A FINANCIAL ANALYSIS OF SYNTHETIC FUEL TECHNOLOGIES

by

Saman Majd

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Certified by ______________________
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Accepted by ______________________
Chairman, Department Committee

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ABSTRACT

One of the primary goals of the United States' national energy policy is a reduced dependence on foreign oil imports. New technologies for the production of synthetic fuels from coal and shale rock are being proposed as a means of reducing these imports. Private industry, however, claims the need for various forms of government support during the commercialization stage in order to offset the high risks and costs of developing these technologies.

In this thesis we: (a) present collected data for the investment and operating costs of selected synthetic fuels technologies; (b) obtain quantitative measures of their profitability and risk using a Monte Carlo simulation technique; (c) present a method for the valuation of demonstration plants for new technologies; (d) examine the major areas of risk and uncertainty involved in synthetic fuels development; and, (e) discuss briefly the role of the government in the commercialization stage of the development of synthetic fuels.

The appendix contains, in addition to the detailed cost estimates and results of the financial analysis, a summary of the major environmental problems anticipated with synfuels production, and a brief description of the technologies analyzed in this thesis.

Thesis Supervisor: Stewart C. Myers (Professor of Finance)

CONTENTS

I. Introduction

Ever since the 1974 energy crisis, when world oil prices increased dramatically, awareness of the United States' dependence on imported liquid fuels has greatly increased: this dependence is viewed as an economic, and hence a national security, threat. Consequently, independence from foreign supplies of oil, or more precisely, protection from the threat of another oil embargo, has become a primary goal of U.S. national energy policy, and policies aimed at increasing domestic supplies of oil and natural gas are being pursued by the Department of Energy.

The DOE is currently showing great interest in technologies for the production of synthetic oil and gas, particularly oil shale and coal liquefaction and gasification. The primary reason for this interest is the enormous quantity of synthetic fuel potentially recoverable from coal and shales. One source* estimates the U.S. share of the world's recoverable shale resources (approximately 800 billion barrels oil equivalent) to be 30.8%, and of the world's recoverable coal resources (approximately 1,100 billion bbl oil equivalent) to be 72.7%. The same source estimates the total world recoverable crude oil reserves to be 716 million barrels, and the U.S.'s share to be only 35 billion barrels (although these latter figures seem

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* See Reference (1).

rather low).

The basic technology for producing oil and gas from coal and oil shales has been known for many years. During World War II, Germany built twelve coal liquefaction plants that accounted for a large proportion of her consumption of liquid fuels, and South Africa is at present using the German technology (the "Fisher-Tropsch" method) to produce both natural gas and liquids from coal.* Other technologies have been under research and development for many years: some are only just emerging from bench-scale experimentation, others are at the demonstration plant stage.**

Given the existence of such vast reserves, and the relative level of development of certain of these technologies, why has private industry not exploited these technologies to develop the coal and shale resources of the United States?

The oil companies involved in the research and development of synthetic fuels claim the need for government support at

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* See Reference (1).

** Although there are no clear boundaries between the different stages from bench-scale experimentation to full commercialization, the demonstration stage falls roughly between development and commercialization. Demonstration essentially involves scaling-up the basic research and linking together the various components of the process, although not necessarily at full-scale. An important part of demonstration is the measurement of various technical parameters and obtaining cost estimates for the process. Commercialization is necessarily at full-scale, and results in pinning down the costs. It may also be interpreted as including the diffusion of the process into the market place.

the commercialization stage, often quoting high costs and a high degree of risk and uncertainty. The major areas of risk and uncertainty associated with such projects can be identified as follows:

1. With any new and untried technology, there are technological problems encountered in scaling up the process to a commercial scale. These are "risks" in two ways: first, any unforeseen and lengthy delays in construction and operation of the plant caused by technological problems can greatly increase the cost of the plant; second, any design changes or refinements that must be made can increase both the construction and the operating costs.

2. There are uncertainties over the exact environmental impacts of full-scale operation of such plants, and over the future environmental regulations that will apply. If it transpires that the commercial-size plants do not satisfy the Federal or state environmental requirements, the pollution control equipment required to comply with the regulations will increase the costs. Even if the plant meets current requirements, pressure from environmental protection groups may cause future regulations to become more stringent. Finally, a very large number of permits must be obtained before construction of plants can be completed, and inordinate delays in the time required to obtain them can delay construction and increase costs.

3. There is great uncertainty over the future world price oil, and over government controls of the domestic price. Producers may not be allowed to sell their porducts at the world price, and if they are allowed to do so the path of world oil prices becomes critical in determining the profitability of the plant. On top of this there is the possibility that the government may tax away "excess profits" from such plants, leaving the company a distribution of returns that may be truncated at the upper tail.

Although it is relatively easy to identify the major areas of risk and uncertainty, it is not easy to quantify them. It is clear, however, that the economics of synthetic fuels production must be better understood before we can discuss whether or not the government should be involved in their development. More specifically, we need a quantitative measure of the profitability and riskiness of such projects, and this is the principal aim of this paper.

In the next section we present investment and operating cost estimates for some favored synthetic fuel technologies, and describe, in Section III, our financial analysis and present the results. In light of our results, we conclude, in Section IV, with a discussion of issues related to government involvement in the commercialization of synthetic fuels.

Appendix A contains a brief overview of the technologies analyzed in this paper. A brief discussion of our sources of cost data and a detailed breakdown of the cost estimates will be found in Appendix B. Detailed results of the financial analysis are presented in Appendix C, and in Appendix D we present an overview of the major environmental issues involved.

II. Investment and Operating Costs For Selected Technologies

As stated in the Introduction, our principal aim in this study is to gain a better understanding of the economics of synthetic fuels production, so that we may have a sounder basis for discussing the role of the government in developing these technologies.

As a first step, we must obtain estimates of the construction and operating costs for a commercial-size plant for the technologies under consideration. Unfortunately, this is, for various reasons, the most difficult part of the study. First, there are the endogenous uncertainties regarding the technologies themselves. As no full-sized plants have yet been built in the U.S., all the hard engineering data is from small-scale testing, or at most, pilot plants. Furthermore, different components of the entire production process are at different stages of development, some more technologically uncertain than others. Hence, technical problems can be expected when scaling-up the process to full size, and this can cause cost overruns for two reasons: (1) inordinate delays during construction are costly, no matter what their origin; and (2) any changes or refinements that may become necessary will also increase costs.

The other reasons for uncertainty in present cost estimates are essentially exogenous, and can cause cost overruns for the same reasons as above; that is , they can cause delays in construction or necessitate expensive alterations in design. One such reason is the concern over the environmental impact of synfuels production. The possibility of lengthy delays in obtaining the necessary permits or due to action by environmental protection groups has added to the preceived risk and costs of these projects.

In addition to the above problems, the researcher in search of cost estimates faces several others. First, the sources generally do not give adequate information about the assumptions or parameters used in arriving at their figures; second, the most recent and complete cost estimates are proprietary property of the companies involved, and hence unavailable.

The technolgoical uncertainties do, in principle, lend themselves to quantitative treatment. The effect of cost overruns on profitability and the variance of the profitability can be calculated, and this is the subject of Section III. The other, exogenous, problems are relatively more difficult to quantify, and we have not attempted to do so in this paper. (The main environmental issues, however, are summarized and discussed qualitatively in Appendix D.)

In this report we examine four coal liquefaction technologies (SRC, Synthoil, H-Coal, and EDS) and a modified in-situ oil shale technology. The four coal liquefaction technologies were chosen for two reasons: (1) they are at or near the pilot plant stage, and have received attention at the Department of Energy; and, (2) reasonably complete cost data was available, and the costs appear to be in the same range as those of other liquefaction and gasification technologies. A modified in-situ technology was chosen for oil shale as it is the variation considered most likely to be commercialized in the near future. A brief background to these technologies is given in Appendix A, and our sources of cost data are briefly discussed in Appendix B.

The investment and annual operating costs for the technologies are summarized in Table 1 (a more detailed breakdown is given in Appendix B). The assumptions and parameters used in arriving at these figures are summarized as follows:

1. 1976 dollars are used throughout.
2. The plants yield 50,000 bb/stream day (60,000 bbl/sd EDS), and operate 330 days/year.
3. Because the processes yield different products of differing value, the operating costs have been adjusted to reflect this fact, and to put them on a comparable basis. The calculations for this are described in Appendix B.
4. The operating costs do not provide for the replacement of worn-out equipment, and provision for this is included in the cashflow analysis in Section III.
5. As a contingency for difficulties with the process in the first year, the output in that year is taken as only 50% of normal, as is the consumption of coal (or shale) and utilities.

6. Wyodak coal will be at $7.50/ton and Illinois and Western Kentucky coal will be at $20/ton* throughout the life of the plant.
7. In Table 1, the figures refer to startup of operations in 1987, whereas the figures in Appendix B refer to startup in 1976. The costs have been escalated (in real terms) to account for increases in labor and materials costs in the interim.

From the figures in Table 1 we can see that EDS has the highest investment and operating costs of the coal liquefaction technolgoies, and that modified in-situ oil shale appears less expensive than the coal liquefaction technologies. Because we have adjusted the operating costs to account for the differing grades of liquid products from the technologies, H-Coal appears to have the lowest operating costs. This is due to the fact that the H-Coal process examined here includes some refining of the products to produce more expensive fuels. This is also reflected in the high investment costs of H-Coal as compared to SRC and Synthoil.

Our cost estimates are not as recent or reliable as we would have wished, and are subject to considerable uncertainty. What is important, however, is that they are representative of the order of magnitude of the costs, and therefore will provide us with a range of values to work with in our financial analysis.

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* From private communication with Professor Martin Zimmerman at Sloan School of Management, M.I.T.

TABLE 1: Cost summary for selected technologies (000)*

	First year operating costs	Annual operating costs	Subtotal for depreciation	Total investment
SRC	138,617	203,706	791,102	854,390
SYNTHOIL	189,725	245,004	647,051	771,756
H-COAL	127,350	143,500	1,171,796	1,265,539
EDS	246,747	374,760	1,648,843	1,741,687
IN-SITU SHALE	135,792	192,163	674,560	748,760

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* For assumptions involved in arriving at these figures, see text. A breakdown of these figures is presented in Appendix B. Note, however, that these costs have been escalated at 2% per year to a 1987 startup (but in 1976 $), whereas the figures in the Appendix are for a 1976 startup.

III. Financial Analysis

Having presented estimates of the investment and operating costs for our selected technologies, we now describe how these estimates are used to arrive at measures of profitability and risk.

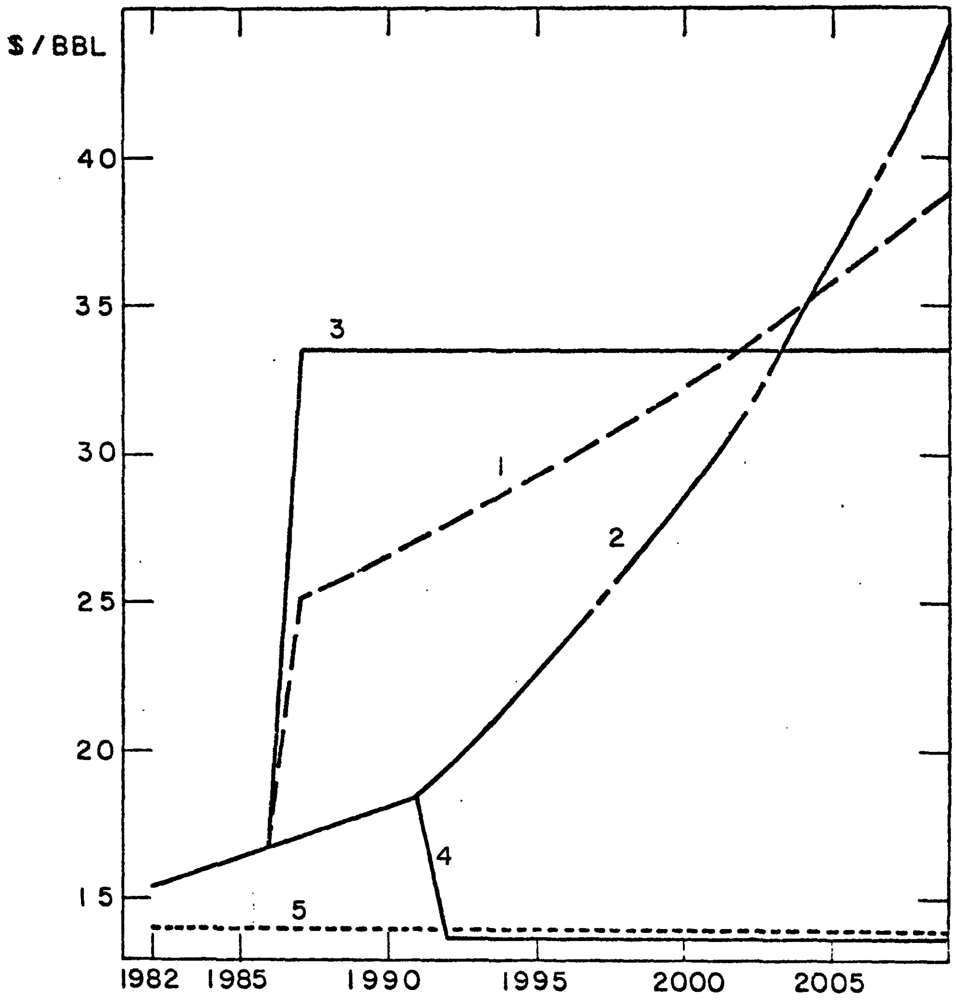
As a first step, we calculate the after-tax annual cashflows to the plant, and use their net present value (NPV) as our measure of profitability. Our basic equation for calculating the cashflow is:

> after-tax annual cashflow =
> [(annual quantity of oil produced x world price per barrel) - annual operating costs] x (1 - tax rate) + (annual depreciation x tax rate).

