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June 1977

A FRAMEWORK FOR EVALUATING SYNTHETIC FUELS COMMERCIALIZATION PROPOSALS VOLUME I: COAL GASIFICATION

By: DEAN W. BOYD
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ABSTRACT

This report describes a framework developed for the ERDA Office of Commercialization to be used for evaluating synthetic fuels commercialization proposals. This volume describes the application of the framework to high Btu coal gasification. A supplementary volume will describe its application to oil shale processing proposals. Initially, commercialization and its interaction with other ERDA responsibilities such as research and development is discussed. Then the main body of the report presents a methodology for evaluating alternative proposals for government assistance. In this report, the form of government assistance is assumed to be a loan guarantee program; however, the framework is flexible enough to determine the impacts of other types of programs. The methodology considers two types of impacts of gasification proposals -- the short term effects caused by the first commercial plant or plants and long term national effects resulting from the first plant construction. In both the short and long term, the economic, technological, environmental, and socioeconomic outcomes of commercialization are evaluated. By assigning tradeoffs to these outcomes, an overall value or measure of desirability for each competing coal gasification proposal can be developed. Since no commercialization program has yet been authorized, there are no specific proposals to evaluate using the framework. However, to provide general understanding of the important contributors to the value of a coal gasification commercialization program, a base case is defined and evaluated. This base case uses current estimates of economic, technical, social, and environmental factors and assumes that other factors such as regulation and international relations will be generally favorable to gasification. The base case and sensitivity cases imply that economics impacts are dominant. Socioeconomic impacts are small for the nation as a whole, but large for the producing area. Environmental effects are small in the short term, but have more impact in the longer term.

Preface and Acknowledgements

The present project grew out of a previous SRI project undertaken in 1975 for the Interagency Task Force on Synthetic Fuels Commercialization in which the following question was analyzed: Is a federally financed commercial demonstration program in the national interest, and if so, what size program? Subsequently, ERDA decided to pursue such a program, and this study was initiated to determine what the structure of that program should be, i.e., the best size, mix, and location of plants to be built under the program. The charter of this study is not to determine whether federally financed commercial demonstration is justified; rather, the charter is to determine how that federal financing should be allocated among commercial demonstration plant bids assuming there will be a program.

The framework we have built and will discuss here is robust enough to answer the first question (should there be a program) as well as the second question (what should the program consist of), although we have answered neither question in this report simply because neither decision is imminent. Should either question become imminent, the framework can quickly be used to:

- o Analyze whether federally financed commercial demonstration is justified (on a technology-by-technology basis);
- o Determine which bids should be funded and which should be rejected if the program is instituted;
- o Determine what information should be called for in commercial demonstration plant RFP's and how ERDA should evaluate competing proposals.

The authors wish to acknowledge the invaluable contributions of a number of individuals in a number of organizations. First, all five

announced candidates for coal gasification plants (as of the beginning of this study) were contacted personally. Their contributions and those of their staff are gratefully acknowledged:

American Natural Gas: Al Browning

El Paso Natural Gas: Mack Acheson

Natural Gas Pipeline Company of America: Al Weiss

Panhandle Eastern Pipeline Company: Ray Newsom

Western Coal Gasification Company: Bob Rudzik and Jack Wooten

Our discussions with these industry people helped greatly to ensure that the study does not simply reflect government information or biases.

We wish to acknowledge the valuable guidance of Dr. Edward Cazalet, the project supervisor, and to acknowledge his original design of the SRI National Energy Model. Useful contributions were made by Mr. Ronald Dickenson and Mr. Roger Goldstein of SRI's Energy Center regarding coal gasification technologies, and from Dr. D. Warner North who facilitated the interface of this project with another SRI project for ERDA-Fossil Energy dealing with setting R&D priorities for technologies including coal gasification.

Finally, we wish to acknowledge the support and interest of the project manager in ERDA, Mr. Robert Kelly, and his assistant, Mr. Hans Bickel. Dr. William McCormick, the former director of the Office of Commercialization in ERDA who originally commissioned this study, provided valuable support and encouragement and is acknowledged for his contributions and continuing interest. Others in ERDA including Mr. David Beecy, Mr. Jack Cadogan, Ms. Eileen Glassman, Mr. Ed Myerson, and Mr. Paul Petri made valuable suggestions along the way. Our apologies to all contributors whose names have been inadvertently omitted from these quickly prepared lists.

A FRAMEWORK FOR EVALUATING
SYNTHETIC FUELS COMMERCIALIZATION PROPOSALS

Volume 1: Coal Gasification

Table of Contents

Abstract	ii
Preface and Acknowledgements	iii
Executive Summary	ix-xx
Background	ix
Focus of the Study	x
The Framework	xi
Summary of the Base Case Results	xvii
Summary of the Sensitivity Analysis	xviii
Summary Insights	xviii
I. Introduction	1-3
1.1 Goal of the Study	1
1.2 Outline of the Report	2
2. Overview of Commercialization and its Relationship to R&D	4-11
3. Decision Analysis Model of Commercialization	12-17
3.1 Commercialization - Decision Tree	14
4. Deterministic Model of Coal Gasification Bid Selection Decision	18-37
4.1.0 Local Model	20-22
4.1.1 Plant Model	22
Learning	24
A Simple Learning Model	24
A Learning Curve	26
Uncertainty	29
Summary of Current Status of Learning Model	34
Plant Outcomes	34
Base Case Results	34

Table of Contents (Continued)

4.1.2 Financial Model	37-86
Cost of Service Pricing	38
Operating and Maintenance Costs	38
Capital-Related Costs and the Rate Base	39
By-Product Credits and Other Costs	43
Base Case	43
Sensitivity Analysis	48
The Return on Equity for the Utility	49
Investment Tax Credit	56
Inflation	63
Summary of the Base Case Results	85
Financial Model Outcomes	87
4.1.3 Local Socioeconomic Model	87-114
Characteristics and Structure of the Socioeconomic Model	89
Detailed Interactions	93
Population Submodel	95
Local Economy Submodel	95
Housing Submodel	95
Social Services Submodel	96
Local Government Revenue Submodel	97
Local Socioeconomic Model Results	97
Sensitivity Analysis	100
Detailed Model Runs	106
Summary of Local Socioeconomic Results	111
Socioeconomic Outcomes	111
4.1.4 Coal Mine Model	115
Mine Outcomes	115
4.1.5 Water Supply Model	115
Water Supply Outcomes	116
4.1.6 Government Cost Model	116-123
Subsidies	116
Construction Grants	116
Administrative	117
Transfer Payments	117
Lost Taxes and Defaults	119

Table of Contents (Continued)

4.1.6 (Continued)	
Lost Taxes	121
Default	121
Results of the Base Case	124
4.2.0 Long Run Effects	124-125
4.2.1 Energy System Model Capabilities	126-192
Economic Effects	126
Static (Single Year) Economic Surplus	133
Dynamic Approximation to Economic Surplus	141
Base Case Results - Economic Effects	146
Cost of First Lurgi Plant (Short Run Economic Effects)	148
Sensitivity Analysis	152
Long Run Benefits	156
Energy Model Assumptions and Results	159
Implications for High Btu Gas	167
Calculation of Long Run Benefits	169
Consumer's Surplus	170
Producer's Surplus	178
Long Run Environmental Impact	181
Base Case Results - Long Run Environmental Impacts	185
Socioeconomic Impacts	193
4.3.0 Social Value Model	193-205
Outcomes	193
Material Well-Being	195
Equitable Resource Distribution	195
Wise Use of Natural Resources	195
Socioeconomic Impacts	196
Promote Energy Independence	196
Cost to Government	196
Preference Tradeoffs	196
Preference Tradeoff Values	200
Material Well-Being	200
Air Pollution	201
Water Pollution	202
Water Usage	202
Land Disruption	202

Table of Contents (Continued)

4.3.0 (Continued)	
Socioeconomic Impacts	202
Cost to Government	204
Time Preference	204
4.4.0 Summary Discussion of the Base Case	204
4.4.1 Major Assumptions	205
4.4.2 Base Case Outcome Summary	205-207
4.4.3 Base Case Outcome Evaluation	207-214
5. Summary of Information Required for Evaluation of Coal Gasification Commercialization Proposals	215
5.1 Basis for Evaluation	215
5.2 Information Required from Bidders	216-218
Appendix A: Equations for Socioeconomic Model	A-1
Appendix B: SRI National Energy Model	B-1
Appendix C: Regulation of Natural Gas	C-1

EXECUTIVE SUMMARY

BACKGROUND

In addition to conducting basic energy research and development, ERDA has been chartered with the responsibility of demonstrating the commercial feasibility of energy-related technologies. Because R&D and commercial demonstration are closely interrelated, both must be considered in order to analyze commercialization. The function of the R&D process is to deliver a set of technical outcomes, i.e., possible methods of extracting, converting, storing, or transporting energy from diverse sources, such as fossil fuels, nuclear reactions, solar flux, or geothermal reservoirs. Thus, the R&D process itself produces mostly costs, not benefits, when considered on a stand-alone basis. The benefits of R&D are realized only when the technical outcomes are actually implemented, resulting in new or cheaper energy forms to compete in the energy market -- by which we mean energy market in the broadest sense, including, for example, a "market" for air pollution. In fact, R&D pays benefits only if it changes future decisions that would otherwise be made differently. Commercial demonstration of a technology is therefore an essential step for the benefits of R&D to be realized, although it is not clear whether it should be funded by government or industry.

Coal gasification is a technology that is a candidate for commercial demonstration. The first generation Lurgi technology exists and is currently operating in other countries. However, it has never been used to produce high Btu gas in the United States. Presently investors perceive that economic, financial, and regulatory conditions do not justify totally private initiatives in Lurgi commercialization. In addition to the Lurgi technology, a number of second generation technologies, offering perhaps lower gas prices than Lurgi, are currently undergoing R&D. These technologies might also benefit from the commercialization of a Lurgi plant

due to their varying degrees of similarity with Lurgi. For example, the Lurgi plant might teach ERDA and the gas industry about the chemistry and physics of gasification in general, management of gasification projects, project financing, and environmental and socioeconomic impact mitigation. Such learning might expedite the introduction of a second generation technology that was delivered to the marketplace by the R&D process.

FOCUS OF THE STUDY

ERDA's decision as to which commercial demonstration bids to accept can be viewed on two levels:

1. First, selecting among competing bids for each technology type;
2. Second, coordinating the acceptance of these bids to achieve an optimum portfolio (mix) of plants.

At both levels, any analysis must take into account economic, environmental, social, and other considerations. This report focuses on the first level of decision. A comprehensive framework has been developed to evaluate alternative bids for government assistance in commercializing a synthetic fuels technology. This volume of the report deals with the commercialization of Lurgi coal gasification plants. A subsequent volume will apply the framework to oil shale processing.

To analyze this first level of decision requires a finer level of detail on the technologies than the second level of decision. In moving to the second decision, the coordination of bids among different technologies, the level of detail developed for the first level of decision will be more than sufficient. Thus, we chose to analyze the bid selection decision among similar technologies -- Lurgi versus Lurgi, shale versus shale, and so forth. Once a framework is developed for each technology, the coordination problem will be relatively simple.

Our framework considers the consequences of awarding government assistance to a company, resulting in the construction of a full scale Lurgi coal gasification plant (or perhaps the failure of the first plant).

Presently we assume the government assistance takes the form of a loan guarantee, but the framework is flexible enough to consider other types of assistance. The model considers both the specific impacts of the first plant itself and the long run changes introduced by the demonstration program. These long run effects result from the interaction of the first Lurgi plant with second generation gasification technologies as well as all other fuel-producing technologies. Thus, the framework considers interfuel and intertechnology competition among all fuels and technologies. Finally, the outcomes associated with each bid are traded off to allow consistent comparison among bids.

THE FRAMEWORK

To motivate the framework, one must understand the sequence of decisions and outcomes possible in the commercial demonstration process. This sequence is best illustrated using the format of a decision tree. The decision tree that represents the Lurgi plant commercialization decision appears in Figure E1. The simplest interpretation of the decision tree is that it simply represents the chronology of the commercialization process as it unfolds. The square nodes indicate decision points, points at which government decision makers can choose an alternative. The circular nodes indicate outcome points, points at which government decision makers cannot choose, but must accept an outcome.

We will briefly walk through the tree to illustrate decision points, outcome points, the large number of players, and the dynamic nature of the decision. Beginning on the left, ERDA first selects specific bids in Node 1. In Nodes 2-4, the first plant outcomes and outcomes for the technology as a whole are realized. In Node 5, foreign suppliers react to the technologies available in the U.S. In Node 6, the government regulators respond to the energy situation that exists at that time. In Node 7, the private sector responds to the government regulation decisions and the state of the world existing at that time. In Node 8, industry ultimately decides whether or not to build a coal gasification industry. As mentioned previously, changes

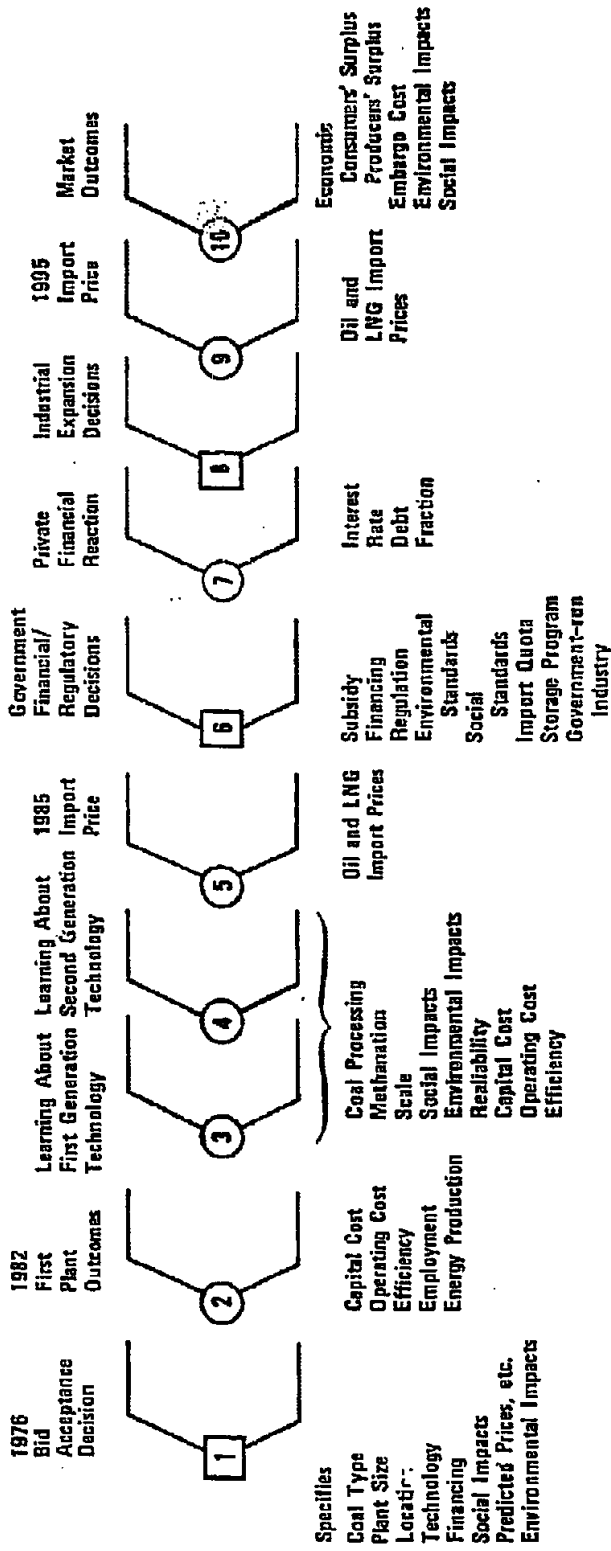


FIGURE E.1 DECISION TREE

in this decision determine most of the benefits of the commercial demonstration program. Finally, in Nodes 9 and 10, foreign and domestic energy suppliers and consumers respond to the prices and quantities of energy available.

There are a large number of players involved in this process -- government regulators, the financial community, and the utility industry are explicitly represented -- while a large number of agents are included implicitly, such as in energy markets. In addition, the tree is dynamic in that information which influences the costs and rewards to the various players is revealed only after the decisions are committed to. For example, utilities must commit to capacity decisions in 1985 before the energy market outcomes of 1995, and hence profitability, are known.

This decision tree can be used to evaluate Lurgi commercialization proposals if we can

1. Quantify the outcomes at all stages;
2. Encode probability distributions for all outcome points;
3. Trade off the possible outcomes.

In this study, we began by constructing a deterministic model of the commercialization process, i.e., with Step 1. We found in so doing that the commercialization process was more complicated than anticipated. In view of this complexity, and the fact that commercialization decisions are not now imminent, we chose to build deterministic models for coal gasification and shale commercialization. Even though the decision tree in Figure E1 was not used to recommend a decision, it nonetheless serves as a useful "roadmap" for this analysis. Using the groundwork laid in this study, such a tree could be quickly constructed and used to recommend policy.

As discussed above, in order to use the decision tree for evaluating bids, a deterministic structural model must be built to generate the outcomes for each particular path through the tree. This volume discusses that model, which will be discussed in two parts. First, the impacts of the first plant will be considered. Second, the effect of the first plant

on the long run outcomes will be discussed.

The first plant model is best discussed in terms of Figure E2. The figure shows the six submodels that generate the first plant outcomes and how they interact. The water supply model calculates the water required to support mining and gas production. The coal mine model supplies the feedstock to the gasification plant. It calculates the expected number of mining deaths, and the amount of land disrupted and reclaimed. The mine environmental emissions are also determined. The government cost model calculates the administrative expenses of a commercialization program, the transfer payments saved due to increased employment, and the possible lost taxes and loan default payments if the first plant is not successful.

The plant model relates the nameplate capacity of the plant, the thermal efficiency of the plant, and the stream factor to calculate the quantity of gas produced. Environmental residuals are also determined. The plant model explicitly considers learning. The hardware can be broken into units, and a different rate of learning specified for each unit; this reflects the fact that some portions of a gasification facility are based on conventional technology while other parts require the acquisition of new skills that should exhibit strong learning with experience.

The first plant financial model calculates the plant gate gas price. These facilities will be controlled by regulated utilities, with the gas sold in a regulated environment. Thus, the model is based upon the "cost of service" pricing mechanism. The financial model produces the gas price trajectory under various regulatory conditions. For example, the utility might be required to pass tax savings from the investment tax credit on to its customers. Or the customers might pay a surcharge during construction to reduce the capital exposure. The effect of inflation on gas price is explicitly considered. The model also calculates the cash flow and hence the return to equity for the utility, providing an indication of the attractiveness of the project to utility investors.

