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Abstract

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COSTS OF SYNTHESIS GASES AND METHANOL

(February 1983)

The report and the associated interactive computer program (SYNCOST) provide a framework for projecting the cost of large scale manufacture of syngases, carbon monoxide, hydrogen, and methanol. The context is one in which the syngases and related products would serve as feedstocks for non-traditional routes to bulk chemicals. The raw materials covered are natural gas, vacuum residue, and a bituminous coal.

Costs were estimated for producing syngases of various H_2:CO ratios, for producing hydrogen, for separating the syngas mixtures, for recovering CO_2 from flue gases, and for methanol synthesis. These were computerized in the form of a set of cost modules which comprise the SYNCOST program. Raw materials, selected values of the H_2:CO ratio in the syngas, and scale of production are the primary independent variables. Some of the modules are independent and some are linked, but no optimization of costs is performed by SYNCOST. The program is designed so that the user can readily change most of the calculation parameters. For forward calculations the user can enter projected raw materials and other unit costs to the year 2001. A set of nominal default values is provided.

In addition to the updated evaluations noted above, the background material covered in the report includes general overviews of the sources and uses of syngases, the gasification of coal, and the mechanics of producing syngases with low H_2:CO ratios (<3) by steam reforming of natural gas.

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Report No. 148

COSTS OF SYNTHESIS GASES AND METHANOL

PART I

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For detailed marketing data and information, the reader is referred to one of the SRI programs specializing in marketing research. The CHEMICAL ECONOMICS HANDBOOK Program covers most major chemicals and chemical products produced in the United States and the WORLD PETROCHEMICALS Program covers major hydrocarbons and their derivatives on a worldwide basis. In addition, the SRI DIRECTORY OF CHEMICAL PRODUCERS services provide detailed lists of chemical producers by company, product, and plant for the United States and Western Europe.

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1 INTRODUCTION

Mixtures of carbon monoxide and hydrogen, commonly known as syngases, are produced on an enormous scale for the manufacture of ammonia, hydrogen, methanol, and other chemicals. Less traditional uses of syngases continue to be developed and have increased in importance in recent years, viz., acetic acid and acetic anhydride manufacture. Among the promising new developments in syngas chemistry are routes to ethylene.

The syngas routes may be attractive in themselves, irrespective of raw materials, or they may provide the option to use alternative and ultimately cheaper raw materials such as coal and, in certain circumstances, natural gas. The search for alternative feedstocks has been given considerable impetus by the fact that for petroleum based commodity chemicals, feedstock costs now compose the major part of the product value. An added attraction of syngas is that it can be manufactured from almost any raw material containing carbon; hence the availability of feedstocks is ensured. The developments in syngas chemistry have the potential for radical impacts on the chemical industry. They open the door to the possible return of the industry to its traditional position—a capital intensive industry adding a high value to a low cost feedstock.

The cost of syngas can be highly variable, depending on hydrogen/carbon monoxide ratio, raw material and process, scale of operation and extent of integration with other processes, cost of CO_2, credit for hydrogen, and so on. Often, the syngas routes are indirect, proceeding via methanol and including a carbonylation step using carbon monoxide per se. In addition, over the past decade, cost components have escalated at widely different rates, sometimes with large step changes. A frequent problem for analysis in this area has thus been the lack of readily available data for current and representative costs of syngases and related products. To serve this need we therefore developed a flexible and easily updated computer model called SYNCOST, which calculates the costs of syngas and related products.

In this study we present the data base used for the SYNCOST program, and describe the use and limitations of the program. To add the perspective which we found lacking in much of the published work, we also review at some length the background considerations to the production and use of syngases. The report is issued in two volumes. Volume II contains the detailed evaluations of process economics. Volume I is intended to serve more as a user mannual for SYNCOST. It contains summary data and a description and listing of SYNCOST, written in Fortran 77. (The program is also available on tape for an additional charge.)

The information in this report derives primarily from material published in patents and the open literature. However, we are indebted to a number of people in industry who gave us initial direction and insight, and subsequently were kind enough to comment on the draft material. These include staff at Celanese Chemical, ICI, Humphries and Glasgow, Davy-McKee, Air Products and Chemicals, Du Pont, and the Alternate Energy and Resources Department of Texaco. In addition, information was supplied by Tenneco Chemicals and Kawasaki Heavy Industries on Cosorb®, by Union Carbide on PSA and cryogenic separations, by Monsanto on Prism® separator systems, and by Humphries and Glasgow on hydrogen production systems. This we gratefully acknowledge. We are also indebted to the Tennessee Valley Authority (TVA) for permitting us to visit their Texaco gasification unit at Muscle Shoals, Alabama.

2 OVERVIEW

The primary aim of the present work is to provide a flexible framework for calculating and projecting the cost of large scale manufacture of synthesis gases, methanol, carbon monoxide, and hydrogen. The term synthesis gas or syngas, for short, is used here to refer to mixtures of hydrogen and carbon monoxide. If a mixture also contains substantial amounts of carbon dioxide, we normally qualify it, as for example, "raw syngas" or "methanol syngas."

We have estimated costs for syngas production from a range of raw materials and computerized the data in the form of cost modules. Raw materials, selected values of the H_2:CO ratio in the syngas, and scale of production are the primary independent variables. Some of the modules are independent and some are linked, but no optimization of costs is attempted within the program.

The raw materials covered are natural gas, vacuum residue, and a bituminous coal. The context is one in which the syngases and related products would serve as feedstocks for nontraditional routes to bulk chemicals, i.e., the base cases relate to a large scale of production and to syngases with low H_2:CO ratios (<3).

Background

Syngas derived mainly from natural gas is currently used on a huge scale for the production of ammonia, and hydrogen, and on a lesser scale for the production of methanol and miscellaneous chemicals such as oxo alcohols.

The impetus for the present work, however, derives from the interest in a new generation of processes for bulk chemicals via syngas or "C_1" routes which are expected to increase in importance in the coming years. Examples of this trend are the highly successful commercialization by Monsanto of a syngas route to acetic acid (see, e.g., PEP Review 78-3-4), the imminent commercialization of the Eastman/Halcon technology for acetic anhydride, and the research being devoted to both direct and indirect (via methanol) routes to ethylene from syngas (see PEP Report 146, Bulk Chemicals from Synthesis Gas).

The syngas based processes in the development stage generally do not appear competitive with established processes at present relative prices of petroleum products and syngas derived from natural gas (basis a trendline uncontrolled price close to that of fuel oil). A major driving force for these developments has been the perception that crude oil prices are likely to continue escalating over the longer term faster on average than the costs of construction and the price of coal. Given this, syngas or methanol made from coal or low cost natural gas will eventually become a competitive feedstock for manufacture of several primary bulk chemicals. The biggest impact on the industry would be if this were the case regarding production of ethylene.

Our study took place during a period in which the trend of oil prices sharply reversed. At the start of the study, in late 1980, there were still oil shortages, and oil prices were increasing steadily (average refiner acquisition cost of imported oil peaked at close to 40$/bbl in early 1981). At the time of writing this summary in mid-1982, in contrast, there is a deep worldwide recession and an oil glut, and falling oil prices are the norm (currently ca. 32$/bbl). The industry consensus regarding the future course of oil prices and the prospects for synfuels also has changed. Opinion has polarized into two schools of economic thought over the present oil glut. One group holds that it is a temporary phenomenon; the other believes that more than ample oil supplies are likely for the rest of the century. We have summarized some of their key arguments in Appendix A.

The first school expects frequent interruptions of oil supplies during the next 20 years, with oil prices climbing faster than general inflation. The opposite school, probably the current majority, sees

OPEC losing its ability to control prices, which are projected to increase little, if at all, in real terms through the year 2000.

If the latter school is right, most of the capital intensive coal based routes will not become competitive before the end of the century. As noted in Section 3, a key criterion here is that the crude oil price escalates on average faster in real terms (perhaps a minimum of 2%/yr) than do construction costs. The relative rate of escalation between oil and coal has a much more minor impact.

The authors of the present report incline toward the first school of thought about the eventual course of oil prices. However, the main point here is that, because the sensitivities to the differential rates of escalation are very large, and the uncertainties in projecting costs are high, it is prudent to carry out ongoing analysis of alternative scenarios and alternative feedstock options as better defined data become available or as perceptions change. To this end our computer program, which enables rapid and ready estimation of screening level costs of syngases from various raw materials, should be of particular utility.

Features of Syngas Supply and Use

"Syngas" is a generic name for a class of feedstocks (and fuel gases) which are comprised primarily of mixtures of hydrogen and carbon monoxide. For certain uses, appreciable amounts of carbon dioxide or methane may also be left in the mixture. The cost of syngas varies over a wide range, depending on circumstances and constraints applicable to a particular site. The cost of syngas in the general case is therefore moot. The reasons for this include the following:

On the supply side:

- Syngas is made from a multitude of raw materials by various processes (see Table 3.1 and Figure 3.1 in the next section).
- The scale of production varies by a factor of 1,000 or more. For the components CO and H_2 as such, pipeline networks exist in areas of plant concentration like the U.S. Gulf Coast, and add a further option.

- If very large facilities are constructed to produce methanol, substitute natural gas (SNG), or Fischer-Tropsch liquids for the fuel market, using a portion of the syngas feedstocks for chemicals manufacture is likely to give the most substantial economies of scale.
- The more promising coal gasification technologies are not yet fully developed or demonstrated.

On the demand side:

- The H_2:CO ratios of the syngas vary with the feedstock and process, and rarely match the H_2:CO ratios optimally required by a given process.
- The strategy and economics of adjusting the H_2:CO ratio may be contingent on the overall hydrogen/carbon balance at a given location (i.e., extent to which integration is feasible or desirable with other units on site). Often this boils down to the requirement for, and value to be assigned to hydrogen at a given location.
- The syngas routes often consist of several process steps, and the actual feedstocks comprise, for example, methanol and carbon monoxide rather than the stoichiometrically equivalent syngas with a 1:1 H_2:CO ratio (viz, acetic acid and anhydride processes). In practice, the methanol and CO may be produced in totally independent facilities which differ in scale by an order of magnitude (see Table 3.2 and Figure 3.2 in the next section).
- Both production and user processes typically give rise to larger heat flows. For optimum economics, close integration of the heat balance is necessary.

In developing a cost model, therefore, considerable simplification appeared justified because even a very sophisticated model would likely fail to give better than screening level accuracy in the general case. Scope limitations of a PEP study also required that we focus onto a certain area of syngas utilization, and a modular approach appeared to be the most practical. The set of modules was selected by working backward and trying to match the "demand side" requirements for manufacture of bulk chemicals from syngas by nontraditional routes (see Section 3). This resulted in focusing on the costs and options for producing, on a large scale, syngases with low H_2:CO ratios (<3:1), and methanol/carbon monoxide combinations. We also included the economics of large scale production of hydrogen to provide reference values, since hydrogen is a by-product in certain processes for the adjustment of H_2:CO ratios, and in CO production. However, the economics of ammonia production per se, or of hydrogen production on a small scale are not included. In general, the scale of production examined is substantially above that which would correspond to facilities dedicated to "oxo" chemicals production. The study also limits itself to examining the costs of on-purpose production only. Recovery from by-product streams (e.g., CO from blast furnace gases) is outside the present scope.

Study Features, Limitations, and Caveats

The end product of SRI's study is the SYNCOST (Syngas Cost Estimating) computer program, which provides production cost estimates for the product modules detailed in Table 2.1 and illustrated in Figures 2.1 to 2.3. In addition, sufficient background is presented on reforming and gasification to brief a user who lacks familiarity with the ramifications of syngas production.

To help the user avoid some pitfalls, below we first call out some caveats regarding the program. A more systematic description of the program is given in Appendix B.

The program runs in an interactive mode. A prime emphasis in its design was flexibility. Ultimately all the data within it (e.g., capital costs as well as feedstock prices) can be replaced by the user. The same applies to the various factored parameters, e.g., percentages allowed for maintenance labor and materials, G&A, ROI, etc.

Data are entered for and the program calculates costs for actual years from 1980 onward. The default values for raw materials and utilities prices in the program as initially compiled (and on the tape optionally available to clients), comprise actual representative values in the United States for 1980 and 1981. For 1982 and onward, the default values are based on a trendline extrapolation made in late 1981, which assumes moderate oil price increases from 1985 onward (see below and also Appendix A). Being a trendline projection it, does not

Table 2.1

SYNCOST PROGRAM MODULES

Module Number	Module Name	Base Case*	Default†	Min	Max
1	Syngas (0.75) from coal (MM scfd)	802.0	802.0	50	1,600
2	Syngas (1.0) from coal (MM scfd)	803.2	803.2	50	1,600
3	Syngas (1.0) from natural gas (CO_2 import) (MM scfd)	302.8	200.0	15	600
4	Syngas (1.0) from syngas (3.0) by skimming (MM scfd)	141.7	97.6§	40	570
5	Syngas (1.0) from syngas (2.0) by skimming (MM scfd)	190.0	129.2§	40	760
6	Syngas (1.0) from vacuum resid (MM scfd)	298.3	200.0	50	600
7	Syngas (1.5) from coal (MM scfd)	804.3	804.3	50	1,600
8	Syngas (2.0) from coal (MM scfd)	805.0	805.0	50	1,600
9	Syngas (2.0) from natural gas (CO_2 import) (MM scfd)	294.6	200.0	40	600
10	Syngas (2.0) from vacuum resid (MM scfd)	295.9	200.0	50	600
11	Syngas (2.0) from syngas (3.0) by skimming (MM scfd)	220.5	151.5§	40	880
12	Syngas (3.0) from natural gas (MM scfd)	290.5	200.0	40	600
13	Methanol syngas (2.26) from coal (MM scfd)	805.3	805.3#	50	1,600
14	Crude syngas (4.9) from natural gas (MM scfd)	264.9	264.9**	90	530
15	CO from gas-derived syngas (3.0) (via Cosorb®) (MM lb/yr)	149.3	149.3	70	600
16	CO from gas-derived syngas (3.0) (via cryogenic) (MM lb/yr)	149.3	149.3	70	600
17	CO from gas-derived crude syngas (via Cosorb®) (MM lb/yr)	149.3	149.3	70	600
18	CO from gas-derived crude syngas (via cryogenic) (MM lb/yr)	149.3	149.3	70	600
19	CO from coal-derived methanol syngas (via Cosorb®) (MM lb/yr)	149.3	149.3	70	600
20	CO from resid-derived syngas (2.0) (via cryogenic) (MM lb/yr)	149.3	149.3	70	600
21	Hydrogen (97%) from natural gas (MM scfd)	276.9	100.0	8	560
22	Hydrogen (97%) from coal (MM scfd)	781.0	200.0	50	1,560
23	Hydrogen (98%) from vacuum resid (MM scfd)	286.1	100.0	50	1,150
24	Methanol from natural gas (metric tons/day)	2,500	2,500	140	5,000
25	Methanol from gas-derived crude syngas (metric tons/day)	2,500	2,500	960	5,000
26	Methanol from coal (metric tons/day)	10,000	10,000	600	20,000
27	Methanol from coal-derived methanol syngas (metric tons/day)	10,000	10,000	600	20,000
28	Carbon dioxide from flue gas (MM lb/yr)	870	870	400	1,750

*Capacity at which design was carried out and a detailed cost estimate made. Except for coal the base case also represents the capacity above which parallel lines are needed.

†This is the capacity for which the program automatically calculates costs. The selection of this value is largely arbitrary.

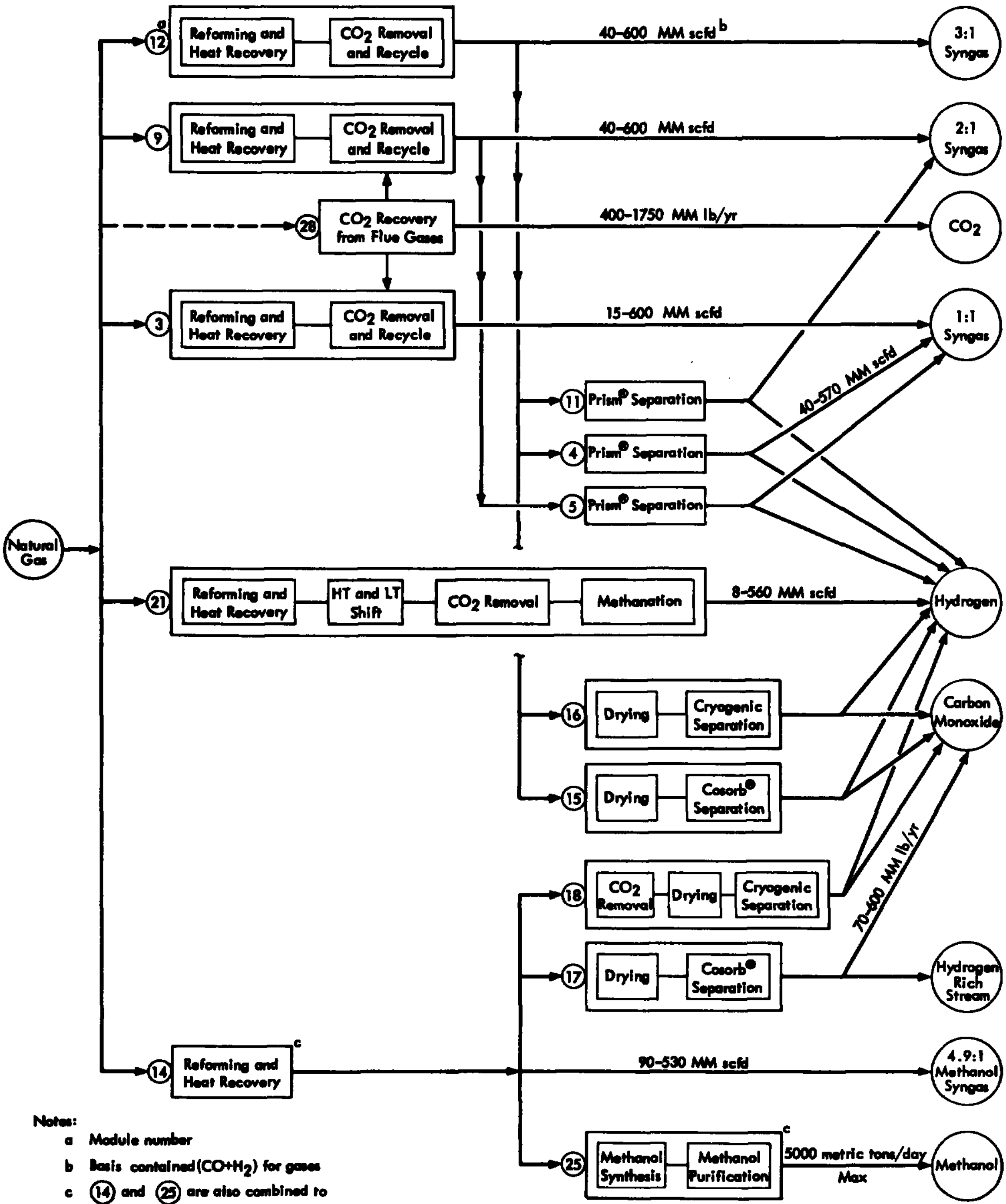
§Product capacity for 200 MM scfd feed.

#Matches 10,000 metric tons/day methanol capacity.

**Matches 2,500 metric tons/day methanol capacity.

Figure 2.1

NATURAL GAS BASED MODULES



Notes:

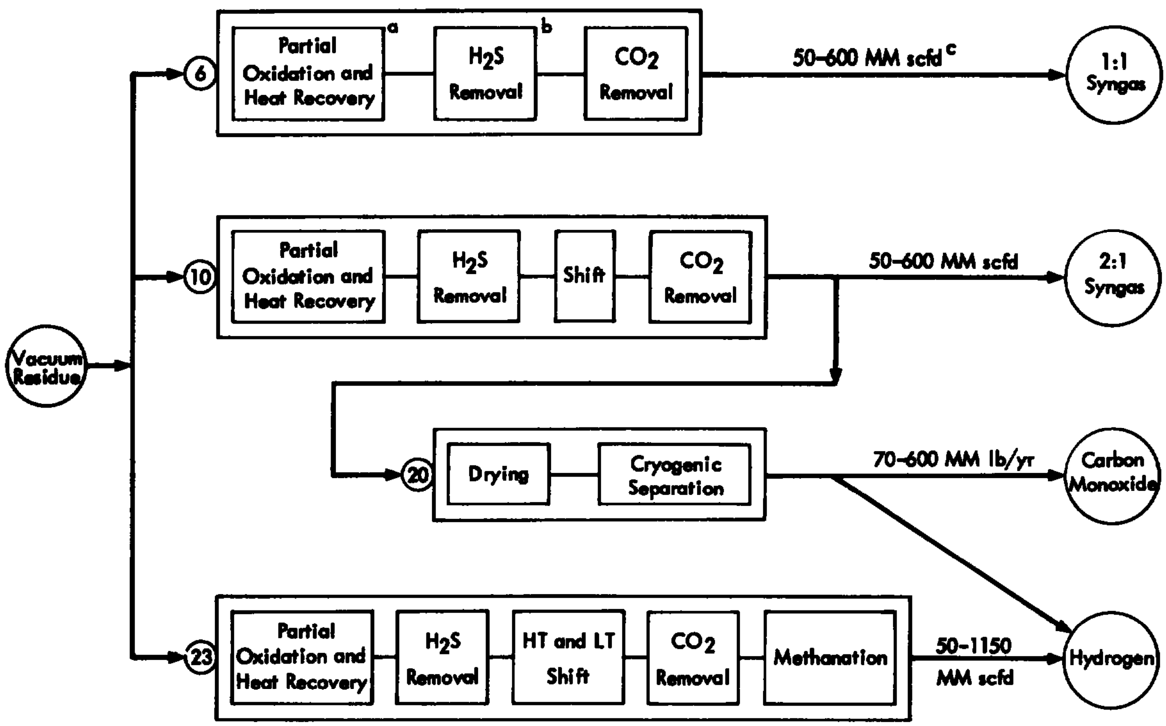
a Module number

b Basis contained ($CO+H_2$) for gases

c (14) and (25) are also combined to give the single module (24)

Figure 2.2

PARTIAL OXIDATION MODULES



Notes:

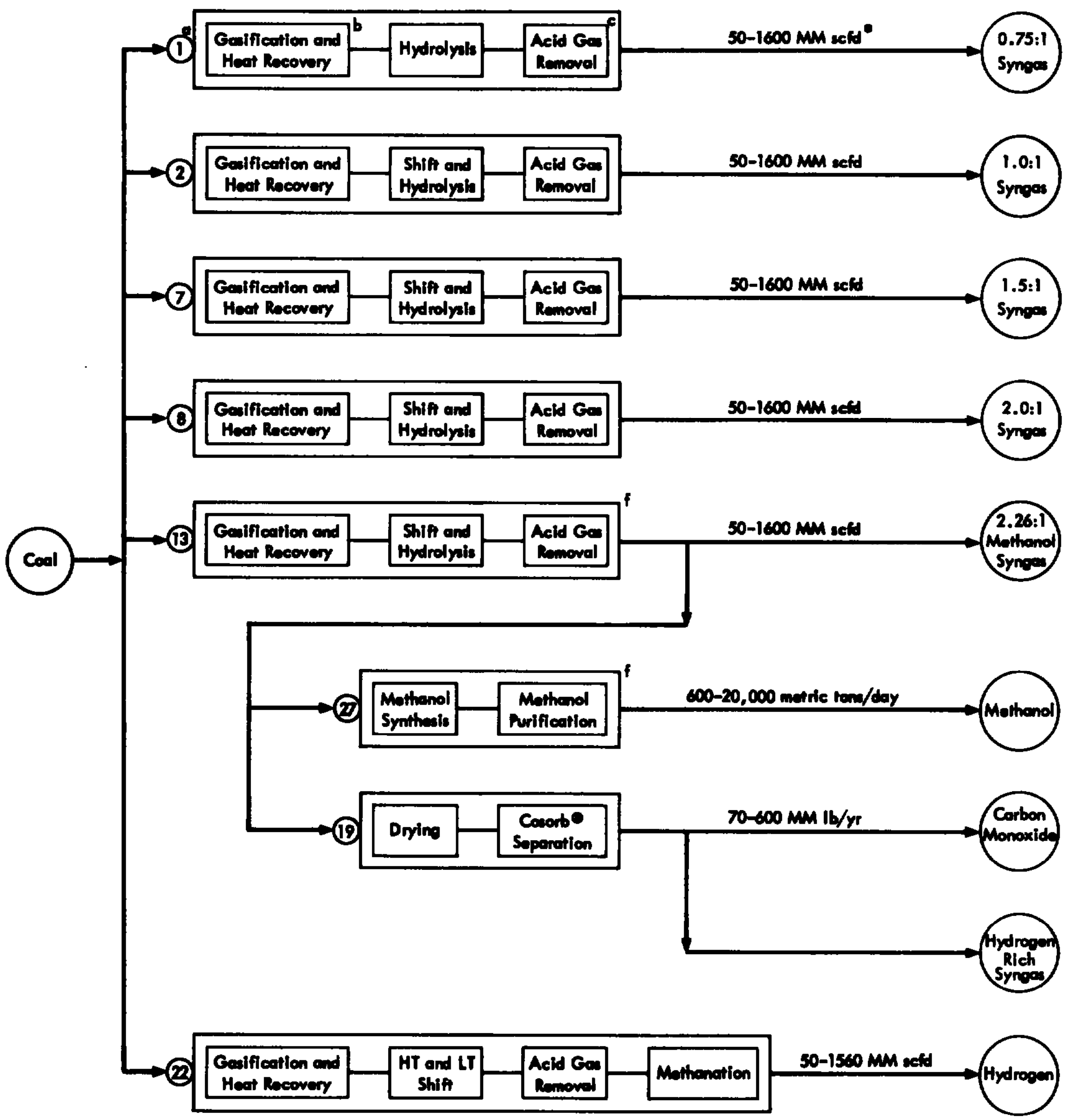
a Includes oxygen plant in all cases

b Includes sulfur recovery in all cases

c Basis contained ($CO+H_2$)

Figure 2.3

COAL GASIFICATION MODULES



Notes:

a Module numbers

b Includes oxygen plant in all cases

c Includes sulfur recovery in all cases

e Basis contained ($CO+H_2$) for gases

f 13 and 27 can also be combined to give a single module 26 recognize economic ups and downs. The values for 1982 in particular deviate considerably from actual prices.