The cashflow for each year is calculated using the appropriate values for the parameters and in accordance with the assumptions of the model (described below).

We have already mentioned the uncertainty over the future world price of oil. In order to illustrate the impact of the future prices on profitability, or more specifically, the future <u>path</u> of oil prices, we have chosen five scenarios for the world price of oil, all starting at $14/bbl in 1977. These scenarios range from highly optimistic to pessimistic price projections (from the point of view of the oil companies), and are illustrated in Figure 1. It must be emphasized that we are not

Figure I. Scenarios for the world price of oil



attempting to forecast future oil prices, but have chosen the scenarios to illustrate a range of reasonable prices.

In addition to those listed in Section II, the assumptions and parameters on which our model is based are summarized as follows:

1. The plant has an operating life of 20 years. Initial investment in plant and equipment is made in one lump sum at the beginning of year one, and the cashflows are received at the end of each year.
2. The products can be sold at the prevailing world price of oil. (Adjustments have been made to allow for the different grades of fuel from the different processes, and the calculations are described in Appendix B.)
3. Total taxes amount to 50% of taxable income.
4. An annual deferred investment of $9.9 MM (except in the last two years) is added to the operating costs for replacement of worn-our equipment.
5. The initial investment is depreciated over thirteen years by the sum-of-years digits method (100% capitalization assumed).
6. The entire project is 100% equity funded.
7. The operating costs escalate at a real rate of 2% per year.

Having generated the stream of cashflows to the projects (one stream for each technology under each scenario), we calculate the NPV of each stream at discount rates between 0%

and 20% in increments of 2%.* In order to determine the sensitivity of profitability to cost overruns, we repeat the calculations for 20% and 40% cost overruns.

The results of these calculations are presented in Tables C.1, C.2, and C.3 of appendix C. For the case of no cost overrun (Table C.1), we see that none of the technolgoies are profitable (i.e., have positive NPV) under scenarios 4 and 5. Excluding EDS, they are profitable for discount rates less than 8-10% under scenario 2, and less than 16% under scenarios 1 and 3. EDS, the most expensive of the five technologies and the one for which our cost estimates are more realistic (see Appendix B) is only profitable under scenarios 1 and 3, and then only for discount rates less than 4-6%. The cost overruns (Tables C.2 and C.3) naturally have the effect of reducing profitability: in the case of a 40% cost overrun (which is not unheard of in large construction projects involving untried technology), none of the technologies have positive NPV for discount rates above 10%, even under extremely

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* Although net present value is fairly well accepted as a measure of profitability, there is some controversy over the discount rate that should be used in the calculation. Generally speaking, the discount rate should reflect the riskiness of the project: the more risky the project, the higher the discount rate that should be used. Alternatively, it may be argued that the discount rate should be the firm's weighted cost of capital. Rather than discuss these issues, here we have used the range of discount rates mentioned to illustrate the effect of NPV, and refer the reader to Reference (12) for discussion of alternative measures of profitability and choice of discount rates.

high oil price scenarios (for example, scenario 3). To sum up, then, the technologies examined in this report (and therefore other technologies in the same cost range) will only be profitable if the price of oil rises very rapidly in the next five or six years and remains high over the life of the plant.

Thus far in our financial analysis, we have used only expected values for the cost estimates, and our sensitivity analysis has been simply to examine the effects of 20% and 40% cost overruns on profitability. We would like, however, to obtain a measure of the variability of the net present value of the cashflow streams. More specifically, we would like to investigate a continuum of cost overruns, each weighted by the probability of its occurrence. In general, this type of analysis is performed by first assigning appropriate probability distributions to the input parameters of the model (appropriate in the sense that the distribution captures as nearly as possible values of that parameter). Then, using a computer to generate values from the probability distribution for each parameter, the NPV is calculated using those values. This procedure is repeated a large number of times, each time drawing values from the same distributions, thus generating an approximate, discrete, probability distribution for the NPV. The standard deviation and mean of this distribution will approximate those of the "true" distribution of the net present value.*

In order to perform such simulations, we must represent the probability distributions of the basic input parameters to our cashflow model, the investment and operating costs of each technology. To do this it is necessary to make several simplifying assumptions, which we summarize as follows:

1. The investment and operating costs are assumed to be normally distributed.
2. Experience shows that cost estimates given before the construction of the first commercial plant are nearly always too low, and that "cost underruns" are rarely heard of. Therefore it is not reasonable to use the cost estimates in Table 1 as the means of our distributions, as that would generate values both above and below the estimates. Rather, it would appear more reasonable to view the figures in Table 1 as lower bounds, and to arrange our distributions so that the bulk of the values generated lie above these estimates. This is achieved by choosing a suitable cost overrun as the mean of the distribution and by taking the difference between this figure and the corresponding value in Table 1 as being equal to two standard deviations.**

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* For a discussion of risk analysis in capital investment decisions, see References (13), (14), and (15).

** 95% of the area under a normal distribution lies within two standard deviations on either side of the mean.

3. In the case of EDS, Exxon Research and Engineering Company has estimated and employed a 40% overall contigency on costs based on their "process development allowance."* Since we did not include this in our EDS figures in Table 1, we use a 40% cost overrun as the mean of the EDS investment and operating cost distributions.

4. Because of the relatively greater uncertainty in our cost data (an not necessarily fundamental to the technology), we take 50% cost overruns for the SRC, Synthoil and H-Coal cost distributions, and a 60% cost overrun for the shale oil cost distributions.

5. We assume that the investment and operating costs are perfectly correlated, as situations involving large investment but low operating costs (or vice-versa) are very unlikely to occur. For the purposes of the simulations, the subtotal for depreciation is taken as 93% of the total investment, and the first-year costs are held in the same ratio to the annual operating costs as found in Table 1.

6. As our main purpose in performing the simulations is to obtain order-of-magnitude estimates of the means and standard deviations of the NPV distributions, and to be able to compare across technologies, we have not used the range of discount rates employed above, and instead use the risk-free discount rate of 3% (use of a risk-adjusted rate would involve double-counting**).

The results of our simulations are summarized in Table 2,

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* See Reference (5).

** See Reference (15).

and are illustrated graphically in Figures C.1-C.5 in Appendix C.*

As explained in points 2, 3, and 4 above, we have taken the means of the distributions of investment and operating costs as being greater than the estimates in Table 1 (this was to avoid the large number of "cost underruns" which would have occurred if we had taken the estimates in Table 1 as the means). Hence it is not surprising that the mean net present values in Table 2 are much lower than those calculated previously. In particular, we see that only under the high oil price scenarios (scenarios 1 and 3) are the net present values positive, and then only for SRC, H-Coal and in-situ shale. Synthoil has positive NPV only under scenario 3, and EDS has negative NPV under all five scenarios.

The standard deviations of the net present value of each technology are fairly consistent from scenario to scenario (at least within the bounds of accuracy of our method). Across technologies, we find that EDS has the greatest absolute standard deviation, in-situ shale the next largest, followed by Synthoil, SRC, and H-Coal. They all have large standard deviations, ranging from approximately $540 MM to $1100 MM, and in the few instances where the mean NPV is positive, the standard deviation is significantly larger than the mean.

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* The means and standard deviations were calculated by assuming that all the points within each NPV range are located at the center of the range.

TABLE 2: Summary of the simulation results*

TECHNOLOGY	SCENARIO	DISTRIBUTION OF NPV: MEAN ($MM)	STANDARD DEVIATION ($MM)
SRC	1	40	627
	2	-659	591
	3	426	632
	4	-1806	541
	5	-1880	560
SYNTHOIL	1	-302	583
	2	-1062	694
	3	20	696
	4	-2215	648
	5	-2358	596
H-COAL	1	464	551
	2	-184	488
	3	945	496
	4	-1279	481
	5	-1482	517
EDS	1	-1671	966
	2	-2760	709
	3	-1224	861
	4	-3804	920
	5	-4654	1091
IN-SITU SHALE	1	56	710
	2	-772	755
	3	394	628
	4	-1820	656
	5	-1912	665

* The distributions are illustrated in Figures C.1 - C.5 in Appendix C.

As we stated at the outset of this paper, it is necessary to obatin some quantitative measure of the economic viability of synthetic fuels production before government policy regarding their commercialization can be formulated. It does not matter so much that our cost estimates for the technologies are subject to uncertainty, nor that we have had to make many simplifying assumptions in order to arrive at the measures of profitability. What is important is to recognize where the major uncertainties lie, and to appreciate that the order-of-magnitude of the results alone can further our understanding of the economics of these technologies. It is appropriate at this point to review some of the assumptions of our model and the way in which it treats the major sources of uncertainty.

Broadly speaking, the two most important elements of any model designed to perform this sort of analysis are: (1) the way in which the parameters entering into the cashflow calculation interact, their correlation and interdependence; and, (2) how the uncertainties, both exogenous and endogenous to the model, are captured in the analysis.

These two elements are clearly closely related: in designing the model one must identify the parameters necessary to calculate the cashflows to the project, determine their interdependence and correlation, and evaluate the uncertainties surrounding them. To model all the uncertainties would clearly serve only to obscure the important features of the problem, so in most cases only the key sources of uncertainty are modeled. These are typically the parameters that would be incorporated in a standard sensitivity analysis, where expected values are utilized for the other, less uncertain, parameters. This reflects the essential nature of simulation risk analysis: it represents a continuum of sensitivity tests, each weighted by the probability of its occurence.

Of the major sources of uncertainty involved in these projects, the first is the technological uncertainty regarding the scaling-up of the process to a commercial size. The uncertainty we are referring to here is not so much whether or not the process will work at the commercial scale, but what modifications in yields and throughputs will be necessary, and how these will affect both the investment and operating costs. These uncertainties are resolved very early in the life of the plant, although in principle problems can arise in later years. In addition, the first generation of plants will experience a "learning curve" in the first few years, which would have the effect of lowering the operating costs and investment costs of subsequent plants. In our model we have assumed that the investment and operating costs are known with certainty once the plant is built, but have allowed for technical problems in the first year by allowing for only half the normal output in that year (see page 12, point 5).

As explained earlier in this section, we modeled the cost uncertainties by assigning probability distributions to the investment and operating costs, and used expected values for the other parameters entering into the cashflow calculations (except for the world price of oil, as explained below). Clearly the assignment of these distributions is a difficult task, as the very lack of technical information that causes the uncertainty over the investment and operating costs also makes the exact form of their distributions difficult to specify. An important point to bear in mind when attempting to estimate these distributions is that often the cost estimates given by the engineers are the modes and not the means of the distributions. In the context of the decision to build a commerical plant for a new technology, the mode of the distribution of investment costs (or the most likely value) may be considered the best estimate of the investment costs of the first plant, whereas the mean of the distribution may be considered as the long-run average, or the average cost if many such plants are built (for a symmetric distribution, these two values are equal). We employed a normal distribution for investment and operating costs simply because we lacked specific information regarding whether or not the cost estimates were the modes or means of the distributions. If we did know which they were, we could employ a lognormal distribution for the costs. By arranging the 'zero' of the lognormal distribution to be our cost estimate from table 1, we could avoid the problem of 'cost underruns' during our simulations (see page 20, point 2).

The difficulties in estimating the variance of the distributions are even greater: in principle one would have to ask the engineers such questions as, "what percentage of the time do you think that the costs will fall below such-and-such a value?", although in practice the answers are vague and subject to great uncertainty. For want of more precise information, we estimated the standard deviations of the distributions in the approximate form of a percentage of the original cost estimates in table 1. Overall, the uncertainties and subjective evaluations regarding the distributions leave much to be desired, and since the derived distributions of NPV depend critically on the input distributions, one must take care in interpreting the NPV distributions.