The local socioeconomic model describes the interactions that occur when a large scale industrial facility is constructed and operated in a

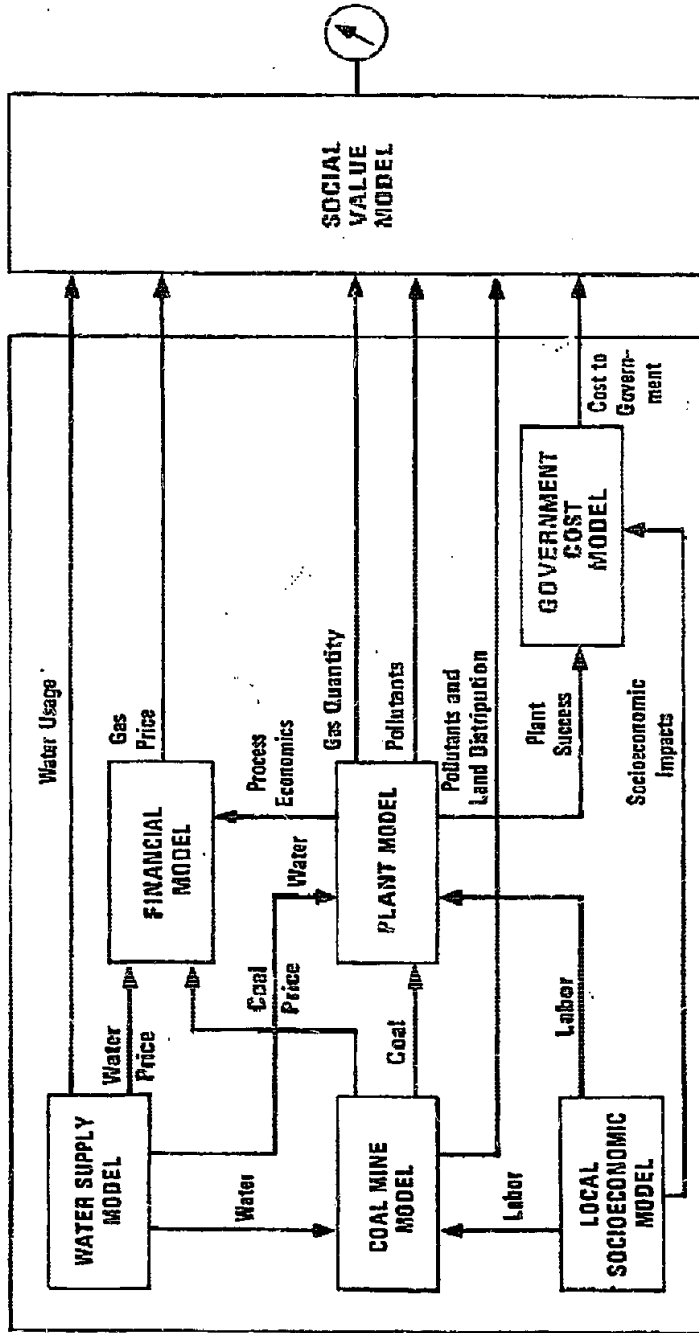


FIGURE E.2 FIRST PLANT, SHORT RUN COMMERCIALIZATION DECISION INTERACTIONS

remote area. The model is dynamic, in that present actions influence future outcomes. It is interactive, in that various portions of the local community influence the actions of one another. The local town is divided into sectors including population, the housing market, the local economy, the government revenue flows, and the social services provided. The model calculates the factors that influence the quality of life, such as the possible shortage of housing and social infrastructure.

To consider the long run effects of a bid acceptance decision, the analysis makes extensive use of the SRI National Energy Model. This model calculates the equilibrium prices and quantities that equate supply and demand for virtually all energy types. The model contains significant regional detail for both end use consumption of energy and primary resource production. The country is connected by transportation links. Conversion processes can convert energy from one form to another. Calculation of long run economic benefits as manifested through price and quantity changes is straightforward. For varying degrees of success and failure of the first commercial gasification plant, data inputs to the energy model can be changed and the economic consequences identified. The energy model has a submodel to track environmental emissions that are consistent with the energy supply/demand balance. This produces the long run environmental consequences of commercialization. Increases in population in remote, energy resource-rich areas are also calculated, providing the long run socioeconomic impacts of a commercialization program. Both the short and long term outcomes must be evaluated on a consistent basis to determine the value of any particular proposal. The social value model performs this task. By assigning judgmental tradeoffs among the various outcomes, an overall value or measure of desirability can be assigned to each gasification proposal.

Finally, it is important to realize that the evaluation framework defines the structure of any request for commercialization proposals. This relationship is spelled out in the last section of the report.

SUMMARY OF BASE CASE RESULTS

The detailed assumptions defining the base case are contained in the body of the report. To summarize the base case, we will relate it to the tree in Figure E1. Given a decision at Fan 1 to accept a bid for a 250MM Scf/stream dry Lurgi plant, we assume that the plant begins operation in 1981 (an optimistic branch in Fan 2 of Figure E1). It produces gas at an average price of \$3.18/Mcf. We assume for Fans 3 and 4 that the program accelerates the Lurgi industry five years (from 1990 to 1985) and all other coal gasification based technologies (second generation, hydrogen, methanol, low Btu gas) by three years. In particular, the second generation gasification industry is accelerated to 1989, which is a relatively optimistic branch in Fan 4. In Fan 5, we assume high prices for imported gas and oil, which favors the program. For Fans 6 and 7, we assume favorable investment and regulatory conditions. Thus, in Fan 8, the industry is assumed to expand if it is economically attractive to do so -- that is, if synthetic gas is price-competitive with other fuels. In Fan 9, we assume continued high import prices and in Fan 10 favorable investment conditions. The net result of our assumptions is to create a rather optimistic set of assumptions for accelerating coal gasification. Again, we emphasize that it is but a single scenario -- to recommend policy, consideration of many more scenarios and their likelihood of occurrence would be required.

We will now summarize first the short run results and then the long run results in the base case. The first Lurgi plant produces gas at an average cost of \$3.18 per Mcf. Since this price is in excess of prices for competing gas over most of its life, the first plant has an economic cost of about one half a billion dollars. The construction and operation of the plant disrupts the local community, causing an increase in population and shortages of social services and housing. The local environmental residuals are not large. The cost to the federal government is minor.

In the long term, we assume that the first plant accelerates the availability of coal gasification technology five years in the case of

Lurgi, and three years for all other gasification technologies. This produces a long run increase in the amount of high Btu gas produced from coal, and reduces its price for a period of fifteen years. Thus, a long run economic benefit in the range of one billion dollars is produced. The long run environmental and socioeconomic impacts are negative -- the amounts of pollution and socioeconomic disruption in remote areas increases.

Table E1 shows the evaluation of the base case outcomes as computed by the social value model. Under the base case assumptions for coal gasification, the long run economic benefits dominate. The net benefit (benefit minus cost) of the program is \$245 million. The major costs of the program are the first plant economic cost and the long run socioeconomic and environmental impacts.

SUMMARY OF SENSITIVITY ANALYSIS

Since the base case assumptions are somewhat optimistic, a number of alternative cases must be generated, many of which would drive the net benefit negative. Any adverse change in the long run fans of the decision tree of Figure E1 would reduce the long run benefit. For example, if the OPEC cartel collapsed, decreasing the cost of imported crude oil and LNG, the gasification industry growth might be less and the long run economic benefits would be reduced. Similarly, government regulators could deem gasification pollution unacceptable and limit industry growth and the associated benefits. Any shortcoming in first plant performance would increase the economic cost.

SUMMARY INSIGHTS

Based upon the results of our sensitivity analyses, we have gained the following insights:

1. Economic effects dominate. The long run and first plant economic effects are the two largest contributors to the cost and benefits of a bid. The value of a bid acceptance decision is strongly dependent upon the ability of a plant to accelerate gasification technology availability at a reduced price.

BASE CASE VALUE

	<u>\$ Millions</u>	
	<u>Costs</u>	<u>Benefits</u>
First Plant		
Economic	526	
Environmental	27	
Socioeconomic	52	
Long Run		
Economic		1,100
Environmental and Socioeconomic	250	
Total	<u>855</u>	<u>1,100</u>
Net		245

TABLE E-1

2. Environmental costs are not great in the short run, but have more impact in the longer term.
3. Socioeconomic costs are not large on a national basis. However, they are large for the small number of people who have to bear them. Mitigation efforts can reduce but not eliminate these problems.

These insights are not sensitive to reasonable changes in any of the assumptions or parameter values that we have used.

INTRODUCTION

Assuming that a synthetic fuels bill similar to H.R. 12112, which was narrowly defeated in the 94th Congress, passes in the reasonably near future, the Office of Commercialization of ERDA will soon be charged with evaluating which of several synthetic fuel plant bids to accept. In fact, the fundamental decision facing the Office of Commercialization will be what set of bids to accept. The synthetic fuels commercialization program will be constructed from the set of bids received and will consist of a mix of technologies, involving plants of different sizes, based perhaps on different processes, and at different locations.

In order to obtain the optimal mix, size, and location of these plants, we have developed a framework for analyzing bids for one technology -- high Btu gas from coal. The framework is quite general and will be adapted to other technologies being considered in the proposed loan guarantee program. This report is intended to communicate the details of the coal gasification bid selection model. The model discussed in this report is deterministic, meaning that uncertainty has been included so far only through sensitivity analysis. The coal gasification model is relatively detailed; its purpose is first to interrelate all potentially important variables and then to help us understand which are actually important. Before proceeding with a detailed description of our deterministic framework, we will summarize the goals of this study and which of those goals are addressed by our work thus far.

1.1 GOAL OF THE STUDY

The Office of Commercialization's decision problem can be viewed on two levels:

- a. First, selecting among bids from each technology type;
- b. Second, coordinating the acceptance of these bids to achieve an optimum portfolio (mix) of plants.

At both levels, any analysis must take into account economic, environmental, social and other pertinent considerations. This report focuses on the first level decision. We have developed a methodology for making the bid selection

decision for bids based on the same technology type -- high Btu gas from coal. This methodology is the critical building block for solving the higher level decision problem -- selecting the optimum portfolio of plants, as well as for focusing on the bid selection decision for the other technology types. In fact, the framework we have developed for analyzing coal gasification bids lends considerable insight to the process of commercialization in general.

In SRI's analysis in 1975 as to whether to have a synthetic fuels program and if so what size, it was not necessary to analyze economic, technological, environmental, social, regulatory, or financial aspects of each technology in great detail. However, in order to design an optimal mix of plants from a set of bids, it is necessary to understand these aspects for each proposed plant. Once we have the methodology to design an optimal plant mix, we will be able as well to "redo" the original synthetic fuels analysis on a technology-by-technology basis.

Our focus so far has been on the production of high Btu gas from coal for two reasons. First, coal gasification appears to be central to the synthetic fuels commercialization program and implementation decisions appear more imminent. Second, as we have seen, it is necessary to understand one technology in some detail before moving to other technologies.

The framework we have developed for coal gasification represents a significant broadening of perspective from the original synthetic fuels task force analysis. In particular, a great deal of modeling work has been incorporated to understand socioeconomic and environmental outcomes at nearer the level the SRI Energy Model allows us to understand economic impacts. The framework is an integration of explicit short and long term

- economic
- environmental
- socioeconomic

models.

1.2 OUTLINE OF THE REPORT

To put the commercialization program in perspective with respect to ERDA's overall operations, we will briefly discuss the relationship between

commercialization and R&D in the next section. Section 3 then outlines the overall decision analysis model for the commercialization bid acceptance decision. The bulk of the report is devoted to the coal gasification deterministic model. Finally, the information that bidders should provide ERDA is listed in Section 5.

OVERVIEW OF COMMERCIALIZATION AND ITS RELATIONSHIP TO R&D

As chartered by the Congress in Public Law 93-438, ERDA has a responsibility to support both basic R&D and the demonstration of commercial feasibility. In particular, ERDA has responsibility for "encouraging and conducting research and development, including demonstration of commercial feasibility and practical applications of the extraction, conversion, storage, transmission, and utilization phases related to the development and use of energy from fossil, nuclear, solar, geothermal, and other sources." Thus it is important to clearly understand the relationship between commercialization and R&D and to ensure that any potential commercialization program is consistent with ERDA's overall operations.

To begin with, it is essential to think of commercialization and R&D not as two distinct processes, but rather as two interrelated phases in the delivery of a technology to the energy market. This process of delivering a technology to the energy market involves the interaction of a large number of decision makers -- those who allocate R&D resources (e.g., ERDA, oil companies); those who use R&D resources and develop commercially feasible technologies (engineers, physicists, chemists); those who decide whether to implement those technologies (e.g., private investors, financial community, utilities, oil companies, perhaps government); those outside the U.S. energy system who can affect it (e.g., OPEC); regulators (e.g., FPC, PUC's); those who make public policy (e.g., Congress, executive branch, the courts); and finally, those who decide what energy forms to purchase (e.g., end users, refinery operators). The costs and benefits of R&D and commercialization depend upon the interaction of all these decision makers and hence a robust analytical structure must explicitly recognize each of the decision makers.

The analytical structure used in this study of commercialization explicitly recognizes its interrelationship with R&D. The structure can be viewed as in Figure 2.1. To place the commercialization decision into its proper perspective, a detailed description of Figure 2.1 will be given.

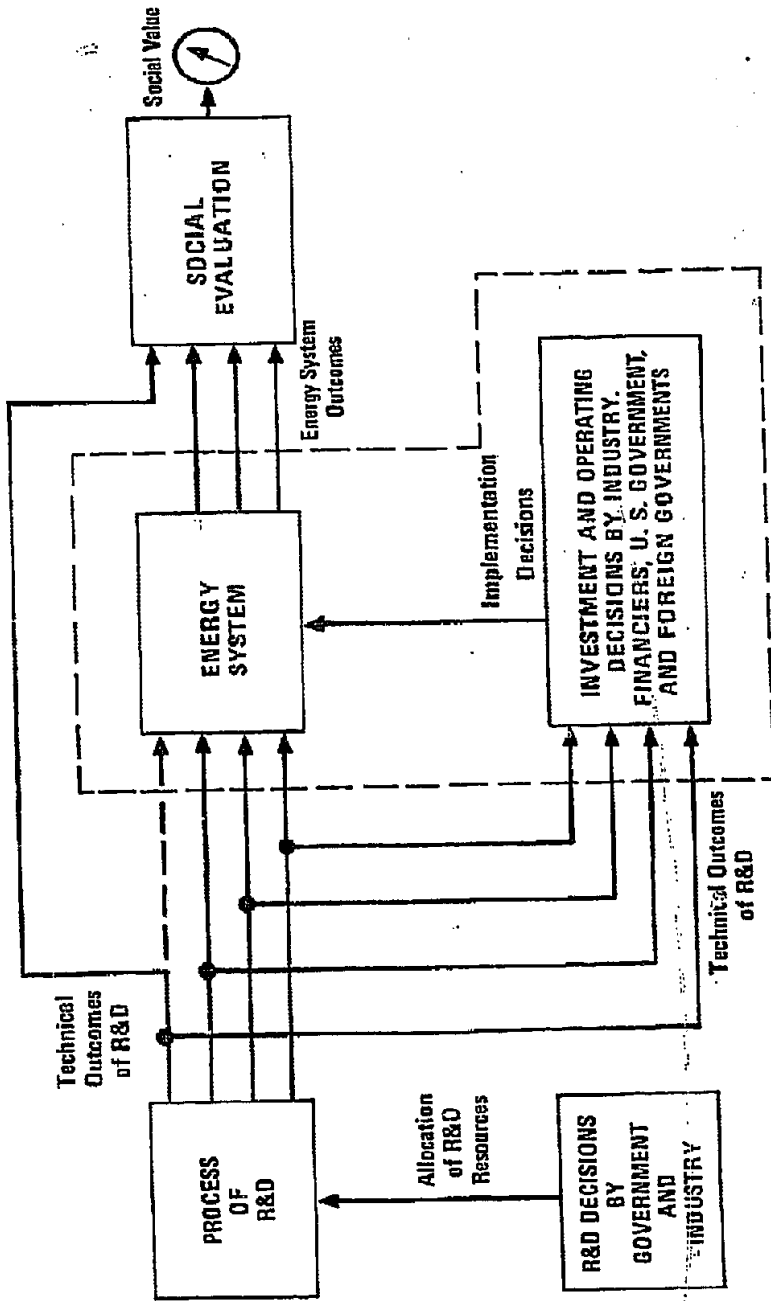


FIGURE 2.1 ALLOCATION OF R&D RESOURCES

The first set of decisions in the process of delivering a technology to the energy market involve the "level of effort" devoted to that technology. In Figure 2.1, this decision is represented in the lower left hand box and is called allocation of R&D resources. Such a decision might be to spend \$100 million/year on in situ coal gasification, \$10 million/year on solar collector research, \$350 million for a CO₂ acceptor pilot plant, and to kill the breeder program. The set of decisions to allocate R&D resources is made by the government (e.g., ERDA) as well as private industries (e.g., oil company-sponsored development). These decisions are quite complex, involving many different technologies at different stages of development. They have a strong effect on the characteristics and timing of each technology at each point in time.

Because it is easy to measure the cost of allocating R&D resources, a naive decision maker might conclude that R&D is "too costly." A brief example will illustrate that the R&D process must be followed out to its conclusion before such an assertion can be made. The example shows that such criteria as "cost to government" when used alone lead to ludicrous conclusions. Consider two hypothetical R&D options, A and B. Option A costs \$10 billion to pursue and returns \$20 billion in benefits, giving a net benefit of \$10 billion. Option B costs \$10 million to pursue and returns \$100 million in benefits, giving a net benefit of \$90 million. Which option is more attractive? Certainly Option A is by far the more attractive, yielding \$10 billion in net benefits while Option B yields only \$90 million. Our naive decision maker who evaluates R&D based only on its cost would conclude that Option A is too expensive and Option B is better. To avoid this erroneous conclusion, a framework used to analyze R&D decisions must look well behind the allocation of R&D resources decision itself in order to understand the entire process of R&D -- in particular, the eventual use of the results of R&D.

Once R&D allocations have been made, research and technical development work begins. Engineers, physicists, chemists, environmental scientists, social scientists, and the like utilize the resources available to them and

begin a complex process of basic research, bench scale experiments, pilot plant construction, demonstration plant construction, and so forth. This process, which we have denoted in Figure 2.1 as the process of R&D, is, in an important sense, outside the control of those who allocated the R&D resources. To illustrate, ERDA cannot "decide" the results of the R&D process; their only decision involves how much money to give to the developers of each technology. That is, ERDA's control over the evolution of the technologies comes through their resource allocation decisions. Figure 2.1 illustrates that the outcomes of the process of R&D are the technical, environmental, social, and engineering parameters at each point in time. They are called the technical outcomes of R&D. The technical outcomes include thermal efficiencies of processes, engineering design and capital and operating costs of potential plants, necessary environmental control hardware, and so forth.

Once these technical outcomes of R&D have been delivered to the energy market, the commercialization or implementation decision making process begins. It is important to note that the technical outcomes of R&D are not "hard and fast" numbers, but in fact are uncertain. The decision makers who decide whether to commercialize the technology will take this uncertainty into account in their decision making process. The present analysis focuses on the commercialization decisions that will be made regarding synthetic fuels technologies whose stage of development is far enough along that a commercial plant could be built. In this report, we are focusing on high Btu gas from coal, using the Lurgi technology with methanation, but a subsequent report will consider shale oil processing.

The commercialization decision in Figure 2.1 is termed the implementation decision. The implementation decisions, whether or not to actually utilize the technology in commercial projects, involve the same diverse set of decision makers who were involved in the R&D allocation decision. We will shortly describe a structure that allows us to understand the interrelationships among these decision makers. As shown in Figure 2.1, each of these decision makers will consider the technical outcomes of R&D in their decisions.

Oil companies and utilities will design plants and assess their profitability. The government will consider the technical outcomes in deciding on subsidies, price regulations, quotas, or allocation schemes. Foreign governments may monitor the technical outcomes of R&D in establishing prices for energy imports. Lending institutions will project the likelihood of success in the marketplace in establishing interest rates and lending amounts. The results of the implementation decisions determine what plants of all types are in place and ready to compete with one another to satisfy customer demands and what imported energy forms are available at what price.

