41E+07
27	7.11E+07	4.47E+06	1.21E+07	0.00E+00	1.82E+07	5.28E+07	1.85E+07
28	7.67E+07	4.82E+06	1.27E+07	0.00E+00	1.93E+07	5.74E+07	2.29E+07
29	8.28E+07	5.20E+06	1.34E+07	0.00E+00	2.04E+07	6.23E+07	2.72E+07
30	8.93E+07	5.62E+06	1.40E+07	0.00E+00	2.16E+07	6.77E+07	3.15E+07

Table 36

Net Present Value - Transmission Distant

Transmission Distant	Density Pop. per sq. mile	30,000	20,000	10,000
1 mile		1.00E8*	9.09E7	5.87E7
5 miles		7.39E7	6.52E7	3.15E7
10 miles		4.15E7	3.24E7	-2.75E6

*E8= 10^8

Table 37

Net Present Value - Interest Rate

Interest Rate	Density Pop. per sq. mile	30,000	20,000	10,000
.05		2.31E8	2.18E8	1.65E8
.10		7.39E7	6.52E7	3.15E7
.15		1.80E7	1.17E7	-1.28E7

Table 38

Net Present Value - Energy Inflation Rates

Energy Inflation Rate	Density pop. per sq. mile	30,000	20,000	10,000
.09		1.30E8	1.21E8	8.73E7
.07		7.39E7	6.52E7	3.15E7
.05		3.43E7	2.57E7	-7.69E6

Table 39

Net Present Value - Busbar Cost

Busbar Cost $/kwh	Density pop. per sq. mile	30,000	20,000	10,000
.024		7.39E7	6.52E7	3.15E7
.030		7.09E7	6.22E7	2.86E7
.036		6.80E7	5.93E7	2.57E7

Table 40

Net Present Value - Pipeline Cost

Cost Factor	Density pop. per sq. mile	30,000	20,000	10,000
1x		7.39E7	6.52E7	3.15E7
1.2x		5.95E7	4.88E7	8.67E6
1.4x		4.51E7	3.29E7	-1.37E7

Table 41

Net Present Value - Nominal Rates

Nominal Rates of inflation (construction, energy, interest rate)	Density pop. per sq. mile	30,000	20,000	10,000
.05,.07,.1		7.39E7	6.52E7	3.15E7
.07,.09,.12		7.31E7	6.42E7	2.97E7
.10,.12,.15		7.15E7	6.22E7	2.61E7

Table 42

Net Present Value - Attraction Rate

Attraction Rate	Density pop. per sq. mile	30,000	20,000	10,000
.75 + .008 (I-5)		7.39E7	6.52E7	3.15E7
.70 + .01 (I-5)		6.96E7	6.09E7	2.72E7
.65 + .012 (I-5)		6.53E7	5.66E7	-1.13E7

Table 43

City Population Rank and Density: 1975

City	Rank	Density
New York, NY	1	24,964
Manhattan		62,953
Brooklyn		34,257
Bronx		32,900
Queens		18,182
Staten Island		5,655
Houston, Texas	6	2,744
San Antonio, Texas	11	2,935
San Francisco, California	16	14,637
New Orleans, Louisiana	21	2,840
Denver, Colorado	26	5,090
Cincinnati, Ohio	31	5,283
Toledo, Ohio	36	4,528
Newark, New Jersey	41	14,450
Baton Rouge, Louisiana	46	6,146
Tampa, Florida	51	3,138
Wichita, Kansas	56	2,800
Richmond, Virginia	61	3,856
Shreveport, Louisiana	71	3,020
Minneapolis, Minnesota	34	6,813
St. Paul, Minnesota	52	5,355
Detroit, Michigan	5	9,675
Piqua, Ohio	**	3,276

**Not Available

Source: U.S., Department of Commerce, <u>County and City Data Book: 1977</u>, p. 804.

Table 44

The Relationship Between Feasibility and Sponsoring Agent

Performing Agent	Sponsoring Agent	Location	Feasibility
1. James H. Watt and George Sommerfield (private consultants)	Toledo Edison	Toledo, Ohio	Not feasible.
2. Smith, Minchman, and Grylls (private consultants)	Detroit Edison	Detroit, Mich.	Not feasible.
3. Madison Gas and Electric Co., Wisconsin Public Service Corp., Wisconsin Power and Light	Wisconsin State Energy Office	Madison, Wisc. Greenbay, Wisc. Janesville/ Beloit, Wisc.	Feasible under fortuitous circumstances with private finance; feasible with municipal finance for the distribution system.
4. Georgia Institute of Technology Engineering Experiment Station	City of Piqua, Ohio	Piqua, Ohio	Feasible.

Table 44 Continued:

Performing Agent	Sponsoring Agent	Location	Feasibility
5. Peter Margen (employee of Swedish engineering company)	Oak Ridge National Laboratory	Minneapolis-St. Paul, Minn.	Feasible with municipal finance for the distribution system.
6. Grels Berg (employee of Swedish engineering firm)	New York State Energy Research and Development Agency	Brooklyn and Owens, N.Y.	Feasible.
7. J. Harkleck, E. Beardsworth and J. Powell (employees of Brookhaven National Laboratory	Brookhaven National Laboratory	New York, N.Y. Philadelphia, Pa. Los Angeles, Calif. New Orleans, La. Baton Rouge, La. Jersey City, N.J. Newark, N.J. Paterson, N.J.	Feasible.
8. Gerald Pine (dissertation)	Department of Nuclear Engineering, Massachusetts Institute of Technology	experimental city with New York City temperature pattern	Feasible.

Table 44 Continued:

Performing Agent	Sponsoring Agent	Location	Feasibility
9. I. Oliker (private consultant)	paper delivered at the American Power Conference; preliminary work finance by Oak Ridge National Laboratory	experimental city with peak load 3000 MWt	Feasible.

Table 45

Single Purpose Electric Utility Revenue

	Hours x	Load x	Price =	Revenue
Summer	4380	1232	$.024 kwh	$129,508
Winter	4380	800	$.024 kwh	$ 84,096
(365x24) =	8760			$213,604

Table 46

Gas Sales

Plant Capacity	3080 kw
Plant Heat Efficiency	62%
Pipeline Distribution Efficiency	95%
Hours	4380
Conversion Rate	1 kw = 3413 BTU
Home Boiler Efficiency	70%
Heat Content per MCF	10^6 BTU
Price of Gas	$3.34 per MCF

Table 47

Heat Cost

Coal Cost = \$.01 kwh

I. Incremental Heat Cost

a) Year 1

2540 kw input in dual purpose operation
2000 kw input while generating electricity
540 kw incremental input

Cost = Hours x Input x \$/kwh

\$23,652 = 4380 x 540 x .01

b) Year 2

3080 kw input in dual purpose operation
2000 kw input while generating electricity
1080 kw incremental input