The depth of technical analysis backing up the data varies, depending on the depth of the current analysis, availability of past PEP analysis, industry input, etc. It is generally lightest for the vacuum residue cases. For the mainstream natural gas and coal based processes previously covered by PEP, we did a substantial amount of reevaluation and updating. For the H_2-CO separations, we relied more heavily on the face value of data supplied by licensors of the various technologies than we would have in a normal PEP evaluation. For the base case costs relating to coal gasification, we made use of cost data from detailed studies by contractors. However, in the final analysis we increased the capital estimates to reflect a more conservative design basis. (See also below.)

Because of budget limitations on the study some of the rough edges are left showing. In particular, the outputs as generated by the program, in most cases, have a somewhat different basis and give numbers which differ in various degrees from those shown in the background analyses. The key areas in which there is lack of uniformity are as follows:

- <u>All the SYNCOST cost and capacity data are on a "contained basis."</u> For syngases these data refer to the ($CO + H_2$) content only. In contrast, the costs and capacities of syngases in Sections 4, 5, and 7 are presented on a total dry stream basis. This makes very substantial differences for streams with a larger CO_2 content, such as methanol syngas.

  For methanol and the separated components H_2 and CO, however, the data are on a contained basis (e.g., per unit of 100% methanol) throughout the report.

- The capital costs in SYNCOST for the coal based cases are 20 to 25% higher than those shown in Section 6. This results from adopting a more conservative design for the program database (see below).

- The capital costs in SYNCOST and the text may also differ somewhat because of the following:

  a. The program data are curve-fitted and the match to the input point data is not perfect.

b. The program costs for imported steam include an allowance for capital, and are based on coal fired boilers. In some instances in the text the capital for boilers for imported steam is included in the off-sites investment, and coal and oil firing is variously assumed.

- The SYNCOST default value for CO_2 cost is zero. In the text, various values are assigned to CO_2 cost. In both text and program, however, no credit is taken for any CO_2 produced. It is assumed to be vented.
- The SYNCOST default credits and debits low pressure steam at a fractional value of high pressure steam in proportion to heating values. In Section 6 low pressure steam is credited at zero value.

As noted, the default values are readily changed (see Appendix B).

The program, as it stands, calculates syngas costs only for the selected discrete values of the H_2:CO ratio shown in Table 2.1. For intermediate values manual interpolation is needed. In general, for syngas made by gasification, the cost changes little for moderate changes in the H_2:CO ratio.

Regarding the production of CO, numerous variations are possible from various combinations of separation processes, raw materials, and alternative points at which feedstock for separation could be withdrawn. The modules for estimating CO costs can therefore only give a selection of illustrative costs.

Hydrogen of various purities is the coproduct in the separation of CO from syngas and in "skimming" to lower the H_2:CO ratio of syngases. The compositions produced by the various processes evaluated in the present study are shown in Table 2.2. The value assigned to the coproduct hydrogen has a major influence on the value of the primary product. Syngases made by partial oxidation are typically hydrogen lean with respect to the consuming processes (see Section 3); the H_2:CO ratio is increased by shifting. If in such a situation CO is separated from a slip stream, the system can be designed so that the hydrogen is mixed back into the main syngas stream. One logical option is then to value the hydrogen the same as the syngas feedstock. Syngas made by steam reforming, in contrast, typically is hydrogen rich, and the hydrogen

Table 2.2

HYDROGEN COMPOSITIONS

	Direct Manufacturing			Coproduct in CO Production					
Program module no.	21	22	23	18	17[§]	15	16	20	19[#]
Primary feedstock	Natural gas	Coal	Vacuum resid	Natural gas	Natural gas	Natural gas	Natural gas	Vacuum resid	Coal
Intermediate feedstock	—	—	—	Crude syngas	Crude syngas	Syngas (3:1)	Syngas (3:1)	Syngas (2:1)	Crude syngas
Process	Reforming	Gasification	Partial oxidation	Cryogenic separation	Cosorb®	Cosorb® + methanation	Cryogenic separation	Cryogenic separation	Cosorb®
Primary product	Hydrogen	Hydrogen	Hydrogen	CO	CO	CO	CO	CO	CO
Hydrogen composition (vol%)[*]									
H_2	96.6	96.6	98.1	98.5	85.44	97.85	98.5	99.41	93.00
CO	tr	tr	tr	tr	0.92	tr	tr	tr	0.05
CO_2	tr	tr	tr	tr	9.10	tr	tr	tr	4.36
CH_4	2.5	1.3	0.7	1.38	4.31	1.82	1.47	0.33	0.54
N_2 + Ar	0.2	1.5	1.1	0.12	0.22	0.26	0.03	0.26	2.05
H_2O[†]	0.7	1.0	0.1	—	—	0.07	—	—	—
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Pressure (psia)	220	715	1020	230	240	230	230	1040	770
HHV (Btu/scf contained H_2)	351	339	332	339	379	343	340	328	331

	Coproduct in Skimming		
Program module no.	11	4	5
Primary feedstock	Natural gas	Natural gas	Natural gas
Intermediate feedstock	Syngas (3:1)	Syngas (3:1)	Syngas (2:1)
Process	Prism® + methanation	Prism® + methanation	Prism® + methanation
Primary product	Syngas (2:1)	Syngas (1:1)	Syngas (1:1)
Hydrogen composition (vol%)[*]			
H_2	97.52	96.99	96.46
CO	tr	tr	tr
CO_2	tr	tr	tr
CH_4	2.10	2.63	3.16
N_2 + Ar	tr	tr	tr
H_2O[†]	0.38	0.38	0.38
Total	100.0	100.0	100.0
Pressure (psia)	250	250	250
HHV (Btu/scf contained H_2)	347	353	359

[*]tr = <10 ppmv.

[†]The water content is typically that corresponding to saturation.

[§]The default values in the SYNCOST program for the credit given to this stream are taken as fuel value.

[#]The default values for the credit given to this stream are taken to be the same as the syngas feedstock values.

needs to find an outside use. In the general case its value is therefore moot. It could range from chemical value (e.g., for synthesis or hydrogenation) down to fuel value.

In SYNCOST, the default credit given to hydrogen in all separation modules except 17 and 19 (see Table 2.2.) is an estimated "chemical value." The latter corresponds to the product value (production cost + 25% ROI) for hydrogen made from natural gas in a 100 million scfd plant. This scale of production is that associated, for example, with large scale refinery usage. For 1981 the chemical transfer value (without G&A charges) is estimated as 258¢/1,000 scf (basis 417¢/million Btu natural gas) as compared with a fuel equivalent of 154¢/1,000 scf (basis 476¢/million Btu fuel oil).

Modules for on-purpose hydrogen production on a large scale from all the raw materials are included in the program to provide reference points for allocating values to hydrogen coproduct in other circumstances.

The base case designs for syngas deliver product at the following pressures:

	Product Pressure (psia)	
	Syngas	H_2
Natural gas reforming	240	220
Coal gasification	785	715
Partial oxidation of resid	1050	1050

The cost data from the program relate to product delivered at these same pressures. This introduces a slight bias against the partial oxidation processes, particularly if the user process runs at high pressures. However, in general the incremental cost of syngas compression is not large. Costs of syngas compression are examined in Section 4 and estimated to be 5¢ to 13¢/1,000 scf for compression at the rate of 300 million scfd from 240 psia to 480–1200 psia (1981 basis). Unit costs for compression from low pressures, however, are much larger.

For the CO separation and skimming cases, when either of the coproduct pressures is reduced below feed pressure, the costs of recompression to ca. 240 psia are included in the production cost.

Units of Measure

As our standard measures of quantity we adopted the units noted below. The program provides the option to print out costs in selected alternative units as well.

(a) Syngases and hydrogen. Standard cubic feet and normal cubic meters of contained ($CO + H_2$) are used as the normal measures. The reference bases used here are:

- Standard cubic feed (scf) at 60°F, 760 mm Hg
- Normal cubic meters (Nm^3) at 0°C, 760 mm Hg
- [Nm^3] x 37.325 = [scf]

Capacities are typically quoted on a per day basis and conversions to a yearly basis made with a 0.9 on-stream factor (i.e., operation for 328.5 days per year). In the printouts M refers to a thousand and MM to a million; e.g., MMSCFD is short for a million standard cubic feet per day. A billion refers to 10^9.

(b) Methanol and coal. A single measure, the metric ton (or tonne), which is equal to 1,000 kg and 2,205 lb was adopted as the standard. Again capacities are typically quoted on a daily basis.

(c) Carbon oxides. Capacities and costs typically refer to a pound as the unit of quantity, and to a year as the time unit.

The rationale for the selections is briefly as follows. Our emphasis is on uniformity. However, at the same time we do not want to depart too much from the traditional industry quantity measures because of the loss in the perception of scale. Since the field covers elements from various industries, e.g., chemicals, industrial gases, and utilities, which traditionally use different units and even different reference bases, any compromise, particularly in an international context, leads to some units of questionable parentage, e.g., heating values in Btu/metric ton.

Traditionally PEP expresses all costs and capacities on a weight basis. However, for syngases, weight is an awkward measure because the molecular weight changes as the H_2:CO ratio changes. In contrast, the volume of contained (CO + H_2) stays constant even as the ratio of H_2:CO is stoichiometrically changed by shifting.

ROI and Profitability

As a general yardstick for comparison of the overall economic attractiveness of competing processes, PEP uses the concept of a product value, i.e., a unit production cost plus an annual capital charge. The capital charge traditionally included by PEP has been a simple 25%/yr before-tax return on total fixed capital (TFC), sometimes loosely referred to as a 25% ROI. (In this approach the TFC is that estimated for instantaneous construction, and does not include allowances for funds during construction, escalation or start-up costs). We feel that such an approach remains an adequate and in fact a preferred measure for the types of comparisons being made in this study. In contrast, much of the published work dealing with coal gasification economics has recourse to complex criteria for return on capital invested, and often places great emphasis on "creative" financing to lower the cost of capital.

Because the coal based plants require large amounts of capital per unit of production, the level of return required on that capital is a key factor determining the competitiveness of such plants. Obviously availability of low cost financing will result in lower revenue requirements. Similarly any investment credits and accelerated depreciation allowed for tax purposes would have a significant impact on the price required for the product. For any specific project, therefore, a detailed analysis of the projected cash flows as a function of possible financing arrangements is indispensible.

The aim of this study, however, is to provide cost numbers for general screening level evaluations and projections. A prime advantage of using a capital charge based on a simple ROI is in fact the simplicity of the approach. It is unambiguous, easily calculated, and readily understood. For projects in which the associated parameters such as construction periods and capacity build-up rates, are comparable, the correlations between the discounted-cash-flow (DCF) yields and the ROI are very similar for all of the projects. For such projects, comparisons in terms of ROI mirror closely the comparisons in terms of DCF yield. For gas based plants compared with coal based plants, construction periods and other constraints differ, and a given ROI does not represent quite the same DCF yield in each case. However, we expect the correlation to be close enough in general to justify retaining the simple ROI as a realistic measure of profitability.

The return on capital that should be expected is, of course, open to debate. For the constraints on a typical petrochemical plant, the cash flow represented by a 10%/yr depreciation allowance and a 25%/yr pretax ROI generally is equivalent to a DCF yield of 12-17%. To aim for 15% yield on a constant dollar basis used to be traditional for screening level analyses of petrochemical projects. In recent times expectations have perhaps diminished. For a risky project such as a coal based facility, a higher than average return on equity might normally be allowed for. However, many of the published analyses base project value calculations on real yields on capital of less than 10%/yr. Therefore, the default product values calculated here for coal based products are perhaps conservative.

For SYNCOST we elected to stay with the product value and ROI concepts, but provided the option for the user to select the % ROI.

Design Bases and Costs

The modules in the SYNCOST program are listed in Table 2.1. Additional modules can be added by the user (see Appendix B).

A sample printout showing illustrative production cost estimates for each module is included at the end of this section. The sample outputs give costs at the default capacity with default values for raw materials and utilities costs. (The term default value here refers to the values entered in the SYNCOST program data base at the time of issue of this study, and as sent out to PEP subscribers. The various default values can be changed by the user--see Appendix B.)

Please note that in all the cases shown at the end of this section, the costs include an allowance for G&A costs. That is, they correspond to final product rather than intermediate product modules. In contrast, when modules are used in sequence, G&A costs are not allocated to an intermediate module (e.g., syngas for CO production), unless a user so elects. This avoids snowballing of G&A allowances. For the same reason, the default values entered in the raw material data base for intermediate syngas streams, and also for hydrogen credits do not contain a G&A allowance. Also note that the sample outputs for the skimming modules (4, 5, 11) are shown for a capacity of 200 million scfd product, rather than for the actual program default capacity, 200 million scfd feed.

The default costs and prices entered for 1980 and 1981 are estimates of representative average mid-year values for the U.S. Gulf Coast (USGC).

For convenience illustrative default values are also entered in the SYNCOST data base for 1982 onward. Below, we use some estimates based on these to illustrate possible trends. However, we would emphasize the following:

- The values for 1980-1982 derive from a somewhat arbitrary scenario (detailed in Appendix A) constructed in late 1981 to project trendline prices.
- The scenario assumes that oil prices will start to escalate again in real terms past 1985.
- The values are trendline estimates, which ignore the ups and downs in the economy. Thus for example, the 1982 values are estimates of prices, given an economic recovery; they differ substantially from actual prices as at mid-1982 (see illustrations in Appendix A).
- The values for 1990 onward are simple extrapolations at constant rates of escalation.

Figure 2.4

COSTS OF SYNGASES FROM REFORMING OF NATURAL GAS AND PARTIAL OXIDATION OF RESID

USGC mid-1981, PEP Cost Index = 400
H_2 Credit at 258 ¢/1000 scf
Free CO_2

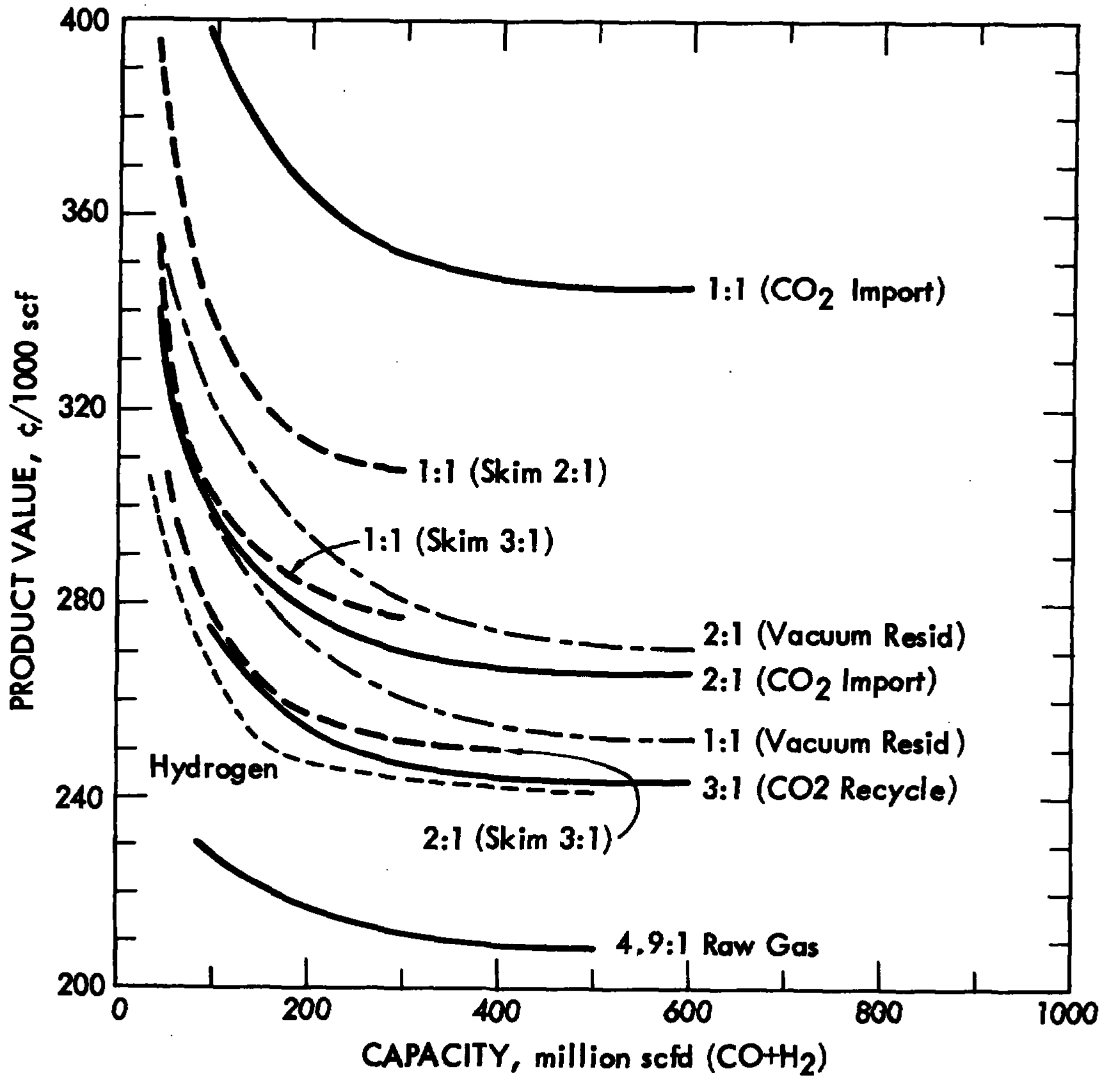
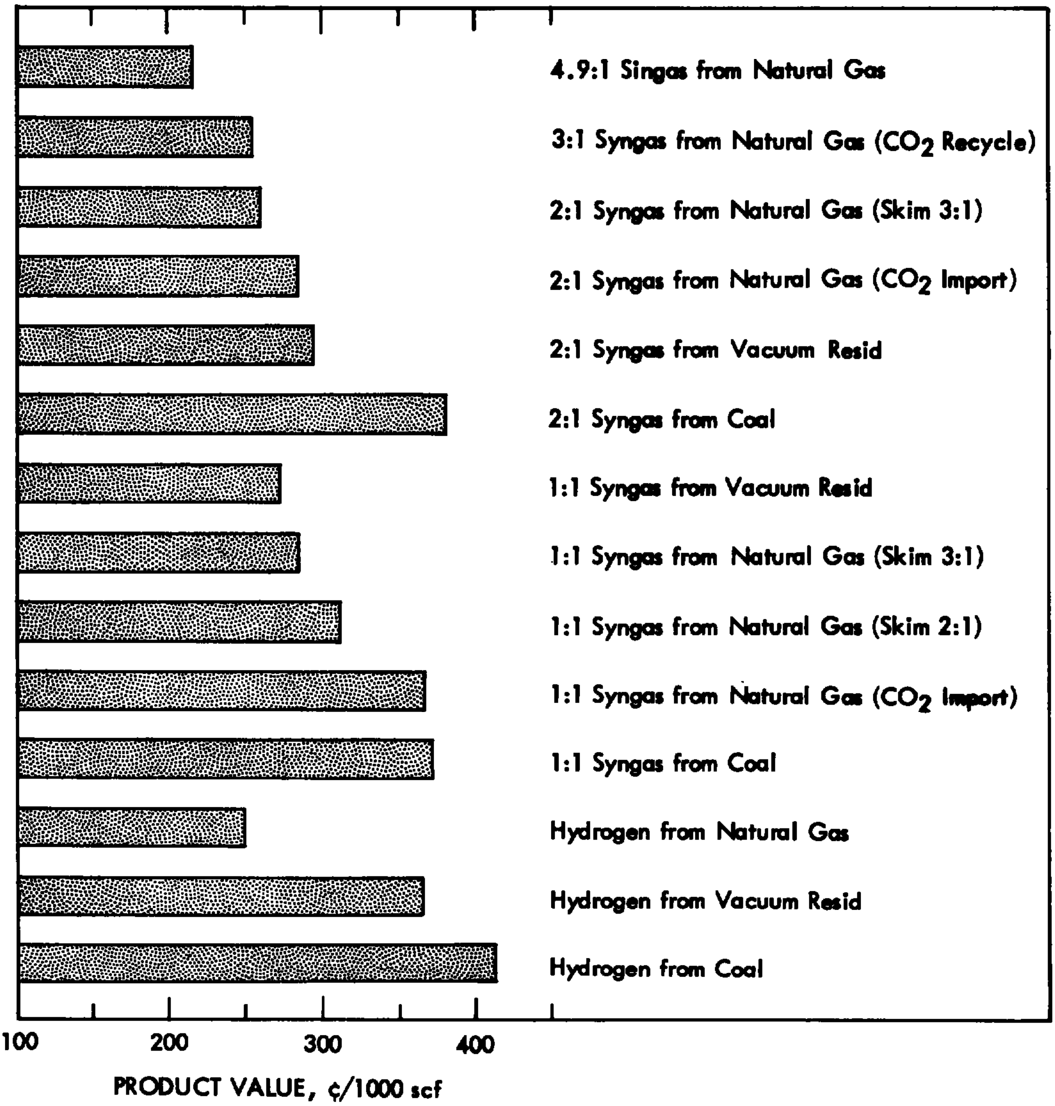


Figure 2.5

COMPARISONS OF PRODUCT VALUES

USGC mid-1981, PEP Cost Index = 400
Free CO_2
H_2 Credits at 258 ¢/1000 scf
200 million scfd Capacity in all Cases



Some comparative cost data are plotted in Figures 2.4 and 2.5, with comments being given in the subsections below. However, given that the prime aim of this study is to facilitate the user to generate syngas cost data for the user's own specific constraints, no extensive tabulation of cost data is included.