Finally, after all implementation decisions have been made, the consumers of energy decide which energy forms to purchase. These decisions are represented by the box designated energy system in Figure 2.1. Energy purchasers receive an economic benefit from R&D if prices to them drop as a result of implementing the new technologies. Conversely, energy purchasers receive no economic benefit if prices do not drop. Assuming the new technologies do decrease energy prices, the interrelationships among energy suppliers and purchasers will have readjusted as a result of the R&D and implementation decisions. When environmental and social readjustments in the system as a result of R&D and implementation are also considered, one has the comprehensive set of energy system outcomes listed in Figure 2.1 which give rise to the benefits and costs of R&D and commercialization.

The energy system outcomes in Figure 2.1 are evaluated by the different decision makers when they make their R&D and implementation decisions. Generally, different decision makers focus on different outcomes. For example, utilities will focus on the return they receive on their investment, whereas environmental advocates might focus solely on environmental outcomes. Alternatively, we can introduce the notion of a social value by establishing explicit tradeoffs on all of the energy system outcomes. This is the value that ERDA would consider in making R&D or commercialization decisions.

The decisions to allocate R&D resources and the commercialization decisions facing ERDA interact because the benefits of R&D are not realized until after implementation. But they interact in another important way as well. At the time when the commercialization decision is made, ERDA must

decide whether to spend its money on commercial plants or to spend it on R&D for technologies to be implemented later. That is, because of ERDA's budget limitations, all R&D and commercialization cannot be funded simultaneously. Thus there is a resource limitation that ties the allocation of R&D resources decisions and the commercialization together. To illustrate this interconnection, consider the sequence of decisions and outcomes in the R&D sequence through which a technology evolves. Figure 2.2 shows five stages:

- 1) Resources are made available to develop the technology;
- 2) Technical outcomes of R&D occur for the technology;
- 3) Decision makers outside ERDA's control react;
- 4) Implementation decisions are made; and
- 5) Market outcomes are realized.

These five stages are self-explanatory and are consistent with the description of Figure 2.1.

Suppose now there are two technologies whose R&D procedures are sequenced as in Figure 2.3. Figure 2.3 illustrates that in fact the allocation of R&D resources decision for Technology II competes directly with the commercialization decision for Technology I. The decision facing ERDA at that time is shown in Figure 2.3. Budget limitations could limit the alternatives available and change the costs and benefits from both Technologies I and II.

The framework to be described in the remainder of this report focuses specifically on the commercialization decision, but care has been taken to consider the interaction with R&D decisions as well. A more specific and detailed discussion of where commercialization fits into the scheme of ERDA's business is given in the section entitled Long Run Economic Benefits. The next section discusses the specific problem addressed in this study and future sections discuss the model we have developed to analyze that problem.

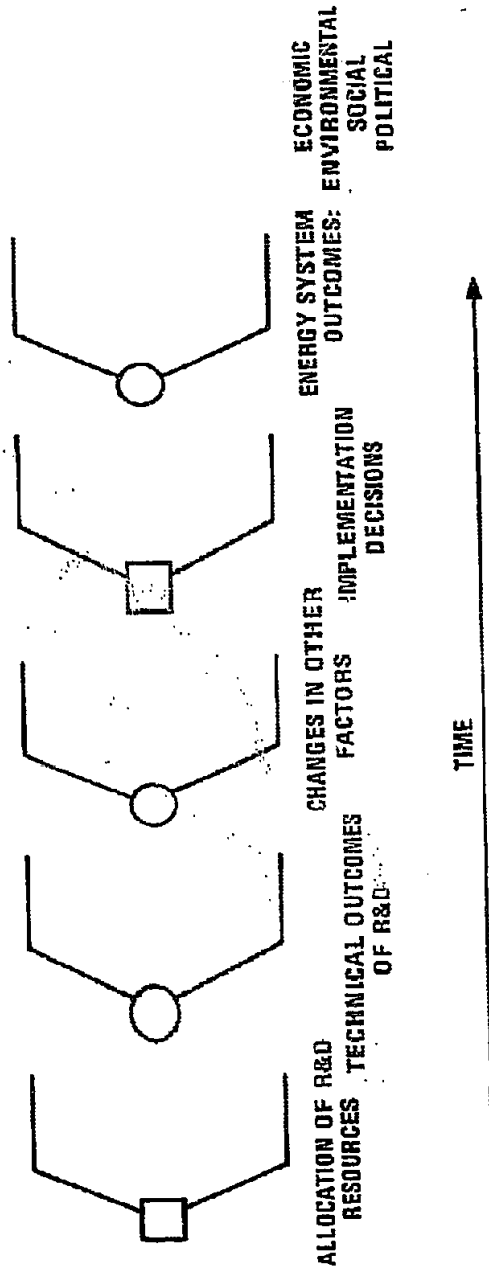


FIGURE 2.2 SEQUENCE OF DECISIONS AND OUTCOMES OF R&D

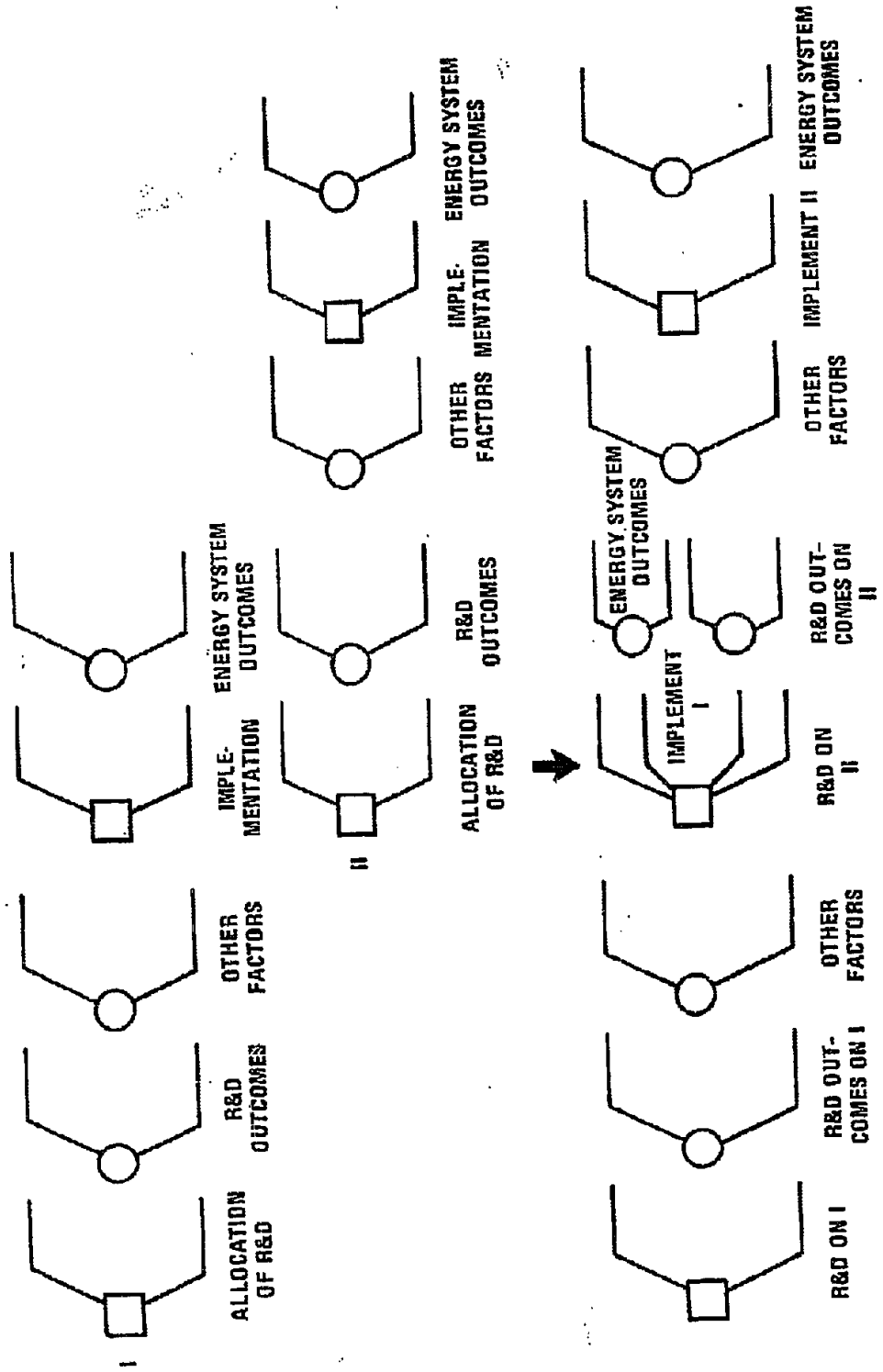


FIGURE 2.3

DECISION ANALYSIS MODEL OF COMMERCIALIZATION

In Figure 3.1 we have constructed an outline of the decision problem faced by ERDA Office of Commercialization. The figure illustrates the interrelationships of the various aspects of the commercialization problem, particularly among the various decision making parties -- ERDA, government regulators, the financial community, and the synthetic fuels industry. We will briefly discuss the rationale for this outline.

ERDA interacts with the synthetic fuels industry by receiving a set of bids and accepting some of them. For those bids that are accepted by ERDA, commercial demonstration plants are constructed, as represented by the "R&D, Commercialization" arrow in Figure 3.1. As a result of building and operating these commercial demonstration plants, the synthetic fuels industry acquires new knowledge regarding synthetic fuels processes. Such knowledge might include improved plant design, measure for reducing capital and operating costs, improved efficiency, or decreased environmental impact. This learning, represented in the "Synfuels Technology" box in Figure 3.1, will be discussed extensively for the coal gasification bid selection decision in this report. The synfuels technology model provides a consistent framework for obtaining expert judgment on the various components of each plant, and for synthesizing these judgments into a consistent assessment of overall plant economics and learning. Although we have built such a model only for coal gasification, the same approach can be used for all technologies.

As shown in Figure 3.1, the synthetic fuels industry interacts directly with the U.S. energy market through implementation of its technologies. To understand the complex and dynamic economic interactions between synthetic fuels technologies and the rest of the society, we have integrated two models. A short term model calculates the impacts of the first plant and a long term model, based on the SRI National Energy Model, calculates subsequent long term effects throughout the society resulting from the first plant

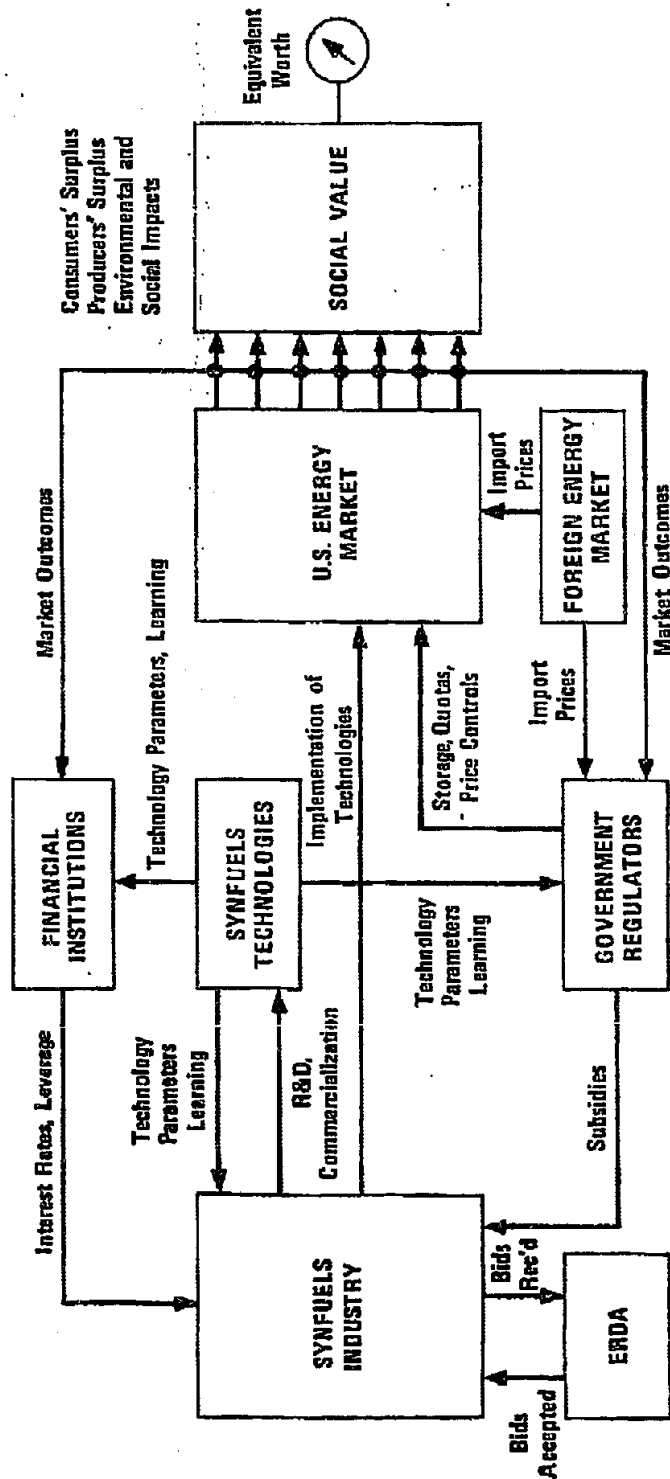


FIGURE 3.1 ALLOCATION OF R&D RESOURCES

construction. Both models consider the economic, including technological, environmental, and socioeconomic outcomes of commercialization.

3.1 COMMERCIALIZATION - DECISION TREE

It is useful to "lay out" the key elements of the bid selection decision analysis in terms of the decision tree shown in Figure 3.2. The tree serves as a medium of communication and helps to focus on the decision at hand. The decision tree provides a framework for understanding the decision process -- the sequence of decisions that are outlined in Figure 3.1. In addition, it clearly indicates where uncertainty in problem variables will be added to the deterministic analysis outlined in the following section.

The leftmost fan of the tree represents the decision as to which bids ERDA will accept. Each bid will specify coal type, plant size, location, technology, financial parameters, environmental impacts and social impacts. The rest of the tree must be able to capture these distinctions. Once a bid is accepted, the plant will be constructed. Its technical and economic outcomes are uncertain and thus we have included the second fan in the tree. After construction and operation of the first plant, ERDA will learn about the cost and performance of future plants based on either the first generation technology itself, or perhaps even second generation technologies. It appears that learning about second generation technologies (Bigas, Hygas, CO₂ Acceptor, Synthane) may be more important than learning about first generation technology (Lurgi with methanation) because second generation technologies promise to be quite attractive if present estimates are accurate. The tree in Figure 3.2 considers this effect in Fans 3 and 4.

After the resolution of uncertainty regarding synfuels prices, the U.S. will face uncertainty on world energy prices -- Fan 5. This fan will allow us to consider foreign reaction, if any, to the outcomes of the program. Next, the government must make decisions regarding further subsidies, price regulation, quotas, storage, and so forth, and these decisions will depend on what has happened previously. Fan 6 represents this possibility. Following these government decisions (made in about 1985), the domestic financial

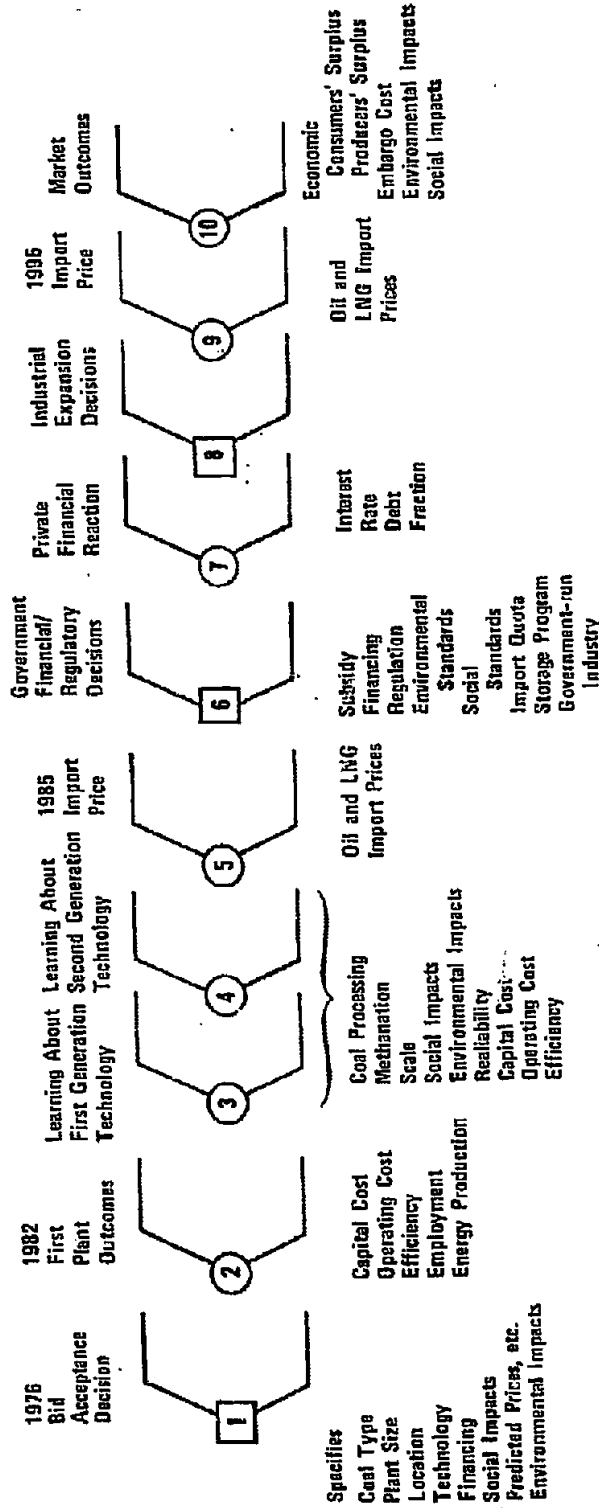


FIGURE 3.2 DECISION TREE

institutions will respond. Since synthetic gas prices are quite sensitive to financial parameters, the costs and benefits of the program can change substantially. Fan 7 allows us to consider this possibility.

Next, in Fan 8, the synthetics industry will decide whether to invest in synthetic gas plants for 1990 and beyond. This decision will obviously depend on all that has gone before -- program outcomes, government decisions, and world energy prices. Finally, in Fans 9 and 10, the U.S. will face the energy market outcomes -- prices, quantities, social outcomes, and environmental outcomes. At this point in time, the U.S. receives the major benefits from commercialization.

Although the eventual decision made by ERDA will require the analysis of a decision tree like that in Figure 3.2, it would be premature to undertake such a detailed analysis at this point. Since a commercialization program has not yet been authorized, there are no firm proposals to provide the parameter values and probability assessments inherent in Figure 3.2. Furthermore, such an evaluation presupposes some framework for evaluating the consequences of traveling down and particular sequence of branches in the decision tree.

The focus of this analysis is the development of the evaluation framework, not making predictions or establishing the value of a particular program by evaluating a tree such as that in Figure 3.2. However, to provide insight into the important determinants of a commercialization proposal's value, a "base case" has been defined for purposes of exercising the framework. The base case can be thought of as one particular path through the decision tree in Figure 3.2. This base case incorporates current estimates for the technical, economic, environmental, and social parameters associated with coal gasification. These are based on currently available information and our conversations with industry and non-industry sources. They will be discussed in detail later in the report. Furthermore, the base case assumes that other factors affecting gasification such as regulations and foreign developments are all generally favorable to gasification.