Cost = Hours x Input x \$/kwh

\$47,304 = 4380 x 1080 x .01

II. Proportional

a) Year 1

Output = Electric output + Heat output

1755 = 800 kw + 955 kw

Heat cost proportion $= \frac{955}{1755} = .54$

Cost = Hours x Input x Proportion x \$/kwh

\$60,076 = 4380 x 2540 x .54 x .01

Table 47 Continued:

b) Year 2

Output = Electric output + Heat output

2710 = 800 + 1910

Heat cost proportion = $\frac{1910}{2710}$ = .7

Cost = Hours x Input x Proportion x \$/kwh

\$94,432 = 4380 x 3080 x .7 x .01

Table 48

District Heating Profits

I. Profits under the incremental joint allocation scheme

a) Year 1

Revenue = Potential gas sales x attraction rate x discount

129,388 x .5 x .9

equals 58,224

Revenue	58,224
Heat cost	23,652
Other costs	50,000
Profits	-15,428

b) Year 2

Revenue = Potential gas sales x attraction rate x discount
129,388 x 1.0 x .9

equals 116,449

Revenue	116,449
Heat cost	47,304
Other costs	50,000
Profits	19,145

II. Profits under the proportional joint cost allocation scheme

a) Year 1

Revenue	58,224
Heat costs	60,076
Other costs	50,000
Profits	-51,852

b) Year 2

Revenue	116,449
Heat costs	94,432
Other costs	50,000
Profits	-27,983

Table 49

Profits of the Electric Utility

I. Profits under the incremental joint cost allocation scheme

a) <u>Year 1</u>

	Revenue	Costs	Economic Profit
Electric Business	213,604	213,604	0
Heat Sale	23,652	23,652	0
Flow of Funds		+ 5,428	- 15,428
Total	237,256	252,684	- 15,428

b) <u>Year 2</u>

	Revenue	Costs	Economic Profit
Electric Business	213,604	213,604	0
Heat Sales	47,304	47,304	0
Flow of Funds	19,145	0	19,145
Total	280,053	260,908	19,145

Net present value of economic profits assuming a 10 percent discount rate

NPV = -15,428 + 17,404 = 1,976

Table 50

The Detroit Edison Company Availability

Incentive Provision

System Availability (ECAR) Plus Periodic Factor	Equity Return Incentive
100% - 92.01%	+ .50%
92.00% - 90.76%	+ .40%
90.75% - 89.51%	+ .30%
89.50% - 88.26%	+ .20%
88.25% - 87.01%	+ .10%
87.00% - 81.01%	- 0 -
81.00% - 80.01%	- .05%
80.00% - 79.01%	- .10%
79.00% - 78.01%	- .15%
78.00% - 77.01%	- .20%
77.00% -	- .25%

Source: Michigan Public Service Commission, Exhibit D: Availability Incentive Clause Filing Requirements, Detroit Edison Case Number U-6006, p. 2.

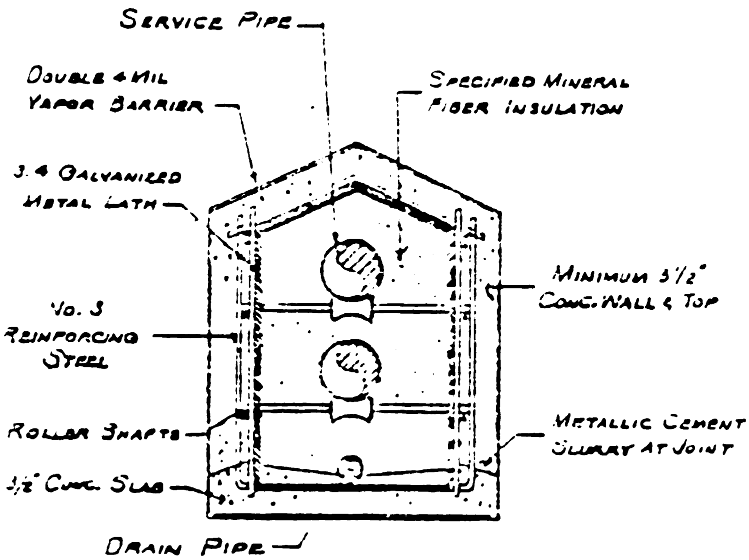


Figure 21

Insulated Pipe in Concrete Enclosure

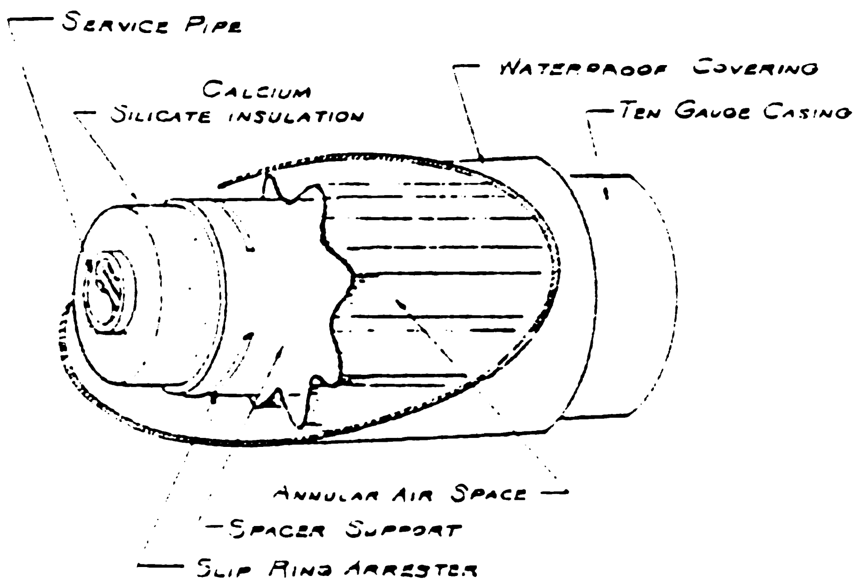


Figure 22

Insulated Pipe in Steel Conduit

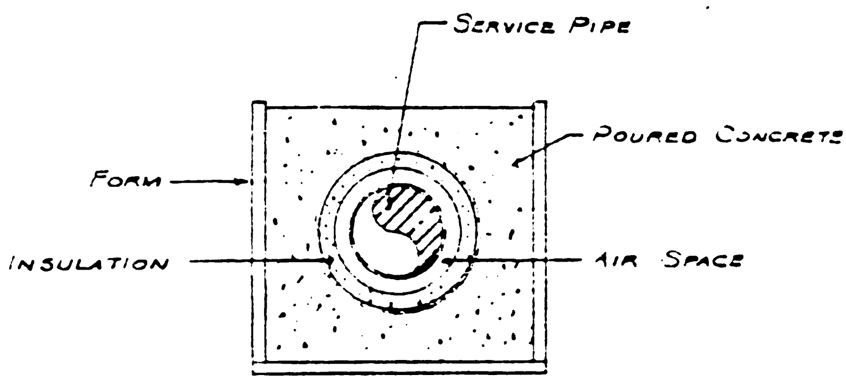
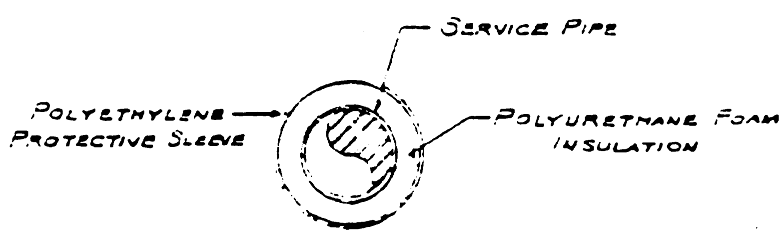


Figure 23

Insulated Pipe in Poured Concrete



INSULATED PIPE
IN PLASTIC CONDUIT

TYPICAL CONSTRUCTION BASED ON DETAILS SUPPLIED BY M. L. SHELDON PLASTICS CO.