Another major source of uncertainty regarding the profitability of the synthetic fuels plants is that of the world price of oil. This is present throughout the life of the plant, and is quite independent of the technological uncertainties discussed above. This source of uncertainty is much more difficult to model by simulation, because we not only have all the problems of estimating the distributions of the oil price in future years, but must also model the serial correlation of the prices from year to year. In principle this can be accomplished by modeling the future path of oil prices as a continuous time stochastic process with three components: a deterministic drift (or expected path), a diffusion term (or Weiner process) representing the variance about this drift, and a jump (or Poisson) process. The drift and diffusion terms combined would have continuous sample paths, and the jumps would represent discontinuities or sudden shocks to the system. That the world price of oil should exhibit such properties is not unreasonable: over the years there is an expected drift or trend in oil prices with some variance about it. This would be due to factors whose effects were gradually absorbed into the price of oil. The discrete jumps could be due to such shocks as a sudden price hike by OPEC or the sudden cut off of oil from Iran, although these two examples have different characteristics. The revolution in Iran is completely random both in the timing and the impact of its occurence, and is thus almost impossible to account for in a simulation model such as ours. The regular annual meeting of the OPEC cartel may prove easier to model in that the frequency of the events is known, and what is uncertain is the magnitude of the jump. This uncertainty in turn can be considered as varying randomly but continuously up until the announcement of the new price, though of course the price change will be a discontinuous jump at that point.

We have not attempted to incorporate such complexities in our simple model: our treatment of the price uncertainty involved choosing a range of possible scenarios for the price of oil, with the path of prices within any scenario being completely deterministic. Since our range of scenarios is not exhaustive, and since it is hard to assign probability estimates to their occurence, we did not attempt to simulate over the range of scenarios.

Having discussed some of the major sources of uncertainty and how they were treated in our model, it is time to ask the very important question, "how do we interpret the resulting NPV distributions?". Just looking at the distributions it is not immediately clear what their variance is telling us about the riskiness of the project. The units of the standard deviation of NPV are not as intuitive as, say, the standard deviation of the cashflow in any particular year. And in any case, unless one has performed this type of analysis for many other projects for which one has an intuitive idea of the riskiness, then there is nothing with which to compare the variance of the NPV. We have been lead only to the qualitative result that the technologies are only profitable (in terms of expected NPV) for the very high price scenarios (scenarios 1 and 3), and that even then the standard deviation is such that there is a probability that the NPV will be less than zero (see table 2).

An examination of the distributions on individual annual cashflows might provide more information, but only if our model were extended to include the price uncertainty from year to year. Otherwise the distributions would be meaningless due to the fact that our model is deterministic once the costs have been drawn from their distributions at startup. The possible advantages of looking at distributions on each year's cashflow are that one can observe the pattern of uncertainty over time in the manner in which the variance of the cashflow distribution changes from year to year. In addition, any skewness in the distributions would be revealed, and might aid us in forecasting the cashflows over the life of the project. As we have stated above, though, this would require the abandonment of the price scenarios in favour of some appropriate stochastic process for the oil price.

IV. The Demonstration Plant

Thus far in our analysis we have considered only the commercial plant and the problems of assessing its profitability and riskiness. Although the commercial plant is the focus of the decision process, many important decisions must be made prior to the last stage. The uncertainties surrounding the commercial plant, and the way in which we treat them in our valuation of such an investment will clearly be significant for our treatment of the preceding decisions.

The process leading ultimately to investments in new technologies begins with very basic bench-scale experimentation, and proceeds through various stages of research and development until the demonstration stage is reached. This stage essentially involves scaling up the technology and linking together the various components of the process. It is generally at or very near full scale, and most often includes all the major components of the process.

It is important to understand what demonstration plants, in principle, can and cannot achieve. The primary focus of a demonstration plant is the purely technological uncertainty: for example, building the demonstration plant allows a more detailed and accurate estimation of yields, throughputs, and overall costs for the specific process in question. Such a plant does not, in general, address any institutional barriers or political or social issues that may be involved, and only partially clarifies some of the environmental problems by allowing a better assessment of the environmental impacts of full-scale production.

As the demonstration plant is not in and of itself a cashflow-producing asset, the standard valuation techniques based on the discounted present value of a cashflow stream must be modified to take into account the special features of such an investment.

The fundamental characteristic of research and development in general, and demonstration plants in particular, is that they are part of a series of investments whose ultimate payoff depends on the value of the resulting real (i.e., cashflow-producing) asset, in this case the commercial plant. In this sense, the demonstration plant is similar to a call option on the commercial plant, and one would imagine that some of the properties of options on corporate securities might carry over to demonstration plants.

The benefits of a demonstration plant arise from the reduction in the technological uncertainties surrounding the commerical plant, particularly the uncertainty in the investment and operating costs. Other uncertainties, such as that regarding the world price of oil during the life of the plant, are not in any way reduced by the demonstration. Thus, the construction of a demonstration plant may be thought of as sampling from the probability distributions on the costs. This would reduce both the variance of these distributions and that of the distribution on NPV.

To pursue this line of reasoning further, consider a highly simplified paradigm of the decision process outlined above. The assumptions defining our paradigm may be summarized as follows:

(1) The only uncertainty present once the commercial plant has been built is that of the price of oil. All other uncertainties are resolved with the construction of the commerical plant.

(2) The operating costs of the commerical plant are known, and only the investment costs are uncertain prior to construction of the commercial plant. Further, assume that the investment costs, I, are normally distributed with mean μ_I and variance σ^2.

(3) There are no taxes. This assumption insures that the distribution on the present value of net revenues from the commercial plant, V, is independent of the distribution of the investment costs (because there are no depreciation tax shields).

(4) To further simplify the decision process, assume that the commercial plant can only be built at time t=0, or not at all, and similarly that the

demonstration plant can only be built one period before, at $t=-1$.

(5) The cost of building the demonstration plant is D, and its construction reduces the variance of the investment costs to zero.

The decision tree depicting this situation is shown in figure 2. If the demonstration plant is not build at $t=-1$, (A→C), the situation is left unchanged, and one can look forward to expected net benefits of $\max [E(V)-E(I),0]$. If it is built, however, (A→B), the true costs of building the commercial plant are revealed. Therefore at B, the decision rule is: build the commercial plant only if the revealed investment costs are less than the expected present value of net revenues from the commercial plant, E(V). Hence, viewed from A, this will occur with probability

$$\text{pr }[I<E(V)],$$

and will yield a net benefit of

$$E(V)-E(I|I<E(V)),$$

(remember that we are assuming that V is independent of I).

Again, viewed from A, the probability that the commerical plant will not be built if a demonstration plant is built is

$$1-\text{pr}[I<E(V)],$$

and will yield zero benefits. Hence at A, one looks forward to expected net benefits

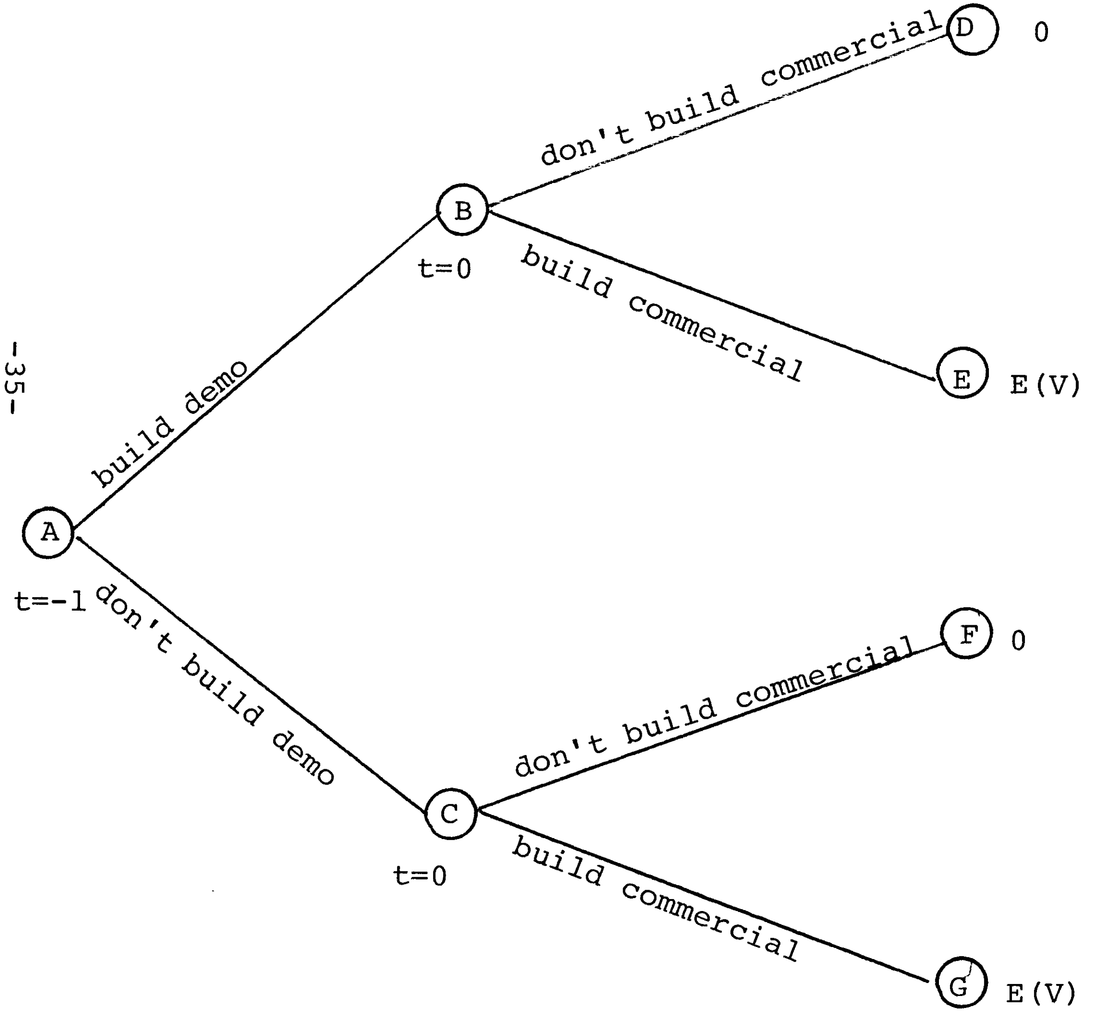


FIGURE 2: Decision Tree for the Decision to Build the Demonstration Plant

$$[E(V)-E(I|I<E(V))]\mathrm{pr}(I<E(V)]-D,$$

if the demonstration plant is built, and to

$$\max\ [E(V)-E(I),0]$$

if it is not. The demonstration plant should be built only if

$$[E(V)-E(I|I<E(V))]\mathrm{pr}[I<E(V)]-D>\max[E(V)-E(I),0].$$

The first term on the left is

$$\left[\mu_V - \frac{\int_{-\infty}^{\mu_V} I\, f(I)\,dI}{\int_{-\infty}^{\mu_V} f(I)\,dI}\right]\int_{-\infty}^{\mu_V} f(I)\,dI = \left[\mu_V \int_{-\infty}^{\mu_V} \frac{e^{-(I-\mu_I)^2/2\sigma^2}}{\sqrt{2\pi}\,\sigma}\,dI\right] - \left[\int_{-\infty}^{\mu_V} \frac{I e^{-(I-\mu_I)^2/2\sigma^2}}{\sqrt{2\pi}\,\sigma}\,dI\right]$$

where $\mu_V = E(V)$.

This can be written as

$$\left[\mu_V\, \Phi\left(\frac{\mu_V-\mu_I}{\sigma}\right)\right] - \left[\mu_I\, \Phi\left(\frac{\mu_V-\mu_I}{\sigma}\right) - \frac{\sigma}{\sqrt{2\pi}}\, e^{-(\mu_V-\mu_I)^2/2\sigma^2}\right]$$

where $\Phi(x) = \frac{1}{\sqrt{2\pi}}\int_{-\infty}^{x} e^{-z^2/2}\,dz$ is the cumulative normal distribution. The value of the demonstration plant, F_D, is therefore

$$F_D = \frac{\sigma}{\sqrt{2\pi}}\, e^{-\Delta^2/2\sigma^2} + \Delta\, \Phi\left(\frac{\Delta}{\sigma}\right) - D - \max[\Delta, 0]$$

where $\Delta = \mu_V - \mu_I$.