To summarize the detailed assumptions of the base case, we will relate it to the tree in Figure E1. Given a decision to accept a bid, we assume

that the first plant begins operation in 1981 (an optimistic branch in Fan 2 of Figure E1). It produces gas at an average price of \$3.18/Mcf. We assume for Fans 3 and 4 that the program accelerates the Lurgi industry five years (from 1990 to 1985) and all other coal gasification-based technologies (second generation, hydrogen, methanol, low Btu gas) by three years. In particular, the second generation gasification industry is accelerated to 1989, which is a relatively optimistic branch in Fan 4. In Fan 5, we assume high prices for imported gas and oil, which favors the program. For Fans 6 and 7, we assume favorable investment and regulatory conditions. Thus for Fan 8, the industry is assumed to expand if it is economically attractive to do so, that is, if synthetic gas is competitive with other fuels. In Fan 9, we assume continued high import prices and in Fan 10, favorable investment conditions. The net result of our assumptions is to create a rather optimistic scenario for accelerating coal gasification. Again, we emphasize that it is but a single scenario -- to recommend policy, consideration of many more scenarios and their likelihood of occurrence would be required.

The base case is just that -- a base to exercise the framework and from which to determine the sensitivity of results to changes in various parameters. The base case (and its results) do not constitute a prediction of the most likely outcome of a coal gasification program, nor a statement that an explicit consideration of the uncertainty indicated in Figure 3.2 can be avoided.

DETERMINISTIC MODEL OF COAL GASIFICATION BID SELECTION DECISION

This section outlines the current development of our deterministic model for the coal gasification decision. The aim of this model is to capture at a simple but comprehensive level the variables that could potentially be important in the coal gasification bid selection decision, and to then determine which of those variables actually are important through sensitivity analysis. Sensitivity analysis in the model helps determine if its behavior is reasonable across a broad range of assumptions, whether further detail should be added in certain areas, and what factors in the model must be treated probabilistically. Probability distributions must be assessed on all the latter factors before using the framework to evaluate specific proposals.

In thinking about the implications of building gasification plants, it is useful to distinguish two dimensions:

1. Geographic, and
2. Time.

The important distinctions on the geographic dimension are the local area(s) in which plants may be built, the demand region(s) in which gas is sold, and the nation as a whole. We want to evaluate gasification decisions from the nation's point of view, but we want to do this taking into account different local and regional impacts. On the time scale, it is useful to distinguish between the short term period when the first gasification plant or plants are being built and operated, and the long term extending out into the next fifty years.

The model we have constructed is a synthesis of two models as summarized in Figure 4.1. A model dealing with local, short term impacts has been constructed especially for this project. The regional and national long term impacts are represented by interfacing the local model with the SRI Energy Model. We will discuss both in detail in this report.

The outcomes of the two interacting models are expressed in quantities like the amount of water used, the quantity of gas produced, and the level of emission from a plant by emission type -- measured both over the short

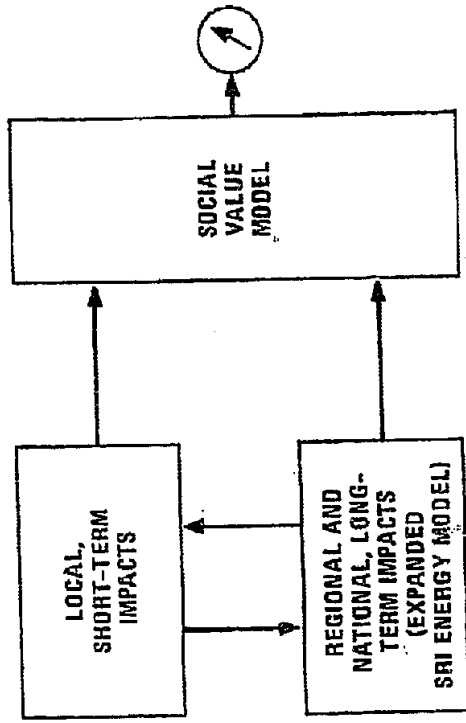


FIGURE 4.1 STRUCTURAL MODEL OF COMMERCIALIZATION

and the long term. These outcomes are output from the model near the right-hand side of Figure 4.1. These variables represent the quantities that ERDA Office of Commercialization will be monitoring when making the commercial plant selections.

In order to make a decision, value judgments must be applied to these variables. Is the potential increase in gas supply worth the environmental degradation from the plants? Questions such as this must be answered by assigning explicit tradeoffs to the outcomes shown in Figure 4.1. This is the purpose of the social value model. The output of the social value model is then an overall measure of the desirability of a particular project or set of projects.

The important local, short term interactions resulting from a decision to commercialize a coal gasification plant is shown in Figure 4.2. This figure can be thought of as a closer look at the energy system and implementation boxes in Figure 2.1, discussed previously. The blocks and arrows on the left-hand side of Figure 4.2 represent processes that determine the outcomes.

The framework shown in Figure 4.2 outlines the local short term model. The next few subsections will discuss it in detail. The long run model consists of four submodels, all of which are contained in the enhanced version of the SRI National Energy Model used in this study:

1. Regional economic model
2. National economic model
3. Regional environmental model
4. Regional social model

When we have completed our discussion of the local submodels, we will discuss how long run benefits of commercial demonstration from a national perspective can be calculated using the SRI National Energy Model.

Finally, the social value model will be described by explaining how each of the outcomes is currently evaluated.

4.1.0 LOCAL MODEL

The local model is composed of six submodels:

1. Plant model
2. Financial model

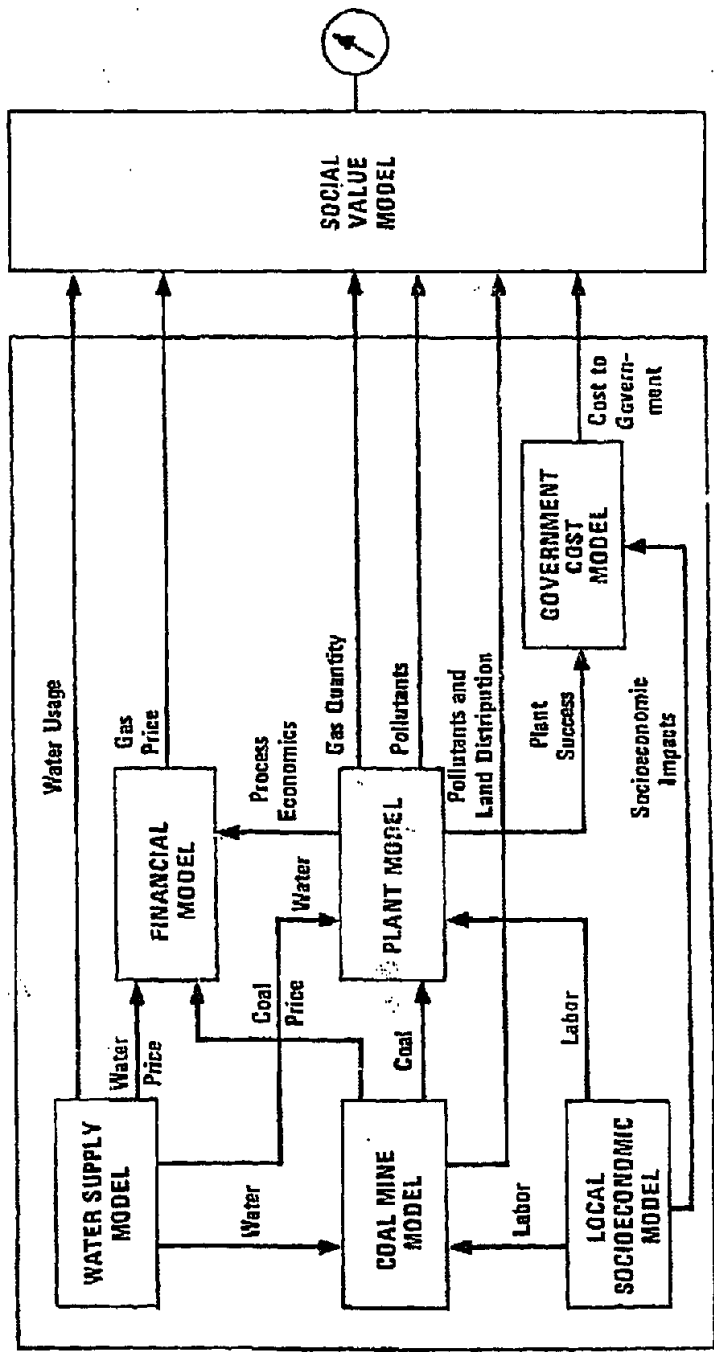


FIGURE 4.2 FIRST PLANT, SHORT RUN COMMERCIALIZATION DECISION INTERACTIONS

3. Socioeconomic model
4. Coal mine model
5. Water model
6. Government cost model

The following subsection will describe each in detail. As each submodel is described, the base case assumptions defining that model will be specified. In addition, any implications or results of those assumptions will be discussed. The base case assumptions and results integrating both the short and long term models will then be summarized and reviewed in Section 4.4.

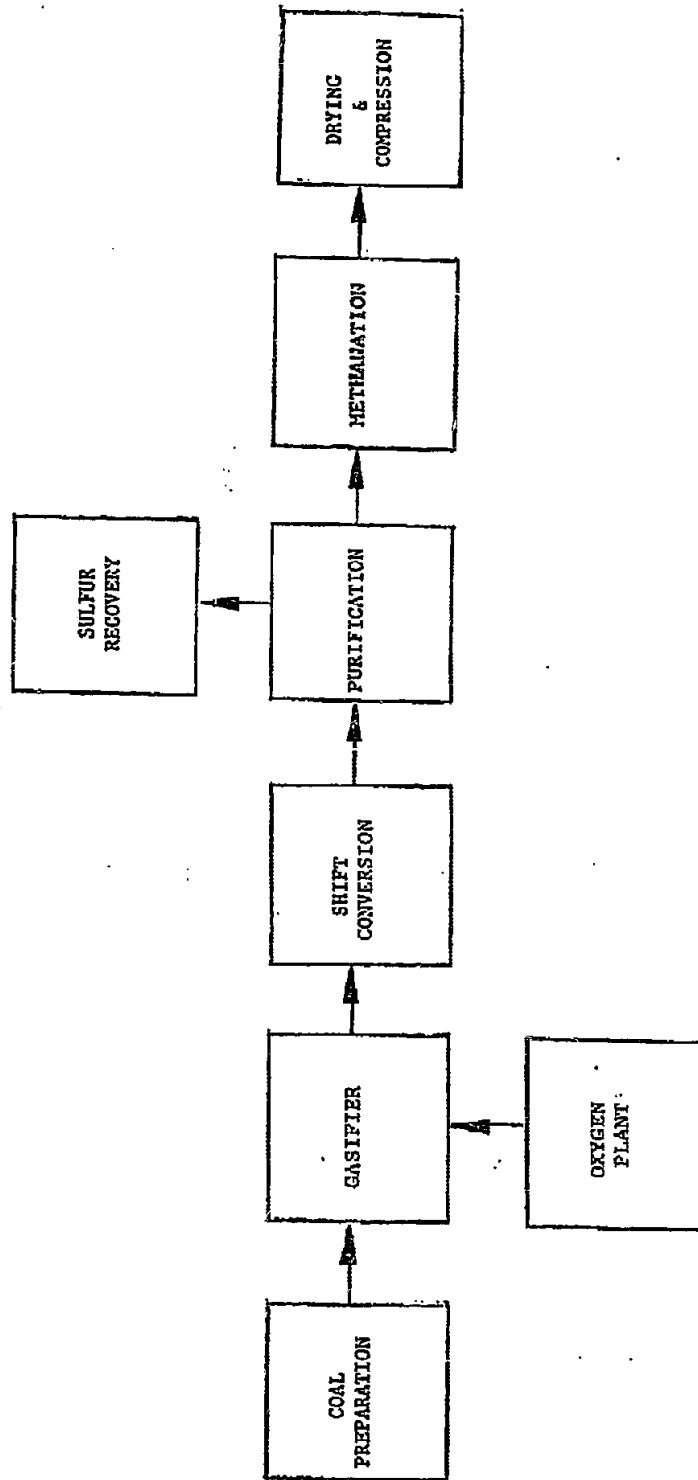
4.1.1 PLANT MODEL

The focus of Figure 4.2 is the plant model, which is a simplified representation of the gasification process outlined in Figure 4.3. From a technological point of view, the greatest uncertainty in the gasification process is in the thermal efficiency of the gasifier. In fact, it is currently believed that the thermal efficiency is sufficiently uncertain to warrant its treatment in a probabilistic sense when actual proposals are evaluated. Thus, the plant model calculates the overall thermal efficiency of the plant as a function of the thermal efficiency of the gasifier. The plant thermal efficiency can then be used to calculate the production from the plant and the coal cost component of the gas price.

The amount of gas produced per year is the "nameplate" size of the plant times 365 days a year times the stream factor achieved, modified by the actual thermal efficiency of the plant. If the thermal efficiency of the plant is higher than estimated during construction, gas production is increased. Similarly, the quantity of gas produced can decrease if the thermal efficiency falls below that estimated. Currently, actual plant production is given by a simple ratio of the actual thermal efficiency divided by the estimated thermal efficiency multiplied by the estimated plant production.

During production of the gas, some undesirable pollutants are emitted to the air and water. Currently, six air pollutants and three water pollutants are accounted for in the model. These pollutants are each

Figure 4.3
Outline of Coal Gasification Process



proportional to the output of the plant. Air pollutants considered are hydrocarbons, NO_x , SO_x , particulates, aldehydes, and CO. Water pollutants considered are dissolved solids, suspended solids and organics. The quantity of each pollutant per unit of output, called an emission coefficient; is entered as data. An emission coefficient for each pollutant is entered for both the plant and the mine. In order that the thermal efficiency of the gasification process can be taken into account, the emission per Btu for the mine is divided by the thermal efficiency of the total plant. This scales up the emissions from coal mining to reflect the facts that coal is used in the plant for process heat as well as to produce gas and that some energy is lost in the process.

LEARNING

One of the potential benefits of the synthetic fuels commercialization program is the knowledge that might be acquired regarding synthetic fuels processes. Such knowledge might include improved plant design, measures for reducing capital and operating cost, improving efficiency, or decreasing environmental impact. Taking coal gasification as an example, learning effects can be categorized in broad terms as those that ultimately affect:

1. The economics of gasification through impact on gas price, or
2. The social acceptability of gasification through demonstrating the actual operation of a plant.

The economic effects can be further broken down into those effects concerned directly with the construction and operation of plants and the related effects concerned with the financing and regulation of plants. This subsection will briefly outline the model that we will use to represent the economic learning effects related to the construction and operation of Lurgi coal gasification plants. Similar concepts can be used to model other types of learning.

A SIMPLE LEARNING MODEL

From the point of view of the operation and construction of a Lurgi plant, the ultimate effect of learning is to reduce the uncertainty in

the price of gas produced by Lurgi gasification. The most direct approach to learning would be expert assessment. For example, an expert's (or experts') opinion of what the price of synthetic gas would be some year in the future, both with and without a commercialization program, could be assessed. The difference would represent the learning from the program and could be used in calculations to yield potential economic benefit. Although this learning model appears to be simple and direct, previous experience has shown that it gives unreliable results. The basic problem is that the price is a function of so many different factors -- thermal efficiencies, stream factors, capital costs, and so on -- so that even knowledgeable experts cannot process all the interactions intuitively. Thus we need a more structured model.

To develop a more structured model we could relate the price of gas to some of the main factors that determine it. For example, in greatly simplified terms we can write the price per unit of output as

$$P_{out} = \frac{SCC \times CCR}{a} + OM + \frac{P_{in}}{\eta}$$

where

P_{out} \equiv price per unit of output

SCC \equiv specific capital cost per unit of capacity

CCR \equiv capital charge rate

a \equiv plant availability

OM \equiv operating and maintenance cost per unit of output

P_{in} \equiv price per unit of input

η \equiv thermal efficiency of the plant

In actuality, the pricing formula used for regulated gas is a more complicated function of similar components. However, in either case, a learning model could be based on the critical factors influencing price and then the effect of these factors on price could be determined. Let's consider how we might develop a learning model for the capital cost of the plant.

A LEARNING CURVE

A convenient way to represent the reduction in capital cost that results from constructing and operating a gasification plant is through the use of a learning curve. Suppose for the moment that there is no uncertainty so that learning results purely from experience gained over time. This experience is reflected in a reduction in capital costs. Such an effect might be represented by a curve such as shown in Figure 4.4. As more and more units are installed, the capital cost per unit declines until it reaches a steady state level below which it declines no more. This, of course, assumes constant dollars with no inflation.

The curve shown in Figure 4.4 can be usefully parameterized as follows:

$$C(n) = C(0) [f_{\infty} + (1 - f_{\infty})e^{-\lambda n}]$$

where

$$C(n) \equiv \text{capital cost } n^{\text{th}} \text{ unit}$$

$$f_{\infty} \equiv \text{ratio of the steady state cost to the initial cost}$$

$$\lambda \equiv \text{measure of rate at which capital cost declines}$$

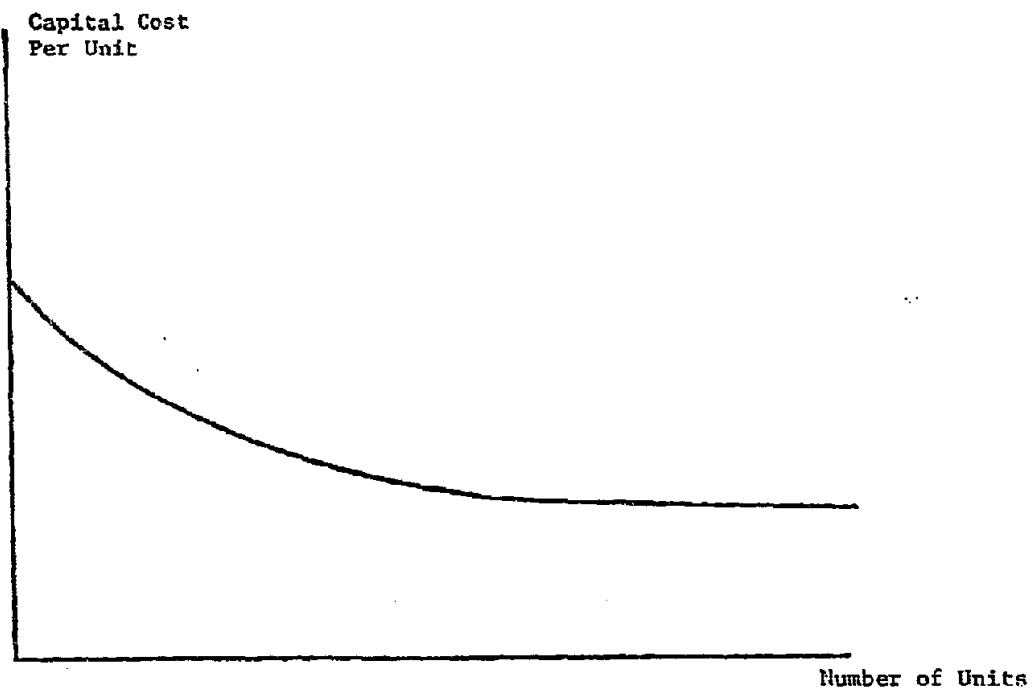
As shown in Figure 4.5, increasing λ causes the capital cost to drop more rapidly. As a rough measure, when

$$n \frac{1}{\lambda}$$

the capital costs will have dropped two-thirds of the way from the initial cost to the steady state cost. Learning curves similar to these are commonly used in industries such as chemical processing and aircraft.