Natural Gas Reforming

The ratio of H_2:CO in the product from steam reforming of natural gas is characteristically well above 3:1, and normally closer to 5:1, because of the shift reaction in the reformer. Most of the proposed syngas routes to bulk chemicals, however, require ratios of 2:1 or less, or sometimes methanol and carbon monoxide.

To produce these lower ratios one can either separate (skim off) some hydrogen from the reformer product, or feed carbon dioxide to the reformer, or both. The carbon dioxide can, in part, be recycled from the reformer product, be recovered from reformer flue gases, or be imported. Addition of CO_2 to the reformer feed has typically been practiced in connection with oxo syngas production at relatively small scales of operation. However, little has been published on the comparative economics of these options.

It could well be, that by the time some of the proposed syngas routes approach commercial status, production of syngas from coal may be more economic in the United States than production from natural gas. In addition, certain coal gasification processes yield low H_2:CO ratios (approaching 0.5) which can readily be shifted upward, and in this sense are inherently more suited for the majority of potential syntheses.

However, natural gas reforming is a well established and highly refined technology which currently remains the most widely used, and in general still the most economic route for synthesis gas generation. Also, the future availability and relative pricing of natural gas seems particularly uncertain. We therefore feel that natural gas reforming and variations thereon must still be taken to provide the reference basis, or calibration, for cost comparisons and projections relating to syngases.

We keyed reformer design for syngas production rather closely to that typical of methanol plants, because integration with methanol production facilities may often be an option to be considered, and not infrequently methanol itself may be an intermediate feedstock in the syngas route to a given chemical. For methanol itself, existing PEP analysis did not cover the highest efficiency designs that are now claimed to be practical for the two leading processes, viz., those licensed by ICI and Lurgi. We therefore reevaluated a "high efficiency design" for the ICI process. The economics of the Lurgi process are believed to be very similar. Lurgi is likely to have a slight edge in energy efficiency, but requires more complex reactors. For a high efficiency ICI design without CO_2 addition we estimate a feed and fuel natural gas usage of 32.8 million Btu or 34.6 GJ/metric ton of methanol (HHV basis). However, the most energy efficient design would not necessarily be optimal for production of methanol if low cost natural gas is available; in the nearer term, new methanol capacity is most likely to be added in locations where gas is cheap.

The question of steam balance is an important aspect of reforming economics. As discussed in Section 4, reformer design has become sophisticated enough to provide the designer considerable flexibility in optimizing the steam balance. For the syngas cases, we elected to use designs which were self-sufficient with respect to steam generation. The only exception was the crude-syngas module (14) which comprises the front end of a methanol unit. Here we in effect cut the flow sheet in two, with matching steam credits and debits. Also the hydrogen rich purge stream used as reformer fuel in the two resulting modules was converted into a natural gas equivalent based on heating values. In practice, of course, the reformer heat balance for the other cases as well would be similarly integrated with some downstream process, so that application of costs derived for the general case must necessarily entail an approximation.

The base case designs were carried out at a natural gas feedstock rate corresponding to 2,500 metric tons/day of methanol. This approaches the maximum single-train methanol unit capacity considered to be feasible with current engineering experience. Above this capacity, use of parallel trains is assumed and costs are scaled accordingly (exponent ca. 0.9). Scaling of costs down to about 1,000 tons/day capacity equivalent is also relatively straightforward. However, much below this, one has to allow both for reductions in energy efficiency, and for changes in design philosophy, e.g., use of electric drives instead of steam turbine drives for compressors at the smaller capacities. Examination of the effects of such factors in a few selected cases enabled them to be roughly quantified. However, no detailed design was done for the lower capacities. The costs estimated for capacities approaching the lower limits shown should be considered increasingly approximate.

We evaluated a number of alternatives for lowering the H_2:CO ratio of the product gases, including addition of CO_2 to reformer feed, and the use of various separation techniques to skim off some hydrogen (cryogenic, Cosorb®, PSA, Prism®). A 3:1 H_2:CO ratio can be attained by recovering and recycling the CO_2 in the reformer product. CO_2 recoverable from the product and the flue gases would suffice to lower the ratio to about 1.2. For ratios below this, import of CO_2 is necessary. Of the skimming processes, Monsanto's Prism® membrane separation technology appears to be the most attractive, in part because it skims hydrogen without a major reduction in the pressure of the syngas stream. The skimming cases in SYNCOST are based on use of this process.

Some comparative syngas cost data are shown in Figure 2.4 to illustrate the range of costs. These costs are derived on the basis of using a value of 258¢/1,000 scf for hydrogen produced as coproduct in skimming (i.e., assuming a chemical use for hydrogen), and charging CO_2 at zero cost for the cases entailing CO_2 addition.

It is evident that reducing the H_2:CO ratio is relatively costly. The costs of the process using CO_2 addition increase very sharply as the H_2:CO ratio decreases, even with free CO_2 because of the increasingly large amounts of CO_2 being handled. The costs for the 1:1 gas would be off the scale of the chart if CO_2 is recovered by flue gas scrubbing. Thus, as a general rule, skimming to obtain low ratios is more attractive. However, the absolute and relative costs are sensitive to the charges/credits for H_2, CO_2, and the scale of operations. To provide some reference values for H_2 and CO_2 costs we evaluated on-purpose large-scale production of hydrogen, and the recovery of CO_2 from flue gases.

The hydrogen cost data entered in the program are for a conventional process using steam reforming, combined with high and low temperature shift, CO_2 removal, and methanation, to produce hydrogen at a rate of 100 million scfd. We also screened a proposed modification to the conventional process for hydrogen in which Pressure Swing Adsorption (PSA) replaces the steps downstream of high temperature shift. We found the economics to look attractive, but dependent on substantial export steam credits. If we had used the lower product values estimated for hydrogen produced by PSA as default values for hydrogen credit, the economics of skimming would look somewhat less favorable.

For CO_2, we estimated costs for recovery from flue gases by scrubbing with MEA; a module for this is included in the program. The CO_2 is generated at close to atmospheric pressure. In general, scrubbing of the gases appears to be uneconomic, although we understand that it is still practiced in certain instances. We also note that very recently Dow has announced an improved technology for such a process. Location adjacent to an ammonia plant, on the other hand, could provide effectively free CO_2 and would be the preferable way to go in the present context. This is the implicit assumption made regarding the zero default value assigned to CO_2 in the SYNCOST program.

Some illustrative costs for carbon monoxide production are shown in Figure 2.6. The choice here is typically either a cryogenic separation or the Cosorb® process. The latter uses a selective solvent consisting of cuprous aluminum chloride dissolved in toluene. Both these methods are capable of producing a CO of better than 99% (v) purity. The other methods we examined for hydrogen skimming (viz, PSA and Prism®) do not yield a CO of the purity typically required for feedstock use. For separation of CO from syngases the cryogenic process appears to have the edge. As in skimming, values assigned to hydrogen coproduct have a major influence on the cost. Examination of the economics of CO recovery from various by produced streams is outside the scope of the present work. However, we would note that economics for recovery of CO from blast furnace gases are presented in PEP Report 123. The Cosorb® process was found to be well suited for the latter application because nitrogen, which goes with the CO in the cryogenic process, has very low solubility in the Cosorb® solvent. We understand that many of the initial problems encountered with commercial application of the Cosorb® process have now been overcome.

The economics of natural gas based production are compared further below with those of coal and residue based production. Generally, such comparisons are best done for the products made from the syngas rather than for the syngas itself, because stoichiometric considerations may make it difficult to establish a uniform basis for comparison.

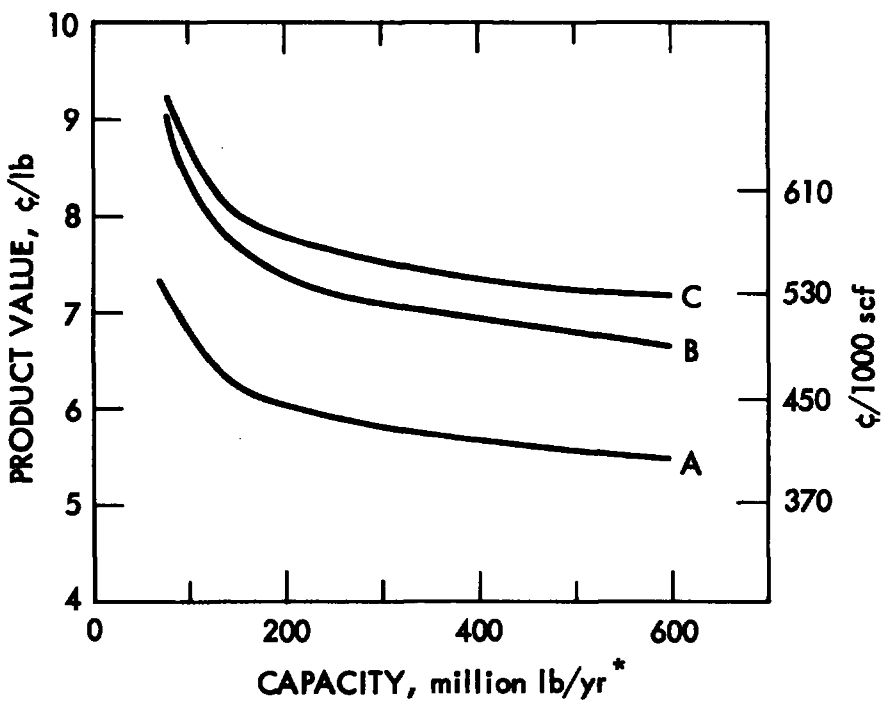
Partial Oxidation of Vacuum Residue

In partial oxidation processes, the greater part of the oxygen in the syngas product is supplied directly as oxygen rather than deriving from steam, as in reforming. H_2:CO ratios of syngases produced by partial oxidation are thus characteristically much lower than those produced by steam reforming, and match well the ratios needed for oxo feedstocks and the feedstocks for most of the proposed routes to bulk chemicals. The typical H_2:CO ratio for partial oxidation of vacuum resid is for example, approximately 1:1 (see also Table 3.1). Higher

Figure 2.6

COSTS OF CARBON MONOXIDE

USGC 1981, PEP Cost Index = 400
Hydrogen Credit at 258 ¢/1000 scf



A Cryogenic separation from 3/1 syngas made by steam reforming of natural gas at 200 million scfd.

B Cosorb® separation from 3/1 syngas made by steam reforming of natural gas at 200 million scfd.

C Cryogenic separation from 2/1 syngas made by partial oxidation of vacuum resid at 200 million scfd.

* Multiply by 0.0413 to obtain million scfd

ratios as required can be obtained readily and economically by the shift reaction, and in contrast to steam reforming, the cost of the syngas is thus not highly sensitive to the H_2:CO ratio.

Another feature of noncatalytic partial oxidation processes is that they lend themselves well to processing a very wide range of raw materials, including the "bottom of the barrel," which sometimes contains high levels of sulfur and metallic impurities. In contrast, the use of steam reforming is restricted to sulfur free feedstocks with carbon numbers up to the naphtha range (i.e., up to C_9). This is because the catalysts used in steam reforming cannot tolerate sulfur, and exhibit an increased tendency to coke with heavier feedstocks. Partly because of its flexibility, partial oxidation has been used selectively to produce syngas for the traditional large scale applications such as ammonia, methanol, and hydrogen and as well as the smaller scale uses such as oxo chemicals, acetic acid, and carbon monoxide. The most recent methanol plant started up in the United States (part of a methanol/acetic acid complex operated as a joint venture by Du Pont/USI) is based on partial oxidation of heavy residue.

Within the limitations of the present study it was not possible to do any extensive new design work for partial oxidation. Nevertheless, on the basis of previous PEP work and industry inputs, we feel that the cost estimates given here for syngas generation by partial oxidation are both consistent with the other data in this study and representative of current practice. The costs relate to a complex based on Texaco gasifiers, Rectisol® acid gas removal, and a Claus/SCOT® sulfur recovery system. Other proven technologies are also available for the various operations. The present selection was based on convenience.

A module for methanol is not entered. Approximate costs for methanol from vacuum residue can be obtained by judiciously combining modules 10 and 27, i.e., 2:1 syngas from resid, with methanol from coal derived syngas.

As seen in Figure 2.4, given the price structures assumed for 1981, partial oxidation of residue is attractive for production of syngases with low H_2:CO ratios. Vacuum residue, has in the past been sold primarily as residual fuel oil. However, it may become increasingly difficult to sell it as fuel because of environmental restrictions on the sulfur content of fuels and because of competition from coal. At the same time the average crude oil processed in refineries will become progressively heavier. This increasing supply and declining demand for vacuum residue may result in a longer term price trend which makes it more generally attractive as a feedstock for syngas based processes. A PEP report on vacuum residue will issue in 1983.

Coal Gasification

In the present study we review the background to gasification, and zero in on the economics of syngas production by the second-generation entrained-flow gasification technology pioneered by Texaco.

Entrained flow gasifiers are in principle very similar to the partial oxidation reactors used to produce syngases and hydrogen from miscellaneous hydrocarbon feedstocks. However, as compared with processes using gaseous or liquid feedstocks, use of coal obviously presents special problems relating to the handling of large flows of abrasive and corrosive solids under extreme conditions. The design of safe and efficient pressure feeders has proved to be particularly intractable. In addition, the makeup of coal is complex and highly variable; therefore, different coals behave very differently both in the way they handle physically and in the way they react chemically. Even coal from a given geological formation may show considerable variability.

The ratios of H_2, CO, CO_2, and CH_4 in a gasifier product vary only slightly with the type of coal, but are highly dependent on the type of gasification system. The amounts of oxygen and steam required vary both with the type of coal and the process.

Entrained flow gasifiers are favored for production of syngas to be used as a chemical feedstock because they produce the low H_2:CO ratios typically required, and minimize the residual methane in the product (each mol of methane represents the loss of three mols of syngas). However, because certain types of gasifiers are inherently more suitable for certain coals, the optimal choice of a gasifier is rarely clear cut. For commercial systems, demonstrated operability may, of course, be the dominating factor.

The cost data presented in this study are keyed to:

- Illinois No. 6 bituminous coal delivered to the U.S. Gulf Coast.
- Texaco gasification, Rectisol® acid gas removal, ICI methanol process.
- U.S. Gulf Coast construction costs.
- Base case capacity equivalent to 10,000 metric tons/day of methanol.

The rationale for these selections is outlined below. Reference material relating to this is detailed in the more extended discussion in Section 6 of the report.

The status of entrained flow gasifiers appears to be as follows:

- Koppers-Totzek (atmospheric, dry feed) - Operated on a commercial scale for ammonia synthesis.
- Texaco (pressure, slurry feed) - Several large pilot units in operation; a commercial unit and a demonstration plant under construction.
- Shell-Koppers (pressure, dry feed) - Advanced large pilot development.
- Saarberg-Otto (pressure, dry feed) - Large pilot development.

The Koppers-Totzek process is in commercial operation in South Africa, India, and elsewhere, and has also recently been chosen by the Tennessee Valley Authority (TVA) for its proposed commercial-scale coal gasification facilities at Murphy Hill, Alabama. However, the disadvantages of operating at atmospheric pressure make it an unlikely competitor for the longer term.

In terms of efficiency and the range of processable coals, the Shell-Koppers and Saarberg-Otto pressurized, dry feed, entrained flow gasifiers (PDEG) are the most attractive. However, the Saarberg-Otto process is in a relatively early stage of development. The Shell-Koppers process has undergone extensive testing in large pilot units, and proposals have been made for its commercialization. It is therefore likely that a PDEG could be demonstrated on a commercial scale in the latter half of this decade. However, the published information and the analysis regarding the Shell-Koppers technology are rather limited; resolution of one of the most intractable problems, the development of an efficient pressurized dry feed system suitable for commercial operation, may still be some way off. (Recently Shell and Krupp-Koppers terminated their association, and each company is continuing some development on its own.)

Of the pressurized entrained flow developments, the Texaco technology, which feeds coal as a water slurry, has progressed the furthest. Variations of this technology have been successfully piloted on a substantial scale by Ruhrkohle/Ruhrchemie (RAG/RCH), Dow, and TVA. Construction of a demonstration plant to gasify some 1,000 metric tons/day of coal is proceeding at the Cool Water generating station in Barstow, California. This is a project to demonstrate gasification/combined-cycle technology for electricity generation. Texaco gasifiers of a similar size are under construction as part of Tennessee Eastman's commercial venture to produce acetic anhydride from coal derived syngas (see Section 3).

We believe that the costs keyed to Texaco gasification are conservatively representative of what might be expected by 1990. Another advantage to our selecting Texaco technology is the large number of openly published technoeconomic studies (for projects using such gasifiers) which have been carried out by major contractors for the U.S. Department of Energy and the Electric Power Research Institute (EPRI). Availability of a selection of well-honed designs and estimates by contractors with experience in this area increases confidence in the numbers.

Acid gas removal and sulfur recovery systems typically account for up to 20% of the gasification system investment. For sulfur recovery, a Claus plant with a tail gas treating unit is often chosen. Choice of the optimum acid gas removal process is not clear-cut, but the Rectisol® (Linde and Lurgi) and Selexol® (Norton Company) selective physical solvent processes have been the ones most commonly specified in proposed gasification designs. The Rectisol® process, which uses refrigerated methanol as a solvent, is commercially well established in coal gasification and other systems. It has a successful history of protecting sulfur-sensitive catalysts such as those used in methanol systems. Costs associated with it should therefore be representative for our general case.

The Illinois No. 6 coal as the feedstock and the U.S. Gulf Coast as the manufacturing location, are advantageous choices because both have in many ways become standard reference points and are used widely as a basis for comparison. It could be argued that despite this advantage, the combination departs too far from anticipated reality--that because of the expense of transporting coal, gasification complexes will most likely be located at the mine. We are not altogether convinced of this. Gasification economics are highly capital intensive and the extra costs and problems of setting up in a remote location, together with the transport costs of the product, could negate the advantages of the cheaper coal. Thus particularly for chemicals production, an established manufacturing location could prove to be the most economic site.

After screening the mass of published work on gasification, we concluded that the most recent in a series of studies for EPRI by Fluor Inc. (472120) presented technoeconomic data sufficiently well fitted to the criteria for our base case. Fluor had evaluated the production of methanol at a scale close to 10,000 metric tons/day from Illinois No. 6 bituminous coal with Texaco coal gasifiers, Rectisol® acid gas removal, and ICI methanol synthesis. The evaluation was based on design data supplied by both Texaco and ICI for their respective units, and on design and cost data supplied by Lotepro for the Rectisol® process. Both technical and economic data were presented in sufficient detail to enable breaking out costs of syngas manufacture per se. We therefore used the data presented in reference 472120 as the source of our base case numbers. The base case data were adjusted for a slightly different scale and scope and the costs were also escalated forward to 1981. We scaled the costs by section to arrive at overall costs for lower capacities. In the final analysis we also opted for a somewhat more conservative design basis (see further below under Gasification Capital).

For syngases per se we used the front section of the methanol plant design. There is less flexibility to adjust the process steam balance internally in gasification than in steam reforming designs. For the coal based syngases we therefore chose not to make the designs self-sufficient in steam, but kept the hardware as for the front end of the methanol plant and made appropriate credits and debits in utilities. This resulted in a net import of high pressure steam for the syngas cases.

The design was adjusted to include less shift and acid gas removal capacity for H_2:CO ratios lower than the 2.26:1 used for the methanol synthesis. We also estimated incremental costs for modification of the design to include a low temperature shift and a methanation stage for the production of hydrogen at very large capacities. The overall designs are in all cases keyed to the use of a sulfur tolerant shift catalyst, so that the feed to shift is not dried or fully cooled. This is advantageous because enough steam for the shift reaction is introduced as part of the upstream quench operation. There appears to be potential for backing out some of this quench steam when lower H_2:CO ratios are required. With optimization of an overall design in each instance, therefore, syngas product values may be more sensitive to the H_2:CO ratio than the present data indicate, with somewhat lower values at the lower ratios.

Gasification Capital

The capital investment values for the coal gasification processes used in the SYNCOST data are higher than those shown in Section 6. The differences for the base cases are detailed in Table 2.3.

Subsequent PEP evaluations of gasification (PEP Report 154, Coal Gasification) together with industry feedback convinced us that a somewhat more conservative design basis than that used in Section 6 should be adopted to match the assumed stream factor of 0.9, even for a mature plant. In particular we increased the sparing of equipment in the gasification and heat recovery sections to 50%, and provided for more extensive coal preparation. In addition, auxiliary steam generating facilities were increased to simplify start-up and some additions were made to the general service facilities. The estimated additional capital was $190 million on the battery limits investment (BLI) and $70 million on the off-sites for the base case in 1981. The resulting increases in the total fixed capital (TFC) in absolute and percentage terms for the various modules are as shown in Table 2.3.

Table 2.3

CAPITAL COSTS FOR COAL GASIFICATION MODULES

Program Module	Product	Capacity MM scfd or (tonnes/day)	Total Fixed Capital ($ million) Section 6	SYNCOST	% Increase
1	Syngas (0.75:1)	802	1,032	1,292	25.2
2	Syngas (1:1)	803	1,055	1,315	24.6
7	Syngas (1.5:1)	804	1,080	1,340	24.1
8	Syngas (2:1)	805	1,096	1,356	23.7
13	Syngas (2.26:1)	805	1,102	1,362	23.6
22	Hydrogen	781	1,243	1,503	20.9
26	Methanol from coal	(10,000)	1,322	1,582	19.7
27	Methanol from syngas	(10,000)	220	220	—

The program data thus correspond to a relatively conservative estimate, whereas the Section 6 data represent an optimistic projection of the costs associated with second generation gasification technology.

Product Values—Comparisons and Projections

The estimated 1981 product values (production costs + 25% ROI) for coal based syngases are shown in Figure 2.7. The two bands correspond to (A) the SYNCOST default values and (B) the more optimistic capital estimates detailed in Section 6. In contrast to steam reforming, the cost of syngas is relatively insensitive to the H_2:CO ratio. The gasification produces a raw gas with a low ratio (0.75), which can be increased readily and economically by shifting.

Also plotted for comparison are the product values of syngases made by reforming of natural gas for the process scheme in which the H_2:CO ratio is reduced to 2:1 by recycle and import of CO_2. However, because user processes may be optimized around different H_2:CO ratios, direct comparison of coal and natural gas based syngas costs at a given ratio may be misleading. Comparison of the costs of first line derivatives can be made on a more uniform and clear-cut basis, and is here done for methanol in Figure 2.8. It is seen that for the assumed price relativities, coal based methanol would not at present be directly competitive except in the optimistic case at very large scales of manufacture. We emphasize again that this is without any special financing arrangements or subsidies, on the basis of a bituminous coal shipped to the U.S. Gulf Coast (i.e., a fairly high coal price), and for current world scale capacities. We also show a range of methanol values calculated on the basis of 50¢/million Btu gas and location factors of 1.3 to 1.7 (see bar on the plot). The values also include an allowance of 1¢/lb for shipping. These figures roughly match the range of costs that might be anticipated for methanol made in the Middle East and shipped in large tankers to the U.S. Gulf Coast, and indicate that such methanol could be highly competitive.