Figure 24

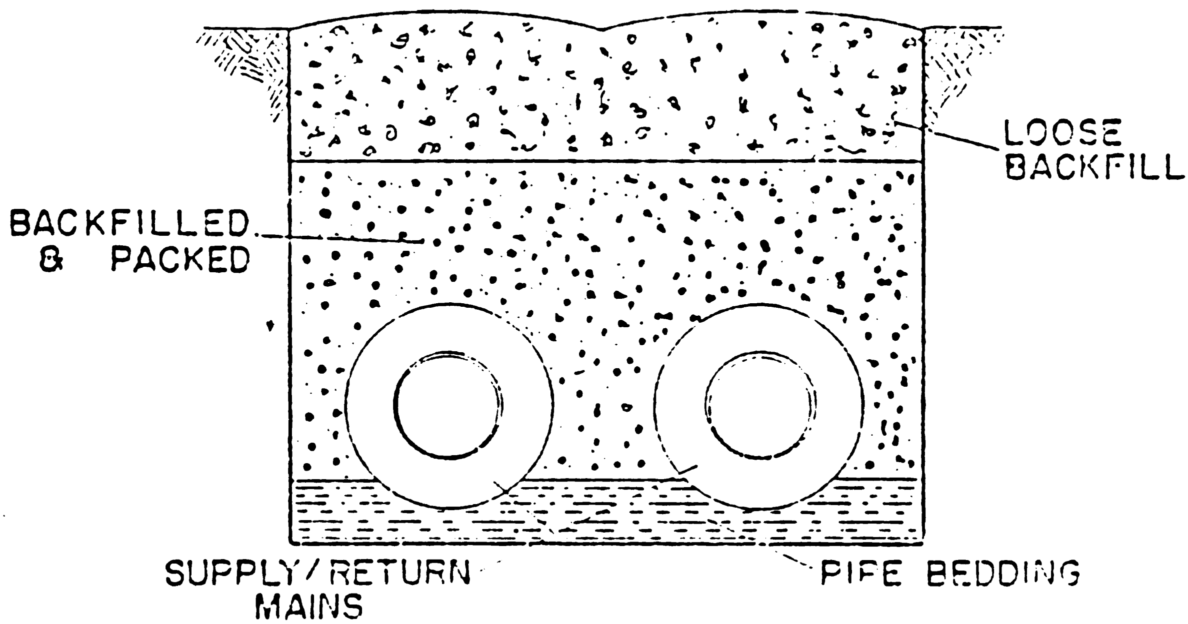
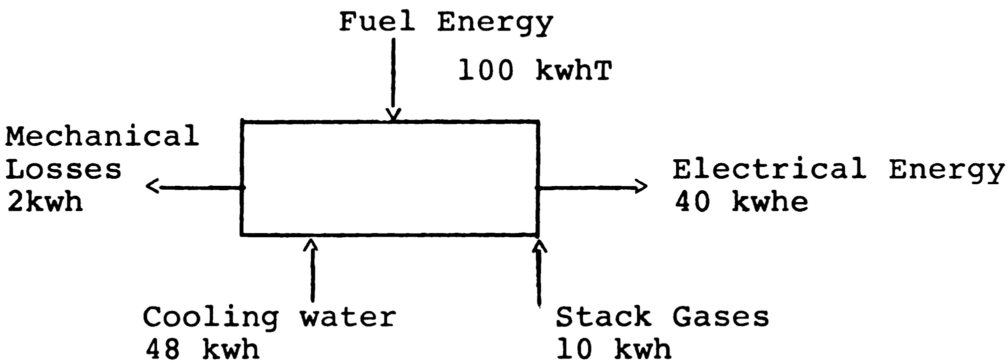


Figure 25

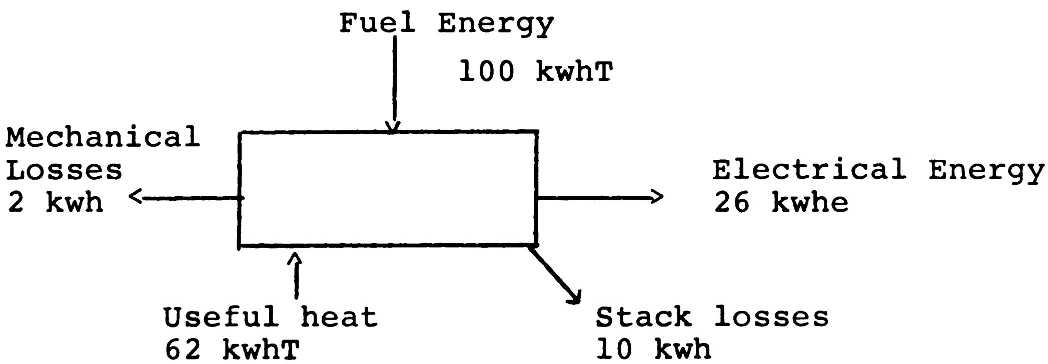
Insulated Pipe - Construction Completed

I. Fossil fuel fired electric plant energy cycles

a) Conventional: Heat rejection
To cooling water at 100°F



b) Waste Heat utilization
Heat rejection at 300°F



II. Alternative stylized instanteous input/output choices of the hypothetical electrical utility

Input	Output
1. 3080 kw_t	1. 1232 kw_e
2. 3080 kw_t	2. 800 kw_e 1910 kw_t
3. 2540 kw_t	3. 800 kw_e 955 kw_t
4. 2000 kw_t	4. 800 kw_e

Figure 26

Electric Utility Technology

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CHAPTER IV

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[15]Mikkelsen, "Development of District Heating in Denmark," p. 762.

[16]U.S., Department of Energy, *Monthly Energy Review*, April 1982, p. 88.

[17]Mikkelsen, "Development of District Heating in Denmark," p. 756.

[18]The national average gas price for Commercial customers is calculated by dividing revenue by sales for commercial customers. For 1980, the price was $3.34 per MCF; See American Gas Association, *Gas Facts* (Arlington, Virginia: American Gas Association, 1980), p. 75.

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[25]Pine, "Assessment of Integrated Urban Energy Options," p. 87.

[26]$\$3.34/\text{MCF} \times \frac{1\text{MCF}}{10^6\text{BTU}} \times \frac{1}{.7} = \frac{\$4.77}{10^6\text{BTU}}$

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[54]Mathew McLogan, Commissioner, Michigan Public Service Commission, interviewed 14 December 1982.

[55]The variable values were: one, transmission distance, 10 miles; two, interest rate, .015; three, energy inflation rate, .05; four, pipeline cost, 1.44; five, attraction rate, .65 + .012(I-5).

[56]EUS, Incorporated, Dual Energy Use Systems - District Heating Systems, p. 4.7.

[57]Wisconsin Energy Office, Power Plant Retrofit, p. 4:39.

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[59]Ibid., p. 4:43.

