COGENERATION IN THE U.S.:
AN ECONOMIC AND TECHNICAL ANALYSIS

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ABSTRACT

Traditionally, only space heating and transportation have consumed more fuel than industrial process steam generation. Several recent studies have examined electricity and industrial steam supply and have recommended vigorous federal efforts to increase the cogeneration, or joint production, of electricity and process steam. The conceptual approach and analytic methods employed in these studies contain flaws that make them incomplete. The studies' recommendations are premised upon the existence of distortions in the markets surrounding cogeneration, but they offer only anecdotal evidence of such market failures. They propose increased cogeneration, citing aggregate energy savings for a single year and cumulative capital savings, but the analytic techniques they use in simulating market behavior and evaluating the desirability of various levels of cogeneration lack needed sophistication.

This research addresses several of the methodological objections to the earlier studies. To unite this effort, the report poses two focal questions on cogeneration policy and economics:

- Can the historical decline in cogeneration's importance be explained by changes in fuel prices and technologies alone?
- What is the best future role for cogeneration if the choice is based on economic efficiency?

First, the markets associated with cogeneration are examined from a qualitative perspective, employing the classic basic conditions/market structure/conduct/performance approach of industrial economics to explore the potential for inefficient market performance. Engineering production and cost functions are developed for a simple cogeneration plant design, offering insights into the economies of scale and joint production problems involved in the choice between cogeneration and separated production alternatives. Second, a multi-period linear programming model, called the Joint Generation Supply Model or JGSM, is formulated to simulate competitive market behavior in the aggregate U.S. electricity and process steam supply markets throughout a given time interval. JGSM is used to study the historical performance of these markets for 1960 to 1972 and the future role of cogeneration for 1975 to 2000. Appendices survey cogeneration technologies and the issues in integrating cogeneration plants into the utility system.

The modeling of the historical question shows the decline can be explained by changes in cost conditions, but these results are very sensitive to the engineering cost assumptions. Analysis of cogeneration's future role indicates cogeneration should increase from its 4.5% share of electricity supply in 1975 to 9% in 1985; it should also serve more than half the process steam supply. If cogeneration remains at its 1975 share through 2000, the additional costs imposed are worth about $10 billion in discounted capital and operating expenses. Too much cogeneration can hurt as much as too little: forcing it up to a 20% share by 1985 imposes similar costs. For comparison of these losses to another issue, JGSM calculated that failure to develop low-Btu coal-gasifying combined cycle power technologies results in losses worth $4 billion.
PREFACE

An exposure to the early stages of the first Dow Chemical Co. et al. (1975a) industrial cogeneration study inspired this author to undertake a different approach to the economic analyses in that effort and the ThermoElectron (1976) and Resource Planning Associates (1977) cogeneration policy studies. This report, a minor revision of a thesis completed in the summer of 1978, is intended to provide better insight into the complex economics surrounding cogeneration rather than suggest policy guidelines.

Since the research was carried out over an extended period, not all the technological aspects are up to date. The discussions are based primarily on steam topping cogeneration. This limitation, however, does not restrict its comments on the historical and institutional aspects of cogeneration. The examination of the future potential for cogeneration, primarily Chapter 5, should be treated as a new analytical approach to this problem -- with the qualitative aspects of that discussion still holding.

This work is a portion of research efforts on utility operation and planning being carried out within the Utility Systems Program at the MIT Energy Laboratory.
ACKNOWLEDGEMENTS

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Chapter 1
INTRODUCTION

Early proposals for alleviating the "energy crisis" induced by the 1973 oil embargo concentrated upon projects for providing new sources of energy supplies. The nation treated energy conservation measures as only short-term solutions — mandatory controls on energy consuming activities to get the U.S. through the transition to new sources of supply. In the industrial sector, most spokesmen felt that industry was using energy as efficiently as possible. A small group, however, began to present a different story for the nation and, specifically, for the industrial sector: they contended energy conservation through the more effective utilization of fuels could achieve significant energy savings without necessarily forcing reductions in the consumption of final goods. Furthermore, they argued that the savings were technologically and economically feasible before the embargo but institutional barriers often deterred the reassessment of changes or prevented their implementation. Given the huge shifts in fuel prices since the embargo, they reasoned that many more opportunities for more thermodynamically efficient utilization of fuel were now eminently desirable.

Processes for the integrated production of electricity and industrial process steam, or cogeneration, attracted a great deal of attention in the debates on industrial energy conservation. Several major studies and a number of shorter ones estimated the U.S. could obtain a large fraction of its electric generation and process steam needs from cogeneration plants while saving both fuel and capital. Most of the studies...
cited institutional barriers when questioning why the role of cogeneration declined in both electricity and steam energy supply; two studies, however, asserted that the decline occurred primarily because of equipment and fuel costs changes. All the studies supported their statements on institutional barriers with only anecdotal evidence — none applied any formal analytic methods to the question.

This report first, focuses on the question of whether or not the historical changes in cogeneration's importance in electricity and industrial process steam supply can be explained by cost influences alone. Second, it uses a model developed for addressing this question to examine the future role for cogeneration. The effort makes several significant improvements in the approach followed by the earlier studies. This chapter presents a brief introduction to the historical role of cogeneration and then reviews several earlier studies. The chapter concludes with a description of the report's purpose and structure.

1.1 COGENERATION IN U.S. ELECTRICITY AND INDUSTRIAL STEAM SUPPLY

Fuels for the generation of industrial process steam constituted nearly 17% of the total U.S. fuel consumption in 1968, as shown by Figure 1.1. Only transportation and combined residential and commercial space heating exceed this share in the end uses of fuels. Electricity generation, which is considered an intermediate process before the end use of energy, received nearly 21% of the total fuels directly consumed. Any change in the fuel consumption patterns and conversion
Figure 1.1

Source: Stanford Research Institute (1972)
efficiency that affects both process steam and electricity generation could be expected to have a major impact on total fuel consumption and, therefore, upon the overall national costs for energy supplies.

A number of organizational options exist for supplying electricity and process steam. As illustrated by Figure 1.2A, an industry and a utility can separately produce steam and power. Alternatively, as in Figure 1.2B and 1.2C, industry can produce steam and power in a by-product cogeneration plant, or the utility can cogenerate steam for industry in a dual-purpose power plant. The cogeneration plants can also be jointly owned. For a period survey of the technologies used for cogeneration, see Appendix A.

The concept of cogeneration is certainly not new: in the first half of this century a number of paper mills provided power for the local towns in this manner. The importance of congeneration has declined considerably since that time; as illustrated by Figure 1.3, its share in total electricity supply has dropped from 18% in 1941 to 4.3% in 1975. In contrast to the U.S., about 12% of West Germany's electricity generation comes from industrial cogeneration. For the U.S., the absolute level has remained within a narrow band since 1960; if steam demand is the key determinant of cogenerated electricity production, the faster growth rate of electricity generation relative to manufacturing output may partially explain the steady decline of cogeneration in electricity supply. Figure 1.4 indicates the role of cogeneration in industrial steam supply has clearly declined only since the late 1950's. The ratio of industrial generation to manufacturing output varied erratically before that time. This implies significant changes occurred in the early 1960's.
Figure 1.2
Source: Dow (1975a)
THE SHARE OF

INDUSTRIAL ELECTRICITY GENERATION IN TOTAL U.S. ELECTRICITY GENERATION


FIGURE 1.3
THE RATIO OF INDUSTRIAL ELECTRICITY GENERATION TO THE FRB INDEX OF TOTAL MANUFACTURING PRODUCTION


FIGURE 1.4
1.2 A SURVEY OF STUDIES ON COGENERATION ECONOMICS
AND POLICY

This section reviews the three major studies on cogeneration and comments briefly on several other studies that have dealt with some aspect of cogeneration. It then identifies the major shortcomings in the scope of these studies and critically evaluates the analytical techniques.

To assist the reader, Table 1.1 summarizes the key goals, assumptions, analytical methods, and results of the studies. Special attention should be devoted to the assumptions on steam and electricity consumption growth rates and the minimum economic scale for cogeneration plants. The absolute level of the steam consumption growth rate determines the importance of new installations as opposed to the conversion of existing industrial sites. With the approach taken by this and previous studies, the growth rate of steam relative to electric energy consumption determines the share of cogenerated electricity in overall electricity generation. The minimum economic cogeneration plant size, an intermediate conclusion within most of the studies, determines the fraction of total steam consumption that could eventually be served by cogeneration.

The Dow (1975a) study, the earliest effort, explored the impacts of both increased industrial electricity generation and process steam supply by utilities. The analysis covered the technological, environmental, financial, and legal aspects of increased cogeneration. The economic analysis considered the U.S. situation through 1985 as an aggregate, without separation into industry groups or geographic regions. Industrial and utility capital investment behavior was modeled by assuming firms would require a fixed minimum, before-tax rate of return for investments in cogeneration facilities. This engineering-economic calculation determined
# Comparison of the Major Cogeneration Studies

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<td>270,000-2,500,000</td>
<td>145,000 - 570,000</td>
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<td>-Recommended cogeneration (% of total US electric energy consumption).</td>
<td>22.6%</td>
<td>6 - 44%</td>
<td>3.7%**</td>
</tr>
<tr>
<td>(% of total US process steam consumption)</td>
<td>40%</td>
<td>63%</td>
<td>43%</td>
</tr>
<tr>
<td>-Recommended policy actions.</td>
<td>More Policy studies</td>
<td>Loan guarantees.</td>
<td>Investment tax credit, loan guarantees, regulatory change, state policy assistance, etc.</td>
</tr>
</tbody>
</table>

* Estimated assuming the plant scales from the appropriate report. **Estimated assuming a 4.8%/yr electricity consumption growth.

**TABLE 1.1**
the national levels of cogenerated steam and power. The relative capital investments by the industrial plants and by the utilities and the subsequent steam and power generation form the basis for computation of capital and fuel savings; these, in turn, are used to determine the electricity rates for various customer classes. No explicit consideration is given to the influence of steam costs on steam consumption. They conclude that increased industrial and utility cogeneration can result in capital savings of $1.7 to 3.9 billion/yr and fuel savings of 535,000 to 725,000 bbl/day by 1985 with respect to the costs if historical trends continue. Although the study does not address specific policy alternatives, they suggest an examination of utility rate structures and franchise, regulations affecting industrial fuel choice and cogeneration plant investment, tax incentives for cogeneration, and the existing legal disincentives for industrial sales of electricity to utilities.

The Federal Energy Administration commissioned the ThermoElectron (1976) study to examine policy questions associated with increased inplant generation in three industries: chemicals, petroleum refining, and pulp and paper. According to their information, these three industries account for 25% of total U.S. process steam consumption. The study builds upon the Dow results; the analysis was limited to the technological and economic side of increased inplant electricity generation through 1985 with and without the sales of the excess electricity to the local utility. The ThermoElectron report, in contrast to the Dow study, disaggregates the analysis of the three industries by regions and size of the industrial facilities. They consider cogeneration from gas turbine plants, diesel engines, and bottoming cycles on rejected process heat, stressing retrofit of existing facilities rather than replacement. The economic
calculations of the anticipated investment in cogeneration projects, like the Dow study, are based on the rate of return on investment (r.o.i.). The Dow study selected a single before-tax rate threshold for industry (20%) and for utilities (12%); ThermoElectron, however, uses a distribution specifying the percentage of industries or utilities that would invest in a type of cogeneration receiving a given after-tax rate of return. This distribution is based on financial sectoral rates of return and their variance; it then subjectively shifts upward the industrial sector's distribution of companies that would be willing to invest at given rate of return because industry considers cogeneration "an ancillary investment requiring higher rates of return since it is not associated with the profitability or expansion of its primary market." It concludes that a large portion of the electric energy consumed in some regions can be generated by gas turbine or diesel-type cogeneration. The report's consideration of the utility sector, government regulation, environmental impacts and capital availability was in a "story-telling" format rather than any formal analytic discussion. The analysis of federal policy alternatives was limited: only three incentives packages were considered by their economic calculations. It estimated that the maximum economic potential for fuel savings in 1985 from increased cogeneration of process steam and electricity would result in a 415,000 to 2,260,000 bbl/day savings, depending upon the economic incentives, technologies, and the patterns of ownership.

Resource Planning Associates (1977), henceforth RPA, has recently completed an analysis of federal policy actions toward cogeneration, concentrating on the potential for cogeneration in six major industries through 1985. The six industries analyzed in detail were the chemical,
petroleum refining, pulp and paper, steel, food processing, and textile industries. The study specifically excludes consideration of utility-owned projects but includes cogeneration with process steam and with process heat from ordinary fuels or through waste heat recovery. Their analysis estimates levels of industrial cogeneration with and without government action; it specifies the effectiveness of various federal cogeneration programs according to their incremental fuel savings and governmental cost. The fuel savings are determined from industrial investments in cogeneration plants; the industrial investment behavior is predicted on the basis of the differing after-tax returns on investment from alternative process steam, waste heat recovery, and cogeneration projects for each industry. As in the ThermoElectron study, a distribution for the number of firms willing to invest in a cogeneration project at a given rate of return determines the overall level of cogeneration; RPA, however, disaggregates by manufacturing sector in addition to separating industry as a whole from the utility sector. RPA derives these distributions from interviews of executives. Again, "story telling" covered issues such as the threat of increased governmental economic regulation, environmental restrictions, capital availability, utility rates, and uncertainty over fuel prices and availability. The RPA report includes more industries than ThermoElectron and estimates the cogeneration beyond the six considered explicitly but does not disaggregate regionally. It concludes the U.S. can save between 145,000 and 420,000 bbl/day oil equivalent over historical trends by 1985 without any government intervention, "mostly oil used for utility generation." This is expected to occur through market influences alone; governmental programs studied by RPA are estimated to increase these...
savings by approximately 40,000 to 150,000 bbl/day oil equivalent in 1985.

Several other studies have examined various aspects of cogeneration. Dow (1975b) surveys the technologies and process economics of new industrial heat sources. Von Hippel and Williams (1976) propose cogeneration as an important component in a U.S. energy strategy designed to avoid the need for a plutonium economy. Miller et al. (1971) study the use of cogeneration plants to provide thermal energy for agricultural, industrial, commercial, and residential heat demands near an urban area. General Electric (1975) and Smiley et al. (1976) report on nuclear energy parks, which are sites where a dozen or more nuclear electricity plants and support facilities are constructed; some of these plants can cogenerate steam for co-located industrial firms. Gyftopoulos et al. (1974) calculate that cogeneration could have produced up to 53% of the electricity generation in 1968. Hafele and Sasson (1975) suggest cogenerated heat and steam as a additional application of nuclear power. Wakefield (1975) develops a series of models to determine the influence of a single district-heating cogeneration plant on the local utility and the regional energy markets.

A number of problems in the approach and analytical methods employed by the key cogeneration studies make their efforts incomplete.

- None of the studies evaluates the performance of the markets associated with cogeneration from a formal market basic conditions/structure/conduct/performance perspective; their analyses of market imperfections are limited to anecdotal evidence. Since most of the policy proposals presume these markets are severely distorted, this assumption should be given careful
examination.

- In comparing cogeneration to other sources of steam and electricity supply, the measures of economic performance being employed are inadequate for comparisons from a public perspective:
  - Fuel and capital savings are not combined to form a single measure discounted to one point in time.
  - All the studies calculate fuel savings in Btu's; few will argue, however, that a Btu of waste wood products is worth as much as a Btu of imported oil.

- The studies only consider effects through 1985, calculating investment behavior within this horizon by their single-period return-on-investment method. Since most central station electricity development is already planned through the 1980's and new steam and electricity generation technologies will become available in the mid-1980's, the problem requires a framework that has a longer time horizon and can allow capacity installed now to be abandoned when new technologies arrive.

- Cogeneration technologies could jointly influence the prices of electricity and process steam, but the studies all assume a price for one of the outputs when calculating the incremental rates of return for new cogeneration plant investments.

- Most of the studies concentrate on cogeneration's role in electricity supplies through examination focusing on the supply costs -- it could be that both steam and electricity demand conditions are also important in determining the level of cogeneration in both electricity and steam supply.
Little exploration is made of the costs of abandoning utility-owned power plants in favor of drastically increased cogeneration; this could also impose special financial problems for the utilities.

- The economies of scale and joint production intertwine in the costs of cogeneration -- no study directly addresses this problem.

- The rates of return needed for the acceptance of a cogeneration project have been subjectively modified in the studies so that they differ from the market rates of return; this buries a number of assumptions concerning uncertainties about the projects and possible market imperfections.

1.3 THE FOCUS AND STRUCTURE OF THE REPORT

In order to unite the methodological improvements made in this research, the report poses two focal questions on cogeneration policy and economics:

- Did the importance of cogeneration in electricity and steam supply decline because of market imperfections, or can this decline be explained by changes in fuel prices and technologies alone?

- What is the best future role for cogeneration if the choice is based on economic efficiency?

Although the analysis here will not resolve these issues, centering the discussion on them provides a basis for evaluating the usefulness of the methods and suggests areas for further study.
Chapter 2 examines the markets associated with cogeneration from a qualitative perspective, using an industrial organization approach to explore formally the potential for imperfect market performance. One special aspect of this analysis is the derivation of a cogeneration engineering cost function that addresses the joint production and economics of scale issues. Chapter 3 develops a dynamic linear programming model, called JGSM, for simulating competitive behavior in the aggregate U.S. process steam and electricity supply markets over several planning periods. Chapter 4 studies the performance of these markets for 1960-1972 using this model; the chapter principally addresses the first fundamental question noted above. Chapter 5 uses JGSM to study the future role of cogeneration for 1975-2000. Chapter 6 summarizes the results and, noting the flaws in these efforts, suggests directions for further research. Appendix A describes a selected group of technologies for electricity and steam supply, surveying their capital costs and operating characteristics. Appendix B notes important issues and potential problems in the integration of cogeneration plants with the utility grid. Appendix C lists the cost and energy conversion factors used in this study. Appendices D through F document the JGSM model and the data used for the analyses in Chapters 4 and 5.

This report, in improving upon the earlier studies, concentrates on the first four weaknesses noted in the last section: the lack of a formal analysis of market imperfections and their pre-conditions; the need for a combined measure of fuel and capital impacts throughout the horizon; the inadequacy of the single-period investment calcula-
tions that do not allow for the economic obsolescence of current capacity in future periods; and the deficient treatment of cogeneration's joint product nature.
Footnotes for Chapter 1

1. See Berg (1974) and Gyftopoulos et al. (1974). The concept of energy conservation through effectively utilizing fuels by matching the quality of an energy source to the quality needed is popularized in Commoner (1976) and Lovins (1976).


3. In this report the terms cogeneration and joint generation denote the simultaneous production of steam and electricity. Common types of cogeneration plants include total energy plants, by-product power plants, and dual-purpose power plants; the usage depends upon the plant's ownership, its scale, the types of end-use demands served, and the mix of steam and electricity outputs. Total energy plants supply steam heat and electricity to commercial and residential buildings. In addition to producing electricity, by-product power plants serve industrial steam demands while dual-purpose power plants supply steam for district heating and industrial processes. A site where several industrial plants have co-located with a dual-purpose plant is often called an industrial energy center.

4. The major studies are Dow (1975a), ThermoElectron (1976), and Resource Planning Associates (1977).

5. Foremost in the group are ThermoElectron (1976), Resource Planning Associates (1977), and von Hippel and Williams (1976).

6. Dow (1975a) and Dow (1975b).

7. Complete data on the historical levels of cogeneration do not exist. Information on cogeneration by utility-owned plants is available in U.S. Federal Power Commission (1973). Industrial cogeneration must be inferred from data on industrial electricity production; since economies of scale for electricity-only generation plants make it more expensive for an industrial firm to generate its own electricity unless it is geographically isolated, industrial electric energy production is assumed to be essentially all cogeneration. The differing reports on West German cogeneration (12% in von Hippel and Williams, 1976, and 29% in Lovins, 1976) illustrate the problem with this assumption: the higher figure was based on industrial electricity generation -- a large portion of this is from industry-owned mine-mouth central station plants (personal communication with P.C. Kalischer, Rheinisch Westfalishes Elektrizitatwerk AG, September, 1977).

7a. This assumes industrial steam consumption varies in direct proportion to manufacturing output and the average production of cogenerated electric energy per unit of cogenerated steam has not diminished over time.
8. According to earlier figures by Miller et al. (1971), they account for 79%. The Miller et al. estimates are detailed by Table 2.2.

Chapter 2

ISSUES IN THE MARKET STRUCTURE AND MICROECONOMICS

ASSOCIATED WITH COGENERATION

The amount of electric energy supplied by cogeneration has increased fourfold since the 1930's. Its estimated share of total U.S. electricity supply, however, has diminished from 18% in 1941 to 4.3% in 1975. This market behavior stands in contrast to what would be anticipated given cogeneration's low operating costs relative to typical electricity generation technologies owing to its very high fuel conversion efficiencies. Is this because its capital costs are too high? Have the industrial sites that are economic for cogeneration been exhausted? Do the first or second law thermodynamic efficiency figures give a correct reflection of the operating costs for this joint product technology? Do artificial barriers restrict the entry of cogenerated electricity into the bulk electricity market?

The decline in cogeneration relative to the total U.S. electricity supply has been attributed principally to two different sets of conditions. The view presented by the Dow (1975a) report blames changes in fuel prices and the advent of cheap low-pressure oil- and gas-fired package boilers for the shift away from cogeneration, which historically has required more expensive field-erected boilers. The contrasting view held by the ThermoElectron (1976) study for FEA, cites the negative attitudes of some utilities toward electricity purchases from industries.
Furthermore, the ThermoElectron report states private industry is hesitant to engage in cogeneration projects because of uncertainties over the application of state and federal regulations to plants selling to utilities. An additional point, not raised by the ThermoElectron study, is that the declining block rate structure for utility electricity undervalues the cost of large block sales to industry; this makes cogenerated electricity less economic from the industrial perspective. If cogeneration is actually less expensive, then such biases result in artificial market restrictions and, thus, in social welfare losses.

The examination of these potential market restrictions is important within two areas of governmental policy-making. First, one continuing goal of regulatory and antitrust actions calls for the elimination of market imperfections because of the welfare losses and income transfers in the associated markets. Second, the current public focus on energy policy makes market imperfections particularly important since they may impede adjustments to higher energy prices and frustrate price-induced energy conservation measures. This results in strategically undesirable higher oil imports.

The opinions offered by the Dow, Resource Planning Associates (1977), and ThermoElectron studies have been based on professional engineering cost analyses, executive interviews, and legal research. No study has yet presented a formal analysis of the complex markets surrounding cogeneration from the perspective of industrial organization economics. This analytic paradigm, as illustrated in Figure 2.1, examines markets by analyzing their basic conditions, the market structure, the conduct of the parties involved, and the relationship
A SIMPLE MODEL OF INDUSTRIAL ORGANIZATION ANALYSIS

Figure 2.1

From Scherer (1970)
of these factors to measures of market performance.\textsuperscript{3}

This chapter prefaces the quantitative analysis of the steam and electricity market performance in Chapters 3, 4, and 5 with a qualitative industrial organization analysis. Because of the multiple products being considered simultaneously in this discussion, the analysis adheres closely to the classic Basic Conditions/Structure/Conduct/Performance framework. The first section discusses two perspectives for discussing the markets under consideration. The second section looks at the basic supply and demand conditions, the market structure, and the conduct within the market. It covers, in particular, the unusual cost and production relationships for cogeneration, the economies of scale problems, industry concentration issues, barriers to market entry, and possible regulatory distortions. An engineering production function is developed for a single, simple cogeneration process—this offers insights into the effects of scale economies and joint product problems upon the industrial choice between cogeneration and the separated production alternatives. The chapter's conclusion comments on relating basic market conditions to performance in order to measure the "best possible" economic performance for these markets.

2.1 A DESCRIPTION OF THE STEAM AND ELECTRICITY MARKET PARTICIPANTS

The interrelationships between industry and the local utility in the industrial steam and electricity markets can be viewed two different ways. In the first approach, the firms participating in the market are separated into two categories: the local utility, which is a regulated monopoly, and the private industries. Figure 2.2 illustrates
this "market participant" or institutional perspective. A cogeneration plant can be owned by an industrial firm, by the utility, or jointly by both. This approach devotes its attention to the visible transactions between the two classes of firms: industrial sales of excess cogenerated electricity to the utility; industrial electricity purchases from the utility; and, if the utility operates a steam-producing plant, process steam purchases by industry from the utility.

In the alternative approach, the "production process" view, the market is described on the basis of the production processes. Others have called this the "pre-institutional" perspective. The schematization shown in Figure 2.3 separates all steam and electricity generation, including cogeneration, from the basic industrial processes and from the utility transmission system. Overlaying the ownership patterns for the steam and electricity generating facilities recreates the "market participant" perspective: typically, industry owns the steam and cogeneration plants while the utility owns the electricity generating plants. All varieties of the market structure can be built up from the process ownership patterns. The process perspective, hence, has the advantage of being more disaggregated than the market participant view; the influences from the special characteristics of the different production relationships can be considered separately.

In summary, the technological aspects of the processes drive much of the industrial and utility firms' behavior with respect to cogeneration, necessitating this disaggregation of the institutions into the processes. Table 2.1 summarizes the interrelationships for each of the two perspectives. In both cases, the two products of concern are
Electricity for Non-Industrial Customers

Utility

Transmission

and Distribution

System

Cogenergened

Electricity

for Industry

Basic

Industrial

Processes

Principle

Products

Electricity

Electricity

Generation (EG)

Steam and

Electricity

Cogeneration (CC)

Steam

Production (SP)
SUMMARY OF THE MARKET INTERACTIONS

a. Market Participant or Institutional View

<table>
<thead>
<tr>
<th>Market</th>
<th>Abbreviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial electricity sales to the utility</td>
<td>IES</td>
</tr>
<tr>
<td>Utility electricity sales to industry</td>
<td>UES</td>
</tr>
<tr>
<td>Utility steam sales to industry</td>
<td>USS</td>
</tr>
</tbody>
</table>

b. Production process or Pre-Institutional View

<table>
<thead>
<tr>
<th>Derived Demand (and Associated Supply Source)</th>
<th>Abbreviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam used in the basic industrial processes (from SG and CG)</td>
<td>SI</td>
</tr>
<tr>
<td>Electricity used in the basic industrial processes (from CG and the utility distribution system)</td>
<td>EI</td>
</tr>
<tr>
<td>Electricity into the utility bulk transmission system (from EG and CG)</td>
<td>EU</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Supply Technology Type (and Associated Demands)</th>
<th>Abbreviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electricity—only generation (for EU)</td>
<td>EG</td>
</tr>
<tr>
<td>Steam—only generation (for SI)</td>
<td>SG</td>
</tr>
<tr>
<td>Cogeneration of electricity and process steam (for SI, EI, and EU)</td>
<td>CG</td>
</tr>
</tbody>
</table>

Table 2.1
steam and electricity. In the process perspective, three different classes of supply technologies produce these products: plants producing only steam; plants generating only electricity; and cogeneration plants supplying steam and electricity as joint products. The demands for the products generated by the steam and electricity supply technologies come from three sources. A derived demand for steam results from the production of the industry's principle products. Likewise, there is a derived demand for electricity by the basic industrial processes. Finally, the utility system demands electricity; this results in the electricity distributed to both industrial and non-industrial customers. In the market participant perspective, the ownership patterns bury the demands derived from the separated production processes; the market shows only the industrial electricity purchases by the utility and the steam and electricity purchases by the industry.

2.2 THE BASIC CONDITIONS, STRUCTURE, AND CONDUCT IN THE PROCESS STEAM AND ELECTRICITY MARKETS

This section surveys reasons why the markets described in the previous section might not achieve the performance attainable under purely competitive or even monopoly conditions. As the discussion progresses from basic conditions to market conduct, the focus will alternate between the process and the participant descriptions of the market; the different supply, demand, and market abbreviations in Table 2.1 will be used in an attempt to keep the exposition of relationships in this complex market clear.
2.2.1 BASIC CONDITIONS

The process view provides more insight into most aspects of the basic market conditions. Before delving into the separated derived demand and supply technology sides, however, one problem must be commented on from a market participant perspective.

Both the Dow (1975a) and ThermoElectron (1976) studies remark upon industrial and utility manager's attitudes toward adding cogeneration. Many perceive cogeneration as adding a product that is not in their firm's primary product line—the interviewers report statements such as "[we] are an electric utility and are not in the business of selling steam" or "we're not in the power business." These opinions, however, are not universally held. A question remains as to whether these attitudes are reflections of corporate objectives or they are individually held conclusions based upon perceptions of cogeneration's potential for influencing profits. If these business attitudes are, in fact, conclusions on profitability, they can alter rapidly with changes in market structure or fuel and capital costs; if they are truly a sense of corporate purpose, different means will be required to shift them.

2.2.1.1 THE DEMAND SIDE

On the demand side, important attributes of the derived demands are their concentration in a few industries and at specific sites, regional differences, the quality characteristics of the desired product, the price elasticity of demand, and the comparative growth rates in consumption.
Consumption by Industry
A small number of industries account for the vast majority of the aggregate SI demand. Furthermore, as shown in Table 2.2, a significant portion of the industrial electricity purchases (UES) coincides with the largest process steam users. The industrial electricity purchase proportions understate the magnitude of the electricity usage in the basic processes (EI) since they may also be generating electricity internally in these industries where cogeneration is especially advantageous.

Site Scale of Demand
Owing to the scale economies for cogeneration plants and the high transportation costs for steam relative to other forms of energy, the extent of the derived demand for SI at individual sites is very important. Figure 2.4 illustrates the cumulative percentage of steam energy consumption at sites below a given size. The Dow (1975a) report develops this curve from the 1967 Census of Manufacturers water use and establishment size data, so it does not reflect instances where two or more establishments are co-located and could share the same steam generating plant. Changes in the economics of cogeneration, however, can shift this curve: joint siting of several industrial plants in "energy parks" may result in significant cost savings—with the alteration of siting patterns causing the distribution of the SI demand per location to shift toward larger scale sites.

Regional Differences
The aggregate consumption of SI, EI and EU varies considerably from region to region. Taking industrial non-electric fuel choices as an indication of industrial steam raising and cogeneration, and hence SI, Table 2.3 shows a factor of 20 difference between New England and the West South-Central region in 1972. Taking industrial electricity
ESTIMATES OF ELECTRIC ENERGY, STEAM ENERGY AND STEAM PRESSURE DISTRIBUTIONS IN 1980

<table>
<thead>
<tr>
<th>Industry</th>
<th>% of Total Electricity Purchased by Industry (1968)</th>
<th>% of Total Process Steam Usage</th>
<th>Steam Pressures &amp; Distributions</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Pressure Range (psig)</td>
</tr>
<tr>
<td>Chemicals and allied products</td>
<td>29</td>
<td>39</td>
<td>450-1000</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>200-450</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>100-200</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>100</td>
</tr>
<tr>
<td>Petroleum refining and related industries</td>
<td>4</td>
<td>22</td>
<td>150-600</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>150</td>
</tr>
<tr>
<td>Paper and allied products</td>
<td>5</td>
<td>18</td>
<td>100-200</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>100</td>
</tr>
<tr>
<td>Food and kindred products</td>
<td>6</td>
<td>13</td>
<td>50-100</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>50</td>
</tr>
<tr>
<td>Other industries</td>
<td>56</td>
<td>8</td>
<td></td>
</tr>
</tbody>
</table>


Table 2.2
THE CUMULATIVE DISTRIBUTION OF TOTAL INDUSTRIAL STEAM LOAD IN 1967

Figure 2.4
Source: Dow (1975a)
COMPARISON OF REGIONAL ENERGY CONSUMPTION PATTERNS IN 1972

<table>
<thead>
<tr>
<th></th>
<th>Industrial Fuel Purchases (Non-Electric)</th>
<th>Industrial Electricity Purchases</th>
<th>Total Utility Electricity Distributed</th>
</tr>
</thead>
<tbody>
<tr>
<td>New England</td>
<td>274</td>
<td>78</td>
<td>242</td>
</tr>
<tr>
<td>Middle Atlantic</td>
<td>1984</td>
<td>334</td>
<td>834</td>
</tr>
<tr>
<td>East North-Central</td>
<td>3939</td>
<td>550</td>
<td>1155</td>
</tr>
<tr>
<td>West North-Central</td>
<td>1006</td>
<td>134</td>
<td>382</td>
</tr>
<tr>
<td>South Atlantic</td>
<td>1747</td>
<td>344</td>
<td>959</td>
</tr>
<tr>
<td>East South-Central</td>
<td>1157</td>
<td>329</td>
<td>582</td>
</tr>
<tr>
<td>West South-Central</td>
<td>5678</td>
<td>290</td>
<td>690</td>
</tr>
<tr>
<td>Mountain</td>
<td>826</td>
<td>102</td>
<td>272</td>
</tr>
<tr>
<td>Pacific</td>
<td>1323</td>
<td>330</td>
<td>869</td>
</tr>
</tbody>
</table>

Energy consumption in trillion Btu's
Source: US Department of Interior (1974)

Table 2.3
purchases as an indication of EU, large regional differences are similarly evident.

**Quality of the Products**

Two important quality characteristics influence the demands for industrial process steam (SI). First, as shown in Table 2.2, the vast majority of the total steam energy consumption lies in pressure ranges where it would be economically possible to cogenerate such steam. Second, since the steam is a necessary input for the basic processes, severe losses are incurred if the supply is interrupted. Thus, the source for the steam must be reliable—this often means cogeneration installations have a back-up, oil-fired package boiler for use during any outages at the main facility. The capacity factors for boiler and cogeneration systems give a crude estimate of the reliability required: for industrial systems, the capacity factors are usually about 85%.9

Similar concerns over reliability exist for the EI and EU demands. Typically, utility electricity acts as the back-up for electricity cogenerated to supply EI but some utility rate structures make this very expensive. The reliability of single units is not as important for the EU demands because of the large number of units connected to the transmission system and the relatively small size of the cogeneration plants.

**Demand Fluctuations**

All the rates of SI, EI, and EU consumption vary within a fixed time period. The annual capacity factors for a single site's EI and SI consumption in most of the heavy steam consuming industries are very high—so only limited operating flexibility is needed in the supply technologies.10 The consumption of EU varies diurnally; for economic and stable operations, the utilities prefer centralized operating control.
over the instantaneous energy from supply processes.

**Price Elasticities**

After the foregoing discussion of the differences in SI, EI, and EU demand implied by the differences in consumption between regions, industries, and so forth, speculation on the price elasticity of aggregate demand in these markets does not appear relevant. The relative aggregate price elasticities along with the comparative growth rates in the demand unadjusted for price changes plus knowledge of the size distribution of the steam using industrial sites, however, put bounds on the maximum cogeneration possible. Since institutional boundaries obscure the derived demands discussed here, the price elasticities must be loosely inferred from econometric evidence based on observed fuel sales data. No study has attempted an estimation of the price elasticity for SI; the long run industrial demand price elasticity for all energy gives a crude bound on the elasticity of process steam. Pindyck's (1977) survey shows these price elasticity estimates lie in the -.3 to -.9 range. The industrial demand elasticity for purchased electricity (UES) has to be used to estimate the ET elasticity; the elasticity for EI would be lower than for UES since a firm could cogenerate, substituting internal generation for purchased electricity. Joskow and Baughman (1976) estimate the long-run aggregate industrial electricity price elasticity at -1.28 and the survey by Taylor (1975) finds estimates in the -1.25 to -1.94 range. Pindyck (1977), however, finds the total own price elasticity to be much smaller: -0.54 to -0.92. The demand elasticity for electricity generation (EU) can be taken as identical to the total electricity demand elasticity if locational patterns and the characteristics of the transmission systems are assumed unchanged: Manne (1976), using process modeling and
econometric information, estimates it to be about -0.75 in the 1970-2000 period.

**Growth Rates**

Finally, the changing levels of electric energy and process steam consumption, given the nature of the supply technologies, limit the relative role for cogeneration in the total electricity and steam supply. Table 2.4 lists the historical and estimated future growth rates for SI, EI, and EU consumption. The growth rates in consumption unfortunately combine assumptions on the underlying demand growth, changes in supply technologies and interactions between supply and demand.

### 2.2.1.2 THE SUPPLY SIDE

Transmission costs, the long life of the installed equipment, differences in input prices between utility scale plants and industrial facilities, and special production characteristics of the supply technologies affect the market structure from the supply side of the basic conditions. In addition, uncertainty in the interpretation of numerous statutes and regulations also influences the supply side, but discussion of these legal barriers is delayed until Section 2.2.2.