This equation relates the value of the demonstration plant to the variance on the distribution of investment costs, the difference between the expected present value of net revenues and expected investment costs, and the cost of building the demonstration plant. In order to determine precisely how the value of the demonstration plant varies with these parameters, we must examine the derivatives of F_D with respect to and These are:

$$\frac{\partial F_D}{\partial \sigma} = \frac{1}{\sqrt{2\pi}} e^{-\Delta^2/2\sigma^2}$$

, and is always positive;

$$\frac{\partial F_D}{\partial \Delta} = \Phi\left(\frac{\Delta}{\sigma}\right) - \begin{cases} 1, & \text{if } \Delta > 0 \\ 0, & \text{if } \Delta \leq 0 \end{cases}$$

,and is negative when $\Delta > 0$ and positive when $\Delta \leq 0$;

$$\frac{\partial^2 F_D}{\partial \sigma^2} = \frac{\Delta^2 e^{-\Delta^2/2\sigma^2}}{\sigma^3 \sqrt{2\pi}}$$

,and is always positive;

$$\frac{\partial^2 F_D}{\partial \Delta^2} = \frac{e^{-\Delta^2/2\sigma^2}}{\sqrt{2\pi}}$$

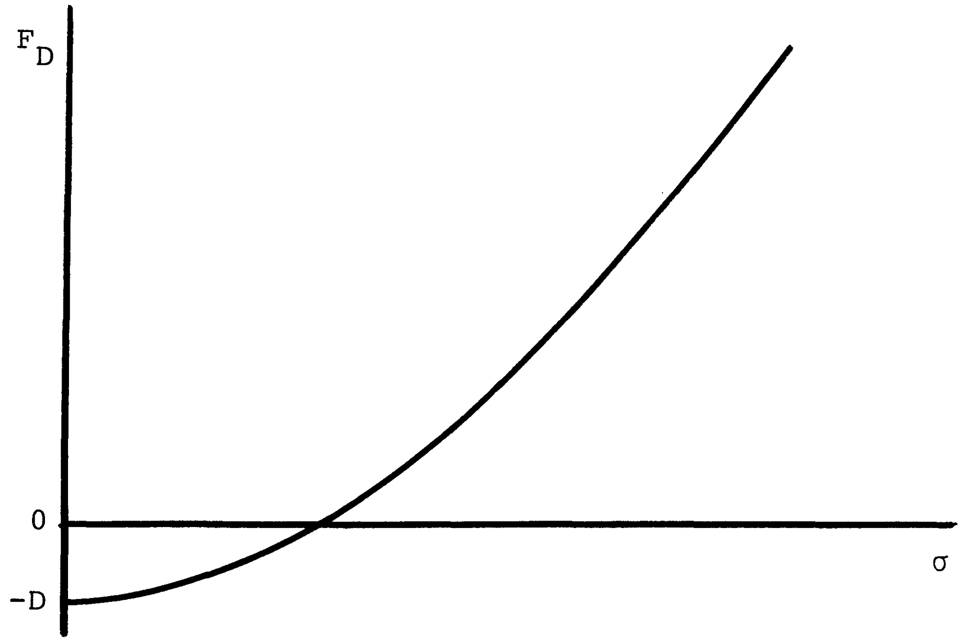
,and is always positive.

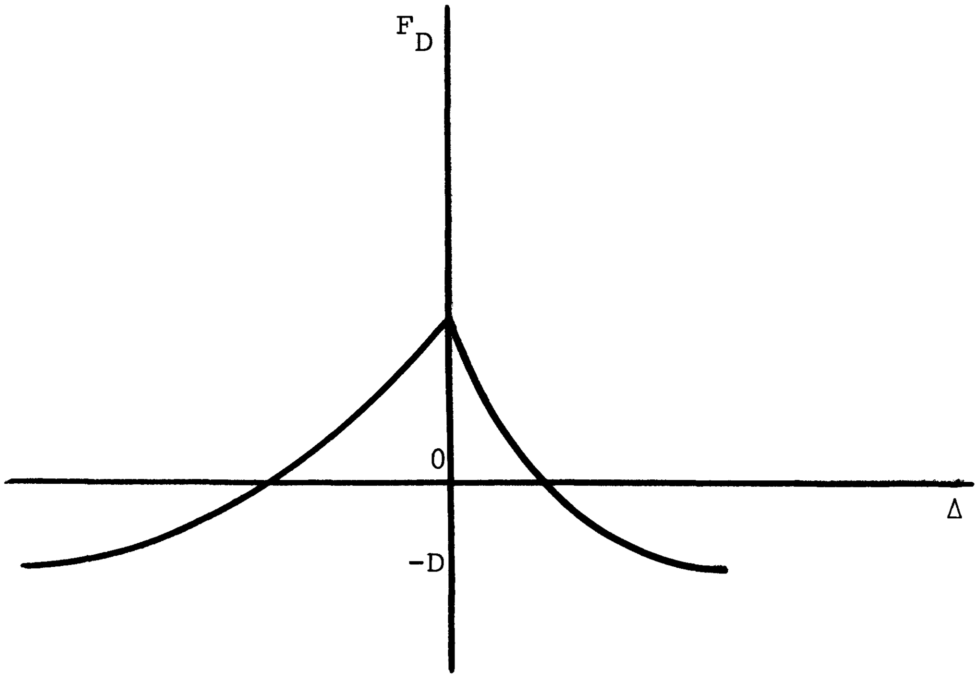
We can use these derivatives and the equation for F_D to arrive at the graphs of F_D against σ and Δ (figure 3).

Although we have treated only a very simple case, the qualitative results that can be drawn can be quite valuable, and it is reassuring that they are in accordance with our prior intuition on the subject. For example, it was clear that the value of the demonstration plant would be an increasing function of the variance of the investment cost of the commercial plant, and that if I were known with certainty (i.e., $\sigma=0$), the value of the demonstration would be -D. Similarly, as the absolute difference between the expected benefits from the commercial plant, μ_V, and the expected investment costs, μ_I, grown larger and larger, we would again expect the demonstration to be worth -D (in the limit), since the probability that the commercial plant will be profitable (in the case where $\Delta \to -\infty$), or that the commercial plant will not be profitable (in the case that $\Delta \to +\infty$), tends to zero. We would also expect that the demonstration plant would be more valuable if $\mu_V < \mu_I$ than if the reverse were true. All these intuitive beliefs are captured in our equation for F_D above.

Although we have obtained an expression for the value of the demonstration plant in a very simple case, it is important to realize where our model may not be a good approximation to reality, and where further research could introduce useful

FIGURE 3: The Value of the Demonstration Plant as a Function of Certain Parameters (see text)





refinements.

First, the assumption that the operating costs are known with certainty can be relaxed, and the construction of a demonstration plant would now sample from the distributions of both investment and operating costs, or more precisely, their joint probability distribution (as we stated in point 5, page , it is likely that the investment and operating costs will be highly correlated, although not necessarily perfectly so). Taxes could at the same time be introduced so that the investment costs would be correlated with the distribution of V (via the depreciation tax shields).

Another assumption, implicit in our analysis, is that once the commercial plant is built, it will be operated throughout its lifetime, regardless of the behavior of the oil price or the general economy. Clearly, a dramatic drop in oil prices (with expected low prices in the future) might cause the operators of the commercial plant to shut down operations and cut their losses. In effect, this would eliminate the very low tail of the distribution of V, and could be incorporated into the analysis by deriving an optimal stopping rule for the commercial plant operations. By postulating a stochastic process to drive oil prices, one could in principle apply a dynamic programming technique in optimizing the value of continued operations during the life of the plant. It must be emphasized, however, that this would affect the value of the demonstration plant only through its effect on E(V), the expected value of net revenues from the commercial plant.

The simple model developed here, however, is useful in that it focuses on what the demonstration plant really achieves, and how its value depends on some of the uncertainties surrounding the commercial plant. If the model were expanded to include some of the refinements mentioned above, it would clearly become more mathematically complex, and might draw our attention away from the important features of the problem. These, we feel, are illustrated in the simple example given above.

V. Conclusions

In section I we outlined some of the major areas of risk and uncertainty facing synthetic fuels producers, and discussed these at greater length above. These risks and uncertainties are generally quoted as the main reasons why the government should provide support for private industry in the commercialization of synthetic fuels. Here we will discuss breifly some of the main arguments why the government should or should not do so*.

First, in perfect capital markets, the private sector will commercialize new technologies if and when they are economically viable (i.e., when the net present value of the cashflows from the project, discounted at a rate appropriate to the riskiness of the cashflows, is positive). If the government steps in and commercializes these technologies before they are viable, it is creating a social cost, which is ultimately borne by the taxpayers.

Second, heavy government funding of specific synthetic fuels technologies may take funds away from other technologies that may eventually prove more economical than those pursued by the government. Again, in efficient markets, the private sector will be able to evaluate the relevant information and choose the correct technologies when they make economic sense.

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* See reference (16) for a deeper discussion of these issues.

Finally, the technological problems and risks associated with synfuels production seem typical of those encountered in the development of any new and complex technology. Markets for such risks have functioned adequately in the past, and in the absence of any special reasons for market failure, should continue to do so in the future.

One reason why markets may have failed, of course, is that existing government policy in certain areas, and lack of clear policy in others has created risks that are beyond the normal risks mentioned above. For example, although there is a probability that these projects will be profitable, it is in just those situations that the government might impose an excess profits tax, thereby leaving the project facing a distribution of returns that exhibits great down-side risk but no up-side potential. Financial markets may not be able to internalize these uncertainties regarding government policies or regulations, and therefore the government must either issue clear directives regarding its intended policy, or stimulate investment in synthetic fuels by some other means.

Another possible justification for government support may be summarized as follows: given that a primary goal of U.S. national energy policy is to reduce dependence on imported oil (and assuming for the moment that this is a worthwhile policy in and of its own right), the return to society from investment in domestic sources of liquid fuels may be greater than that preceived by private investors. Hence, it may be argued, society (i.e., the government) should bear the costs of development and commercialization of these new domestic sources. It is not clear, however, that forcing the early commercialization of certain synthetic fuels is the least expensive or most efficient policy for reducing imports.

Our analysis shows that the five technologies studied in this report (and any others in the same range of costs) are not economically viable unless world oil prices rise dramatically in the next five or six years, and then only if the domestic price of oil is deregulated. We would recommend, therefore, that rather than provide direct support for commercialization through price supports, loan guarantees, or tax credits, the government should work to remove some of the disincentives to investments in synthetic fuels that it has created, particularly regarding domestic oil price regulation and the relevant environmental restrictions.

VI. APPENDIX

A. The technologies analyzed in this report.

B. Our sources of cost data and a breakdown of the cost estimates.

C. The results of our financial analysis.

D. Overview of the major environmental issues.

APPENDIX A: The Technologies analyzed in this paper.

Although our discussion and method of analysis in this paper is applicable to any of the synthetic fuels technologies, we have chosen specific technologies on which to perform our analysis. These include four coal liquefaction technologies and a modified in-situ oil shale technology.

The four coal technologies were chosen for two reasons: (1) they are at or near the pilot plant stage, and have received much attention at the Department of Energy; and, (2) reasonably complete cost data was available, and the costs appear to be in the same range as those of other coal liquefaction and gasification technologies. Hence the financial analysis will give results that may be considered representative of the other technologies.

H-COAL*

A mixture of finely ground coal in oil and hydrogen is passed through an ebullated bed catalytic reactor containing a fixed, solid catalyst. Pressure and temperature parameters can be controlled to produce either syncrude (equivalent to a no. 2 fuel oil) with low quality naphtha or fuel oil with low quality naphtha. The H-coal process requires dried coal, but can accept all common types of coal, with minor impacts on product quality and output rate. The variation of the process

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*See Reference (4).

examined in this paper uses Wyodak coal. Because this process yields high nitrogen fuels, further refining is both difficult and expensive. The process studied in this paper includes the refining stage, and we have adjusted the operating costs for the different grades of products from the technologies (see Appendix B). The reactor system is the only part of the different technologies that is unique, and because of its sophisticated design, H-coal's reactor system involves the greatest technical uncertainty. A 200-600 ton/day pilot plant is under construction at Cattlesburg, Kentucky.*

EXXON DONOR SOLVENT (EDS) **

A special coal-oil base solvent dissolves the coal and increases the hydrogen-carbon ratio: the recycled solvent is then re-hydrogenated continuously during the process. In this way, direct contact of the coal with a solid catalyst is avoided. A "flexicoker" stage is included in the Exxon proprietary process and converts the heavy residual products to higher grades. The EDS process can accept all the usual types of coal, again with differences in the quality of the products recoverable and the output rate. The process studied in this paper uses Illinois coal. The fuel oil derived from this process is high in nitrogen, has a low gravity, and is not

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*See Reference (10).

**See Reference (4).

compatible with petroleum-derived fuel oil. The operating costs have been adjusted for the quality of the product (see Appendix B). Like H-coal, the process has not been demonstrated at full scale, but the sub-units involved are fully developed (technical problems still exist, however). Construction will soon begin on a 250 ton/day pilot plant in Baytown, Texas.*

SOLVENT REFINED COAL (SRC) **

Apart from the solvent used, the process is similar to the EDS process. SRC has two modes of operation: solid (SRCI) or liquid (SRCII) product. In this paper we study only the latter, referring to it simply as SRC. Again, it can accept all common types of coal. The process covered in this paper, however, uses Wyodak coal. The main product of the SRC process is industrial boiler fuel, and can satisfy current air pollution requirements. However, if the sulfur removal requirements are made more stringent, the SRC process may have problems. A 50 ton/day pilot plant has successfully been operated, and plans are underway to construct a 6000 ton/day commercialisized module.+

SYNTHOIL ++

The process uses dried, finely ground, coal which is mixed

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* See Reference (10).

**See Reference (4).

\+ See Reference (10).

++See Reference (7).

with recycled heavy oil. The mixture is then catalytically hydrogenated in the presence of hydrogen in the char and coal gasification unit. The process studied in this paper uses Western Kentucky coal with a high sulfur content. The main product is a heavy fuel oil, low in sulfur, suitable primarily for use as a boiler fuel. The U.S. Bureau of Mines had developed a 10 ton/day pilot plant.*

Oil from shale rock does not, in principle, require sophisticated technology: the rock must be crushed and then heated to very high temperatures ("retorting") before it gives up its crude oil. Most problems, however, are associated with the very large scale of mining activities involved in the process. There are basically two kinds of oil shale technology: (1) the rock is mined and retorted at the surface; and, (2) modified in-situ retorting, where only a portion of the overburden is mined. The rest is blasted to form an underground cavern of crushed rock which is then retorted and the resulting oil is brought to the surface. The in-situ process offers potential economic and environmental advantages over aboveground retorting, and is considered the one most likely to be commercialized in the near future. Different variations of the in-situ technology are required for different deposits of shale rock, and no single technology can process all types.