Figure 2.7

COSTS OF SYNGASES FROM COAL GASIFICATION

USGC mid-1981, PEP Cost Index = 400

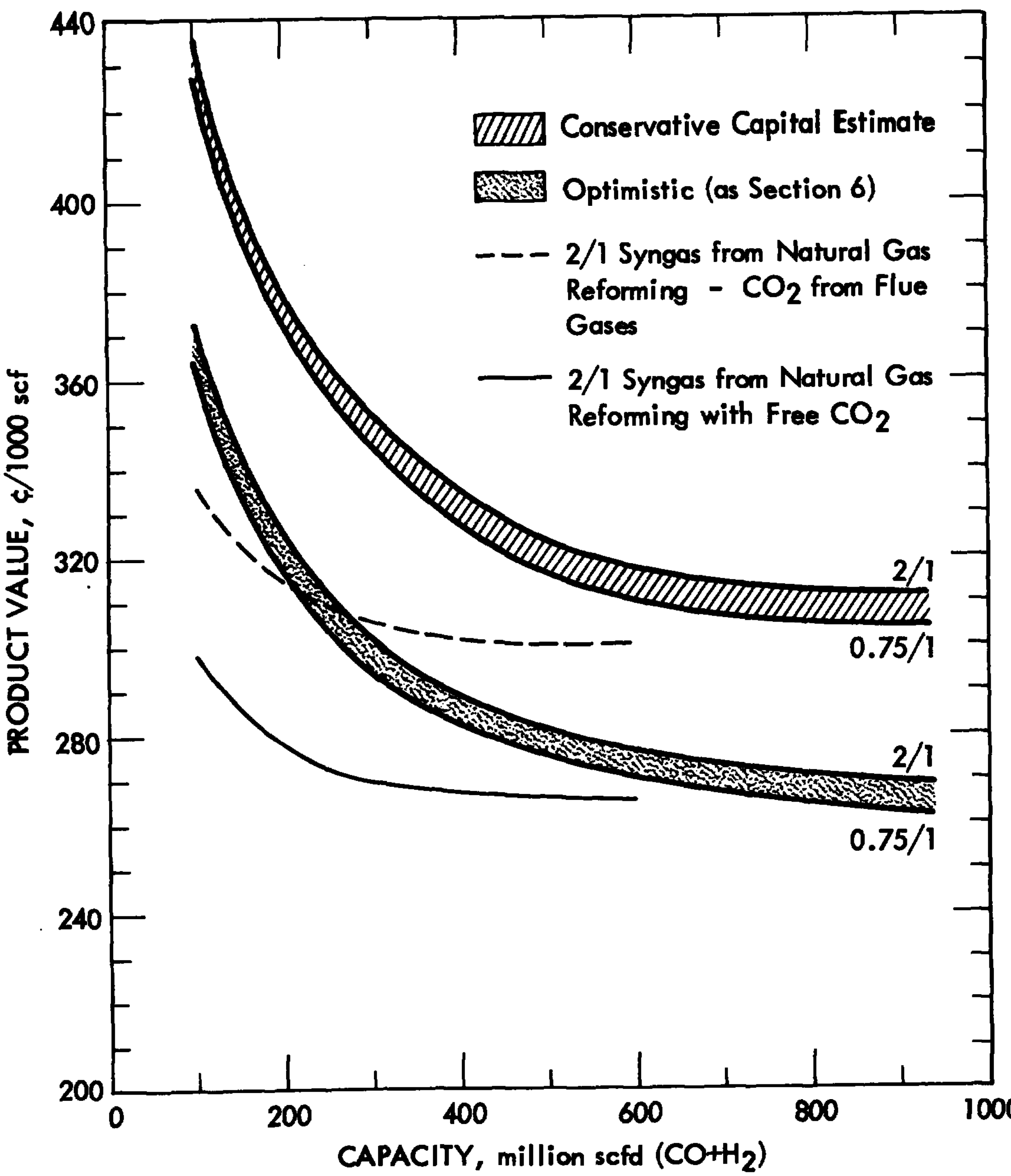
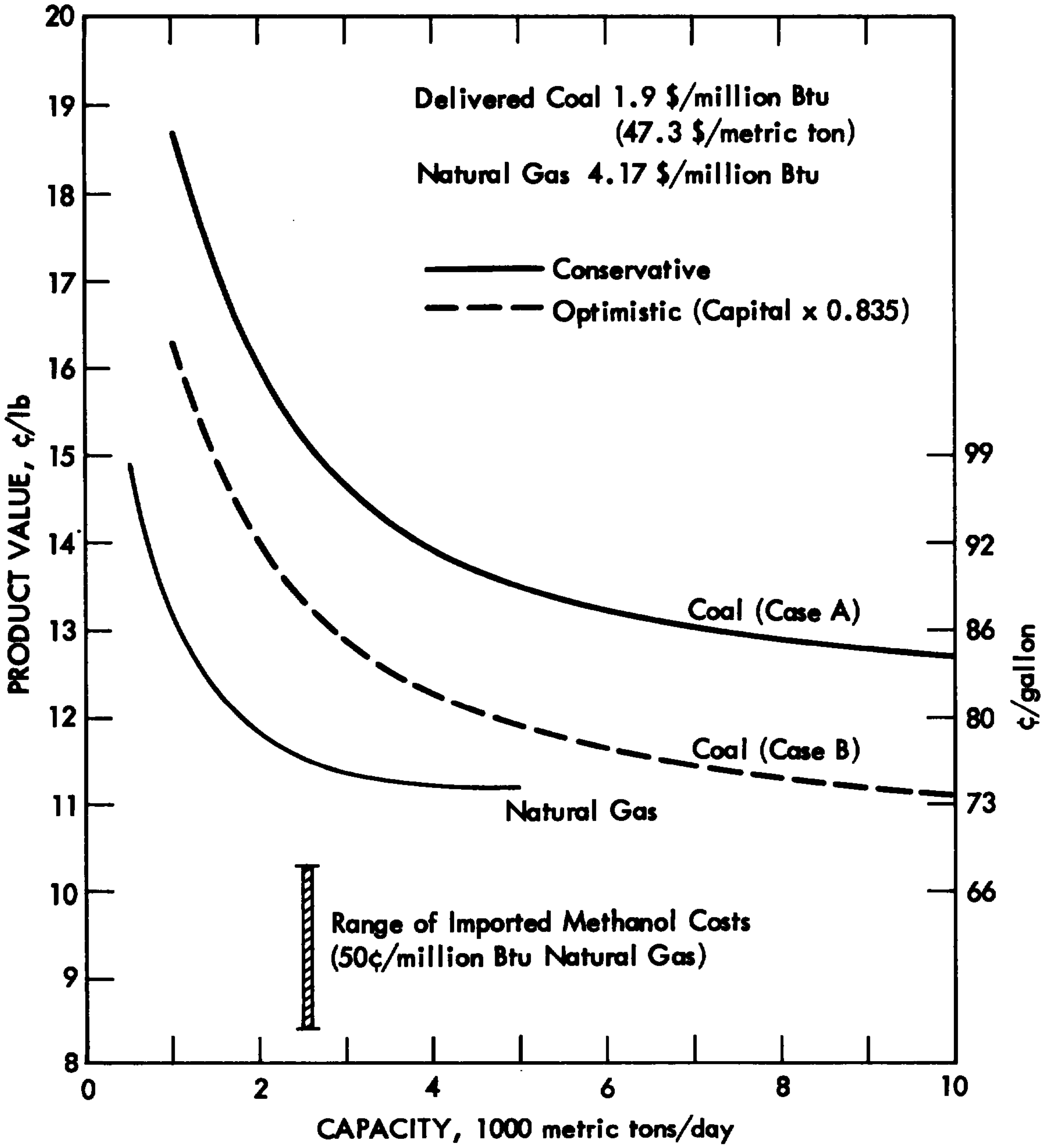


Figure 2.8

COSTS OF METHANOL

USGC mid-1981, PEP Cost Index = 400



The breakdown of the 1981 costs into basic components is as follows:

Cost Component	Methanol from Natural Gas	Methanol from Coal
Natural gas or coal related costs	55%	21%
Labor related costs	7	8
Capital related costs	38	71
Total	100%	100%

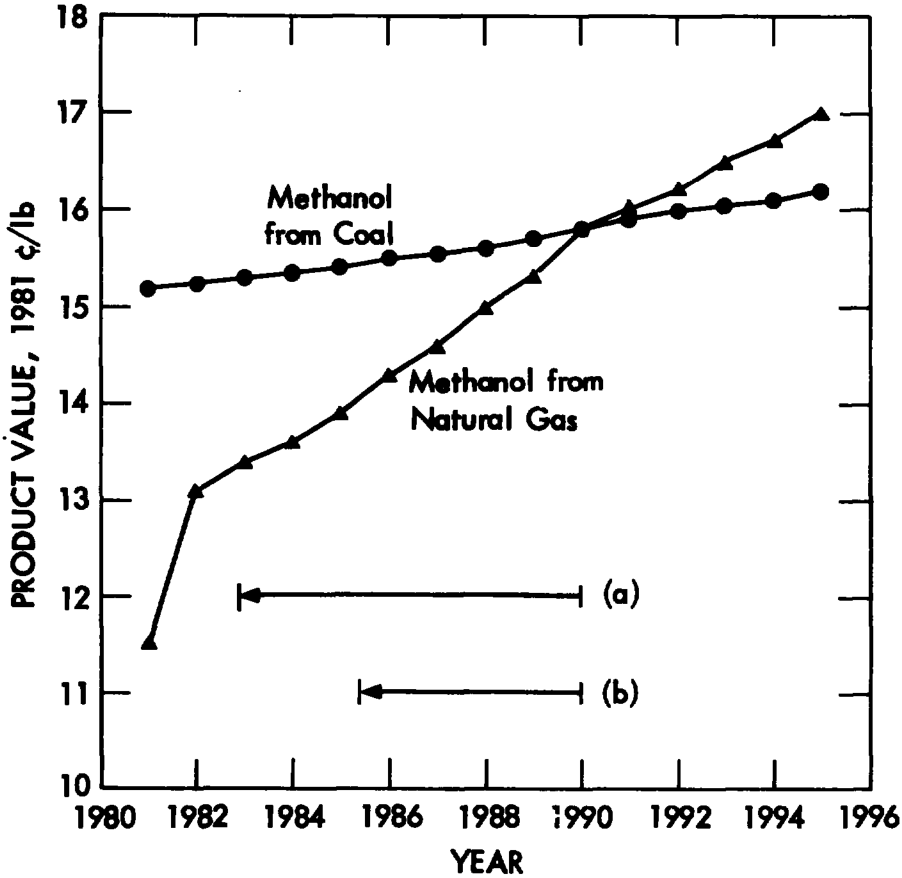
The 25% ROI accounts for 46 of the 71 capital related points for the coal case, compared with 25 of the 38 for the natural gas based case. The figures illustrate the high sensitivity of the natural gas based economics to gas (i.e., ultimately oil) price, and the extreme sensitivity of the coal based economics to capital requirements.

Figure 2.9 shows projected costs for methanol manufacture, based on the cost projections for input factors as discussed in Appendix A. The plot is made in constant 1981 $ so that the effects of the general level of inflation are eliminated, i.e., the cost increases shown are those over and above general inflation. For the scenario used, the crossover for natural gas based methanol compared with coal based methanol manufactured at 2,500 metric tons/day takes place in 1990. (By crossover we here mean the time at which product values by two routes become equal.) If the more optimistic capital estimates of Section 6 are used without modification, the crossover occurs in 1983. For comparisons made at 5,000 metric tons/day, the crossover moves to 1985, as it does if 20% ROI were used in the product value calculation instead of 25%. Thus only relatively modest real increases in natural gas prices are needed to make coal based methanol competitive with gas based methanol in the United States. However, the competitive product may by then have become methanol produced in areas where cheaper gas is available.

Figure 2.9

METHANOL COST PROJECTIONS

USGC 2500 metric tons/day
Trendline Projections (See Appendix A)
Constant 1981 $



(a) Crossover point change for optismistic coal case (Capital x 0.835).

(b) Crossover point change if comparisons made at 5000 metric tons/day capacity, or with 20% ROI for coal case.

The economics of proposed nontraditional syngas routes for some major bulk chemicals were examined in PEP Report 146. For coal based compared with oil based ethylene processes, crossovers were estimated to occur this side of 1990. Such a conclusion would, of course, have radical implications for the competitive structure of the world chemical industry. However, the estimates were based on a scenario with an oil price escalation which might be considered high in terms of present perceptions. As noted at the end of Section 3, the illustrative scenario used in the present study, which projects oil price increases at somewhat more modest rates, would push such crossovers much closer to the year 2000.

With the general perception of more modest oil price increases, some of the urgency associated with syngas developments has vanished. Nonetheless, the expanding area of syngas chemistry remains an exciting one, with potential for radical developments. The present work should aid ongoing evaluations.

SYNGAS(H2/CO=0.75) FROM COAL

802.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
COAL AT MINE	32.30$/TONNE	0.0187	60.34
COAL TRANSPORT	15.00$/TONNE	0.0187	28.02
ASH DISPOSAL	5.00$/TONNE	0.0019	0.93
MISC. CHEM. & CAT.			0.51
			89.80
BY PRODUCTS			
SULFUR	4.54C/LB	(1.2570)	(5.71)
			(5.71)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	0.0120	9.24
ELECTRICITY	3.60C/KWH	(0.1810)	(0.65)
CLARIFIED WATER	41.00C/MGAL	0.0148	0.61
			9.20
TOTAL VARIABLE COSTS			93.29

SYNGAS(H2/CO=0.75) FROM COAL (MODULE # 1)

802.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	934.4	1052.8	1406.1	2018.6
TOTAL FIXED CAPITAL(TFC)	1146.6	1291.9	1725.4	2477.0
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
COAL AT MINE ($/TONNE)	28.80	32.30	42.30	61.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	80.87	89.80	117.73	169.71
BY-PRODUCT CREDIT	(4.83)	(5.71)	(7.55)	(11.15)
IMPORTED UTILITIES	8.31	9.20	12.03	16.99
VARIABLE COSTS	84.35	93.29	122.21	175.55
OPERATING LABOR(42.0/SHIFT)	2.15	2.44	3.30	4.66
MAINTENANCE LABOR(1.6% BLI)	5.67	6.39	8.54	12.26
CONTROL LAB LABOR(20.0% OF LABOR)	0.43	0.49	0.66	0.93
TOTAL DIRECT LABOR	8.25	9.32	12.50	17.85
MAINTENANCE MATERIALS(2.4% BLI)	8.51	9.59	12.81	18.39
OPERATING SUPPLIES(10.0% OF LABOR)	0.21	0.24	0.33	0.47
	8.72	9.83	13.14	18.86
PLANT OVERHEAD(30.0% TOTAL LABOR)	2.47	2.80	3.75	5.35
TAXES AND INSURANCE(2.0% TFC)	8.70	9.81	13.10	18.80
DEPRECIATION(10.0% TFC)	43.52	49.04	65.49	94.02
	54.69	61.65	82.34	118.17
SUBTOTAL: PLANT GATE COST	156.01	174.09	230.19	330.43
G&A, SALES, RESEARCH(3.0% PV)	8.34	9.35	12.42	17.83
ROI BEFORE TAXES(25.0% TFC)	108.80	122.59	163.73	235.05
PRODUCT VALUE(PV), C/MSCF	273.15	306.03	406.34	583.31

SYNGAS(H2/CO=1.0) FROM COAL

803.20 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
COAL AT MINE	32.30$/TONNE	0.0187	60.27
COAL TRANSPORT	15.00$/TONNE	0.0187	27.99
ASH DISPOSAL	5.00$/TONNE	0.0019	0.93
MISC. CHEM. & CAT.			0.54
			89.73
BY PRODUCTS			
SULFUR	4.54C/LB	(1.2570)	(5.71)
			(5.71)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	0.0110	8.47
ELECTRICITY	3.60C/KWH	(0.1530)	(0.55)
CLARIFIED WATER	41.00C/MGAL	0.0149	0.61
			8.53
TOTAL VARIABLE COSTS			92.55

SYNGAS(H2/CO=1.0) FROM COAL (MODULE # 2)

803.20 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	952.2	1072.8	1432.8	2056.9
TOTAL FIXED CAPITAL(TFC)	1166.6	1314.5	1755.5	2520.3
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
COAL AT MINE ($/TONNE)	28.80	32.30	42.30	61.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	80.81	89.73	117.64	169.59
BY-PRODUCT CREDIT	(4.83)	(5.71)	(7.55)	(11.15)
IMPORTED UTILITIES	7.72	8.53	11.18	15.82
VARIABLE COSTS	83.70	92.55	121.27	174.26
OPERATING LABOR(42.0/SHIFT)	2.15	2.44	3.29	4.66
MAINTENANCE LABOR(1.6% BLI)	5.77	6.51	8.69	12.47
CONTROL LAB LABOR(20.0% OP LABOR)	0.43	0.49	0.66	0.93
TOTAL DIRECT LABOR	8.35	9.44	12.64	18.06
MAINTENANCE MATERIALS(2.4% BLI)	8.66	9.76	13.03	18.71
OPERATING SUPPLIES(10.0% OP LABOR)	0.21	0.24	0.33	0.47
	8.87	10.00	13.36	19.18
PLANT OVERHEAD(30.0% TOTAL LABOR)	2.50	2.83	3.79	5.42
TAXES AND INSURANCE(2.0% TFC)	8.84	9.96	13.31	19.10
DEPRECIATION(10.0% TFC)	44.21	49.82	66.53	95.52
	55.55	62.61	83.63	120.04
SUBTOTAL: PLANT GATE COST	156.47	174.60	230.90	331.54
G&A, SALES, RESEARCH(3.0% PV)	8.41	9.43	12.52	17.98
ROI BEFORE TAXES(25.0% TFC)	110.54	124.55	166.33	238.80
PRODUCT VALUE(PV), C/MSCF	275.42	308.58	409.75	588.32

SYNGAS(H2/CO=1.0) FROM NATURAL GAS
WITH CO2 IMPORT

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
NATURAL GAS	4.17$/MMBTU	0.2540	105.92
CARBON DIOXIDE	0.00C/LB	27.8500	0.00
MISC. CHEM. & CAT.			0.84
MISC. CHEM. & CAT.			1.75
			108.51
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	0.2300	95.91
LP STEAM	5.20$/MLB	0.0502	26.10
ELECTRICITY	3.60C/KWH	1.2770	4.60
COOLING WATER	5.40C/MGAL	0.7410	4.00
PROCESS WATER	68.00C/MGAL	0.0075	0.51
			131.12
TOTAL VARIABLE COSTS			239.63

SYNGAS(H2/CO=1.0) FROM NATURAL GAS (MODULE # 3)
WITH CO2 IMPORT

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	131.2	147.8	197.4	283.4
TOTAL FIXED CAPITAL(TFC)	162.2	182.8	244.1	350.5
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
NATURAL GAS ($/MMBTU)	4.00	4.17	7.37	12.43
PRODUCTION COST, C/MSCF				
RAW MATERIALS	103.79	108.51	190.63	320.78
IMPORTED UTILITIES	124.01	131.12	218.25	357.48
VARIABLE COSTS	227.80	239.63	408.88	678.26
OPERATING LABOR(4.0/SHIFT)	0.82	0.93	1.26	1.78
MAINTENANCE LABOR(1.5% BLI)	3.00	3.37	4.51	6.47
CONTROL LAB LABOR(20.0% OF LABOR)	0.16	0.19	0.25	0.36
TOTAL DIRECT LABOR	3.98	4.49	6.02	8.61
MAINTENANCE MATERIALS(1.5% BLI)	3.00	3.37	4.51	6.47
OPERATING SUPPLIES(10.0% OF LABOR)	0.08	0.09	0.13	0.18
	3.08	3.46	4.64	6.65
PLANT OVERHEAD(80.0% TOTAL LABOR)	3.18	3.59	4.82	6.89
TAXES AND INSURANCE(2.0% TFC)	4.94	5.56	7.43	10.67
DEPRECIATION(10.0% TFC)	24.69	27.82	37.15	53.35
	32.81	36.97	49.40	70.91
SUBTOTAL: PLANT GATE COST	267.67	284.55	468.94	764.43
G&A, SALES, RESEARCH(3.0% PV)	10.19	10.95	17.38	27.77
ROI BEFORE TAXES(25.0% TFC)	61.72	69.56	92.88	133.37
PRODUCT VALUE(PV), C/MSCF	339.58	365.06	579.20	925.57

SYNGAS(H2/CO=1.0) FROM SYNGAS(H2/CO=3.0)
BY SKIMMING

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
SYNGAS(3.0)/G	2.38$/MSCF	2.0500	488.27
			488.27
BY PRODUCTS			
HYDROGEN	2.58$/MSCF	(0.9700)	(250.26)
			(250.26)
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	0.0013	0.53
ELECTRICITY	3.60C/KWH	1.5240	5.49
			6.02
TOTAL VARIABLE COSTS			244.03

SYNGAS(H2/CO=1.0) FROM SYNGAS(H2/CO=3.0) (MODULE # 4)
BY SKIMMING

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	32.3	36.4	48.7	69.9
TOTAL FIXED CAPITAL(TFC)	32.4	36.5	48.8	70.0
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(3.0)/G ($/MSCF)	2.24	2.38	3.96	6.48
PRODUCTION COST, C/MSCF				
RAW MATERIALS	459.73	488.27	811.68	1329.34
BY-PRODUCT CREDIT	(233.77)	(250.26)	(408.37)	(663.48)
IMPORTED UTILITIES	5.68	6.02	9.92	16.35
VARIABLE COSTS	231.64	244.03	413.23	682.21
OPERATING LABOR(0.0/SHIFT)	0.00	0.00	0.00	0.00
MAINTENANCE LABOR(1.5% BLI)	0.74	0.83	1.11	1.60
CONTROL LAB LABOR(20.0% OP LABOR)	0.00	0.00	0.00	0.00
TOTAL DIRECT LABOR	0.74	0.83	1.11	1.60
MAINTENANCE MATERIALS(1.5% BLI)	0.74	0.83	1.11	1.60
OPERATING SUPPLIES(10.0% OP LABOR)	0.00	0.00	0.00	0.00
	0.74	0.83	1.11	1.60
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.59	0.66	0.89	1.28
TAXES AND INSURANCE(2.0% TFC)	0.99	1.11	1.49	2.13
DEPRECIATION(10.0% TFC)	4.93	5.56	7.43	10.65
	6.51	7.33	9.81	14.06
SUBTOTAL: PLANT GATE COST	239.63	253.02	425.26	699.47
G&A, SALES, RESEARCH(3.0% PV)	15.02	15.99	26.36	42.98
ROI BEFORE TAXES(25.0% TFC)	12.33	13.89	18.57	26.64
PRODUCT VALUE(PV), C/MSCF	266.98	282.90	470.19	769.09

SYNGAS(H2/CO=1.0) FROM SYNGAS(H2/CO=2.0)
BY SKIMMING

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
SYNGAS(2.0)/G	2.62$/MSCF	1.5480	405.08
			405.08
BY PRODUCTS			
HYDROGEN	2.58$/MSCF	(0.4800)	(123.84)
			(123.84)
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	0.0006	0.27
ELECTRICITY	3.60C/KWH	1.5030	5.41
			5.68
TOTAL VARIABLE COSTS			286.92

SYNGAS(H2/CO=1.0) FROM SYNGAS(H2/CO=2.0) (MODULE # 5)
BY SKIMMING

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	17.5	19.7	26.3	37.8
TOTAL FIXED CAPITAL(TFC)	17.5	19.7	26.4	37.8
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(2.0)/G ($/MSCF)	2.46	2.62	4.32	7.05
PRODUCTION COST, C/MSCF				
RAW MATERIALS	380.64	405.08	668.64	1091.12
BY-PRODUCT CREDIT	(115.68)	(123.84)	(202.08)	(328.32)
IMPORTED UTILITIES	5.37	5.68	9.35	15.38
VARIABLE COSTS	270.33	286.92	475.91	778.18
OPERATING LABOR(0.0/SHIFT)	0.00	0.00	0.00	0.00
MAINTENANCE LABOR(1.5% BLI)	0.40	0.45	0.60	0.86
CONTROL LAB LABOR(20.0% OP LABOR)	0.00	0.00	0.00	0.00
TOTAL DIRECT LABOR	0.40	0.45	0.60	0.86
MAINTENANCE MATERIALS(1.5% BLI)	0.40	0.45	0.60	0.86
OPERATING SUPPLIES(10.0% OP LABOR)	0.00	0.00	0.00	0.00
	0.40	0.45	0.60	0.86
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.32	0.36	0.48	0.69
TAXES AND INSURANCE(2.0% TFC)	0.53	0.60	0.80	1.15
DEPRECIATION(10.0% TFC)	2.66	3.00	4.02	5.75
	3.51	3.96	5.30	7.59
SUBTOTAL: PLANT GATE COST	274.64	291.78	482.41	787.49
G&A, SALES, RESEARCH(3.0% PV)	12.28	13.09	21.48	34.95
ROI BEFORE TAXES(25.0% TFC)	6.66	7.50	10.05	14.38
PRODUCT VALUE(PV), C/MSCF	293.58	312.37	513.94	836.82