**Transmission Costs:** The costs per mile of transmitting high pressure steam exceed those of electricity by a factor of about ten.\(^{11}\) According to the National Power Survey,\(^{12}\) the 1% per 100 miles losses plus the electric transmission capital and operating costs add up to costs of 0.5 to 2.0 mills/kwhr (1968 dollars) per 200 miles; Dow estimated transmission charges for wheeling cogenerated power could range from 0.6 to 2.7 mills/kwhr for 200 miles.\(^{13}\) These are costs for a single line; the marginal costs for
## ENERGY CONSUMPTION GROWTH RATES

<table>
<thead>
<tr>
<th>Growth Rate</th>
<th>Period</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Process Steam (SI)</td>
<td>3.6% 1960-1968</td>
<td>Stanford Research Institute, (1972)</td>
</tr>
<tr>
<td></td>
<td>4.0% e 1975-1985</td>
<td>Dow (1975a)</td>
</tr>
<tr>
<td></td>
<td>3.2% e 1975-1985</td>
<td>ThermoElectron (1976)</td>
</tr>
<tr>
<td></td>
<td>2.8% e 1975-2000</td>
<td>Chapter 4, this report</td>
</tr>
<tr>
<td>Electricity in Industry (EI)</td>
<td>4.6% 1960-1972</td>
<td>Edison Electric Institute (1973b) (Industrial plus large light and power sales)</td>
</tr>
<tr>
<td>Electricity Generation for the Utilities (EU)</td>
<td>7.2% 1960-1972</td>
<td>Edison Electric Institute (1973b) (Total generation less industrials)</td>
</tr>
<tr>
<td></td>
<td>4.7% e 1975-1990</td>
<td>Manne (1976)</td>
</tr>
<tr>
<td></td>
<td>4.3% e 1975-1990</td>
<td>Joskow and Baughman (1976)</td>
</tr>
</tbody>
</table>

e = estimated rate of increase.

Table 2.4
a network would be lower. These costs do not reflect the excess capacity necessary for network reliability.

Steam transmission costs are high enough in relationship to the economies of joint production and scale for cogeneration so that high pressure process steam is only transmitted for short distances. The General Electric (1975) study on energy parks specified industrial plants could be located from three to five miles from the generating plants—it is difficult to determine from the report whether these are assumptions or conclusions. Ayorinde (1973) calculated the maximum economic distance for high pressure steam transmission to be 5 to 12 miles, depending upon the cogeneration plant size. His analysis is unique in that it optimizes insulation and pumping before the cost comparison to an oil-fired boiler located at the transmission termination. The cost comparisons in both the studies, however, were made between on-site boilers and off-site cogeneration—on-site cogeneration should also be included as an option.

Plant Life: Although EG, SG, and CG facilities all have long plant lives, equipment located at industrial sites often has a much shorter economic life. Since manufacturing installations frequently become obsolete in 10 to 12 years, SG and CG plants are limited to this life unless they can be resold. The life of a typical large electric generating plant is 25 to 40 years.

Input Prices: Unit fuel and capital equipment costs are commonly higher for industrial facilities than for utility plants. EG plants are usually much larger than CG and SG systems; EG plants can take advantage of the economies associated with unit train coal deliveries while the smaller facilities at industrial sites cannot. Second, EG stations and package boilers have standardized designs owing to the similarities between
different installations; CG plants and field-erected coal boilers are typically sized for a specific industrial facility—this imposes the delays and costs associated with custom designs. The concentration of process steam consumption in a few industries may alleviate this effect because of similarities between manufacturing plants within an industry.

**Special Characteristics of the Technologies:** Economies of scale and joint production play an important role in the comparative advantages of separated versus cogeneration. First, however, the problem of defining and estimating economies of scale must be confronted before comparing EG, SG and CG. For single output technologies like SG and EG, economies of scale are defined as a cost condition where marginal costs decline over a range of increasing output.\(^{17}\) For joint product technologies like CG, the definition depends upon the combination in which the outputs are increased. Both Ruud (1975) and Panzar and Willig (1977) explore definitions and their implications for joint product situations.\(^{18}\)

Four different approaches have been used for inferring economies of scale: the econometric estimation of production and cost functions from behavioral data; the derivation of production and cost functions from engineering relationships; tests based upon firm survivorship; and analyses based on firm profitability.\(^{19}\) The methodology depends upon whether the author wishes to examine the problem at the firm, plant, or component level and upon the data available.

A large number of studies have examined economies of scale for electricity generation—almost universally they conclude such economies exist at the generating plant level.\(^{20}\) These studies are all based upon
econometric or engineering analyses at the plant level since profitability and survivorship techniques are not appropriate in a regulated situation.

Little information is available upon scale economies for SG boilers. Engineering cost estimates from American Boiler Manufactures Association (1975), Dow (1975a), and Dow (1975b) indicate some scale economies for field-erected, coal-fired boilers. Mass produced oil- and gas-fired, package boilers, which became available in the late 1950s, supposedly have similar scale economies; their capital costs, however, are a fourth to a fifth of the field-erected boilers. The nearly constant returns to scale for fuel costs make the total costs for package boilers less than those for field-erected boilers up to a certain output rate; this switch-over output rate is sensitive to fuel prices. Furthermore, typical package boiler designs cannot be changed to coal firing while field-erected designs can usually be switched between coal and oil.

Economies of scale and of joint production make the analysis of cogeneration's technological characteristics difficult. Since there are concerns about the ability of small firms to manage a cogeneration plant owing to a lack of trained personnel, an examination at the firm level would be desirable. 21 Unfortunately, a cogeneration facility is a small aspect of the firm's business—data at the firm level, if they were available, would probably be so sensitive to such a wide variety of factors that the economies of the CG plant could not be distinguished from other influences. At the CG plant level, problems with the lack of data and functional specification rule out an econometric investigation of the production or cost functions. First, it would be very difficult
to separate accounting data for the cogeneration plant from that of the manufacturing plant, i.e., the data exists at the institutional level rather than the process level. Second, no convenient, credible, and well understood functional form is available for specifying and estimating the technology's characteristics. Current multi-output versions of constant elasticity of substitution and the translog production functions do not reflect non-homotheticity, which engineering relationships indicate exists in cogeneration facilities. Furthermore, a great deal of debate has taken place on the problems of estimating even much simpler multi-output production and cost functions.

Setting aside the questions about the comparative ability of industrial or utility firms to manage CG plants, this section takes the engineering approach for the exploration of production and cost relationships in a simple cogeneration plant. Appendix A makes a partial survey of cogeneration technologies, examining seven designs in detail; the analysis here limits itself to a simple version of the back-pressure cogeneration plant type described in Section A.2.1. Figure 2.5 illustrates the plant design.

The production function being calculated is an ex ante two input, two output relationship: it incorporates the feasible input and output combinations from a perspective previous to the plant's construction. The standard algebraic representation for such a production set is:

\[ g(E, M; K, F) \leq 0 \]  

(2.1)

where

\[ K \] = the capital investment input for the plant in millions of
FLOW SHEET FOR THE SIMPLIFIED BACK-PRESSURE JOINT GENERATION
PLANT PORTRAYED BY THE ENGINEERING PRODUCTION FUNCTION

Figure 2.5
dollars,

\[ F = \text{the fuel input rate in Btu/hr needed to achieve capacity,} \]
\[ E = \text{the electrical power output capacity in MW, and} \]
\[ M = \text{the steam output capacity in lb/hr of 150 psi steam.} \]

\textit{Ex post}, the plant operates at either full capacity or shuts down.

The function \( g(.) \) can be expressed in a series of engineering relationships combining the thermodynamics and capital equipment cost functions. The capital investment is specified as the sum of two types of capital equipment costs—those related to the electrical output and those related to the steam flow rate and boiler steam conditions:

\[ K = KE(E) + KS(M,P) \quad (2.2) \]

where \( KE(.) = \) the electricity generating equipment costs,

\( KS(.) = \) the costs for the facilities generating steam, and

\( P = \) the maximum boiler outlet steam pressure.

In a more complex plant design, the outlet steam rate from the boiler would differ from that of the plant, but here they are the same. The Dow (1975a, p. 71) electricity-related and steam-related cost functions are:

\[ KE(E) = 0.67 \times E \quad (2.3) \]

and

\[ KS(M,P) = 4.0 \left( \frac{M}{100,000} \right)^{0.846} \left( \frac{P}{900} \right)^{0.125} \quad (2.4) \]

The steam pressures in the following analysis went higher than the range intended for equation 2.4, so it was modified using information from Cootner and Løf (1965, p. 12). Cootner and Løf derived the marginal capital cost increases associated with increases in an electric
generating station's boiler design pressure or temperature. Since a back-pressure cogeneration plant has a fixed relationship between the boiler outlet pressure and temperature once the process steam characteristics are specified, the boiler steam temperature is known when the electrical output and boiler pressure are given. Thus, for boiler outlet pressures above 2800 psi, the steam-related capital cost function was altered to account for the special construction required at high pressures and, hence, temperatures:

\[
K_S(M,P) = 4.0 \left( \frac{M}{100,000} \right) 0.846 \left( \frac{P}{900} \right) 0.125 + 0.04 \left( \frac{P}{2800} - 1 \right)^2
\]

for

\[ P \geq 2800 \text{ psi}. \]

Figure 2.6 shows the old and modified steam-related capital cost functions.

The physical relationships between the fuel input and the outputs from equations A.11 and A.12 are:

\[
M = \frac{\eta_b F}{(h_4 - h_1 - h_{34})}\]

\[
E = \frac{\eta_t \eta_g}{3.412 \times 10^{-6} \text{ Btu/MWhr}} (-h_{34})M
\]

where \( h_1 \) and \( h_4 \) = the specific enthalpy ("the unit energy content") of the boiler feedwater and process steam in Btu/lb.

\( \eta_b, \eta_t, \) and \( \eta_g \) = efficiencies of the boiler, turbine, and generator, and \( h_{34} \) = the enthalpy drop (negative) through the turbine in Btu/lb.

The variables in this system of equations are \( h_{34}, F, M, \) and \( E \). Since
STEAM-RELATED CAPITAL COSTS
AS A FUNCTION OF PRESSURE

DOW MODIFIED BY INFORMATION FROM COOTNER AND LÖF (1965, p. 19)

DOW (1975a, p. 71) COST FUNCTION

Steam flow rate capacity, M, is fixed at 200,000 lbm/hr

Figure 2.6
the process steam output is assumed to be saturated 150 psi steam, the
boiler outlet pressure depends on $h_{34}$. The calculations in this section
approximated the pressure-enthalpy relationship as:

$$ P = 150 \exp (-0.012 h_{34}). \quad (2.8) $$

The boiler, turbine, and generator efficiencies were assumed to be .9, .85,
and .95 respectively.

Production possibilities curves can be derived by solving $g(E,M;K,F)$
for the non-inferior output combinations given fixed levels of $K$ and $F$.
This is equivalent to solving the mathematical programming problem below
for a series of power output capacities, $E^*$:

$$\begin{align*}
\max (M) \\
g(E,M;K,F) &\leq 0 \\
F &\leq F^* \\
K &\leq K^* \\
E &= E^*
\end{align*} \quad (2.9)$$

where $F^*$, $K^*$, and $E^*$ are constants, and $g(.)$ embodies equations 2.2
through 2.8. The solution of this non-linear programming problem for-
tunately requires only a one dimensional search across the feasible
values of $h_{34}$ for each level of $E^*$.

Figures 2.7 and 2.8 plot the production possibilities curves for
varying levels of capital investment and fuel input. When the fuel in-
put constraint is binding, it appears as a line along the right edge of
the curve. The capital constraint, owing to the returns to scale for
electrical and boiler output capacity, causes the production set to be
PRODUCTION POSSIBILITIES CURVES FOR FIXED FUEL INPUT
AND VARYING LEVELS OF CAPITAL INVESTMENT

Figure 2.7

K = $14 Million
K = $12 Million
K = $10 Million
K = $8 Million

F = 3.86 x 10^8 Btu/hr

M, DESIGNED PROCESS STEAM OUTPUT
(10^5 lbm/hr)

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PRODUCTION POSSIBILITIES CURVES FOR FIXED CAPITAL
INVESTMENT AND VARYING LEVELS OF FUEL INPUT

\[ K = \$10 \text{ Million} \]

\[ F = 1.28 \times 10^8 \text{ Btu/hr} \]

\[ F = 2.57 \times 10^8 \text{ Btu/hr} \]

\[ F = 3.86 \times 10^8 \text{ Btu/hr} \]

\[ F = 5.14 \times 10^8 \text{ Btu/hr} \]

\[ M, \text{ DESIGNED PROCESS STEAM OUTPUT} \]

\( (10^5 \text{ lbm/hr}) \)

Figure 2.8
non-convex—thus the production function cannot be homothetic. Note the possibilities curve for K=8 million in Figure 2.7; the fuel constraint is not binding here. As electrical output is increased, the non-inferior production set curves inward slightly. The production set has a sharp point at about M=1.2 and E = 7 since boiler costs increase quickly in this area owing to the high boiler steam pressures. The flat "top" on the production set also results from the pressure aspects of the capital cost constraint.

The input isoquants can be similarly derived by the parametric solution of the following minimization problem for differing values of F*:

\[
\begin{align*}
\min (K) \\
g(E, M; K, F) < 0 \\
E > E^* \\
M > M^* \\
F = F^*
\end{align*}
\]

where E*, M*, and F* are constants. As shown in Figures 2.9 and 2.10, these isoquants also exhibit an unusual shape. First, since burning more fuel requires a larger boiler at most electrical output rates, the isoquants are backward bending in most cases. Second, the optimal combination of capital and fuel at all positive factor prices is fixed for a broad range of output combinations. The inputs are flexible only when the steam/power ratio is low due to the high boiler outlet pressures and the associated special capital cost influences.

Finally, it is possible to derive isocost curves for this simplified cogeneration plant by parametrically solving the following for different
ISOQUANTS FOR FIXED DESIGNED STEAM OUTPUT AND VARYING LEVELS OF DESIGNED POWER OUTPUT

Figure 2.9

M = 200,000 lbm/hr

F, FUEL INPUT (10^8 BTU/HR)
ISOQUANTS FOR FIXED DESIGNED POWER OUTPUT
AND VARYING LEVELS OF DESIGNED STEAM OUTPUT

Figure 2.10
values of $M^*$:

\[
\text{max}(E) \quad (2.11)
\]

\[
r K + \frac{8760}{10^{12}} \lambda p F \leq B
\]

\[
g(E, M; K, F) \leq 0
\]

\[M = M^*
\]

where $B$ = the annual plant budget in millions of dollars,

$r$ = the capital charge rate,

$\lambda$ = the annual load factor for the plant,

$p$ = the price of coal in dollars/MMBtu, and

$M^*$, $B$, $r$, $\lambda$, and $p$ are constants. Figure 2.11 illustrates the solution of this parametric mathematical programming problem for various budget levels. Note, like the production possibilities curves, the cost possibilities set is non convex. This means a small change in the relative prices of steam and power can result in a drastic shift between the zero electrical/maximum steam output point and the moderate mix corner. The trade-off between steam and electricity is at one site, however, so the choices cannot be adequately represented by a price line.

The production relationships in the previous pages have been for an unrealistically simple cogeneration plant. The functional designs typically have back-up boilers and can operate over a range of steam and power output mixtures. This implies the ex ante isocost curves for these plants do not have as sharp a corner as those in Figure 2.11. Nevertheless, it appears that the CG plant's cost function is of the
ISO-COST CURVES FOR A BACK-PRESSURE COGENERATION PLANT

Budget: B
Load Factor, \( \lambda \): 85%
Capital Charge Rate, \( r \): 7.5%
Coal Price, \( p \): $0.85/MBtu

Figure 2.11
special form Baumol (1977b) has called "sub-additive," i.e., embodying both returns to scale and joint production.27

2.2.2 MARKET STRUCTURE

This section surveys the structure of the markets associated with the derived demands for electricity from the transmission system (EU) and electricity (EI). Two conditions predominate in these markets: vertical integration of the demanding institutions backward into the supply processes; and concentrated utility purchasing of generation combined with generation ownership concentrated in the hands of a few bulk power producers in some areas. This does not mean, however, that those in the possession of this potentially monopolistic or oligopolistic power do exercise it but merely that they could.

High transportation costs for both steam and electricity cause locational differentiation of these products in spite of the returns to scale in their supply technologies. Discussions of market structure must therefore pertain to market structure on a sub-regional level. Some local concentration data exist for the electricity supply (EU) markets, but the examination of the SI and EI markets must proceed with little local concentration information.

The EU Market: An electric utility, in order to meet the obligations of its franchise28, must acquire generation for the demands derived through its transmission system. Within the geographic limits of its franchise, a utility has monosonistic control over the electricity acquisition from its internally owned generation,29 purchases from industries (IES), and purchases from the utilities it surrounds (in cases where the
buying utility can erect barriers to the wheeling of electricity between the encompassed utilities and other wholesale purchasers). The Otter Tail case eliminated the wheeling barrier between bulk purchasers on the basis of antitrust considerations, but other effects still allow a utility to exercise considerable control. First, some states have regulations specifying wholesale service areas or antipirating laws preventing wholesale power competition. Second, large bulk-power consuming utilities can collude, merge, or vertically integrate. Finally, the high transmission costs for electricity can eliminate a seller's economies of scale from the perspective of a distant buyer. Thus the cost structure may allow monopsonistic control of prices even without a wheeling barrier. It is an open question, however, as to whether or not the Otter Tail decision applies to wheeling from an industrial firm to another utility; pending legislation allows the Federal Energy Regulatory Commission to order such wheeling.

Table 2.5 shows the high supplier concentration in the EU market surrounding several major cities. This is usually because of a large retail utility's vertical integration into wholesale electricity generation. According to Weiss, about 69% of all sales to ultimate consumers and 92% of private sales in 1968 were on a privately owned, vertically integrated basis. The 100 MW cutt-off in the Weiss (1975) concentration ratio, however, means most cogeneration facilities are neglected in the calculations.

Is an industrial firm ever liable to have any market power in the EU Market? Industrial monopoly or an industrial/utility wholesaler oligopoly requires several conditions:

1. The industrial firm's steam demands would have to be large
### ESTIMATED CONCENTRATION IN ELECTRIC GENERATING CAPACITY WITHIN 100 AND 200 MILES OF TEN MAJOR LOAD CENTERS, 1968

<table>
<thead>
<tr>
<th>Load center</th>
<th>Number of firms with greater of four largest megawatt firm capacity (percent)</th>
<th>Share of four largest firms capacity (percent)</th>
<th>Number of firms with greater of four largest megawatt firm capacity (percent)</th>
<th>Share of four largest firms capacity (percent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York</td>
<td>12</td>
<td>29</td>
<td>75</td>
<td>18</td>
</tr>
<tr>
<td>Chicago</td>
<td>7</td>
<td>61</td>
<td>93</td>
<td>17</td>
</tr>
<tr>
<td>Los Angeles</td>
<td>6</td>
<td>67</td>
<td>97</td>
<td>8</td>
</tr>
<tr>
<td>San Francisco</td>
<td>2</td>
<td>97</td>
<td>100</td>
<td>8</td>
</tr>
<tr>
<td>Detroit b</td>
<td>8</td>
<td>48</td>
<td>90</td>
<td>13</td>
</tr>
<tr>
<td>Philadelphia</td>
<td>9</td>
<td>29</td>
<td>79</td>
<td>19</td>
</tr>
<tr>
<td>Houston</td>
<td>2</td>
<td>79</td>
<td>100</td>
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<td>St. Louis</td>
<td>5</td>
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<td>15</td>
</tr>
<tr>
<td>Washington</td>
<td>8</td>
<td>38</td>
<td>79</td>
<td>11</td>
</tr>
<tr>
<td>Boston</td>
<td>6</td>
<td>26</td>
<td>79</td>
<td>14</td>
</tr>
</tbody>
</table>

All members of a holding company are treated as a single firm, but members of pools are treated as separate firms. Where data are available, joint ventures are allocated among owners within the specific market in the proportions reported; on an equal-shares basis otherwise. The portion of joint ventures within a market owned by firms outside the market is considered a single firm. All federal capacity and individual municipals in a market are also treated as owned by a single firm.

b Includes Hydro-Electric Power Commission of Ontario.

Source: Weiss (1975)

Table 2.5
enough that the economies of scale and joint production from the industrial cogeneration would be significant with respect to the extent of the local EU demand. A large percentage of aggregate steam consumption is in a few industries (Table 2.2) and the scale of the minimum efficient plant size in some of these industries implies a significant fraction of the national steam consumption at one site.  

If one of these plants located in an area with a limited electricity demand and no competing cogenerators, its potential electricity output from CG would be large compared to the EU demand. These situations are liable to be rare: no concentration information is available, but electric industry statistics show all except six states had more than one thousand large light and power customers in 1972.  

2. The industrial firm would have to encounter no barriers to the sale of its excess electricity—such as the local utility's refusal to wheel the power or the rejection of the sales contract terms by a state public utility commission.  

3. There would also have to be no monopsony power on the buyer's side of the EU transaction, or otherwise a bilateral monopoly situation would develop.  

In summary, the utility buyer and seller concentration in the EU market places the industrial firm wishing to sell excess electricity (IES) in a situation where it must bargain with a potential monopsonist (the EU buying utility) while competing with much larger firms on the sales side (the concentrated bulk EG utilities).  

The EI and SI Markets: Industrial firms, the buyers in the SI and EI
markets, can either integrate by acquiring ownership of SG or CG supply technologies or purchase the electricity or steam, when it is available, from the local utility. Occasionally, the steam may be available through a third party. 36 For the reasons noted above, an industrial firm rarely has any market power with respect to electricity purchases from the local utility—in the long run, its major substitution options are to move its plant or to produce its own electricity from internal sources. Joskow and Baughman's (1976) estimates of a high -2.0 elasticity for state industrial energy demand (with 25 years adjustment) and a -0.2 national elasticity give an indication of the relative locational and price-induced conservation effects. On the steam purchasing side, it is difficult to discuss buyer concentration meaningfully because steam transportation costs make the market very localized. Industrial generation for internal use was 16% of the total industrial electricity consumption (EI) in 1972 and 20% in 1960 evidence of a declining but moderate industrial integration into its electricity supply. No similar information is available concerning steam supply; the examples of utility or third party steam sales in Appendix A and the ThermoElectron (1976) report offer a few instances where industrial firms have not integrated into their steam supply processes.

On the supply side for EI, industry must purchase electricity from the local utility (UES), a regulated monopoly, unless the industrial firm has integrated into the EG or CG supply processes. As discussed in Section 2.2.1.2, the economies of scale for EG make it unlikely that a firm will generate a large amount of electric energy unless it cogenerates it. Since the economies of scale for SG are small, steam transmission costs high, and retail steam sales franchises very rare, it is doubtful
that local monopoly power could exist in steam supply unless it was held by a cogenerating electric utility that integrated forward into industrial steam supply under the right demand and cost conditions; nothing other than anecdotal evidence of such a situation is available. Since the markets for boilers and fuel are competitive, an industrial firm or a third party could easily enter into steam production.

Given a locality with a large utility-controlled buyer and seller concentration in the EU market along with the utility's retail UES monopoly franchise, an industrial firm faces potential monopoly control in both the purchase (UES) and sale (IES) of electricity—the only means of applying immediate competitive pressures are the balancing SI and EI consumption at a mix appropriate for an internally-owned CG plant causing little UES or IES through the trade-off of SI and EI consumption against cost increases by changes in the basic processes.

**Factors Influencing the Market Structure:** What conditions and which aspects of market behavior have caused the market structure described above? What promotes the concentration on the buyer and seller sides of the EU market? What contributes to the backward vertical integration of the utilities and industry into their respective supply technologies?

On the buyer side of the EU market, public recognition of the economies of scale for electricity transmission and distribution has resulted in the granting of a retail electricity sales monopoly franchise for a given geographic area. This, combined with mergers of retail utilities in the 1960's, gives individual utilities control over a wide geographic area. The high costs of transmitting electricity in comparison to generation costs, the durable nature of industrial facilities, and the problems of wheeling when a transmission company does not wish to cooperate
allow a utility considerable short-term monopsony power.

A large number of factors could have contributed to the integration of retail utilities and bulk power producers and the concentrated ownership of generating capacity (EU supply). Until recently, the cost conditions for industrial cogeneration may have been unfavorable so industrial firms would not have wanted to enter even a competitive suppliers' market; this will be discussed in greater detail below. The local extent of the industrial steam demand also limits cogeneration. On the other hand, the threat of extensive regulation for an industrial firm that sells electricity to a utility is a significant barrier to entry.39 The generating utilities, through their economies of scale in EG and the costs of wheeling electricity out of a local area, could exercise a limit pricing strategy that would restrict the entry of industrial cogenerators (IES) as suppliers in the EU market.39a

According to Weiss (1975), lax enforcement of the merger laws with respect to the electric power industry up to the late 1960's allowed retail and large wholesale utilities to horizontally and vertically integrate. Two possible behavioral models suggest reasons why such vertical integration may be desirable. The first model, proposed by Arrow (1975), indicates a firm facing uncertainty in input supply has an incentive to integrate into upstream firms that possess a better knowledge of supply conditions; this is due to the incentive to minimize inefficiency from uncertainty rather than the urge to merge for monopolization. The second model, recently expanded to cover the dominant firm case by Perry (1978), shows a monopolist that cannot price discriminate will integrate downstream into the industries with more elastic demands. The reasoning also applies to the case of the monopsonist: a monopsonist will integrate upstream.
into all industries except the one with the least elastic supply functions. This could explain why retail utilities integrate into EG and not into CG if the elasticity of supply from EG is greater than for CG. In the dominant firm case, the degree of integration depends on the extent of the competitive fringe. Horizontal merges extend the geographic coverage of the utility, reducing the influence of the neighboring utilities, the competitive fringe.

On the buyer side of the SI and EI markets, the industrial firm typically has little market power. The firm usually integrates into steam supply because of the high transmission costs and only slight economies of scale. It may also want to integrate for reasons of supply security, as implied by Arrow's (1975) model mentioned above. The cost structures facing the firm for the choice of whether or not to integrate into its electricity supply by cogenerating are rather complex and unique. Taking the iso-cost curves for a cogeneration plant from Figure 2.11, Figure 2.12 illustrates the non-inferior steam and electricity outputs at one cost level for the combined options of a coal-fired boiler and utility electricity purchases, an oil-fired boiler and utility electricity purchase, or an integrated cogeneration plant with no utility electricity purchases or industrial electricity sales (IES). The trade-offs between steam and electricity inputs to the basic industrial processes can only be in a limited range for cogeneration to be preferred. Since the iso-cost surface for the cogeneration plant protrudes only slightly beyond the coal/utility electricity purchase option, the cost structure is very sensitive to the price of utility electricity and the relative prices of coal and oil: oil price conditions similar to those in the 1960's would make

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ISO-COST SURFACE FOR PROCESS STEAM AND ELECTRICITY SUPPLIES

Budget: $2 million/yr
Load Factor: 85%
Capital Charge Rate: 7.5%
Energy Prices: $.84/MMBtu for Coal
$2.99/MMBtu for Oil
$.02/kwhr for Utility Electric

- Coal-Fired Back Pressure Cogeneration Plant with No Utility Electricity
- Coal-Fired Boiler and Utility Electricity
- Oil-Fired Package Boiler and Utility Electricity

Figure 2.12

M, DESIGNED PROCESS STEAM OUTPUT
(10^5 lbm/hr)
oil-fired boilers preferable to coal-fired in this situation. The sensi-
tivity of the utility electricity/cogenerate iso-cost curves and the
sharp nature of the steam/electricity output trade-offs for the back-
pressure cogeneration plant imply shifts in the choice between integra-
tion and utility electricity purchases could occur aburptly.

As discussed above, the local utility's franchise monopoly on the
supply side of the EI market is limited by the substitution possibilities
available to the industrial firms. This power is weaker when industries
can shop for electricity by moving or switching to cogeneration. This
switching or moving is slowed by the durable nature of industrial plants.

How might the structure change: The rapid increases in oil prices
in the early 1970's along with the increases for utility electricity mean
costs have shifted in favor of cogeneration in spite of the scale econo-
mies for EG at the utility level. The long life of industrial plants
combined with a reduction in the growth rate for process steam demand
implies the major portion of any shift toward more cogeneration would
have to come at existing facilities. Anti-trust action against utilities,
a new federal no-merger stance in the public utility area, and the
establishment of formal rate schedules for the purchase of electricity
from cogenerators will encourage more non-integrated generation in the
EU market. Federal and state activities are now underway to reduce the
legal barriers industrial firms face when they wish to sell electricity.
Changes in costs and regulatory reviews of IES purchasing rates and wheel-
ing charges could reduce the opportunities utilities have for controlling
the entry of industrial firms into electricity supply.
2.2.3 MARKET CONDUCT

Other than the anecdotes and perceptions from the interviews conducted for the ThermoElectron (1976) and Resource Planning Associates (1977) reports, there is no comprehensive information on the actual pricing and production behavior in the IES market. Furthermore, only rudimentary models exist for economic behavior under the complex structure and basic conditions observed in the markets surrounding cogeneration. The lack of behavioral data and the elementary nature of the direct behavioral models makes direct testing for market distortions and measurement of welfare losses impossible; much more realistic models are needed.

Anecdotal evidence garnered from interviews is not adequate for a comprehensive assessment of market imperfections. A quote from McGee on the evaluation of managerial efficiency by interview offers a comment on such analysis:

Scherer says that the managers of big and little firms seemed equally dynamic, intelligent, aware, and skillful. Although I am sympathetic, I am not impressed. Babe Ruth didn't look like much to me until he hit the ball. The great Jim Brown looked thoroughly moribund between plays. Off the field, the Gas House Gang looked to me a good deal like they sound, and Jim Dickey doesn't look or talk much like a poet. If anything, this proves only that appearances are deceiving, and that Scherer and I are better off as economists than we would be as talent brokers, executives, and recruiters. Professionals are to be judged by how well they do what they are paid to do, not by how impressive they seem in interviews with economists and engineers. God help economists if executives are permitted to evaluate us in interviews.44

By the same token, a thorough evaluation of the behavior and subsequent behavior in a market should take account of what the participants do and the conditions under which they do it, not merely what they say about the market and factors that affect their decisions in it.

Microeconomic theory for multiple-input/multiple-output firms, which is germane for the analysis of the industrial side of the market, is currently
being explored in the literature.\textsuperscript{45} Discussion has just begun on the meaning and effects of economies of scale in these situations; the results are in some cases opposite what the single-output theory would imply.\textsuperscript{46} As noted in Section 2.1.2, econometric estimation of multiple input and output production and cost functions is at an even more rudimentary state of development.\textsuperscript{47} Most operational models of joint production in industry are based on process analysis, typically in a linear programming framework. Manne and Markowitz (1963) survey the early theory and application of models analyzing industrial capability through a reflection of the physical production processes. More recently, Griffin has utilized the process analysis approach for characterizing capacity in a joint product industry; together with Adams, he has linked an econometrically estimated model with a process analysis model for simulating and forecasting the behavior of the US petroleum refining industry.\textsuperscript{48}

Models of regulated firms are at an even more elementary state of development. The most widely used framework, the Averch-Johnson approach, is a static model with the regulators setting only the rate of return when, in fact, their role is much more complex.\textsuperscript{49} Baughman and Joskow (1974) have developed a more realistic econometric/process analysis model of the electric utility industry; such a model, however, must be adapted for the analysis of each new situation because of the necessarily specific focus of the modeling detail.

The simple Averch-Johnson model indicates the regulated firm will over-invest in capital equipment and under-utilize other inputs since the regulatory constraint lowers the cost of capital with respect to other inputs. This alone implies a utility would buy too little industrially co-generated electricity. The monopsony power of the local utility raises
the marginal expenditure of IES above its price; this biases the utility even more toward its own capital equipment. Under conditions of rising prices and regulation with discrete lagged adjustments in retail electricity prices, the utility has a counteracting incentive to minimize costs.

A much broader model is required to capture the behavior that is anticipated to be important in this market. The lack of industrial cogeneration has been blamed on legal entry barriers, restrictive utility pricing strategies for IES and UES, or merely the belief of the utilities that the economies of scale for EG are greater than the economies of joint production for CG. The utility pricing strategies could take the form of price discrimination since IES contracts have been individually negotiated, or they could be limit pricing. The R&D spending and the adoption of new EG and CG technologies could be affected by the concentration of utilities in the EU market, the durability of the capital equipment, the closeness of a new technology's costs to that of existing equipment, or Averch-Johnson biases.
2.3 CONCLUSIONS

Have market imperfections caused poor market performance in the markets surrounding cogeneration? This chapter has shown that the preconditions for a variety of market failures exist but also that the behavior of these markets may have been caused by fuel and capital costs changes. Except for cost relationships illustrated by Figure 2.12, which shows the sensitivities of the cost relationships, no hard evidence can be offered in either direction. The accounting data and behavioral models are too weak to give a definitive answer to the market imperfections question through an econometric analysis. There is, however, an abundance of engineering and cost information on the individual EG, CG, and SG technologies and on steam and electricity consumption: a process analysis approach can simulate how the market should have behaved given the basic market conditions.

Both equity and economic efficiency questions usually arise in the examination of a market's performance. The market biases could transfer profits from industry to the local utility; no exploration was made of these equity considerations or of the possible effects upon residential rates. An analysis based on efficiency consideration, on the other hand, is concerned with changes in the total economic surplus from steam and power production without regard to institutional boundaries. The equivalence between optimizing process analysis models and competitive market equilibrium, to be discussed in the next chapter, provides a framework for simulating the performance of a competitive market from the basic conditions described in Section 2.2.1. When the aggregate data on the market's behavior are substituted into the model, changes in
the model's objective function indicate the magnitude of the dollar efficiency losses in the real market's performance. The process analysis approach provides a short-cut from basic conditions to the measurement of market performance—avoiding the lack of information on market structure and behavior and the weaknesses of the current models for predicting behavior and performance from the market conditions and structure. This is a significant improvement over measuring the potential of cogeneration's development in terms of what is thermodynamically achievable, without regard to fuel or capital costs, and then calculating behavior on the basis of executive interviews.
Footnotes for Chapter 2

1. Edison Electric Institute (1973b) and a personal communication with Sam Ferraro, US Federal Power Commission (December 1975). The data from these sources are total industrial electric energy production and capacity; it is assumed that essentially all industrially generated electric energy is cogenerated—otherwise the economies of scale in electricity generation make it cheaper to purchase the energy from a utility.

2. von Hippel and Williams (1976) allude to this problem.

3. See Scherer (1970) Chapter 1, for a text on this approach.


5. The separated relationships shown by Figure 2.3 only approximate the real situation. In petroleum refining, for example, steam is produced from heat recovery in the refining operations and is thus a joint product along with the refined petroleum. Also, it is technologically feasible for high pressure steam to be transmitted in a distribution system, like electricity, although it is rarely economic. The electricity-only generation (EG) is shown going only into the utility grid (EU); in fact, small amounts of electricity are generated on industrial sites by back-up systems. The analysis here will assume no electricity-only generation will be done on industrial sites because of the proven scale economies for this technology.

6. In a purely competitive market, all production takes place at minimum cost for the given levels of output, and firms receive no excess profits since prices equal the marginal costs of production and new firms will enter until economic profits are zero. In a pure monopoly, production still occurs at the minimum cost for the given level of output, but the monopoly reaps excess profits through restrictions in the level of total output. The output restriction results in welfare losses and a transfer of income to the monopolists. See Scherer (1970), Henderson and Quandt (1971), and Baumol (1977a).


8. Since most process steam consumption is at these lower pressures, this report will adopt one pressure (150 psig) for all calculations. Shifting this over a 50 psig to 250 psig range changes the results little.

9. Dow (1975a, p. 39); since higher plant availabilities are assumed in Appendix B, the capacity factors reported there are even higher.

10. Ibid.


14. The longest example in Dow (1975a, pp. 101-102) is 9000 ft.


16. Noting the assumptions in Joskow and Baughman (1976), Manne (1976), and Dow (1975a).

17. See Baumol (1977b) or Henderson and Quandt (1971) for more detailed definition of economies of scale or returns to scale.

18. This is a topic being actively discussed in the economic theory literature.


20. Galatin (1968) surveys the literature; it is interesting to note that he criticizes one of the frequently quoted studies, Nerlove (1965), for mixing technological change effects with scale economies—a problem that could arise in an aggregate comparison of cogeneration and steam technologies.

21. This may not be a problem if firms contract the management of their cogeneration plant to another firm specializing in such an area. Firms building and managing cogeneration facilities do exist (personal communication with Nancy Alexander, Director of Marketing Services, Energy Unlimited, Ltd., November 1977).

22. Jensen (1974) briefly surveys the problem of cost allocation for joint production, focusing on the simplest case of fixed proportions.


25. Homotheticity is a generalization of the returns to scale concept; among other things, it implies the expansion path is linear, which is not the case for the simple engineering production function derived in this section. See Baumol (1977a, pp. 280-286) for a detailed explanation of homothetic production functions.