[60]Ibid.

[61]City of Piqua, Power Plant Retrofit, p. 191.

CHAPTER V

CONCLUSION

Most economists will agree that if it is possible to make at least one person better off without making anyone worse off, social welfare has increased. This study shows first, that such a possibility exists, and second, that the transformation of the possibility into reality mandates a change in the present system of regulation.

The source of the potential gain lies in the existence of an x-inefficiency. In particular, the present system of electric and heat supply is more expensive than an alternative mode. Today, electricity is usually generated at power plants that dissipate two-thirds of the energy input into the atmosphere. Only one-third is transformed into electricity. Natural gas, where it is available, is the cheapest form of heat supply for most individuals. Alternatively, both heat and electricity can be generated from the same plant. The plant is connected to both an electric grid and a heat supply pipeline network. It has been shown, under a set of reasonable conditions, that the second alternative is cheaper than the first. That is, the savings in energy costs associated with cogeneration are greater than the expense of constructing a new pipeline network. The net savings, calculated in net present value terms, is the measure of the x-inefficiency.

Harvey Leibenstein offered three causes for its existence. "These are: a) contracts for labor are incomplete, or b) the production function is not completely specified or known, or c) not all inputs are marketed, or if marketed, are not available on equal terms to all buyers."[1] This study offers a fourth cause based on the theory of bounded rationality. It is that humans will purposefully ignore possible benefits in order to accomplish more limited satisficing goals; and with the passage of time, it will no longer be necessary to ignore the benefits because their existence will be forgotten. The utility companies built electric companies. They could have built full-service energy empires.

It is also necessary to explain the existence of the small and declining district heating industry in the United States. One explanation, consistent with the theory of bounded rationality, is that the industry was used as a loss leader. It gathered in customers for the electric utility. Once it had served its purpose, it was ignored and left to decline.

The alternative hypothesis is that at one time district heating was profitable, but now it is not. The cause of this reversal was the completion of the interstate natural gas pipeline network in the early 1950's. With the introduction of gas, district heating companies lost customers to gas companies, revenues dropped relative to cost, so profits fell. In order to substantiate this hypothesis, it is necessary to show: first that natural gas and steam are substitutes, second, that the decline in the price of natural gas relative to steam was sufficiently large to induce fuel substitution by a large number of steam customers, and third, that evidence of fuel substitution exists.

Two commodities are considered substitutes "if compensating variations in income keep the consumer on the same indifference curve, an increase in price of commodity one will induce the consumer to substitute commodity two for commodity one. Then $\left[\frac{\partial q_2}{\partial P_1}\right]_{u = \text{const}} > 0$."[2] To test the hypothesis that steam and gas were substitutes, a series of demand curves was estimated. In only 14 of 244 estimated steam demand curves was the gas coefficient positive and significant. This evidence will not support a claim that steam and gas are substitutes. However, it simultaneously will not support the claim that steam and gas are not substitutes. The estimations, if the demand curves model reality accurately, can only estimate the uncompensated demand curve. Therefore the coefficient reported reflects the response of the quantity of steam demanded to a change in price. The response includes both an income and substitution effect. If the income effect overwhelms the substitution effect, then substitutes can appear to be complements or independent.

Even if the demand curves were estimated incorrectly or if the income effect overwhelmed the substitution effect, implying that steam and gas were substitutes, it still would be necessary to show that substitution of fuel inputs took place.

Data on the number of customers who switched from steam to gas are not available prior to 1969. However, implications can be drawn from the available data. It is known that the price of gas was higher than the price of steam in terms of energy units purchased prior to 1970 in the majority of cities studied. Customers incur transformation costs when switching from steam to gas. Labor and insurance costs associated with gas heat are higher than those associated with steam heat. Thus, few customers had an incentive to switch.

An examination of customer trends reveals the following set of facts. The number of customers served by the eleven major cities peaked in 1954 and has declined steadily since then. The percent of total industry customers served by the eleven major cities rose steadily from 1950 to 1969 and continued to rise during the seventies. For the entire industry, new customers added exceeded the number of customers lost to other heat suppliers in every year prior to 1973.[4]

From this set of facts one can conclude that the decline in customers served was due to the loss of potential customers within the service area rather than a loss of customers to a competitive fuel, and that potential customers within the service area preferred steam heat to alternative fuels at least until 1973.

This combination of evidence discounts the thesis that customer substitution to natural gas explains the low profits of the district heating industry and that, in turn, low profits explain the retarded state of the industry.

This line of reasoning exposes another unanswered question. Why did the industry remain within its old boundaries, when its customers moved? Here the availability of natural gas could provide an answer. That is, while natural gas could not penetrate the existing service area, it did provide a ring around the service area. In fulfilling this function, the availability of natural gas led to the downfall of the industry.

Again, evidence contradicting the latter hypothesis is available. This evidence supports the notion that lack of interest, rather than lack of profits, led to the demise of the industry.

First, the U.S. industry did not avail itself of techniques developed in Europe. These techniques--hot water distribution, pre-fabricated pipe, and trash burning--reduce the cost of district heating and allow the costs to remain low when the service area is extended.

Second, there is no record of established firms attempting to extend service areas. Executives who were interviewed stated that their companies did not investigate potential extension of service into urban renewal areas during the 1950's and 1960's.

Third, the only new system built during the 1960's was built due to the persistence of a real estate developer. The developer insisted that burning gas in a central boiler and distributing heat via steam pipes was cheaper than distrubuting gas to the individual buildings where it would burn in smaller boilers.

Finally, a series of feasibility studies provide examples of potentially profitable new service areas. If the industry had pursued these possibilities, it might have fulfilled its potential. Instead the companies did nothing.

The Institutional Setting

The district heating industry in Europe is viable and growing. Government ownership and/or promotion is often cited as the crucial reason for the European success. The government finances the projects. In so doing, it provides the financial resources that every project needs in the developmental years, and it subsidizes the projects through lower than market interest rates.

While this study recognizes district heating projects' need for financial backing, it shows that the backing need not be a subsidy. In Europe, it is recognized that heating via district heating is provided at a cost significantly less than alternatives. European executives believe that their companies would earn significant profits if they were allowed to behave according to private ownership standards.[5]

District heating projects in the United States also need financial backing during their developmental years. Here, governments are reluctant to finance utilities directly. However, commissions do allow one group of utility customers to finance projects that serve another group. These financing schemes usually occur across time. It could also occur when electric customers finance the development of district heating. The justification for such action is that electric customers will receive reduced rates in the future.

Finally, the electric utility reluctance to take on new district heating projects must be addressed. A plan to overcome that reluctance was proposed. The plan would allow the utility to keep part of the net benefits through higher allowed rates of return.

Why should a utility receive a bonus for simply performing its legitimate tasks? The bonus is needed to crack the shell of self-imposed restrictions. The commission holds up the bait of higher returns to utility executives so they will recognize and invest in profitable projects.