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* See Reference (3).

Unfortunately, we were unable to obtain reasonable cost data for any particular form of the technology (the data is still proprietary), and were forced to rely on data from a "conceptual process model" of the modified in-situ technology. Apart from the cost data itself, which we discuss in the next section, the general process studied in this report will serve as a representative of the various modified in-situ oil shale technologies.

APPENDIX B: Our sources of cost data and a breakdown of the cost estimates.

As we have already discussed in Section II of this paper, there are many sources of uncertainty in the cost estimates for synthetic fuel technologies. Most of these uncertainties are difficult, if not impossible, to quantify, and are often taken into account by adding on an overall contingency for delays and other problems during construction and operation. For most of the technologies, large-scale plants have not been built, and for the most developed, only small-scale pilot plants have been operated. Hence all cost estimates are necessarily projections from engineering data, and their accuracy depends a great deal on the depth of engineering detail used in preparing the estimates.

Although we have tried to put the costs on a comparable basis, the sources of our figures are not all the same. The figures for SRC, Synthoil, and H-coal are from engineering studies by the U.S. Bureau of Mines.* The estimates are "assumed to be at a point on the learning curve where there are relatively few areas of uncertainty. Therefore spaces have been provided for only the very corrosive or other severe conditions; also no alternate processing equipment has been provided".** It would appear, then, that the Bureau of Mines

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* See References (6), (7), (8).

**See References (6), (7), (8).

estimates are optimistic and should be taken as a minimum almost certain to be exceeded in practice.

The figures for EDS are taken from a report by the Exxon Research and Engineering Company,* representing the commercial study phase of the EDS process development. Again, the estimates are based on engineering data, but this time the work was carried out at a later stage of development, using more up-to-date data and a great deal of engineering detail. The figures for EDS, therefore, can be considered to be the more realistic of the coal liquefaction data, and in order of magnitude are probably representative of other liquefaction and gasification technologies.

We had great difficulty in obtaining cost data for modified in-situ oil shale processing, the version considered most likely to be commercialized in the near future. Occidental Petroleum, one of the leaders in this technology, has kept its data proprietary. The only data in an appropriate form was that persented by the Synfuels Interagency Taskforce in 1975.** Their report included cost estimates for modified in-situ oil shale processing based on a conceptual process model. These figures are not as recent as those for the other technologies

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* See Reference (5).

**See Reference (2).

in this paper, nor are they based on the same degree of process development or engineering detail. They are therefore considered the most uncertain of our cost estimates, and experience shows that they are likely to be on the low side.

Tables B.2 through B.11 present the investment and operating cost estimates for the five technologies studied in this paper (these costs are summarized in Table 1 in the text). Table B.1 shows how we have calculated the adjustment to the operating costs to correct for the different values of the products of these technologies. The adjustment is made so as to put the costs on a comparable basis for our financial analysis. The assumptions in Section II of the report should be read in conjunction with this section of the appendix. In particular, note that the figures in the tables that follow are in 1976 $, and that these have been escalated at a real rate of 2% per year to bring them to their values for a 1987 start-up * This is to account for increases in construction, materials, and labor costs.

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* These escalated values are in Table 1 in the text.

TABLE B.1: Adjustment for the differing grades of products from the processes.

From Platt's Oil Price Handbook and Oilmanack,* we find that in 1976 the average price of:

gasoline	was	$137.13/metric ton	= $16.89/bbl
boiler fuel	"	66.46 " "	= 9.80 "
naphtha	"	130.69 " "	= 17.87 "

The average price of Middle Eastern crude oil in 1976 was $12.24/bbl. Assuming that the price differential between these products and crude oil remains approximately constant over time, we adjust the operating costs of the processes by:

$4.65/bbl of gasoline produced
-$2.44/bbl " boiler fuel "
$5.63/bbl " naphtha "

The processes produced the following quantities of:

	SRC	Synthoil	H-Coal	EDS	In-situ shale
gasoline	0	0	32,500	0	0
boiler fuel	45,978	50,000	0	60,000	50,000
naphtha	4,022	0	17,500	0	0
(bbl/stream day)	50,000	50,000	50,000	60,000	50,000

Therefore, we must add to the operating costs:

SRC	(45,978x330x2.44) + (4,022x330x-5.63)	= 29,549
Synthoil	(50,000x330x2.44)	= 40,260
H-Coal	(17,500x330x-5.63)+ (32,500x330x-4.65)	=-82,385
EDS	(60,000x330x2.44)	= 48,312
In-situ shale	(50,000x330x2.44)	= 40,260

Note that this adjustment is made only so that we may compare the technologies at the world price of oil.

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* See Reference (9).

TABLE B.2: SRC Wyodak Coal.

Total Capital Requirements (1976 $)

	$000
Coal preparation	29,284
Coal slurrying and pumping	2,055
Coal liquefaction and filtration	169,345
Dissolver acid gas removal	59,738
Coal liquefaction and product distillation	8,793
Fuel oil hydrogenation	65,658
Naphtha hydrogenation	5,763
Fuel gas sulfur removal	4,804
Gasification	20,791
Acid gas removal	22,592
Shift conversion	17,917
CO_2 removal	12,042
Methanation	824
Sulfur recovery	2,172
Oxygen plant	28,236
Product storage and slag removal	17,371
Steam and power plant	53,810
Process waste water treatment	3,815
Plant facilities	39,376
Plant utilities	56,438
Total construction	620,826
Initial catalyst requirements	2,239
Total plant cost (insurance and tax bases)	623,065
Interest during construction	93,460
Subtotal for depreciation	716,525
Working capital	57,322
TOTAL INVESTMENT	773,847

(Source: Reference (6)).

TABLE B.3: SRC - Wyodak Coal: Annual Operating Costs (1976 $)

	$000	
Direct cost:		
Raw materials & utilities:		
Coal ($7.50/ton x 33,904 tpd x 330 sd/yr)	$3,912	
Raw water (15 Mgpm x $0.15/Mgal x 1440 min/day x 330 sd/yr)	1,069	
Catalyst and chemicals	4,989	
		89,970
Direct labor:		
864 manhour/day ($6/manhour x 365 day/yr)	1,892	
Supervision (15% of labor)	284	
		2,176
Plant maintenance:		
708 men ($15,000/yr)	10,620	
Supervision (20% of maintenance labor)	2,124	
Materials	15,930	
		28,674
Payroll overhead (30% of payroll)		4,476
Operating supplies (20% of plant maintenance)		5,735
Total direct cost............		131,031
Indirect cost (administration & general overhead) (40% of labor, maintenance & supplies)		14,634
Fixed cost		
Taxes & insurance (2% of plant cost)		11,475
Total operating costs, before credits........		157,140
Credits: Sulfur (222 tpd x $25/ton x 330 day/yr)		1,832
Power (11,680 Kwhr/hr x $0.01/Kwhr x 24 hr/day x 330 day/yr)		925
Total operating costs, after credits.........		154,383
Adjustment to operating costs (see Table B.1).........		29,549
TOTAL.........		183,932

(Source: Reference (6)).

TABLE B.4: Synthoil - Western Kentucky Coal

Total Capital Investment (1976 $)

	$000
Coal preparation	20,692
Paste preparation	18,070
Coal hydrogenation	140,857
Coal hydrogenation - heat exchange	66,225
Char de-oiling	20,136
H_2S removal	9,483
H_2S and NH_3 recovery	15,300
Hydrogen production*	108,744
Steam & power plant	29,174
Plant facilities	32,151
Plant utilities	46,083
Total construction	**506,912**
Initial catalyst requirements	**2,700**
Total plant cost (insurance & tax bases)	**509,612**
Interest during construction	**76,442**
Subtotal for depreciation	**586,054**
Working capital	58,605
TOTAL INVESTMENT	644,659

* Includes gasification, dust removal, shift conversion, oxygen plant, sulfur recovery.

(Source: Reference (7)).

TABLE B.5: Synthoil: Annual Operating Costs (1976 $)

	$000	
Direct cost:		
Raw materials & utilities:		
Coal (825.8 tph x 7,920 hr/yr x $20/ton)	130,807	
Raw water (792 Mgph x 7920 hr/yr x $0.15/Mgal)	941	
Catalyst and chemicals	3,511	
Methane (40.4 Mscfh x 7920 hr/yr x $0.75/Mscf)	240	
		135,499
Direct labor:		
1584 manhour/day ($6/manhour x 365 day/yr)	3,469	
Supervision (15% of labor)	520	
		3,989
Plant maintenance:		
629 men ($15,000/yr)	9,435	
Supervision (20% of maintenance labor)	1,887	
Material & contracts	14,152	
		25,475
Payroll overhead (30% of payroll)		4,593
Operating supplies (20% of maintenance)		5,095
Total direct cost		174,651
Indirect cost (administration and general overhead) (40% of labor, maintenance & supplies)		13,824
Fixed cost		
Taxes & insurance (2% of plant cost)		10,192
Total operating cost, before credits		198,667
Credits: $(NH_4)_2SO_4$ (21.4 tph x 7920 hr/yr x $45/ton)		7,627
H_2SO_4 (15.86 tph x 7920 hr/yr x $20/ton)		2,512
Sulfur (564.6 tpd x 330 sd/yr x $25/ton)		4,658
Fuel gas (850 Mscfh x 7920 hr/yr x $0.33/Mscf)		2,222
Total operating cost, after credits		181,648
Adjustment to operating costs (see Table B.1)		40,260
TOTAL		221,908

(Source: Reference (7)).

TABLE B.6: H-Coal - Wyodak coal

Total Capital Investment (1976 $)

	$000
Coal preparation	47,964
Hydrogenation	372,672
Refinery gas cleanup	24,604
Oxygen plant	62,977
Hydrogen production	100,998
Hydrogen compression	44,531
Ammonia and H_2S removal	2,180
Sulfur recovery	5,087
Oil refining	40,092
Hydrogen plant	14,424
Steam and power plant	58,443
Plant facilities	58,048
Plant utilities	83,202
Total construction	915,223
Initial catalyst requirements	7,674
Total plant cost (insurance & tax bases)	922,897
Interest during construction	138,435
Subtotal for depreciation	1,061,332
Working capital	84,907
TOTAL INVESTMENT	1,146,238

(Source: Reference (8)).

TABLE B.7: H-Coal: Annual Operating Costs (1976 $)

	$000	
Direct cost:		
Raw materials & utilities:		
Coal (1,625.19 tph x 7920 hr/yr x $7.50/ton)	96,536	
Water (1056 Mgph x 7920 hr/yr x $0.15/Mgal)	1,255	
Catalyst & chemicals	17,369	
		115,160
Direct labor:		
1560 manhour/day ($6/manhour x 365 day/yr)	3,416	
Supervision (15% of labor)	513	
		3,929
Plant maintenance:		
1049 men ($15,000/yr)	15,735	
Supervision (20% of maintenance labor)	3,147	
Materials & contracts	23,603	
		42,485
Payroll overhead (30% of payroll)		6,843
Operating supplies (20% plant maintenance)		8,497
Total direct cost		176,914
Indirect cost (administration & general overhead) (40% of labor, maintenance & supplies)		21,964
Fixed cost		
Taxes and insurance (2% of plant cost)		16,996
Total operating cost, before credits		215,874
Credits: Ammonia (78.48 tpd x 330 day/yr x $60/ton)		1,554
Sulfur (206.40 tpd x 330 day/yr x $25/ton)		1,703
Coke (78.06 tpd x 330 day/yr x $10/ton)		258
Total operating costs, after credits		212,359
Adjustment to operating costs (see Table B.1)		-82,385
TOTAL		129,974

(Source: Reference (8)).

TABLE B.8: EDS - Illinois coal

Plant Investment

		($MM)
On sites:	liquefaction	246.3
	solvent hydrogenation	83.5
	flexicoker	163.8
	hydrogen recovery & generation	246.3
	gas & water treatment	49.7
	product recovery	8.5
	Total on sites	798.0
Off sites:	coal receipt storage & crushing	27.5
	ash handling	13.7
	building, mobile equipment	23.3
	utilities	26.4
	waste water treatment	67.6
	electric power distribution	34.9
	tankage/product loading	26.4
	Total off sites	253.7
	Total erected cost (TEC)	1051.7
	Startup costs (6% TEC)	63.1
	Total plant cost (insurance & tax bases)	1114.8
	Interest during construction (@9%)	378.6
	Subtotal for depreciation	1493.4
	Working capital (8% TEC)	84.1
	TOTAL INVESTMENT	1577.5

(Source: Reference (5)).