26. The earliest work was by Meyer *et al.* (1959) on a linear cost function for rail transportation. Mundlak (1963) examined the problem from a more theoretical viewpoint, questioning both the specification and estimation. A more recent econometric paper by Vinod (1968) provoked a round of corrections, an experience indicating the pitfalls in this area (Chetty, 1969, Dhrymes and Mitchell, 1969, and Rao, 1969).
27. Economies of joint production are also known as economies of scope or transray subadditivity.

28. In a long series of decisions resulting in an evolution of constitutional thought, the US Supreme Court has determined that the states have the power to require a utility to render service within the region of its franchise because of--among other reasons--the exclusive monopoly privileges granted to the utility within its franchise area. (Kahn, 1970, Vol. 1, p. 4)

29. This can include utility-owned cogeneration plants.


31. This draws upon the discussion on bulk sales and antitrust law by Weiss (1975, p. 161).

32. US Executive Office of the President (1977, p. 45).

33. "The electric utility industry consisted in 1965 of 3,614 companies in all. Some 3,000 of these were local distribution systems owned by municipalities or rural cooperatives, the majority of which did not generate their own power, but purchased it from the 42 federal projects and from the 243 privately owned systems, preponderantly fully integrated (in generation, transmission, and distribution).... The 243 private companies generated 75% of the power sold for public use, the federal projects an additional 14%. The publically but not federally owned companies and cooperatives accounted for another 11% of the power generated but served perhaps 20% of the retail customers." Kahn (1971, Vol. 2, p. 74).

34. Bain (as quoted in Scherer, 1970, p. 84) finds the minimum optimal petroleum refinery to be about 1.75% of total national capacity—and petroleum refining consumed more than 20% of the total national process steam (see Table 2.2). This is the case most likely to lead to EU seller concentration held by an industrial firm—and it appears to be a weak case.

35. Edison Electric Institute (1973b), Table 29S.

36. Most state electric utility franchises would allow the utility to prevent third party from retailing electricity from a cogeneration plant unless the utility was involved within the third party arrangement.

37. This is based on industrial generation for internal use as a percentage of industrial generation for internal use and total utility industry energy sales to large light and power customers (Edison Electric Institute, 1973a, Tables 8S and 19S). Including small light and power commercial and industrial sales as a part of the total industrial consumption lowers the percentage to 9% in 1972 and 15% in 1960.

39. The Dow (1975a) report has the most comprehensive survey of legal barriers to the sale of electricity by industrial firms.

39a. See the sample calculations in Appendix B on the effect of transmission costs.

39b. The oil-fired boiler is a package boiler having a capital cost of 25% of the coal-fired one.


42. As ordered in Resolution No. E-1738 Public Utilities Commission of the State of California, San Francisco, CA: January 10, 1978; actions in several other states are at the formative level. (See, for example, Massachusetts Governor's Commission on Cogeneration, October 1978).


45. See Frisch (1965), Shephard (1970), Lau (1972), and Sakai (1974).

46. Under certain conditions, a firm with economies of scale can recover costs with marginal cost pricing; furthermore, locally decreasing average costs along a ray of output combinations is neither necessary nor sufficient for monopoly to be the least cost production made. See Panzar and Willig (1977), Ruud (1975), and Baumol (1977b).

47. See note 26 in this chapter.

48. See Griffin (1971, 1972a, and 1972b) and Adams and Griffin (1972).

49. For a general discussion see Kahn (1971). One of the empirical tests of the Averch-Johnson hypothesis is by Peterson (1975).

50. As was discussed in greater detail in Section 2.2.2.

51. See Mansfield (1968) for the pioneering explorations into the influences of these factors on innovation and the adoption of new technologies.
This chapter describes the process analysis model used in Chapters 4 and 5 to study the economics of cogeneration from a public benefit-cost perspective by simulating a competitive market. The first section summarizes the purpose and general approach of this model, called the Joint Generation Supply Model or JGSM for short. The second relates the model's basic structure to economic theory and briefly contrasts its market coverage and formulation with several other process-type energy models. The final section contains a detailed exposition of the model in a linear programming format.

3.1 SELECTION OF AN ANALYTIC APPROACH FOR STUDYING THE AGGREGATE ECONOMICS OF COGENERATION

As Chapter 1 notes, a modeling framework needs to be established to:

- Simulate the behavior of a competitive combined market for process steam and electricity. The projections of behavior for the 1975-2000 period complicate the modeling problem because the analysis must reflect the influences from technological change embodied in the new plant types available in the mid-1980's as well as changing capital equipment and fuel costs.

- Measure the economic welfare impacts of:
  - Market performance that does not coincide with that of a welfare maximizing competitive market's.
  - New technologies.
The modeling effort therefore has two aspects: predictive modeling of behavior, and the normative measurement of the total social costs of the "best" behavior and deviations from it.

The economic studies of cogeneration in the Dow (1975a), Dow (1975b), ThermoElectron (1976), and, to some extent, Resource Planning Associates (1977) reports lack several important features that are vital for an analysis appropriate from a public perspective:

- Since both fuels and capital are scarce commodities in the U.S. economy, they should both weigh into any national comparison of actions pertaining to cogeneration. No study has yet combined fuel and capital costs from a national income perspective to yield the net present costs for alternative levels of cogeneration in national electricity and process steam supply.

- Cogeneration links electricity supply with industrial process steam supply; if cogeneration is one of the marginal technologies, its cost characteristics can determine the price of both electric and process steam energy. Previous studies have concentrated on financial analyses from only an individual industrial firm's or utility's perspective with the price for one of the two cogeneration plant outputs assumed exogeneous (electricity for an industrial firm, steam for a utility).

- The availability of new technologies or significant changes in fuel or capital costs may make the early retirement of existing steam and electricity facilities economic. The single-period return-on-investment analytical approach used by the studies cited above cannot consider such trade-offs except at the
beginning of the time interval under examination.

What analytical approach can serve the purposes of this effort and also address the objections above to the previous studies? If the data and a functional form appropriate to characterize the technological relationships were available, an econometric model could be estimated for predicting the total costs for electricity and process steam production under various basic conditions, market structures, and structures on behavior. Unfortunately, as discussed in the previous chapter, it is impossible to obtain meaningful historical cost data for industrial steam: the value of any accounting data is very questionable because of the joint costs associated with cogeneration. Furthermore, behavioral models and practical functional forms for joint production situations with economies of scale are just being explored. The engineering production function derived in Chapter 2 calculated the costs and trade-offs in a multi-input, multi-output situation with economies of scale, but the determination of these cost functions for a large number of technologies would be prohibitively complex. The process analysis approach, which allows simplified linear treatment of these engineering relationships, can approximate the equilibrium of a competitive market from the basic market demand, factor price, and technological conditions.

Given the problems with the econometric and direct engineering production function methods, this report selects the process analysis modeling approach. Still, however, several problems remain. All the electricity, steam, and cogeneration technologies exhibit economies of scale; a linear programming process analysis, however, uses technologies with linear costs. The problem being addressed requires predictive modeling;
extensions are required to the normal process analysis framework which simulates competitive markets, to simulate non-competitive market behavior. The demands for steam and electricity are sensitive to the marginal supply costs; most linear programming formulations are based on fixed demands. Unlike econometric models, process models provide no direct estimate of the uncertainties embodied in a projection.

The process analysis model, JGSM, uses linear programming to minimize the total discounted social capital, fuel, and operating costs of meeting exogenously specified total U.S. electricity and process steam energy demands. As will be discussed in the next section, this approximates a competitive market equilibrium. In achieving the energy demands, it chooses between a number of electricity-only, steam-only, and cogeneration technologies without regard to institutional boundaries, i.e., changes are evaluated as if the gainers could compensate the losers. The cost minimization spans a number of time periods in which capacity can be added and the production mix can be altered within the limits of current capacity; this permits an analysis of the impacts from future technologies and time-varying fuel and capital costs. In addition to the simulation of a competitive, joint product market through the simultaneous determination of electricity and steam supply, the model provides a framework for evaluating the incremental costs of less-than-competitive market performance. The prediction and normative measurement aspects of the problem are thus combined within this one model: the unrestricted model simultaneously calculates the minimum cost of meeting demand and also predicts the competitive market equilibrium. The minimum cost solution provides the basis for evaluating the economic efficiency losses from patterns of cogeneration that deviate from the competitive solution.
Thus the JGSM modeling framework does alleviate several of the methodological problems with the previous studies. Both fuel and capital costs are combined and discounted to yield the present value of supply costs; if the prices of the equipment and fuel reflect their social value and the discount rate is appropriate, changes in the discounted costs measure the national income benefits or costs of the factor that induced the cost change. The mathematical programming solution allocates resources between technologies for meeting the steam and electricity demands in a manner cognizant of the joint products from the cogeneration technologies. The multiple periods in the model horizon allow installed capacity to be abandoned before it becomes physically obsolete when changes in fuel costs or technologies warrant it.

Problems with the basic process analysis approach, briefly discussed above, can be dealt with to a limited degree. The model, as formulated, only simulates competitive market behavior; the pattern of deviation from this competitive standard must be assumed before measuring the implied costs -- for example, it cannot predict how monopsony power held by utilities will effect the amount of cogeneration, it can only indicate the increments above competitive costs once the behavior under the imperfect conditions is given. Sensitivity analysis can provide some insight into the effects of uncertainty. The specification of a minimum efficient size for each type of cogeneration plant, which is discussed in Section 3.3, addresses the economies of scale problem in part; since these minimum size plants are determined before the JGSM analysis, this is a sub-optimization. If the choice of technologies in the model does not effect the marginal price implied for the exogenously specified demands, then the fixed demand assumption is an accurate approximation.
3.2 A COMPARISON OF JGSM TO OTHER ENERGY MODELS

A comparative discussion of energy models should address the purpose, the theoretical foundations, the solution method, and the level of detail in each model. The details include the scope of the supply and demand coverage, the representation of technological processes, the geographic and temporal dimensions, and the treatment of uncertainty. This section focuses on the process approach to energy modeling, presenting the common theoretical foundations and comparing the solution methods and level of detail in several of these models.

Process-based energy models typically assume a causal structure in the markets under study for the purpose of predicting the markets' performance from the behavioral assumptions and basic market conditions. The models often have the capability to measure the economic efficiency impacts of deviations from the predicted behavior. Since they are used to explore as well as predict, econometric models provide a check on the model builder at the estimation stage; process models based purely on engineering cost information and competitive market assumptions do not have this built-in check.

The linkage between market mechanisms and maximization provides the theoretical basis for most process analysis models -- especially for those using mathematical programming for their solution technique. The connection was first established by Samuelson (1947, reprinted 1963); Samuelson (1952) explicitly developed the interrelationship between linear programming and market equilibrium. Manne and Markowitz (1963) present a survey of early practical applications of this theory to the modeling of various industries in both the energy and non-energy sectors.
The formulation and interconnection of these models has achieved a particularly high degree of sophistication from their applications to planning economic development; many energy models borrow their structure from work in this field.

Most applied mathematical programming-based process analysis models approximate market equilibria by maximizing net economic surplus. The "supply price equals demand price" condition for market equilibrium is the first-order condition necessary for the maximization of producers' plus consumers' surplus. In JGSM, consumers' surplus is assumed fixed and the equilibrium is approximated by maximizing producers' surplus, which is identical to minimizing the costs of production for fixed levels of demand. This assumption allows the problems associated with calculating and using consumers' surplus to be avoided.

Hoffman and Wood (1975) group the market coverage of energy models into four classes:

1. Energy-Economic Models, which include the energy sector and its interactions with the macroeconomy.
2. Energy System Models, which encompass the markets for all fuels.
3. Industry Market Models, which specify both supply and demand interactions for a group of fuels.
4. Sectoral Models, which specify only the supply or the demand for certain fuels.

Several models in each of these classes incorporate the mathematical programming/supply-demand equilibrium equivalence. Nordhaus (1973) has built a world energy system model that is based on linear programming. Manne's (1976) ETA model of the U.S. energy system treats
consumers' surplus for the model's two types of energy by a constant elasticity of substitution demand function; this makes the maximization of the economic surplus into a non-linear programming problem. Adams and Griffin (1972) combine an econometric demand model with a linear programming process analysis of supply to form a model of the petroleum products markets. Anderson (1972) surveys a number of models for electricity supply, many of which rely on mathematical programming. In Goreux and Manne (1973), a supply model combining electricity generation, petroleum production and refining, and steel production uses a dynamic linear programming formulation for studying these supply sectors. JGSM is a dynamic linear programming supply model for the steam and electricity sectors.

On the other hand, a number of process-based energy models avoid the mathematical programming formulation. Just (1973) uses an input-output model of the U.S. economy to calculate the impact of several new energy technologies. Cazalet (1977) has developed a model of the U.S. energy sector that searches for equilibrium prices directly rather than obtaining them from a maximization of economic surplus. The Baughman and Joskow (1974) electricity sector model combines an econometric model of electricity demand with an engineering model of electricity supply and a financial model for the regulatory determination of electricity prices. Wakefield (1975) has built a systems dynamics model to study the influence of one total energy cogeneration plant on a regional energy market. Turvey (1968) uses marginal analysis and engineering descriptions of electricity generation to analyze electricity supply.

The treatment of detail in these process models ranges from describing the energy sector as two products with no regional disaggregation...
to explicitly including 17 end-use demands in 9 U.S. regions, supplied through 2700 conversion processes. The treatment of time varies from a single year to 200 years and from one period to over twenty. Except for process models that contain an econometric submodel, all produce only point estimates; most determine behavior as if the future is known with certainty.

In the light of this discussion, JGSM does not appear to be an unusual energy model. It uses an accepted method for approximating a market equilibrium, especially in supply situations with joint products. The dynamic, multi-period structure is also not uncommon. The model innovates, however, by combining the multi-period, joint product, and separated production and capacity features for the purpose of studying the costs of market distortions in a market with changing factor prices and technologies.

3.3 THE JOINT GENERATION SUPPLY MODEL

This section presents, first, an overview of JGSM's structure and key assumptions and, then, the detailed algebraic linear programming formulation.

3.3.1 OVERVIEW OF THE MODEL

JGSM is a linear programming model of aggregate U.S. industrial process steam supply and base and intermediate electricity generation. A FORTRAN program was written to transform the process and demand information into the LP matrix. This problem formulation is sufficiently general to handle both the historical 1960-1972 study in Chapter 4 and
the prospective 1975-2000 analysis in Chapter 5.

**Time Horizon** The model separates the time within the modeling horizon into several fixed length periods. Production rates and the capacities of the supply technologies change linearly between the end points of each period.

**Demands** The base year aggregate electric and steam energy demand and their growth rates between the period end points are specified outside the model. Although they are assumed fixed and unaffected by costs of supply, this is a less severe assumption than it appears; if electricity and steam consumption are estimated in more general industry models that include supply and demand interactions but do not contain the detail necessary to analyze cogeneration, then small changes in electricity and steam supply conditions at JGSM's modeling level will probably have little effect on the overall demand.

Electricity demand is treated as if all electric energy demand was concentrated at one point for the U.S. Transmission costs are ignored. The model treats the load duration effects very crudely; since the key industrial cogeneration plant types are dispatched at base load or very low intermediate load levels, as discussed in Appendix B, the electrical demand relevant for the trade-offs in this study was assumed to be total electric energy demand less the energy typically produced by quick-starting steam-cycle plants, internal combustion engines, and gas turbine plants. The remainder of the load duration effects is approximated by alterations in the capacity factors and constraints on the introduction of new nuclear capacity.

Steam energy demand is also for the U.S. in aggregate. In order to approximate economies of scale for cogeneration, information from
Figure 2.4 on distribution of steam consumption according to site size used to limit the maximum percentage of steam energy that a plant type with an assumed minimum efficient scale can serve. There can be no transmission of steam between sites. Furthermore, all the technologies are described on the basis of 150 psig steam; Section A.1.2 explains this assumption in detail.

**Supply Technologies** The model explicitly includes the capacity of each technology and its production level during each of the periods of the process analysis. The production technologies have upper limits set by the capacity, where the capital expenditures can increase the capacity of each technology at a constant rate during each period. The model abandons capacity by not producing up to its physical limit; in its place, the model will build new capacity for another technology. It is not possible for one plant type to be converted into another, such as a coal-fired boiler being converted into a back-pressure cogeneration plant. The separated steam and electricity generation technologies are treated as linear processes with one input, fuel, and one output, steam or electric energy respectively. Cogeneration technologies each have one input, again fuel, and two outputs in fixed proportions, electricity and steam. The fuel input rate and the proportion of electricity to steam output varies between the technologies.

The sharp trade-off between inputs and outputs for back-pressure cogeneration, which was illustrated in Section 2.2.1.2, justifies the approximation of the cogeneration technologies by the fixed input and output proportions linear programming activities. The differing cogeneration technology types can combine in the linear program to allow a wide range
of trade-offs between steam and electricity for the economy as a whole.

The model treats environmental requirements by assuming that all capital and operating costs reflect the necessary environmental controls.

Capacity factors for cogeneration plants are assumed to be similar to those for steam plants because industry will use them in accordance with the steam needs rather than with power system loads.

The cogeneration production technologies each have a maximum percentage of the total U.S. steam supply that they can serve owing to their economies of scale, i.e., the individual technologies will not be used at geographic locations using less steam than their minimum efficient scale. In modeling the future role of cogeneration, limits can be set on the maximum rate of new capacity introduction for different classes of new technologies.

Since many manufacturing installations become obsolete in 10 to 15 years, steam and smaller scale cogeneration plants are assumed to have plant lives in this range, which is much shorter than a full scale electric utility plant.

**Costs** The model bases the simulation and the measurement of market distortions on the present value of the social costs for capacity, operations and maintenance, and fuel. Since costs are evaluated as discounted cash flows, depreciation and capital recovery charges are excluded because including them would be double counting. Following Manne (1976), income and property taxes are excluded from the social cost calculation for they are private, not social costs. The model thus simulates a competitive market in which taxes do not distort private behavior from the most socially efficient equilibrium. The optimization
takethat place without regard to institutional barriers. All sectors are making their investment decisions at one market cost of capital. All values are in 1975 constant or real dollars discounted to the end of 1975.

Often the choice of the discount rate fundamentally influences the results of benefit-cost calculations, so considerable debate has taken place over the rate appropriate for discounting costs in public benefit-cost analyses. Two options are commonly offered: the social opportunity cost of capital, which is the before-tax real rate of return, since society benefits through the taxes as well as through the private profits; or the social rate of time preference, which is approximated by after-tax returns, since the after-tax returns and time preference are equal in a market in equilibrium. The U.S. Office of Management and Budget (1972) requires a 10% rate: this choice is apparently based on a social opportunity cost of capital study by Stockfisch (1969) that concluded the U.S. value was 10.4% for 1961 to 1965. Jenkins (1973) obtained a similar 9.5% social opportunity cost of capital estimate for Canada for the period 1965 through 1969. Christensen and Jorgenson (1973, p. 317) find the real after-tax rate of return on investment ranges from about 3% to 12% for the corporate and non-corporate business sectors during the 1945-1969 period. This study bases all its calculations on a single 7.5% rate, which is more in accord with the Christensen and Jorgenson study than the OMB value. Parametric studies in Chapter 5, however, show the benefits of cogeneration are much less sensitive to the discount rate than the benefits of new technologies.
The model avoids the problems associated with discounting under inflation by treating all costs in real dollars and calculating the present values with an inflation-free rate. It is much simpler to account for relative price changes in constant dollars and use the real discount rate than to use current prices and a discount rate that changes with the rate of inflation.

Each production activity has an associated heat rate. The plant heat rate together with the average fuel price is used to calculate fuel costs for the period. Operation and maintenance costs are computed according to fuel costs for the period. The capital cost data in Appendices A, D, and E specify capital costs as direct construction costs; to represent the true costs to the economy, they must be discounted from the time the capital is installed rather than when it starts operating. A social "allowance for funds used during construction" is computed from the direct costs and the distribution of capital expenses prior to the plant's start-up. Transmission and distribution costs are excluded.

In a multi-period process analysis model in which the life of new capacity additions can extend beyond the model's horizon, corrections must be made to avoid distortions in the terminal years of the model. The two principal ways for correcting these effects in supply-type models involve either specifying the terminal year capacities or reducing the costs of capacity additions within the model for technologies whose life extends beyond the modeling horizon. With either of the approaches, lengthening the modeling period also reduces the terminal year effects within the original study period.
Measuring the Cost of Market Distortions  
When actual market performance differs from the model's, the model can be constrained to produce the same amount of cogeneration as the market. The change in the objective function between the constrained and unconstrained cases measures the welfare impacts of distortion in the market. The constrained case assumes the market produces at minimum cost except that it must limit cogeneration to the levels specified. Once a distortion is introduced, there is no guarantee the market will produce at minimum cost in other aspects, so the estimate of the welfare impact is a lower bound on the actual value.¹²

Solving the Model  
The linear program is solved by the revised simplex method¹³ using IBM's MPSX solution package.¹⁴ The multi-period nature of the model, with capacity being passed from one period to the next, gives the linear programming matrix a "stair-case" structure. Special decomposition methods, such as described by Ho and Manne (1974), could be used to find the optimum for very large problems of this type, but the size of the case studies in this report did not warrant the use of such special solution methods. Appendix F describes the computer programs implementing the model.
3.3.2 ALGEBRAIC FORMULATION

The equations below describe JGSM by row type according to a linear programming format. Table 3.1 summarizes the different row types. Table 3.2 lists the LP column activity classes, except for the implied surplus, slack, and artificial activities. Table 3.3 identifies the sub- and superscripts, and Table 3.4 describes their mnemonics and limits. Unless a constraint row is being specifically discussed, all unbarred upper-case activity symbols denote linear programming unknowns, all barred upper-case symbols denote fixed linear programming activities or right-hand-side constants, and all other symbols denote parameters. A raised index denotes a time superscript, except for bracketed expressions, where a raised index denotes an exponent.

The two products in the supply model, steam (ST) and electricity (EL), come from three classes of technologies, electricity-only (EG), steam only (SG), and cogeneration (CG). The model divides the interval under study into \( N \) n-year periods. In each period, a technology \( k \) is represented by two types of activities, production (\( PD_k^i \) and \( DP_k^i \) columns) and capacity (\( PC_k^i \) and \( DC_k^i \) columns). Production rates and capacity are assumed to be changing linearly between the endpoints of time periods. Thus the rates of change, \( DP_k^i \) and \( DC_k^i \), for these two quantities are constant throughout each n-year modeling period. The \( DC_k^i \) activities are needed to calculate the costs of capacity additions directly. The \( DP_k^i \) activities are not always explicitly specified in a cost minimizing
## SUMMARY OF CONSTRAINT ROWS

<table>
<thead>
<tr>
<th>Group</th>
<th>Description (Units in parentheses)</th>
<th>Number of Rows</th>
</tr>
</thead>
<tbody>
<tr>
<td>DM&lt;sub&gt;j&lt;/sub&gt;</td>
<td>Electric and steam energy demands (GW-yr for EL; q for ST)</td>
<td>2(N)</td>
</tr>
<tr>
<td>CP&lt;sub&gt;k&lt;/sub&gt;</td>
<td>Capacity constraints on production (GW for EG and CG; q/yr for SG)</td>
<td>N(M)</td>
</tr>
<tr>
<td>PP&lt;sub&gt;k&lt;/sub&gt;</td>
<td>Production continuity constraints (GW-yr for EG and CG; q for SG)</td>
<td>N(M)</td>
</tr>
<tr>
<td>CC&lt;sub&gt;k&lt;/sub&gt;</td>
<td>Capacity continuity constraints (GW for EG and EG; q/yr for SG)</td>
<td>N(M)</td>
</tr>
<tr>
<td>NC&lt;sub&gt;r&lt;/sub&gt;</td>
<td>Constraints on new capacity introduction (GW for EG and CG; q/yr for SG)</td>
<td>N(S)</td>
</tr>
<tr>
<td>JC&lt;sub&gt;k&lt;/sub&gt;</td>
<td>Constraints on the maximum share of cogeneration or steam plant production in total steam energy production for plants of minimum efficient scale given the size distribution of steam consuming sites (q)</td>
<td>N(M&lt;sub&gt;CG&lt;/sub&gt;)</td>
</tr>
<tr>
<td>JE&lt;sub&gt;i&lt;/sub&gt;</td>
<td>Constraints limiting the aggregate share of cogenerated electricity under market restriction conditions (GW-yr)</td>
<td>N</td>
</tr>
<tr>
<td>OB&lt;sub&gt;d&lt;/sub&gt;</td>
<td>The objective: the present value of all capacity and production costs (billions of 1975 $ discounted at rate d to end of 1975)</td>
<td>1</td>
</tr>
</tbody>
</table>

Table 3.1
<table>
<thead>
<tr>
<th>Name</th>
<th>Description</th>
<th>Number of Columns</th>
</tr>
</thead>
<tbody>
<tr>
<td>PD&lt;sub&gt;i&lt;/sub&gt;&lt;sup&gt;k&lt;/sup&gt;</td>
<td>Annual rate of production at the end of period i for technology type k (GW-yr for EG or CG; q for SG)</td>
<td>N(M)</td>
</tr>
<tr>
<td>DP&lt;sub&gt;i&lt;/sub&gt;&lt;sup&gt;k&lt;/sup&gt;</td>
<td>Annual rate of increase in production from technology type k during period i (GW-yr per year for EG or CG and q per year for SG; can be positive or negative.)</td>
<td>N(M)</td>
</tr>
<tr>
<td>PC&lt;sub&gt;i&lt;/sub&gt;&lt;sup&gt;k&lt;/sup&gt;</td>
<td>Total capacity in technology type k at the end of period i (GW for EG or CG; q/yr for SG)</td>
<td>N(M)</td>
</tr>
<tr>
<td>DC&lt;sub&gt;i&lt;/sub&gt;&lt;sup&gt;k&lt;/sup&gt;</td>
<td>New capacity of technology type k installed annually during period i (GW per year for EG or CG; q/yr per year for SG).</td>
<td>N(M)</td>
</tr>
</tbody>
</table>

All activities are restricted to non-negative values unless noted otherwise.

Table 3.2
## SUMMARY OF SUBSCRIPTS AND SUPERSCRIPTS

<table>
<thead>
<tr>
<th>Subscript</th>
<th>Description</th>
<th>Number or Limits</th>
<th>Abbreviation used in Subscript</th>
</tr>
</thead>
<tbody>
<tr>
<td>i</td>
<td>Model period</td>
<td>1 to N</td>
<td>Integers</td>
</tr>
<tr>
<td>j</td>
<td>Demand type</td>
<td>2</td>
<td>&quot;EL&quot; or &quot;ST&quot;</td>
</tr>
<tr>
<td>k</td>
<td>Type of technology</td>
<td>M</td>
<td>&quot;Ex,&quot; &quot;Bx,&quot; or &quot;Jx&quot;</td>
</tr>
<tr>
<td>r</td>
<td>Types of new capacity introduction rate</td>
<td>S</td>
<td>Specified in case study</td>
</tr>
<tr>
<td></td>
<td>constraints</td>
<td></td>
<td></td>
</tr>
<tr>
<td>f&lt;sub&gt;k&lt;/sub&gt;</td>
<td>Type of fuel for technology k</td>
<td>F</td>
<td>Specified in case study</td>
</tr>
<tr>
<td>t</td>
<td>Year</td>
<td>1 to n(N)</td>
<td>Integers</td>
</tr>
<tr>
<td>d</td>
<td>Discount rate for the objective function</td>
<td>--</td>
<td>Percentage</td>
</tr>
</tbody>
</table>

Table 3.3

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<table>
<thead>
<tr>
<th>Description</th>
<th>Table 3.4</th>
</tr>
</thead>
<tbody>
<tr>
<td>&quot;EL&quot; Electricity output related</td>
<td>106</td>
</tr>
<tr>
<td>&quot;ST&quot; Steam output related</td>
<td></td>
</tr>
<tr>
<td>&quot;EG&quot; Related to electricity-only technologies</td>
<td></td>
</tr>
<tr>
<td>&quot;SG&quot; Related to steam-only technologies</td>
<td></td>
</tr>
<tr>
<td>&quot;CG&quot; Related to cogeneration technologies</td>
<td></td>
</tr>
<tr>
<td>&quot;Ex&quot; Abbreviation for a specific electricity-only technology</td>
<td></td>
</tr>
<tr>
<td>&quot;Bx&quot; Abbreviation for a specific steam-only technology</td>
<td></td>
</tr>
<tr>
<td>&quot;Jx&quot; Abbreviation for a specific joint or cogeneration technology</td>
<td></td>
</tr>
<tr>
<td>N Number of periods in model horizon</td>
<td></td>
</tr>
<tr>
<td>M Total number of technologies</td>
<td></td>
</tr>
<tr>
<td>$M_{EG}$ Number of electricity-only technologies</td>
<td></td>
</tr>
<tr>
<td>$M_{SG}$ Number of steam-only technologies</td>
<td></td>
</tr>
<tr>
<td>$M_{CG}$ Number of cogeneration technologies</td>
<td></td>
</tr>
<tr>
<td>S Number of new capacity introduction rate constraint types</td>
<td></td>
</tr>
<tr>
<td>F Number of fuel types</td>
<td></td>
</tr>
<tr>
<td>n Number of years in a period</td>
<td></td>
</tr>
</tbody>
</table>
production and capacity model; production costs are often approximated instead by the end-of-period production activity levels. Here, however, the benefit-cost comparisons require an accurate accounting for the comparative costs in different scenarios, hence the need for the more involved calculation of production costs using a linear approximation of production rates between period end points. The objective row description explains this cost computation in detail.

**Demand Constraints, DM**

The steam and electric energy produced must meet the fixed steam and electric energy demands at the end of each period. For electricity, in each period \( i = 1, \ldots, N \),

\[
\sum_{k=EG}^{PD_i^1} \left[ \text{Electric energy generation from EG plants at the end of period } i \right] + \sum_{k=CG}^{PD_i^1} \left[ \text{Electric energy generation from CG plants at the end of period } i \right] \geq \left[ \text{Base and intermediate electric energy demand at the end of period } i \right]
\]

\[
\sum_{k=EG}^{PD_i^1} + \sum_{k=CG}^{PD_i^1} \geq \left[ \text{base}_{EL} \right] \left[ 1 + \text{dgrow}_{EL} \right]^{(n)(i)}
\]

\( (3.1) \)
For process steam in each period $i=1, \ldots, N$,

\[
\begin{align*}
\text{Steam energy from steam-only plants at the end of } i & \text{ Sum over all CG types } k \\
& \text{Steam output per unit of electric energy for } k \\
& \text{Electric energy generation from CG plant type } k \text{ at the end of period } i
\end{align*}
\]

\[
\sum_{k=\text{SG only}}^{\text{CG only}} P_{Di}^k + \sum_{k=\text{CG only}}^{\text{CG only}} \left[ q_{ST,k} \right] \left[ PD_{k}^i \right]
\]

\[
\begin{align*}
& \geq \text{Total U.S. steam energy demand at the end of period } i \\
& \geq \left[ \text{dbase}_{ST} \right] \left[ 1 + \text{dgrow}_{ST} \right]^{(n)(i)}
\end{align*}
\]

(3.2)

Energy demands grow exponentially at period end points starting with the end of the year before the start of the model; within each period, demands grow linearly. The annual rate of demand increase is $\text{dgrow}_j$ starting from $\text{dbase}_j$. For each unit of electric energy output, each cogeneration plant type $k$ produces $q_{ST,k}$ units of steam energy.

\underline{Capacity Continuity Constraints, $\text{CC}_{k}^i$} Capacity increases at a fixed annual amount between period end points. So for each period $i=1, \ldots, N$,

\[
\begin{align*}
\text{Capacity for } k \text{ at the end of period } i & = \text{Capacity for } k \text{ at the end of period } i-1 \\
\left[ \text{PC}_{k}^i \right] & = \left[ \text{PC}_{k}^{i-1} \right]
\end{align*}
\]

(cont'd on next page)
\[
\begin{align*}
\text{Years in the period} & + \text{Annual additions in new capacity} - \text{Annual retirement of physically obsolete capacity} \\
+ n & \left[ DC^i_k - DC^{i-\text{life}_k}_k \right]
\end{align*}
\]

(3.3)

where

\[ \text{life}_k = \text{the physical life of technology } k \text{ in periods} \]

When \([i-\text{life}_k]\) is prior to the first period, the retirements, \(DC^{i-\text{life}_k}_k\), must be specified exogenously. The initial capacity, \(FC^0_k\), must also be provided.

**Production Continuity Constraints, \(PP_k^i\)** The annual increase in production is defined by these constraints for each period \(i=1,\ldots,N\) and each \(k\):

\[
\begin{align*}
\text{Energy production from plant type } k \text{ at the end of } i & = \text{Years in period} \times \text{Annual increase in production for } k \\
& \text{[during period } i\text{]} \\
PD^i_k & = n \left[ DP^i_k \right]
\end{align*}
\]

(cont'd on next page)
Energy production from plant type \( k \) at the previous period's end

\[ + \begin{align*}
&\text{Energy production from plant type } k \\
&\text{at the previous period's end}
\end{align*} + P_{D_k}^{i-1} \quad (3.4)
\]

The initial capacity, \( P_{D_k}^0 \), is specified in the process.

**Capacity Constraints on Production, \( C_{P_k}^i \)**

Energy production from a given plant type cannot exceed the capacity adjusted by the equivalent load factor embodying a plant's availability and merit in dispatching. So for every, \( i = 1, \ldots, N \):

\[ \text{Energy production from } k \text{ at end of } i \leq \text{load factor for } k \times \text{capacity of } k \text{ at end of period } i \]

\[ P_{D_k}^i \leq \text{loadf}^i_k \times [P_{C_k}^i] \quad (3.5) \]

where \( \text{loadf}^i_k \) = the annual equivalent load factor for technology \( k \).

**New Capacity Introduction Constraints, \( N_{C_k}^i \)**

Often, in order to approximate load duration curve effects or the restrained adoption of new technologies, constraints are needed on the rate of introduction for a specific technology with respect to a set of technologies in which it is included. These comparative introduction rate constraints can be expressed as:
for each period $i = 1, \ldots, N$ for which the constraint $r$ applies. For example, the advanced coal-fired electricity and cogeneration technologies are restricted in such a manner: new advanced coal-fired plants in combined regular and cogeneration capacity, cannot be more than 20% of all the new electrical capacity.

A second type of new capacity constraint limits the absolute amount of new capacity from one or a group of plant types: for each absolute constraint $r$ in periods $i = 1, \ldots, N$,

$$\sum DC_k^i \leq m x n e w_r^i$$

The matrix generating program can also specify similar restrictions for single technologies by the use of activity bounds, but bounds cannot be changed in a parametric analyses.
Cogeneration Scale Constraints, $J_{ik}$

In order to allow for the plant economies of scale in cogeneration, the model approximates by limiting each cogeneration technology to serve only industrial sites above a specified size. This specified size is known as the technology's "minimum efficient scale," or MES. The MES is assumed for each type on the basis of typical plant scale information from Appendix A. As market conditions change, however, the MES can change so the assumption of a fixed, exogenously determined MES is rather crude. The size distribution of industrial steam comes from Figure 2.4, which was developed using data from the 1967 Census of Manufacturers. The $J_{ik}$ constraint is specified for each cogeneration technology $k$ in each period $i = 1, \ldots, N$:

$$
\sum_{\ell} \left[ q_{ST,\ell} \right] \left[ PD_{\ell}^{i} \right] \leq \left[ scvr_{k} \right] \left[ base_{ST}^{i} \right] \left[ 1 + dgrows_{ST}^{(n)} \right] \left( i \right)
$$

where $scvr_{k}$ = the fraction of total steam consumption at sites of a size above the MES of $k$. 

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Market Restrictions Constraints, $JE^i$

Since data on the types of cogeneration plants actually built and operated are difficult to obtain, the efficiency effects of imperfect market performance are measured by restricting the model to produce no more total cogenerated electric energy than specified under the assumed or historical market behavior. For each period $i = 1, \ldots, N$:

$$\sum_{k=CG}^{types} PD^i_k \leq d_{hist}^i_{CG}$$

(3.9)

where $d_{hist}^i_{CG}$ is the historical or assumed behavioral trend in electricity cogeneration.

Bounds

Upper bounds can be set on the capacity increases of certain plant types because of their long lead times and because only a limited amount of capacity has been scheduled. Hydroelectric production, $PD^i_{EH}$, is fixed in both case studies to historical levels or their trend; nuclear, $PD^i_{EN}$, is fixed throughout the 1960-1972 case study period. All activities are restricted to positive values except the $DP^i_k$ columns, which can be either positive or negative.

The Objective Function, $OB_d$

The simulation and measurement of market distortions are both based on the discounted capital, operation,
and fuel costs for all electricity and steam supply within the modeling horizon. These costs are expressed in billions of 1975 real dollars discounted or compounded to 1975. Operation and fuel costs are computed for each period from the \( PD_k^i \) and \( DP_k^i \) activities, capital costs are calculated from the \( DC_k^i \) activities.