Table 51

Changes in Customers Served:

All Cities, 1950-1978

Year	New Customers	Customers Lost to Other Heat Suppliers*
1950	984	81
1951	849	54
1952	676	70
1953	529	47
1954	521	44
1955	510	44
1956	448	59
1957	455	73
1958	355	50
1959	275	71
1960	278	41
1961	258	42
1962	291	56
1963	247	70
1964	231	80
1965	305	56
1966	218	82
1967	224	57
1968	352	19
1969	241	54 (45)
1970	203	46 (38)
1971	133	70 (56)
1972	130	60 (55)
1973	31	58 (42)
1974	102	86 (22)
1975	42	154 (50)
1976	73	128 (30)
1977	85	73 (16)
1978	67	95 (23)

Source: "Annual Business Report for 1978," Proceedings of the Seventieth Annual International District Heating Association (Pittsburgh: International District Heating Association, 1979), pp. 1-2.

*The numbers in parenthesis are the number of steam customers that switched to gas.

REFERENCE

CHAPTER V

[1]Harvey Leibenstein, "Allocative vs. X-Efficiency," *American Economic Review* 56(June 1966), p. 412.

[2]Henderson and Quandt, *Microeconomic Theory*, 3rd ed., p. 31.

[3]*Ibid*., p. 32.

[4]See Table 51, p. 294.

[5]Larsson, "Development Plans for a Low Temperature Heating System in Odense," p. 128.

APPENDIX

Table 52

Model One: Ordinary Least Squares 1946-78

City	B_0	P_S B_1	P_G B_2	NC B_3	DD B_4	YR B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Concord	-403.4* (733)	2.14 (4.72)	14.2* (7.54)	.086 (.099)	.018* (.005)	4.71* (1.01)	.95	33	.58
Piqua	227.2 (66.6)	-110.9* (15.8)	-16.1 (21.3)	7.73* (3.19)	.018* (.008)	-1.21* (.297)	.84	28	1.73
Philadelphia	-8686* (732)	-813.8* (135)	-169.7 (330)	.41 (2.26)	.053 (.164)	249.6* (29.7)	.99	33	1.01
New York	-167328* (27067)	-2048.4* (685)	7721* (1913)	42.4* (7.96)	.673 (.48)	1194.3* (123)	.96	33	.66
Toledo	-61.37 (282)	-77.7* (16.9)	-52.2 (77.0)	1.23 (.89)	.102* .023	1.87 (2.34)	.78	33	.98
Detroit	-3968.1 (3078)	-334.8 (360)	-1120.7 (829)	1.39* (.53)	.278 (.22)	118.7* (27.4)	.90	33	.94
Boston	1896 (6187)	-315.96 (212.9)	383.4 (439.9)	-7.24* (2.58)	-.357 (.333)	127.7* (54.0)	.88	33	.65
Indianapolis	-3307.1 (4801)	182.7 (399.2)	650.1 (677)	1.09 (.84)	.177 (.19)	57.5 (50.3)	.38	33	.73
Rochester	2407* (1161)	-314.8* (47.3)	-442.6* (131.1)	2.01 (1.89)	.043 (.079)	32.98* (11.74)	.96	33	1.60

Table 52 (Continued)

City	B_0	P_S B_1	P_G B_2	NC B_3	DD B_4	YR B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Baltimore	-2699 (1703)	-213.2 (137)	495.3 (223.9)	.109 (.53)	-.152 (.134)	68.8* (15.8)	.89	33	.80
Cleveland	2287 (4162)	74.9 (156.6)	-248.88 (400)	1.72 (3.4)	-.152 (.168)	4.31 (39.8)	.27	33	2.19
St. Louis	1851 (1440)	-188.9* (62.8)	-443.4* (203.1)	-0.07 (.71)	.167* (.09)	3.57 (.27)	.69	33	1.14
Dayton	215.7 (476)	-168.1* (47.1)	-699.1* (84.2)	2.39* (.49)	.051 (.034)	17.67* (3.69)	.94	33	1.44
Akron	-63.84 (321.1)	-91.7* (25.0)	-24.6 (98.7)	.852* (.27)	.045* (.020)	6.38* (3.72)	.81	30	1.79
San Diego	-745.5* (130.6)	229.0* (39.2)	-392.5* (63.43)	1.17* (.40)	.058* (.012)	13.86* (.89)	.99	24	1.66
Pittsburgh	102.9 (666)	-92.3* (24.2)	-395.8* (130.7)	2.23* (.81)	.086 (.054)	14.7* (5.5)	.83	33	1.30
Denver	-1247.7* (170)	-16.58 (92.9)	-523.3* (176.4)	.327 (.71)	.029 (.013)	38.1* (1.48)	.98	33	1.38
Seattle	313.5 (730)	-205.9* (28.6)	38.26 (23.5)	-.56 (.53)	.104* (.03)	15.09* (6.4)	.92	33	1.3
Harrisburg	4921.9* (1258)	-53.3* (26.1)	-584.5* (106.9)	-1.49* (.57)	.128* (.047)	-35.2* (11.3)	.87	33	1.58

Table 52 (Continued)

City	B_0	P_S B_1	P_G B_2	NC B_3	DD B_4	YR B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Atlanta	436.3	44.85*	-244.4*	.54*	.086*	-.294	.78	30	1.64
	(292.7)	(13.62)	(59.56)	(.29)	(.021)	(3.24)			
Grand Rapids	-755.09	-37.17	134.49	-.995	-.022	21.6*	.80	30	.33
	(1282)	(110.2)	(229.6)	(4.87)	(.04)	(7.7)			

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Table 53

Model One: Ordinary Least Squares 1947-78
Using Cochrane-Orcutt Transformed Data

City	B_0	P_S B_1	P_A B_2	NC B_3	DD B_4	YR B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Concord	-85.89* (16.13)	1.98 (3.38)	3.87 (5.03)	.084 (.05)	.012* (.002)	3.97* (.67)	.86	32	1.60
Piqua	262.9* (63.6)	-107.9* (13.9)	-11.7 (19.7)	4.06 (3.38)	.018* (.006)	-1.40* (.29)	.86	27	1.64
Philadelphia	-4404.7* (406.4)	-602.9* (163.3)	-77.2 (401.7)	4.09 (2.62)	.05 (.13)	200.7* (34.5)	.97	32	1.69
New York	-32456* (6115)	-1926.1* (541)	870.5 (1447)	24.9* (5.38)	.53 (.006)	956 (91.7)	.90	32	1.19
Toledo	192 (137)	-68.5* (18.0)	-43.5 (91.4)	-.216 (.44)	.054* (.018)	.59 (2.17)	.61	32	1.24
Detroit	-914.2 (1400)	-601.9 (397)	-392.6 (860)	.612 (.64)	.194 (.16)	106.9* (28.9)	.68	32	1.84
Boston	-4752* (2455)	-198.8 (160.7)	580.1 (395)	4.91 (4.92)	.194 (.148)	246.6* (79.7)	.66	32	1.04
Indianapolis	15.4 (1433)	-207.5 (331)	589.1 (513.9)	-.15 (91)	.329* (1.28)	26.1 (37.9)	.24	32	1.48

Table 53 (Continued)