TABLE B.9: EDS - Illinois coal

Annual Operating Costs

	($MM)
coal (24 kT/sd x $20/ton x 330 days/yr)	158.40
power	39.12
water	0.45
catalyst & chemicals	7.82
manpower	42.39
repair materials & other	65.14
LESS: byproduct credit (sulfur & ammonia)	(22.20)
Annual operating costs	291.12
Adjustment to operating costs (see Table B.1)	48.31
TOTAL	339.43

(Source: Reference (5)).

TABLE B.10: Modified in-situ shale oil

Plant Investment

	($000)
plant facilities	20,769
plant utilities	58,031
equipment capital	258,249
Total construction	337,049
Initial catalyst & startup expense	26,772
Total plant cost (tax & insurance bases)	363,821
Interest during construction	56,030
Subtotal for depreciation	419,851
Working capital	67,208
Total investment	487,059
Cost of shale land*	287,100
TOTAL	774,159

* In a lecture at Boston University, Dr. R.E. Lumpkin of Occidental Research Corporation quoted the cost of one of Occidental's shale leases to have been $211 mm (1972 $), which we have included here in 1976 $.

(Source: Reference (2)).

TABLE B.11: Modified in-situ shale oil

Annual Operating Costs

	($000)	
Direct costs:		
raw materials & utilities	17,514	
direct labor	30,814	
payroll overhead	12,087	
maintenance	9,055	
operating supplies	44,337	
Subtotal		113,808
Indirect costs:		3,143
Fixed costs:		
taxes & insurance	14,381	
royalty	2,456	
Subtotal		16,837
Total operating costs		133,788
Adjustment to operating costs (see Table B.1)		40,260
TOTAL		174,048

(Source: Reference (2)).

APPENDIX C: The results of our financial analysis.

In this section of the appendix we present the results of our financial analysis. Tables C.1, C.2, and C.3 show the net present values of the technologies under each of the oil price scenarios for no cost overrun, 20% cost overrun, and 40% cost overrun, respectively. Figures C.1 - C.5 present the results of the simulations for each of the five technologies. For a discussion of the tables and figures, refer to Section III of the text.

TABLE C.1: No cost overrun

TECHNOLOGY	DISCOUNT RATE (%)	NET PRESENT VALUE ($MM) UNDER SCENARIO:				
		1	2	3	4	5
SRC	0	2016	1172	2491	-636	-765
	2	1485	751	1923	-602	-726
	4	1084	441	1486	-584	-702
	6	776	208	1146	-577	-690
	8	536	32	878	-577	-684
	10	347	-105	662	-581	-683
	12	196	-211	487	-588	-685
	14	74	-295	344	-597	-689
	16	-27	-363	224	-606	-694
	18	-110	-418	124	-616	-699
	20	-180	-463	38	-625	-705
SYNTHOIL	0	1563	719	2038	-1090	-1218
	2	1140	405	1577	-948	-1072
	4	819	176	1221	-849	-968
	6	573	5	944	-780	-893
	8	382	-123	723	-731	-839
	10	231	-221	546	-697	-799
	12	111	-296	402	-673	-771
	14	13	-356	283	-657	-749
	16	-67	-403	184	-646	-734
	18	-133	-441	101	-638	-722
	20	-188	-471	30	-634	-714

(Continued on next page.)

TABLE C.1: No cost overrun (continued from previous page)

TECHNOLOGY	DIS-COUNT RATE (%)	NET PRESENT VALUE ($MM) UNDER SCENARIO:				
		1	2	3	4	5
H-COAL	0	2523	1679	2998	-129	-258
	2	1829	1095	2266	-258	-382
	4	1303	660	1706	-365	-483
	6	900	332	1270	-454	-566
	8	585	80	926	-529	-636
	10	336	-116	651	-592	-694
	12	137	-270	428	-647	-744
	14	-24	-393	245	-695	-787
	16	-157	-493	94	-736	-824
	18	-268	-575	-34	-773	-857
	20	-360	-643	-142	-805	-885
EDS	0	437	-576	1006	-2746	-2901
	2	83	-798	608	-2422	-2570
	4	-190	-962	293	-2192	-2334
	6	-404	-1085	41	-2028	-2163
	8	-573	-1179	-164	-1910	-2038
	10	-710	-1252	-332	-1824	-1942
	12	-821	-1310	-472	-1763	-1879
	14	-914	-1356	-590	-1718	-1829
	16	-991	-1394	-690	-1686	-1791
	18	-1056	-1425	-775	-1662	-1763
	20	-1112	-1451	-849	-1646	-1742
SHALE	0	2131	1287	2606	-521	-650
	2	1577	843	2015	-510	-633
	4	1159	516	1562	-509	-627
	6	839	272	1210	-514	-627
	8	591	86	932	-523	-630
	10	395	-57	710	-534	-636
	12	239	-168	530	-547	-643
	14	113	-256	382	-558	-650
	16	9	-327	260	-570	-658
	18	-76	-384	157	-582	-666
	20	-148	-431	70	-593	-673

TABLE C.2: 20% cost overrun

TECHNOLOGY	DIS-COUNT RATE (%)	NET PRESENT VALUE ($MM) UNDER SCENARIO:				
		1	2	3	4	5
SRC	0	1413	569	1888	-1239	-1368
	2	974	241	1412	-1113	-1236
	4	641	-2	1044	-1027	-1145
	6	385	-183	755	-968	-1081
	8	185	-320	526	-929	-1036
	10	26	-426	340	-903	-1005
	12	-102	-509	189	-887	-984
	14	-206	-575	64	-876	-969
	16	-292	-628	-41	-871	-959
	18	-363	-671	-129	-868	-952
	20	-423	-706	-205	-868	-948
SYNTHOIL	0	869	25	1344	-1783	-1912
	2	559	-175	997	-1528	-1652
	4	323	-320	726	-1345	-1463
	6	142	-426	512	-1212	-1324
	8	-1	-506	341	-1114	-1222
	10	-114	-566	201	-1042	-1144
	12	-204	-612	87	-989	-1086
	14	-278	-647	-9	-949	-1086
	16	-339	-675	-89	-919	-1007
	18	-390	-698	-157	-896	-980
	20	-433	-716	-215	-878	-958

(Continued on next page.)

TABLE C.2: 20% cost overrun (continued from previous page)

TECHNOLOGY	DIS-COUNT RATE (%)	NET PRESENT VALUE ($MM) UNDER SCENARIO:				
		1	2	3	4	5
H-COAL	0	2021	1177	2496	-631	-760
	2	1387	653	1824	-700	-824
	4	905	262	1307	-763	-881
	6	533	-34	904	-820	-733
	8	243	-262	584	-871	-978
	10	12	-440	327	-916	-1018
	12	-173	-580	118	-957	-1054
	14	-324	-693	-54	-994	-1087
	16	-448	-784	-197	-1027	-1115
	18	-552	-860	-318	-1057	-1141
	20	-639	-922	-421	-1085	-1164
EDS	0	-687	-1700	-117	-3870	-4024
	2	-873	-1754	-348	-3378	-3526
	4	-1022	-1794	-539	-3024	-3165
	6	-1142	-1824	-698	-2766	-2901
	8	-1241	-1847	-832	-2577	-2706
	10	-1323	-1866	-945	-2438	-2560
	12	-1392	-1881	-1043	-2334	-2450
	14	-1451	-1894	-1127	-2255	-2366
	16	-1501	-1905	-1200	-2197	-2307
	18	-1545	-1914	-1265	-2152	-2252
	20	-1583	-1923	-1321	-2118	-2213
SHALE	0	1567	722	2041	-1085	-1215
	2	1100	366	1538	-987	-1111
	4	747	104	1150	-921	-1039
	6	476	-92	847	-877	-990
	8	265	-240	606	-849	-956
	10	98	-354	413	-831	-933
	12	-36	-443	255	-820	-917
	14	-144	-513	126	-815	-907
	16	-233	-569	17	-813	-901
	18	-307	-615	-74	-813	-897
	20	-370	-653	-151	-815	-895

TABLE C.3: 40% cost overrun

TECHNOLOGY	DISCOUNT RATE (%)	NET PRESENT VALUE ($MM) UNDER SCENARIO:				
		1	2	3	4	5
SRC	0	810	-34	1285	-1842	-1971
	2	464	-270	901	-1623	-1747
	4	199	-444	602	-1469	-1587
	6	-6	-574	364	-1359	-1472
	8	-167	-672	174	-1281	-1388
	10	-296	-748	19	-1225	-1327
	12	-400	-808	-109	-1185	-1282
	14	-486	-855	-216	-1156	-1249
	16	-556	-893	-306	-1136	-1224
	18	-616	-923	-382	-1121	-1205
	20	-666	-949	-448	-1111	-1191
SYNTHOIL	0	176	-669	650	-2477	-2606
	2	-21	-755	417	-2108	-2232
	4	-172	-815	231	-1840	-1958
	6	-290	-858	80	-1643	-1756
	8	-383	-888	-42	-1497	-1604
	10	-459	-911	-144	-1387	-1489
	12	-520	-927	-229	-1304	-1401
	14	-570	-939	-300	-1241	-1333
	16	-612	-948	-361	-1191	-1279
	18	-648	-955	-414	-1153	-1237
	20	-678	-961	-460	-1123	-1203

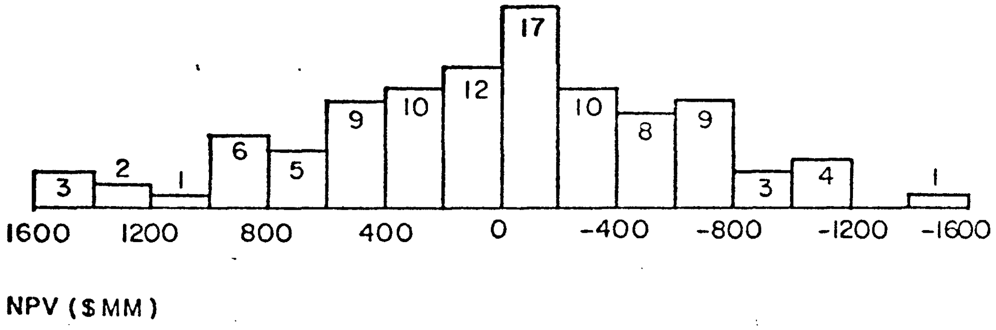
(Continued on next page.)

TABLE C.3: 40% cost overrun (continued from previous page)

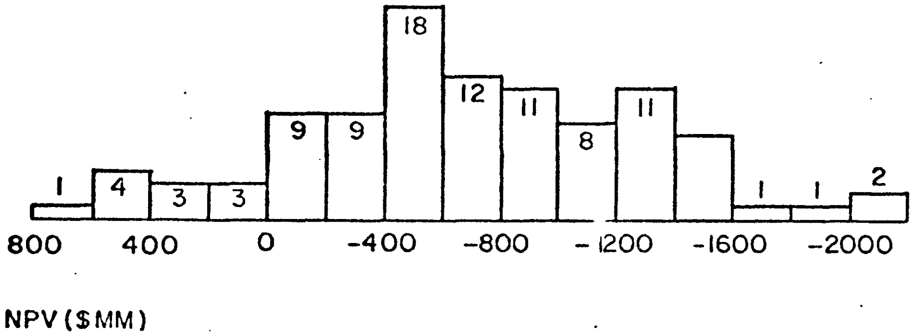
TECHNOLOGY	DIS-COUNT RATE (%)	NET PRESENT VALUE ($MM) UNDER SCENARIO:				
		1	2	3	4	5
H-COAL	0	1520	676	1995	-1133	-1261
	2	945	211	1382	-1142	-1266
	4	506	-137	909	-1162	-1280
	6	167	-401	537	-1186	-1299
	8	-99	-604	242	-1213	-1320
	10	-312	-764	3	-1240	-1342
	12	-483	-890	-192	-1267	-1365
	14	-623	-992	-353	-1294	-1386
	16	-739	-1075	-488	-1318	-1406
	18	-836	-1144	-602	-1342	-1425
	20	-918	-1201	-700	-1364	-1443
EDS	0	-1811	-2824	-1241	-4994	-5148
	2	-1829	-2710	-1304	-4334	-4482
	4	-1854	-2625	-1370	-3855	-3997
	6	-1881	-2562	-1436	-3505	-3640
	8	-1909	-2515	-1499	-3245	-3374
	10	-1936	-2479	-1559	-3051	-3173
	12	-1963	-2452	-1614	-2904	-3021
	14	-1988	-2431	-1665	-2793	-2904
	16	-2012	-2415	-1711	-2707	-2813
	18	-2034	-2404	-1754	-2641	-2741
	20	-2055	-2395	-1793	-2589	-2685
SHALE	0	1002	157	1476	-1651	-1779
	2	623	-111	1061	-1464	-1588
	4	335	-308	738	-1333	-1451
	6	113	-455	483	-1240	-1353
	8	-61	-566	280	-1175	-1282
	10	-199	-651	116	-1128	-1230
	12	-310	-718	-19	-1095	-1192
	14	-401	-770	-131	-1071	-1164
	16	-476	-812	-225	-1055	-1143
	18	-538	-846	-305	-1044	-1128
	20	-591	-874	-373	-1036	-1116