At the specified discrete annual discount rate, \( d \), the objective function (minimand) is:

\[
\text{Minimize} \quad \sum \text{over all feasible activities} \quad \text{Sum over all periods} \quad \text{Factor for discounting costs from the end of period } i \text{ to the end of 1975}
\]

\[
\text{Min} \quad \sum_{i=1}^{N} \left( \frac{1}{(1+d)^i} \right) (n(i)-nbase)
\]

\[
\begin{cases}
\text{The operation, maintenance, and fuel cost per unit of output by technology } k \text{ during period } k \\
\text{[(pvblock) } (PD_k^i) - (pvwedge) (DP_k^i)]}
\end{cases}
\]

(cont'd on next page)
\[
\text{Factor to account for the value of the capital during construction for technology } k + \text{Factor for the value of the levelized capital costs within the modeling horizon for the new capacity starting up in period } i \text{ Per unit direct annual new capacity additions for technology } k \text{ during period } i
\]
\[
+ [\text{const}_k] [\text{pvim}_k^i] [\text{cap}_k^i] [\text{DC}_k^i]
\]
\]

where

\text{nbase} = \text{the number of years between the beginning of the modeling horizon and the end of 1975,}
\text{com}_k^i = \text{the operation and maintenance costs in } \$10^9 \text{ per unit of production for technology } k \text{ during period } i,
\text{f}_k = \text{the fuel type used by technology } k,
\text{pfuel}_f^i = \text{the price of fuel } f \text{ in } \$10^9/\text{quad during period } i,
\text{q}_{f,k}^i = \text{the amount of fuel } f \text{ in quads per unit of production by technology } k, \text{ and}
\text{cap}_k^i = \text{the direct capital costs in } \$10^9 \text{ for a unit of capacity of technology } k \text{ entering production during period } i.

The present value factors (pvblock, pvwedge, const_k, and pvim_k) need to be explained in detail.

Since production increases linearly from the end of one period to the next, the total discounted production costs during this period must reflect not just the end of the period production but the instantaneous
rates of production throughout the period. Figure 3.1 illustrates a case where production drops by $D_{k}^{1}$ per year from $P_{k}^{0}$ at the beginning of the period to $P_{k}^{1}$ at the end. Note $D_{k}^{1}$ is negative in this example.

Total production in the $n$ year period equals the area of the rectangle $A$ plus the triangle $B$; the rectangle's area can be calculated from $P_{k}^{1}$, and the triangle's from $D_{k}^{1}$. The discounted instantaneous production costs can therefore be determined in two parts: the costs associated with the area $A$, which will be known as 'pvblock' for a unit level of $P_{k}^{1}$; and the costs associated with the area $B$, which will be known as 'pvwedge' for a one unit $D_{k}^{1}$. The present value of production costs in area $A$ at the end of the period is

$$[pvblock] [P_{k}^{1}] = [P_{k}^{1}] \left[ \exp(\rho \cdot n) \right] \int_{0}^{n} \exp(-\rho \cdot t) dt$$

(3.11)

where $\rho = \ln(1+d) = \text{the instantaneous discount rate.}$

Thus

$$pvblock = \frac{1}{\rho} \left[ \exp(\rho \cdot n) - 1 \right] = \frac{(1+d)^{n}-1}{\ln(1+d)}$$

(3.12)

The discounted costs associated with the triangle $B$ at the end of the period are

$$[pvwedge] [D_{k}^{1}] =$$

$$- \exp(\rho \cdot n) \int_{0}^{n} \left[ (n)(D_{k}^{1})-(t)(D_{k}^{1}) \right] \exp(-\rho \cdot t) dt$$

(3.13)
Figure 3.1

\[
n \left( PD_k^i \right) = PD_k^i - PD_k^0
\]

Calculation of Production Costs
Thus, dividing by $D^p_k$, Equation 3.13 becomes:

\[
pv_{\text{wedge}} = \exp(p'\cdot n) \int_0^n [n-t] \exp(-\rho \cdot t) dt
\]

\[
= \left[ \frac{[n]\exp(p\cdot n)}{\rho} + \frac{[1-\exp(p\cdot n)]}{[\rho]^2} \right]
\]

\[
= \frac{[n][1+d]^n}{\ln(1+d)} + \frac{[1-(1+d)^n]}{[\ln(1+d)]^2}
\]

(3.14)

The data on plant capital costs are based on direct construction costs. Since the actual capital expenditures are made for a number of years before the plant becomes operational, society incurs costs before the plant's start-up; this increase in costs can be calculated from the distribution of expenditures and the discount rate:

\[
\text{const}_k = \Sigma_{t=1}^{n_{\text{const}}_k} (1+d)^t \text{ (cflow}_{t,k})
\]

(3.15)

where

\[
\text{const}_k = \text{the ratio of the direct expenditures compounded up to the start-up time and the undiscounted direct construction costs for technology k,}
\]

\[
n_{\text{const}}_k = \text{the number of years that a plant type k is under construction,}
\]

\[
\text{cflow}_{t,k} = \text{the fraction of direct construction expenditures made t years prior to the first operational year for technology k.}
\]
To avoid the terminal year effects from the model's finite horizon, only the levelized capacity costs for a plant's physical life inside the modeling horizon are counted toward the total costs. This may bias the total costs downward for plant expenditures near the horizon since a new technology or a change in fuel costs just after the end of the modeling horizon could make the installed plants uneconomic to operate—so the entire capital costs of these plants inside the modeling period should have been borne within the modeling horizon. The factor for adjusting for the capital expenditures during a period when the plant's physical life is entirely within the modeling horizon is:

\[
pvim^i_k = \left[ \exp(\rho \cdot n) \right] \int_0^n \exp(-\rho \cdot t) \, dt \\
= \frac{1}{\rho} \left[ \exp(\rho \cdot n) - 1 \right] \\
= \frac{(1+d)^n-1}{\ln(1+d)}, \quad i \leq N\text{-life}_k,
\]

for discounting to the end of the period the annual new capital expenditures made during period \( i \) for technology \( k \). When the plant's life extends beyond the horizon, the factor for the in-horizon value of the new capital expenditures at the end of the period is:
Discounting instantaneous costs at the installation time \( t \) to the end of period \( i \) costs at the installation time \( t \) to the end of period \( i \):

\[
pvim_k^i = \exp(\rho \cdot n) \int_0^n \frac{\rho}{1-\exp(-\rho \cdot \text{life}_k)} \left[ \exp(-\rho \cdot t) \right] dt \, dt
\]

\[
= \frac{1}{1-\exp(-\rho \cdot \text{life}_k)} \left\{ \frac{1}{\rho} \left[ \exp(\rho \cdot n) - 1 \right] - [n] \left[ \exp(-\rho \cdot n \cdot (N-i)) \right] \right\}
\]

\[
= \frac{1}{1-(1+d)^{-\text{life}_k}} \left\{ \frac{(1+d)^n - 1}{n(1+d)} - n(1+d)^{-n(N-i)} \right\}
\]

(3.17)

for \( i > N-\text{life}_k \). The matrix generator computes this through a discrete approximation of the integral.
3.4 SUMMARY AND CONCLUSIONS

This chapter proposes a general model for simulating the behavior of a competitive market in the process steam and electricity supply sectors; the model also provides the framework for measuring the additional costs associated with non-competitive behavior and the benefits of new technologies. The model improves significantly on the analytical methods used in earlier studies of cogeneration economics and policy by:

- Combining discounted fuel and capital costs to measure benefits.
- Determining the implied prices for steam and electricity within the model.
- Allowing the production of a technology to decrease before the end of its physical life when its operating costs are above the costs of replacing it with new plants.

The model still has a number of failings:

- Economies of scale are handled very crudely.
- It cannot predict behavior in a non-competitive market: it only measures the additional costs once the pattern of the behavior is assumed.
- The demand for electricity and steam was assumed to be perfectly inelastic.
- No attempt was made to deal with uncertainty — a problem that has many facets:
  - Future fuel and equipment costs, demands, and the availability of new technologies are not known with certainty.
  - Planned and unexpected plant outages affect operation costs.
- Different financial conditions for various industries influence the investment decisions; a single discount rate only roughly approximates the behavior of the capital markets.
Footnotes for Chapter 3

1. See Baumol (1977b), Panzar and Willig (1977), and Rudd (1975).

1a. Following the approach advocated by Harberger (1971).

2. This is the typology that Hoffman and Wood (1975) use in their survey of energy systems modeling.

3. The survey in Blitzer, Clark, and Taylor (1975) and the research in Goreux and Manne (1973) show the state of the art in this type of modeling before the crisis-induced development of a multitude of energy models.

4. See Hoffman and Wood (1975) and Brock and Nesbitt (1977) for surveys on the structure of energy models.

5. Brock and Nesbitt (1977, section IID) give an exposition of this relationship as it relates to large-scale energy planning models.

6. Brock and Nesbitt (1977) discuss the "integrability" problem, which restricts the demand relationships for which consumers' surplus exists. Hicks (1940-41), Harberger (1971), and Baumol (1977a) comment on the usefulness and accuracy of consumers' surplus for measuring changes in economic welfare when the utility of money is not constant. In spite of these problems, it is the principle measure used in applied welfare economics and in large-scale process models that include demand effects (see Goreux and Manne, 1973, p. 23, Harberger, 1971, and Manne, 1976).


6b. For example, Griffin (1971) and Nordhaus (1973).

7. These adjustments were made using information on the share of peaking units from Olmsted (1975 and before), U.S. Federal Power Commission (1972a), and Edison Electric Institute (1973a and b).

8. All cogeneration capacity and production is specified in terms of its electrical capacity or output; it also has the proportional steam capacity and output. See the end of Section A.2.1 for a more detailed explanation.


10. Hanke, Carver, and Bugg (1975) resolve this problem.
11. The distribution of the construction expenditures is derived from the data presented in Kamat (1975, Appendix A) and is shown in Tables D.5 and E.5. The distributions for boilers and small cogeneration plants are based on the cash flows for gas turbine plants; the distributions for large cogeneration plants are based on the cash flows for similar electricity-only technologies.

12. See the comments on the theory of the second best in Baumol (1977) and Henderson and Quandt (1971). The model reaches the second-best optimum — the market may not.


Chapter 4

JGSM ANALYSIS FOR 1960 TO 1972: CAN THE LEVELS OF COGENERATION BE EXPLAINED BY COST INFLUENCES ALONE?

This chapter uses JGSM and historical process, fuel price, capital cost, and steam and electricity consumption data to examine the question:

- Did the importance of cogeneration in electricity and steam supply decline because of market imperfections, or can this decline be explained by changes in fuel prices and technologies?

This question provokes several secondary questions:

- If the changes can be attributed solely to cost changes, how sensitive are these results to alterations in the data assumptions?
- If cost conditions alone do not explain the markets' behavior, what are the economic efficiency losses associated with this non-competitive market performance?
- If the market is shown to be imperfect, does the behavior distort factor utilization away from the most efficient behavior in any specific direction?

The first section describes the data assumptions and the specifics of the JGSM model formulation needed for this case study. The second section reports the results of the modeling effort.

4.1 THE MODEL FORMULATION FOR THE HISTORICAL ANALYSIS

This section describes the implementation of JGSM for the 1960–1972...
historical analysis. Appendix D contains the detailed data listings and documents the process data inputs for the model.

**Time Horizon**  This historical analysis simulates the performance of a competitive market in the electricity generation and industrial steam supply sectors for a period from the end of 1960 to the end of 1972. This horizon is divided into three 4-year periods.

**Demands**  As described in the previous chapter, the model minimizes the national income-based costs of supplying inelastic demands for steam and electricity throughout the horizon. The estimates of actual steam consumption for the 1960-1972 interval were obtained by extrapolating the 1960 and 1968 Stanford Research Institute (1972) data, which finds process steam grew at 3.6%/year. Figure 2.4 provides the distribution of the steam energy consumption by site size.

The estimates of electricity generation were obtained from Edison Electric Institute (1973a and b), henceforth known as EEI; these were reduced to include only generation by base and intermediate load units, excluding electric energy generation by internal combustion, gas turbine, and quick starting steam units. This generation data was smoothed by a log-linear regression to give a 6.75%/year growth for the interval studied.

**Technologies**  Table 4.1 briefly describes the technologies used for the historical analysis. Appendix A and Table D.1 provide their detailed characteristics. The load factors for cogeneration technologies were assumed to be similar to those for boilers, in accordance with the information in Dow (1975a and b). The minimum efficient scale
TECHNOLOGIES USED IN 1960-1972 ANALYSIS

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ELECTRICITY GENERATION</td>
<td></td>
</tr>
<tr>
<td>EC</td>
<td>A typical coal-fired steam-electric power plant</td>
</tr>
<tr>
<td>EN</td>
<td>A standard LWR nuclear power plant</td>
</tr>
<tr>
<td>EP</td>
<td>A typical gas or oil-fired steam-electric power plant</td>
</tr>
<tr>
<td>EH</td>
<td>A hydroelectric plant</td>
</tr>
<tr>
<td>STEAM GENERATION</td>
<td></td>
</tr>
<tr>
<td>BF</td>
<td>A field-erected coal-fired boiler employing stack gas clean-up</td>
</tr>
<tr>
<td>BP</td>
<td>A package boiler burning low-sulfur oil or natural gas</td>
</tr>
<tr>
<td>COGENERATION</td>
<td></td>
</tr>
<tr>
<td>JC</td>
<td>A coal-fired dual-purpose power station</td>
</tr>
<tr>
<td>JL</td>
<td>A large industrial, coal-fired by-product steam and power plant with back-pressure and condensing power generation. It has a higher steam to power ratio than a JI unit.</td>
</tr>
<tr>
<td>JI</td>
<td>A large industrial, coal-fired by-product power and steam plant with back-pressure and extra-condensing power generation.</td>
</tr>
<tr>
<td>JB</td>
<td>A coal-fired industrial by-product power and steam plant employing back-pressure power generation.</td>
</tr>
</tbody>
</table>

TABLE 4.1
of the cogeneration plants was set on the basis of the surveys in Appendix A, subjectively allowing a slight margin below the typical unit sizes.

Information on actual retirements is available for some electricity-only plant types from the EEI data. For the other technologies, the pattern of retirements because of physical obsolescence, $\overline{DC}_k$, must be derived from the assumed plant lives and the earlier patterns of new capacity construction. The fraction, $g_k^i$, of the 1960 capacity for technology $k$ retiring at the end of period $i$ is:

$$g_k^i = \left[ \frac{1 - r}{1 - (r)\text{life}_k} \right] [r]^{i-1}$$

(4.1)

where $r = \text{the assumed growth per period in capacity retirements for reasons of physical obsolescence},$

$\text{life}_k = \text{the life of the technology in periods};$

thus the capacity retiring in period $i$ is:

$$\overline{DC}_k^{i-\text{life}_k} = [PC_k^0] [g_k^i]$$

(4.2)

For this study, all such retirements were assumed to grow at 6%/year so:

$$r = (1.06)^4.$$  

(4.3)

The initial production and capacity data for electricity-only plants were derived from the EEI information. The initial conditions
for JC cogeneration were assumed on the basis of the plant history data from the U.S. Federal Power Commission (1973). The industrial by-product cogeneration technologies (JB, JI, and JL) were each assumed to generate a third of the industrial electricity production at the end of 1960. Their steam production was subtracted from the total steam demand in 1960 to get the total BF steam production; package boilers, BP, were assumed to have no capacity in that year.

**Costs** The discount rate used for the market simulation was 7.5%. Fuel prices were assumed to be the average EEI-reported prices paid by electric utilities during the period. Construction and O&M costs for electricity-only plants were varied according to the average costs for the period based on the information in *Electrical World*’s biennial surveys (Olmsted, 1975 and every two years before); coal-fired boilers and cogeneration plants costs were assumed to follow the percentage changes in coal-fired electricity-only plant costs. Chapter 3 described the derivation of the distribution of capital expenditures during construction.

**Historical Cogeneration Patterns** The historical pattern of cogeneration for the calculation of economic efficiency losses was assumed to be the electric energy generated by industrial establishments (EEI data). This is used by the restricted cases in the JE^i constraints.

**New Capacity Constraints** There were no NC^i_r constraints on new capacity introduction.

**Bounds** Hydroelectric and nuclear electric production were not determined within the model but were assumed to follow the historical pattern for the period; this is because they were a relatively
unimportant share of generation, a share whose role depends upon many factors other than the comparative costs with respect to fossil fueled plants.

4.2 THE RESULTS

The model, as implemented, is a medium-size linear program with 141 rows, 120 columns, and 860 non-zero elements (excluding slack and surplus variables). This count includes several non-constraint rows used to generate report information.

4.2.1 THE BASE CASE

Figures 4.1 and 4.2 illustrate the results of the base case simulation. Cogeneration in electricity and steam supply declined owing to a lack in new investments in cogeneration capacity combined with the gradual phase-out of existing plants because of physical obsolescence. All of the new fossil-fired electricity generation capacity went to oil- and gas-fired plants rather than coal-fired units. As suggested by the Dow (1975a), packageboilers took over the steam supply, even forcing the existing coal-fired boiler capacity out of production in the final 1968-1972 model period. Figure 4.3 shows the fuel consumption for the combined sectors; in accord with the nation's historical experience, oil and gas consumption rose considerably while coal consumption diminished.

As demonstrated in Figure 4.4 for electricity generation and Figure 4.5 for a measure of steam consumption, the cost-based modeling had cogeneration's share of electricity and steam production drop faster than the real market had it actually fall off. One group of constraints was responsible for the absolute level of cogeneration under these cost conditions: the exogenous capacity retirements. The share in each
Figure 4.1
PROCESS STEAM GENERATION: BASE CASE

Figure 4.2

Figure 4.2
FUEL CONSUMPTION FOR PROCESS STEAM
AND ELECTRICITY GENERATION: BASE CASE

Figure 4.3
THE SHARE OF ELECTRICITY COGENERATION PREDICTED BY JGSM COMPARED TO THE ACTUAL SHARE OF INDUSTRIAL ELECTRICITY GENERATION IN TOTAL U.S. ELECTRICITY GENERATION

Source: Figure 4.4 and model results

Figure 4.4

Historical data

Percentage Share

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COMPARISON OF THE JGSM PREDICTION OF
COGENERATION'S ROLE IN STEAM SUPPLY
AND THE ESTIMATE OF THE ACTUAL BEHAVIOR

- Historical
- JGSM simulation of the share of cogenerated steam in total steam supply; the initial year is set equal to the industrial electricity/manufacturing output ratio.

Source: Figure 1.4 and model results
Figure 4.5
output class was determined by this diminishing absolute level and the growth in demand. The model's cogeneration of electricity in the initial year is greater than the historical industrial generation because it includes generation by the dual-purpose cogeneration technology, JC.

4.2.2 THE SENSITIVITY ANALYSIS

Considerable difference of opinion exists in the estimates of operation and maintenance costs for the small by-product cogeneration plants, a group which includes the JB, JI, and JL technologies. The technological data sources surveyed in Table A.7 differ by more than a factor of six on the reported O&M costs, exclusive of fuel costs. The base case modeling effort used the more widely accepted Dow (1975a and b) values as a basis for the calculations.

As the O&M costs for by-product cogeneration decrease, this type of cogeneration becomes more advantageous. If the O&M costs are significantly lower than those used in the Base Case, the market misallocates resources: Figure 4.6 shows the implied economic efficiency or welfare losses if the O&M costs are lower than those used in the Base Case. When the electricity supplied by cogeneration is restricted by the \( J_E^i \) constraints to be less than or equal to the historical experience, the total sectoral costs begin differing between the restricted and unrestricted cases when the O&M costs reach 55% of the Base Case assumptions -- well within the cited values.\(^1\)

To analyze the distortions implied by O&M costs being at these reduced values, two additional cases were used:

- Case A -- Electricity cogeneration can be set at optimizing
WELFARE LOSS DUE TO JOINT GENERATION
RESTRICTIONS AS A FUNCTION OF O&M COST ASSUMPTIONS

Figure 4.6
levels; O&M costs for the by-product cogeneration technologies (JB, JI, JL) are assumed to be 25% of their Base Case values.

- Case B — Electricity cogeneration is restricted by Ja constraints to be less than or equal to its actual historical levels; O&M costs for the by-product cogeneration technologies are assumed to be 25% of their Base Case values.

Figure 4.7 through 4.10 show the results of the simulations for these cases. The welfare loss in Case B with respect to Case A is worth $3.2 billion in fuel, capital, and O&M costs discounted to the end of 1975.

For Case A, cogeneration grew to the level of coal-fired electricity-only generation by 1972, capturing the market share held by oil- and gas-fired power generation. In the steam sector, it reached the limits set by the minimum efficient scale constraints on the smallest scale cogeneration technology, JcJB. As in the Base Case, no new coal-fired electricity generation was added, and the field-erected coal-fired boiler capacity remaining in the 1968-1972 period was retired for economic reasons.

For Case B, electricity cogeneration coincided with the Base Case and Case A for the first period but remains pinned at the historical levels for the last two periods.

Figures 4.11 through 4.15 compare the simulation results for the three different cases. Figure 4.11 shows that electricity cogeneration rises in Case A substantially over the Base Case; this occurs because much of the new cogeneration capacity is in JI by-product plants, which
ELECTRICITY GENERATION: JOINT GENERATION
O&M COSTS AT 25% OF BASE CASE (CASE A)

Figure 4.7

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PROCESS STEAM GENERATION: JOINT GENERATION

O&M COSTS AT 25% OF BASE CASE (CASE A)

Figure 4.8
ELECTRICITY GENERATION: JOINT GENERATION O&M COSTS
AT 25% OF BASE CASE AND JOINT GENERATION
RESTRICTED TO HISTORICAL LEVELS (CASE B)

Figure 4.9
PROCESS STEAM GENERATION: JOINT GENERATION O&M COSTS
AT 25% OF BASE CASE AND JOINT GENERATION
RESTRICTED TO HISTORICAL LEVELS (CASE B)

Figure 4.10

Figure 4.10

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ELECTRICITY GENERATION: CASE COMPARISON
OF THE JOINT GENERATION SHARE

Figure 4.11
STEAM GENERATION: CASE COMPARISON
OF THE JOINT GENERATION SHARE

Figure 4.12
COAL CONSUMPTION FOR PROCESS STEAM
AND ELECTRICITY GENERATION: CASE COMPARISON

Figure 4.13

Figure 4.13

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Figure 4.14

OIL AND GAS CONSUMPTION FOR PROCESS STEAM AND ELECTRICITY GENERATION: CASE COMPARISON
CAPITAL INVESTMENT ENTERING SERVICE FOR PROCESS STEAM AND ELECTRICITY GENERATION: CASE COMPARISON

Figure 4.15
produce more electricity per unit of steam than the other type of cogeneration plants installed. The JI plant capacity is not installed in Case B or the Base Case. Coal consumption is higher for the unrestricted Case A, while oil and gas consumption is higher for Case B.

The capital investment patterns for the steam and electricity sectors are of special interest owing to the capital investment distortions predicted because of the monopsony market structure and rate-of-return regulation conditions on the utility side of the markets. Extrapolating from experience in economy-wide development planning models, however, these investment predictions must be treated with caution. 2

The restricted Case B had lower investment costs than Case A in the middle period, but higher costs in the final period. When only the investment costs for the technologies that utilities would own (EC, EN, EP, EH, and JC) are compared for the two cases, a pattern appears: Figure 4.16 shows the restricted Case B required substantially more utility investment than the Case A competitive market simulation. Note that Case B simulates second-best situation in which the market is assumed to achieve minimum production costs while restricted to produce the historical levels of cogenerated electricity; there is no guarantee that the real market would reach this minimum cost. Linear programming models also exhibit a bang-bang choice behavior causes wide changes in factor use for only small changes in total costs. Nevertheless, the results in Figure 4.16 indicate utilities may be able to build up their rate bases through exercising their market power to restrict cogeneration. Empirical studies on the Averch-Johnson effects have been based on electric utility biases away from fuel consumption toward capital equipment;
UTILITY-TYPE CAPITAL INVESTMENT ENTERING SERVICE FOR PROCESS STEAM AND ELECTRICITY GENERATION:

CASE COMPARISON

ADDITIONAL UTILITY-TYPE INVESTMENT REQUIRED WITH HISTORICAL JOINT GENERATION LEVELS

CAPITAL INVESTMENT ENTERING SERVICE ANNUALLY (CURRENT VALUE IN BILLIONS OF 1975 DOLLARS INCLUDING 7.5% SOCIAL INTEREST DURING CONSTRUCTION)

YEAR

CASE A

CASE B

1960 1964 1968 1972

Figure 4.16

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they have never considered the possibility that the utilities could have purchased more electricity from industrial cogenerators.3

4.3 CONCLUDING COMMENTS

Conclusions concerning the influences upon the historical decline of cogeneration vary with the assumptions adopted for the by-product cogeneration O&M costs. If high levels of O&M costs are accepted, the changes in fuel costs and the advent of package boilers provide the explanation. Under the lower O&M cost assumptions, the historical experience deviates substantially from the competitive market simulation; one must then look toward market failure explanations.

Experience with the model shows it chooses the direction of the production and capacity expansion patterns with an acceptable degree of stability. The degree of the production and capacity shifts often depends on the minimum efficient scale constraints. The behavior of the model could be refined by a more careful specification of plant scale economies. In addition, regionalizing the fuel costs and aggregating production and capacity to obtain the national results would also provide more robust solutions.
Footnotes for Chapter 4

1. As shown in Table A.7, Doherty (ASME-75) lists JB O&M costs as low as 3.9 mills/kw hr and Dow (1975a) cites 15.6 mills/kw hr for similar units.

2. Blitzer, Clark, and Taylor (1975, p. 95).

3. See Kahn (1971, vol. 2, pp. 50-59) and, for a specific study, see Peterson (1975).
Chapter 5

JGSM ANALYSIS FOR 1975 to 2000:

WHAT IS THE FUTURE ROLE FOR COGENERATION?

This chapter employs JGSM and projections of fuel prices, capital equipment costs, technological conditions, and electricity and steam demands to explore the question:

- What should the future role for cogeneration be if the nation bases the choice on economic efficiency?

This focal question raises several subsidiary questions:

- What is the cost reduction associated with this optimal policy in relationship to holding cogeneration at its current share of electricity generation?

- How sensitive are its role and the associated benefits to changes in capital costs and the availability of new technologies?

- What are the incremental costs attached to policies that either too cautiously or too aggressively encourage cogeneration?

The first section explains the assumptions required to carry out a case study examining the period 1975 to 2000. The second section describes the results of the model's application.

5.1 THE MODEL FORMULATION FOR THE PROSPECTIVE ANALYSIS

This section presents the implementation of JGSM used in the 1975-2000 prospective analysis. As with any forward-looking economic modeling, the cost, price, and technological conditions are based on
subjective judgments; the values employed here reflect the author's best conjectures as of late 1976. In order to make this effort comparable to other studies concentrating on the electricity sector, many of the cost and price assumptions are derived from those used in Manne (1976) and in Joskow and Rozanski (1976).

**Time Horizon** The model determines the minimum discounted costs for meeting inelastic demands for electricity and industrial process steam from the end of 1975 to the end of 2000. As discussed in Chapter 3, the cost minimization approximates the performance of the supply sector in a competitive market. The horizon is divided into five 5-year periods.

**Demands** Predictions of electric energy consumption growth rates are listed in Table 2.4. Since the energy demands specified for the model are the demands for base and intermediate load generation and since load management techniques are expected to become more important during the 1975-2000 period, electricity demand was assumed to grow at 4.8% year, slightly higher than the consumption growth forecast by Manne (1976) and Joskow and Rosanski (1976). The base year demand was taken from Edison Electric Institute (1976). Using information from Olmsted (1975), EEI, and U.S. Federal Power Commission (1972a), the total initial generation was reduced to eliminate energy production by peaking units.

Table 2.4 also lists projections for the growth in steam consumption. This study combined two approaches for forecasting the
the growth in steam consumption. First, the projections of industrial
growth by sector from U.S. Department of Commerce (1974 and 1976) and
the anticipated drop in industrial energy consumption per unit of
value added in Meyer et al. (1974) can be weighted by the shares in
overall steam consumption from Miller et al. (1971) and Miles (1970)
to obtain a 1.7%/year growth rate for 1975 to 1980. Second, the Dow
(1975b, Table V-4) projection can be weighted by the Miller et al.
and Miles shares, resulting in a 4.1%/year rate for 1975 to 1985.
This modeling effort selected an intermediate 2.8%/year growth rate
for the entirety of the 1975-2000 period. As in the Chapter 4 case
study, Figure 2.4 provided the distribution of steam energy consumption
by site scale. The base year steam consumption was obtained by extrap-
olating the Stanford Research Institute (1972) data at 3.4%/year from
1968 to 1972; the Dow (1975b, p. 39) forecast was then employed to
extend this to 1975.

Technologies Table 5.1 summarizes the technologies used in
the prospective analysis. Appendix A and Tables E.1 and E.2 give the
details of their assumed characteristics. Note this is not a complete
set of the important technologies for cogeneration: for example, gas-
and oil-fired combined cycle cogeneration plants without gasifiers
and diesel units are excluded from the model. The capacity factors for
cogeneration plants were assumed to be similar to those for boilers,
following Dow (1975a and b); Appendix B corroborates this choice.
The minimum efficient scale of each cogeneration technology was
selected on the basis of the survey in Appendix A, subjectively
### TECHNOLOGIES USED IN 1975–2000 ANALYSIS

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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</thead>
<tbody>
<tr>
<td><strong>ELECTRICITY GENERATION</strong></td>
<td></td>
</tr>
<tr>
<td>EC</td>
<td>A typical coal-fired steam-electric power plant employing stack gas clean-up</td>
</tr>
<tr>
<td>EA</td>
<td>A coal-fired low-Btu gasifier integrated with an advanced combined cycle power plant; becomes available in the late 1980's.</td>
</tr>
<tr>
<td>EN</td>
<td>A standard LWR nuclear power plant</td>
</tr>
<tr>
<td>EP</td>
<td>A typical oil-fired steam-electric power plant employing stack gas clean-up</td>
</tr>
<tr>
<td>EO</td>
<td>An oil-fired low-Btu gasifier integrated with a combined cycle power plant; becomes available in the early 1980's.</td>
</tr>
<tr>
<td>EH</td>
<td>A hydroelectric plant</td>
</tr>
<tr>
<td><strong>STEAM GENERATION</strong></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>JC</td>
<td>A coal-fired dual-purpose power station</td>
</tr>
<tr>
<td>JA</td>
<td>A coal-fed, low-Btu gasifier integrated with an advanced combined cycle power plant employing joint generation in the steam section through a back-pressure steam turbine; becomes available in the late 1980's.</td>
</tr>
<tr>
<td>JN</td>
<td>A nuclear dual-purpose power station</td>
</tr>
<tr>
<td>JO</td>
<td>An oil-fired low-Btu gasifier integrated with a combined cycle power plant employing joint generation in the steam section through a back-pressure steam turbine; becomes available in the early 1980's.</td>
</tr>
<tr>
<td>JL</td>
<td>A large industrial, coal-fired by-product steam and power plant with back-pressure and condensing power generation. This standard design is assumed unable to function as a cycling unit for the power system. It has a higher steam to power ratio than a JI design.</td>
</tr>
<tr>
<td>JI</td>
<td>A large industrial, coal-fired by-product power and steam plant with back-pressure and extra condensing power generation. This standard design is assumed capable of cycling duty for the power system.</td>
</tr>
<tr>
<td>JB</td>
<td>A coal-fired industrial by-product power and steam plant employing back-pressure power generation. This standard design cannot cycle for the power system.</td>
</tr>
</tbody>
</table>

Table 5.1
allowing a slight margin below the typical unit sizes. In the case of gasifier/combined cycle units, the minimum scale was made even smaller; the per unit capital costs were increased according to the available information on the economies of scale.

The patterns of capacity retirements owing to physical obsolescence follow the formulae in Equations 4.1 and 4.2. The per period growth in retirements, \( r \), was set to incorporate a 6%/year growth rate:

\[
    r = (1.06)^5. 
\]  

(5.1)

Table E.7 lists the results of these calculations.

The initial conditions for production by electricity-only technologies were obtained from Edison Electric Institute (1973b and 1976); the initial capacity was set in accordance with the initial production and the assumed capacity factors. The initial conditions for JC cogeneration were derived from plant history data in U.S. Federal Power Commission (1973). Each industrial by-product cogeneration technology (JB, JI, and JL) was assumed to produce a third of the industrial electric energy at the end of 1975. Their steam production was subtracted from the total steam demand in 1975 to get the total steam production by the BF and BP boiler technologies. Primarily on the basis of the boiler sales information in Dow (1975a, p. 30-33), this production was divided 80%/20% between the oil-fired package boilers (BP) and the field-erected coal-fired boilers (BF).

Costs: Unless otherwise noted, the discount rate used in the calculations for this prospective analysis is 7.5%/year. All values are
in 1975 dollars.

Fuel prices were taken from Joskow and Rozanski (1976),

hereinafter J&R.

The escalation for inflation was removed, and they

were averaged across regions and throughouteach 5-year time period.
Nuclear fuel prices were based on the average costs of the

U308 and

separative work in J&R and the miscellaneous cost assumptions in Manne
(1976, p. 405); note that the detailed modeling of the nuclear fuel
cycle in these reports is grossly simplified here to the average cost per
Btu.

Following Dow (1975a), low sulfur oil for package boilers is given

a 15% differential above the cost of the lower quality residual and
crude oil.
Appendix A derives the base year capital costs.

All plants based

on coal boilers (electricity-only, steam-only, and cogeneration) follow
the J&R cost trend assumptions for coal-fired power plants.

All plants

based on oil boilers follow the J&R assumptions for oil-fired power plants.
Similarly to their assumption for gas turbine plants, the advanced coal
and oil technologies (EA, EO, JA, and JO) do not change in price over
time when the effects of inflation are removed.

The distribution of

the direct captial expenditures during a plant's construction is derived
from Kamat (1975), as described in Chapter 3, Footnote 11.
Operation and maintenance costs for the electricity-only technologies

were assumed to be the identical to those used by Manne (1976).

The sources for boiler and cogeneration O&M costs are described in
Appendix A.
New Capacity Constraints

Five different types of NC

r

con-

straints were placed on the introduction of new capacity; three were the
relative introduction rate type, Equation 3.6, and two were the absolute
157


To approximate the need for intermediate load capacity and the difficulties of building new nuclear capacity, the share of nuclear-fueled capacity was restricted to be less than a given share of all new electricity-only and cogeneration capacity by $\text{NC}^i_{\text{CN}}$ constraints. The JL and JB cogeneration technologies were not included in the restricting set because they should be dispatched before JN and EN plants if they depend on oil-fired back-up boilers. The constraints $\text{NC}^i_{\text{CN}}$ are:

for each $i$,

$$\left[ \text{Nuclear fueled capacity} \right] \leq \left[ \frac{\text{An assumed maximum capable of generating electricity, except } JI \text{ and JB}}{\text{share for this period}} \right]$$

$$\text{DC}^i_{\text{EN}} + \text{DC}^i_{\text{JN}} \leq \left[ \text{mxfrac}^i_{\text{CN}} \right]$$

$$\left[ \sum \text{DC}^i_k \right]$$

$k = \text{EN, EC, EA, EP, EO, EH, JC, JA, JN, JO, JI}$

(5.2)

The maximum shares, $\text{mxfrac}^i_{\text{CN}}$, are listed in Table E.9.

To model the cautious adoption of new technologies, this implementation of JGSM used $\text{NC}^i_{\text{A2}}$ and $\text{NC}^i_{\text{O2}}$ constraints to limit the share of the advanced coal and oil technologies in new capacity capable of generating electricity. The $\text{NC}^i_{\text{A2}}$ constraints on the advanced coal technologies are:
for each $i$,

\[
\text{New advanced coal capacity} \leq \text{An assumed maximum share for period } i \leq \text{All new capacity capable of generating electricity}
\]

\[
DC_{EA}^i + DC_{JA}^i \leq \left[ \text{mxfrac}_{A2}^i \right] \quad \left[ \sum DC_k^i \right]
\]

\[k = \text{EN, EC, EA, EP, EO, EH, JC,JA, JN, JO, JL, JI, JB}\]

\[(5.3)\]

The maximum shares, $\text{mxfrac}_{A2}^i$, are tabulated in Table E.9. The $NC_{02}^i$ constraints on the advanced oil-fired technologies are:

for each $i$,

\[
\text{New advanced oil capacity} \leq \text{An assumed maximum share for period } i \leq \text{All new capacity capable of generating electricity}
\]

\[
DC_{EO}^i + DC_{JO}^i \leq \text{mxfrac}_{02}^i \quad \left[ \sum DC_k^i \right]
\]

\[k = \text{EN, EC, EA, AP, EO, EH, JC, JA, JN, JO, JL, JI, JB}\]

\[(5.4)\]

where $\text{mxfrac}_{02}^i$ is listed in Table E.9.