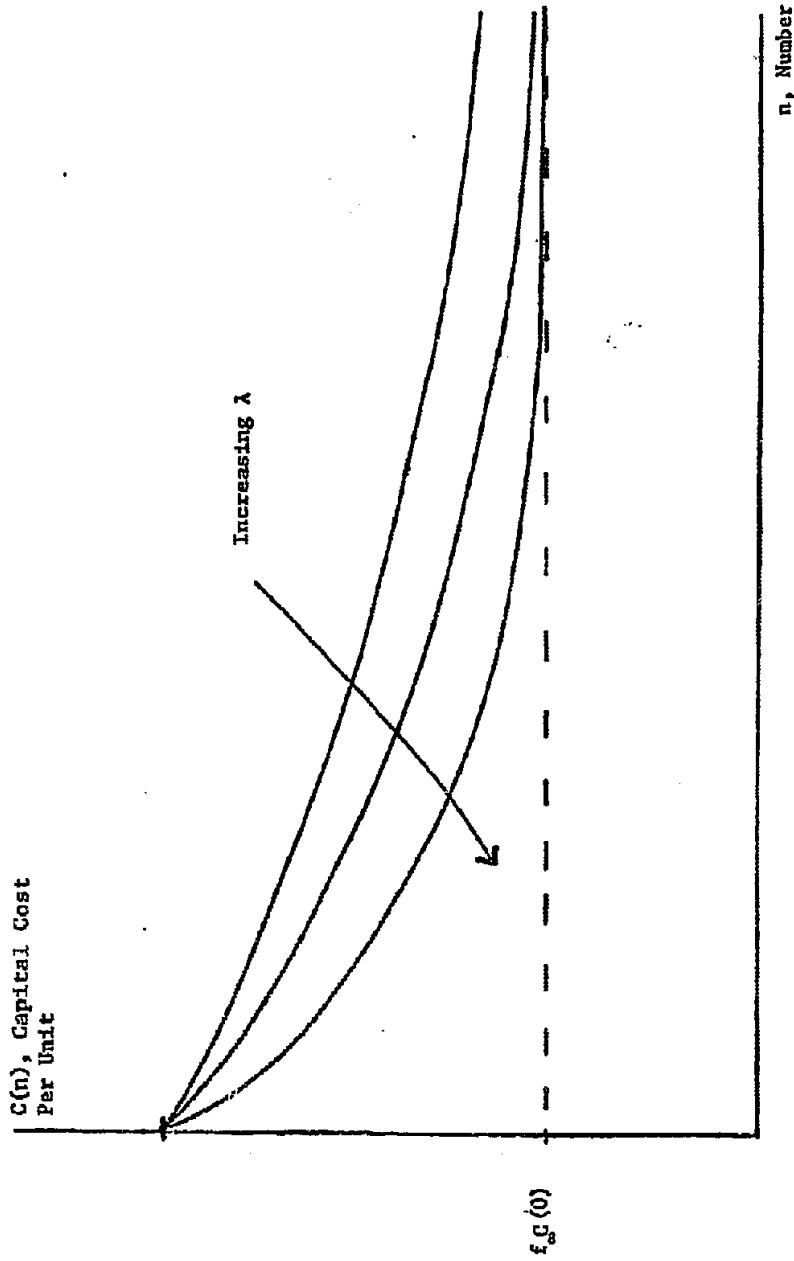
Using learning curves like those in Figure 4.5, rather than trying to assess changes in price directly, we would assess the parameters $C(0)$, f_{∞} , and λ , and then determine the effect on price. Experts familiar with the construction and operation of gasification plants are much more comfortable thinking in terms of the initial capital cost and the steady state capital cost rather than price directly.

As a numerical example, suppose we determined that the initial capital cost of a gasification plant was \$1.1 billion ($C(0) = \1.1 billion), the steady state capital cost was \$0.88 billion ($f_{\infty} = .8$), and the rate of learning was one tenth ($\lambda = 0.1$). The effect of learning on Lurgi gas



A Learning Curve

Figure 4.4



Parameterized Learning Curves

Figure 4.5

price would be as shown in Figure 4.6. As can be seen, the price of gas declines. The rate of decline decreases, so that the curve reaches a limiting value. The first plant produces gas at \$4.10 /Mcf. The second plant price is \$4.06/Mcf, 4.4¢/Mcf lower. The eighth plant gas price is \$3.851/Mcf, 2.6¢/Mcf below the previous plant. If very many plants were built, learning on capital cost would drive the price to \$3.63/Mcf.

UNCERTAINTY

The problem with curves such as those discussed in the last section is that they neglect uncertainty. If there were no uncertainty about construction, chemical processes and so on, they might be good descriptors of the learning phenomenon. However, there is uncertainty that must be dealt with. For example, technical experts might be uncertain initially as to whether or not the plant were a "high" cost plant, a "medium" cost plant, or a "low" cost plant. If it were a "high" cost plant, the plant capital cost would move down the "high" curve in Figure 4.7. Similarly, "medium" and "low" cost plants would move down their respective trajectories.

To take account of the experts' uncertainty, we must encode explicitly the probability of each of the three possibilities. Thus we have the situation summarized in Figure 4.8. The figure is a way of summarizing the experts' state of information regarding capital costs prior to building the first plant.

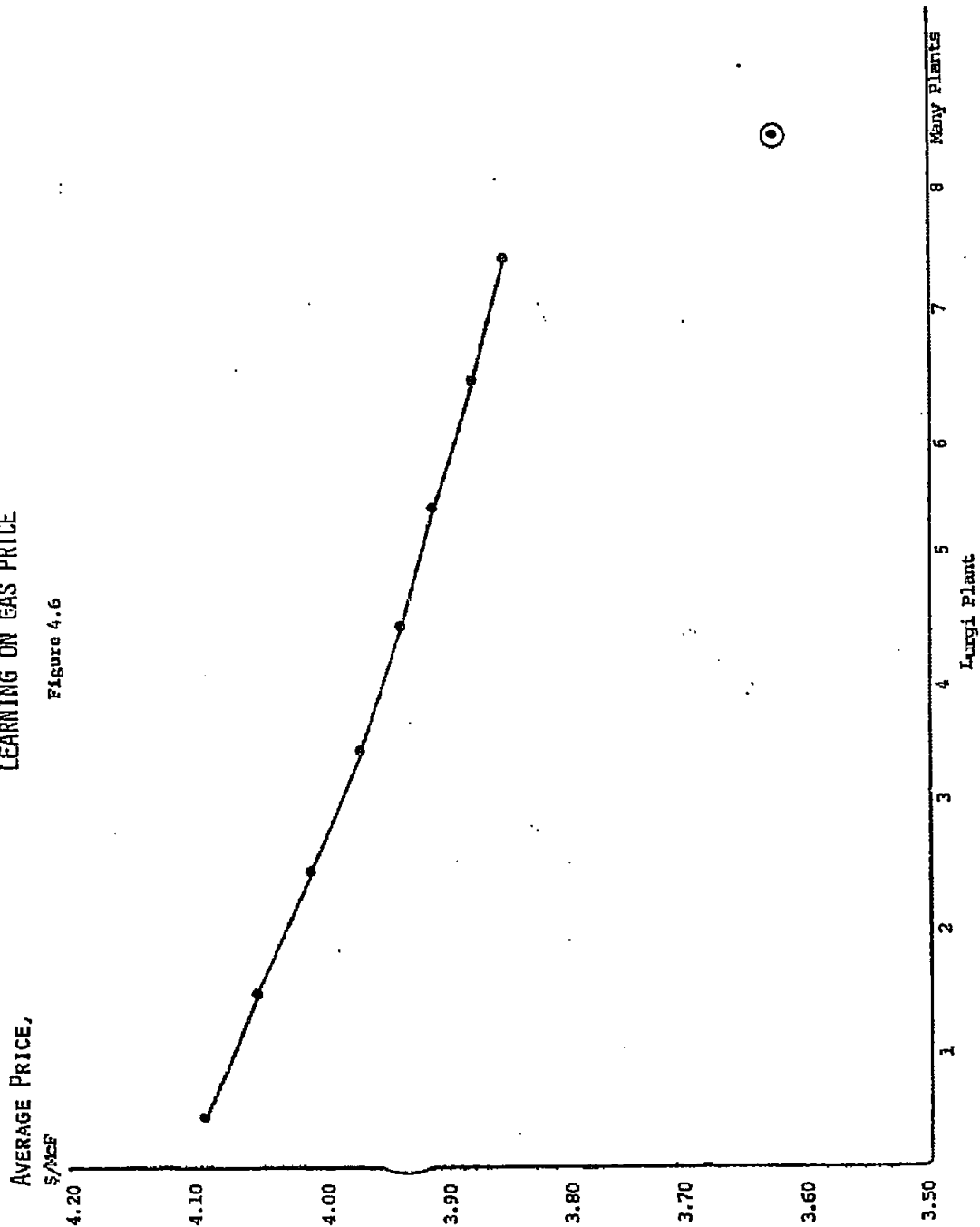
After the first plant is built, the experts have some new information and might want to revise their probabilities of the plant's being on each of the cost trajectories. In other words, if the first plant comes in at a low price, the probability of the next plant being on the low cost learning curve might be increased. This revision of probabilities is summarized in Figure 4.9.

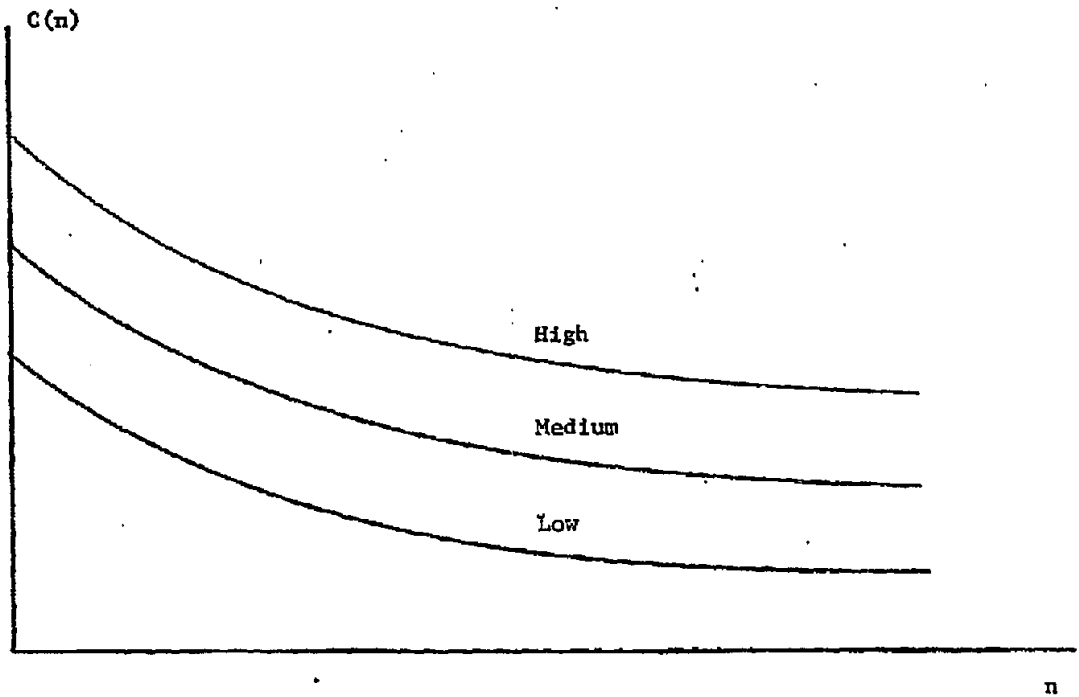
Conceptually, the same expansion of the probability tree shown in Figure 4.9 will occur after each plant is built. However, practically, only a limited number of such conditional probabilities will have to be considered.

Explicitly factoring in the uncertainty gives a much richer and more useful model of the learning phenomenon. It is interesting to note that

LEARNING ON GAS PRICE

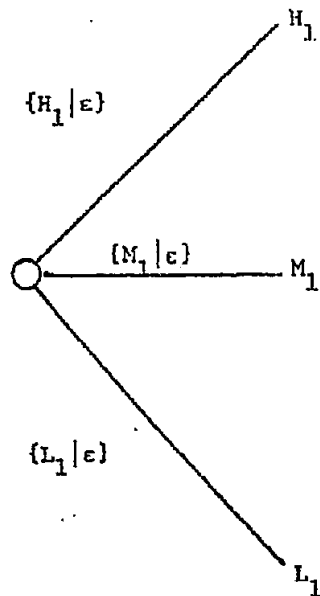
Figure 4.6





Alternate Learning Curves

Figure 4.7



$H_1 \equiv$ 1st Plant Is High Cost

$M_1 \equiv$ 1st Plant Is Medium Cost

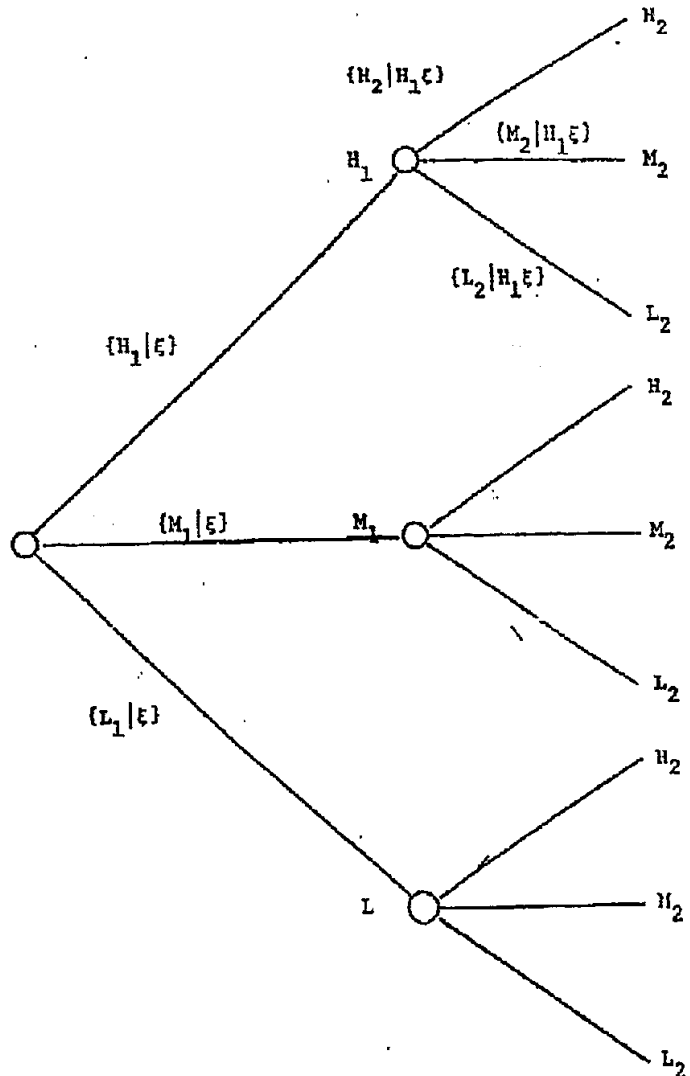
$L_1 \equiv$ 1st Plant Is Low Cost

$\epsilon \equiv$ State of Information Prior to First Construction

$\{H_1|\epsilon\} \equiv$ Probability First Plant is High Cost Given Prior Information

Probabilistic Description of Expert Opinion of Capital Cost of First Plant Prior to Construction.

Figure 4.8



$\{H_2|H_1\epsilon\} \equiv$ Probability second plant is high cost given first plant is high cost and given prior information

Probabilistic Description of Expert Opinion of Capital Cost of First and Second Plant Prior to Construction

Figure 4.9

the probabilistic model "explains" an occurrence often cited in the learning curve literature. Although practitioners agree that theoretically learning curves should look like those in Figure 4.5, in practice, the estimates over time of the cost of the next plant look like Figure 4.10. For appropriate values of the probabilities, Figure 4.10 is just the "average" learning curve.

SUMMARY OF CURRENT STATUS OF LEARNING MODEL

After discussion with both industry and SRI experts, we have determined that the critical variables for which learning must be modeled are capital costs, and perhaps gasifier efficiency. At present, the model has the capability of representing capital cost learning either at the plant level or at the individual process component level. The model was used in producing the results shown in Figure 4.6. Sensitivity analysis will guide the degree of disaggregation that is ultimately used.

PLANT OUTCOMES

The outcomes from the plant model are:

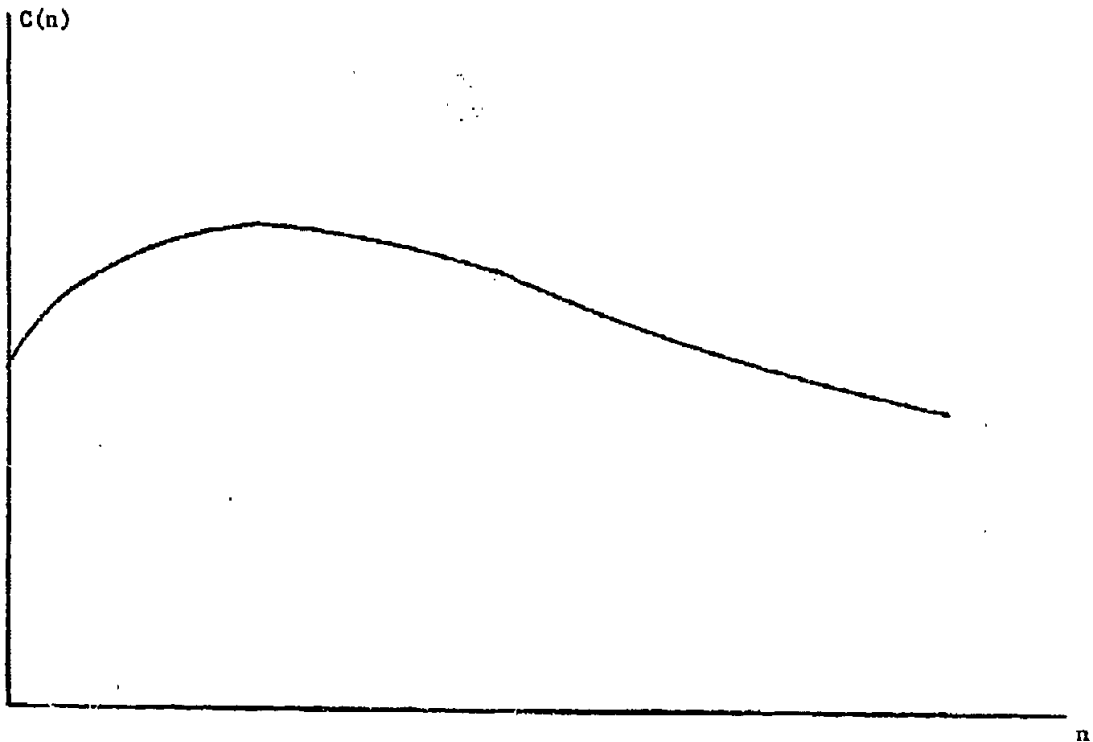
1. The amount of gas produced per year measured in millions of cubic feet, and
2. The air and water pollutants produced by the plant per year -- the specific pollutants are detailed in Table 4.1.