Figure C.1 – SRC

Scenario 1



Scenario 2



Scenario 3

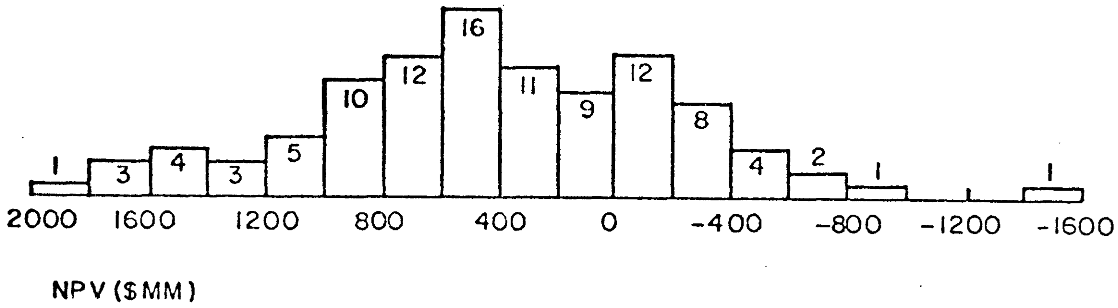
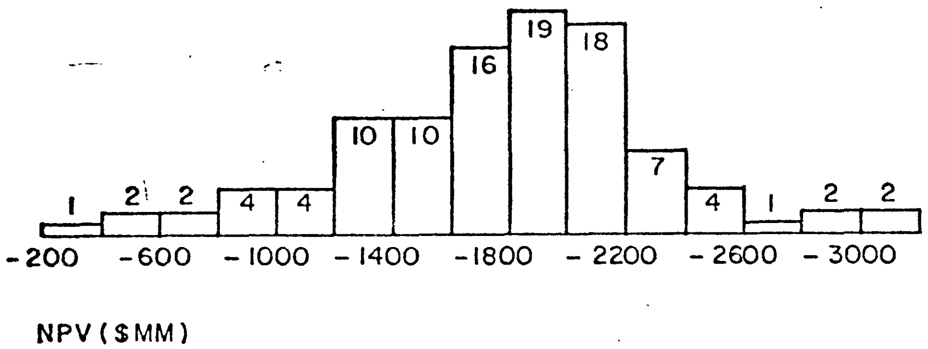


Figure C.I – SRC (cont.)

Scenario 4



Scenario 5

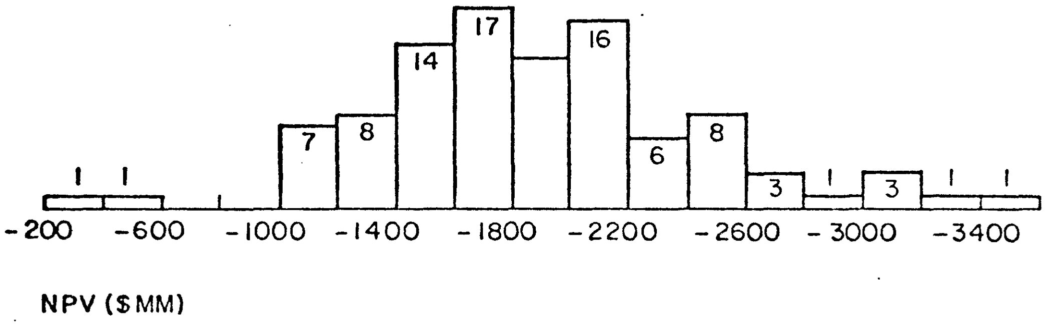
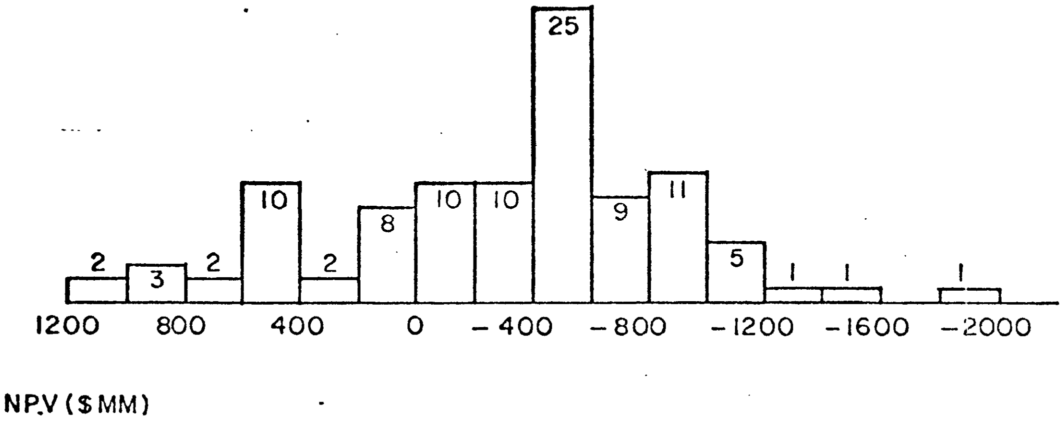
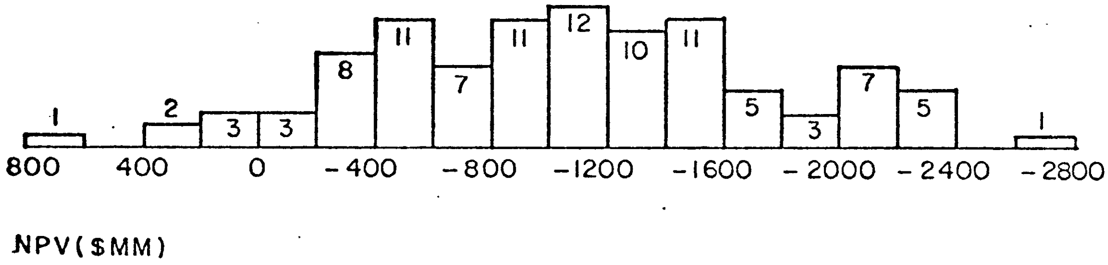


Figure C.2 - Synthoil

Scenario 1



Scenario 2



Scenario 3

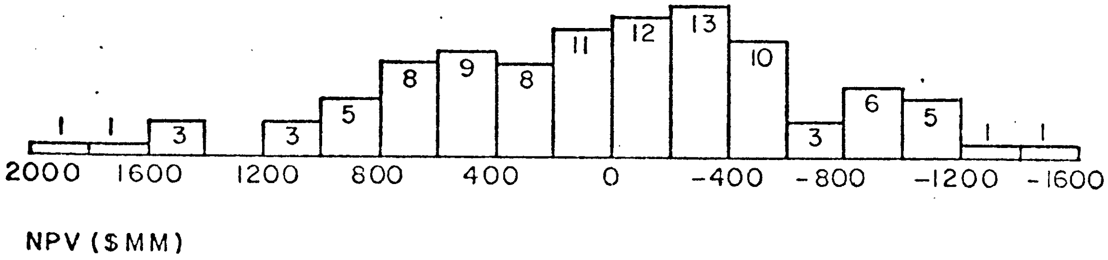
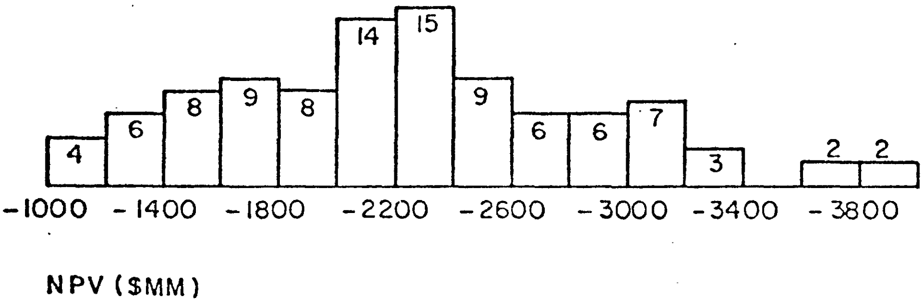


Figure C.2 - Synthoil (cont.)

Scenario 4



Scenario 5

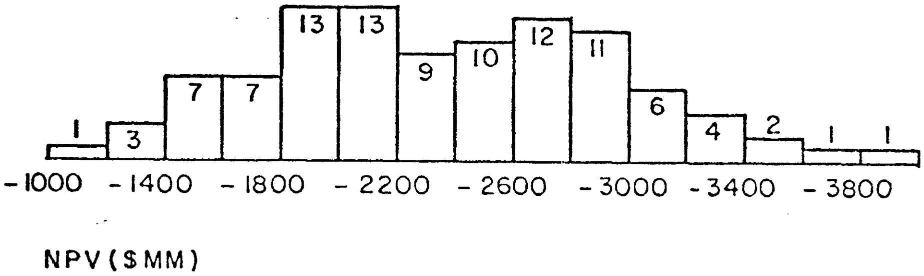
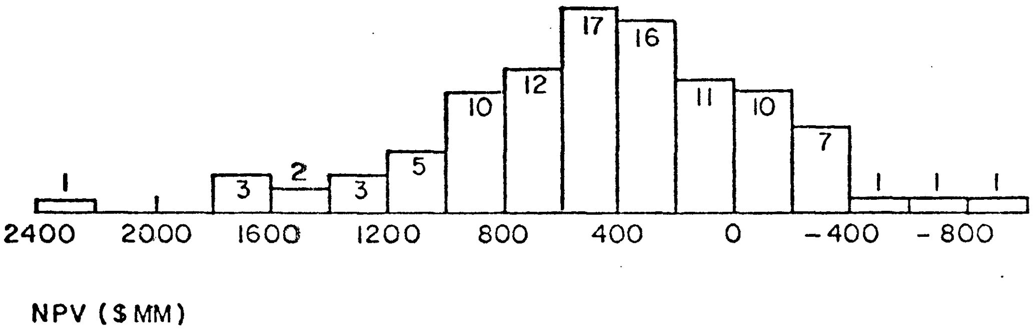
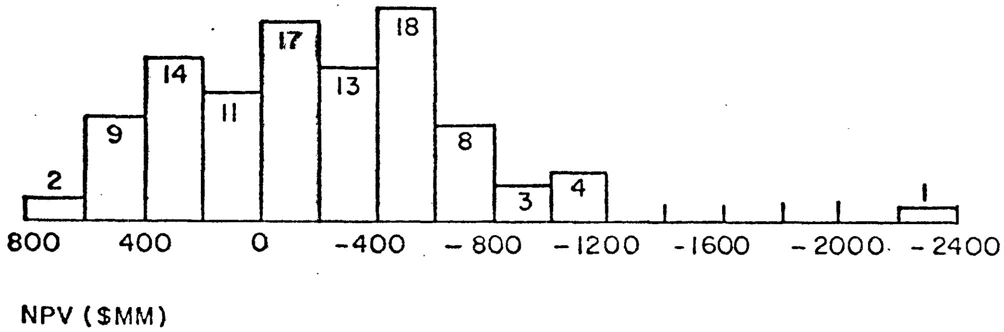


Figure C.3 – H – Coal

Scenario 1



Scenario 2



Scenario 3

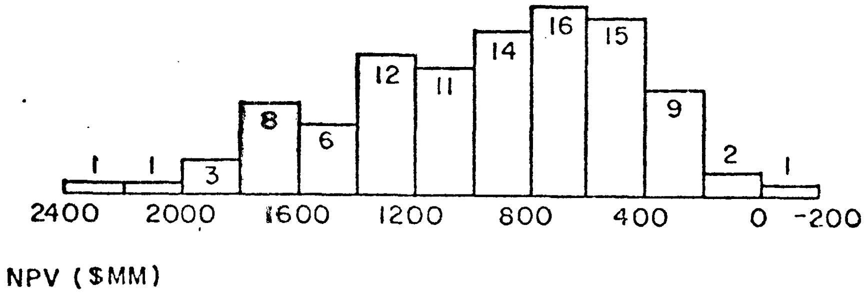
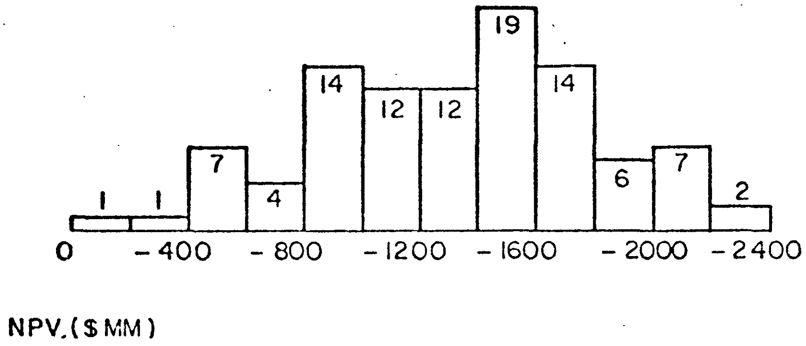


Figure C.3 -H- Coal (cont.)