SYNGAS(H2/CO=1.0) FROM VACUUM RESIDUE

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
VACUUM RESIDUE	5.65C/LB	22.9600	129.72
MISC. CHEM. & CAT.			0.46
			130.18
BY PRODUCTS			
SULFUR	4.54C/LB	(1.3600)	(6.17)
			(6.17)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	(0.0040)	(3.08)
ELECTRICITY	3.60C/KWH	0.6940	2.50
COOLING WATER	5.40C/MGAL	0.0980	0.53
PROCESS WATER	68.00C/MGAL	0.0091	0.62
			0.57
TOTAL VARIABLE COSTS			124.58

SYNGAS(H2/CO=1.0) FROM VACUUM RESIDUE (MODULE # 6)

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	149.5	168.5	225.0	323.0
TOTAL FIXED CAPITAL(TFC)	197.2	222.2	296.8	426.1
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
VACUUM RESIDUE (C/LB)	5.15	5.65	10.50	15.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	118.63	130.18	241.69	363.67
BY-PRODUCT CREDIT	(5.22)	(6.17)	(8.17)	(12.06)
IMPORTED UTILITIES	0.59	0.57	1.65	3.34
VARIABLE COSTS	114.00	124.58	235.17	354.95
OPERATING LABOR(8.0/SHIFT)	1.64	1.87	2.52	3.56
MAINTENANCE LABOR(1.5% BLI)	3.41	3.85	5.14	7.37
CONTROL LAB LABOR(20.0% OP LABOR)	0.33	0.37	0.50	0.71
TOTAL DIRECT LABOR	5.38	6.09	8.16	11.64
MAINTENANCE MATERIALS(1.5% BLI)	3.41	3.85	5.14	7.37
OPERATING SUPPLIES(10.0% OP LABOR)	0.16	0.19	0.25	0.36
	3.57	4.04	5.39	7.73
PLANT OVERHEAD(80.0% TOTAL LABOR)	4.30	4.87	6.53	9.31
TAXES AND INSURANCE(2.0% TFC)	6.00	6.76	9.04	12.97
DEPRECIATION(10.0% TFC)	30.02	33.82	45.18	64.86
	40.32	45.45	60.75	87.14
SUBTOTAL: PLANT GATE COST	163.27	180.16	309.47	461.46
G&A, SALES, RESEARCH(3.0% PV)	7.53	8.38	13.32	19.66
ROI BEFORE TAXES(25.0% TFC)	75.04	84.55	112.94	162.14
PRODUCT VALUE(PV), C/MSCF	245.84	273.09	435.73	643.26

SYNGAS(H2/CO=1.5) FROM COAL

804.30 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
COAL AT MINE	32.30$/TONNE	0.0186	60.21
COAL TRANSPORT	15.00$/TONNE	0.0186	27.96
ASH DISPOSAL	5.00$/TONNE	0.0019	0.93
MISC. CHEM. & CAT.			0.58
			89.68
BY PRODUCTS			
SULFUR	4.54C/LB	(1.2570)	(5.71)
			(5.71)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	0.0090	6.93
ELECTRICITY	3.60C/KWH	(0.1160)	(0.42)
CLARIFIED WATER	41.00C/MGAL	0.0150	0.62
			7.13
TOTAL VARIABLE COSTS			91.10

SYNGAS(H2/CO=1.5) FROM COAL (MODULE # 7)

804.30 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	971.9	1095.0	1462.4	2099.5
TOTAL FIXED CAPITAL(TFC)	1189.4	1340.2	1789.9	2569.5
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
COAL AT MINE ($/TONNE)	28.80	32.30	42.30	61.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	80.75	89.68	117.57	169.49
BY-PRODUCT CREDIT	(4.83)	(5.71)	(7.55)	(11.15)
IMPORTED UTILITIES	6.45	7.13	9.37	13.26
VARIABLE COSTS	82.37	91.10	119.39	171.60
OPERATING LABOR(42.0/SHIFT)	2.14	2.44	3.29	4.65
MAINTENANCE LABOR(1.6% BLI)	5.89	6.63	8.86	12.71
CONTROL LAB LABOR(20.0% OP LABOR)	0.43	0.49	0.66	0.93
TOTAL DIRECT LABOR	8.46	9.56	12.81	18.29
MAINTENANCE MATERIALS(2.4% BLI)	8.83	9.95	13.28	19.07
OPERATING SUPPLIES(10.0% OP LABOR)	0.21	0.24	0.33	0.47
	9.04	10.19	13.61	19.54
PLANT OVERHEAD(30.0% TOTAL LABOR)	2.54	2.87	3.84	5.49
TAXES AND INSURANCE(2.0% TFC)	9.00	10.14	13.55	19.45
DEPRECIATION(10.0% TFC)	45.02	50.72	67.74	97.25
	56.56	63.73	85.13	122.19
SUBTOTAL: PLANT GATE COST	156.43	174.58	230.94	331.62
G&A, SALES, RESEARCH(3.0% PV)	8.47	9.50	12.61	18.12
ROI BEFORE TAXES(25.0% TFC)	112.54	126.81	169.36	243.13
PRODUCT VALUE(PV), C/MSCF	277.44	310.89	412.91	592.87

SYNGAS(H2/CO=2.0) FROM COAL

805.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
COAL AT MINE	32.30$/TONNE	0.0186	60.21
COAL TRANSPORT	15.00$/TONNE	0.0186	27.96
ASH DISPOSAL	5.00$/TONNE	0.0019	0.93
MISC. CHEM. & CAT.			0.61
			89.71
BY PRODUCTS			
SULFUR	4.54C/LB	(1.2570)	(5.71)
			(5.71)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	0.0080	6.16
ELECTRICITY	3.60C/KWH	(0.0910)	(0.33)
CLARIFIED WATER	41.00C/MGAL	0.0151	0.62
			6.45
TOTAL VARIABLE COSTS			90.45

SYNGAS(H2/CO=2.0) FROM COAL (MODULE # 8)

805.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	984.4	1109.2	1481.4	2126.6
TOTAL FIXED CAPITAL(TFC)	1203.2	1355.7	1810.6	2599.3
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
COAL AT MINE ($/TONNE)	28.80	32.30	42.30	61.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	80.77	89.71	117.60	169.55
BY-PRODUCT CREDIT	(4.83)	(5.71)	(7.55)	(11.15)
IMPORTED UTILITIES	5.83	6.45	8.50	12.05
VARIABLE COSTS	81.77	90.45	118.55	170.45
OPERATING LABOR(42.0/SHIFT)	2.14	2.43	3.28	4.65
MAINTENANCE LABOR(1.6% BLI)	5.96	6.71	8.96	12.87
CONTROL LAB LABOR(20.0% OP LABOR)	0.43	0.49	0.66	0.93
TOTAL DIRECT LABOR	8.53	9.63	12.90	18.45
MAINTENANCE MATERIALS(2.4% BLI)	8.93	10.07	13.44	19.30
OPERATING SUPPLIES(10.0% OP LABOR)	0.21	0.24	0.33	0.47
	9.14	10.31	13.77	19.77
PLANT OVERHEAD(30.0% TOTAL LABOR)	2.56	2.89	3.87	5.54
TAXES AND INSURANCE(2.0% TFC)	9.10	10.25	13.69	19.66
DEPRECIATION(10.0% TFC)	45.50	51.27	68.47	98.29
	57.16	64.41	86.03	123.49
SUBTOTAL: PLANT GATE COST	156.60	174.80	231.25	332.16
G&A, SALES, RESEARCH(3.0% PV)	8.51	9.55	12.68	18.22
ROI BEFORE TAXES(25.0% TFC)	113.75	128.17	171.17	245.73
PRODUCT VALUE(PV), C/MSCF	278.86	312.52	415.10	596.11

SYNGAS(H2/CO=2.0) FROM NATURAL GAS
WITH CO2 IMPORT

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
NATURAL GAS	4.17$/MMBTU	0.2610	108.84
CARBON DIOXIDE	0.00C/LB	8.9600	0.00
MISC. CHEM. & CAT.			1.23
			110.07
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	0.1880	78.40
ELECTRICITY	3.60C/KWH	1.2020	4.33
COOLING WATER	5.40C/MGAL	0.3190	1.72
PROCESS WATER	68.00C/MGAL	0.0064	0.43
			84.88
TOTAL VARIABLE COSTS			194.95

SYNGAS(H2/CO=2.0) FROM NATURAL GAS (MODULE # 9)
WITH CO2 IMPORT

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	78.7	88.7	118.4	170.0
TOTAL FIXED CAPITAL(TFC)	105.9	119.3	159.3	228.7
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
NATURAL GAS ($/MMBTU)	4.00	4.17	7.37	12.43
PRODUCTION COST, C/MSCF				
RAW MATERIALS	105.44	110.07	193.99	326.82
IMPORTED UTILITIES	81.23	84.88	148.78	250.08
VARIABLE COSTS	186.67	194.95	342.77	576.90
OPERATING LABOR(4.0/SHIFT)	0.82	0.93	1.26	1.78
MAINTENANCE LABOR(1.5% BLI)	1.80	2.03	2.70	3.88
CONTROL LAB LABOR(20.0% OP LABOR)	0.16	0.19	0.25	0.36
TOTAL DIRECT LABOR	2.78	3.15	4.21	6.02
MAINTENANCE MATERIALS(1.5% BLI)	1.80	2.03	2.70	3.88
OPERATING SUPPLIES(10.0% OP LABOR)	0.08	0.09	0.13	0.18
	1.88	2.12	2.83	4.06
PLANT OVERHEAD(80.0% TOTAL LABOR)	2.22	2.52	3.37	4.82
TAXES AND INSURANCE(2.0% TFC)	3.22	3.63	4.85	6.96
DEPRECIATION(10.0% TFC)	16.12	18.16	24.25	34.81
	21.56	24.31	32.47	46.59
SUBTOTAL: PLANT GATE COST	212.89	224.53	382.28	633.57
G&A, SALES, RESEARCH(3.0% PV)	7.83	8.35	13.70	22.29
ROI BEFORE TAXES(25.0% TFC)	40.30	45.40	60.62	87.02
PRODUCT VALUE(PV), C/MSCF	261.02	278.28	456.60	742.88

SYNGAS(H2/CO=2.0) FROM VACUUM RESIDUE

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
VACUUM RESIDUE	5.65C/LB	22.4100	126.62
MISC. CHEM. & CAT.			0.51
			127.13
BY PRODUCTS			
SULFUR	4.54C/LB	(1.3200)	(5.99)
			(5.99)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	0.0104	8.01
ELECTRICITY	3.60C/KWH	0.8620	3.10
COOLING WATER	5.40C/MGAL	0.1160	0.63
PROCESS WATER	68.00C/MGAL	0.0082	0.56
			12.30
TOTAL VARIABLE COSTS			133.44

SYNGAS(H2/CO=2.0) FROM VACUUM RESIDUE (MODULE #10)

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	157.6	177.6	237.2	340.6
TOTAL FIXED CAPITAL(TFC)	212.8	239.8	320.2	459.7
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
VACUUM RESIDUE (C/LB)	5.15	5.65	10.50	15.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	115.84	127.13	235.99	355.08
BY-PRODUCT CREDIT	(5.07)	(5.99)	(7.93)	(11.71)
IMPORTED UTILITIES	11.27	12.30	17.41	26.07
VARIABLE COSTS	122.04	133.44	245.47	369.44
OPERATING LABOR(8.0/SHIFT)	1.64	1.87	2.52	3.56
MAINTENANCE LABOR(1.5% BLI)	3.60	4.05	5.42	7.78
CONTROL LAB LABOR(20.0% OP LABOR)	0.33	0.37	0.50	0.71
TOTAL DIRECT LABOR	5.57	6.29	8.44	12.05
MAINTENANCE MATERIALS(1.5% BLI)	3.60	4.05	5.42	7.78
OPERATING SUPPLIES(10.0% OP LABOR)	0.16	0.19	0.25	0.36
	3.76	4.24	5.67	8.14
PLANT OVERHEAD(80.0% TOTAL LABOR)	4.46	5.03	6.75	9.64
TAXES AND INSURANCE(2.0% TFC)	6.48	7.30	9.75	13.99
DEPRECIATION(10.0% TFC)	32.39	36.50	48.74	69.97
	43.33	48.83	65.24	93.60
SUBTOTAL: PLANT GATE COST	174.70	192.80	324.82	483.23
G&A, SALES, RESEARCH(3.0% PV)	8.06	8.97	14.06	20.72
ROI BEFORE TAXES(25.0% TFC)	80.97	91.25	121.84	174.92
PRODUCT VALUE(PV), C/MSCF	263.73	293.02	460.72	678.87

SYNGAS(H2/CO=2.0) FROM SYNGAS(H2/CO=3.0)
BY SKIMMING

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
SYNGAS(3.0)/G	2.41$/MSCF	1.3200	318.49
			318.49
BY PRODUCTS			
HYDROGEN	2.58$/MSCF	(0.3193)	(82.38)
			(82.38)
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	0.0004	0.16
ELECTRICITY	3.60C/KWH	0.9330	3.36
			3.52
TOTAL VARIABLE COSTS			239.63

SYNGAS(H2/CO=2.0) FROM SYNGAS(H2/CO=3.0) (MODULE #11)
BY SKIMMING

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	9.8	11.0	14.7	21.1
TOTAL FIXED CAPITAL(TFC)	9.8	11.0	14.7	21.2
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(3.0)/G ($/MSCF)	2.27	2.41	4.00	6.54
PRODUCTION COST, C/MSCF				
RAW MATERIALS	299.65	318.49	528.11	863.82
BY-PRODUCT CREDIT	(76.95)	(82.38)	(134.43)	(218.40)
IMPORTED UTILITIES	3.33	3.52	5.79	9.54
VARIABLE COSTS	226.03	239.63	399.47	654.96
OPERATING LABOR(0.0/SHIFT)	0.00	0.00	0.00	0.00
MAINTENANCE LABOR(1.5% BLI)	0.22	0.25	0.34	0.48
CONTROL LAB LABOR(20.0% OF LABOR)	0.00	0.00	0.00	0.00
TOTAL DIRECT LABOR	0.22	0.25	0.34	0.48
MAINTENANCE MATERIALS(1.5% BLI)	0.22	0.25	0.34	0.48
OPERATING SUPPLIES(10.0% OF LABOR)	0.00	0.00	0.00	0.00
	0.22	0.25	0.34	0.48
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.18	0.20	0.27	0.38
TAXES AND INSURANCE(2.0% TFC)	0.30	0.33	0.45	0.65
DEPRECIATION(10.0% TFC)	1.49	1.67	2.24	3.23
	1.97	2.20	2.96	4.26
SUBTOTAL: PLANT GATE COST	228.44	242.33	403.11	660.18
G&A, SALES, RESEARCH(3.0% PV)	9.56	10.17	16.80	27.42
ROI BEFORE TAXES(25.0% TFC)	3.73	4.19	5.59	8.07
PRODUCT VALUE(PV), C/MSCF	241.73	256.69	425.50	695.67

SYNGAS(H2/CO=3.0) FROM NATURAL GAS
WITH CO2 RECYCLE

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
NATURAL GAS	4.17$/MMBTU	0.2650	110.51
MISC. CHEM. & CAT.			0.90
			111.41
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	0.1600	66.72
ELECTRICITY	3.60C/KWH	1.0180	3.66
COOLING WATER	5.40C/MGAL	0.2230	1.20
PROCESS WATER	68.00C/MGAL	0.0065	0.44
			72.02
TOTAL VARIABLE COSTS			183.43

SYNGAS(H2/CO=3.0) FROM NATURAL GAS (MODULE #12)
WITH CO2 RECYCLE

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	66.2	74.6	99.6	143.0
TOTAL FIXED CAPITAL(TFC)	88.2	99.4	132.8	190.6
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
NATURAL GAS ($/MMBTU)	4.00	4.17	7.37	12.43
PRODUCTION COST, C/MSCF				
RAW MATERIALS	106.76	111.41	196.50	331.16
IMPORTED UTILITIES	68.94	72.02	126.31	212.34
VARIABLE COSTS	175.70	183.43	322.81	543.50
OPERATING LABOR(4.0/SHIFT)	0.82	0.93	1.26	1.78
MAINTENANCE LABOR(1.5% BLI)	1.51	1.70	2.27	3.26
CONTROL LAB LABOR(20.0% OF LABOR)	0.16	0.19	0.25	0.36
TOTAL DIRECT LABOR	2.49	2.82	3.78	5.40
MAINTENANCE MATERIALS(1.5% BLI)	1.51	1.70	2.27	3.26
OPERATING SUPPLIES(10.0% OF LABOR)	0.08	0.09	0.13	0.18
	1.59	1.79	2.40	3.44
PLANT OVERHEAD(80.0% TOTAL LABOR)	1.99	2.26	3.02	4.32
TAXES AND INSURANCE(2.0% TFC)	2.68	3.03	4.04	5.80
DEPRECIATION(10.0% TFC)	13.42	15.13	20.21	29.01
	18.09	20.42	27.27	39.13
SUBTOTAL: PLANT GATE COST	197.87	208.46	356.26	591.47
G&A, SALES, RESEARCH(3.0% PV)	7.16	7.62	12.58	20.54
ROI BEFORE TAXES(25.0% TFC)	33.56	37.82	50.53	72.53
PRODUCT VALUE(PV), C/MSCF	238.59	253.90	419.37	684.54

METHANOL SYNGAS(H2/CO=2.26) FROM COAL

805.30 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
COAL AT MINE	32.30$/TONNE	0.0186	60.21
COAL TRANSPORT	15.00$/TONNE	0.0186	27.96
ASH DISPOSAL	5.00$/TONNE	0.0019	0.93
MISC. CHEM. & CAT.			0.62
			89.72
BY PRODUCTS			
SULFUR	4.54C/LB	(1.2570)	(5.71)
			(5.71)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	0.0076	5.85
ELECTRICITY	3.60C/KWH	(0.0825)	(0.30)
CLARIFIED WATER	41.00C/MGAL	0.0151	0.62
			6.17
TOTAL VARIABLE COSTS			90.18

METHANOL SYNGAS(H2/CO=2.26) FROM COAL (MODULE #13)

805.30 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	989.0	1114.3	1488.2	2136.4
TOTAL FIXED CAPITAL(TFC)	1208.4	1361.6	1818.4	2610.6
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
COAL AT MINE (\$/TONNE)	28.80	32.30	42.30	61.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	80.78	89.72	117.62	169.56
BY-PRODUCT CREDIT	(4.83)	(5.71)	(7.55)	(11.15)
IMPORTED UTILITIES	5.58	6.17	8.14	11.55
VARIABLE COSTS	81.53	90.18	118.21	169.96
OPERATING LABOR(42.0/SHIFT)	2.14	2.43	3.28	4.65
MAINTENANCE LABOR(1.6% BLI)	5.98	6.74	9.00	12.92
CONTROL LAB LABOR(20.0% OP LABOR)	0.43	0.49	0.66	0.93
TOTAL DIRECT LABOR	8.55	9.66	12.94	18.50
MAINTENANCE MATERIALS(2.4% BLI)	8.97	10.11	13.50	19.38
OPERATING SUPPLIES(10.0% OP LABOR)	0.21	0.24	0.33	0.47
	9.18	10.35	13.83	19.85
PLANT OVERHEAD(30.0% TOTAL LABOR)	2.56	2.90	3.88	5.55
TAXES AND INSURANCE(2.0% TFC)	9.14	10.29	13.75	19.74
DEPRECIATION(10.0% TFC)	45.68	51.47	68.74	98.68
	57.38	64.66	86.37	123.97
SUBTOTAL: PLANT GATE COST	156.64	174.85	231.35	332.28
G&A, SALES, RESEARCH(3.0% PV)	8.53	9.56	12.70	18.25
ROI BEFORE TAXES(25.0% TFC)	114.20	128.68	171.84	246.71
PRODUCT VALUE(PV), C/MSCF	279.37	313.09	415.89	597.24

CRUDE SYNGAS(H2/CO=4.92)
FROM NATURAL GAS

264.90 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
NATURAL GAS	4.17$/MMBTU	0.3080	128.44
MISC. CHEM. & CAT.			0.33
			128.77
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	0.1256	52.38
HP STEAM	7.70$/MLB	(0.0461)	(35.49)
MP STEAM	6.50$/MLB	0.0208	13.53
ELECTRICITY	3.60C/KWH	0.7170	2.58
COOLING WATER	5.40C/MGAL	0.0047	0.03
PROCESS WATER	68.00C/MGAL	0.0028	0.19
			33.22
TOTAL VARIABLE COSTS			161.99

CRUDE SYNGAS(H2/CO=4.92) (MODULE #14)
FROM NATURAL GAS

264.90 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	65.3	73.6	98.3	141.2
TOTAL FIXED CAPITAL(TFC)	82.4	92.8	124.0	178.0
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
NATURAL GAS ($/MMBTU)	4.00	4.17	7.37	12.43
PRODUCTION COST, C/MSCF				
RAW MATERIALS	123.48	128.77	227.44	383.48
IMPORTED UTILITIES	32.89	33.22	68.01	121.84
VARIABLE COSTS	156.37	161.99	295.45	505.32
OPERATING LABOR(2.0/SHIFT)	0.31	0.35	0.48	0.67
MAINTENANCE LABOR(1.5% BLI)	1.13	1.27	1.69	2.43
CONTROL LAB LABOR(20.0% OP LABOR)	0.06	0.07	0.10	0.13
TOTAL DIRECT LABOR	1.50	1.69	2.27	3.23
MAINTENANCE MATERIALS(1.5% BLI)	1.13	1.27	1.69	2.43
OPERATING SUPPLIES(10.0% OP LABOR)	0.03	0.04	0.05	0.07
	1.16	1.31	1.74	2.50
PLANT OVERHEAD(80.0% TOTAL LABOR)	1.20	1.35	1.82	2.58
TAXES AND INSURANCE(2.0% TFC)	1.89	2.13	2.85	4.09
DEPRECIATION(10.0% TFC)	9.47	10.66	14.25	20.46
	12.56	14.14	18.92	27.13
SUBTOTAL: PLANT GATE COST	171.59	179.13	318.38	538.18
G&A, SALES, RESEARCH(3.0% PV)	6.04	6.36	10.95	18.23
ROI BEFORE TAXES(25.0% TFC)	23.67	26.66	35.62	51.14
PRODUCT VALUE(PV), C/MSCF	201.30	212.15	364.95	607.55

CO FROM GAS-DERIVED SYNGAS(H2/CO=3.0)
BY COSORB SEPARATION

149.30 MMLB/YR

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER LB	C/LB
RAW MATERIALS			
SYNGAS(3.0)/G	2.46$/MSCF	0.0539	13.26
MISC. CHEM. & CAT.			0.13
			13.39
BY PRODUCTS			
HYDROGEN	2.58$/MSCF	(0.0400)	(10.32)
FUEL GAS	4.76$/MMBTU	(0.0001)	(0.04)
			(10.36)
IMPORTED UTILITIES			
LP STEAM	5.20$/MLB	0.0010	0.54
ELECTRICITY	3.60C/KWH	0.1200	0.43
COOLING WATER	5.40C/MGAL	0.0030	0.02
			0.99
TOTAL VARIABLE COSTS			4.02