To simplify calculating the value of new oil and coal technologies, $NC_r^i$ constraints of the type in Equation 3.7 were placed on their availability. In the base case, the restrictions $A1$ and $O1$ were set at levels so that they were not constraining after the times shown in Table E.8.

When the technologies were assumed to be unavailable, the right hand
sides \( (\text{mxnew}_i^1) \) were all set so no capacity of the EA, A0, JA, and JO types could be built.

**Bounds** Hydroelectric energy production was not determined within the model; it was assumed to grow at a fixed rate of 2%/year. Since plans have already been made for all fossil plants through at least 1980 and all nuclear plants through 1985, bounds were set on the maximum additions to EC, EN, EP, JC, and JN capacity. Table E.8 lists these assumptions, which were derived from information in Rittenhouse (1976).

**Historical Trend** For the calculation of the incremental costs of retaining the current share of cogeneration in electricity supply, the JE\(^1\) constraint restricts the cogeneration of electricity to less than 4.9% of total electricity demand, \( \text{DM}_i^{EL} \).

5.2 THE RESULTS

This implementation of the JGSM model is a medium-sized linear program with 353 rows, 300 columns, and 2437 non-zero elements (excluding slack and surplus columns). As noted in Appendix F, this row count includes several non-constraining rows used to generate report information.

5.2.1 THE BASE CASE AND ITS COMPARISON TO THE HISTORICAL TREND

Figures 5.1 and 5.2 illustrate the changing role for cogeneration if the nation follows the minimum cost path implied by the model's Base Case results. In the electricity supply sector, the share of cogeneration in electricity supply doubles in the first five year period;
ELECTRICITY GENERATION: BASE CASE

Figure 5.1

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PROCESS STEAM GENERATION: BASE CASE

Figure 5.2

ANNUAL PROCESS STEAM PRODUCTION (QUADRILLION BTUS)

0 5 10 15


YEAR

Total Demand
Joint Generation
Field-Erected Boilers
Package Boilers

Figure 5.2

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after that it increases at approximately the same rate as steam demand. Except for a tiny amount of JN nuclear cogeneration built in the first period, all new cogeneration capacity in the Base Case comes from the JB by-product cogeneration technology. Its role remains small in comparison to the other supply technologies. Production by non-peak oil-fired plants (EP) drops off by 1985. In the steam supply sector, cogeneration captures all steam demands down to the 100,000 lb/hour sites by the end of the first period; this forces the early retirement of all oil-fired package boilers (the BP technology). Coal-fired boilers (BF) serve the steam demands at sites smaller than 100,000 lb/hour, taking over this share from package boilers. After the first period, production by both cogeneration plants and coal-fired boilers expands at the rate of steam demand growth.

Figure 5.3 shows the fuel consumption by the combined electricity and steam supply sectors. Oil use diminished to zero by 1985 as the last oil-fired power plants are retired for economic reasons; this results from the bang-bang behavior of the linear programming model, the national aggregate nature of the prices used, and the exclusion of some very efficient oil-fired electricity-only and cogeneration plants. Nuclear energy consumption increases more rapidly than coal. It would increase even more rapidly, but the new capacity constraints on nuclear units prevent this from occurring. Figure 5.4 presents current value of the capital investments entering production in each period; to give an indication of what share may be borne by the utilities, the investment in utility-type plants (all electricity-only technologies plus JC and JN) is also plotted.  

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FUEL CONSUMPTION FOR PROCESS
STEAM AND ELECTRICITY GENERATION:
BASE CASE

Figure 5.3


Year

ANNUAL FUEL CONSUMPTION
(QUADRILLION BTUS)

10-

Coal

20-

Nuclear

30-

Hydro (Coal Equivalent)

40-

High Sulfur Oil

50-

0 10 20 30 40 50

Figure 5.3
CAPITAL INVESTMENT ENTERING
SERVICE FOR PROCESS STEAM AND
ELECTRICITY GENERATION:
BASE CASE

Figure 5.4
Examining the implied prices for steam and electric energy provides a check on the model assumptions and an insight into the changing market conditions. The shadow prices for each modeling period must be converted to single year prices before they can be compared with information from the market and from other models. Letting

\[ P = \text{the shadow price on steam or electric energy for the} \]
\[ \text{5 year period (the dual variables on the demand constraints)} \]
\[ p = \text{the implied constant price for the steam or electric energy} \]
\[ \text{for one year in the given period} \]
\[ d = \text{the discount rate, and} \]
\[ n = \text{number of years in the period,} \]

thus

\[
P = \sum_{t=1}^{n} \left( \frac{p}{n} \right) [1 + d]^{n-t} \quad (5.5)
\]

since a one unit change in input over a period implies a \(1/n\) unit change during each year of the period and, hence, the shadow price for the period is the discounted value of these increments. So

\[
p = \frac{n[P]}{[(1 + d)^n] \left[ \sum_{t=1}^{n} t(1 + d)^{t} \right]} \quad (5.6)
\]

Figure 5.5 presents the annual prices derived from the model's dual variables on the demand constraints. The price of electricity drops off rapidly because of the retirement of the oil-fired capacity; the marginal output still comes from these units in 1980. It diminishes
THE SHADOW PRICES
FOR
POWER AND PROCESS STEAM: BASE CASE

Figure 5.5

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in the final periods owing to the advent of the advanced coal technologies and the model’s terminal year approximations. Steam prices rise slightly over time because of the rising price of coal; their prices also show the terminal year approximations.

**Comparison of the Base Case with a Case Restricting Cogeneration to Its Current Share**

Figure 5.6 shows the incremental supply costs if cogeneration's share in total electricity supply is restricted to 4.9\% of intermediate and base load electric energy demand. It also demonstrates that the benefits from the increased cogeneration are relatively insensitive to changes in the discount rate. The minimum cost share for cogeneration in electricity supply is about 9\% in 1985; Figures 5.7 and 5.8 compare the restricted and unrestricted shares of cogeneration in electricity and steam supply. In order to put the cogeneration benefits into perspective, the figure also illustrates the benefits associated with the development of advanced low-Btu coal gasifiers integrated with combined-cycle power or cogeneration plants (technologies EA and JA); since the cost reductions resulting from the introduction of these technologies do not occur until the mid-1980's, their benefits are more sensitive to the discount rate. The combined benefits for both cogeneration and the advanced coal technologies add directly because, in this case, they are not synergistic.

**5.2.2 SENSITIVITY STUDIES**

**Forcing the Issue** The previous section indicated that the economic efficiency losses will occur if cogeneration remains at its mid-1970's
THE EFFECT OF THE DISCOUNT RATE ON WELFARE LOSSES

Figure 5.6

Limited Joint Generation and No Advanced Coal Systems

Joint Generation Limited To 1975 Percentage of Electricity Supply

No Advanced Coal-Fired Combined Cycle Systems

PRESENT VALUE IN 1975 OF LOSSES (BILLIONS OF 1975 DOLLARS)

SOCIAL DISCOUNT RATE
JOINT ELECTRICITY PRODUCTION: CASE COMPARISON

Figure 5.7

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JOINT PROCESS STEAM PRODUCTION: CASE COMPARISON

Figure 5.8
share of the electricity supply. Tax and other incentives programs designed to increase cogeneration may act as private inducements to encourage cogeneration beyond its minimum cost share. Figure 5.9 shows the welfare losses if cogeneration is forced to be a given share of the electricity supply in 1985 and then must increase at least as fast as the steam demand growth rate after 1985. The results from this parameterization of cogeneration’s share imply that too much cogeneration can inflict economic inefficiencies that are as serious as those from too little cogeneration; a program promoting cogeneration must balance the risks of having too little cogeneration with the risks of encouraging too much.

O&M costs for By-Product Cogeneration Plants  The sensitivity studies in Chapter 4 indicated that the uncertainty in operation and maintenance costs, excluding fuel costs, is significant enough to influence the conclusions of whether or not historical trends could explain changes in cogenerations' share of electricity generation. Figure 5.10 shows the result of a similar parameterization for the JB, JI, and JL technologies in this 1975-2000 analysis. As the O&M costs diminish, the economic efficiency losses from restricting cogeneration to a 4.9% share dramatically increase. Figure 5.11 compares the unrestricted Base Case to the optimal path for cogenerated electricity production if the O&M costs for the by-product cogeneration technologies are actually 25% of their assumed Base Case values.
WELFARE LOSSES DUE TO RESTRICTIONS ON JOINT ELECTRICITY GENERATION LEVELS FOR 1985 AND AFTER

Figure 5.9
THE SENSITIVITY OF WELFARE LOSSES TO BY-PRODUCT POWER PLANT O & M COSTS (TECHNOLOGIES JL, JI, AND JB)

JL, JI, and JB O & M COSTS AS A PERCENTAGE OF THE BASE CASE ASSUMPTIONS

Figure 5.10

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THE EFFECT OF REDUCED O & M COSTS FOR BY-PRODUCT POWER PLANTS (TECHNOLOGIES JB, JI, AND JL) ON THE OPTIMAL LEVEL OF JOINT GENERATION

Figure 5.11
Capital and O&M Costs for the Advanced Coal-Fired Cogeneration Technologies

In the Base Case, of the two types of advanced coal plants, only EA capacity is built; Figure 5.12 shows large reductions in the capital and O&M costs for the JA technology are needed before it will be economic. Two cases are presented in Figure 5.12; first, just the O&M costs were reduced from 100% to 40% of their Base Case assumptions (the dotted line); second, the capital costs were reduced to 70% of their Base Case values while the O&M costs were simultaneously reduced twice as quickly to 40% of their original values (the solid line in the figure). Figure 5.13 depicts the cogenerated electricity resulting from several different cases in this parameterization. Its role in electricity supply increases because JA plants produce much more electricity per unit of steam than the regular by-product cogeneration technologies. It is doubtful that the cost reductions needed to make this technology economic will occur because the JA competes with the EA plants on the electricity supply side; it is unlikely that the reductions would occur for the JA plants and similar reductions would not take place in the almost identical EA plants.

Nuclear Capital Costs

As shown in Figure 5.14, a large increase in the capital costs for nuclear technologies (EN and JN) produces little increase in the benefits of either the advanced coal systems or cogeneration. The parameterization causes only a small shift in the capacity and production patterns.
THE SENSITIVITY OF WELFARE LOSSES TO ADVANCED COAL-FIRED COMBINED CYCLE JOINT GENERATION PLANT COSTS (TECHNOLOGY JA)

Figure 5.12
THE EFFECT OF REDUCED COSTS FOR ADVANCED COAL-FIRED COMBINED CYCLE JOINT GENERATION PLANTS (TECHNOLOGY JA) ON THE OPTIMAL LEVELS OF JOINT GENERATION

<table>
<thead>
<tr>
<th>Case</th>
<th>O &amp; M</th>
<th>Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>40%</td>
<td>70%</td>
</tr>
<tr>
<td>B</td>
<td>40%</td>
<td>100%</td>
</tr>
<tr>
<td>C</td>
<td>60%</td>
<td>80%</td>
</tr>
</tbody>
</table>

Figure 5.13
THE SENSITIVITY OF WELFARE LOSSES TO NUCLEAR CAPITAL COSTS (TECHNOLOGIES EN AND JN)

Figure 5.14

PRESENT VALUE IN 1975 OF LOSSES (BILLIONS OF 1975 DOLLARS)

NUCLEAR CAPITAL COSTS AS A PERCENTAGE OF THE BASE CASE ASSUMPTIONS

No Advanced Coal-Fired Combined Cycle Systems

and Limited Joint Generation

Joint Generation Limited to its 1975 Percentage of Electricity Supply

Figure 5.14
5.3 CONCLUDING COMMENTS

On the basis of the modeling results presented above, the share of cogeneration in total U.S. electricity supply should approximately double by 1985. If it stays at its current share, the nation will suffer an economic loss worth about $10.5 billion in 1975 (1975$). The value of the loss increases rapidly when less conservative estimates for the by-product cogeneration O&M costs are employed in the calculations.

Figure 5.9 illustrated that the nation must balance its policies toward cogeneration. The economic efficiency losses from too much electricity production through cogeneration can be as severe as the losses from too little cogeneration.

This implementation also tested the validity of several of the model's assumptions. The first test pertained to simulating the market's investment behavior with a discount rate identical to that used for evaluating benefits. If the market chooses capacity and production levels according to a 10% discount rate instead of a 5% rate, while the social cost comparisons are still made at a 5% rate, the benefits of increased cogeneration change by only 0.4% -- thus the change in behavior is extremely slight. The second test supported the assumption that the market could be adequately described by a cost minimizing supply model rather than resorting to a framework that simultaneously calculates supply and demand interactions for the electricity and industrial process steam sectors. The dual variables for the inelastic steam and electricity demands, or their shadow
prices, almost never shifted between the restricted and unrestricted cogeneration cases, even in most of the cost parameterizations. The electricity prices did shift between the alternative cases testing the value of the advanced coal technologies. If the electricity demand was treated more thoroughly to account for load duration effects, however, this inelastic demand assumption may not prove to be as appropriate.
Footnotes for Chapter 5

1. See Appendix B.

2. As noted in Chapter 4, such projections from LP models should be used with caution. See Blitzer, Clark and Taylor (1975, p.95).

3. The shadow price projections from LP models are often unstable. "Nonetheless, experience has shown that the prices are useful in measuring the trade-offs implicit in any particular LP model, and that these trade-offs are of interest to policy makers." Blitzer, Clark, and Taylor (1975, p.82 and 95).

4. This 25% value is within the range of published values cited in Table A.7.
Cogeneration should form a valuable segment of the nation's total steam and electricity supply sectors, particularly for steam generation. Changes in fuel costs and technologies during the 1960's may account for the previous drop in the importance of cogeneration, but these results are very sensitive to the assumptions made--plus the pre-conditions for market failures exist in these markets associated with cogeneration. Cost conditions have now reversed--pointing towards an increased role for cogeneration.

The modeling effort in this report addresses cogeneration investments from an aggregate national income viewpoint and places an economic value on the promotion of cogeneration to a specific share of steam and electricity supply. Earlier studies analyze potential incentives programs but offer no advice on how much cogeneration is enough. The results derived here show that there must be a balance between cogeneration and other sources of steam and electricity. In addition the benefits estimates in some of the earlier studies may be overstated.

This chapter reviews the results from previous chapters and, given the weaknesses in this and other studies, suggests directions for further research.
6.1 REVIEW OF RESULTS

The introduction posed two questions on cogeneration economics. The results from Chapters 2, 4, and 5 provide some insight into the answers.

- Can the historical decline in cogeneration's importance be explained by cost conditions alone? Chapter 2 demonstrates the market structure could permit utility behavior that would cause severe distortions in the markets associated with cogeneration, but the cogeneration engineering cost function shown in Figure 2.12 has characteristics that could also explain the historical shift. The JGSM simulation of the electricity and steam supply markets in Chapter 4 showed the actual market roughly follows the modeling results from competitive behavior, which is dictated by changes in costs and technologies. Altering the operating and maintenance cost assumptions for by-product cogeneration plants changes these conclusions: with the O&M costs reduced by 75%, a level within the range of experience, the actual market's behavior deviates from the simulated conditions, thereby incurring losses worth $3.2 billion in 1975. Under these changes, more investment in utility-type equipment also occurs under the restricted historical conditions.

- What is the best future role for cogeneration? On the basis of economic efficiency, the share of cogeneration in electricity supply should double by 1985 and also
increase to over half of the industrial process steam supply. If cogenerated electricity remains at its 1975 share of total electricity generation, the nation will incur losses worth at least $10 billion in 1975. For comparison, failure to develop low-Btu coal-gasifying combined cycle power technologies will result in losses worth about $4 billion in 1975. The losses associated with too little cogeneration are sensitive to reductions in by-product power plant O&M costs, relatively insensitive to the capital and operation costs for the advanced coal-fired cogeneration technologies, and insensitive to reasonable changes in the discount rate and nuclear capital costs. As illustrated by Figure 5.9, policies that encourage too much cogeneration can precipitate losses as large as conditions that restrict cogeneration to its current share of electricity supply.

Table 6.1, in a format comparable to Table 1.1, summarizes the major assumptions and results of JGSM's application to these two questions.

In addressing the methodological problems raised in the introduction, Chapter 2 has taken a first step in the formal analysis of market imperfections. The JGSM combines fuel and capital expenditures to measure the costs for differing levels of cogeneration; the cost of oil was set at the world price. National policy concerns, however, may dictate it receives a higher weight when evaluating programs from
### Summary of the Results for Comparison to Earlier Reports

<table>
<thead>
<tr>
<th>Goals</th>
<th>Prospective Study (Chapter 5)</th>
<th>Historical Analysis (Chapter 4)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Levels of Detail and Key Assumptions:</td>
<td>Analysis of past cogeneration market performance from a formal industrial organization economics perspective and improvement of the methods for evaluating the future role for cogeneration.</td>
<td></td>
</tr>
<tr>
<td>Time Horizon Growth Rates for Consumption</td>
<td>1975-2000 in five 5-year periods</td>
<td>1960-1972 in three 4-year periods</td>
</tr>
<tr>
<td>-Industrial Process Steam</td>
<td>2.8%</td>
<td>3.6%</td>
</tr>
<tr>
<td>-Electric Energy</td>
<td>4.8%</td>
<td>6.75%</td>
</tr>
<tr>
<td>Treatment of Cogeneration/Utility Interactions</td>
<td>Simultaneous determination of electricity and steam prices.</td>
<td></td>
</tr>
<tr>
<td>Number of Basic Cogeneration Technology Designs</td>
<td>Seven with new or replacement installations.</td>
<td>Four with new or replacement installations.</td>
</tr>
<tr>
<td>Disaggregation by Industry</td>
<td></td>
<td></td>
</tr>
<tr>
<td>-by Steam Pressure</td>
<td>Single Pressure</td>
<td>Single Pressure</td>
</tr>
<tr>
<td>-by Region</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td>-by Plant Scale</td>
<td>Yes (&gt;100,000 lb./hr.)</td>
<td>Yes (&gt;100,000 lb./hr.)</td>
</tr>
<tr>
<td>Method for Analysis of Economic Behavior</td>
<td>Equivalence of economic equilibrium and linear programming.</td>
<td></td>
</tr>
<tr>
<td>Measures for Analysis of Issues and Federal Policy Choices</td>
<td>Present value of net social economic surplus; this combines fuel and capital costs.</td>
<td></td>
</tr>
<tr>
<td>Results</td>
<td></td>
<td></td>
</tr>
<tr>
<td>-Fuel savings over historical trend (bbl/day oil equivalent)</td>
<td>in 1985</td>
<td>in 1972</td>
</tr>
<tr>
<td></td>
<td>350,000</td>
<td>--</td>
</tr>
<tr>
<td>-Recommended cogeneration (% of total U.S. electric energy consumption)</td>
<td>9%</td>
<td>1.7%</td>
</tr>
<tr>
<td>(% of total U.S. process steam consumption)</td>
<td>63%</td>
<td>5.6%</td>
</tr>
<tr>
<td>Conclusions</td>
<td>Too much cogeneration can be as expensive as too little, but increasing cogeneration to 9% of the electricity supply saves $10 billion (discounted to 1975) over the costs of keeping it at the present share.</td>
<td>Historical behavior can be explained by cost influences alone, but these conclusions are sensitive to reasonable changes in O&amp;M assumptions.</td>
</tr>
</tbody>
</table>

| TABLE 6.1 |
a public perspective. The structure of the JGSM allows the abandon-
ment of economically obsolete capacity; in the prospective case study,
the horizon was extended 15 years beyond that of earlier studies. The
linear programming formulation of the model allows the joint product
nature of cogeneration to be explicitly incorporated.

The model and the case studies are incomplete in several respects.
First, JGSM simulates perfect markets; the effectiveness of government
programs depends upon the behavior of the actual markets, not on how a
competitive market would operate. Second, the scope of technologies
used in the 1975-2000 analysis inadequately represents the range of co-
generation technologies available. For example, natural gas-fired
combined cycle cogeneration plans are not included. Third, a number of
the problems cited in the introduction are still treated inadequately.
Demand elasticity is neglected. The economies of scale and joint pro-
duction are modeled in detail in Chapter 2 for one type of cogeneration,
but JGSM specifies the cost of each plant type at a predetermined mini-
mum efficient scale. Behavioral modeling is needed to fully capture
the effects of abandoning existing plants on the financial condition
of industries and utilities; an economic efficiency criterion is inade-
quate when evaluating the compensation necessary between these parties
to ensure fairness. The JGSM bases the simulation on a single discount
rate; this is a simpler treatment of financial conditions than employed
in the financial modeling by the ThermoElectron and Resource Planning
Associates studies, although sensitivity studies vindicate the assump-
tion for the national income calculations, improvements on the financial
calculations are needed for future behavioral modeling.
6.2 DIRECTIONS FOR FURTHER RESEARCH

This research effort concentrated upon the national perspective. Methods for industrial and utility planning also need improvement, but the remarks here will be limited to suggestions for future efforts related to governmental program planning. Research directions can be separated into two categories: (1) those extending the competitive market simulation approach contained in this report; and (2) those developing behavioral models that include the influences of governmental incentives and regulations.

Within the Existing Framework

First, the current implementation of JGSM could be extended by:

- Regionalizing the capital cost, fuel price, and demand information.
- Adding the cogeneration technologies neglected in the 1975-2000 case study.
- Disaggregating technologies and demands by industry groups.

Second, while still maintaining the competitive market nature of the simulation, rather than modeling behavior directly, the model formulation could be improved to:

- Treat the economies of scale for cogeneration plants serving different scale steam demand sites in a more detailed fashion.
• Allow for technological change in existing types of steam and electricity generation technologies by changing capital costs and fuel efficiency both over time and as more experience is gained.

• Include waste fuels as a possible source of fuel for cogeneration plants and boilers in some industries. 3

• Calculate the supply-demand equilibrium by including price elasticity of demand for electricity and industrial steam. The economies of scale for cogeneration may also affect the size distribution of steam consuming sites.

• Compare the advantages of different levels of cogeneration by considering the multiple objectives of reducing oil imports and minimizing the costs of electricity and steam supply.

• Include the fluctuating nature of electricity consumption and the effects cogeneration may have on electricity transmission costs and system reliability.

• Evaluate the effects of uncertainty in fuel prices, capital costs, demands, and the availability of new technologies.
Model the Behavior of the Industrial and Utility Sectors Directly

Models like JGSM only indicate the best achievable performance in the markets associated with cogeneration but not what incentives will result in attainment of such performance. The evaluation of tax and regulatory programs, especially the recent proposals for reducing industrial oil and gas consumption, requires models of utility and industrial behavior that explicitly include the influence of:

- New rate schedules and increased industrial cogeneration upon the utilities.
- Tax incentives, fuel restrictions, and utility rate structures upon industry.
- Financial markets, fuel markets, and the uncertainties in these markets on both utilities and industry.

The behavioral models should also embody the improvements suggested for the JGSM approach.
Footnotes for Chapter 6

1. See Table A.7.


3. Work has been initiated on this problem by Helliwell and Cox (forthcoming 1979).

Appendix A

TECHNOLOGIES FOR POWER AND INDUSTRIAL STEAM GENERATION

This appendix describes the technological alternatives that appear promising as means for joint process steam and electric power generation. Before examining these in detail, however, the first section reviews the basic thermodynamics and technologies for separated power and steam generation. The second section surveys the joint generation thermodynamics and technologies. First, it delves into the thermodynamics of the simplest type of joint generation, back pressure generation. Second, it describes designs for the more complex systems that combine back pressure generation with standard condensing power generation. This class of plants includes most small industrial by-product power plants and the large, typically utility-operated, dual-purpose power plants. Finally, the joint generation section concludes with a discussion of integrated gasifier/combined-cycle systems as advanced by-product joint generation plants -- since this new technology promises to be particularly attractive, environmentally and economically.

The provision of technological and cost data for the economic modeling in the body of the report serves as the chief purpose of this appendix. Towards that end, this appendix surveys engineering technology and cost studies done over a period of almost a decade. The assumptions used in developing the capital and O & M cost estimates vary
considerably between these sources. Fuel conversion efficiencies do provide some common basis for comparisons, but the inclusion or exclusion of environmental controls and the differences between waste heat rejection methods weakens even this simple standard. Consequently, an effort has been made to adjust capital and O & M cost data from all sources by comparisons with a standard coal-fired steam electric plant using flue gas desulfurization. If a source quotes costs for a typical coal-fired power plant along with figures for the special system under study, the coal-fired steam plant costs from that source are used for adjusting the source's other cost estimates to the standard coal-fired steam plant design described in Section A.1.1.1. For sources that do not quote costs for a coal-fired plant, historical cost data from Electrical World's annual steam plant cost surveys are used for adjusting the source's data. The costs are given in 1975 dollars for facilities initiating operations in 1975. Capital costs are the direct construction expenditures; they do not include interest during construction. For advanced technologies, this is intended to represent the costs if the system could be built in 1975. These base year capital and O & M costs are changed over time in the modeling described in Chapters 4 and 5; later appendices document the patterns for these changes.

For each technology to be used in the JGSM power and steam supply modeling in the thesis, a typical design is selected. These standard design plants for each technology are given a two-letter mnemonic: the first letter designates its class (E for electricity-only, B for boiler or steam-only, and J for joint generation. The
second letter distinguishes it from other technologies in its class. For example, "EC" is a coal-fired steam electric power plant, and "BF" is a coal-fired field-erected boiler.

A.1 SEPARATED GENERATION TECHNOLOGIES

Although this report focuses on joint generation, this section describes the basic thermodynamics, process economics and technologies for separated steam and power generation systems. Chapters 4 & 5 use this information for the comparison of joint and separated generation. Special attention is devoted to advanced power generation technologies that can be adapted for joint generation systems.

A.1.1 POWER GENERATION

Figure A.1 gives a flow sheet for a very simplified steam-electric power plant. This generation cycle can be powered by coal-, oil-, or natural gas-fired boilers or by a nuclear heat source. The efficiency of this conversion from thermal energy to mechanical and then electrical energy is limited by the second law of thermodynamics: the temperature of the water exiting the boiler and the water in the condenser set the Carnot cycle limits on the efficiency.\(^2\) The energy cycle in a steam-electric plant is depicted by the first set of columns in Figure A.2. The boiler adds energy to the water up to the maximum design temperature and pressure. The steam exiting the boiler expands in the turbine, losing energy and dropping in temperature -- this is energy available for power in Figure A.2. As the steam approaches the point where water starts forming in the steam, it is sent to the condenser, where the remaining heat from the steam is released as waste heat. Figure A.3
ENERGY BALANCES FOR STEAM AND POWER GENERATION

Power Only  Steam Only  Back Pressure  Joint Generation

A. Steam For Power Generation  — —  — —
B. Process Steam  — —
C. Steam At Boiling Point  — —
D. Water At Boiling Point  — —
Feedwater  — —

Energy Added For Power Generation  — —
Waste Heat  — —
Energy Available For Power  — —
Energy Added For Process Steam  — —
Energy Available As Process Steam  — —
Energy Added  — —
Energy Available As Process Steam  — —
Waste Heat  — —
Waste Heat  — —

Figure A.2
Adapted from Dow (1975a)
A Simplified Power Plant
Temperature-Entropy Diagram

Figure A.3
provides another perspective of this cyclical process. Point 1 is before the condenser water has been compressed by the boiler feed pump. After Point 2, the water enters the boiler and begins the heating process. As the transition from water to steam takes place, the fluid increases in temperature and entropy along a constant pressure line. At the entrance to the turbine, Point 3, the steam temperature is at its maximum. If the turbine could perfectly convert the expansion of the steam to mechanical energy, the temperature would fall to Point 4 without any increase in entropy; in a real system, however, this conversion is only 95% efficient and the entropy increases slightly. At the exit from the turbine, the steam is slightly wet -- too high a water/steam mix is damaging to the turbine. The exhaust steam condensation back to feed water takes place along the constant pressure line between Points 4 and 1.

A.1.1.1 CURRENT POWER GENERATION TECHNOLOGIES

The typical overall efficiency for the conversion of the fuels to electrical energy in a steam-electric plant is about 33%. This is commonly expressed as the Btu's of fuel required to produce one kilowatt-hour of electricity and is known as the heat rate. The 1970 National Power Survey listed the best annual heat rate for a power plant as 8534 Btu/kwhr, or about 40%. The national average heat rate for all coal-, oil-, and gas-fired plants in 1974 was about 10480 Btu/kwhr, or 32.6%. Temperature limitations on nuclear plants resulted in a slightly worse heat rate of 10660 Btu/kwhr.
As stated in the Introduction, efficiency data alone cannot provide sufficient information for evaluating energy alternatives. Table A.1 lists heat rates, capital costs, and operating and maintenance costs for the standard design coal, oil and gas, and nuclear fueled steam-electric power plants to be used in the modeling work in later chapters. The capital costs come from national averages of the figures used in Joskow and Rozanski (1976). The operation and maintenance costs are based on the data selected for the modeling effort by Manne (1976); the O & M costs for oil- and gas-fired plants are based on an adjustment of historical data compared to the assumed standard coal-fired plant O & M costs. The heat rate for the hydro plant is technologically meaningless -- here it is intended to represent the amount of coal consumption replaced by these plants.

A.1.1.2 ADVANCED POWER GENERATION TECHNOLOGIES

Numerous new power generation technologies will become commercial between now and the year 2000. The key characteristics being sought in these new systems are environmental cleanness, high energy conversion efficiencies, and the usage of less expensive fuels -- such as coal or nuclear energy. Coal-fired fluidized bed boilers offer environmental cleanliness. Advanced nuclear reactors like the HTGR and the LMFBR are expected to have higher efficiencies and reduced nuclear fuel costs. One class of advanced electric power generation technologies, however, particularly lends itself to adaptation to joint generation and so is discussed in detail here: combined-cycle gas turbines fueled by integral low-Btu oil or coal gasifiers. The survey here neglects the other
### Standard Power Generation Technologies

"EC", "EN", "EP", and "EH"

<table>
<thead>
<tr>
<th>Standard Designs for the Model</th>
<th>Typical Unit Size (MW)</th>
<th>Heat Rate (Btu/kwhr)</th>
<th>Capital Cost ($/KW)</th>
<th>O &amp; M Cost (Mills/kwhr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC: A coal-fired power plant with flue gas desulfurization</td>
<td>1000</td>
<td>10450</td>
<td>314</td>
<td>2.0</td>
</tr>
<tr>
<td>EN: A nuclear power plant</td>
<td>1200</td>
<td>10660</td>
<td>405</td>
<td>2.0</td>
</tr>
<tr>
<td>EP: A high sulfur oil-fired power plant</td>
<td>1000</td>
<td>10450</td>
<td>245</td>
<td>1.0</td>
</tr>
<tr>
<td>EH: A hydroelectric facility</td>
<td>-</td>
<td>10450</td>
<td>470</td>
<td>2.0</td>
</tr>
</tbody>
</table>

*For 1975 only. These assumptions change over time in the Chapter 4 and 5 analyses. The capital costs for the BF, BP, JB, JI, JL, JC, and JN systems are keyed to these capital costs.*

Table A.1
advanced systems. This section, first, describes the basic combined-cycle power systems and second, focuses on the costs and operating characteristics of the integrated systems. Section A.2.3 will describe the adaptation of these systems to joint generation.

Simple gas turbines have low capital costs, poor thermal efficiencies, produce nitrogen oxide pollutants, and require high quality fuels such as naptha or natural gas. Combined-cycle plants have much higher efficiencies than simple gas turbines, but they still require the same scarce, expensive fuels. In a combined-cycle gas turbine, the exhaust gases exiting from the gas turbine stage pass through a heat recovery boiler; the boiler, in turn, raises steam for a steam turbine-generator set.

Early combined-cycle plants were custom-designed and field-erected; their heat recovery boilers could be supplementarily fired directly, which provided an extra degree of reliability for the system. Package units that can deliver up to 600 MW of base load power now compete with the field-erected combined cycle plants, although they do not offer the supplementary firing feature in their more compact heat recovery boilers. The cost of the package units is expected to drop significantly below that of the field-erected units due to design standardization. All gas turbine systems -- particularly the package combined-cycle systems -- will improve in efficiency without any anticipated cost increases because of projected design and materials innovations. A United Aircraft Research Labs study estimates the system efficiencies of package combined cycle systems (multiple gas turbines feeding to a boiler) to be
47% for plants available by the late 1970s, 54.5% in the 1980s, and 57% in the early 1990s, based on fuel inputs to the gas turbines for 1000MW base-loaded plants. The efficiency improvements result from metallurgical technology improvements which allow higher gas turbine operating temperatures: these increase from 1800°F currently to over 3100°F in the 1990s.

Several major turbine manufacturers now offer these package combined-cycle power plants. General Electric\(^8\) is currently selling 400MW and 600MW cycle plants, which can be operated either as base load or on peaking duty. Both models have efficiencies greater than 42%. The 400MW plant consists of four gas turbines, each with its own heat recovery boiler and a single steam turbine for the plant. The 600MW system has six gas turbine/boiler units and one steam turbine. These systems have a lead time of 30 months from release date to the initiation of commercial operation, a much shorter lead time than for a steam-electric plant. Westinghouse's\(^9\) pre-engineered PACE combined cycle systems (Power at Combined Efficiencies) have been in use since early 1974. The first unit was a 260 MW system with two turbines and heat generators supplying steam to a single steam turbine. With the system operating at capacity, the design heat rate is 8500 Btu per kwhr -- an efficiency of 40.1%.

Several factors combine to make combined-cycle less attractive than one would expect from the efficiency information above. The largest single factor is the current scarcity of natural gas and the high price of light distillates. Fuels with high organic nitrogen or sulfur
levels also pose problems for environmental clean-up of the exhaust gas. Noise has caused local environmental problems with open cycle gas turbines; the heat recovery equipment in combined-cycle plants fortunately reduces this problem.  

The integration of gasification facilities with combined cycle generation facilities promises several advantages over separate siting for each system. The gas exiting from coal or oil gasifiers contains about 30% of its energy in sensible heat. Although current processes for the removal of sulfur compounds from the fuel gas operate at a temperature much below that of the gasifier output, this energy can be effectively utilized in the combined cycle generation system by a second heat recovery boiler cooling the fuel gas to the temperatures required by the gas clean-up system. The steam from this boiler and the gas turbine heat recovery boiler is used in the steam turbine. For example, 80% of the steam produced in a Texaco/United Aircraft oil gasifier/combined-cycle system is from the fuel gas boiler. Hydrogen sulfide (H$_2$S) and carbonyl sulfide (COS) compounds in the fuel gas stream can be removed much more cheaply than sulfur pollutants could be removed from the turbine exhaust gas. Nitrogen oxides do not form from the organic nitrogen in the gasifier environment. Since the facilities are co-located, there is no need to increase the chemical energy density of the fuel gas to medium or high Btu levels. Clean-up of low-Btu gas is simpler since there is no need to protect any methanation catalyst necessary for high-Btu gasification. The electrical load following characteristics of these integrated systems appear to pose no
severe problems.14

Oil Gasifier/Combined-Cycle Power Plants The block process diagram in Figure A.4 shows the material flows for a typical integrated oil gasifier/combined-cycle plant design. The reduced air requirements for low-Btu gas combustion necessitate the redesign of the turbine compressor and combustor from the standard combined-cycle systems. One solution, as shown in the process diagram, has been to bleed off the excess air from the compressor and use it to provide the air to oil gasifier. Several of the designs proposed for integrated oil gasifier/combined-cycle power plants are shown in Table A.2. Due to the advances in gas turbine technologies, the capital costs for these systems are assumed to remain the same in constant dollar terms over the 1975-2000 horizon. This is in contrast to the anticipated cost increases for standard oil- and coal-fired plants because of tightened environmental standards.