City	B_O	P_S B_1	P_A B_2	NC B_3	DD B_4	YR B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Rochester	2753 (1103)	-282.9* (46.9)	-544.3* (131.9)	.649* (.36)	.060 (.07)	26.7* (11.4)	.96	32	1.88
Baltimore	-1496 428	-157.7 (99.1)	241 (190)	.313 (1.146)	.186* (.07)	66.1* (10.2)	.83	32	.74
Cleveland	5287 (4599)	-40.0 (173)	47.0 (444)	-.523 (3.73)	-.222 (.17)	-17.7 (42.0)	.31	32	2.29
St. Louis	-471 (726)	-111.7 (86.0)	-951.2* (343.8)	1.46* (.637)	.337* (.06)	21.7* (13.8)	.90	32	1.94
Dayton	197.4 (544)	-165.9* (55.9)	-702.9* (99.6)	2.41 (.54)	.051 (.036)	17.7* (3.88)	.92	32	1.43
Akron	736 (183)	-57.5 (25.1)	-202.9* (103)	.091 (.075)	.083* (.017)	-3.66* (1.37)	.74	29	1.31
San Diego	-736* (130)	236.5* (39.6)	-406.6* (64.5)		.062* (.013)	13.7* (.90)	.99	23	1.83
Pittsburgh	330 (555)	-110.0* 30.7	-282.6* 159.8	1.50 1.05	.087* (.048)	11.8* (1.82)	.70	32	1.79
Denver	-882* (142)	-62.1 (89.0)	-423.9* (178)	-.084 (.89)	.018 (.012)	38.3* (1.77)	.96	32	1.59
Seattle	-408 (696)	-178.9* (33.8)	33.6 (29.7)	.101 .72	.12 (.03)	21.4* (9.36)	.87	32	1.52

Table 53 (Continued)

City	B_0	P_S B_1	P_A B_2	NC B_3	DD B_4	YR B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Harrisburg	5173*	-57.1*	-580.9*	-1.60*	.119*	-36.9*	.87	32	1.59
	(1445)	(28.4)	(109.7)	(.64)	(.054)	(12.4)			
Atlanta	391.8	49.5*	-275.6*	.596*	.089*	.273	.78	29	1.62
	(306)	(16.1)	(81.4)	(.306)	(.022)	(3.42)			
Grand Rapids	-397*	-34.2	-62.9	3.22	.014	34.3*	.60	29	1.81
	(139)	(62.4)	(117.7)	(2.53)	(.014)	(7.3)			

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Table 54

Model Two: Ordinary Least Squares 1946-78

City	B_O	P_S B_1	P_A B_2	NC B_3	DD B_4	RS B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Concord	-109.25* (38.12)	-6.31 (5.67)	-4.93* (2.82)	.041 (.08)	.015* (.004)	.116* (.018)	.97	33	1.11
Philadelphia	6256. (4131)	-182.18 (157.43)	542.14 (487.41)	14.23* (1.51)	-.231 (.25)	-.238* (.07)	.97	33	1.15
New York	34929 (35000)	-1832 (1184)	-5162* (1391)	38.44* (10.25)	1.00 (1.85)	-.633* (.11)	.94	33	1.33
Detroit	9559* (2299)	-228.3 (573)	-2271* (903)	1.76* (.87)	.277 (.272)	-.16* (.06)	.85	33	1.14
Rochester	5079* (882)	-181.8* (59.5)	-802.7* (39.5)	-.804 (.65)	.036 (.08)	.069 (.08)	.95	33	2.04
Cleveland	2688 (1743)	84.9 (256)	-279.8 (352)	2.10 (4.6)	-.15 (.16)	-.018 (.13)	.27	33	2.13
Boston	13629* (2520)	175.3 (189)	-557.8* (220)	-7.33* (4.13)	-.48 (.341)	-.09 (.179)	.87	33	.61
Denver	-2636 (331)	361.0* (151.7)	-606.9* (223)	-1.81 (1.55)	.03 (.02)	.288* (.027)	.94	33	1.19

Table 54 (Continued)

City	B_0	P_S B_1	P_A B_2	NC B_3	DD B_4	RS B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Seattle	2283* (499)	-255.7* (50)	29.2 (29)	-2.22* (.36)	.09* (.04)	.005 (.015)	.88	33	1.12
Harrisburg	1226* (386)	-102.1* (29.9)	-388.1* (67.1)	.672* (.218)	.107* (.05)	-.207* (.096)	.84	33	1.44
Baltimore	4731* (765)	219.5* (120)	-392.9* (56.6)	-.162 (.233)	.03 (.07)	-.159* (.029)	.97	33	1.57
St. Louis	4348* (1110)	-1390* (355)	-408.7* (132)	-.42 (.71)	.327* (.07)	-.036 (.043)	.85	33	.91
Dayton	1814* (333)	-143.7* (49)	-684.4* (99)	-1.18* (.57)	.12* (.02)	.158* (.05)	.93	33	1.39
Pittsburgh	2085* (418)	-96.25* (22)	-462.9* (106)	.09* (.05)	2.66* (.947)	-.08 (.03)	.84	33	1.50

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Table 55

Model Two: Ordinary Least Squares 1947-78
Using Cochrane-Orcutt Transformed Data

City	P_S B_1	P_G B_2	NC B_3	DD B_4	RS B_5	Correlation Coefficient	# of Observation
Concord	-5.18	-8.42*	.0001	.0001	.12*	.99	32
	(3.5)	(2.2)	(.11)	(.02)	(.02)		
Philadelphia	-11.54	1129*	16.5*	-0.23	-.135*	.99	32
	(92)	(534)	(.88)	(.37)	(.02)		
New York	-688	-5291*	42.7*	2.4	-.66*	.99	32
	(701)	(1047)	(5.42)	(1.8)	(.11)		
Detroit	40.2	-378.6*	-2.03*	.23*	.33*	.99	32
	(38)	(160)	(.84)	(.03)	(.07)		
Rochester	42.1	-734.1*	-2.19*	.46*	.35*	.99	32
	(50.6)	(49.2)	(.81)	(.07)	(.08)		
Cleveland	215.1*	116.5	-2.96	.13*	.16	.98	32
	(118)	(457)	(5.09)	(.06)	(.13)		
Boston	601.3*	-515.7	-8.69	1.24*	.11	.97	32
	(194)	(359)	(7.69)	(.34)	(.33)		
Denver	496.9*	-1696.2*	-1.77*	.06*	.13*	.99	32
	(45.7)	(112)	(.90)	(.02)	(.016)		

Table 55 (Continued)

City	P_S B_1	P_G B_2	NC B_3	DD B_4	RS B_5	Correlation Coefficient	# of Observation
Seattle	-88.4* (29.1)	10.46 (38.0)	-1.23* (.31)	.23* (.04)	.05* (.01)	.99	32
Harrisburg	-31.5 (19.6)	-524.2* (84.1)	1.1* (.22)	.30* (.03)	-.28* (.10)	.99	32
Baltimore	422.9* (59.9)	-407.6* (107)	-1.13* (.56)	.49* (.15)	.03 (.04)	.99	32
St. Louis	-111.6 (67.9)	-858.9* (156)	-1.53* (.67)	.55* (.04)	.09* (.02)	.99	32
Dayton	40.2 (38)	-378.7* (160)	-2.04* (.84)	.23* (.03)	.33* (.07)	.99	32
Pittsburgh	-28.1 (20.0)	-709.1* (141)	3.84* (1.32)	.32* (.03)	-.05 (.03)	.99	32