CO FROM GAS-DERIVED SYNGAS(H2/CO=3.0) (MODULE #15)
BY COSORB SEPARATION

149.30 MMLB/YR

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	7.6	8.6	11.5	16.5
TOTAL FIXED CAPITAL(TFC)	8.6	9.7	12.9	18.6
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(3.0)/G ($/MSCF)	2.31	2.46	4.07	6.64
PRODUCTION COST, C/LB				
RAW MATERIALS	12.56	13.39	22.11	36.04
BY-PRODUCT CREDIT	(9.68)	(10.36)	(16.91)	(27.47)
IMPORTED UTILITIES	0.90	0.99	1.44	2.21
VARIABLE COSTS	3.78	4.02	6.64	10.78
OPERATING LABOR(2.0/SHIFT)	0.18	0.21	0.28	0.39
MAINTENANCE LABOR(2.0% BLI)	0.10	0.12	0.15	0.22
CONTROL LAB LABOR(20.0% OP LABOR)	0.04	0.04	0.06	0.08
TOTAL DIRECT LABOR	0.32	0.37	0.49	0.69
MAINTENANCE MATERIALS(2.0% BLI)	0.10	0.12	0.15	0.22
OPERATING SUPPLIES(10.0% OP LABOR)	0.02	0.02	0.03	0.04
	0.12	0.14	0.18	0.26
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.26	0.30	0.39	0.55
TAXES AND INSURANCE(2.0% TFC)	0.12	0.13	0.17	0.25
DEPRECIATION(10.0% TFC)	0.58	0.65	0.86	1.25
	0.96	1.08	1.42	2.05
SUBTOTAL: PLANT GATE COST	5.18	5.61	8.73	13.78
G&A, SALES, RESEARCH(3.0% PV)	0.50	0.54	0.86	1.37
ROI BEFORE TAXES(25.0% TFC)	1.44	1.62	2.16	3.11
PRODUCT VALUE(PV), C/LB	7.12	7.77	11.75	18.26

CO FROM GAS-DERIVED SYNGAS(H2/CO=3.0)
BY CRYOGENIC SEPARATION

149.30 MMLB/YR

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER LB	C/LB
RAW MATERIALS			
SYNGAS(3.0)/G	2.46$/MSCF	0.0541	13.31
MISC. CHEM. & CAT.			0.05
			13.36
BY PRODUCTS			
HYDROGEN	2.58$/MSCF	(0.0393)	(10.14)
FUEL GAS	4.76$/MMBTU	(0.0005)	(0.24)
			(10.38)
IMPORTED UTILITIES			
ELECTRICITY	3.60C/KWH	0.1970	0.71
COOLING WATER	5.40C/MGAL	0.0012	0.01
			0.72
TOTAL VARIABLE COSTS			3.70

CO FROM GAS-DERIVED SYNGAS(H2/CO=3.0) (MODULE #16)
BY CRYOGENIC SEPARATION

149.30 MMLB/YR

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	4.3	4.8	6.4	9.2
TOTAL FIXED CAPITAL(TFC)	4.9	5.5	7.3	10.5
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(3.0)/G ($/MSCF)	2.31	2.46	4.07	6.64
PRODUCTION COST, C/LB				
RAW MATERIALS	12.54	13.36	22.09	36.02
BY-PRODUCT CREDIT	(9.69)	(10.38)	(16.95)	(27.49)
IMPORTED UTILITIES	0.68	0.72	1.17	1.92
VARIABLE COSTS	3.53	3.70	6.31	10.45
OPERATING LABOR(2.0/SHIFT)	0.18	0.21	0.28	0.39
MAINTENANCE LABOR(2.0% BLI)	0.06	0.06	0.09	0.12
CONTROL LAB LABOR(20.0% OP LABOR)	0.04	0.04	0.06	0.08
TOTAL DIRECT LABOR	0.28	0.31	0.43	0.59
MAINTENANCE MATERIALS(2.0% BLI)	0.06	0.06	0.09	0.12
OPERATING SUPPLIES(10.0% OP LABOR)	0.02	0.02	0.03	0.04
	0.08	0.08	0.12	0.16
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.22	0.25	0.34	0.47
TAXES AND INSURANCE(2.0% TFC)	0.07	0.07	0.10	0.14
DEPRECIATION(10.0% TFC)	0.33	0.37	0.49	0.70
	0.62	0.69	0.93	1.31
SUBTOTAL: PLANT GATE COST	4.51	4.78	7.79	12.51
G&A, SALES, RESEARCH(3.0% PV)	0.46	0.50	0.80	1.29
ROI BEFORE TAXES(25.0% TFC)	0.82	0.92	1.22	1.76
PRODUCT VALUE(PV), C/LB	5.79	6.20	9.81	15.56

CO FROM GAS-DERIVED CRUDE SYNGAS
(H2/CO=4.9) BY COSORB SEPARATION

149.30 MMLB/YR

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER LB	C/LB
RAW MATERIALS			
SYNGAS(4.9)/G	2.06$/MSCF	0.0846	17.43
MISC. CHEM. & CAT.			0.16
			17.59
BY PRODUCTS			
HYDROGEN(85.4%)	1.54$/MSCF	(0.0699)	(10.76)
			(10.76)
IMPORTED UTILITIES			
LP STEAM	5.20$/MLB	0.0012	0.65
ELECTRICITY	3.60C/KWH	0.1660	0.60
COOLING WATER	5.40C/MGAL	0.0036	0.02
			1.27
TOTAL VARIABLE COSTS			8.10

CO FROM GAS-DERIVED CRUDE SYNGAS (MODULE #17)
(H2/CO=4.9) BY COSORB SEPARATION

149.30 MMLB/YR

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	9.2	10.4	13.9	19.9
TOTAL FIXED CAPITAL(TFC)	12.1	13.6	18.2	26.1
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(4.9)/G ($/MSCF)	1.95	2.06	3.54	5.89
PRODUCTION COST, C/LB				
RAW MATERIALS	16.63	17.59	30.16	50.13
BY-PRODUCT CREDIT	(10.00)	(10.76)	(18.31)	(27.89)
IMPORTED UTILITIES	1.17	1.27	1.87	2.88
VARIABLE COSTS	7.80	8.10	13.72	25.12
OPERATING LABOR(2.0/SHIFT)	0.18	0.21	0.28	0.39
MAINTENANCE LABOR(2.0% BLI)	0.12	0.14	0.19	0.27
CONTROL LAB LABOR(20.0% OP LABOR)	0.04	0.04	0.06	0.08
TOTAL DIRECT LABOR	0.34	0.39	0.53	0.74
MAINTENANCE MATERIALS(2.0% BLI)	0.12	0.14	0.19	0.27
OPERATING SUPPLIES(10.0% OP LABOR)	0.02	0.02	0.03	0.04
	0.14	0.16	0.22	0.31
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.27	0.31	0.42	0.59
TAXES AND INSURANCE(2.0% TFC)	0.16	0.18	0.24	0.35
DEPRECIATION(10.0% TFC)	0.81	0.91	1.22	1.75
	1.24	1.40	1.88	2.69
SUBTOTAL: PLANT GATE COST	9.52	10.05	16.35	28.86
G&A, SALES, RESEARCH(3.0% PV)	0.67	0.71	1.17	1.89
ROI BEFORE TAXES(25.0% TFC)	2.03	2.28	3.05	4.37
PRODUCT VALUE(PV), C/LB	12.22	13.04	20.57	35.12

CO FROM GAS-DERIVED CRUDE SYNGAS
(H2/CO=4.9) BY CRYOGENIC SEPARATION

149.30 MMLB/YR

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER LB	C/LB
RAW MATERIALS			
SYNGAS(4.9)/G	2.06$/MSCF	0.0891	18.35
MISC. CHEM. & CAT.			0.21
			18.56
BY PRODUCTS			
CARBON DIOXIDE	0.00C/LB	(0.9130)	(0.00)
HYDROGEN	2.58$/MSCF	(0.0712)	(18.37)
FUEL GAS	4.76$/MMBTU	(0.0039)	(1.88)
			(20.25)
IMPORTED UTILITIES			
LP STEAM	5.20$/MLB	0.0012	0.60
ELECTRICITY	3.60C/KWH	0.3530	1.27
COOLING WATER	5.40C/MGAL	0.0192	0.10
			1.97
TOTAL VARIABLE COSTS			0.28

CO FROM GAS-DERIVED CRUDE SYNGAS (MODULE #18)
(H2/CO=4.9) BY CRYOGENIC SEPARATION

149.30 MMLB/YR

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	15.9	17.9	23.9	34.3
TOTAL FIXED CAPITAL(TFC)	17.2	19.3	25.8	37.1
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(4.9)/G ($/MSCF)	1.95	2.06	3.54	5.89
PRODUCTION COST, C/LB				
RAW MATERIALS	17.55	18.56	31.82	52.89
BY-PRODUCT CREDIT	(18.89)	(20.25)	(33.17)	(53.55)
IMPORTED UTILITIES	1.84	1.97	3.03	4.79
VARIABLE COSTS	0.50	0.28	1.68	4.13
OPERATING LABOR(4.0/SHIFT)	0.36	0.41	0.55	0.78
MAINTENANCE LABOR(2.0% BLI)	0.21	0.24	0.32	0.46
CONTROL LAB LABOR(20.0% OF LABOR)	0.07	0.08	0.11	0.16
TOTAL DIRECT LABOR	0.64	0.73	0.98	1.40
MAINTENANCE MATERIALS(2.0% BLI)	0.21	0.24	0.32	0.46
OPERATING SUPPLIES(10.0% OF LABOR)	0.04	0.04	0.06	0.08
	0.25	0.28	0.38	0.54
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.51	0.58	0.78	1.12
TAXES AND INSURANCE(2.0% TFC)	0.23	0.26	0.35	0.50
DEPRECIATION(10.0% TFC)	1.15	1.29	1.73	2.48
	1.89	2.13	2.86	4.10
SUBTOTAL: PLANT GATE COST	3.28	3.42	5.90	10.17
G&A, SALES, RESEARCH(3.0% PV)	0.77	0.83	1.34	2.16
ROI BEFORE TAXES(25.0% TFC)	2.88	3.23	4.32	6.21
PRODUCT VALUE(PV), C/LB	6.93	7.48	11.56	18.54

CO FROM COAL-DERIVED METHANOL SYNGAS
(H2/CO=2.26) BY COSORB SEPARATION

149.30 MMLB/YR

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER LB	C/LB
RAW MATERIALS			
SYNGAS(2.26)/C	3.04$/MSCF	0.0445	13.52
MISC. CHEM. & CAT.			0.13
			13.65
BY PRODUCTS			
HYDROGEN(93%)	3.04$/MSCF	(0.0306)	(9.30)
			(9.30)
IMPORTED UTILITIES			
LP STEAM	5.20$/MLB	0.0010	0.54
ELECTRICITY	3.60C/KWH	0.1200	0.43
COOLING WATER	5.40C/MGAL	0.0030	0.02
			0.99
TOTAL VARIABLE COSTS			5.34

CO FROM COAL-DERIVED METHANOL SYNGAS (MODULE #19)
(H2/CO=2.26) BY COSORB SEPARATION

149.30 MMLB/YR

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	7.5	8.4	11.2	16.1
TOTAL FIXED CAPITAL(TFC)	8.3	9.4	12.5	18.0
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(2.26)/C ($/MSCF)	2.71	3.04	4.03	5.79
PRODUCTION COST, C/LB				
RAW MATERIALS	12.16	13.65	18.09	25.99
BY-PRODUCT CREDIT	(8.29)	(9.30)	(12.33)	(17.72)
IMPORTED UTILITIES	0.90	0.99	1.44	2.21
VARIABLE COSTS	4.77	5.34	7.20	10.48
OPERATING LABOR(2.0/SHIFT)	0.18	0.21	0.28	0.39
MAINTENANCE LABOR(2.0% BLI)	0.10	0.11	0.15	0.22
CONTROL LAB LABOR(20.0% OP LABOR)	0.04	0.04	0.06	0.08
TOTAL DIRECT LABOR	0.32	0.36	0.49	0.69
MAINTENANCE MATERIALS(2.0% BLI)	0.10	0.11	0.15	0.22
OPERATING SUPPLIES(10.0% OP LABOR)	0.02	0.02	0.03	0.04
	0.12	0.13	0.18	0.26
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.26	0.29	0.39	0.55
TAXES AND INSURANCE(2.0% TFC)	0.11	0.13	0.17	0.24
DEPRECIATION(10.0% TFC)	0.56	0.63	0.84	1.21
	0.93	1.05	1.40	2.00
SUBTOTAL: PLANT GATE COST	6.14	6.88	9.27	13.43
G&A, SALES, RESEARCH(3.0% PV)	0.49	0.55	0.73	1.06
ROI BEFORE TAXES(25.0% TFC)	1.39	1.57	2.09	3.01
PRODUCT VALUE(PV), C/LB	8.02	9.00	12.09	17.50

CO FROM RESID-DERIVED SYNGAS(H2/CO=2.0)
BY CRYOGENIC SEPARATION

149.30 MMLB/YR

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER LB	C/LB
RAW MATERIALS			
SYNGAS(2.0)/R	2.84$/MSCF	0.0419	11.90
MISC. CHEM. & CAT.			0.04
			11.94
BY PRODUCTS			
HYDROGEN	2.58$/MSCF	(0.0271)	(6.99)
FUEL GAS	4.76$/MMBTU	(0.0004)	(0.18)
			(7.17)
IMPORTED UTILITIES			
ELECTRICITY	3.60C/KWH	0.1630	0.59
COOLING WATER	5.40C/MGAL	0.0012	0.01
			0.60
TOTAL VARIABLE COSTS			5.37

CO FROM RESID-DERIVED SYNGAS(H2/CO=2.0) (MODULE #20)
BY CRYOGENIC SEPARATION

149.30 MMLB/YR

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	4.6	5.2	6.9	10.0
TOTAL FIXED CAPITAL(TFC)	5.3	6.0	8.0	11.5
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(2.0)/R ($/MSCF)	2.56	2.84	4.47	6.58
PRODUCTION COST, C/LB				
RAW MATERIALS	10.76	11.94	18.78	27.65
BY-PRODUCT CREDIT	(6.70)	(7.17)	(11.72)	(19.01)
IMPORTED UTILITIES	0.56	0.60	0.97	1.59
VARIABLE COSTS	4.62	5.37	8.03	10.23
OPERATING LABOR(2.0/SHIFT)	0.18	0.21	0.28	0.39
MAINTENANCE LABOR(2.0% BLI)	0.06	0.07	0.09	0.13
CONTROL LAB LABOR(20.0% OF LABOR)	0.04	0.04	0.06	0.08
TOTAL DIRECT LABOR	0.28	0.32	0.43	0.60
MAINTENANCE MATERIALS(2.0% BLI)	0.06	0.07	0.09	0.13
OPERATING SUPPLIES(10.0% OF LABOR)	0.02	0.02	0.03	0.04
	0.08	0.09	0.12	0.17
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.22	0.26	0.34	0.48
TAXES AND INSURANCE(2.0% TFC)	0.07	0.08	0.11	0.15
DEPRECIATION(10.0% TFC)	0.35	0.40	0.54	0.77
	0.64	0.74	0.99	1.40
SUBTOTAL: PLANT GATE COST	5.62	6.52	9.57	12.40
G&A, SALES, RESEARCH(3.0% PV)	0.41	0.45	0.70	1.03
ROI BEFORE TAXES(25.0% TFC)	0.89	1.00	1.34	1.93
PRODUCT VALUE(PV), C/LB	6.92	7.97	11.61	15.36

HYDROGEN(97%) FROM NATURAL GAS

100.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
NATURAL GAS	4.17$/MMBTU	0.2780	115.93
MISC. CHEM. & CAT.			2.37
			118.30
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	0.1440	60.05
HP STEAM	7.70$/MLB	(0.0544)	(41.89)
MP STEAM	6.50$/MLB	0.0544	35.36
LP STEAM	5.20$/MLB	0.0134	6.97
ELECTRICITY	3.60C/KWH	0.8380	3.02
COOLING WATER	5.40C/MGAL	0.2020	1.09
PROCESS WATER	68.00C/MGAL	0.0067	0.46
			65.06
TOTAL VARIABLE COSTS			183.36

HYDROGEN(97%) FROM NATURAL GAS (MODULE #21)

100.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	38.2	43.0	57.4	82.5
TOTAL FIXED CAPITAL(TFC)	51.0	57.5	76.8	110.2
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
NATURAL GAS ($/MMBTU)	4.00	4.17	7.37	12.43
PRODUCTION COST, C/MSCF				
RAW MATERIALS	113.20	118.30	208.03	350.18
IMPORTED UTILITIES	62.16	65.06	113.85	191.10
VARIABLE COSTS	175.36	183.36	321.88	541.28
OPERATING LABOR(4.0/SHIFT)	1.64	1.87	2.52	3.56
MAINTENANCE LABOR(1.5% BLI)	1.74	1.96	2.62	3.77
CONTROL LAB LABOR(20.0% OP LABOR)	0.33	0.37	0.50	0.71
TOTAL DIRECT LABOR	3.71	4.20	5.64	8.04
MAINTENANCE MATERIALS(1.5% BLI)	1.74	1.96	2.62	3.77
OPERATING SUPPLIES(10.0% OP LABOR)	0.16	0.19	0.25	0.36
	1.90	2.15	2.87	4.13
PLANT OVERHEAD(80.0% TOTAL LABOR)	2.97	3.36	4.51	6.43
TAXES AND INSURANCE(2.0% TFC)	3.11	3.50	4.68	6.71
DEPRECIATION(10.0% TFC)	15.53	17.50	23.38	33.55
	21.61	24.36	32.57	46.69
SUBTOTAL: PLANT GATE COST	202.58	214.07	362.96	600.14
G&A, SALES, RESEARCH(3.0% PV)	7.47	7.97	13.03	21.15
ROI BEFORE TAXES(25.0% TFC)	38.81	43.76	58.45	83.87
PRODUCT VALUE(PV), C/MSCF	248.86	265.80	434.44	705.16

HYDROGEN(97%) FROM COAL

200.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
COAL AT MINE	32.30$/TONNE	0.0192	61.98
COAL TRANSPORT	15.00$/TONNE	0.0192	28.79
ASH DISPOSAL	5.00$/TONNE	0.0019	0.96
MISC. CHEM. & CAT.			1.53
			93.26
BY PRODUCTS			
SULFUR	4.54C/LB	(1.2570)	(5.71)
			(5.71)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	0.0163	12.55
LP STEAM	5.20$/MLB	(0.0169)	(8.79)
ELECTRICITY	3.60C/KWH	0.0307	0.11
CLARIFIED WATER	41.00C/MGAL	0.0160	0.66
			4.53
TOTAL VARIABLE COSTS			92.08

HYDROGEN(97%) FROM COAL (MODULE #22)

200.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	343.1	386.5	516.2	741.1
TOTAL FIXED CAPITAL(TFC)	439.0	494.7	660.7	948.4
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
COAL AT MINE ($/TONNE)	28.80	32.30	42.30	61.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	83.92	93.26	122.27	176.31
BY-PRODUCT CREDIT	(4.83)	(5.71)	(7.55)	(11.15)
IMPORTED UTILITIES	4.15	4.53	6.08	8.87
VARIABLE COSTS	83.24	92.08	120.80	174.03
OPERATING LABOR(20.0/SHIFT)	4.11	4.67	6.29	8.91
MAINTENANCE LABOR(1.6% BLI)	8.36	9.41	12.57	18.05
CONTROL LAB LABOR(20.0% OP LABOR)	0.82	0.93	1.26	1.78
TOTAL DIRECT LABOR	13.29	15.01	20.12	28.74
MAINTENANCE MATERIALS(2.4% BLI)	12.53	14.12	18.86	27.07
OPERATING SUPPLIES(10.0% OP LABOR)	0.41	0.47	0.63	0.89
	12.94	14.59	19.49	27.96
PLANT OVERHEAD(30.0% TOTAL LABOR)	3.99	4.50	6.04	8.62
TAXES AND INSURANCE(2.0% TFC)	13.36	15.06	20.11	28.87
DEPRECIATION(10.0% TFC)	66.82	75.30	100.56	144.35
	84.17	94.86	126.71	181.84
SUBTOTAL: PLANT GATE COST	193.64	216.54	287.12	412.57
G&A, SALES, RESEARCH(3.0% PV)	11.30	12.70	16.89	24.27
ROI BEFORE TAXES(25.0% TFC)	167.05	188.24	251.41	360.88
PRODUCT VALUE(PV), C/MSCF	371.99	417.48	555.42	797.72

HYDROGEN(98%) FROM VACUUM RESIDUE

100.00 MMSCFD

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
VACUUM RESIDUE	5.65C/LB	23.2500	131.36
MISC. CHEM. & CAT.			0.79
			132.15
BY PRODUCTS			
SULFUR	4.54C/LB	(1.3800)	(6.27)
			(6.27)
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	0.0622	47.89
ELECTRICITY	3.60C/KWH	1.2650	4.55
COOLING WATER	5.40C/MGAL	0.1720	0.93
PROCESS WATER	68.00C/MGAL	0.0086	0.58
			53.95
TOTAL VARIABLE COSTS			179.83

HYDROGEN(98%) FROM VACUUM RESIDUE (MODULE #23)

100.00 MMSCFD

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	104.5	117.7	157.3	225.7
TOTAL FIXED CAPITAL(TFC)	140.9	158.7	212.0	304.3
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
VACUUM RESIDUE (C/LB)	5.15	5.65	10.50	15.80
PRODUCTION COST, C/MSCF				
RAW MATERIALS	120.41	132.15	245.18	368.89
BY-PRODUCT CREDIT	(5.30)	(6.27)	(8.29)	(12.24)
IMPORTED UTILITIES	49.20	53.95	73.08	106.35
VARIABLE COSTS	164.31	179.83	309.97	463.00
OPERATING LABOR(8.0/SHIFT)	3.29	3.73	5.03	7.13
MAINTENANCE LABOR(1.5% BLI)	4.77	5.37	7.18	10.31
CONTROL LAB LABOR(20.0% OP LABOR)	0.66	0.75	1.01	1.43
TOTAL DIRECT LABOR	8.72	9.85	13.22	18.87
MAINTENANCE MATERIALS(1.5% BLI)	4.77	5.37	7.18	10.31
OPERATING SUPPLIES(10.0% OP LABOR)	0.33	0.37	0.50	0.71
	5.10	5.74	7.68	11.02
PLANT OVERHEAD(80.0% TOTAL LABOR)	6.98	7.88	10.58	15.10
TAXES AND INSURANCE(2.0% TFC)	8.58	9.66	12.91	18.53
DEPRECIATION(10.0% TFC)	42.89	48.31	64.54	92.63
	58.45	65.85	88.03	126.26
SUBTOTAL: PLANT GATE COST	236.58	261.27	418.90	619.15
G&A, SALES, RESEARCH(3.0% PV)	10.80	12.01	18.20	26.69
ROI BEFORE TAXES(25.0% TFC)	107.23	120.78	161.34	231.58
PRODUCT VALUE(PV), C/MSCF	354.61	394.06	598.44	877.42

METHANOL FROM NATURAL GAS

2490.70 TONNE/D

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER TONNE	$/TONNE
RAW MATERIALS			
NATURAL GAS	4.17$/MMBTU	30.8600	128.69
ACTIVE CARBON	1.75$/LB	0.0220	0.04
REFORMING CATALYST	2.00$/LB	0.1540	0.31
METHANOL CATALYST	4.00$/LB	0.2870	1.15
			130.19
BY PRODUCTS			
HIGHER ALCOHOLS	4.80C/LB	(16.4700)	(0.79)
			(0.79)
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	1.8700	7.80
ELECTRICITY	3.60C/KWH	33.0700	1.19
COOLING WATER	5.40C/MGAL	28.6600	1.55
PROCESS WATER	68.00C/MGAL	0.2980	0.20
			10.74
TOTAL VARIABLE COSTS			140.14

METHANOL FROM NATURAL GAS (MODULE #24)