The process used for gasifying oil is the partial oxidation reaction:15

\[ C_{\frac{n}{m}}H_{\frac{n}{m}} + \frac{n}{2}O_2 \rightarrow nCO + \frac{m}{2}H_2 \]  \hspace{1cm} (A.1)

The manufacturers claim that this non-catalytic process will work for any liquid hydrocarbon regardless of the sulfur content. Although such units have traditionally operated with oxygen, here they function on air, producing low rather than medium Btu gas and eliminating the need for an expensive oxygen source. Both Texaco and Shell have extensive experience with such reactions with more than 240 units in 94
Table A.2
Advanced Combined-Cycle Oil-Fired Power Generation Technology "BD"

<table>
<thead>
<tr>
<th>Design</th>
<th>Typical Unit Size</th>
<th>Heat Rate Btu/kwh</th>
<th>Capital Cost $/KW</th>
<th>O&amp;M Cost Mills/kwh</th>
<th>Available in</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>GE Combined Cycle with Oil Gasifier</td>
<td>243MW</td>
<td>9500</td>
<td>$250</td>
<td></td>
<td>1975</td>
<td>D.J. Ahner &amp; W.A. Boothe ASME: 75-GI-73</td>
</tr>
<tr>
<td>&quot;</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>1975</td>
<td></td>
</tr>
<tr>
<td>UA 2200°F Turbine* Combined Cycle with Texaco Oil Gasifier</td>
<td>985MW</td>
<td>8540</td>
<td>$206</td>
<td>2.24</td>
<td>1980</td>
<td>F.L. Robson et al. (1970) and an 85% Eff. Gasifier</td>
</tr>
<tr>
<td>UA 2800°F Turbine* Combined Cycle with Texaco Oil Gasifier</td>
<td>987MW</td>
<td>7370</td>
<td>$198</td>
<td>2.07</td>
<td>1985</td>
<td>F.L. Robson et al. (1970)</td>
</tr>
<tr>
<td>UA 3100°F Turbine* Combined Cycle with Advanced Oil Gasifier</td>
<td>978MW</td>
<td>6960</td>
<td>$205</td>
<td>2.10</td>
<td>1990's</td>
<td></td>
</tr>
<tr>
<td>Standard Design for Model</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Advanced Combined Cycle with a Texaco Type Low Btu Oil Gasifier</td>
<td>300MW</td>
<td>8700</td>
<td>$288/KW</td>
<td>2.24</td>
<td>1980</td>
<td>JGSM Assumption</td>
</tr>
</tbody>
</table>

*Estimates based on comparison to 1968-1972 O&M costs and projected oil-fired steam-electric capital costs.
The oil gasification process allows a much wider choice of fuels — high sulfur, bottom of the barrel residues are acceptable. The low Btu gas to the gas turbine has the sulfur compounds and metals removed using current technologies. The by-products of the Shell and Texaco gasification and sulfur removal process are high quality sulfur and ash slag deposited as a solid in the bottom of the gasification reactor. The slag can be easily removed when the system is shut down for routine inspection.

Coal-Gasification/Combined-Cycle Plants. The coal gasifying combined-cycle power plants do not differ significantly from the oil gasifying units, as illustrated by Figure A.5. The key difference is that coal gasification requires steam, which the heat recovery boilers can provide. Here the integration of the gasifier and combined-cycle plants becomes particularly advantageous because of the sensible heat in the gasifier output and the ability of the combined-cycle system to supply steam to the gasifier input. As with the other systems containing gas turbines, the costs for the standard plant design are assumed constant owing to the improvements in turbine technologies, in particular the increases in the gas turbine inlet temperature limits. The perfection of entrained and fluidized bed coal gasification technologies also heavily influences the costs and performances of the integrated power plants.

All the low-Btu coal gasification processes function using three basic chemical reactions:
A Simplified Flow Sheet
Coal Gasifier/Combined-Cycle Power Plant

Figure A.5
\[ C + H_2O \text{ (steam)} = CO + H_2 \] (A.2)
\[ CO + H_2O \text{ (steam)} = CO_2 + H_2 \] (A.3)
\[ C + 1/2 O_2 = CO \] (A.4)

where the carbon (C) is provided by the devolitalized coal and the oxygen is a constituent of the air that is blown into the gasifier.\(^{17}\) The combined chemical equation for the low Btu gasification reactions is, crudely:
\[ \text{Air} + a(\text{Steam}) + b(\text{Coal}) = dCO + eCO_2 + fH_2 + gN_2 \] (A.5)

where the molar proportions a through g depend upon the specific process.

The generations of improving coal gasification technologies do not differ in their basic chemical processes but in their handling of the coal and waste products. The first generation of gasifiers is typified by the Lurgi process -- coal and ash are mechanically moved into the gasification retort and are stirred in a fixed reaction bed during the gasification process. The second generation gasifiers, such as the Texaco Partial Oxidation Gasifier, transport the coal and the gasification products in fluidized beds or entrained in the air, steam, and gas stream: the gasification occurs more rapidly because of the increased operating temperatures. The higher temperatures are impossible without the newer coal transport mechanisms because of the coal caking and slagging characteristics. The increased reaction rates mean smaller gasifiers; the increased operating temperatures mean more sensible heat to be recovered in the product gases -- this is where the
integration with the combined cycle gas turbine becomes more important.

Table A.3 lists the early plans for low-Btu coal gasification projects. Since that time, low Btu coal gasification has gone through a period of intense study -- the negative results for its application as a regular boiler fuel do not apply to integrated combined-cycle systems because of the advantages of the high pressure fuel feed and the requirements for high quality fuels in gas turbines. 18

Table A.4 lists several design alternatives for two generations of integrated coal gasification/combined-cycle systems along with the standard design selected for the process analysis modeling in Chapter 5. The first generation designs, which appear in the late 1970s and early 1980s, will not be economic. These systems will be improvements on the 70MW pilot plant built by the Office of Coal Research team composed of Foster-Wheeler, Pittsburgh and Midway Mining, and Northern State Power Companies, 19 and on the 170MW system being tested by Lurgi in Luen, Germany. 20 The second generation systems, available in the late 1980s, incorporate the advanced coal gasifiers and the higher temperature gas turbines. The standard design is based on the second generation plants.

A.1.2 STEAM GENERATION

In contrast to the power generation process, steam raising is not a cyclical process converting heat to work; the laws of nature, therefore, do not impose the limitations of the Carnot cycle. Figure A.6 illustrates the flow sheet for steam generation. The boiler feed pump
<table>
<thead>
<tr>
<th>Process</th>
<th>Reactor Bed Type</th>
<th>Nature of Residue</th>
<th>Pressure, Atm.</th>
<th>Temperature, °F</th>
<th>Capacity Tons/Day</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commercial</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winkler</td>
<td>Entrained</td>
<td>Dry ash</td>
<td>1</td>
<td>Approx. 1,500</td>
<td>2,000</td>
</tr>
<tr>
<td>Demonstration</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Luigi</td>
<td>Fixed</td>
<td>Dry ash</td>
<td>20</td>
<td>1,000</td>
<td>2,000</td>
</tr>
<tr>
<td>Pilot Plants</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stirred fixed producer (USBM)</td>
<td>Fixed</td>
<td>Dry ash</td>
<td>20</td>
<td>1,000</td>
<td>20</td>
</tr>
<tr>
<td>General Electric fixed bed</td>
<td>Fixed</td>
<td>Dry ash</td>
<td>8</td>
<td>1,000</td>
<td>0.25</td>
</tr>
<tr>
<td>Combustion Engineering-Consolidated Edison gasifier</td>
<td>Entrained</td>
<td>Slag</td>
<td>1</td>
<td>&gt;2,100</td>
<td>180</td>
</tr>
<tr>
<td>Westinghouse Electric Corp. gasifier</td>
<td>Multiple fluid beds</td>
<td>Dry ash</td>
<td>10-16</td>
<td>1,300-1,700 and 2,000</td>
<td>15</td>
</tr>
<tr>
<td>Pittsburg-Midway gasifier</td>
<td>Entrained (2-stage)</td>
<td>Slag</td>
<td>4-35</td>
<td>&gt;2,100</td>
<td>1,200</td>
</tr>
<tr>
<td>IGT U-gas</td>
<td>Fluid bed</td>
<td>Dry ash</td>
<td>20</td>
<td>1,900</td>
<td>30-50</td>
</tr>
</tbody>
</table>

Source: Perry (1974)
<table>
<thead>
<tr>
<th>Typical Unit Size</th>
<th>Heat Rate Btu/kwh</th>
<th>Capital Cost $/KW</th>
<th>O&amp;M Cost Mills/kwh</th>
<th>Available in</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>United Aircraft 2200°F COGAS Combined Cycle with Lurgi Gasifier</td>
<td>918MW</td>
<td>9454</td>
<td>$308/KW</td>
<td>3.50</td>
<td>1979</td>
</tr>
<tr>
<td>United Aircraft 3100°F COGAS Combined Cycle with Texaco Partial Oxidization Gasifier</td>
<td>933MW</td>
<td>6840</td>
<td>$249/KW</td>
<td>2.50</td>
<td>1990's</td>
</tr>
<tr>
<td>GE 1800°F Turbine Combined Cycle with Lurgi Gasifier</td>
<td>430MW</td>
<td>9900</td>
<td>$326/KW</td>
<td>2.05</td>
<td>1980</td>
</tr>
<tr>
<td>GE 2400°F Turbine Combined Cycle with Lurgi Gasifier</td>
<td>1005MW</td>
<td>8900</td>
<td>$300/KW</td>
<td>1983+</td>
<td></td>
</tr>
<tr>
<td>GE 2800°F Turbine Combined Cycle with Lurgi Gasifier</td>
<td>7882</td>
<td>1985</td>
<td>Kydd (1975)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Combined Cycle with Integrated Gasifier in Gulf/SRI Model</td>
<td>10035</td>
<td>$336/KW</td>
<td>2.47</td>
<td>1979</td>
<td>Gulf Oil Co./MIT Energy Lab Meeting (1976)</td>
</tr>
<tr>
<td>Standard Design for Model EA 2800°F Combined Cycle with an Advanced Low Btu Gasifier</td>
<td>900MW</td>
<td>7700</td>
<td>$358/KW</td>
<td>2.50</td>
<td>1985</td>
</tr>
</tbody>
</table>
Figure A.6: Industrial Boiler Steam Supply Flow Sheet
forces the feedwater into the boiler, where it is heated to the temperatures and pressures required for the industrial processes. The only waste heat in this transformation is the loss through the flue gases. The middle columns in Figure A.2 show the steps in this process: energy is added to the water until it reaches the levels for process steam, and then the steam is a product in itself. Note, as pointed out in Chapter 1, the steam pressures required for almost all processes are below that used for power generation. Another interpretation for the thermodynamics of steam raising is shown in Figure A.7, with the feedpump compression of the water from Point 1 to Point 2, the transformation from water to steam along the constant pressure line from Point 2 to 3, where the steam exits from the generation process.

Not all processes require the same temperature and pressure steam. This report bases all calculations on saturated dry 150 psig steam for process use. Information on the distribution of steam pressures in industrial processes, as shown in Chapter 2, supports this assumption. The additional energy required if saturated steam pressures exceed this value is relatively small. The energy necessary to raise one pound of water from 70°F to dry saturated steam at 150 psig in a 100% efficient boiler is:

\[ h_{13} = h_3 - h_1 = 1158 \text{ Btu/lbm} \quad (A.6) \]

where \( h_{ij} \) is the difference in specific enthalpy between points \( i \) and \( j \) in the flow sheet in Figure A.6 and where \( h_1 \) is the standard specific enthalpy for the water or steam at point \( i \). If the boiler was producing 300 psig dry saturated steam, the energy input required is:
Industrial Boiler Steam Supply
Temperature-Entropy Diagram

Figure A.7

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or a fuel energy input increase of only .6%. As the steam becomes superheated, this energy input difference does become larger—but Dow (1976, p.4) claims that 85% of the process steam requirement is below 400°F and not significantly superheated.

The boiler technologies for the generation of steam can be separated into two distinct classes:

1. Coal-fired boilers that are erected at the industrial site. These boilers can burn a wide range of fuels, and their designs can be adapted for a wide range of pressures.

2. Oil or natural gas burning package boilers that are mass-produced and shipped in one or only a few pieces to the industrial user. These designs, because of their close boiler tube spacing, must only use clean burning oil or natural gas. They are rarely used for high pressure steam generation.

Tables A.5 and A.6 list efficiencies and costs for field-erected and package boilers, respectively. In spite of the data from Doherty (ASME 75), most sources contend that package boilers have lower efficiencies than the field-erected class. In addition, the field-erected boilers typically have a 15-year or longer life while package boilers have a shorter life (Dow (1975a)).

Package boilers first became available in the late 1950s. Owing to their significantly lower capital costs, they replaced field-erected boilers as the primary industrial steam source. Environmental objections to coal-burning boilers hastened this switch to oil- and natural
<table>
<thead>
<tr>
<th>Typical Unifluid Bed boiler with Flue Gas Design</th>
<th>Stream Rate Bed, lb/hr</th>
<th>Capital Cost, $/MW</th>
<th>O&amp;M Cost, $10^-7/MW/hr</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>2,000</td>
<td>.95</td>
<td>.0177</td>
<td>3.94X10^-7</td>
<td>Dow (1975b)</td>
</tr>
<tr>
<td>1,000</td>
<td>.80</td>
<td>.0233</td>
<td>3.94X10^-7</td>
<td>&quot;</td>
</tr>
<tr>
<td>400</td>
<td>.80</td>
<td>.0280</td>
<td>5.5X10^-7</td>
<td>&quot;</td>
</tr>
<tr>
<td>100</td>
<td>.78</td>
<td>.0345</td>
<td>8.11X10^-7</td>
<td>&quot;</td>
</tr>
<tr>
<td>440</td>
<td>.88</td>
<td>.0238</td>
<td>1.6X10^-7</td>
<td>Dow (1975a)</td>
</tr>
<tr>
<td>2,000</td>
<td>.85</td>
<td>.0243</td>
<td>1.4X10^-7</td>
<td>Dw (1975b)</td>
</tr>
<tr>
<td>400</td>
<td>.85</td>
<td>.0268</td>
<td>5.2X10^-7</td>
<td>JCSS Assumption</td>
</tr>
</tbody>
</table>

Table A.5

Field-Fractured Coal-Fired Boilers "Typical"
<table>
<thead>
<tr>
<th>Design</th>
<th>Typical Unit Size</th>
<th>Steam Rate</th>
<th>Capital Cost</th>
<th>O&amp;M Cost</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil and Gas Fired Package Boiler</td>
<td>600 (4 units)</td>
<td>.88</td>
<td>.0107</td>
<td></td>
<td>M.C. Doherty</td>
</tr>
<tr>
<td></td>
<td>450 (3 units)</td>
<td>.88</td>
<td>.0115</td>
<td>.925x10^-7</td>
<td>ASME 75-IPWR-12</td>
</tr>
<tr>
<td></td>
<td>150 (1 unit)</td>
<td>.88</td>
<td>.0144</td>
<td></td>
<td>&quot;</td>
</tr>
<tr>
<td></td>
<td>400 (multiple units)</td>
<td>.80</td>
<td>.00558</td>
<td>.690x10^-7</td>
<td>Dow (1975a)</td>
</tr>
</tbody>
</table>

**Standard Design for Model BP**

- **Low Sulfur Oil or Gas Fired Package Boiler**
  - 150
  - .80
  - .0098
  - .81x10^-7
  - JGSM Assumption

*(varies with EP costs)*
gas-burning package boilers. Dow (1975a) and Magione and Petkovsch (ASME 1975) claim that the increases in fuel costs since 1972 have destroyed the cost advantage for package boilers. These conclusions on the effects of costs will be investigated in detail in Chapters 4 and 5. Since no data was found on the fluctuations of boiler capital costs over time, the field-erected boilers are assumed to follow the costs of coal-fired electric plants and package boilers the costs of oil-fired power plants.

A.2. JOINT GENERATION TECHNOLOGIES

Joint generation is not a new technology. Paper mills in the 1920s and 1930s often produced excess power and sold it to nearby towns. Babcock and Wilcox (1955, p. 10-22) cite the advantages of by-product power generation. Beeman (1955), in his book on industrial power systems, includes a chapter on by-product power.

This section first surveys the thermodynamics for the simplest category of joint generation plants—back-pressure generation. Next, Section 2.2.2 describes the more complex installations, giving examples of some larger plants. Finally, Section 2.2.3 discusses the alteration of advanced power generation technologies for joint generation. This section does not attempt a comprehensive discussion of the thermodynamics and technological alternatives for joint generation. For a more complete presentation, the reader is referred to Diamant (1970). This report limits itself to joint generation technologies centered around standard boilers or around advanced integrated gasifier/combined-cycle systems with the steam being used for industrial processes.
Mitchell (1975) and ThermoElectron (1976) contain analyses of joint generation using cooling water from diesel engines. United Technologies Corp. (1976) has suggested the use of fuel cells for joint generation. Industrial processes are not the only users of the steam from joint generation; the use of joint generation for district home and commercial space heating is discussed in Diamant (1970), Miller et al (1971), and Wakefield (1975). For an in-depth review of advanced coal-burning joint generation systems for apartment and commercial total energy systems, see Fraas, et al. (1976).

A.2.1 BACK-PRESSURE JOINT GENERATION

The simplest type of joint generation process is the back-pressure turbine arrangement shown in Figure A.8. This, like the steam-raising process, escapes the limitations imposed by the Carnot cycle. Return water from the industrial processes and new make-up feedwater are forced into the boiler, where the steam is raised to the pressures and temperatures appropriate for power generation. The steam expands in a turbine, generating power, and exits the turbine at the pressure desired for the process steam. The losses in back pressure joint generation occur through the flue gases at the boiler and the turbine-generation conversion inefficiencies. The right-hand columns in Figure A.2 simplistically illustrate the energy balances for this process; energy is added in the boiler to generate the high-pressure steam; the steam is expanded down to the energy level required for the process steam; at this point, the steam exits the plant to be used in the process. This contrasts with the power-only arrangement, where steam
Figure A.8: Back-Pressure Joint Generation Plant Flow Sheet

Diagram showing the flow of steam and water in a back-pressure joint generation plant.
with only slightly less energy exits from the turbine as waste.

Figure A.9 gives an alternate view of this transformation. The feedwater enters the system at Point 1. Between Points 1 and 2 it is raised to the boiler pressure by the boiler feed pump. If the pump was perfect, the 1-2 line would be vertical, indicating no change in entropy. Between Points 2 and 3, the boiler raises the fluid temperature and entropy at constant pressure through the change from water to steam. The steam expands in the turbine between Points 3 and 4; if the turbine was 100% efficient in converting the expansion of the steam to work, this line would be vertical. The steam exits at Point 4. The efficiency of the turbine determines the slope of the line between Points 3 and 4. The amount of power to be produced per unit of steam mass through the system determines the length of the line 3-4 by the temperature, entropy and enthalpy relationships for steam.

Stating this process in mathematical terms, the fuel and feedpump energy input is:

\[ F = \frac{M \ h_{13}}{\eta_b} \]  \hspace{1cm} (A.7)

where  
\( F \) = the energy input into the system in Btu/hr (mostly from the boiler since the feedpump is relatively efficient and the work required for pumping is small).
\( M \) = the water flow rate through the boiler in lbm/hr.
\( h_{13} \) = the enthalpy change of the water between points 1 and 3 in Btu/lbm, and
\( \eta_b \) = the thermal conversion efficiency of the boiler.
Temperature-Entropy Diagram

Back-Pressure Joint Generation Plant
Temperature-Entropy Diagram

Figure A.9
The electricity produced by the plant is:

\[
E = \frac{M \cdot \eta_t \cdot \eta_g (-h_{34})}{3.412 \times 10^6 \text{ Btu/MWhr}} \tag{A.8}
\]

where

- \( E \) = the power output from the generator in MW
- \( \eta_t \) = the efficiency of the turbine,
- \( \eta_g \) = the efficiency of the generator, and
- \( h_{34} \) = the enthalpy change of the water between Points 3 and 4 in Btu/lbm, i.e. across the turbine.

Since the temperature and pressure characteristics of the desired process steam are known, the entropy and enthalpy are also known. For a perfectly efficient turbine, the entropy of the boiler outlet equals that of the process steam; for an imperfect turbine, the relationship depends on the turbine efficiency and the enthalpy change across the turbine. Once the entropy and enthalpy of the boiler outlet steam is known, the temperature and pressure characteristics are determined.\(^{23}\)

For a given turbine efficiency, in a back pressure generation system, the boiler outlet steam conditions can be given solely as a function of the desired process steam characteristics and the enthalpy change across the turbine, \( h_{34} \).

Given the enthalpy of the feedwater \( (h_1) \), the process steam \( (h_4) \), and the drop across the turbine \( (h_{34}) \),

\[
h_3 = h_4 - h_{34} \tag{A.9}
\]

and

\[
h_{13} = h_3 - h_1 = h_4 - h_{34} - h_1 \tag{A.10}
\]
The new forms for the fuel consumption, electricity, and steam flow rate relationships are:

\[
F = M \cdot \frac{(h_4 - h_1 - h_{34})}{\eta_b} \quad \text{(A.11)}
\]

and

\[
E = M \cdot \eta_t \cdot \eta_g \cdot (-h_{34}) \quad \text{(A.12)}
\]

\[3.412 \times 10^6 \text{ Btu/MWhr}\]

where \(\eta_t, \eta_g, \eta_b, h_4, \) and \(h_1\) are given.

The non-linear relationships between boiler outlet steam conditions, assuming superheated conditions, will be left generally specified as \(^{24}\):

\[
T_3 = f (h_{34}; h_4, \eta_t) \quad \text{(A.13)}
\]

and

\[
P_3 = g (h_{34}; h_4, \eta_t) \quad \text{(A.14)}
\]

where \(T_3\) = the temperature of the boiler outlet steam in \(^\circ\text{R}\) and

\(P_3\) = the pressure of the boiler outlet steam in psig.

Metallurgical limitations provide temperature and pressure constraints upon the boiler outlet steam and, hence, upon \(h_{34}, M, E, \) and \(F.\) These physical relationships are combined with fuel and capital cost information in Chapter 2 to construct production possibility, isoquant, and isocost surfaces for a simple back pressure joint generation plant.

Provided that the industrial plant employing joint generation has fixed requirements for process steam and power, a back pressure plant is the simplest and most efficient joint generation plant. Table A.7
<table>
<thead>
<tr>
<th>Design</th>
<th>Typical Unit Size</th>
<th>Heat Rate 10^3 Btu/kwh</th>
<th>Steam Rate 10^3 Btu/kwh</th>
<th>Capital Cost $/KW</th>
<th>O&amp;M Cost mills/kwh</th>
<th>Availability</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Fired Boiler with Flue Gas Desulfurization providing Back-Pressure Power and Process Steam</td>
<td>20.95 MW: 450X10^3 lbm/hr</td>
<td>30,530</td>
<td>24,890</td>
<td>$678/KW</td>
<td>3.9</td>
<td></td>
<td>Doherty ASME 75-IPWR-12</td>
</tr>
<tr>
<td>&quot;</td>
<td>28.6 MW: 450X10^3 lbm/hr</td>
<td>23,220</td>
<td>18,230</td>
<td>$520/KW</td>
<td>2.9</td>
<td></td>
<td>&quot;</td>
</tr>
<tr>
<td>&quot;</td>
<td>9.5 MW: 150X10^3 lbm/hr</td>
<td>23,220</td>
<td>18,230</td>
<td>$713/KW</td>
<td>15.6</td>
<td></td>
<td>Scaled estimate from Doherty Dow (1975a)</td>
</tr>
<tr>
<td>&quot;</td>
<td>20 MW: 414X10^3 lbm/hr</td>
<td>35,520</td>
<td>23,990</td>
<td>$850/KW</td>
<td>15.6</td>
<td></td>
<td>Dow (1975a)</td>
</tr>
<tr>
<td>Coal Fired Boiler with F. G. D. ... Fluided Bed Coal Boiler, Back-pressure generation</td>
<td>7.25 MW: 150X10^3 lbm/hr</td>
<td>35,520</td>
<td>23,990</td>
<td>$1260/KW</td>
<td>1980+</td>
<td></td>
<td>Scaled estimate from Dow (1975a) Dow (1975b)</td>
</tr>
<tr>
<td>&quot;</td>
<td>18.5 MW: 400X10^3 lbm/hr</td>
<td>31,940</td>
<td>25,050</td>
<td>$973/KW</td>
<td>1980+</td>
<td></td>
<td>&quot;</td>
</tr>
<tr>
<td>&quot;</td>
<td>5 MW: 100X10^3 lbm/hr</td>
<td>31,000</td>
<td>23,170</td>
<td>$1180/KW</td>
<td>18.5</td>
<td></td>
<td>&quot;</td>
</tr>
<tr>
<td>Standard Design for Model JB (85% overall efficiency)</td>
<td>7.25 MW and 150X10^3 lbm/hr</td>
<td>32,250</td>
<td>24,000</td>
<td>$1000/KW</td>
<td>15.6</td>
<td>40%</td>
<td>JGSM Assumption</td>
</tr>
<tr>
<td>&quot;</td>
<td>150 psig saturated steam</td>
<td>(20.7 lbm)(3.18 X EC)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
presents the technology and cost survey for these plants. The heat rate for the joint generation plants is the ratio of fuel input to electrical energy output. These values appear high at first glance—remember they include the energy required to produce the process steam. The amount of steam output per unit of electrical output is given by the steam rate; this can be converted to pounds of steam per kilowatt-hour by dividing by 1158.7 Btu/lbm. The capital and operations costs, likewise, are based on the proportional power output for a given design. For example, a standard design back-pressure by-product power plant that generates one kilowatt would also produce 24,000 Btu of steam per hour (or 20.7 lbm/hr steam). The capital cost for the system would be $1,000; the unit would cost 15.6 mills/hr to operate, exclusive of fuel and capital costs.

A.2.2 BACK-PRESSURE/CONDENSING POWER JOINT GENERATION

If the industrial site requires flexibility in the operation of the joint generation plant, back-pressure joint generation becomes infeasible. A hybrid design combining back-pressure generation with a typical condensing power cycle often can provide the operational flexibility desired, and the design capacities for steam and power output can be tailored to the requirements of the specific plant. A vast number of alternative designs exist; Figure A.10 illustrates one of the simpler ones. The design capacities of the high pressure and low pressure steam turbines are specified for the desired long-term mix of process steam output and power generation. When process steam and low pressure turbine demands temporary exceed the capacity of steam flow
through the high pressure turbine, extra steam is shunted around the high pressure turbine—this is a waste of the available energy in this steam, but on a short-term operational basis this flexibility is valuable. If process steam demands fall below the high pressure turbine to the joint generation plant design allows the high pressure turbine to be larger; this means an overall increase in the power output per unit of process steam output.

Figure A.11 shows the thermodynamic cycle for this process. As in the back-pressure plant in Figure A.9, the process steam exits the cycle at Point 4. The dotted line in Figure A.11 illustrates the steam that passes into the low pressure steam turbine and then enters the condenser at Point 5. This condensate is added to the return and make-up water at Point 1, beginning the cycle again.

Two design extremes exist for these back-pressure joint generation plants with exhaust condensing power:

1. By-Product Power Plants—small plants with only a little extra condensing power. These plants are generally owned by the industrial user.

2. Dual-Purpose Power Plants—large utility plants, which only extract a small amount of process steam relative to the overall steam through the system.

Two standard designs are given in Table A.8 for the smaller "by-product power plants" along with the survey of several designs. The broad latitude of possible designs dictated the specification of two standard designs for this alternative. Table A.9 lists design alterna-
Back-Pressure with Exhaust Condensing
Joint Generation Plant Temperature-Entropy Diagram

Figure A.11
<table>
<thead>
<tr>
<th>Design</th>
<th>Typical Unit Size</th>
<th>Heat Rate</th>
<th>Steam Rate</th>
<th>Capital Cost</th>
<th>O&amp;M Cost</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal Fired By-product Power and Steam Plant with Incremental Condensing Power</td>
<td>25.49MW:  450X10^3lbm/hr</td>
<td>27,730</td>
<td>20,460</td>
<td>$680/KW</td>
<td>3.5</td>
<td>Doherty ASME 75-IPWR-12</td>
</tr>
<tr>
<td>&quot;</td>
<td>30MW:  414X10^3lbm/hr</td>
<td>27,010</td>
<td>15,990</td>
<td>$653/KW</td>
<td>12.8</td>
<td>Dow (1975a)</td>
</tr>
<tr>
<td>&quot;</td>
<td>40MW:  414X10^3lbm/hr</td>
<td>22,430</td>
<td>11,990</td>
<td>$511/KW</td>
<td>11.3</td>
<td>&quot;</td>
</tr>
</tbody>
</table>

**Standard Designs for Model**

| JI (69% efficiency) Can cycle with power system                      | 43.5MW:  450X10^3lbm/hr | 22,340    | 12,000     | $515/KW     | 12.8      | JGSM Assumption |
| JI (72% overall efficiency) Cannot be used as a power system cycling unit | 32.6MW and 450X10^3lbm/hr | 26,960    | 16,000     | $655/KW     | 11.3      | "            |

150 psig saturated steam
Table A.9

<table>
<thead>
<tr>
<th>Design</th>
<th>Typical Unit Size</th>
<th>Heat Rate</th>
<th>Steam Rate</th>
<th>Capital Cost</th>
<th>O&amp;M Cost</th>
<th>Availability</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cayuga Station of Public Service Indiana</td>
<td>1000 MWe: 225x10^3 lb/hr</td>
<td>13,730</td>
<td>3495</td>
<td>$377/KW</td>
<td>7.67</td>
<td>In service</td>
<td>Dow (1975a) and S.W. Shields &amp; D.O. Parish in Am. Power Conf. (1974)</td>
</tr>
<tr>
<td>Coal Fired Boiler Power Plant, Dual Purpose</td>
<td>663 MWe: 2000x10^3 lb/hr</td>
<td>11,688</td>
<td>3495</td>
<td>$377/KW</td>
<td>6.45</td>
<td>1975</td>
<td>Dow (1975a)</td>
</tr>
<tr>
<td>&quot;</td>
<td>&quot;</td>
<td>60 MWe: 1160x10^3 lb/hr</td>
<td>32,000</td>
<td>22400</td>
<td>$723/KW</td>
<td>36.8</td>
<td>1975</td>
</tr>
<tr>
<td>Coal Fired Fluidized Bed Power Plant, Dual Purpose</td>
<td>45 MWe: 1000x10^3 lb/hr</td>
<td>32,749</td>
<td>25749</td>
<td>$874/KW</td>
<td></td>
<td>1980+</td>
<td>&quot;</td>
</tr>
</tbody>
</table>

Standard Design for Model

| JC (54% overall efficiency) | 332 MWe & 12,700 | 3495 | $377/KW | 7.06 | 1975 | JGSM Assumption |

150 psig saturated steam
tives for utility-sized coal-fired "dual-purpose power plants", and Table A.10 specifies a number of nuclear-powered systems. Note that the steam rates drop along with the heat rates for these larger plants.

"By-product power plants" have been in operation since the 1920s. The "by-product power plant" common in industrial use is the design described in this section rather than the simpler back-pressure design because of the greater operational flexibility for these more complex systems. Babcock and Wilcox (1955), Diamant (1970), and Dow (1975a and b) give numerous examples of typical designs. Designs employing gas turbines are also common--these will be discussed in Section A.2.3.

The large "dual-purpose power plants" are less common. Two examples, however, are the proposed Consumers Power nuclear plant at Midland, Michigan, and the coal-fired Cayuga of Public Service Indiana. Both have been designed to simultaneously generate electric power and supply process steam to a single adjoining industrial site. Several sources have suggested the siting of multiple industrial plants together with one or more dual-purpose power plants. This arrangement is typically known as an industrial energy center.

The proposed design for the Midland plant of Consumers Power consists of two nuclear reactors. One unit is a typical pressurized water reactor with 816MW electrical output. The entire thermal output of 2452MW is directed toward the generation of this power, hence its efficiency is 33.3% (a typical heat rate for a nuclear plant, about 10,250 Btu/kwh). The other nuclear reactor has an identical thermal output but, after the steam has passed through the high pressure turbine, it
Table A.10

Dual Purpose Nuclear Plants "JN"

<table>
<thead>
<tr>
<th>Design</th>
<th>Typical Unit Size</th>
<th>Heat Rate MW and 10^3 lbm/hr</th>
<th>Steam Rate Btu/kwhr</th>
<th>Capital Cost $/kwhr</th>
<th>O&amp;M Cost mills/kwhr</th>
<th>Avail- able in</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dual Purpose LWR Nuclear Plant</td>
<td>650 MWe, 6000X10^3 lbm/hr</td>
<td>19,760</td>
<td>10,700</td>
<td>$666</td>
<td>4.40</td>
<td>1985</td>
<td>Dow (1975b)</td>
</tr>
<tr>
<td>Dual Purpose HTGR Nuclear Plant</td>
<td>443 MWe, 3100X10^3 lbm/hr</td>
<td>15,780</td>
<td>9,340</td>
<td>$514</td>
<td>4.70</td>
<td>1980</td>
<td>Dow (1975b)</td>
</tr>
<tr>
<td>Dual Purpose LWR Nuclear Plant</td>
<td>1200 MWe, 2000X10^3 lbm/hr</td>
<td>12,560</td>
<td>1,930</td>
<td>$541</td>
<td>7.76</td>
<td>1980</td>
<td>Dow (1975a)</td>
</tr>
</tbody>
</table>

Standard Design for Model

| JN Dual Purpose LWR Nuclear Plant (42.5% overall efficiency) | 1200 MWe and 2000X10^3 lbm/hr | 12,560 | 1,930 | $433 | 7.50 | limited JGSM Assumption 1975-85; unlimited after 1985 |

Note: 1.7 lbm \(\times\) 1.07 x EN per kwhr saturated steam
goes through a tertiary heat exchanger which supplies process steam to a nearby Dow chemical plant. This unit generates 491MW of electric power while simultaneously supplying 500,000 lb per hour of 655 psig saturated steam and 3,650,000 lb per hour of 170 psig steam at 370°F to the Dow plant. The tertiary heat exchanger is to guarantee no radiation is passed to the process steam. The overall efficiency of this plant is 77.5%. Note that the steam energy is drawn after the turbine and not through a separate reactor heat loop. If it was taken from a second heat loop through the reactor, the problem of scheduling the steam usage with the electric power generation would not exist. The thermodynamic advantages, though, would also disappear.

The Cayuga plant was originally built as a two boiler, coal-fired, 1025MW steam-turbine plant for the generation of power only. The full plant was first brought into service in June, 1972. In 1973, Inland Container Corporation first discussed with Public Service Indiana the possibility of Inland siting a new paper plant next to a power plant and purchasing process steam from the utility. The Cayuga plant could be safely modified to provide the Inland requirements of 0 to 225,000 lb per hour of process steam at 175 psig. This steam can be withdrawn after the high pressure turbine and before the reheat cycle from either of the two generation units at the plant. The steam pressure at this stage of the generation cycle is sufficient so that the generator can be at a 50% operating level and still provide the steam pressure that Inland requires. Condensate is not returned; Inland has built a plant to provide make-up water. The rate considerations between Public Ser-
vice Indiana and Inland are based on fuel costs, and incremental capital costs, and the loss of electrical capability because of the steam extraction from the existing cycle. These costs would have been less if the generation plant had been designed with the steam extraction in mind. Inland is billed on the basis of mass steam flow. The joint operation was expected to go into service during the spring of 1975; this author has received no additional information on the project.

Several major technological policy studies have explored the possibilities of the joint siting for industry and power plant facilities. Oak Ridge National Laboratories, in Miller, et al (1971) analyzed the potential for the coordinated planning of new towns and energy centers for the Department of Housing and Urban Development. Extraction of steam from light water nuclear reactors was proposed to provide district heating, domestic hot water, absorption air conditioning, and process steam. They concluded that the costs would be competitive with alternatives.

General Electric (1975) compared dispersed generation to generation concentrated in parks of 20 nuclear generation units or 24 fossil fuel units. This report also explored the opportunities for the co-location of industry. The primary discussion centered on the location of facilities to integrate the nuclear fuel cycle at a nuclear energy park. This is important for transportation cost reductions and security. The advantages of industrial co-location at concentrated energy parks center upon considerations of reliability. In a situation where only one reactor supplies the process steam, the industrial plant
would be forced to shut down if any outage occurs at the nuclear plant, an unacceptable situation for an industry. The multiple units at a large energy center provide the backup if one unit is forced out for unscheduled or scheduled maintenance. The difficulty is that a huge industrial complex is necessary for the benefits of co-location to be recovered. Few kraft paper mills have a capacity of more than 2,000 tons per day, but four such mills require steam equivalent to only a third of a typical nuclear plant's energy output. Here diseconomies of scale appear to have arisen—for effective conservation, a tremendous concentration of industrial activity would have to locate near parks that are also intended to be "secure."

The Nuclear Regulatory Commission has completed a feasibility study examining nuclear energy parks. Again, their primary purpose is the security of the nuclear fuel cycle. As reported in Smiley, et al. (1976), these would be large sanctuaries containing 10 to 40 reactors and, possibly, fuel enrichment and waste handling plants. The study concluded there was no compelling need or great advantage associated with such nuclear energy centers. As also suggested by the G.E. study, it appears unlikely that the potential for energy conservation through industrial co-location with these large energy centers could be fully utilized.

A.2.3 ADVANCED JOINT GENERATION SYSTEMS

The expected importance of combined-cycle systems as joint generation plants was the reason for the devotion of Section A.1.1.2 to a survey of this technology in power-only systems. This section surveys
the use of combined-cycle power plants as joint generation plants. Until the 1973 increases in oil prices and more recent natural gas shortages, natural gas and light distillate fuel combined-cycle plants were becoming increasingly popular as joint generation facilities. Now advanced oil and coal gasifiers integrated with combined-cycle plants offer a substitute—but not immediately. These advance systems will not be fully developed until the 1980s.