BASE CASE RESULTS

The plant has a nameplate capacity of 250 million Scf/stream day. The stream factor is 50% for the first year of operation, 80% for the second year, and 90% for the duration of plant production. This yields the following gas production in millions of standard cubic feet per year.

Year 1	45,625
Year 2	73,000
Years 3-25	82,125

The pollutants produced by the operation are proportional to production. The following list includes both mine and plant emissions. The figures shown are for a peak production year with a 90% stream factor;



Historical Performance

Figure 4.10

Air Pollution (tons/year)

particulites

NOx

SOx

hydrocarbons

CO

aldehydes

Water Pollution (tons/year)

dissolved solids

suspended solids

organics

Plant and Mine Emissions

Table 4.1

the residuals produced could be ratioed downward for lower stream factor years.

<u>Residual</u>	<u>Emission, in tons/year</u>
<u>Air</u>	
Particulates	602
Nitrogen Oxides	6,152
Sulfur Oxides	32
Hydrocarbons	113
Carbon Monoxide	415
Aldehydes	39
<u>Water</u>	
Dissolved Solids	3,540
Suspended Solids	74
Organics	35

4.1.2 FINANCIAL MODEL

Coal gasification plants will be controlled by public utilities and the gas will ultimately be sold in a regulated environment. These utilities are granted a monopoly right to provide public services, and agree to regulation of their prices to the public. The utility is allowed to cover its cost of service through the prices that it charges to the public. This cost of service includes both the current expenses of the utility, and a charge to reflect the amount of capital invested to provide the services. The financial model has the ability to calculate the prices that such a regulated utility would charge. The flexibility exists to vary several assumptions about regulation, and output the resulting prices. Also, several sensitivity cases test the effect of change in model assumptions on the average gas price.

Like all private enterprise companies, utilities try to maximize their financial performance. A complicated financial model of a utility would keep track of many measures of financial performance. However, the decisions facing the ERDA Office of Commercialization do not require such detail. It is possible to model the attractiveness of a coal gasification

plant to a public utility by computing the return to equity for the investment. The return to equity that is actually achieved can differ from the regulated rate of return because of the investment tax credit. The financial model has the ability to calculate the return to equity under various assumptions about the investment tax credit, and the tax status of the parent corporation.

Another factor that is important in regulated pricing is inflation. A plant is built using dollars from early years, yet inflation occurs over its lifetime. The fact that the fixed capital does not inflate in value provides a downward pressure on prices. The method of incorporating inflation into the analysis is discussed, and examples are given.

COST OF SERVICE PRICING

The price that a public utility charges for its service is regulated by public bodies. While the various bodies use different rules when viewed at a detailed level, the major determinants of the price remain constant across regulators. The utility is allowed to charge a price that equals its cost of service. The cost of service can be broken into several categories:

1. Operating and maintenance cost
2. Capital-related costs
 - Interest on debt
 - Return on equity
 - Taxes on income
 - Depreciation
3. By-product credits
4. Other

OPERATING AND MAINTENANCE COST

The operating and maintenance (O&M) category covers a multitude of costs. The cost of water is simply computed as the water used by the plant times the price of water. Chemical and catalyst costs are computed as a dollar amount proportional to the production of the plant. This is a reasonable assumption, since the majority of the catalysts will be used in units downstream of the gasifier. The coal cost represents a price

per million Btu of mined coal divided by the thermal efficiency of the plant. Property taxes are paid on the assessed value of the plant. Other annual operating costs are input directly.

The cost of maintaining the gasification facility is estimated as a percent of the total capital invested in the plant. Currently, two percent per year is used. The model cumulates the capital spent on the plant to a given year, and applies the two percent figure against this cumulated capital spending to compute the maintenance cost. All the yearly costs are summed to come up with the total operating and maintenance cost for the plant.

CAPITAL-RELATED COSTS AND THE RATE BASE

Two kinds of investment are required to operate a coal gasification plant. Capital is invested in the plant itself. A smaller amount of money is necessary to provide the working capital for the operation. The total capital invested is furnished from two sources: debt and equity. A plant is characterized by an equity fraction, the percent of total capital provided by shareholders' equity. Debt financing is used to fund the rest of the capital investment.

The total amount of capital invested at any time is called the rate base. This is split into debt and equity parts. The cost of service must provide funds for the interest on the debt portion of the rate base. This is simply the dollars of debt outstanding times the interest rate on the debt. The utility is allowed a regulated rate of return on its equity investment. The rate base is amortized over the plant life. A part of the cost of service is this depreciation charge. The depreciation monies are first used to decrease the debt associated with the gasification plant. When the debt is reduced to zero, the depreciation is used to repay the equity invested in the plant.

Funds for fixed capital are expended during the construction time, a period of several years' duration for a coal gasification plant. It is necessary to take account of interest on debt, and a return to equity for the money invested during the construction period. There are two major ways of doing this. They each have different effects on the rate bases.

The first method is called allowance for funds used during construction (AFUDC). Every year, the amount of debt and equity is increased by the interest and return on equity respectively. Thus, the financial charges during construction are added to the rate base during the construction period. The rate base at start-up is larger than the actual dollars spent for fixed capital. To illustrate this, consider the following construction spending schedule:

Year	1	2	3	4
Spending	100	100	100	100

Suppose the project is financed 75% by debt, and 25% by equity. The interest on debt is 10%, and the utility is allowed a 15% return on its equity. The spending is spread evenly over each year. In the first year \$25 of equity is spent. The average equity invested is one-half of the \$25, or \$12.50. The allowed return on the average investment is $.15 \times 12.50 = 1.88$. Thus, at the end of Year 1, the utility has \$26.88 worth of equity in the project. The \$1.88 is the equity component of the first year's AFUDC. During the second year, the utility has $26.88 + 12.50 = 39.38$ invested on the average, and earns $.15 \times 39.38 = 5.91$ return. Thus, at the end of Year 2 the utility has $26.88 + 25 + 5.91 = 57.79$ of equity investment. Continuing the calculations, the following table is produced:

Year	1	2	3	4
Equity spent	25.00	25.00	25.00	25.00
AFUDC, equity portion	1.88	5.91	10.54	15.88
Year-end equity investment	26.88	57.79	93.33	134.21

A similar effort produces the table for debt:

Year	1	2	3	4
Debt spent	75.00	75.00	75.00	75.00
AFUDC, debt portion	3.75	11.63	20.29	29.82
Year-end debt investment	78.75	165.28	260.67	365.49

Combining the debt and equity tables produces a project table:

Year	1	2	3	4
Project spending	100.00	100.00	100.00	100.00
AFUDC	5.63	17.54	30.83	45.70
Year-end project investment	105.63	223.17	354.00	499.70

Thus, at plant start-up, the initial rate base is \$499.70, comprised of \$134.21 of equity, and \$365.49 of debt. The \$499.70 is \$400.00 of actual spending on fixed capital, and \$99.70 of AFUDC to cover the financing costs.

The second manner of calculating the initial rate base is called the surcharge method. The future customers for the product of the gasification plant pay the interest on debt and return to equity when they occur during the construction period. The initial rate base is thus equal to the actual capital expenditures. For an example, the spending pattern, the fractions of debt and equity, and the interest rate and return on equity from the previous example will be used. During the first year of construction, an average of $1/2 \times \$25.00 = \12.50 of equity is invested. The return on the average equity is $.15 \times 12.50 = 1.88$. The future customers also pay the income tax associated with the \$1.88 of after-tax earnings. If the tax rate is 50%, the taxes paid are also \$1.88, and the total payment is \$3.76. This is the equity portion of the surcharge for Year 1. The average equity investment in Year 2 is $25.00 + 1/2 \cdot 25.00 = 37.50$, and the allowed return is $.15 \times 37.50 = 5.63$. The total payment, including taxes, is \$11.26. Completing these calculations for the equity spending, and performing similar calculations for debt spending, produces the following tables:

Year	1	2	3	4
Equity spent	25.00	25.00	25.00	25.00
Surcharge, equity portion	3.76	11.26	18.76	26.26
Year-end equity investment	25.00	50.00	75.00	100.00

Year	1	2	3	4
Debt spent	75.00	75.00	75.00	75.00
Surcharge, debt portion	3.75	11.25	18.75	26.25
Year-end debt investment	75.00	150.00	225.00	300.00

Year	1	2	3	4
Project spending	100.00	100.00	100.00	100.00
Surcharge	7.51	22.51	37.51	52.51
Year-end project investment	100.00	200.00	300.00	400.00

Thus, at plant start-up, the initial rate base is \$400.00, equal to the fixed capital spending. The \$400.00 is split into \$100.00 of equity and \$300.00 of debt. The gas consumers have made payments of $7.51 + 22.51 + 37.51 + 52.51 = 120.04$ during the construction period to pay the financing charges.

The method of determining the rate base influences the magnitude and timing of the customer payments. The AFUDC method postpones all of the payments until gas production begins. The surcharge method reduces the product price, by having customers make the financing payments before plant start-up.

The other capital-related costs are taxes, depreciation, and return on working capital. The consumers of the gas pay the utility's tax on income. The tax is related to the regulated income after tax. Consider the following accounting identities:

$$(\text{Profit before tax}) - \text{Tax} = \text{Profit after tax}$$

$$(\text{Profit before tax}) - (\text{Profit before tax}) (\text{Tax rate}) = \text{Profit after tax}$$

$$(\text{Profit before tax}) \times (1 - \text{Tax rate}) = \text{Profit after tax}$$

$$\text{Profit before tax} = (\text{Profit after tax}) \div (1 - \text{Tax rate})$$

But,

$$\text{Profit before tax} = (\text{Profit after tax}) + \text{Tax}$$

So,

$$(\text{Profit after tax}) + \text{Tax} = (\text{Profit after tax}) \div (1 - \text{Tax rate}).$$

Expressed in common terms, to take into account the income taxes that the customers pay, divide the regulated dollar amount of return on equity by one minus the tax rate. This makes sense if a 50% tax rate is considered. If the utility is allowed to earn \$100 after taxes on its equity by the regulators, then it needs \$100 to pay the income tax. Thus:

$$\text{After tax income} + \text{Taxes} = 100 \quad (1 - .5) = \$200$$

Depreciation is figured using a straight line method over the remaining life of the plant. Working capital, as defined by the Federal Power Commission, is one eighth of the yearly operating and maintenance expense. Debt and equity are invested in working capital.

BY-PRODUCT CREDITS AND OTHER COSTS

The next category of costs is called By-Product Credits. A coal gasification plant produces a wide variety of products other than synthetic high Btu gas. These by-products include such things as coal fines, tars, naphtha, phenols, and ammonia, all of which are potentially salable. The proceeds from these sales are used to reduce the revenue that the gas customers are required to furnish.

The other category of costs consists mainly of investment tax credit (ITC) passthrough, which is discussed in detail later in this section. Tax laws currently allow the utility to reduce its income taxes if it makes certain capital investments. Some regulatory agencies require the utility to pass such reduced taxes through to gas consumers in the form of lower prices. The regulatory agency specifies a period over which the ITC is passed on to the consumers. The total ITC is divided by the passthrough period, and the resulting amount is subtracted from the required revenue. For example, if the ITC was \$100, and the passthrough period is four years, \$25 is subtracted from customer-supplied revenue for the first four years of the plant's production.

The above discussion lists the elements that make up the cost of service.

BASE CASE

The financial model has been designed to implement all of the assumptions described in the last subsection. A capital spending pattern over

time is input. Either AFUDC or surcharge can be used to calculate the rate base. After start-up of the facility, capital spending can increase this rate base. To demonstrate the results of the financial calculations, consider the following example. It is called the base case; and, although it does not represent any particular proposal, it is representative of what might be expected for a gasification plant given our present state of information. The major assumptions that define the base case are listed in Table 4.2.

Figure 4.11 shows the trajectory of gas prices plotted against the year of plant operation. They are listed in Table 4.3. The average gas price is \$4.13/Mcf. Several trends are noticeable. The first year's gas price is very high (\$7.83/Mcf). This is caused by the stream factor of 50%, which reduces the gas production that must pay essentially all of the costs associated with the facility when it is running at a full stream factor of 90%. Similarly, the second year price is high because of its stream factor of 80%. After the full stream factor is reached in Year 3, the price starts to decline. This is caused by the decreasing rate base, as the yearly depreciation pays back the initial investment. The rate of price decline is slow at first, as debt, which has a charge of 9% per year, is repaid. In the later years (after Year 19), the decline in gas price is greater. Equity is being repaid. It earns 15% per year, and also provides the pretax income that generates the income taxes that the customers pay.

Consider the fifth year of the operation. The equity investment is \$347M, and the 15% return on it is \$52M. The debt outstanding is \$749M, and the 9% interest on this debt is a charge of \$67M. The return on equity and interest increase to \$53M and \$69M when the working capital charges are included. Thus, it is possible to calculate the cost of service:

	<u>\$M</u>
O&M cost	\$170
Interest on debt	69
Return on equity	53
Taxes on income	56
Depreciation	52

Fixed Plant Capital

\$1,100 M

Fixed Capital Spending Pattern

Year	-4	-3	-2	-1	1	2
	110	220	440	220	55	55

↓
Plant start-up

Yearly Operating Cost at Full Stream Factor \$170M

Yearly By-Product Credit at Full Stream Factor \$ 20M

Coal

Cost \$ 7/ton

Heating Value 8,500 Btu/lb.

Plant Operating Life 25 years

Plant Name Plate Capacity 250 million Scf/stream day

Stream Factor

Year 1 50%

Year 2 80%

Year 3-25 90%

Financial Parameters

Equity Fraction 25%

Debt Fraction 75%

Interest on Debt 9%

Return on Equity 15%

No ITC Pass through

No Surcharge

Tax Rate on Income

Federal 48%

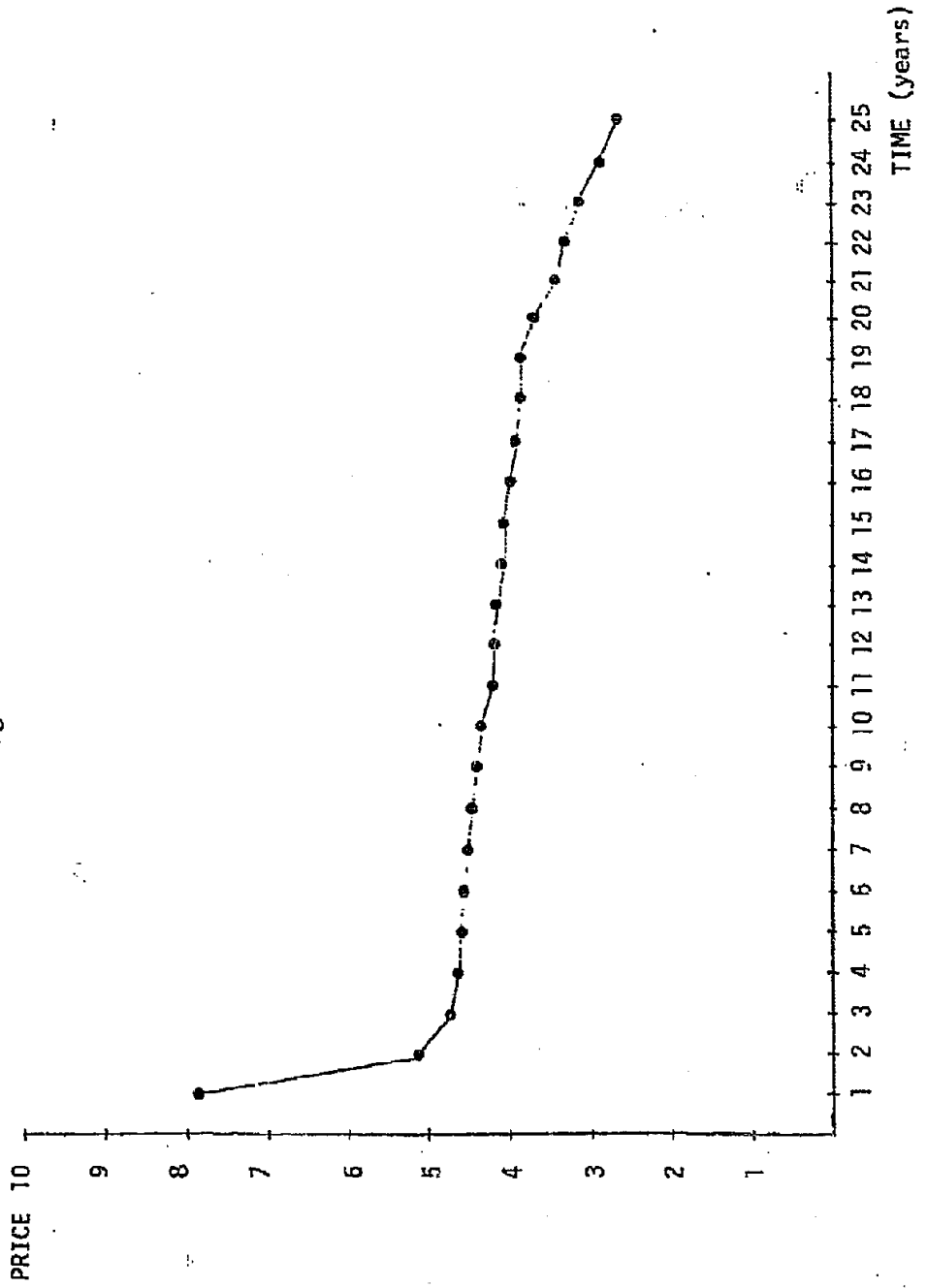
State 4%

Total 52%

Base Case Assumptions

Table 4.2

Figure 4.11: Gas Price



GAS PRICE

<u>YEAR</u>	<u>PRICE</u>
1	7.83
2	5.19
3	4.74
4	4.68
5	4.63
6	4.57
7	4.51
8	4.46
9	4.40
10	4.34
11	4.28
12	4.23
13	4.17
14	4.11
15	4.05
16	4.00
17	4.94
18	3.88
19	3.83
20	3.68
21	4.48
22	3.28
23	3.08
24	2.88
25	2.68

AVERAGE PRICE - 4.13

	<u>\$M</u>
By-product credits	(20)
Total	<u>\$380</u>

The gas production during Year 5 is:

$$250 \text{ million Scf/day} \times 365 \text{ days/year} \times 90\% \text{ stream factor} = 82.125 \text{ million Mcf.}$$

The gas price in Year 5 is:

$$\$380\text{M}/82.125 \text{ million Mcf} = \$4.63/\text{Mcf}$$

This figure can be verified in Table 4.3.

The changes in debt and equity over time are listed in Table 4.4. Several points merit discussion. At plant start-up, \$990 has been expended on fixed capital. Excluding AFUDC, \$742.5M of the fixed investment is debt, and \$247.5M is equity. However, the first year's debt and equity are \$864.0M and \$317.5M respectively. The increases of \$121.5M for debt and \$70.0M for equity represent the AFUDC. Notice that equity increases for two years after start-up, reflecting the capital expenditures made in the first two years of plant operation. Debt is reduced in the early years of plant life, until all debt is repaid by Year 20. Then equity is reduced by the yearly depreciation charged to the customers.

SENSITIVITY ANALYSIS

Figure 4.11 describes the price of the output of the base case plant over time. It is important to understand how sensitive the behavior of the price is to changes in the base case assumptions. Previous discussion covered surcharge and ITC passthrough. Both of these features reduce the gas price over time. A surcharge results in a lower rate base in the year of plant start-up, and thus there is lower interest on debt, return on equity, depreciation, and taxes on income. Passing ITC through also reduces the cost of service, producing a lower gas price. The price is reduced over the passthrough period.