2490.70 TONNE/D

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	137.8	155.2	207.3	297.6
TOTAL FIXED CAPITAL(TFC)	188.9	212.8	284.3	408.1
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
NATURAL GAS ($/MMBTU)	4.00	4.17	7.37	12.43
PRODUCTION COST, $/TONNE				
RAW MATERIALS	124.71	130.19	229.42	386.51
BY-PRODUCT CREDIT	(0.72)	(0.79)	(1.33)	(2.03)
IMPORTED UTILITIES	10.18	10.74	18.28	30.33
VARIABLE COSTS	134.17	140.14	246.37	414.81
OPERATING LABOR(6.0/SHIFT)	0.99	1.12	1.52	2.15
MAINTENANCE LABOR(1.5% BLI)	2.53	2.85	3.80	5.46
CONTROL LAB LABOR(20.0% OF LABOR)	0.20	0.22	0.30	0.43
TOTAL DIRECT LABOR	3.72	4.19	5.62	8.04
MAINTENANCE MATERIALS(1.5% BLI)	2.53	2.85	3.80	5.46
OPERATING SUPPLIES(10.0% OF LABOR)	0.10	0.11	0.15	0.21
	2.63	2.96	3.95	5.67
PLANT OVERHEAD(80.0% TOTAL LABOR)	2.98	3.35	4.50	6.43
TAXES AND INSURANCE(2.0% TFC)	4.62	5.20	6.95	9.98
DEPRECIATION(10.0% TFC)	23.09	26.01	34.75	49.88
	30.69	34.56	46.20	66.29
SUBTOTAL: PLANT GATE COST	171.21	181.85	302.14	494.81
G&A, SALES, RESEARCH(3.0% PV)	7.10	7.66	12.07	19.22
ROI BEFORE TAXES(25.0% TFC)	57.72	65.02	86.87	124.70
PRODUCT VALUE(PV), $/TONNE	236.03	254.53	401.08	638.73

METHANOL FROM GAS-DERIVED
CRUDE SYNGAS(H2/CO=4.9)

2490.70 TONNE/D

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER TONNE	$/TONNE
RAW MATERIALS			
SYNGAS(4.9)/G	2.06$/MSCF	106.5000	219.39
METHANOL CATALYST	4.00$/LB	0.1540	0.62
			220.01
BY PRODUCTS			
HIGHER ALCOHOLS	4.80C/LB	(16.4700)	(0.79)
			(0.79)
IMPORTED UTILITIES			
NAT. GAS FUEL	4.17$/MMBTU	(13.3500)	(55.67)
HP STEAM	7.70$/MLB	4.8900	37.65
MP STEAM	6.50$/MLB	(2.2100)	(14.37)
ELECTRICITY	3.60C/KWH	(42.9900)	(1.55)
COOLING WATER	5.40C/MGAL	28.4400	1.54
			(32.40)
TOTAL VARIABLE COSTS			186.82

METHANOL FROM GAS-DERIVED (MODULE #25)
CRUDE SYNGAS(H2/CO=4.9)

2490.70 TONNE/D

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	72.5	81.7	109.1	156.7
TOTAL FIXED CAPITAL(TFC)	106.5	120.0	160.3	230.1
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(4.9)/G ($/MSCF)	1.95	2.06	3.54	5.89
PRODUCTION COST, $/TONNE				
RAW MATERIALS	208.19	220.01	377.83	628.48
BY-PRODUCT CREDIT	(0.72)	(0.79)	(1.33)	(2.03)
IMPORTED UTILITIES	(32.28)	(32.40)	(67.81)	(122.46)
VARIABLE COSTS	175.19	186.82	308.69	503.99
OPERATING LABOR(4.0/SHIFT)	0.66	0.75	1.01	1.43
MAINTENANCE LABOR(1.5% BLI)	1.33	1.50	2.00	2.87
CONTROL LAB LABOR(20.0% OF LABOR)	0.13	0.15	0.20	0.29
TOTAL DIRECT LABOR	2.12	2.40	3.21	4.59
MAINTENANCE MATERIALS(1.5% BLI)	1.33	1.50	2.00	2.87
OPERATING SUPPLIES(10.0% OF LABOR)	0.07	0.07	0.10	0.14
	1.40	1.57	2.10	3.01
PLANT OVERHEAD(80.0% TOTAL LABOR)	1.70	1.92	2.57	3.67
TAXES AND INSURANCE(2.0% TFC)	2.60	2.93	3.92	5.62
DEPRECIATION(10.0% TFC)	13.02	14.67	19.59	28.12
	17.32	19.52	26.08	37.41
SUBTOTAL: PLANT GATE COST	196.03	210.31	340.08	549.00
G&A, SALES, RESEARCH(3.0% PV)	7.09	7.66	12.07	19.22
ROI BEFORE TAXES(25.0% TFC)	32.54	36.67	48.98	70.31
PRODUCT VALUE(PV), $/TONNE	235.66	254.64	401.13	638.53

METHANOL FROM COAL

10000.00 TONNE/D

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER TONNE	$/TONNE
RAW MATERIALS			
COAL AT MINE	32.30$/TONNE	1.5000	48.45
COAL TRANSPORT	15.00$/TONNE	1.5000	22.50
ASH DISPOSAL	5.00$/TONNE	0.1500	0.75
METHANOL CATALYST	4.00$/LB	0.4000	1.60
MISC. CHEM. & CAT.			0.60
			73.90
BY PRODUCTS			
SULFUR	4.54C/LB	(101.4000)	(4.60)
			(4.60)
IMPORTED UTILITIES			
CLARIFIED WATER	41.00C/MGAL	1.3700	0.56
			0.56
TOTAL VARIABLE COSTS			69.86

METHANOL FROM COAL (MODULE #26)

10000.00 TONNE/D

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	1129.3	1272.5	1699.4	2439.6
TOTAL FIXED CAPITAL(TFC)	1404.4	1582.4	2113.3	3033.9
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
COAL AT MINE ($/TONNE)	28.80	32.30	42.30	61.80
PRODUCTION COST, $/TONNE				
RAW MATERIALS	66.46	73.90	96.90	139.77
BY-PRODUCT CREDIT	(3.89)	(4.60)	(6.09)	(8.99)
IMPORTED UTILITIES	0.49	0.56	0.79	1.14
VARIABLE COSTS	63.06	69.86	91.60	131.92
OPERATING LABOR(62.0/SHIFT)	2.55	2.89	3.90	5.52
MAINTENANCE LABOR(1.6% BLI)	5.50	6.20	8.28	11.88
CONTROL LAB LABOR(20.0% OF LABOR)	0.51	0.58	0.78	1.10
TOTAL DIRECT LABOR	8.56	9.67	12.96	18.50
MAINTENANCE MATERIALS(2.4% BLI)	8.25	9.30	12.42	17.82
OPERATING SUPPLIES(10.0% OP LABOR)	0.26	0.29	0.39	0.55
	8.51	9.59	12.81	18.37
PLANT OVERHEAD(30.0% TOTAL LABOR)	2.57	2.90	3.89	5.55
TAXES AND INSURANCE(2.0% TFC)	8.55	9.63	12.87	18.47
DEPRECIATION(10.0% TFC)	42.75	48.17	64.33	92.36
	53.87	60.70	81.09	116.38
SUBTOTAL: PLANT GATE COST	134.00	149.82	198.46	285.17
G&A, SALES, RESEARCH(3.0% PV)	7.57	8.50	11.30	16.24
ROI BEFORE TAXES(25.0% TFC)	106.88	120.43	160.83	230.89
PRODUCT VALUE(PV), $/TONNE	248.45	278.75	370.59	532.30

METHANOL FROM COAL-DERIVED
METHANOL SYNGAS(H2/CO=2.26)

10000.00 TONNE/D

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER TONNE	$/TONNE
RAW MATERIALS			
SYNGAS(2.26)/C	3.04$/MSCF	80.5000	244.72
METHANOL CATALYST	4.00$/LB	0.4000	1.60
MISC. CHEM. & CAT.			0.10
			246.42
IMPORTED UTILITIES			
HP STEAM	7.70$/MLB	(0.6100)	(4.70)
ELECTRICITY	3.60C/KWH	6.6300	0.24
CLARIFIED WATER	41.00C/MGAL	0.1500	0.06
			(4.40)
TOTAL VARIABLE COSTS			242.02

METHANOL FROM COAL-DERIVED (MODULE #27)
METHANOL SYNGAS(H2/CO=2.26)

10000.00 TONNE/D

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	140.2	158.0	211.0	302.9
TOTAL FIXED CAPITAL(TFC)	195.2	220.0	293.8	421.8
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
SYNGAS(2.26)/C ($/MSCF)	2.71	3.04	4.03	5.79
PRODUCTION COST, $/TONNE				
RAW MATERIALS	219.60	246.42	326.66	469.42
IMPORTED UTILITIES	(3.99)	(4.40)	(5.74)	(8.15)
VARIABLE COSTS	215.61	242.02	320.92	461.27
OPERATING LABOR(20.0/SHIFT)	0.82	0.93	1.26	1.78
MAINTENANCE LABOR(1.6% BLI)	0.68	0.77	1.03	1.48
CONTROL LAB LABOR(20.0% OP LABOR)	0.16	0.19	0.25	0.36
TOTAL DIRECT LABOR	1.66	1.89	2.54	3.62
MAINTENANCE MATERIALS(2.4% BLI)	1.02	1.15	1.54	2.21
OPERATING SUPPLIES(10.0% OP LABOR)	0.08	0.09	0.13	0.18
	1.10	1.24	1.67	2.39
PLANT OVERHEAD(30.0% TOTAL LABOR)	0.50	0.57	0.76	1.09
TAXES AND INSURANCE(2.0% TFC)	1.19	1.34	1.79	2.57
DEPRECIATION(10.0% TFC)	5.94	6.70	8.94	12.84
	7.63	8.61	11.49	16.50
SUBTOTAL: PLANT GATE COST	226.00	253.76	336.62	483.78
G&A, SALES, RESEARCH(3.0% PV)	7.45	8.37	11.10	15.96
ROI BEFORE TAXES(25.0% TFC)	14.86	16.74	22.36	32.10
PRODUCT VALUE(PV), $/TONNE	248.31	278.87	370.08	531.84

CARBON DIOXIDE FROM FLUE GAS SCRUBBING

870.00 MMLB/YR

VARIABLE COST SUMMARY FOR 1981

	UNIT COST	CONSUMPTION PER LB	C/LB
RAW MATERIALS			
MISC. CHEM. & CAT.			0.05
			0.05
IMPORTED UTILITIES			
LP STEAM	5.20$/MLB	0.0024	1.23
ELECTRICITY	3.60C/KWH	0.0910	0.33
COOLING WATER	5.40C/MGAL	0.0157	0.08
			1.64
TOTAL VARIABLE COSTS			1.69

CARBON DIOXIDE FROM FLUE GAS SCRUBBING (MODULE #28)

870.00 MMLB/YR

**COSTS SHOWN IN CURRENT $

	1980	1981	1985	1990
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)	26.7	30.1	40.2	57.7
TOTAL FIXED CAPITAL(TFC)	38.7	43.7	58.3	83.7
COST INDEX(CURRENT $)	355.0	400.0	534.2	766.9
PRODUCTION COST, C/LB				
RAW MATERIALS	0.04	0.05	0.07	0.10
IMPORTED UTILITIES	1.50	1.64	2.29	3.38
VARIABLE COSTS	1.54	1.69	2.36	3.48
OPERATING LABOR(2.0/SHIFT)	0.03	0.04	0.05	0.07
MAINTENANCE LABOR(1.5% BLI)	0.05	0.05	0.07	0.10
CONTROL LAB LABOR(20.0% OF LABOR)	0.01	0.01	0.01	0.01
TOTAL DIRECT LABOR	0.09	0.10	0.13	0.18
MAINTENANCE MATERIALS(1.5% BLI)	0.05	0.05	0.07	0.10
OPERATING SUPPLIES(10.0% OF LABOR)	0.00	0.00	0.01	0.01
	0.05	0.05	0.08	0.11
PLANT OVERHEAD(80.0% TOTAL LABOR)	0.07	0.08	0.10	0.14
TAXES AND INSURANCE(2.0% TFC)	0.09	0.10	0.13	0.19
DEPRECIATION(10.0% TFC)	0.44	0.50	0.67	0.96
	0.60	0.68	0.90	1.29
SUBTOTAL: PLANT GATE COST	2.28	2.52	3.47	5.06
G&A, SALES, RESEARCH(3.0% PV)	0.10	0.12	0.16	0.23
ROI BEFORE TAXES(25.0% TFC)	1.11	1.26	1.68	2.41
PRODUCT VALUE(PV), C/LB	3.49	3.90	5.31	7.70

3 SOURCES AND USES OF SYNGASES

In this section we examine the matching of the stoichiometry and scale of producing syngases to the stoichiometry and scale of using them.

General references to "syngas based processes" are here used to include those processes which use pure carbon monoxide and/or hydrogen derived from syngas mixtures, e.g., the manufacture of ammonia. Thus, syngases are already used on a huge scale. For example, SRI's Chemical Economics Handbook estimates the hydrogen consumption in 1980 for the United States alone as follows:

	10^9 scf	10^9 Nm^3
Ammonia production	1,281	34.3
Refinery operations	587	15.7
Small users	273	7.3
Methanol production	168	4.5
Total	2,309	61.8

Much of this derives from the steam reforming of natural gas. Assuming for illustration that the raw reformer product contains hydrogen and carbon monoxide in a ratio of about 5 to 1, the above is equivalent to an annual production of over 40 billion lb of syngas. This compares with an ethylene production in the United States in 1980 of around 28 billion lb.

The impetus for the present work, however, was not associated with the traditional uses of syngases, but derives from the interest in a new generation of processes for bulk chemicals via "syngas" or "C_1" routes which are expected to increase in importance in the coming years. Examples of this trend are the highly successfully commercialization by Monsanto of a syngas route to acetic acid (see, e.g., PEP Review 78-3-4), the imminent commercialization of the Eastman/Halcon technology for acetic anhydride, and the research being devoted to both direct and indirect (via methanol) routes to ethylene from syngas (see PEP Report 146, Bulk Chemicals from Synthesis Gas).

The search for processes able to use cheaper (or ultimately cheaper) feedstocks such as coal, and in certain circumstances natural gas, derives in part from the fact that for commodity chemicals based on petroleum, the feedstocks currently account for the major part of the product value. Another driving force is the aim to ensure availability of feedstocks over the longer term--this has always been a dominant consideration in the production of fuels and chemicals via syngas in South Africa.

Syngas Sources

Syngas mixtures can be made by many processes and from almost any raw material containing carbon. The processes and feedstocks used commercially are shown in Table 3.1. The main steps in the production of syngases of various H_2:CO ratios and related products are illustrated in the simplified schematic, Figure 3.1.

Steam reforming of natural gas is still the predominant method of syngas production. The capacities of commercial reforming units vary over an amazing range of sizes, something like 3,000:1. As discussed in Section 4, the maximum size of a single train methanol unit is currently about 2,500 metric tons/day, and the reformer unit on this produces some 300 million scfd of syngas. Recent world scale methanol production facilities are being constructed at or close to this capacity. Hydrogen, on the other hand is difficult both to transport and to store in large quantities. Hence hydrogen plants are often built onsite as matching facilities. Reformers with capacities as small as 0.1 million scfd are therefore economic in specific circumstances (385148).

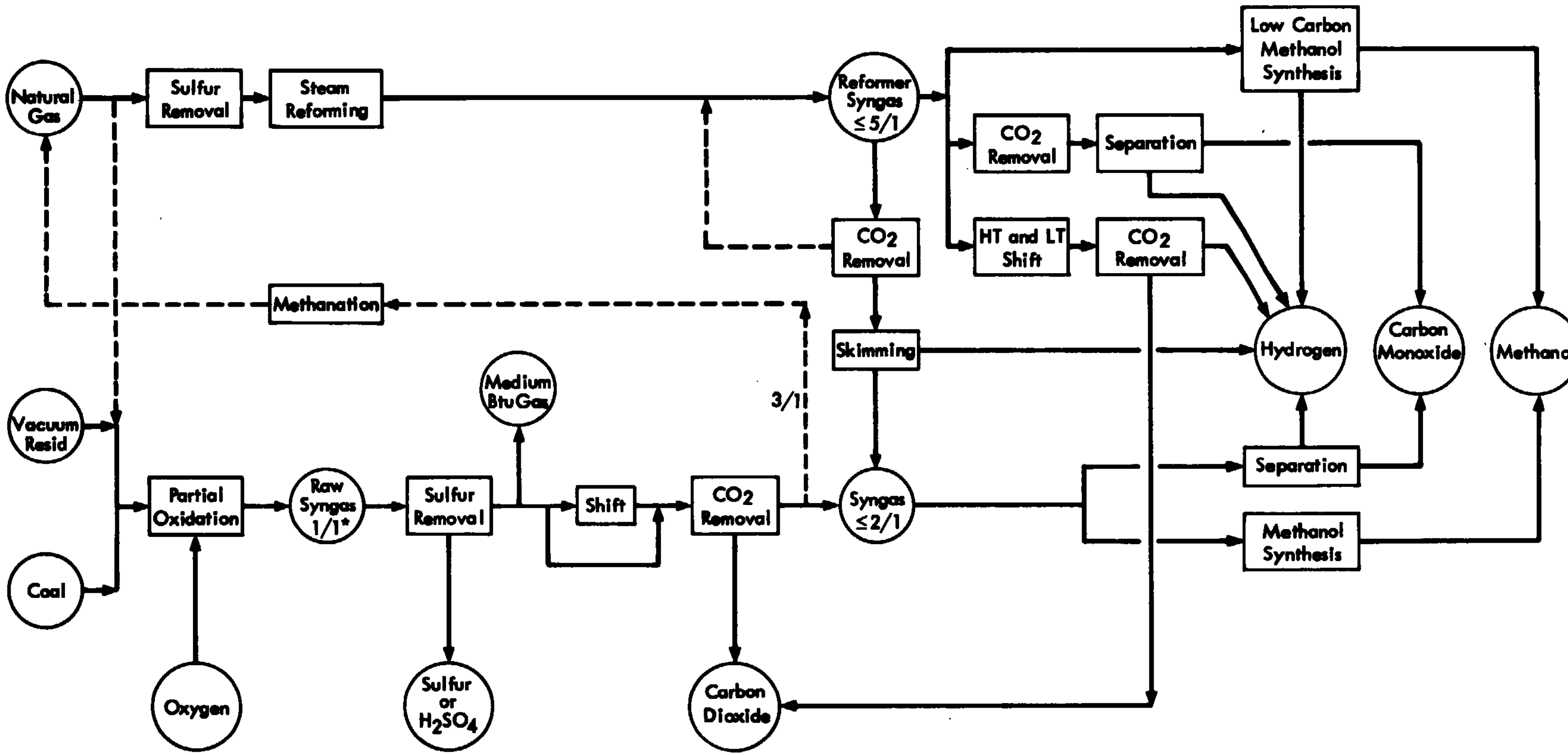
Table 3.1

SYNGAS SOURCES

Process	Feedstock	Typical H_2:CO Volume Ratio in Reactor Product
Steam reforming	Natural gas	5
	Natural gas + imported CO_2	1-5
	Natural gas with CO_2 recycle	3
	Naphtha with CO_2 recycle	2
Partial oxidation	Natural gas	1.75
	Naphtha	1.25
	Vacuum residue	1
Gasification	Coal	
Shell		0.5
Lurgi/BGC		0.5
Koppers-Totzek		0.6
Texaco		0.75
Winkler		0.75
Lurgi		2.2

Figure 3.1

PRODUCTION OF SYNGASES AND RELATED PRODUCTS



* Typical H_2/CO Ratio.

In comparison, partial oxidation/gasification facilities are typically designed to produce 5 to 100 million scfd of syngas per reactor.

A given process and feedstock combination yields a syngas product with a more or less fixed ratio of H_2 to CO which is characteristic of that process and feedstock combination (see Table 3.1). To change this intrinsic ratio requires modification of the feedstock or additional downstream processing, which may be expensive.

The chemistries of steam reforming and partial oxidation (gasification) are examined in later sections in some detail. In all cases a key reaction is the exothermic water gas shift reaction,

$$CO + H_2O \rightleftharpoons CO_2 + H_2 \qquad (3.1)$$

which usually proceeds to virtual equilibrium. Hence addition of carbon dioxide to the feedstock for reforming or gasification will result in a product with a reduced molar ratio of H_2 to CO. As discussed in Section 4 the increase in CO concentration also tends to increase carbon formation.

Under typical reforming conditions (e.g., as optimized for methanol synthesis) about 1/3 of the CO produced by reforming of methane, viz,

$$CH_4 + H_2O \longrightarrow CO + 3H_2 \qquad (3.2)$$

shifts to CO_2. As a result the syngas produced has an H_2:CO ratio of about 5:1. Extraction and recycling of the CO_2 produced (or import of the equivalent amount of CO_2) can yield a product with an H_2:CO ratio as low as 3:1. To lower the ratio further requires import of additional CO_2. However, as shown in Section 4, to approach H_2:CO ratios as low as 1:1, relatively large amounts of CO_2 need to be imported and recycled, and the cost penalty for this becomes increasingly severe. This holds even when the CO_2 is available at zero transfer value from an adjacent facility (e.g., ammonia manufacture). However, for relatively small scale operations like oxo synthesis, addition of CO_2 to the reformer feed to lower the H_2:CO ratio in a steam reforming facility was traditionally used (19520), and we understand is still practiced today.

Reforming of naphtha (empirical formula typically H/C = 2.1) gives syngases somewhat leaner in hydrogen than those obtained from natural gas reforming. Thus, complete recycle of the CO_2 produced gives a product for which the H_2:CO ratio approaches 2. Reforming of residual fuels is not practical because of the attack of the impurities on the reformer tubes.

In partial oxidation processes the greater part of the oxygen content of the product is supplied directly as oxygen rather than deriving from steam as in reforming. H_2:CO ratios of syngases produced by partial oxidation are thus characteristically much lower than those produced by steam reforming. Partial oxidation is a noncatalytic process carried out at high temperatures in refractory lined reactors. It is a very flexible process and facilities can be designed to process in the same unit feedstocks ranging from natural gas to vacuum residue. A partial oxidation unit currently under construction for a joint venture by Tenneco and USS Chemicals, for example, is reportedly to be fed with a mixture of natural gas and oxo synthesis by-products, with provisions for future conversion to residual oil feed (472204). The H_2:CO ratio of the partial oxidation reactor product is characteristically slightly below 2 for a natural gas feed, and approaches unity for the heavier liquid hydrocarbon feedstocks.

For the gasification (partial oxidation) of coals and lignites, characteristic H_2:CO ratios of the gasifier effluent are typically well below unity. For dry-feed slagging gasifiers the ratio is typically about 0.5. For gasifiers fed with a coal/water slurry, such as those in the Texaco process, the H_2:CO ratio of the gasifier products is somewhat higher. The relatively high ratios ($\leq$2) associated with "dry bottom" (nonslagging) Lurgi gasifiers result from the substantial amount of water gas shift taking place within the gasifier due to the large amounts of steam injected to keep the temperature of the bed below the fusion temperature of the coal.

The H_2:CO ratio in a syngas mixture can, of course, be altered independently of the primary generation process. The ratio can be readily increased by shifting some of the CO to H_2 by the water gas shift reaction. The ratio can be adjusted both up and down by splitting the mixture either into the pure components, or into an H_2 rich and a CO rich stream. Cryogenic, absorption, adsorption, and membrane processes are the primary techniques for such separation or "skimming."

The most common way of increasing the H_2:CO ratio is the water gas shift reaction (see equation 3.1 above). If desired, e.g., for hydrogen or ammonia manufacture, essentially all the CO in the syngas mixture can be shifted to H_2. [The shift reaction of course does not alter the total mols of ($CO + H_2$) in the product, only their ratio. Hence it is convenient in comparisons to deal with capacities and costs of syngases on the basis of the contained volume of ($CO + H_2$). Sometimes comparisons are done in terms of H_2 equivalents, which amounts to the same thing.]