Because of the high prices or administrative curtailments of gas turbine fuels, this section develops full cost surveys only for the integrated gasifier/combined-cycle plants. Moreover, this survey of advanced joint generation technologies is not complete—for example, heat recovery from diesel power systems and process heat from fuel cells and HTGRs have been neglected. For a more comprehensive survey of new sources for process heat, see Dow (1975b). The Dow survey, however, neglects gasifier/combined-cycle plants and several small scale joint generation options.

The Energy Policy Project's fuel effectiveness study27 claimed that up to 79% efficiency can be achieved in combined-cycle joint generation plants. In the design described in their study, a gas turbine generator passes its exhaust gases into a heat recovery boiler. The heat recovery boiler acts as the steam generator for a back-pressure joint generation plant. According to their back-of-the-envelope calculation, industry could have provided 53% of the total U.S. power generation within industry that year. Their short analysis did not account for small size of many industrial operations, operations that
are too small for the economic generation of power.

A large number of by-product combined-cycle generation units have been installed as total energy systems. There were 383 such installations as of January 1971. They typically consisted of a natural gas reciprocating engine or gas turbine generating power with an exhaust gas heat recovery boiler providing steam for heating or absorption air conditioning. Eighty of these units were in manufacturing or process installations; the others were in apartment house complexes or in shopping centers. Significant problems have arisen with fuel supplies and maintenance at small installations, especially where trained personnel are scarce.

Southern California Edison has several units where power is purchased from an industry. When possible, these contracts have included provisions for the availability of power to meet SCE peak demands as well as a fee schedule for energy sales--SCE has paid about $35 per kilowatt for these capacity guarantees. At one heat-recovered gas turbine, SCE owns the turbine and sells the waste heat directly to an attached waste heat boiler, which is owned by the industrial client.

Dow Chemical Co. has been operating a facility consisting of two 50MW General Electric gas turbine generators, two Foster-Wheeler multipressure heat recovery boilers, and 55MW steam turbine. In addition, the facility provides 1,000,000 pounds of steam per hour at various operating temperatures and pressures. The combined cycle efficiency for the facility is more than 86%, 3% better than the design efficiency. The unit provides 25% of the electrical requirements of the
chemical plant, with the remainder being purchased from the local utility.

**Oil Gasifier/Combined-Cycle Joint Generation Plants.** Figure A.12 illustrates an advanced oil gasifier/combined-cycle power plant adapted to joint generation by the alterations of its steam turbine/condenser system to back-pressure generation. Table A.11 lists the expected characteristics of several such systems if their steam sections were converted in this fashion. The large steam output from the power plant-sized units necessitated the scaling down of the standard design so that it could be used at a greater number of sites. This scaling was based on a .85 economies-of-scale factor.\(^{31}\)

The projections of plant characteristics were based on the actual steam flows from design information in the cited sources. The capital costs reflect the reductions in power output and the equipment additions for the process steam system. Operations and maintenance costs are based on the JC O & M costs multiplied by the ratio of EO to EC O & M costs. As with the advanced power-only systems, these capital costs are assumed not to change in the 1975-2000 analysis.

**Coal Gasifier/Combined-Cycle Joint Generation Plants.** The designs for integrated coal gasifier/combined-cycle power plants also had their steam sections adapted to back-pressure joint generation. The steam consumption by the gasifier introduces an additional complication in the projection of the altered plant operation characteristics. Figure 2.13 shows a simplified flow sheet for such a system. Table A.12 describes the adaptations of the coal gasifier/combined-cycle
A Simplified Flow Sheet
Oil Gasifier/Combined-Cycle By-Product Power Plant
Employing Back-Pressure Generation
Figure A.12
Table A.11

<table>
<thead>
<tr>
<th>Design</th>
<th>Typical Unit Size</th>
<th>Heat Rate</th>
<th>Steam Rate</th>
<th>Capital Cost</th>
<th>O&amp;M Cost</th>
<th>Available in</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>GE Combined Cycle with Oil Gasifier</td>
<td>159 MW</td>
<td>14,500</td>
<td>5,680</td>
<td>$382</td>
<td>1975</td>
<td>D.J. Ahner and ASME 75-GT-73 and estimates of conversions.</td>
<td></td>
</tr>
<tr>
<td>United Aircraft 2200°F Combined Cycle with Texaco Oil Gasifier</td>
<td>690 MW</td>
<td>12,190</td>
<td>4,350</td>
<td>$294</td>
<td>1980</td>
<td>F.L. Robson et al. (1970) and conversion analysis.</td>
<td></td>
</tr>
<tr>
<td>United Aircraft 2800°F Combined Cycle with Texaco Oil Gasifier</td>
<td>723 MW</td>
<td>10,060</td>
<td>3,590</td>
<td>$270</td>
<td>1985</td>
<td>&quot;</td>
<td></td>
</tr>
<tr>
<td>United Aircraft 3100°F Combined Cycle with Texaco Oil Gasifier</td>
<td>782 MW</td>
<td>8,700</td>
<td>3,050</td>
<td>$256</td>
<td>1990's</td>
<td>&quot;</td>
<td></td>
</tr>
<tr>
<td>Combined Cycle with Low Btu Oil Gasifier</td>
<td>217 MW</td>
<td>12,020</td>
<td>5,000</td>
<td>$398</td>
<td>1980</td>
<td>Conversion analysis of EO.</td>
<td></td>
</tr>
<tr>
<td>Standard Design for Model JO</td>
<td>108 MW and 468X10^3 lbm/hr</td>
<td>12,020</td>
<td>5,000</td>
<td>$455</td>
<td>1980</td>
<td>JGSM Assumption (Scaled)</td>
<td></td>
</tr>
<tr>
<td>JO A 2200°F Combined Cycle with a Low Btu Oil Gasifier (70% overall efficiency)</td>
<td>150 psig saturated steam</td>
<td>4.3 lbm/kwhr</td>
<td>7.9</td>
<td>1980</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
A Simplified Flow Sheet
Coal Gasifier/Combined-Cycle By-Product Power Plant
Employing Back-Pressure Generation
Figure A.13
<table>
<thead>
<tr>
<th>Design</th>
<th>Typical Unit Size(10^3)lbm/hr</th>
<th>Heat Rate Btu/hr</th>
<th>Steam Rate Btu/hr</th>
<th>Capital Cost $/kW</th>
<th>O&amp;M Cost $/kWhr</th>
<th>Available in</th>
<th>Data Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>COGAS 2200°F Turbine Combined Cycle with Lurgi Gasifier</td>
<td>611 MW; 2,590X10^3 lbm/hr</td>
<td>14,430</td>
<td>4910</td>
<td>$463</td>
<td></td>
<td>1979</td>
<td>P.L. Roberts (1970) &amp; estimates of conversion to back-pressure generation</td>
</tr>
<tr>
<td>COGAS 2800°F Turbine Combined Cycle with Gasifier</td>
<td>672 MW; 2,240X10^3 lbm/hr</td>
<td>10,080</td>
<td>3860</td>
<td>$342</td>
<td></td>
<td>1985</td>
<td></td>
</tr>
<tr>
<td>COGAS 3100°F Turbine Combined Cycle with Texaco Gasifier</td>
<td>737 MW; 1,830X10^3 lbm/hr</td>
<td>8,660</td>
<td>2880</td>
<td>$315</td>
<td></td>
<td>1990's</td>
<td></td>
</tr>
<tr>
<td>GE 1800°F Turbine Combined Cycle with Lurgi Gasifier</td>
<td>383 MW; 814X10^3 lbm/hr</td>
<td>11,110</td>
<td>2460</td>
<td>$366</td>
<td></td>
<td>1980</td>
<td>D.J. Ahner &amp; W. A. Boothe, ASME 75-GT-73 &amp; estimates on conversion</td>
</tr>
<tr>
<td>GE 1800°F Turbine Combined Cycle with Lurgi Gasifier</td>
<td>728 MW; 1,200X10^3 lbm/hr</td>
<td>12,310</td>
<td>1910</td>
<td>$401</td>
<td></td>
<td>1980</td>
<td>D.J. Ahner et al. in Am. Power Conf. (1975) &amp; estimates on conversion</td>
</tr>
<tr>
<td>GE 2400°F Turbine Combined Cycle with Lurgi Gasifier</td>
<td>862 MW; 1,190X10^3 lbm/hr</td>
<td>10,380</td>
<td>1600</td>
<td>$350</td>
<td></td>
<td>1983+</td>
<td></td>
</tr>
<tr>
<td>GE 2800°F Turbine Combined Cycle with Lurgi Gasifier</td>
<td>406 MW; 1,250X10^3 lbm/hr</td>
<td>10,910</td>
<td>3570</td>
<td></td>
<td></td>
<td>1985</td>
<td>Kydd (1975) &amp; estimates on conversion</td>
</tr>
<tr>
<td>Advanced Combined Cycle with Advance Low-Btu Gasifier</td>
<td>662 MW; 2,060X10^3 lbm/hr</td>
<td>10,470</td>
<td>3600</td>
<td>$487</td>
<td>8.8</td>
<td>1985</td>
<td>Scaling of EA and conversion to back-pressure generation</td>
</tr>
<tr>
<td>Standard Design for Model JA (67% overall efficiency) 2 Advanced Combined Cycle Units with 8 Advanced Low Btu Gasifiers</td>
<td>165 MW and 10,470 3600 $599 8.8</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>JGSM Assumption</td>
</tr>
</tbody>
</table>

1. This table provides data for advanced combined cycle, coal-fired joint generation plants labeled "JA."
plant designs from Section A.1.1.2 to joint generation.

Similarly to the JO designs, the standard JA design has been scaled down by a .85 economies-of-scale factor to lower process steam output levels. The capital costs have been adjusted for the reductions in power output and the additional costs associated with the process steam system. The operation and maintenance cost estimate is the JC O & M cost times the ratio of EA to EC O & M costs. These estimates are all extremely rough—in the modeling effort in Chapter 5, the sensitivity of the results to variations in these capital and O & M costs will be explored. The capital costs were assumed not to change in the 1975-2000 analysis.

A.3 SUMMARY

Table A.13 summarizes the types of power and steam generation technologies that have been discussed in detail by this chapter. The modeling efforts in Chapters 4 and 5 will use the "standard designs" selected for each technology. The historical analysis of 1960 to 1972 will not incorporate the advanced technologies or the nuclear dual-purpose plant technology, JN. The modeling of the period from 1975 to 2000 in Chapter 5 uses all of these technologies.

No information was found on the variation of boiler and joint generation plant capital costs with time. The BF, JC, JI, JL, and JB technologies were assumed to follow the changes in coal-fired power plant capital costs; the BP capital costs follow those of the EP technology; and the JN costs change with the EN capital costs. The advanced power-only and joint generation system capital costs are
Table A.13
SUMMARY OF TECHNOLOGIES

**Power-Only Technologies**

<table>
<thead>
<tr>
<th>Code</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>A typical coal-fired steam-electric power plant</td>
</tr>
<tr>
<td>EP</td>
<td>A typical oil-fired steam-electric power plant</td>
</tr>
<tr>
<td>EN</td>
<td>A nuclear steam-electric power plant</td>
</tr>
<tr>
<td>EH</td>
<td>A typical hydroelectric power facility</td>
</tr>
</tbody>
</table>

**Advanced Power-Only Technologies**

<table>
<thead>
<tr>
<th>Code</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>EO</td>
<td>An integrated oil-gasifier/combined-cycle power plant</td>
</tr>
<tr>
<td>EA</td>
<td>An integrated coal-gasifier/combined-cycle power plant</td>
</tr>
</tbody>
</table>

**Steam Only Technologies**

<table>
<thead>
<tr>
<th>Code</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>BF</td>
<td>A field-erected coal-fired boiler</td>
</tr>
<tr>
<td>BP</td>
<td>A package oil-fired boiler</td>
</tr>
</tbody>
</table>

**Joint Generation Technologies**

<table>
<thead>
<tr>
<th>Code</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>JB</td>
<td>A back-pressure type by-product power plant</td>
</tr>
<tr>
<td>JI, JL</td>
<td>Coal-fired by-product power plants employing back-pressure with incremental condensing power</td>
</tr>
<tr>
<td>JC</td>
<td>A coal-fired dual-purpose power plant</td>
</tr>
<tr>
<td>JN</td>
<td>A nuclear dual-purpose power plant</td>
</tr>
</tbody>
</table>

**Advanced Joint Generation Technologies**

<table>
<thead>
<tr>
<th>Code</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>JO</td>
<td>An integrated oil-gasifier/combined-cycle power plant employing back-pressure generation in the steam section</td>
</tr>
<tr>
<td>JA</td>
<td>An integrated coal-gasifier/combined-cycle power plant employing back-pressure generation in the steam section</td>
</tr>
</tbody>
</table>
assumed to remain stable throughout the 1975–2000 period. Note that the oil gasifier systems will not be available until 1980, and the coal gasifier systems will not be available commercially until 1985.
Footnotes for Appendix A

1. From Olmsted (1975) and the annual surveys before this issue.

2. These are "first law" thermodynamic efficiencies. The Carnot cycle efficiency limits are based on the maximum temperature of heat entering the cycle and the minimum temperature at which heat is being rejected:

\[
\text{Maximum efficiency} = \eta = 1 - \frac{T_{\min}}{T_{\max}}
\]

where the temperatures are on an absolute scale. Metallurgical conditions limit \( T_{\max} \). See Keenan (1970) or Van Wylen and Sonntag (1973) for further explanations.

3. The numbers in the process flow sheets, such as in Figure A.1, correspond to the numbered points in the temperature-entropy diagrams, like in Figure A.3. Point 2, for example, represents the characteristics of the water entering the boiler.


6. Hoke et al. (ASME 74) and Smith et al. (ASME 74).

7. Robson (1970). These conclusions are supported by Armstrong (ASME 74). The systems available in 1970s will be referred to later as first generation; the ones in the 1980s as second generation; and the ones in the 1990s as third generation.

10. Weiss (ASME 73)
12. Patterson, op. cit.
13. Crouch, et al. (ASME 74)
15. Patterson, op. cit.
18. Excitement over low-Btu coal gasification is evidenced by editors of Electric Light and Power (August 1974) and Giramonte and Lessard (1975). The cost problem with low-Btu gasification for regular boilers is described by editors of Electric Light and Power (March 1975). Comparative analyses of low-Btu coal gasification for boilers and combined-cycle plants are in Kentucky University (1975) and Tennessee Valley Authority (1975). Some gasification processes, such as described in Trilling (ASME 74), cannot be used with gas turbinced because of corrosives in the gas stream. See Giramonti and Lessard (1975) for a brief comparison of several advanced electric power systems; they focus on descriptions of coal gasifier/combined-cycle plants and one type of HTGR.


21. In addition to Dow (1975a), see Buffington (1975) on the comparative costs, fuels, and sizes for package boilers.

22. Other recent technical and engineering cost discussions on in-plant electrical generation include Doherty (ASME 75), Kovacik (ASME 75), Meckler (1976), O'Keefe (1975), Papamancos (1975), and Mangione and Detkovseh (ASME 75)

23. These relationships are tabulated in Keenan, et al. (1969)

24. Note that there is a fixed relationship between temperature and pressure for any given $h_3$, $h_4$, and $\eta_t$ in a back-pressure system.


29. W. Schmus, Southern California Edison, personal communication, July, 1974

250
30. Zanyk (ASME 74)

31. This .85 economies-of-scale factor was developed from the comparative unit size and cost information in Patterson, op. cit.
Appendix B

INCORPORATING COGENERATION PLANTS INTO POWER SYSTEMS OPERATION AND CAPACITY PLANNING

This appendix suggests techniques for managing the maintenance scheduling, unit commitment, dispatch, and capacity expansion of cogeneration facilities connected to a power system. It also describes one utility's approach for coordinating industrial cogeneration plants with the power system operations and planning. The first section presents an overview of these issues. The second section uses a Booth-Baleriaux probabilistic simulation of power system operating costs to estimate the value of different cogeneration plant types that simultaneously supply the power system and an isolated steam load.

B.1 OVERVIEW OF THE PROBLEM AREAS

This section reviews the methods used by one utility for coordinating cogeneration plants with its power system and suggests extensions to current modeling techniques so that they encorporate cogeneration units. Peschon et al. (1977) survey the more general problem of evaluating dispersed generating technologies in power systems.

B.1.1 PLANT PROTECTION AND CONTROL

The connection of an industrial cogeneration plant to a power system poses no unusual technical problems at the plant level. Diamant (1970, Chapter 4) describes a number of governor systems for the control of plants that are operated in isolation from the public power system and in parallel with the public supply. Special controls on power
exports from the industrial plant to the power system would be needed to conform with any special contracts. Precautions must be taken to protect the utility's and the industrial firms' equipment in the event their systems become disconnected. In addition, Diamant (1970, p. 152) notes:

The major danger occurs if a public supply system circuit-breaker, remote from the factory, trips leaving the privately owned generation plant connected to an isolated network. It is essential to ensure that the public supply breaker in the factory trips immediately, to prevent the possibility of the public supply being reconnected out of phase with the privately owned plant. Depending upon the circumstances this is achieved by a reverse power relay, an overload relay or a rate of change of frequency relay fitted on the public supply connection at the plant.

If dispersed cogeneration capacity is to be employed for reducing transmission costs, more elaborate control procedures for such situations must be implemented.

B.1.2 SYSTEM STABILITY

As noted by Dow (1975a, p.68), system stability problems can be caused by the addition of cogeneration plants only if their development occurs rapidly and in an unanticipated fashion. In general, cogeneration plants will be closer to the loads; numerous small generators near the loads should increase the transient and dynamic stability of the system except in special cases. For example, if a large load is connected by weak transmission lines to a large, distant generating unit, a small cogeneration plant at the load may act as a destabilizing influence in the event of a fault. This type of problem, however, can be corrected in the design of governors for the cogeneration plant.
B.1.3 SYSTEM OPERATION

The planning of power system operation in light of economic, environmental, and reliability goals is usually decomposed into three time stages: 

- Maintenance Scheduling, where the planned maintenance of all plants and the refueling of nuclear units is studied over a horizon of one season to several years long. 

- Unit Commitment, where the startup and shutdown of all plants is scheduled over a one day to one week horizon. 

- Dispatch, where the operation of units is determined on a time interval of less than one hour.

To this author's knowledge, no cogeneration plants except large dual-purpose units have been formally included within power system operation models. It appears that cogeneration units are maintained, committed, and dispatched on a heuristic basis.

In one utility that pays cogenerators exporting electricity into the power system for both the energy and capacity provided, the utility manages the maintenance scheduling of the cogeneration units through a coordinator at the individual factories. As a part of the capacity aspects of the purchase agreements, the "unit commitment" is determined by a requirement to run from 9 A.M. to 6 P.M. during a minimum number of summer days in order to receive the capacity payment. As long as the plants meet this peak schedule, they can be dispatched at the discretion of the industrial firm; this utility will soon offer energy purchase rates varying with the time of day. The total capacity of the
units is currently so small with respect to system size it appears that the explicit inclusion of these plants in any operations model is not yet crucial.

If a large amount of cogeneration develops in an area, the handcrafted methods of operating cogeneration plants in coordination with the power system could probably be improved upon by the incorporation of these plant types in formal models. Three approaches for including cogeneration in such models are:

- **Treat the plants individually.** This is possible with the large dual-purpose cogeneration plant types, but it would impose a huge computational burden if a large number of small plants was explicitly included.

- **Aggregate similar plant types with similar steam loads.** This assumes the operation of the plants is still primarily under the utility's control and identical operating orders are given to each group.

- **Specify the cogeneration as a supply source indirectly controlled by purchase rates.** This is similar to treating cogeneration as a "negative demand". The production under different time-of-day energy purchasing rates or capacity credits (perhaps communicated to the plants on a real time basis) would be less certain than under the direct control strategies. This method could beneficially employ the process-based load forecasting methodology developed in Woodward (1975).

The Dow(1975a) report speculates that utilities would prefer direct
control, offering only "dump energy" rates if industrial operators retain the right to control the facility. The practices of the utility cited above show this is not necessarily the case: they do employ indirect control through capacity and energy charges varying with the time-of-day and season.

The special cost characteristics of cogeneration plants affect the specification of operating costs in the models. Regular power plant operating costs depend only on the rate of power output. For cogeneration units, costs are a function of both power and steam output rates. As implied the ex ante cost function in Chapter 2 and the operating cost function in Wakefield (1975), cogeneration operating cost functions have unusual shapes that complicate the optimization problem: the cost of increasing both steam and electricity output is often no higher than increasing only one of the outputs.

Wakefield (1975) has formulated a deterministic dynamic programming model for the annual scheduling of hydroelectric and thermal units where the only thermal plant is a district-heating cogeneration plant. Since it treats the cogeneration unit explicitly, it follows the first approach stated above. Wakefield's examples show that the scheduling of the system is influenced by variations in the steam load as well as the usual variations in electricity load. The model is used to investigate the value of a total energy cogeneration plant in a utility system.

Since some types of cogeneration units have high levels of NOX emission, and since they are typically sited closer to population centers than central generating units, the environmental-economic operations
models described in the Schwegge, Gruhl, and Ruane papers in U.S. Energy Research and Development Administration (1975) may be the best approach with which to explore operating policies for cogeneration plants. The utilities, either through the cogeneration power purchasing rates or direct operating controls on different plant types depending on their costs and emissions, would then be influencing the environmental as well as economic operation of industrial steam supplies.

B.1.4 CAPACITY EXPANSION PLANNING

This section comments on approaches for including cogenerating plants in both generation and combined generation and transmission planning.

Generation Capacity Planning In modifying current generation capacity expansion planning methods, the same three approaches for handling cogeneration plants in systems operations can be employed: treat plants explicitly; aggregate similar plant types into groups; and specify cogeneration capacity development as "negative demand," forecast by techniques similar to those used for load forecasting. Since cogeneration facilities have much shorter lead times than regular electricity generating units, industrial proposals for such plants will typically not be available by the time utilities must commit themselves to large-scale coal or nuclear plants. The decision to forego the large plants must then be made on the basis of the forecast cogeneration development rather than on plant proposals in hand. Shorter term decisions, such as whether or not to build combustion turbine capacity,
can be made with specific information on industrial plans for cogeneration.

Since little historical data exist on the influence of complex cogeneration rates upon its capacity development, methods for forecasting anticipated cogeneration under alternative conditions will have to be based on a process approach. The attractiveness of cogeneration to different industries must probably be treated in a disaggregate fashion, with the special technological, financial, and institutional problems of each industry being examined separately. The key problems are the uncertainty in the future level of cogeneration development within an area and the correlation of this development with other factors that affect the utility's costs, such as the price of oil or the relationship between utility sales to industry and the purchase of cogenerated power by the utility.

A sub-problem within the capacity expansion problem is the estimation of annual operating costs for a utility with cogeneration plants. First, the optimal operating policies for the plants must be determined. Second, the comparison of operating and capital costs for the different cases determines the value of one capacity expansion scenario over another. Two approaches have been used for estimating annual operating costs for power systems: deterministic methods, and stochastic methods, which explicitly allow for plant forced outages. The stochastic methods have proved to be more accurate; the deterministic methods underestimate the operating times of the units last in the loading order.

This author is aware of only two capacity expansion model formulations that incorporate cogeneration; both use the deterministic operating cost
simulation methods. The study by Wakefield (1975) uses a dynamic programming operating cost model with scheduling optimized on a coarse grid to estimate the value of one district-heating cogeneration plant with respect to the installation of a regular electricity-only generation plant and separate heating for the downtown area buildings. Lenton has developed project sequencing model for electricity and water supply in Saudi Arabia; water can be obtained from groundwater, single-purpose, or cogenerating dual-purpose plants. The dual-purpose plants are assumed to be base-loaded, and operating costs are calculated deterministically. Since water can be stored inexpensively, back-up systems are not required in the event of a plant forced outage; this factor makes the formulation inadequate for the analysis of industrial cogeneration since most industrial facilities require a very reliable steam supply.

Ruane (1976) has suggested the Booth-Baleriaux approach for calculating the influence of a cogeneration plant upon a power system because of the potential importance of the exact load shape, the plant's outage rate, and the performance of the rest of the power system. Section B.2 implements this suggestion.

As was noted in the comments on system operation, environmental factors may play an important role in the operating policies of urban cogeneration plants. The capacity expansion models incorporating cogeneration would therefore benefit from the economic-environmental approach to generation capacity expansion planning first suggested in Farrar and Woodruff (1973) and recently surveyed by Ruane et al. 13
Combined Generation and Transmission Planning

Often cogeneration plant capital costs are credited about $50 to $100/kWh for distribution and transmission capacity savings when their benefits are calculated. Initial calculations cited in Peschon et al. (1976) indicate that the cost savings associated with effects arising from transmission systems characteristics may be much higher in certain circumstances: in a rural system with "weak" transmission, a kilowatt of cogeneration capacity sited at the load could replace 2.5 kilowatts of remotely-sited central generation capacity and achieve the same level of reliability at the loads. The dispersed generation is more effective since it protects the loads against transmission as well as generation outages. This type of calculation, if it proves feasible for large-scale systems, could provide valuable information during combined transmission and generation capacity planning of systems with potential cogeneration capacity at load centers.

B.1.5 CORPORATE AND REGULATORY PLANNING

If a utility sets its power purchasing rates so that a large amount of industrial cogenerating capacity develops, the utility's oil-fired plants may have substantially reduced capacity factors in a system with slow load growth owing to the switching of industrial loads to cogeneration. Since rates are determined from the rate base, which includes the unused oil-fired plants, the average electricity sales prices may rise -- encouraging even more cogeneration. Potential problems such as this necessitate corporate financial modeling for the setting
of cogenerated power purchasing rates before promoting cogeneration, and for the consideration of contingencies like the one noted above. Since such rates are now actively being discussed in the regulatory process, the regulatory agencies could also utilize these tools.

B.2 A BOOTH-BALERIAUX SIMULATION OF A COGENERATION PLANT'S INFLUENCE ON A POWER SYSTEMS'S OPERATING COSTS

This section estimates the value of the typical cogeneration plant designs described in Appendix A within a "scaled down" version of an EPRI/Power Technologies Inc. (1977) synthetic utility system.

B.2.1 PROBLEM FORMULATION

The combined steam and power costs for the system with and without a cogeneration plant are estimated by the following algorithm:

1) Select a cogeneration plant design.

2) Set the steam demand rate for this case according to the steam output rate and the typical capacity for the given cogeneration plant design; it is assumed that this demand must always be met and that the boilers are 100% available.

3) Calculate the cost of operating the power system without a cogeneration plant by using capacity factors derived from the single increment probabilistic simulation algorithm described by Finger (1975, pp.10-18). The electric energy load not met is valued at the same cost as the highest regular generation plant's unit costs. Steam costs are calculated assuming the steam load determined in step (2) is served entirely by boilers.
4) Determine the optimal loading of the given cogeneration plant, which is serving both the steam load and the power system; this optimization is accomplished by searching over the merit loading orders. The plant is added to the system; it does not replace any other capacity. When the cogeneration plant is either unavailable or not dispatched, the steam load is served by the same type of boiler as in step (3).

5) The difference between the total boiler and plant operating costs in steps (3) and (4) is the reduction in combined steam and power sector costs because of the added cogeneration capacity. This procedure and the single increment Booth-Baleriaux algorithm were implemented in an APL program, which is available from the author upon request.

Table B.1 lists the types of cogeneration plants tested. They were assumed to have plant availabilities similar to regular power plants of the same size; they are otherwise identical to the designs in Appendix A. Oil burning plants were assumed to have half of the O&M costs of similar coal units. The availabilities given in Power Technologies, Inc. (1977), henceforth PTI, are used to determine the forced outage rates since the algorithm, as implemented, does not allow for scheduled maintenance outages. The base case power system without the cogeneration plant is the "Scaled Down Scenario D" from PTI. To speed up the computational process, the large numbers of similar small plants were grouped as an equivalent blocks of 100% available capacity; the size of each block is the total capacity of the block times the
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Plant Type and Fuel</th>
<th>Capacity (MW)</th>
<th>Availability</th>
<th>O&amp;M Cost (mills/KWhr)</th>
<th>Heat Rate (Btu fuel/KWhr)</th>
<th>Steam Rate (Btu 150 psig steam/KWhr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>JB</td>
<td>Back-pressure cogeneration only</td>
<td>7.25</td>
<td>90.9%</td>
<td>15.6</td>
<td>32,250</td>
<td>24,000</td>
</tr>
<tr>
<td>JBO</td>
<td>A JB plant burning oil</td>
<td>7.25</td>
<td>90.9</td>
<td>7.8</td>
<td>32,250</td>
<td>24,000</td>
</tr>
<tr>
<td>JL</td>
<td>A large back-pressure 32.6 plant with some additional condensing power</td>
<td>32.6</td>
<td>90.9</td>
<td>12.8</td>
<td>26,960</td>
<td>16,000</td>
</tr>
<tr>
<td>JLO</td>
<td>A JL plant burning oil</td>
<td>32.6</td>
<td>90.9</td>
<td>6.4</td>
<td>26,960</td>
<td>16,000</td>
</tr>
<tr>
<td>JI</td>
<td>A large back-pressure 43.5 plant with a large condensing power section</td>
<td>43.5</td>
<td>90.9</td>
<td>11.3</td>
<td>22,340</td>
<td>12,000</td>
</tr>
<tr>
<td>JIO</td>
<td>A JI plant burning oil</td>
<td>43.5</td>
<td>90.9</td>
<td>5.65</td>
<td>22,340</td>
<td>12,000</td>
</tr>
<tr>
<td>JC</td>
<td>Dual-Purpose Coal Plant</td>
<td>332</td>
<td>76.2</td>
<td>7.06</td>
<td>12,700</td>
<td>3,495</td>
</tr>
<tr>
<td>JN</td>
<td>Dual-Purpose Nuclear Plant</td>
<td>1200</td>
<td>73.6</td>
<td>7.50</td>
<td>12,560</td>
<td>1,930</td>
</tr>
</tbody>
</table>
the given plant type's availability. Table B.2 lists the plants according to their loading order. When the search is made for the optimal loading of the cogeneration plant, the order from Table B.2 is not changed; the cogeneration plant is positioned between these plants. The heat rates used are the average 100% output heat rates.

Table B.3 presents an approximation of the annual load curve for the PTI Scenario D with a 23% reserve margin on total (not equivalent) capacity; the loss of load probability is within the correct magnitude for this type of system. This LOLP decreases slightly with the addition of the cogeneration capacity; as noted above, this charge is accounted for by the valuation of the unmet electric energy load at the gas turbine plants' unit costs.

Table B.4 describes the boiler technologies, and Table B.5 lists the assumed fuel prices. Since, for some designs, cogeneration units should be lower in the loading order than nuclear units, and since the nuclear capacity in the base case system always runs, a system where the order of nuclear and cogeneration units can be compared is needed: Table B.6 lists a "nuclear system" where the two Coal I units are replaced by a single nuclear unit. At some times, the system load is low enough so that the output of this third ranking nuclear plant must be reduced. This allows the order of a cogeneration unit and the third nuclear unit to be switched for the purpose of comparing their relative merit order.
<table>
<thead>
<tr>
<th>Plant Loading Order</th>
<th>Plant Type and Fuel</th>
<th>Equivalent Capacity (MW)</th>
<th>Availability</th>
<th>O&amp;M Cost (mills/KWhr)</th>
<th>Heat Rate (Btu/KWhr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Nuclear</td>
<td>1200</td>
<td>73.6</td>
<td>2.0</td>
<td>10,400</td>
</tr>
<tr>
<td>2</td>
<td>Nuclear</td>
<td>1200</td>
<td>73.6</td>
<td>2.0</td>
<td>10,400</td>
</tr>
<tr>
<td>3</td>
<td>Coal I</td>
<td>600</td>
<td>69.3</td>
<td>2.0</td>
<td>8,900</td>
</tr>
<tr>
<td>4</td>
<td>Coal I</td>
<td>600</td>
<td>69.3</td>
<td>2.0</td>
<td>8,900</td>
</tr>
<tr>
<td>5</td>
<td>Coal II</td>
<td>400</td>
<td>76.2</td>
<td>2.0</td>
<td>9,000</td>
</tr>
<tr>
<td>6</td>
<td>Coal II</td>
<td>400</td>
<td>76.2</td>
<td>2.0</td>
<td>9,000</td>
</tr>
<tr>
<td>7</td>
<td>A group of 8 200 MW coal units each with 83.5% availability</td>
<td>1336</td>
<td>100</td>
<td>2.0</td>
<td>9,500</td>
</tr>
<tr>
<td>8</td>
<td>Oil I</td>
<td>800</td>
<td>65.8</td>
<td>1.0</td>
<td>9,100</td>
</tr>
<tr>
<td>9</td>
<td>Oil II</td>
<td>400</td>
<td>76.2</td>
<td>1.0</td>
<td>9,400</td>
</tr>
<tr>
<td>10</td>
<td>A group of 7 200 MW oil units each with 83.5% availability</td>
<td>1169</td>
<td>100</td>
<td>1.0</td>
<td>9,900</td>
</tr>
<tr>
<td>11</td>
<td>A group of 29 50 MW combustion turbines each with 72.3% availability, burning low-sulfur oil</td>
<td>1048</td>
<td>100</td>
<td>1.0</td>
<td>15,000</td>
</tr>
</tbody>
</table>

Note the grouping of small units for computational reasons.
Table B.3

Assumed Load Characteristics

<table>
<thead>
<tr>
<th>Load Curve</th>
<th>Load (MW)</th>
<th>Fraction of Year at Given Load</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3268</td>
<td>5%</td>
</tr>
<tr>
<td></td>
<td>4085</td>
<td>30%</td>
</tr>
<tr>
<td></td>
<td>5106</td>
<td>30%</td>
</tr>
<tr>
<td></td>
<td>6332</td>
<td>30%</td>
</tr>
<tr>
<td></td>
<td>8170</td>
<td>5%</td>
</tr>
</tbody>
</table>

Load Factor 64%

Reserve Margin
- 23% on Scale Down System
- 12% on Modified System with Grouping of Small Units

Loss of Load Probability
- 0.68% for Base Case
- (2.5 days/year)

### Table B.4  
**Boiler Costs**

<table>
<thead>
<tr>
<th>Boiler Type and Fuel</th>
<th>Efficiency</th>
<th>O&amp;M Costs ($/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Field-erected coal-fired</td>
<td>85%</td>
<td>$ .60</td>
</tr>
<tr>
<td>Package, low-sulfur oil-fired</td>
<td>80%</td>
<td>$ .081</td>
</tr>
</tbody>
</table>

### Table B.5  
**Fuel Prices**

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Price ($/MMBtu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>$.32</td>
</tr>
<tr>
<td>Coal</td>
<td>.88</td>
</tr>
<tr>
<td>Oil</td>
<td>1.80</td>
</tr>
<tr>
<td>Low sulfur oil</td>
<td>2.07</td>
</tr>
</tbody>
</table>
Table B.6

Nuclear System

<table>
<thead>
<tr>
<th>Plant Loading Order</th>
<th>Plant Type</th>
<th>Equivalent Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Nuclear</td>
<td>1200</td>
</tr>
<tr>
<td>2</td>
<td>Nuclear</td>
<td>1200</td>
</tr>
<tr>
<td>3</td>
<td>Nuclear</td>
<td>1200</td>
</tr>
<tr>
<td>4</td>
<td>Coal II</td>
<td>400</td>
</tr>
<tr>
<td>5</td>
<td>Coal II</td>
<td>400</td>
</tr>
<tr>
<td>6</td>
<td>Group of 8 small coal units</td>
<td>1336</td>
</tr>
<tr>
<td>7</td>
<td>Oil I</td>
<td>800</td>
</tr>
<tr>
<td>8</td>
<td>Oil II</td>
<td>400</td>
</tr>
<tr>
<td>9</td>
<td>Group of 7 small oil units</td>
<td>1169</td>
</tr>
<tr>
<td>10</td>
<td>Group of 29 Combustion Turbines</td>
<td>1048</td>
</tr>
</tbody>
</table>

Loss of Load Probability for this System Without a Cogeneration Plant: 0.70% or 2.6 days/year
B.2.2 RESULTS

The Base and Extra Nuclear Cases Table B.7 presents the results of the analysis of cogeneration plants' value in the base case power system and the nuclear power system. It lists the optimal loading order for each plant in the two systems and the capacity's value in total and per unit of the steam demand the plant serves (not per unit of its total steam output). Although the cases are not shown, any oil-fired cogeneration unit that can be backed-up by a coal boiler ranks just before combustion turbines in the loading order.

The simple back-pressure cogeneration designs, surprisingly, are dispatched before regular nuclear units. For the other designs, the loading order depends on the plant fuel and the back-up boiler fuel. For the large dual-purpose designs JC and JN, their relatively low steam/power ratio makes them very similar to regular electricity generation units; their steam and heat rate must be derived more carefully before they can be compared to the electricity-only designs used in this analysis. Their higher value per unit of steam demand reflects their high electricity output replacing oil-fired electricity generation.