Scenario 4



Scenario 5

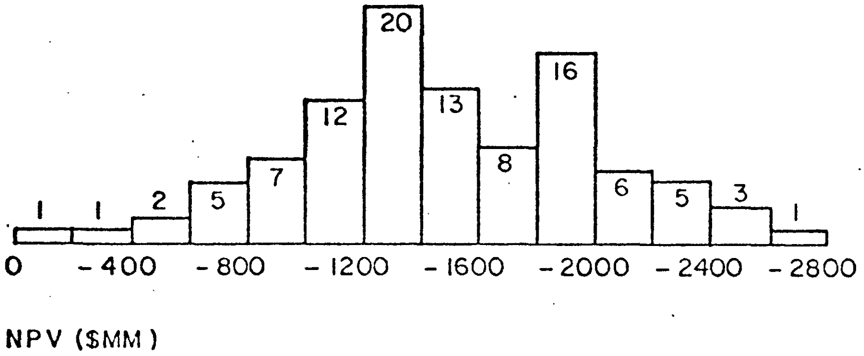
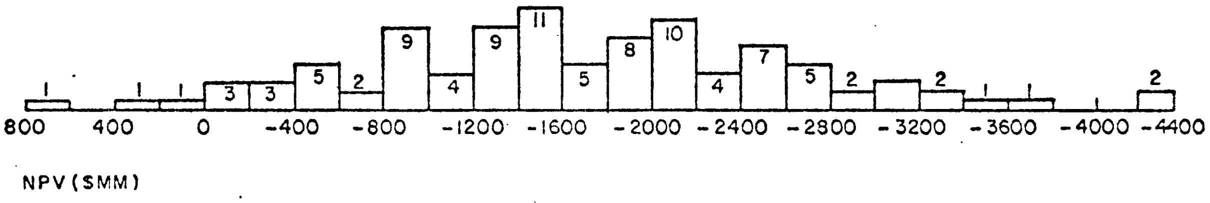
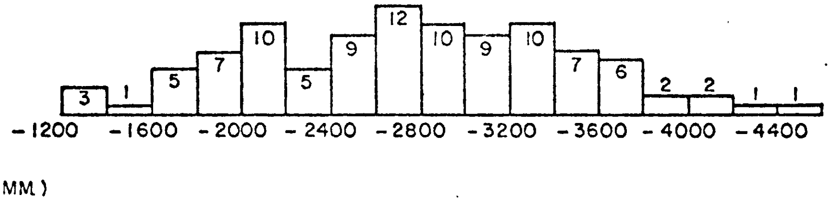


Figure C.4 – EDS

Scenario 1



Scenario 2



Scenario 3

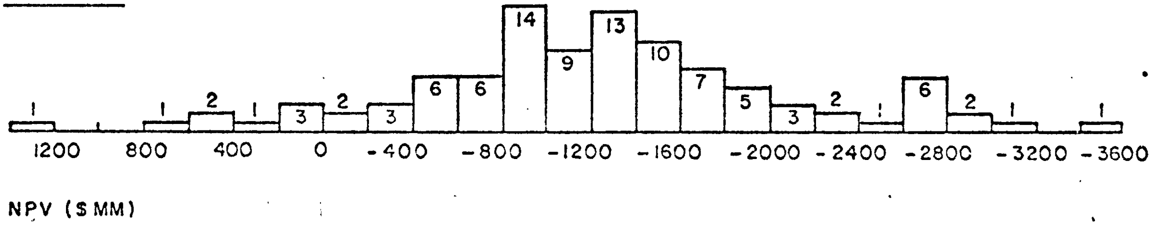
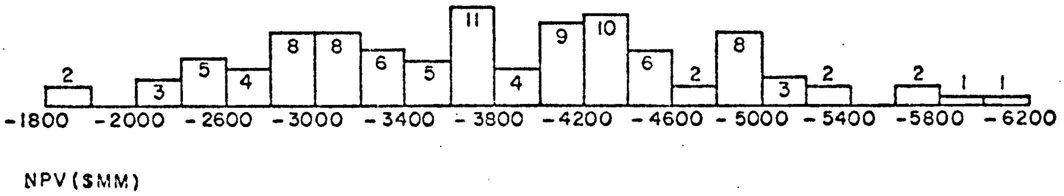


Figure C.4 -EDS (cont.)

Scenario 4



Scenario 5

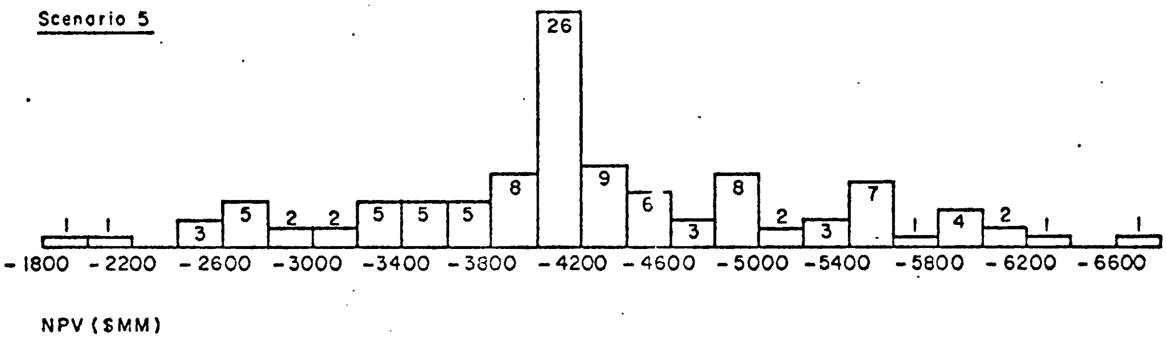
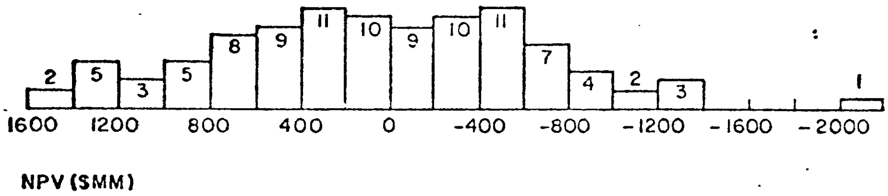
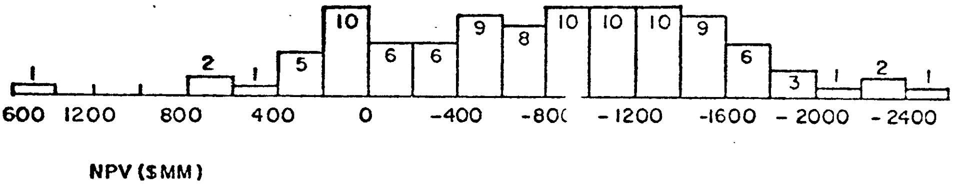


Figure C.5 - INSITU SHALE

Scenario 1



Scenario 2



Scenario 3

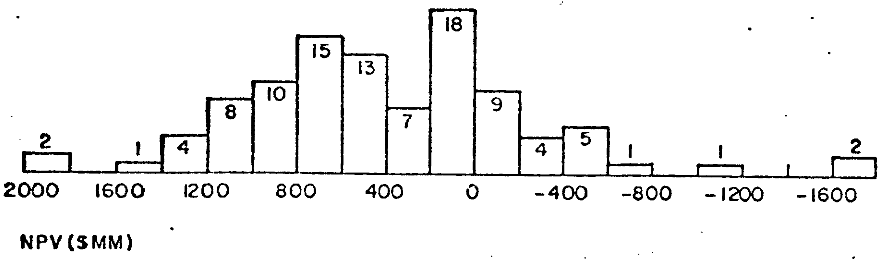
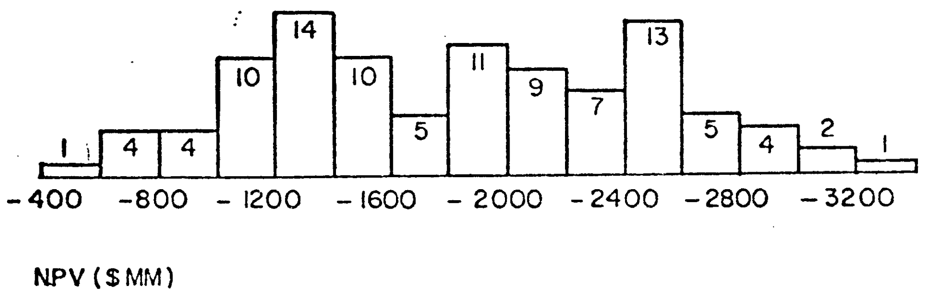
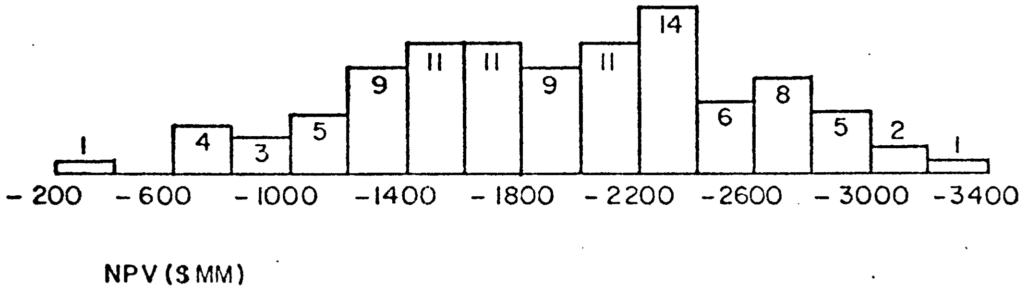


Figure C.5 - INSITU SHALE (cont.)

Scenario 4



Scenario 5



APPENDIX D: Overview of the major environmental issues.*

Each of the technologies within the areas of oil shale processing, coal liquefaction, and coal gasification, differs in the exact form and level of its environmental impact. In general, however, the environmental impacts of concern occur in three distinct forms: (1) the release of pollutants into the atmosphere and water sources; (2) disturbance of the physical environment; and, (3) the allocation and committment of valuable resources that are non-renewable. The effects of these impacts are manifest in the ecology, in occupational health and safety, and in public health (or community exposure). Furthermore, in rural, non-industrialized, low-population areas, the socioeconomic effects of the development of such industries will not be negligible and can have a number of adverse effects. The major areas of impact may be summarized as follows:

1. air quality: Both Federal and state air quality standards exist, and the more stringent of the two is applicable. The concern is mainly over plant emissions during processing and fugitive dust during mining and transportation. In addition, there is concern over the impact on air quality of the eventual use of the synthetic fuels (e.g., impacts of synthetic boiler fuels when used by industry). One of the

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* Although there are numerous sources that deal with the environmental issues connected with synthetic fuels development, the most complete is Reference (3).

risks faced by a synthetic fuels project is that, for many pollutants, the permissible increases in pollutant levels are low relative to the background levels. This, coupled with the naturally occurring wide variation in the background levels makes the determination of the impact of the plant subject to great uncertainty.* Hence, even if the plant is operating within the restrictions imposed, there is a risk that it will be held responsible for the increases in the ambient levels of those pollutants. Furthermore, even in the absence of a synthetic fuels plant, the existing air quality standards present problems: the ambient standards on some of the shale tracts are being violated by naturally occurring hydrocarbons.** This would clearly make the monitoring and control of the emissions from an oil shale plant on that tract subject to further uncertainty.

2. land: A major concern here is the scarring of the landscape due to the plants, mines, and other peripherals, and the disposal of spent shale in the case of oil shale. Equally important is the fact that the use of the land for these plants can permanently alter land use in that neighborhood, destroying vegetation and driving out or destroying wildlife. For example, in the case of coal liquefaction or

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* See Reference (11).

** See Reference (11).

gasification facilities in the Appalacian regions, agricultural and forest lands would not be available for other uses, and reclamation would not totally restore them to their original state. Reclamation and revegetation would be particularly difficult in areas of low precipitation.

3. water: Concern here is both over the availability of adequate supplies and the pollution of existing sources. Synthetic fuels production requires large quantities of water at the sites, and in some regions this would mean a shortage of water for other uses (e.g., for agriculture). The discharge of pollutants into surface streams and leaching into underground sources can be dealt with at the planning stage by designing the plants for "zero discharge", where the spent water is recycled for use at the plant site. Whether or not the discharge is quite "zero" during full-scale operation is not, however, known.

4. occupational health and safety: Although there are dangers present for the operators of the plants, this should not be an insurmountable problem, and has been dealt with in other areas (for example, oil refining).

5. socioeconomic: The socioeconomic impacts are those that can arise from a sudden influx of population into sparsely inhabited, non-industrialized areas lacking the infrastructure necessary to support them (the Appalachian and Eastern Interior regions, though, would not be as seriously affected because of

the existing labor pools). With careful planning, however, the population influx and the attendant problems can be adequately handled.

Many of the above problems have been encountered, and satisfactorily dealt with, by other industries (coal mining and oil refining, for example) and can therefore be solved in principle. What is often presented as unique to synthetic fuels is the uncertainty over future air and water quality standards. This is in addition to the uncertainty regarding the exact level of the impacts of full-scale production and, consequently, some companies have indicated that they are unwilling to proceed until the environmental requirements are fully clarified. It is essential, therefore, that the government issue clear directives in this, and related, areas, thereby removing some of the uncertainties it has helped to create.

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