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Table 56

Model Two: Generalized Least Squares 1946-78

City	B_0	P_S B_1	P_A B_2	NC B_3	DD B_4	RS B_5
Concord	-87.44* (26.4)	-1.02 (4.15)	-7.42* (2.06)	.108* (.05)	.01* (.003)	.092* (.012)
Philadelphia	5436* (2246)	-120.9 (105.3)	648.8* (235.6)	13.9* (.80)	-0.12 (.12)	-.23* (.04)
New York	65711* (22258)	-2100* (952)	-5621* (977)	30.3* (6.05)	.271 (1.16)	-.67* (.08)
Detroit	9653* (1693)	280.0 (415)	-3192* (680)	2.07 (.64)*	.113 (.20)	.146 (.04)*
Boston	12459* (1668)	295.4* (134.1)	-518.5* (158.8)	-5.40* (2.59)	-0.51* (.21)	-.11 (.11)
Rochester	5420.2* (751)	-179.1* (52.3)	-810.4* (38.0)	-.41 (.53)	-.007 (.08)	.04 (.06)
Cleveland	4673.3* (1525)	-93.5 (214.5)	-224.1 (332.4)	2.19 (3.89)	-.34* (.14)	-.04 (.11)
Denver	-2656* (281.5)	442.2* (111.4)	-547.0* (174.5)	-.54 (1.15)	.005 (.017)	.27* (.021)
Seattle	1986.4* (291)	-170.8* (30.65)	4.34 (15.0)	-1.84* (.21)	0.10* (.02)	-.003 (.009)

Table 56 (Continued)

City	B_0	P_S B_1	P_A B_2	NC B_3	DD B_4	RS B_5
Harrisburg	720.6*	-70.2*	-357.9*	.69*	.16*	-.16*
	(293)	(24.5)	(54.9)	(.17)	(.04)	(.07)
Baltimore	4224.7*	291.9*	-388.3*	-.09	.07	-.15*
	(507)	(81)	(41.9)	(.14)	(.05)	(.019)
St. Louis	3624*	-1146*	-343.3*	.11	.32*	-.04*
	(724)	(244)	(85)	(.42)	(.04)	(.02)
Dayton	2301*	-192.2*	-774.8*	-1.11*	.10*	.12*
	(271)	(41)	82	(.46)	(.02)	(.04)
Pittsburgh	1791*	-79.4*	-472.3*	2.82*	.10*	-.07*
	(377)	(20.7)	(94.6)	(.81)	(.04)	(.02)

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Number of observations = 33

Weighted R-square for the system = .9619

Table 57

Model Two: Generalized Least Squares 1947-78
Using Cochrane-Orcutt Transformed Data

City	P_S B_1	P_A B_2	NC B_3	DD B_4	RT B_5
Concord	1.20	-10.2*	.04	.003*	.09*
	(2.66)	(1.77)	(.07)	(.001)	(.01)
Philadelphia	85.0	393.8	14.15*	.36*	-.15*
	(64.1)	(276.8)	(.49)	(.17)	(.01)
New York	157.8	-4928*	36.4*	2.72	-.56*
	(556)	(850)	(3.55)	(1.34)	(.08)
Detroit	289.8	-3270*	1.82*	1.40*	-.08
	(317)	(870)	(.79)	(.12)	(.05)
Rochester	57.8	-631.8*	-1.68*	.43*	.31*
	(38.0)	(43.6)	(.53)	(.05)	(.05)
Cleveland	243.5*	250.6	-.08	.039	.09
	(108)	(405)	(4.35)	(.06)	(.11)
Boston	766.7*	-307.4	-7.46*	.87*	.13
	(123)	(195)	(3.59)	(.21)	(.15)
Denver	500.5*	-1643*	-.83	.047*	.126*
	(37.7)	(89.1)	(.64)	(.01)	(.01)
Seattle	-25.6	-20.9	-.69*	.197*	.039*
	(18.8)	(19.2)	(.17)	(.02)	(.008)

Table 57 (Continued)

City	P_S B_1	P_A B_2	NC B_3	DD B_4	RT B_5
Harrisburg	-26.8* (14.9)	-422.6* (63.9)	.90* (.16)	.25* (.02)	-.16* (.07)
Baltimore	437* (43.4)	-356.6* (74)	-.83* (.34)	.45* (.09)	.02 (.02)
St. Louis	-72.4 (55.8)	-671.2* (131.7)	-0.55 (.52)	.46* (.04)	.059* (.02)
Dayton	24.9 (34.4)	-337.5* (136)	-1.2 (.72)	.22* (.02)	.26* (.05)
Pittsburgh	-24.3 (15.0)	-624.2* (98.8)	2.28* (.82)	.29* (.03)	-.002 (.02)

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Weighted R-square for system = 0.9972

Number of observations = 32

Table 58

Model Two: Ordinary Least Squares 1946-78

City	B_0	P_S B_1	P_A B_2	NC B_3	DD B_4	RS B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Concord	-131.4* (31.3)	2.08 (8.45)	7.52* (2.87)	1.07* (.197)	.008* (.004)	.06* (.017)	.97	27	1.67
Philadelphia	5118 (4569)	426.0 (574)	1150.* (576)	14.6* (1.64)	-.09 (.27)	-.27* (.07)	.98	27	1.07
New York	-1357 (59069)	6817 (4140)	-5188* (1771)	47.6* (14.6)	2.29 (2.2)	.71* (.17)	.92	27	1.19
Detroit	9272* (3005)	42.7 (813)	-1571 (1419)	1.82* (.98)	.35 (.40)	-.21* (.09)	.84	27	1.17
Rochester	5894* (1370)	-233.1 (252)	-813.5* (47.4)	-.22 (.85)	.012 (.12)	-.03 (.10)	.96	27	1.86
Cleveland	5467* (2808)	-148.1 (636)	-1046 (674)	3.26 (5.35)	-.38 (.22)	-.06 (.16)	.31	27	2.36
Boston	16017* (2999)	1088* (425)	-338.4 (237)	-12.6* (4.22)	-.46 (.39)	-.18 (.17)	.82	27	.75
Denver	-76.65 (571)	48.53 (136)	-1554* (284)	-.73 (1.17)	.018 (.019)	.16* (.03)	.96	27	1.65

Table 58 (Continued)

City	B_0	PS B_1	PA B_2	NC B_3	DD B_4	RS B_5	Correlation Coefficient	# of Observation	D. W. Statistics
Seattle	2746* (421)	-313.5* (96.4)	52.1* (24.5)	-2.73* (.37)	.08* (.03)	.001 (.01)	.91	27	1.16
Harrisburg	1871* (435)	-337.3* (104.7)	-383.1* (76)	.63* (.18)	.10* (.04)	-.28* (.08)	.61	27	1.96
Baltimore	3983* (822)	318.5 (208)	-378.3* (69)	-.31 (.25)	.067 (.07)	-.13* (.03)	.93	27	1.27
St. Louis	-889.9 (1281)	1898* (605)	4.97 (159)	1.75* (.84)	.186* (.06)	-.15* (.043)	.91	27	1.73
Dayton	2677* (577)	-364* (139)	-1041* (185)	-.32 (.69)	.067 (.04)	.10 (.06)	.90	27	1.13
Pittsburgh	1490* (534)	104.6 (85)	-432.3* (118)	2.12* (.89)	.11* (.05)	-.07* (.03)	.79	27	1.40