Lower JB Plant Availability Lowering a plant's availability does not effect its optimal loading order, but it does reduce its benefits. Reducing the availability of the JB plant by 10% to 81.8% reduces its total benefits in the base case system by 10%.

Reduced O&M Costs for JB, JL, and JI Plants As in Chapters 4 and 5, reducing the O&M costs for the by-product type of cogeneration plant influences the JGSM results. Cutting the per unit O&M costs to 25% of 269
### Table B.7

**Reductions in Combined Electricity and Steam Costs Through the Addition of a Cogeneration Plant**

<table>
<thead>
<tr>
<th>Cogeneration Plant Type</th>
<th>Assumed Steam Demand Rate</th>
<th>Original Steam Supply</th>
<th>BASE CASE SYSTEM</th>
<th>NUCLEAR SYSTEM</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Optimal Loading</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Order</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>(Refer to Table B.2)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Total Savings Steam ($/hr)</td>
<td>Demand</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>$/MMBtu/hr</td>
<td></td>
</tr>
<tr>
<td>JB (same as above)</td>
<td>Coal</td>
<td>Before Coal (&lt;3)</td>
<td>88</td>
<td>.50</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;3</td>
<td>251</td>
<td>1.44</td>
</tr>
<tr>
<td></td>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Before Nuclear Coal (&lt;3)</td>
<td>84</td>
<td>.48</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;3</td>
<td>248</td>
<td>1.43</td>
</tr>
<tr>
<td>JBO (same as above)</td>
<td>Oil</td>
<td>&lt;3</td>
<td>107</td>
<td>.61</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JL (same as above)</td>
<td>Coal</td>
<td>&lt;3</td>
<td>270</td>
<td>.52</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;3</td>
<td>759</td>
<td>1.46</td>
</tr>
<tr>
<td></td>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Between Nuclear &amp; Coal (3.5)</td>
<td>260</td>
<td>.50</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;3</td>
<td>748</td>
<td>1.43</td>
</tr>
<tr>
<td>JLO (same as above)</td>
<td>Oil</td>
<td>Between Oil &amp; Coal (7.5)</td>
<td>205</td>
<td>.39</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JI (same as above)</td>
<td>Coal</td>
<td></td>
<td>6.5</td>
<td>231</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;3</td>
<td>677</td>
<td>1.30</td>
</tr>
<tr>
<td></td>
<td>Oil</td>
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<td></td>
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</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>6.5</td>
<td>NC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>6.5</td>
<td>NC</td>
</tr>
<tr>
<td>J10 (same as above)</td>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>6.5</td>
<td>NC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>6.5</td>
<td>NC</td>
</tr>
<tr>
<td>JC (1160 MMBtu/hr)</td>
<td>Coal</td>
<td>7.5</td>
<td>1457</td>
<td>1.26</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;3</td>
<td>2144</td>
<td>1.85</td>
</tr>
<tr>
<td></td>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>6.5</td>
<td>NC</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3.5</td>
<td>NC</td>
</tr>
<tr>
<td>JN (2316 MMBtu/hr)</td>
<td>Coal</td>
<td>&lt;3</td>
<td>6579</td>
<td>2.84</td>
</tr>
<tr>
<td></td>
<td></td>
<td>&lt;3</td>
<td>8327</td>
<td>3.60</td>
</tr>
<tr>
<td></td>
<td>Oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3.5</td>
<td>6352</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>3.5</td>
<td>7942</td>
</tr>
</tbody>
</table>

**NC =** Not calculated.
their base values likewise changes the optimal loading order of the JI and JL plants with coal-fired back-up boilers; they are then loaded before nuclear units. JLO and JIO units with oil-fired back-up are loaded between nuclear and coal. In the JI plant case, its capacity factor increases from 54% to 90.9%.

The Effect of 200 Miles of Transmission Costs and Losses

Chapter 2 shows significant monopolistic market power exists in electricity generation markets around some urban areas; this sensitivity case studies the effect of transmitting the cogenerated power to a system 200 miles distant. This is assumed to cost 2 mills/kWh and cause 8% line losses in the transmitted power. This changes the loading order for the JB and JL plants with coal-fired back-up boilers; JB moves to between coal and nuclear while JL is put between oil and coal units. The capacity factor on the JL unit is cut by about 60% in both the nuclear and base case systems. In the JL plant case, the benefits from the plant drop by 25% with coal-fired back-up and by 10% with oil-fired back-up boilers.

B.3 CONCLUSIONS

This section has demonstrated the lack of formal procedures for coordinating the operation and expansion of cogeneration as a part of a power system. Given the greater role forecast nationally for cogeneration, there is a need for the development of these methods.

The investigation of a cogeneration plant's influence on combined power and steam costs showed the importance and sensitivity of the
scheduling to a variety of factors. The calculations were made in a single increment method: a plant's heat rate is assumed constant throughout its operating range. Cogeneration plants, however, have significantly different heat rates for different power and steam output rates; the multiple increment algorithm\textsuperscript{16} needs to be extended to treat this special design characteristic explicitly.
Footnotes for Appendix B

1. F.C. Schweppe, personal communications (April 1976 and May 1978). A comment by Stevenson (1975, pg. 367) suggests that a concentration of plants based on reciprocating engines, such as diesel cogeneration plants, could cause synchronism problems through hunting resulting from periodic variations in the prime mover's torque.

2. Schweppe (1976)

3. See Gruhl (April 1973) for the survey on maintenance or production scheduling with economic, security, and environmental objectives.


8. Thermo Electron (1976, p. 6-48) indicates this could occur in some areas, especially the West South Central census region.

9. Gruhl, Schweppe, and Ruane, op cit., note 1% improvements have been obtained through the use of computerized unit commitment models -- such small percentages often translate into large dollar savings.


12. Introduced to the U.S. by Booth (1972), varying derivations are described in Deaton (1973) and Finger (1975). Bloom (1977) suggests a method for directly including the technique in a non-linear optimal capacity planning model.

14 The calculation method is described in Dersin (1976).

15 Utility corporate planning models are surveyed briefly in Knight et al (1974).

16 Described in Finger (1975, p.18).
Appendix C

COST AND ENERGY CONVERSION FACTORS

Energy

1 GW-yr = 8.76 X 10^9 kwhr
    = 0.0299 q

1 GW = 10^6 kw
    = 0.0299 q/yr
    = 2946 Mlbm/hr standard steam

1 q = 10^{15} Btu
    = 1.64 X 10^8 bbl oil
    = 33.44 GW-yr
    = 10^{12} M Btu
    = 10^9 MM Btu

1 q/yr = 449,000 bbl oil/day
        = 98,512 Mlbm/hr standard steam
        = 33.44 GW

1 Mlbm = 10^3 lbm/hr steam
        = 10^{-3} MMlbm/hr steam
        = 1.015 X 10^{-5} q/yr for standard steam
        = 3.394 X 10^{-4} GW for standard steam

1 (Mlbm/hr) = 1158.7 Btu for standard steam

1 ton of coal = 21.85 X 10^6 Btu (EEI average)

1 bbl oil = 6.1 X 10^6 Btu (EEI average)

The "standard steam" used for the descriptions of all the technologies and for the LP model is 150 psig saturated steam (165 psia). Its specific enthalpy, h, is: h = 1196.4 Btu/lbm steam. The energy content of the steam, Δh, is valued at its enthalpy gain above 70°F saturated water:

Δh = 1158.7 Btu/lbm steam.
Cost

1 mill/kwhr = $8.76 \times 10^{-3}$ billion $/GW\text{-yr}$

$$/KW = 10^{-3}$ billion $$/GW$

MM$/q = 10^{-3}$ billion $$/q$

MM$$(q/yr) = 10^{-3}$ billion $$/(q/yr)$

$$/10^6 \text{ Btu} = $$/MM \text{ Btu}

= billion $$/q$

$$/ (\text{Btu/hr}) = 114.2$ billion $$/ (q/yr)$
Appendix D

DATA SUMMARY FOR THE 1960-1972 ANALYSIS

This appendix summarizes the economic and process assumptions for the 1960-1972 JGSM historical case study. Chapter 4 contains definitions of the abbreviations for the technologies and a brief description of the sources for the economic data. Appendix A surveys the technologies in detail and explains the derivation of the process information.
## Summary of Technologies Used in Simulation, 1961-1972

<table>
<thead>
<tr>
<th>Technology</th>
<th>Life (years)</th>
<th>Capacity Factor</th>
<th>Input Energy (q)</th>
<th>Output Electric (GW-yr)</th>
<th>Output Steam (q)</th>
<th>First Law Efficiency</th>
<th>Minimum Production at a Location</th>
<th>1960 Production (GW-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>30</td>
<td>.75</td>
<td>.0915</td>
<td>1</td>
<td>0</td>
<td>32.6%</td>
<td>-</td>
<td>42.9</td>
</tr>
<tr>
<td>EN</td>
<td>30</td>
<td>.75</td>
<td>.0934</td>
<td>1</td>
<td>0</td>
<td>32 %</td>
<td>-</td>
<td>0.1</td>
</tr>
<tr>
<td>EP</td>
<td>30</td>
<td>.75</td>
<td>.0915</td>
<td>1</td>
<td>0</td>
<td>32.6%</td>
<td>-</td>
<td>21.2</td>
</tr>
<tr>
<td>EH</td>
<td>50</td>
<td>.75</td>
<td>.0915**</td>
<td>1</td>
<td>0</td>
<td>32.6%</td>
<td>-</td>
<td>16.6</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Technology</th>
<th>Life (years)</th>
<th>Capacity Factor</th>
<th>Input Energy (q)</th>
<th>Output Electric (GW-yr)</th>
<th>Output Steam (q)</th>
<th>First Law Efficiency</th>
<th>Minimum Production at a Location</th>
<th>1960 Production (GW-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BF</td>
<td>15</td>
<td>.85</td>
<td>1.176</td>
<td>0</td>
<td>1</td>
<td>85 %</td>
<td>-</td>
<td>3.59</td>
</tr>
<tr>
<td>BP</td>
<td>8</td>
<td>.85</td>
<td>1.25</td>
<td>0</td>
<td>1</td>
<td>80 %</td>
<td>-</td>
<td>0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Technology</th>
<th>Life (years)</th>
<th>Capacity Factor</th>
<th>Input Energy (q)</th>
<th>Output Electric (GW-yr)</th>
<th>Output Steam (q)</th>
<th>First Law Efficiency</th>
<th>Minimum Production at a Location</th>
<th>1960 Production (GW-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>JC</td>
<td>20</td>
<td>.85</td>
<td>.1113</td>
<td>1</td>
<td>.0306</td>
<td>54 %</td>
<td>1,000</td>
<td>1.0</td>
</tr>
<tr>
<td>JL</td>
<td>15</td>
<td>.85</td>
<td>.2362</td>
<td>1</td>
<td>.1402</td>
<td>72 %</td>
<td>400</td>
<td>3.37</td>
</tr>
<tr>
<td>JI</td>
<td>15</td>
<td>.85</td>
<td>.1957</td>
<td>1</td>
<td>.1051</td>
<td>69 %</td>
<td>400</td>
<td>3.37</td>
</tr>
<tr>
<td>JB</td>
<td>15</td>
<td>.85</td>
<td>.2825</td>
<td>1</td>
<td>.2102</td>
<td>85 %</td>
<td>100</td>
<td>3.36</td>
</tr>
</tbody>
</table>

Fueled by Coal: EC, BF, JC, JL, JI, and JB.
Fueled by Oil and Gas: EP and BP.
Nuclear Fueled: EN
Powered by Nature: EH

* Both EH and EN capacity is increased exogenously in this model.

** Coal-equivalent.

*** Plus proportional steam output.

Table D.1
Operation and Maintenance Costs
for Simulation, 1961-1972
(1975 dollars)

For Period Ending:

<table>
<thead>
<tr>
<th></th>
<th>1964</th>
<th>1968</th>
<th>1972</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>1.15</td>
<td>.86</td>
<td>.99</td>
</tr>
<tr>
<td>EN</td>
<td>1.21</td>
<td>1.21</td>
<td>1.21</td>
</tr>
<tr>
<td>EP</td>
<td>.82</td>
<td>.65</td>
<td>.80</td>
</tr>
<tr>
<td>EH</td>
<td>.80</td>
<td>.80</td>
<td>.80</td>
</tr>
</tbody>
</table>

$mills/kwhr$ output

<table>
<thead>
<tr>
<th></th>
<th>$3.45 \times 10^{-7}$</th>
<th>$2.58 \times 10^{-7}$</th>
<th>$2.97 \times 10^{-7}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>BF</td>
<td></td>
<td></td>
<td>$$/Btu$ output</td>
</tr>
<tr>
<td>BP</td>
<td>$.66 \times 10^{-7}</td>
<td>$.53 \times 10^{-7}</td>
<td>$.65 \times 10^{-7}</td>
</tr>
</tbody>
</table>

$mills/kwhr electrical$ and proportional steam output

<table>
<thead>
<tr>
<th></th>
<th>4.06</th>
<th>3.04</th>
<th>3.50</th>
</tr>
</thead>
<tbody>
<tr>
<td>JL</td>
<td>7.36</td>
<td>5.50</td>
<td>6.34</td>
</tr>
<tr>
<td>JI</td>
<td>6.50</td>
<td>4.86</td>
<td>5.59</td>
</tr>
<tr>
<td>JB</td>
<td>8.97</td>
<td>6.71</td>
<td>7.72</td>
</tr>
</tbody>
</table>

Table D.2

279
<table>
<thead>
<tr>
<th>Period</th>
<th>Coal</th>
<th>Nuclear</th>
<th>Combined Oil &amp; Natural Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>1961 - 1964</td>
<td>.448</td>
<td>.320</td>
<td>.488</td>
</tr>
<tr>
<td>1965 - 1968</td>
<td>.403</td>
<td>.320</td>
<td>.434</td>
</tr>
<tr>
<td>1959 - 1972</td>
<td>.447</td>
<td>.320</td>
<td>.484</td>
</tr>
</tbody>
</table>

*This price includes the uranium, its enrichment, fabrication, reprocessing, storage, and inventory costs.

Table D.3
Capital Costs for Simulation, 1961-1972  
(1975 dollars)

For Period Ending:

<table>
<thead>
<tr>
<th></th>
<th>1964</th>
<th>1968</th>
<th>1972</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>279</td>
<td>210</td>
<td>209</td>
</tr>
<tr>
<td>EN</td>
<td>321</td>
<td>321</td>
<td>321</td>
</tr>
<tr>
<td>EP</td>
<td>207</td>
<td>168</td>
<td>130</td>
</tr>
<tr>
<td>EH</td>
<td>470</td>
<td>470</td>
<td>470</td>
</tr>
</tbody>
</table>

| BF    | .0280| .021 | .021 |
| BP    | .0104| .0084| .0065 |

|       |      |      |      |
|JC     | 335  | 252  | 251  |
| JL    | 582  | 438  | 436  |
| JI    | 458  | 344  | 343  |
| JB    | 889  | 669  | 666  |

$/KW Capacity  
$/Btu/hr Capacity  
$/KW Electrical  
Output Capacity

These are direct construction costs. Interest during construction is computed from the cash flow.

Table D.4
### Cash Flows During Construction*

<table>
<thead>
<tr>
<th>Technology</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>32.75</td>
<td>43.52</td>
<td>18.07</td>
<td>5.45</td>
<td>.21</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EN</td>
<td>4.73</td>
<td>33.92</td>
<td>33.87</td>
<td>14.20</td>
<td>8.22</td>
<td>3.50</td>
<td>1.30</td>
<td>.26</td>
</tr>
<tr>
<td>EP</td>
<td>30.47</td>
<td>47.99</td>
<td>18.84</td>
<td>2.64</td>
<td>.06</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EH</td>
<td>34.7</td>
<td>43.1</td>
<td>14.6</td>
<td>6.7</td>
<td>.7</td>
<td>.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>BF</td>
<td>56.9</td>
<td>43.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BP</td>
<td>100.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JC</td>
<td>32.75</td>
<td>43.52</td>
<td>18.07</td>
<td>5.45</td>
<td>.21</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JL</td>
<td>56.9</td>
<td>43.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JI</td>
<td>56.9</td>
<td>43.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JB</td>
<td>56.9</td>
<td>43.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*Percentage of total direct construction expenses occurring in a given year.

**Table D.5**
Pre-Specified Production, Electricity and Steam Energy Demand, and Historical Electricity Cogeneration for Simulation, 1961-1972.

<table>
<thead>
<tr>
<th>Year</th>
<th>Fixed Production (GW-yr)</th>
<th>Demand Electricity (GW-yr)</th>
<th>Steam (q)</th>
<th>Historical Electricity Cogeneration (GW-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>EN EH</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1960</td>
<td>0.1 16.6</td>
<td>91.9</td>
<td>5.15</td>
<td>11.1</td>
</tr>
<tr>
<td>1964</td>
<td>0.38 20.2</td>
<td>119.3</td>
<td>5.93</td>
<td>11.4</td>
</tr>
<tr>
<td>1968</td>
<td>1.43 25.3</td>
<td>155.0</td>
<td>6.83</td>
<td>12.2</td>
</tr>
<tr>
<td>1972</td>
<td>6.16 31.1</td>
<td>201.2</td>
<td>7.87</td>
<td>12.1</td>
</tr>
</tbody>
</table>

Table D.6
### Percentage of Initial Capacity Retiring in a Period Because of Physical Obsolesence for 1961-1972 Simulation Period

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>2.11</td>
<td>1.88</td>
<td>3.04</td>
</tr>
<tr>
<td>EN</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>EP</td>
<td>2.11</td>
<td>1.88</td>
<td>3.04</td>
</tr>
<tr>
<td>EH</td>
<td>1.1</td>
<td>1.3</td>
<td>.07</td>
</tr>
<tr>
<td>BF*</td>
<td>18.79</td>
<td>23.72</td>
<td>29.95</td>
</tr>
<tr>
<td>BP*</td>
<td>4.42</td>
<td>5</td>
<td>E</td>
</tr>
<tr>
<td>JC*</td>
<td>11.89</td>
<td>15.01</td>
<td>18.95</td>
</tr>
<tr>
<td>JL,JI,JB*</td>
<td>18.79</td>
<td>23.42</td>
<td>29.95</td>
</tr>
</tbody>
</table>

E = endogenous within model

* These retirements were assumed to follow the retirement formulae described in Equations 4.1 through 4.3.

**Table D.7**
Appendix E

DATA SUMMARY FOR THE 1975-2000 ANALYSIS

This appendix summarizes the economic and process assumptions for the 1975-2000 JGSM case study. Chapter 5 contains definitions of the abbreviations for the technologies and a general description of the economic data projections. Appendix A describes the technologies and the derivation of the process information in detail.
### Summary of Technologies Used in 1976-2000 Modeling

<table>
<thead>
<tr>
<th>Technology</th>
<th>Life (years)</th>
<th>Capacity Factor</th>
<th>Input Energy (q)</th>
<th>Electrical Output (GW-yr)</th>
<th>Steam Output (q)</th>
<th>First Law Efficiency</th>
<th>O&amp;M Costs (mills/kwhr)</th>
<th>Minimum Production at one Location</th>
<th>1975 Production (GW-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>30</td>
<td>.75</td>
<td>0.0915</td>
<td>1</td>
<td>0</td>
<td>32.6%</td>
<td>2.0</td>
<td>-</td>
<td>94.9</td>
</tr>
<tr>
<td>EA</td>
<td>20</td>
<td>.75</td>
<td>0.0675</td>
<td>1</td>
<td>0</td>
<td>44.3%</td>
<td>2.5</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>EN</td>
<td>30</td>
<td>.75</td>
<td>0.0934</td>
<td>1</td>
<td>0</td>
<td>32.0</td>
<td>2.0</td>
<td>-</td>
<td>19.5</td>
</tr>
<tr>
<td>EP</td>
<td>30</td>
<td>.75</td>
<td>0.0915</td>
<td>1</td>
<td>0</td>
<td>32.6%</td>
<td>1.0</td>
<td>-</td>
<td>59.4</td>
</tr>
<tr>
<td>EO</td>
<td>20</td>
<td>.75</td>
<td>0.0762</td>
<td>1</td>
<td>0</td>
<td>39.2%</td>
<td>2.24</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>EH#</td>
<td>50</td>
<td>.75</td>
<td>0.0915*</td>
<td>1</td>
<td>0</td>
<td>32.6%</td>
<td>2.0</td>
<td>-</td>
<td>34.2</td>
</tr>
<tr>
<td>BF</td>
<td>15</td>
<td>.85</td>
<td>1.176</td>
<td>0</td>
<td>1</td>
<td>85%</td>
<td>6.0x10^{-7}</td>
<td>-</td>
<td>1.18</td>
</tr>
<tr>
<td>BP</td>
<td>10</td>
<td>.85</td>
<td>1.25</td>
<td>0</td>
<td>1</td>
<td>80%</td>
<td>.81x10^{-7}</td>
<td>-</td>
<td>4.72</td>
</tr>
<tr>
<td>JC</td>
<td>20</td>
<td>.85</td>
<td>.1113</td>
<td>1</td>
<td>.0306</td>
<td>54%</td>
<td>7.07</td>
<td>1,000</td>
<td>1</td>
</tr>
<tr>
<td>JA</td>
<td>15</td>
<td>.85</td>
<td>.0917</td>
<td>1</td>
<td>.0315</td>
<td>67%</td>
<td>8.8</td>
<td>500</td>
<td>0</td>
</tr>
<tr>
<td>JN</td>
<td>25</td>
<td>.80</td>
<td>.1100</td>
<td>1</td>
<td>.0169</td>
<td>42.5%</td>
<td>7.5</td>
<td>2,000</td>
<td>0</td>
</tr>
<tr>
<td>JO</td>
<td>15</td>
<td>.85</td>
<td>.1053</td>
<td>1</td>
<td>.0438</td>
<td>70%</td>
<td>7.9</td>
<td>450</td>
<td>0</td>
</tr>
<tr>
<td>JL</td>
<td>15</td>
<td>.85</td>
<td>.2362</td>
<td>1</td>
<td>.1402</td>
<td>72%</td>
<td>12.8</td>
<td>400+</td>
<td>3.23</td>
</tr>
<tr>
<td>JI</td>
<td>15</td>
<td>.85</td>
<td>.1957</td>
<td>1</td>
<td>.1051</td>
<td>69%</td>
<td>11.3</td>
<td>400</td>
<td>3.23</td>
</tr>
<tr>
<td>JB</td>
<td>15</td>
<td>.85</td>
<td>.2825</td>
<td>1</td>
<td>.2102</td>
<td>85%</td>
<td>15.6</td>
<td>100</td>
<td>3.24</td>
</tr>
</tbody>
</table>

---

*coal equivalent input  **plus proportional steam output  #EH capacity is increased exogenously at 2% per year

Table E.1
### Summary of Technologies
#### Used in 1976-2000 Modeling

**Part 2**

<table>
<thead>
<tr>
<th>Technology</th>
<th>Fuel Type</th>
<th>1975 Est. Capacity (GW)</th>
<th>Percentage of Total Steam Use Servable</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>Coal</td>
<td>127.47</td>
<td></td>
</tr>
<tr>
<td>EA</td>
<td>Coal</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>EN</td>
<td>Nuclear</td>
<td>26</td>
<td></td>
</tr>
<tr>
<td>EP</td>
<td>High S Oil</td>
<td>90.27</td>
<td></td>
</tr>
<tr>
<td>EO</td>
<td>Crude Oil</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>EH</td>
<td>Nature</td>
<td>45.6</td>
<td></td>
</tr>
<tr>
<td>BF</td>
<td>Coal</td>
<td>1.39</td>
<td>100%</td>
</tr>
<tr>
<td>BP</td>
<td>Low S Oil</td>
<td>5.56</td>
<td>100%</td>
</tr>
<tr>
<td>JC</td>
<td>Coal</td>
<td>.353</td>
<td>22.8%</td>
</tr>
<tr>
<td>JA</td>
<td>Coal</td>
<td>0</td>
<td>38.6%</td>
</tr>
<tr>
<td>JN</td>
<td>Nuclear</td>
<td>0</td>
<td>10.8%</td>
</tr>
<tr>
<td>JO</td>
<td>Crude Oil</td>
<td>0</td>
<td>40.0%</td>
</tr>
<tr>
<td>JL</td>
<td>Coal</td>
<td>3.53</td>
<td>42.2%</td>
</tr>
<tr>
<td>JI</td>
<td>Coal</td>
<td>3.53</td>
<td>42.3%</td>
</tr>
<tr>
<td>JB</td>
<td>Coal</td>
<td>3.53</td>
<td>62.8%</td>
</tr>
</tbody>
</table>

*Table E.2*
## Fuel Prices for Modeling

**1976-2000**

(1975 dollars $/MM Btu)

<table>
<thead>
<tr>
<th>Modeling Period</th>
<th>Oil Crude</th>
<th>Oil Low S*</th>
<th>Coal</th>
<th>Nuclear **</th>
</tr>
</thead>
<tbody>
<tr>
<td>1976-1980</td>
<td>1.80</td>
<td>2.07</td>
<td>.88</td>
<td>.32</td>
</tr>
<tr>
<td>1981-1985</td>
<td>2.20</td>
<td>2.53</td>
<td>.96</td>
<td>.39</td>
</tr>
<tr>
<td>1986-1990</td>
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<td>2.76</td>
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<tr>
<td>1991-1995</td>
<td>2.50</td>
<td>2.88</td>
<td>1.00</td>
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<tr>
<td>1996-2000</td>
<td>2.60</td>
<td>3.00</td>
<td>1.00</td>
<td>.50</td>
</tr>
</tbody>
</table>

*There is a 15% increase in price for low sulfur oil over high sulfur oil or crude.

**This includes uranium, enrichment, fabrication, reprocessing, storage, and inventory costs.

Table E.3
## Capital Costs for Modeling 1976-2000

For 5-year Period Ending:

<table>
<thead>
<tr>
<th>Year</th>
<th>EC</th>
<th>EA</th>
<th>EN</th>
<th>EP</th>
<th>EO</th>
<th>EH</th>
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<tbody>
<tr>
<td>1980</td>
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<td>443</td>
<td>259</td>
<td>358</td>
<td>326</td>
<td>470</td>
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<tr>
<td>1985</td>
<td>342</td>
<td>485</td>
<td>494</td>
<td>314</td>
<td>288</td>
<td>470</td>
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<tr>
<td>1990</td>
<td>358</td>
<td>358</td>
<td>494</td>
<td>326</td>
<td>288</td>
<td>470</td>
</tr>
<tr>
<td>1995</td>
<td>366</td>
<td>358</td>
<td>502</td>
<td>326</td>
<td>288</td>
<td>470</td>
</tr>
<tr>
<td>2000</td>
<td>364</td>
<td>358</td>
<td>512</td>
<td>326</td>
<td>288</td>
<td>470</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>BF</th>
<th>BP</th>
<th>JC</th>
<th>JA</th>
<th>JN</th>
<th>JO</th>
<th>JL</th>
<th>JI</th>
<th>JB</th>
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<td>0.0326</td>
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<td>678</td>
<td>533</td>
<td>1035</td>
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<td>1985</td>
<td>0.0343</td>
<td>0.0120</td>
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<td>-</td>
<td>519</td>
<td>455</td>
<td>713</td>
<td>561</td>
<td>1089</td>
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<tr>
<td>1990</td>
<td>0.0359</td>
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<td>430</td>
<td>599</td>
<td>529</td>
<td>455</td>
<td>747</td>
<td>587</td>
<td>1140</td>
</tr>
<tr>
<td>1995</td>
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<td>0.0139</td>
<td>440</td>
<td>599</td>
<td>537</td>
<td>455</td>
<td>763</td>
<td>600</td>
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<td>0.0151</td>
<td>437</td>
<td>599</td>
<td>548</td>
<td>455</td>
<td>759</td>
<td>597</td>
<td>1159</td>
</tr>
</tbody>
</table>

**$/KW Capacity**

**$/Btu/hr Capacity**

**$/KW Electrical and Proportional Steam Output Capacity**

**Note:** 1975 Dollars. These are direct construction costs. Interest during construction is computed from cash flows.
# Cash Flows during Construction*

<table>
<thead>
<tr>
<th>Technology</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>32.75</td>
<td>43.52</td>
<td>18.07</td>
<td>5.45</td>
<td>.21</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EA</td>
<td>56.9</td>
<td>30.0</td>
<td>13.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EN</td>
<td>4.73</td>
<td>33.92</td>
<td>33.87</td>
<td>14.20</td>
<td>8.22</td>
<td>3.50</td>
<td>1.30</td>
<td>.26</td>
</tr>
<tr>
<td>EP</td>
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<td>47.99</td>
<td>18.84</td>
<td>2.64</td>
<td>.06</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EO</td>
<td>56.9</td>
<td>30.0</td>
<td>13.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EH</td>
<td>34.7</td>
<td>43.1</td>
<td>14.6</td>
<td>6.7</td>
<td>.7</td>
<td>.2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>BF</td>
<td>56.9</td>
<td>43.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BP</td>
<td>100.0</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JC</td>
<td>32.75</td>
<td>43.52</td>
<td>18.07</td>
<td>5.45</td>
<td>.21</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JA</td>
<td>56.9</td>
<td>30.0</td>
<td>13.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JN</td>
<td>4.73</td>
<td>33.92</td>
<td>33.87</td>
<td>14.20</td>
<td>8.22</td>
<td>3.50</td>
<td>1.30</td>
<td>.26</td>
</tr>
<tr>
<td>JO</td>
<td>56.9</td>
<td>30.0</td>
<td>13.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JL</td>
<td>56.9</td>
<td>43.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JI</td>
<td>56.9</td>
<td>43.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>JB</td>
<td>56.9</td>
<td>43.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

* Percentage of direct construction expenses during this year

---

Table E.5
Pre-Specified Production, Electricity and Steam Energy Demand, and the Historical Extrapolation of the Cogeneration Share for the 1976-2000 Modeling

<table>
<thead>
<tr>
<th>Year</th>
<th>Fixed EH Production (GW-yr)</th>
<th>Demand Electricity (GW-yr)</th>
<th>Steam (q)</th>
<th>Historical Pattern for Cogeneration (GW-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1975</td>
<td>34.2</td>
<td>218.7</td>
<td>7.41</td>
<td>10.7</td>
</tr>
<tr>
<td>1980</td>
<td>37.8</td>
<td>276.5</td>
<td>8.51</td>
<td>13.5</td>
</tr>
<tr>
<td>1985</td>
<td>41.7</td>
<td>348.5</td>
<td>9.77</td>
<td>17.1</td>
</tr>
<tr>
<td>1990</td>
<td>46.0</td>
<td>441.8</td>
<td>11.21</td>
<td>21.6</td>
</tr>
<tr>
<td>1995</td>
<td>50.8</td>
<td>558.6</td>
<td>12.87</td>
<td>27.3</td>
</tr>
<tr>
<td>2000</td>
<td>56.1</td>
<td>706.1</td>
<td>14.78</td>
<td>34.5</td>
</tr>
</tbody>
</table>

Table E.6
Percentage of Initial Capacity Retiring in a Period Because of Physical Obsolesence in 1976-2000 Modeling *

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>EC, EN, EP</td>
<td>7.13</td>
<td>9.54</td>
<td>12.77</td>
<td>17.09</td>
<td>22.87</td>
</tr>
<tr>
<td>EA, EO</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>E</td>
</tr>
<tr>
<td>EH</td>
<td>1.94</td>
<td>2.60</td>
<td>3.48</td>
<td>4.65</td>
<td>6.23</td>
</tr>
<tr>
<td>BF</td>
<td>24.22</td>
<td>32.41</td>
<td>43.37</td>
<td>E</td>
<td>E</td>
</tr>
<tr>
<td>BP</td>
<td>42.77</td>
<td>57.23</td>
<td>E</td>
<td>E</td>
<td>E</td>
</tr>
<tr>
<td>JC</td>
<td>15.32</td>
<td>20.51</td>
<td>27.45</td>
<td>36.72</td>
<td>E</td>
</tr>
<tr>
<td>JA, JO</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>E</td>
<td>E</td>
</tr>
<tr>
<td>JN</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>JL, JI, JB</td>
<td>24.22</td>
<td>32.41</td>
<td>43.37</td>
<td>E</td>
<td>E</td>
</tr>
</tbody>
</table>

E = endogenous within model.
* All retirements here were assumed to follow the formulae given in Equations 4.1, 4.2, and 5.1.

Table E.7
### Upper Limits on New Capacity Introduced Annually Because of New Technology or Lead Times in the 1976-2000 Modeling

<table>
<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>EC</td>
<td>13.3</td>
<td>NL</td>
</tr>
<tr>
<td>EA</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>EN</td>
<td>10.8</td>
<td>21.0</td>
</tr>
<tr>
<td>EP</td>
<td>2.6</td>
<td>NL</td>
</tr>
<tr>
<td>EO</td>
<td>0.0</td>
<td>NL</td>
</tr>
<tr>
<td>JC</td>
<td>0.2</td>
<td>NL</td>
</tr>
<tr>
<td>JN</td>
<td>0.25</td>
<td>0.50</td>
</tr>
<tr>
<td>JA</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>JO</td>
<td>0.0</td>
<td>NL</td>
</tr>
</tbody>
</table>

*NL = no upper limits.*

Table E.8
Limitations on the Maximum Share of Certain Technologies in New Capacity

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>EN and JN as a percentage of all cyclable capacity (i.e., all Ex or Jx except JL and JB) (CN constraint)</td>
<td>50%</td>
<td>50%</td>
<td>55%</td>
</tr>
<tr>
<td>EA and JA as a percentage of all new electrical capacity (A2 constraint)</td>
<td>0%</td>
<td>0%</td>
<td>20%</td>
</tr>
<tr>
<td>EO and JO as a percentage of all new electrical capacity (O2 constraint)</td>
<td>0%</td>
<td>20%</td>
<td>40%</td>
</tr>
</tbody>
</table>

Table E.9
Appendix F

JGSM PROGRAM DOCUMENTATION

Figure F.1 shows the flow chart for the solution of the Joint Generation Supply Model. Appendix F in Pickel (1978) contains the JGSM matrix generator program and the process data for the analyses in Chapters 4 and 5. Documentation is available from the author for the control programs needed to solve the model's linear program using MPSX. International Business Machines Corp. (1973) describes the MPSX mathematical programming solution package.

Rather than program a separate report generator for the JGSM, several non-constraint rows were included in the LP matrix to provide limited report information. Table F.1 defines these rows.
1. Matrix Generation for JGSM Linear Program

Process Data Input

JGSM Matrix Generator

LP Matrix Dataset

2. Solution of JGSM Linear Program

LP Matrix Dataset

MPSX Control Program

MPSX Problem File (for later parameterization runs)

JGSM Solution Printout

Figure F.1
**MODEL NON-CONSTRAINT ROWS NOT DESCRIBED IN CHAPTER 3**

<table>
<thead>
<tr>
<th>Group</th>
<th>Description</th>
<th>Number of Rows</th>
</tr>
</thead>
<tbody>
<tr>
<td>CM_i^j</td>
<td>Production rate from cogeneration technologies at the end of period (i) (GW-yr for EL_i, q for ST)</td>
<td>(2(N))</td>
</tr>
<tr>
<td>CF_i^d</td>
<td>Rate of consumption of fuel (f) at the end of period (i) (q)</td>
<td>(G(N))</td>
</tr>
<tr>
<td>KE_i^d</td>
<td>Annual value of new capacity installed per year during period (i) with the interest during construction calculated at discount rate (d) (billions of 1975 dollars discounted to the beginning of the first operational year)</td>
<td>(N)</td>
</tr>
</tbody>
</table>

*Table F.1*
The bibliography, because of its length, is separated into five sections:

A. General
B. Modeling, Industrial Organization, and Micro-Economics
C. Technology Related
D. Power Systems Operation and Planning
E. Cost and Economic Data Sources

Owing to numerous references to documents from the National Technical Information Service in Springfield, Virginia, the publishing information for these documents is given as: NTIS, document number, date. Materials from the US Government Printing Office in Washington, DC, are cited as being from "USGPO."

Section A--General


Section B--Modeling, Industrial Organization and Micro-Economics


Section C - Technology Related


Buffington, M. A., "How to Select Package Boilers," Chemical Engineering, Vol. 82, No. 23 (27 October 1975) p. 98-106


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Gulf Oil Company, Xeroxed materials distributed on the Gulf/Stanford Research Institute energy model at a Gulf/MIT meeting held in Cambridge, Massachusetts (August 3, 1976)


Meckler, M., "Options for On-Site Power," Power, Vol. 120, No. 3 (March 1976)


Perry, H., "Coal Conversion Technology," Chemical Engineering (July 22, 1974)


Section D--Power Systems Operation and Planning


Section E - Cost and Economic Data Sources


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