Table 4.5 shows four gas price trajectories, which are plotted in Figure 4.12. The four price tracks correspond to the four possible ways of combining the presence or absence of a surcharge with the presence or

absence of the passthrough of ITC. It is identical to the plot in Figure 4.11. Trajectory 2 assumes that there is no surcharge, but that ITC is passed through to the customers over a four-year period. Notice that this set of gas prices is lower than Case 1 during the first four years of plant operation, when ITC passthrough is reducing the cost of service. From Year 5 to the end of operations, the price track is identical for Cases 1 and 2. Trajectory 3 shows the effect of a surcharge during construction. Consumers have made the following surcharge payments:

Year	-4	-3	-2	-1
Equity surcharge, \$M	2.6	10.7	27.6	45.0
Debt surcharge, \$M	4.7	19.2	49.6	81.1
Total surcharge, \$M	7.3	29.9	77.2	126.1

The total paid over the construction period is \$240.5M. Because the consumers have paid the financing charges before plant start-up, the initial rate base is \$990M, instead of the \$1181.5M initial rate base for Price Trajectory 1. Because of the reduced rate base throughout the project life, the gas price is always lower than in Case 1. The final price track, Number 4, shows the combined effects of a surcharge and a passthrough of ITC. The price track is below the first two and the relationship between Trajectories 3 and 4 duplicates that of Trajectories 1 and 2, which was discussed above.

The sensitivity of the average gas price to other model assumptions is summarized in Table 4.6. Coal cost is a significant part of the O&M charge, and a reasonable variation in the price per ton causes a significant change in average gas price. The finance charges, return on equity, and interest on debt also strongly influence the price. If maintenance difficulties are encountered, increasing the maintenance required from two to eight percent of capital, the gas price increases greatly. A more durable facility, expressed as a longer plant life, decreases the average price somewhat. Finally, a cost overrun of 20% increases the average about one eighth.

THE RETURN ON EQUITY FOR THE UTILITY

The regulatory agencies allow the utility a percentage after tax return on their equity investment. This determines a component of the cost of service. However, the cash flows to the equity investment can be such

RATE BASE

<u>YEAR</u>	<u>EQUITY</u>	<u>DEBT</u>	<u>RATE BASE</u>
1	317	864	1182
2	332	860	1192
3	347	853	1200
4	347	801	1148
5	347	749	1096
6	347	697	1044
7	347	644	991
8	347	592	939
9	347	540	887
10	347	488	835
11	347	436	783
12	347	384	731
13	347	331	678
14	347	279	626
15	347	227	574
16	347	175	522
17	347	123	470
18	347	70	417
19	347	18	365
20	313	0	313
21	261	0	261
22	209	0	209
23	157	0	157
24	104	0	104
25	52	0	52

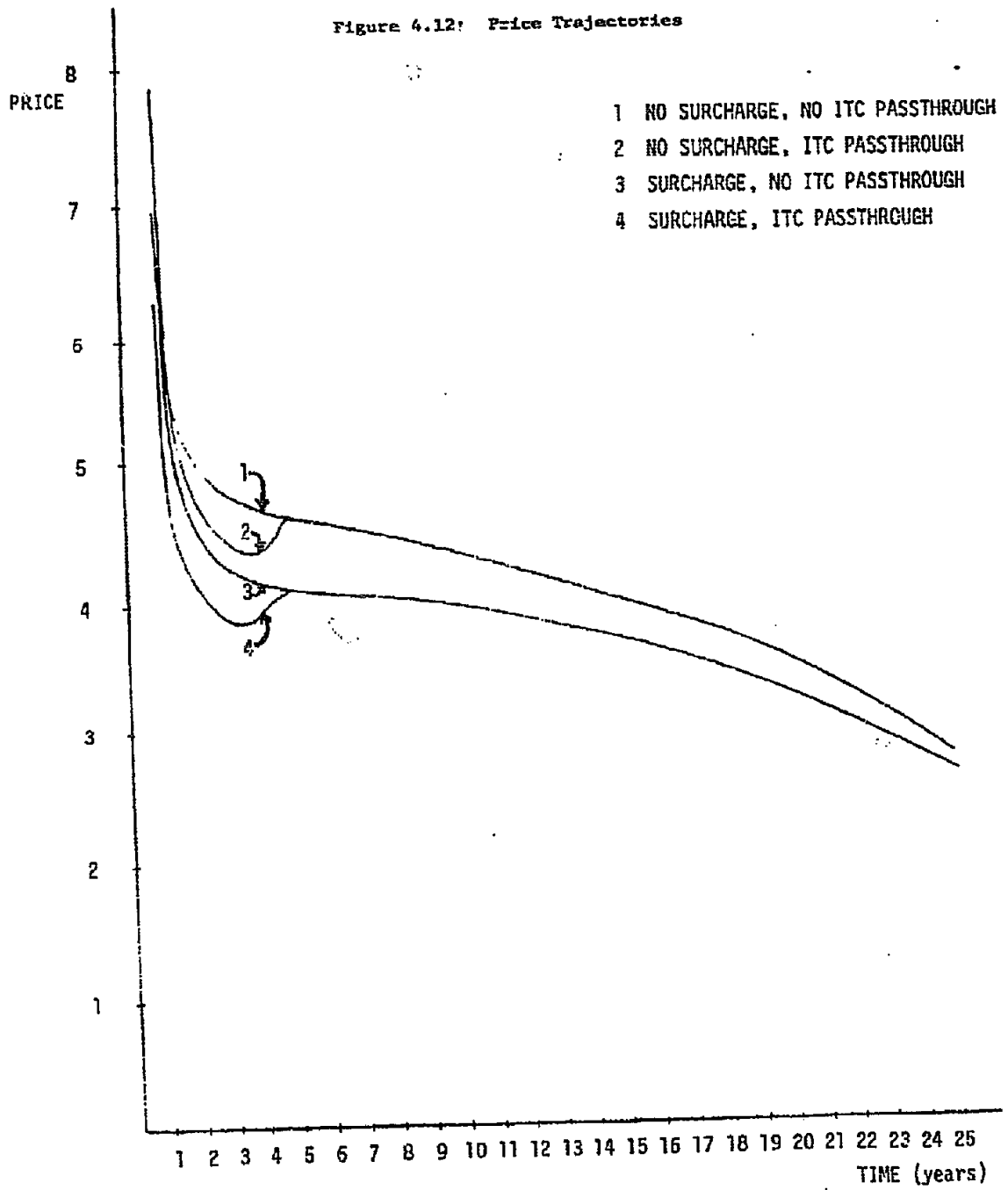
Table 4.4

GAS PRICES

YEAR	NO SURCHARGE NO PASSTHROUGH	NO SURCHARGE PASSTHROUGH	SURCHARGE NO PASSTHROUGH	SURCHARGE PASSTHROUGH
1	7.83	7.23	6.95	6.34
2	5.19	4.82	4.65	4.27
3	4.74	4.41	4.27	3.93
4	4.68	4.35	4.22	3.88
5	4.63	4.63	4.17	4.17
6	4.57	4.57	4.12	4.12
7	4.51	4.12	4.07	4.07
8	4.46	4.46	4.02	4.02
9	4.40	4.40	3.97	3.97
10	4.34	4.34	3.92	3.92
11	4.28	4.28	3.87	3.87
12	4.23	4.23	3.83	3.83
13	4.17	4.17	3.78	3.78
14	4.11	4.11	3.73	3.73
15	4.05	4.05	3.68	3.68
16	4.00	4.00	3.63	3.63
17	3.94	3.94	3.58	3.58
18	3.88	3.88	3.53	3.53
19	3.83	3.83	3.49	3.49
20	3.68	3.68	3.41	3.41
21	3.48	3.48	3.24	3.24
22	3.28	3.28	3.07	3.07
23	3.08	3.08	2.90	2.90
24	2.88	2.88	2.73	2.73
25	2.68	2.68	2.56	2.56

Table 4.5

Figure 4.12: Price Trajectories



that the return to equity can differ from the return allowed by regulators. The financial model has the ability to solve for the return to equity for the utility. In formal terms, the return to equity is the internal rate of return of the equity cash flows. Stated differently, it is the discount rate that makes the discounted value of the cash flows to equity equal to zero.

The cash flow to equity can be thought of as consisting of four components. They are listed at the top of Table 4.7. The equity column represents equity investment for fixed capital (negative in the early project's years), and return on the equity investment by the depreciation flows (positive in the later years of the project). The second component represents the cash flow required to support the equity portion of the working capital. It is negative when production is building up, and positive when the plant shuts down. The profit column represents the after-tax profits resulting from the return on equity allowed by the regulatory agency. The ITC component lists the special tax cash flow, and will be discussed at length below. The cash flow column represents the yearly cash flow to equity; it is the sum of the first four columns. The cumulative cash flow represents the year-end net equity cash outflow (negative) or inflows (positive) for the project.

Table 4.7 is the detailed cash flow associated with the base case. The equity column shows the fixed capital investments made during construction, and return on the equity in the last years of the project. The column sum is a positive \$69M. This results from the fact that AFUDC increases the equity that is placed on the utility's books above the actual cash flows. The payback of equity by depreciation flows covers both the equity portion of the actual cash flow, and the AFUDC. The working capital portion of the cash flow is small, being negative during plant start-up, and positive when operations terminate.

The profit cash flows start in the first year of the plant's operation. They increase for the first three years, the increased equity investment reflecting the continued fixed investment made after start-up. (The actual

OTHER PRICE SENSITIVITIES

	AVERAGE GAS PRICE
BASE CASE	\$4.13
COAL PRICE + 50% \$7 → \$10.50/TON	4.44
HIGH FINANCIAL CHARGES ROE: 15% → 18% INTEREST: 9% → 11%	4.56
HIGHER MAINTENANCE COST PERCENT OF CAPITAL: 2% → 8%	4.96
INCREASED PLANT LIFE 25 → 30 YEARS	4.00
INCREASED CAPITAL COST +20%	4.63

Table 4.6

BASE CASE
CASE 1

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	0	0	-28	-28
-3	-55	0	0	0	-55	-82
-2	-110	0	0	0	-110	-193
-1	-55	-4	0	0	-59	-252
1	-15	-1	48	0	33	-219
2	-15	0	51	0	36	-183
3	0	0	53	0	53	-131
4	0	0	53	0	53	-78
5	0	0	53	0	53	-25
6	0	0	53	0	53	28
7	0	0	53	0	53	81
8	0	0	53	0	53	134
9	0	0	53	0	53	186
10	0	0	53	0	53	240
11	0	0	53	0	53	292
12	0	0	53	0	53	345
13	0	0	53	0	53	398
14	0	0	53	0	53	451
15	0	0	53	0	53	504
16	0	0	53	0	53	556
17	0	0	53	0	53	609
18	0	0	53	0	53	662
19	34	0	53	0	87	749
20	53	0	48	0	100	849
21	52	0	40	0	92	941
22	52	0	32	0	84	1025
23	52	0	24	0	76	1102
24	52	0	16	0	69	1170
25	52	5	9	0	66	1236

ROE = 15.9%

Table 4.7

amount of equity can be found in Table 4.4.) The profit is \$53M from Year 3 to Year 19 because the equity account is unaltered. In Year 20, the depreciation flows are reducing the equity investment, and the regulated return on equity is being applied to a smaller equity base. ITC is not considered in this case, so the ITC column is all zeros. The cash flow column shows a typical project picture: negative cash flows during construction produce an asset that provides positive cash flows over the asset's operating life. The cumulative cash flow shows that the utility has risked a maximum amount of equity, \$262M, at the end of the construction period, that the cumulative cash flow becomes positive in the sixth year of plant operation, and that the project will produce a total positive cash flow of \$2,236M over its lifetime. The return on equity was calculated to be 15.9%, close to the 15% regulated return assumed.

INVESTMENT TAX CREDIT¹

Since the investment tax credit (ITC) may have a large impact on both gas price and the return to equity, it is important to discuss it in some detail. The ITC was instituted to encourage investment. Certain classes of capital expenditures are allowed to generate tax credits. The qualifying amount of investment dollars are multiplied by the ITC rate (a percentage), with the resulting dollar figure used to reduce income taxes. If a company spends \$100 on qualified investments, and the ITC rate is 10%, then company income taxes will be reduced by \$10. There are two necessary qualifiers. First, the company must have sufficient tax liability to benefit from the tax credit. If the above utility were required to pay \$5 of income tax, \$5 of the ITC could be used to reduce the taxes to zero. However, depending on the state of ITC legislation at the time the gasification plants are built, there may be statutory limits on how much taxes can be reduced. In particular, it might not be possible to reduce taxes in any year to zero. Such limits might affect the cases dealing with project taxes (Case 7, for example), but they will not affect the overall conclusions about the effects of ITC.

ITC tax credits not used in a certain year can be carried forward to reduce tax payments in future years, subject to certain limitations. Companies that anticipate that they can never utilize all of the ITC for tax

¹ This model ignores accelerated depreciation for income tax purposes which, we have found in subsequent studies, can have a significant effect on returns to equity.

relief can enter into complex financial arrangements to pass the ITC on to a party that can use it.

The second qualifier on the use of ITC credits pertains to when the ITC on multi-year capital projects becomes available to the company. It is easiest to illustrate this facet with an example. Assume that the company has a five-year construction period, starting in 1976 and spending \$100 every year. The ITC generated each year is \$10. The timing of its availability is summarized in the following table:

Year	1976	1977	1978	1979	1980
Capital spending	100.00	100.00	100.00	100.00	100.00
ITC generated	10.00	10.00	10.00	10.00	10.00
<hr/>					
ITC available from Year 1 spending	2.00	2.00	2.00	2.00	2.00
ITC available from Year 2 spending	-	4.00	2.00	2.00	2.00
ITC available from Year 3 spending	-	-	6.00	2.00	2.00
ITC available from Year 4 spending	-	-	-	8.00	2.00
ITC available from Year 5 spending	-	-	-	-	10.00
<hr/>					
Total ITC available by year	2.00	6.00	10.00	14.00	18.00

Current tax legislation will allow quicker availability of ITC, with immediate availability possible in the time frame of coal gasification plant construction. If construction started in 1980, ITC will be available in the year it was generated. The following ITC picture would result from the above construction spending schedule:

Year	1	2	3	4	5
ITC available by year	10.00	10.00	10.00	10.00	10.00

Table 4.8 contains the detailed cash flows associated with a coal gasification venture with ITC taken as soon as it is available. The gas plants will be owned by subsidiaries of the parent company utilities; thus the early use of ITC would require that it be applied against the parent company income taxes. The first three cash flow components are identical to Case 1 contained in Table 4.7. The ITC column represents the taxes that would be saved by the parent company; these credits reduce tax paid, and thus show up as a positive cash flow on the project accounts. The Cash Flow and Cumulative Cash Flow columns change correspondingly. Notice that the maximum equity exposure is \$152M at plant start-up, versus the previous \$252M where no investment tax credits were considered. The return to equity is 23.0%.

It is possible that a parent company would not have sufficient income tax liability to utilize the ITC generated by a coal gasification venture. Thus Case 3, shown in Table 4.9, was compiled. It is assumed that all reduced tax benefits are used against the coal gasification project's tax bill. Notice that the positive cash flows associated with the ITC column do not start until the plant starts operating, and producing profits that can be taxed. The amount of ITC is the same for Cases 2 and 3, but because the Case 3 credits are taken later in the project life, the return to equity is 20.1%, compared with the 23.0% associated with early ITC use.

Case 4 is shown in Table 4.10, and shows the effect of a surcharge during construction. The initial years of the equity investment cash flows are familiar, with the same pattern of spending to support the construction schedule. However, the last few years of this column show reduced inflows. Because the consumers were charged a surcharge during construction, there is no AFUDC added to actual equity investment spending, so depreciation flows must pay back a smaller sum. In fact, the sum of this column is zero. The working capital is identical to other cases. The profit component has changed significantly. Positive cash flows start during the construction period, reflecting the equity portion of the surcharge. However, less equity is built up. In Case 1, equity at plant start-up is \$317.5M, while the surcharge has reduced the figure to $.25 \times 990 = \$247.5M$. Thus, the

CASE 2

ITC ON PARENT COMPANY TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	0	3	-25	-25
-3	-55	0	0	14	-41	-66
-2	-110	0	0	41	-69	-135
-1	-55	-4	0	41	-18	-152
1	-15	-1	48	6	38	-115
2	-15	0	51	6	41	-73
3	0	0	53	0	53	-21
4	0	0	53	0	53	32
5	0	0	53	0	53	85
6	0	0	53	0	53	138
7	0	0	53	0	53	191
8	0	0	53	0	53	244
9	0	0	53	0	53	296
10	0	0	53	0	53	349
11	0	0	53	0	53	402
12	0	0	53	0	53	455
13	0	0	53	0	53	508
14	0	0	53	0	53	561
15	0	0	53	0	53	614
16	0	0	53	0	53	666
17	0	0	53	0	53	710
18	0	0	53	0	53	772
19	34	0	53	0	87	859
20	53	0	48	0	100	959
21	52	0	40	0	92	1051
22	52	0	32	0	84	1135
23	52	0	24	0	76	1212
24	52	0	16	0	69	1280
25	52	5	9	0	66	1346

ROE = 23.0%

Table 4.8

CASE 3
ITC ON PROJECT TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	0	0	-28	-28
-3	-55	0	0	0	-55	-83
-2	-110	0	0	0	-110	-193
-1	-55	-4	0	0	-59	-252
1	-15	-1	48	52	85	-167
2	-15	0	51	55	90	-76
3	0	0	53	3	56	-21
4	0	0	53	0	53	32
5	0	0	53	0	53	85
6	0	0	53	0	53	138
7	0	0	53	0	53	191
8	0	0	53	0	53	244
9	0	0	53	0	53	296
10	0	0	53	0	53	349
11	0	0	53	0	53	402
12	0	0	53	0	53	455
13	0	0	53	0	53	508
14	0	0	53	0	53	561
15	0	0	53	0	53	614
16	0	0	53	0	53	666
17	0	0	53	0	53	719
18	0	0	53	0	53	772
19	34	0	53	0	87	859
20	53	0	48	0	100	959
21	52	0	40	0	92	1051
22	52	0	32	0	85	1135
23	52	0	24	0	76	1212
24	52	0	16	0	69	1280
25	52	5	9	0	66	1346

ROE = 20.1 %

Table 4.9

CASE 4
SURCHARGE DURING CONSTRUCTION

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	2	0	-26	-28
-3	-55	0	8	0	-47	-72
-2	-110	0	21	0	-89	-162
-1	-55	-4	33	0	-26	-188
1	-15	-1	38	0	22	-166
2	-15	0	40	0	25	-140
3	0	0	42	0	42	-98
4	0	0	42	0	42	-56
5	0	0	42	0	42	-13
6	0	0	42	0	42	29
7	0	0	42	0	42	71
8	0	0	42	0	42	114
9	0	0	42	0	42	156
10	0	0	42	0	42	198
11	0	0	42	0	42	241
12	0	0	42	0	42	283
13	0	0	42	0	42	325
14	0	0	42	0	42	368
15	0	0	42	0	42	410
16	0	0	42	0	42	452
17	0	0	42	0	42	495
18	0	0	42	0	42	537
19	10	0	42	0	52	589
20	45	0	40	0	85	675
21	45	0	34	0	79	753
22	45	0	28	0	72	825
23	45	0	21	0	65	891
24	45	0	14	0	59	949
25	45	5	7	0	58	1007

ROE = 16.1%

Table 4.10

profit is reduced during plant operation -- \$42M versus \$53M. The ITC column contains zeros, reflecting the fact that no investment tax credit effects have been considered. The return to equity is 16.1% for this case.