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Table 59

Model Two: Ordinary Least Squares 1947-72
Using Cochrane-Orcutt Transformed Data

City	P_S B_1	P_G B_2	NC B_3	DD B_4	RS B_5	Correlation Coefficient	# of Observation
Concord	4.70 (3.40)	-6.89 (13.37)	1.01* (.26)	-.005 (.005)	.067* (.024)	.99	26
Philadelphia	841 (538)	1857* (604)	16.6* (.86)	-.23 (.37)	-.23* (.03)	.99	26
New York	7980* (3635)	-6400* (1208)	42.1* (5.76)	3.73* (2.10)	-.84* (.13)	.99	26
Detroit	207.7 (906)	-567.4 (2014)	3.00* (1.24)	1.6* (.32)	-.27* (.13)	.99	26
Rochester	516.6* (234)	-754.2* (51.0)	-2.06* (.82)	.40* (.09)	.28* (.09)	.99	26
Cleveland	885.5* (416)	-.18 (915)	-5.17 (5.48)	-.03 (.12)	0.19 (-.94)	.99	26
Boston	651 (719)	-271.2 (413)	-8.91 (8.3)	1.4* (.44)	.018 (.34)	.96	26
Denver	-131.3 (127)	-1545* (143)	-.91 (.98)	.038* (.016)	.16* (.015)	.99	26

Table 59 (Continued)

City	P_S B_1	P_G B_2	NC B_3	DD B_4	RS B_5	Correlation Coefficient	# of Observation
Seattle	-144.3 (190.3)	18.44 (42.2)	-1.31* (.60)	.24* (.06)	.06* (.01)	.99	26
Harrisburg	-55.2 (101)	-428.8* (119)	1.05* (.25)	.31* (.04)	-.30* (.10)	.99	26
Baltimore	1133* (243)	-492.9* (95)	-.975* (.45)	.211 (.14)	-.022 (.04)	.99	26
St. Louis	1529* (210)	-43.4 (140)	1.63 (.58)	.17 (.06)	-.159* (.03)	.99	26
Dayton	183.7* (86)	-143.7 (212)	-2.07* (.88)	.23* (.03)	.327* (.06)	.99	26
Pittsburgh	207.7 (906)	-567.4 (2014)	3.0* (1.24)	1.60* (.302)	-.27* (.131)	.99	26

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Table 60

Model Two: Generalized Least Squares 1946-72

City	B_O	P_S B_1	P_G B_2	NC B_3	DD B_4	RS B_5
Concord	-124.0*	4.24	7.09*	1.11*	.006*	.057*
	(25.1)	(6.40)	(2.18)	(.146)	(.003)	(.013)
Philadelphia	3989	678.5*	1275*	14.4*	.056	-.28*
	(2824)	(306)	(303)	(.96)	(.15)	(.05)
New York	19952	5661*	-5256*	43.0*	1.28	-0.72*
	(30294)	(2574)	(1186)	(8.09)	(1.41)	(.105)
Detroit	9541*	439.4	-2672*	2.08*	.156	-.178*
	(2416)	(706)	(1101)	(.77)	(.31)	(.06)
Rochester	6248*	-216.3	-809.4*	.29	.0001	-.101
	(834)	(161)	(41)	(.49)	(.08)	(.06)
Cleveland	7898*	-358.4	-1395*	4.41	-.57*	-.12
	(2111)	(499)	(562)	(3.83)	(.16)	(.11)
Boston	14688*	1272*	-290.8*	-10.4*	-.38	-.24*
	(2020)	(246.5)	(151.7)	(2.36)	(.22)	(.09)
Denver	-254	112.6	-1434*	.61	.003	.15*
	(446)	(110.8)	(225)	(.94)	(.014)	(.02)
Seattle	2545*	-241*	22.83*	-2.36*	.085*	-.006
	(271)	(57.0)	(12.8)	(.235)	(.017)	(.009)

Table 60 (Continued)

City	B_0	P_S B_1	P_G B_2	NC B_3	DD B_4	RS B_5
Harrisburg	1705*	-333*	-354*	.63*	.11*	-.26*
	(362)	(85.6)	(63.5)	(.159)	(.041)	(.073)
Baltimore	3725*	173.1	-312.3*	-.34*	.106*	-.116*
	(522)	(119)	(42.3)	(.14)	(.04)	(.023)
St. Louis	-495	1532*	12.2	1.71*	.223*	-.15*
	(1052)	(495)	(133)	(.68)	(.05)	(.03)
Dayton	3324*	-460*	-1218*	-.22	.044	.06
	(369)	(90)	(119)	(.45)	(.02)	(.03)
Pittsburgh	1384*	104	-497*	1.21	.149*	-.04
	(470)	(76)	(103)	(.77)	(.04)	(.025)

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Weight R-square for system = .97

Number of observations = 27

Table 61

Model Two: Generalized Least Squares 1947-72
Using Cochrane-Orcutt Transformed Data

City	P_S B_1	P_A B_2	NC B_3	DD B_4	RT B_5
Concord	-4.03	3.88*	1.12*	.005*	.049*
	(6.17)	(1.97)	(.133)	(.002)	(.012)
Philadelphia	892*	1456*	16.0*	.051	-.217*
	(252)	(248)	(.439)	(.141)	(.020)
New York	7728	-6339	40.6	3.72	-.813
	(2965)	(1006)	(4.19)	(1.58)	(.105)
Detroit	930	-500	3.06*	1.54*	-.303*
	(1119)	(613)	(.713)	(.18)	(.071)
Rochester	443*	-715*	-1.18*	.495*	.167*
	(184)	(47)	(.59)	(.06)	(.06)
Cleveland	743*	118	-2.55	-.051	.135
	(391)	(844)	(4.87)	(.11)	(.13)
Boston	1275*	-384	-7.71*	1.08*	-.002
	(415)	(243)	(4.14)	(.26)	(.18)
Denver	-116.5	-1506*	.219	.021*	.155*
	(79)	(101)	(.66)	(.009)	(.010)
Seattle	-165	-31.8	-.57	.231*	.051*
	(100)	(22.4)	(.34)	(.03)	(.01)

Table 61 (Continued)

City	P_S B_1	P_A B_2	NC B_3	DD B_4	RT B_5
Harrisburg	-86	-393*	.898*	.298*	-.212*
	(82.4)	(92.6)	(.199)	(.038)	(.084)
Baltimore	824*	-446*	-.861*	.285*	.008
	(182)	(69.7)	(.313)	(.096)	(.034)
St. Louis	1537*	-85.7	1.65*	.168*	-.157*
	(189)	(126)	(.52)	(.05)	(.03)
Dayton	152*	-188	-2.55*	.248*	.317*
	(75.3)	(182)	(.725)	(.026)	(.052)
Pittsburgh	264*	-460*	1.69*	.283*	-.037
	(60.1)	(120)	(.815)	(.031)	(.024)

*Significantly different from zero at the 90% level of confidence.

Numbers in parentheses are the estimated standard errors.

Weighted R-square for system = .9982

Number of observations = 26

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