Case 5 reflects the effect of ITC on the previous case. It is detailed in Table 4.11. The cash flows are identical save in the ITC column. The tax reduction is assumed to be taken as soon as it is available. (The surcharge provides early year project taxes that could be reduced, so no "project tax reduction" case is appropriate.) Two main differences appear. First, the return to equity has increased to 26.1%. Second, the maximum equity exposure is reduced from \$188M in the previous case to \$104M in this case.

Next, ITC passthrough will be discussed. It is assumed that the regulatory agency requires that ITC tax savings be used to reduce the cost of service, and lower gas prices. The ITC is assumed to be passed to the consumers over a four-year period, as in previous discussion. Case 6 in Table 4.12 shows the cash flows. The only change from Case 2 is the negative cash flows in Years 1 to 4. This represents the passthrough of ITC to reduce customer charges. The \$22M figure in Years 1 and 2 represents the net outflow resulting from ITC passback of \$28M, and the \$6M of ITC gained from first and second year fixed investment spending. The rate of return on equity is 18.2%. A similar exercise applies the ITC to project taxes in Case 7 shown in Table 4.13. The ITC positive flows are delayed until plant start-up. The return on equity is 16.4%.

Finally, it is possible to combine the effects of a surcharge and ITC passthrough. This is captured in Case 8 on Table 4.14. The equity and profit columns represent the effect of the surcharge during construction, while the ITC column represents the effect of ITC used against parent company taxes, and repaid over the first four years of plant operation. The return to equity is calculated as 19.3%.

The previous discussion has covered many cases. A summary of the rates of return to equity is given in Table 4.15. Where there is no rate of return entered, the case has no relevance.

Previous mention was made of future changes in the tax laws that would allow immediate availability of ITC. This law would allow faster tax reduction for cases where ITC was used to reduce parent company taxes. These cash flows have been developed, called Cases 2A, 5A, 6A, and 8A, and are listed in Tables 4.16, 4.17, 4.18, and 4.19 respectively. The rates of return to equity increase moderately as a result of the faster writeoff, with the actual numbers and a comparison with the existing tax law results, listed on Table 4.20.

It is possible that government loan guarantees may provide a greater portion of the funds during construction. To correspond to financing plans that have been discussed, the following case has been developed. The construction period is financed 90% by debt, and 10% by equity. After the plant is operating satisfactorially, the 75% debt, 25% equity split is established by refinancing 15% of the investment from debt to equity. A surcharge is paid by customers during the construction period. The investment tax credit would be applied against parent company taxes, using current tax laws. This case is shown in Table 4.21. The return to equity is 35.8%. The investment tax credit and surcharge are sufficient to make the cumulative cash flow positive at plant start-up. The refinancing of debt in Year 1 causes the maximum exposure of \$99M. A similar exercise can be performed using the future ITC tax legislation. Table 4.22 shows the results. The ITC and surcharge are sufficient to make the cash flow positive during every year of the construction period. The only year of negative cash flow is the first year of operation, and again the maximum exposure is \$99M. The return to equity is 54.0%.

INFLATION

Any analysis that considers outcomes that span a large number of years requires explicit consideration of inflation. A coal gasification venture has a time horizon of about thirty years, so that inflation can become an important factor. All previous discussion about the financial model has neglected inflation to focus on the subjects at hand.

CASE 5
SURCHARGE WITH ITC ON PARENT COMPANY TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
			2	4	-22	-22
-4	-28	0	8	14	-33	-56
-3	-55	0	21	41	-48	-104
-2	-110	0	33	41	15	-89
-1	-55	-4	38	6	28	-61
1	-15	-1	40	6	21	-30
2	-15	0	42	0	42	12
3	0	0	42	0	42	54
4	0	0	42	0	42	97
5	0	0	42	0	42	140
6	0	0	42	0	42	181
7	0	0	42	0	42	224
8	0	6	42	0	42	266
9	0	0	42	0	42	308
10	0	0	42	0	42	351
11	0	0	42	0	42	393
12	0	0	42	0	42	435
13	0	0	42	0	42	478
14	0	0	42	0	42	520
15	0	0	42	0	42	562
16	0	0	42	0	42	605
17	0	0	42	0	42	647
18	0	0	42	0	52	700
19	10	0	40	0	85	785
20	45	0	34	0	79	863
21	45	0	28	0	72	935
22	45	0	21	0	65	1001
23	45	0	14	0	59	1059
24	45	0	7	0	57	1117
25	45	5				

ROE = 26.1%

Table 4.11

CASE 6

ITC PASSED TO CONSUMERS, TAKEN AGAINST COMPANY TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	0	3	-25	-25
-3	-55	0	0	14	-41	-66
-2	-110	0	0	41	-69	-135
-1	-55	-4	0	41	-18	-153
1	-15	-1	48	-22	11	-142
2	-15	0	51	-22	14	-128
3	0	0	53	-28	25	-103
4	0	0	53	-28	25	-78
5	0	0	53	0	53	-25
6	0	0	53	0	53	28
7	0	0	53	0	53	81
8	0	0	53	0	53	134
9	0	0	53	0	53	186
10	0	0	53	0	53	239
11	0	0	53	0	53	292
12	0	0	53	0	53	345
13	0	0	53	0	53	398
14	0	0	53	0	53	451
15	0	0	53	0	53	504
16	0	0	53	0	53	556
17	0	0	53	0	53	609
18	0	0	53	0	53	662
19	34	0	53	0	87	749
20	52	0	48	0	100	849
21	52	0	40	0	92	941
22	52	0	32	0	84	1025
23	52	0	24	0	76	1102
24	52	0	16	0	69	1170
25	52	5	9	0	66	1236

Table 4.12

ROE = 18.2%

CASE 7
ITC PASSED TO CONSUMERS, TAKEN AGAINST PROJECT TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	0	0	-28	-28
-3	-55	0	0	0	-55	-83
-2	-110	0	0	0	-110	-192
-1	-55	-4	0	0	-59	-252
1	-15	-1	48	25	58	-194
2	-15	0	51	27	63	-142
3	0	0	53	-25	28	-103
4	0	0	53	-27	25	-78
5	0	0	53	0	53	-25
6	0	0	53	0	53	28
7	0	0	53	0	53	81
8	0	0	53	0	53	134
9	0	0	53	0	53	186
10	0	0	53	0	53	239
11	0	0	53	0	53	292
12	0	0	53	0	53	345
13	0	0	53	0	53	398
14	0	0	53	0	53	451
15	0	0	53	0	53	504
16	0	0	53	0	53	556
17	0	0	53	0	53	609
18	0	0	53	0	53	662
19	34	0	53	0	87	749
20	52	0	48	0	100	849
21	52	0	40	0	92	941
22	52	0	32	0	84	1025
23	52	0	24	0	76	1102
24	52	0	16	0	69	1170
25	52	5	9	0	66	1236

Table 4.13

ROE = 16.4%

CASE 8
SURCHARGE; ITC PASSED TO CONSUMERS,
TAKEN AGAINST COMPANY TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	2	3	-23	-23
-3	-55	0	8	14	-33	-56
-2	-110	0	21	41	-48	-104
-1	-55	-4	33	41	15	-89
1	-15	-1	38	-22	0	-89
2	-15	0	40	-22	3	-85
3	0	0	42	-28	15	-71
4	0	0	42	-28	15	-56
5	0	0	42	0	42	-13
6	0	0	42	0	42	29
7	0	0	42	0	42	71
8	0	0	42	0	42	114
9	0	0	42	0	42	156
10	0	0	42	0	42	198
11	0	0	42	0	42	241
12	0	0	42	0	42	283
13	0	0	42	0	42	325
14	0	0	42	0	42	368
15	0	0	42	0	42	410
16	0	0	42	0	42	452
17	0	0	42	0	42	495
18	0	0	42	0	42	537
19	10	0	42	0	52	590
20	45	0	41	0	85	675
21	45	0	34	0	79	753
22	45	0	28	0	72	825
23	45	0	21	0	65	891
24	45	0	14	0	59	949
25	45	5	7	0	57	1007

ROE = 19.3%

Table 4.14

SUMMARY RATES OF RETURN ON EQUITY

CASE		SURCHARGE	AVE. GAS PRICE	ROE, %		
ITC PASSTHROUGH	No ITC			COMPANY ITC	PROJECT ITC	
No	No	4.13	15.9	23.0	20.1	
No	YES	3.75	16.1	26.1	16.4	
YES	No	4.07		18.2		
YES	YES	3.70		19.3		

Table 4.15

To focus on inflation, let's make two definitions. Dollar flows are said to be in constant dollars if they have not been inflated. It is necessary to provide a reference year for such dollars. For example, GNP is often stated in 1958 dollars (1958\$), and coal gasification plant capital costs are expressed in 1975 dollars (1975\$). A coal gasifier would be in 1975\$ if the 1975 price is used. If dollar flows are inflated, they are in current dollars. If the gasifier is to be purchased in 1980, and there is inflation between 1975 and 1980, the price for the gasifier would be higher in 1980. This higher price would be the current dollar cost of the piece of equipment. Assume that the gasifier would cost \$100 if purchased in 1975. Assume that inflation is five percent between 1975 and 1980. Then the price of the gasifier in 1980 would be $100 \times (1.05)^5 = \$127.63$. The constant dollar price is \$100, in 1975 dollars. The current dollar price would be \$127.63 in 1980.

Most energy studies are conducted using constant dollars. This has the convenience of using prices that currently exist. Communication is also facilitated, because dollar quantities can be compared with conventional frames of reference. (For example, if a coal gasification plant costs \$1B in 1975, and if inflation is 5% per annum, the plant would cost \$2.08B in 1990. This figure is difficult for many people to understand or comprehend.) The current study, and previous studies using the SRI National Energy Model, work with prices in 1975 dollars. However, an important inflation correction is required for price-regulated industries.

The majority of the fixed capital investment is made by a utility in the early years of a project's life. These expenditures form the majority of the rate base. The 1975 dollar cost should be inflated to reflect current dollars. However, when the money is spent, the rate base does not continue to grow with inflation. Other expenditures which occur on a yearly basis will inflate over time. Thus, part of the cost of service increases with inflation (the yearly expenditures), and part can be considered to be independent of inflation (the "capital charges"). Thus, if inflation is 5%, part of the cost of service inflates at 5%, and part at 0%, resulting in an average inflation rate of about 3%. If the overall

CASE 2A
NEW ITC LAW TAKEN AGAINST PARENT COMPANY TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	0	11	-17	-17
-3	-55	0	0	22	-33	-50
-2	-110	0	0	44	-66	-116
-1	-55	-4	0	22	-37	-153
1	-15	-1	48	6	38	-115
2	-15	0	51	6	41	-73
3	0	0	53	0	53	-21
4	0	0	53	0	53	32
5	0	0	53	0	53	85
6	0	0	53	0	53	138
7	0	0	53	0	53	191
8	0	0	53	0	53	244
9	0	0	53	0	53	296
10	0	0	53	0	53	349
11	0	0	53	0	53	402
12	0	0	53	0	53	455
13	0	0	53	0	53	508
14	0	0	53	0	53	561
15	0	0	53	0	53	614
16	0	0	53	0	53	666
17	0	0	53	0	53	710
18	0	0	53	0	53	772
19	34	0	53	0	87	859
20	53	0	48	0	100	959
21	52	0	40	0	92	1051
22	52	0	32	0	84	1135
23	52	0	24	0	76	1212
24	52	0	16	0	69	1280
25	52	5	9	0	66	1346

ROE = 24.1%

Table 4.16

CASE 5A
SURCHARGE, NEW ITC TAX LAW WITH ITC
ON PARENT COMPANY TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	2	11	-14	-14
-3	-55	0	8	22	-25	-39
-2	-110	0	21	44	-45	-85
-1	-55	-4	33	22	-4	-89
1	-15	-1	38	6	28	-61
2	-15	0	40	6	21	-30
3	0	0	42	0	42	12
4	0	0	42	0	42	54
5	0	0	42	0	42	97
6	0	0	42	0	42	140
7	0	0	42	0	42	181
8	0	0	42	0	42	224
9	0	0	42	0	42	266
10	0	0	42	0	42	308
11	0	0	42	0	42	351
12	0	0	42	0	42	393
13	0	0	42	0	42	435
14	0	0	42	0	42	478
15	0	0	42	0	42	520
16	0	0	42	0	42	562
17	0	0	42	0	42	605
18	0	0	42	0	42	647
19	10	0	42	0	52	700
20	45	0	40	0	85	785
21	45	0	34	0	79	863
22	45	0	28	0	72	935
23	45	0	21	0	65	1001
24	45	0	14	0	59	1059
25	45	5	7	0	57	1117

ROE = 28.0%

Table 4.17

CASE 6A
 NEW ITC TAX LAW, ITC PASSED
 PASSED TO CONSUMERS, TAKEN AGAINST COMPANY TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	0	11	-17	-17
-3	-55	0	0	22	-33	-50
-2	-110	0	0	44	-56	-116
-1	-55	-4	0	22	-37	-153
1	-15	-1	48	-22	11	-142
2	-15	0	51	-22	14	-128
3	0	0	53	-28	25	-103
4	0	0	53	-28	25	-78
5	0	0	53	0	53	-25
6	0	0	53	0	53	28
7	0	0	53	0	53	81
8	0	0	53	0	53	134
9	0	0	53	0	53	186
10	0	0	53	0	53	239
11	0	0	53	0	53	292
12	0	0	53	0	53	345
13	0	0	53	0	53	398
14	0	0	53	0	53	451
15	0	0	53	0	53	504
16	0	0	53	0	53	556
17	0	0	53	0	53	609
18	0	0	53	0	53	662
19	34	0	53	0	87	749
20	52	0	48	0	100	849
21	52	0	40	0	92	941
22	52	0	32	0	84	1025
23	52	0	24	0	76	1102
24	52	0	16	0	69	1170
25	52	5	9	0	66	1236

ROE = 18.9%

Table 4.18

CASE 8A
 SURCHARGE; NEW ITC TAX LAW, ITC PASSED TO
 CONSUMERS, TAKEN AGAINST COMPANY TAXES

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-28	0	2	11	-14	-14
-3	-55	0	8	22	-25	-39
-2	-110	0	21	44	-45	-85
-1	-35	-4	33	22	-4	-89
1	-15	-1	38	-22	0	-89
2	-15	0	40	-22	3	-85
3	0	0	42	-28	15	-71
4	0	0	42	-28	15	-56
5	0	0	42	0	42	-13
6	0	0	42	0	42	29
7	0	0	42	0	42	71
8	0	0	42	0	42	114
9	0	0	42	0	42	156
10	0	0	42	0	42	198
11	0	0	42	0	42	241
12	0	0	42	0	42	283
13	0	0	42	0	42	325
14	0	0	42	0	42	368
15	0	0	42	0	42	410
16	0	0	42	0	42	452
17	0	0	42	0	42	495
18	0	0	42	0	42	537
19	10	0	42	0	52	590
20	45	0	41	0	85	675
21	45	0	34	0	79	753
22	45	0	28	0	72	825
23	45	0	21	0	65	891
24	45	0	14	0	59	949
25	45	5	7	0	57	1007

ROE = 20.1%

Table 4.19

ITC TAKEN AGAINST PARENT COMPANY

CASE		ROE, %	
ITC PASSTHROUGH	SURCHARGE	NEW LAW	OLD LAW
NO	NO	24.1	23.0
NO	YES	28.0	26.1
YES	NO	18.9	18.2
YES	YES	20.2	19.3

Table 4.20

SPECIAL CASE

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-11	0	1	3	-7	-7
-3	-22	0	3	14	-5	-12
-2	-44	0	8	41	6	-7
-1	-22	-4	13	41	28	21
1	-163	-1	38	6	-120	-99
2	-15	0	40	6	31	-69
3	0	0	42	0	42	-26
4	0	0	42	0	42	16
5	0	0	42	0	42	58
6	0	0	42	0	42	101
7	0	0	42	0	42	143
8	0	0	42	0	42	185
9	0	0	42	0	42	228
10	0	0	42	0	42	270
11	0	0	42	0	42	312
12	0	0	42	0	42	355
13	0	0	42	0	42	397
14	0	0	42	0	42	439
15	0	0	42	0	42	482
16	0	0	42	0	42	524
17	0	0	42	0	42	566
18	0	0	42	0	42	609
19	10	0	42	0	52	661
20	45	0	40	0	85	746
21	45	0	34	0	79	825
22	45	0	28	0	72	897
23	45	0	21	0	65	962
24	45	0	14	0	59	1021
25	45	5	7	0	57	1078

Table 4.21

ROE = 35.8%

SPECIAL CASE, NEW ITC TAX LAW

YEAR	EQUITY INVEST	WORKING CAPITAL	PROFIT	ITC	CASH FLOW TO EQUITY	CUMULATIVE CASH FLOW
-4	-11	0	1	11	1	1
-3	-22	0	3	22	3	4
-2	-44	0	8	44	8	12
-1	-22	-4	13	22	9	21
1	-163	-1	38	6	-120	-99
2	-15	0	40	6	31	-69
3	0	0	42	0	42	-26
4	0	0	42	0	42	16
5	0	0	42	0	42	58
6	0	0	42	0	42	101
7	0	0	42	0	42	143
8	0	0	42	0	42	185
9	0	0	42	0	42	228
10	0	0	42	0	42	270
11	0	0	42	0	42	312
12	0	0	42	0	42	355
13	0	0	42	0	42	397
14	0	0	42	0	42	439
15	0	0	42	0	42	482
16	0	0	42	0	42	524
17	0	0	42	0	42	566
18	0	0	42	0	42	609
19	10	0	42	0	52	661
20	45	0	40	0	85	746
21	45	0	34	0	79	825
22	45	0	28	0	72	897
23	45	0	21	0	65	962
24	45	0	14	0	59	1021
25	45	5	7	0	57	1078

ROE = 54.0%

Table 4.22

inflation rate for the economy is also 5%, then the gas price will be decreasing relative to other prices. Thus, the 1975 dollar price should be less if inflation is considered.

The 1975 dollar costs and prices used in this report do not correspond directly with the conventional usage of the term. Most other studies neglect the inflation effects altogether when calculating 1975 dollar numbers. These other studies take capital cost and operating costs in 1975 dollars, allocate them over time, and discount them to yield the present value cost in 1975 dollars. If the discount rates used by other studies are the same as ours, and if the constant dollar capital and operating costs are equal, the inflation/deflation method we use will result in lower costs in our report.

Again, a detailed example will help in understanding the issues. The example is based on the base case of the previous subsections. Assume that all previous base case numbers are current 1975 dollars. Inflation is 5% per year. The seven categories of charges for cost of service will be discussed, for the fifth year of gas production.

The operating and maintenance cost is \$170M in 1975 dollars. The construction period is four years long, so that nine years of inflation must be factored in to produce the current dollar O&M cost in the fifth year of operation. The calculation yields

$$(1.05)^9 \times 170 = \$264\bar{M}$$

To calculate the interest, return to equity, and tax charges, it is necessary to look at the rate base. The following converts the capital spending from constant to current dollars:

Year	-4	-3	-2	-1	1	2
Spending, 1975 \$M	110	220	440	220	55	55
Year	-4	-3	-2	-1	1	2
Inflator	1.05	1.10	1.16	1.22	1.28	1.34
Spending, current \$M	116	242	509	267	70	74