Generally, increasing the H_2:CO ratio by shifting and incremental acid gas removal can be done relatively cheaply. In comparison, alteration of the ratio by CO_2 addition to the reactor feed, or by separating the components is relatively costly. The economics of the adjustment by separation are in addition very sensitive to the credit that can be assigned in any given instance to the coproduct (normally H_2 or an H_2 rich stream).

Partial oxidation and coal gasification processes yield raw syngases rich in CO. They are thus inherently well suited to provide syngas feedstocks for methanol. The coming generation of new processes for bulk chemicals which, as we shall see below, typically use H_2 and CO in a ratio of 2 or less.

The steam reforming process, on the other hand, yields syngases rich in H_2. It is thus very well suited for H_2 or ammonia production, but less well matched in terms of stoichiometry to provide, for example, methanol syngas. It is interesting that, as commercially developed, methanol synthesis from natural gas does not use anywhere near a stoichiometric syngas feed (see further below). The feed to the synthesis reactors is typically on the H_2 rich side, and a large H_2 rich purge is taken from the reactors to serve as fuel for the reforming furnaces. The synthesis reactors thus in effect also serve as a separation system for the syngas, and produce an H_2 rich coproduct stream which is credited at fuel value. It is likely that a somewhat different overall process configuration would have been developed against a background of much higher feedstock costs. In recent times, for example, separation of H_2 from the purge stream has become a more common practice. The inherent advantages of matching the feed makeup composition to reaction stoichiometry generally increase as feedstock costs increase.

Below we examine the overall stoichiometric requirements of a selection of syngas based processes.

Syngas Uses in General

Table 3.2 lists the major products traditionally made from syngas together with chemicals whose manufacture from syngas is considered to be both feasible and potentially attractive. A schematic of the routes from syngas for the latter is given in Figure 3.2. The listings are illustrative rather than comprehensive.

As is evident from the overview given further below, more often than not, it is the indirect routes that show the best selectivities and the most promise at the present state of the art. Typically these proceed via methanol as an intermediate and sometimes also require a carbonylation step.

Methanol and CO rather than the equivalent stoichiometric syngas are thus more frequently the actual feedstocks. It is for this reason that the economics of methanol production are centrally featured in

Table 3.2

SYNGAS USES

	H_2:CO[a] Ratio	Actual Ratio[b]	Capacity (MM lb/yr)	Syngas Required (MM scfd)[e] [f]	Technology Associated With:
Traditional uses					
Ammonia	H_2	$H_2 + N_2$	986[c]	107	—
Hydrogen	H_2	H_2	173	100	—
Methanol - via natural gas	2/1	4/1-5/1 + CO_2	1,449[d]	212[h]	--
via resid/coal	2/1	2.3/1 + CO_2	1,449[d]	160	—
Oxo alcohols	2/1	2/1 or (1/1 + H_2)	150	9	--
Phosgene	CO	—	150	2	--
Fischer-Tropsch liquids[g]	—	2/1	3,800	1,000	—
Nontraditional uses					
Acetic acid	1/1	Methanol + CO	600	49	Monsanto
Acetic anhydride	1/1	Methanol + CO	500	61	Eastman/Halcon
Vinyl acetate	1.25/1	Methanol + 0.5/1	500	87	Halcon
Ethylene glycol - direct	1.5/1	1.5/1	400	66	Union Carbide
oxalate	2/1	H_2 + CO	400	66	Ube/Union Carbide
Ethanol - direct	2/1	3.5/1 + CO_2	600[i]	345	IFP
homologation	2/1	Methanol + 2/1	1,677	320	—
Ethylene - direct (F-T)	1/1[m]	0.83/1	1,000[j]	795	Ruhrchemie
methanol cracking	2/1	Methanol	1,000[k]	530	Mobil
homologation	2/1	Methanol + 2/1	1,000[l]	320	—

(a) Stoichiometric ratio of hydrogen to CO required by net reaction sequence at a theoretical yield of 100%.

(b) The actual feedstocks used, e.g., (methanol + 0.5/1) means that the synthesis utilizes the syngas in the form of methanol and syngas with a hydrogen/CO ratio of 0.5/1.

(c) 1,500 short tons/day with a stream factor of 0.9.

(d) 2,000 metric tons/day.

(e) Basis contained (CO + H_2); MM represents a million, scfd is standard (60°F, 14.7 psia) cubic feet per day.

(f) Methanol converted to a 2:1 syngas equivalent of 80,000 scf/metric ton.

(g) Approximate values for Sasol 2.

(h) About 1/4 of the feed gas is recovered as a hydrogen rich fuel stream.

(i) About 1.75 lb of other alcohols are coproduced per lb of ethylene.

(j) About 1.4 lb of coproducts are made per lb of ethylene.

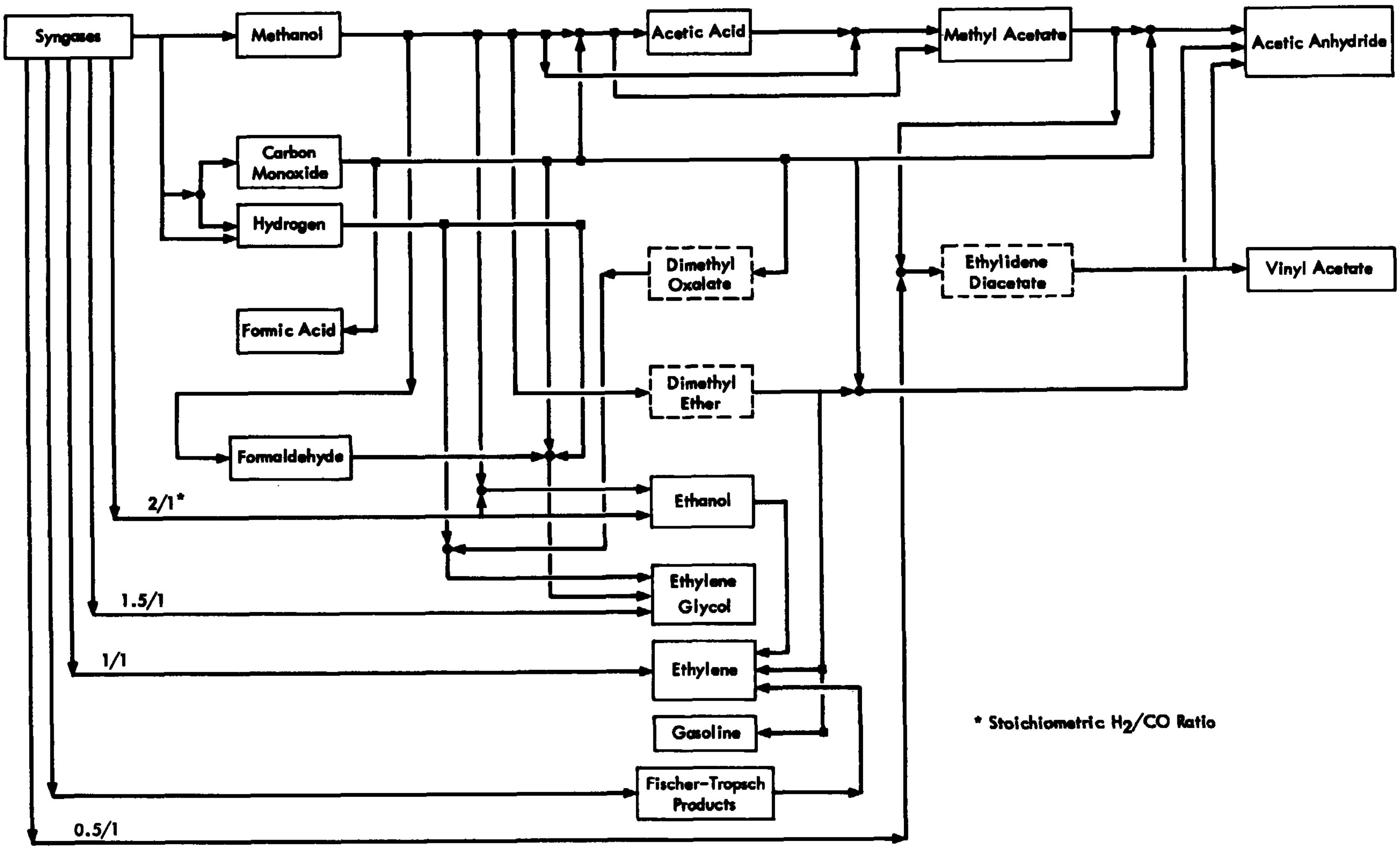
(k) About 1 lb of coproduct is made per lb of ethylene.

(l) Less than 0.2 lb of hydrocarbon coproducts are produced per lb of ethylene.

(m) Net reaction sequence includes an internal shift.

Figure 3.2

NONTRADITIONAL SYNGAS ROUTES TO BULK CHEMICALS



* Stoichiometric H_2/CO Ratio

this study, and options examined for separation of CO from syngases. Because hydrogen is frequently a coproduct, we included the economics of independent large scale hydrogen production primarily to enable better definition of the range of values that might be assigned to such coproduct.

Syngases derived from coal could also eventually provide the foundation for a synfuels industry, e.g., large methyl fuel facilities, or complexes producing medium Btu gas (MBG), power, and methanol as well as supplying feedstocks to satellite chemical production facilities. For example, an MBG complex proposed by the Tennessee Valley Authority (TVA) in the United States (483167) is rated for about 3 x 10^9 Btu per day and would produce some 1,000 million scfd of MBG. The rating of such a complex is equivalent to about 50,000 bbl/day of crude oil and would need 20,000 tons/day of coal. Alternatively, in a gasification/ combined-cycle (GCC) power plant, where a combination of steam and gas turbines is used to generate electricity, such a plant would produce about 2,000 megawatts (472138). The scale of syngas production in such complexes would thus be at or above the largest scale examined here, and allocation of costs between various coproducts as well as methods of financing, would be factors of major importance. For the present study we elected to focus on the production of syngas at scales at which it could be dedicated to bulk chemicals manufacture. Below we comment in more detail on the stoichiometry and scale of the processes listed in Table 3.2.

Traditional Uses

Methanol

As noted, methanol is the key to many of the proposed routes. Its manufacture from both natural gas and coal is therefore reviewed in some detail in Sections 4 and 6 respectively. Some features regarding the stoichiometry of its production are highlighted below.

State-of-the-art methanol processes as exemplified by the technologies developed by Lurgi and ICI, use copper based catalysts to produce methanol from syngas at 50 to 100 atm. The primary reaction, which is exothermic, is:

$$CO + 2H_2 \rightleftharpoons CH_3OH \quad (3.3)$$

In commercial operation, however, maintaining a minimum of some 3% CO_2 in the feed is essential for good catalyst performance and life (472045). The CO_2 appears to maintain the catalyst in an intermediate oxidized active state (487019). In addition the CO_2 reacts with hydrogen over the copper based catalysts to give methanol plus water:

$$CO_2 + 3H_2 \rightleftharpoons CH_3OH + H_2O \quad (3.4)$$

This reaction is reported to proceed to some extent directly, but mainly via a reverse shift (see equation 3.1).

In steam reforming of natural gas, typically one of every three mols of CO produced shifts to CO_2 in the reformer; this CO_2 is not removed from the methanol synthesis feed. In fact, if extra CO_2 is readily available at low cost (e.g., from adjacent ammonia facilities) it normally is attractive to compress some of this and add it either to the reformer feed, or even directly to the synthesis reactor feed. It follows from equations 3.3 and 3.4 that the stoichiometric usage of hydrogen which corresponds to an H_2:(2CO + $3CO_2$) ratio of 1, translates to an H_2:CO ratio of about 3.5, or greater if extra CO_2 is imported. This compares with the H_2:CO ratio of about 5 characteristic of natural gas reforming without CO_2 addition.

As noted above, because of the predominance of natural gas as a feedstock, methanol process designs are optimized in conjunction with steam reforming, i.e., to operate economically with the nonstoichiometric feed coming directly from reforming. (This is sometimes called the "low carbon concept.") Addition of CO_2, when available at low cost, improves the economics by saving about 5% of the total gas requirement. The advantage of CO_2 addition increases of course as the feedstock cost increases.

Syngas made by partial oxidation in contrast, is hydrogen lean with respect to methanol stoichiometry. Hence for methanol synthesis such gas is shifted and the CO_2 removed to give a close match to stoichiometry (H_2:CO ratio ≥ 2). It is advantageous to leave some CO_2 in the syngas (see above) and to run slightly on the hydrogen rich side.

The state-of-the-art maximum single line methanol capacity is somewhat above 2,500 metric tons/day. However, for potential methyl fuel or methanol-to-ethylene plants, operation at even larger scales would be attractive, and larger capacity methanol reactor designs are being developed and offered, e.g., 5,000 tons/day by Davy-McKee/Ammonia Casale (472205).

In terms of scale, the reformer of a 2,500 tons/day methanol unit run on the "low carbon concept" produces about 265 million scfd (7.1 million Nm^3/day) of syngas (basis contained CO and H_2). Roughly 1/4 of this is in effect returned as fuel to the reformer. With the approximately stoichiometric syngas produced by partial oxidation or gasification, about 200 million scfd yields 2,500 tons/day methanol.

Hydrogen

In the production of hydrogen via syngas, essentially all the CO in the mixture is shifted to CO_2 and hydrogen. The hydrogen thus derives in part from the basic feedstock and in part from steam. In all the routes (steam reforming, partial oxidation, and gasification) part of the shifting takes place in the syngas production reactor. Additional steam is then added and the shift reaction is completed, usually in high and low temperature stages. In large scale production the CO_2, and H_2S if present, are traditionally scrubbed out by appropriate regenerative liquid scrubbing processes. Residual carbon oxides are then removed by conversion to methane in a catalytic reactor (i.e., by "methanation," or the reverse of the shift and steam reforming reactions shown by equations 3.1 and 3.2). This gives a hydrogen product containing some methane and inerts (see Table 2.2). At small scales of production, e.g., <1 million scfd) the CO_2 removal and product purification steps are usually combined and performed in fixed bed adsorbers containing a combination of molecular sieves, alumina, and carbon (385148). However, use of a regenerated adsorption step (the Pressure Swing Adsorption, or PSA, process developed by Union Carbide) to replace the low temperature shift, CO_2 removal, and methanation steps also appears to be attractive in certain circumstances on a very much larger scale, particularly if very pure hydrogen is needed (see Section 4).

The steam reforming process is very flexible and lends itself to both small and large operations. Partial oxidation, on the other hand, is impractical for small scale operation (<5 million scfd). For gasification of coal the minimum scale of operation is probably even larger (>50 million scfd).

As shown in the tabulation earlier, the current major use of hydrogen is for ammonia production. A world scale plant typically produces 1,500 short tons/day of ammonia and requires slightly above 100 million scfd of hydrogen. The next largest use of hydrogen is in refinery operations (e.g., for desulfurization, hydrocracking). Capacities for such plants are usually 50 to 100 million scfd. The size of facilities being envisaged for synfuels manufacture by direct coal liquefaction (e.g., EDS, SRC-II) is often about 50,000 barrels/day. They typically require 200 to 300 million scfd of hydrogen.

The interest in the present study was not in hydrogen manufacture per se. However, hydrogen is a major coproduct in the schemes examined here for the production of CO and the adjustment of the H_2:CO ratio of syngas by skimming and separation. The value assigned to the hydrogen coproduct is thus a principal determinant of the cost of the syngas or CO produced. The economics of the independent large scale manufacture of hydrogen from natural gas, vacuum residue, and coal were therefore estimated in order to provide a reference basis for assigning hydrogen credits. The standard default value used in the SYNCOST program for hydrogen is that estimated for production of hydrogen by reforming of natural gas at a capacity of 100 million scfd. On the basis of the default scenario used in the present study, steam reforming of natural gas remains the most economic process to the year 2000 for direct hydrogen production.

Ammonia

The final step in the manufacture of ammonia is the well known exothermic ammonia synthesis reaction represented by the deceptively simple equation:

$$3H_2 + N_2 \rightleftharpoons 2NH_3 \tag{3.5}$$

Commercial catalysts are based on iron and conventionally the synthesis loop is operated at 2000 to 4000 psi. More energy efficient designs operating at pressures as low as 500 psi have also been developed in recent years.

The reactor feedstock contains hydrogen and nitrogen in the stoichiometric 3:1 ratio and is itself also known as a syngas. Production of ammonia syngas is broadly analogous to the production of hydrogen, but the detailed designs differ in some key respects. When the ammonia syngas is made by steam reforming of natural gas, the optimal design entails reforming in two stages. In the primary reformer, conditions are less severe than for hydrogen production because a high methane "slip" is allowable (see Section 4 for details on reforming). The methane remaining in the product from the primary reformer is converted in a secondary reformer, where part of the product is burned with air to provide heat as well as the nitrogen needed for ammonia synthesis. Following reforming, the product is subjected to high and low temperature shift, scrubbed free of CO_2 and methanated to remove traces of carbon oxides. It is then compressed and sent to the ammonia synthesis loop.

When partial oxidation (gasification) is used to produce the hydrogen, nitrogen in a pure state is available from the air separation unit used to provide the oxygen. The methanation stage is then omitted. Instead, the final purification of the hydrogen is done with molecular sieves to remove traces of CO_2, followed by a liquid nitrogen wash to remove CO, CH_4, and most of the argon. More nitrogen gas is then added to arrive at the correct hydrogen/nitrogen ratio before the gas is compressed for ammonia synthesis. The removal of inert gases by the nitrogen wash is an advantage for the synthesis step because the purge stream is reduced to a minimum. A coal based plant is operated in this fashion by AECI Ltd. in South Africa (472190).

A 1,500 short tons/day ammonia plant is typical of state-of-the-art world scale facilities. The amount of hydrogen fed to the synthesis loop in a conventional reaction scheme at this scale would be more than 100 million scfd (see PEP Report 44A, on Ammonia).

The present study emphasizes the economics of producing syngases with low H_2:CO ratios. Production of ammonia, which lies at the other end of the scale of H_2:CO ratios, was therefore excluded from more detailed examination, despite ammonia's status as the major user of syngas.

Oxo Alcohols and Derivatives

Oxo alcohols are produced by first reacting (hydroformylating) an olefin with a syngas (H_2 + CO) to form an aldehyde. Simultaneously in the same reactor, or during subsequent processing, the aldehyde or a derivative of it, is hydrogenated to form an oxo alcohol.

Major applications of this use propylene as a feedstock to manufacture normal butanol, and 2-ethylhexanol (2-EH). n-Butanol is used widely as a solvent, and 2-EH is used in the manufacture of phthalate plasticizers for PVC. The stoichiometry of the main reactions is represented by:

(1) **Hydroformylation--**

$$CH_3CH = CH_2 + CO + H_2 \longrightarrow \underset{\text{n-butyraldehyde}}{CH_3CH_2CH_2CHO} \tag{3.6}$$

$$+$$

$$\begin{array}{l} CH_3 \\ \quad \diagdown \\ \qquad CHCHO \\ \quad \diagup \\ CH_3 \end{array}$$

$$\text{isobutyraldehyde}$$

(2a) **Hydrogenation--**

$$CH_3CH_2CH_2CHO + H_2 \longrightarrow \underset{\text{n-butanol}}{CH_3CH_2CH_2CH_2OH} \tag{3.7}$$

(2b) **Aldol condensation and hydrogenation--**

$$2CH_3CH_2CH_2CHO \longrightarrow CH_3CH_2CH_2CH = \underset{\substack{| \\ CH_2CH_3}}{C} - CHO + H_2O \tag{3.8}$$

$$\text{2-ethylhexenal}$$

$$\text{(2-ethylhexenal)} + 2H_2 \longrightarrow CH_3CH_2CH_2CH_2 - \underset{\substack{| \\ CH_2CH_3}}{CH} - CH_2OH \tag{3.9}$$

$$\text{2-ethylhexanol}$$

Sequence 2b takes place in the presence of alkali. Three different catalytic systems are used industrially to carry out the reactions:

Catalyst	Licensor	Type	Syngas Required
Conventional cobalt	Ruhrchemie	Two step, high pressure (5000 psi)	1:1 gas + hydrogen
Modified cobalt/ phosphine	Shell	One step, medium pressure (1500 psi)	2:1 gas
Rhodium	Union Carbide et al.	Two step, low pressure (300 psi)	1:1 gas + hydrogen

In the one step process (modified cobalt/phosphine catalyst) both hydroformylation and hydrogenation, i.e., steps 1 and 2a or 2b take place in a single reactor. The simplified stoichiometry therefore requires a syngas feed with an H_2:CO ratio of 2:1. Side reactions such as hydrogenation of olefin to paraffin and aldehyde to alcohol consume extra hydrogen; therefore, in practice, a somewhat higher H_2:CO ratio is used. A PEP evaluation for such a process (PEP Report 21B, p. 51) was based on an actual ratio of 2.06:1 in the syngas feed.

In the two step process the hydroformylation and hydrogenation steps are carried out separately, and the simplified stoichiometries shown would require a syngas with an H_2:CO ratio of 1:1 for the first stage, and pure hydrogen for the second stage. Again, because of side reactions, in practice an H_2:CO ratio somewhat above 1:1 is used. In a PEP evaluation of the rhodium catalyst technology (Report 21B, p. 79) the design was based on a feed with an H_2:CO ratio of 1.09:1.

There are also several process developments for the production of methyl methacrylate from both ethylene and propylene by a variety of direct and indirect hydroformulation reactions using, for example, methyl propionate and isobutyric acid intermediates (PEP Report 11B). Typically the stoichiometric requirement is for a 1:1 ratio syngas, or for carbon monoxide and methanol.

In terms of oxo chemicals, facilities producing, for example, 150 million lb/yr of butanol would be considered world scale. A one stage process requires 9.4 million scfd of syngas with an H_2:CO ratio of 2:1. A two stage process requires 5.6 million scfd of a 1:1 syngas and 2.6 million scfd of hydrogen.

Thus, in the present context, world scale facilities for oxo chemicals are very small users of syngas. Production of syngas in dedicated facilities matching oxo synthesis size would therefore be relatively expensive. However, the syngas feedstock represents, for example, only about 20% of the product value of, the n-butanol produced. Hence minimizing the syngas cost may not always be a prime consideration in oxo manufacture.

The present study concerns the economics of producing syngases with the H_2:CO ratios typical of oxo synthesis. However, the study context is that of the new generation of processes for bulk chemicals which require syngas production on a much larger scale. Some discussion on scaling down to the "oxo scale" is included in Section 4. In general, though, any extrapolation of the study data to much lower scales is likely to be highly inaccurate.

Phosgene and Miscellaneous Carbonylations

Phosgene is made by passing dry carbon monoxide and chlorine over hot activated charcoal:

$$CO + Cl_2 \longrightarrow COCl_2 \qquad (3.10)$$

The primary use of phosgene is in the manufacture of isocyanates, most of which are used for polyurethanes. A world scale facility typically produces 150 million lb/yr of phosgene and requires 45 million lb/yr or some 1.85 million scfd of carbon monoxide--in the present context a very small scale of production.

Other even smaller scale uses include the Reppe & Koch hydrocarboxylations which react carbon monoxide and water with olefins to produce various carboxylic acids used in plasticizers and synthetic lubricants (see also PEP Report 123, Section 4).

Fischer-Tropsch Synthesis

The Fischer-Tropsch synthesis using a traditional iron based catalyst is used by Sasol in South Africa to produce motor fuels with chemicals as by-products. The well publicized and recently commissioned Sasol Two unit is reported to produce about 40,000 barrels/day of motor fuels and some 600,000 tons per year of chemical by-products including 160,000 tons/yr of ethylene. Feedstock to the synthesis reactors is some 1,000 million scfd of 2/1 syngas produced by 36 Lurgi coal gasifiers (472093). An almost identical Sasol Three is nearing completion.

The Sasol developments represent a special case, in which security of supply rather than economic competitiveness has been the dominant influence. Nevertheless they demonstrate coal gasification technology on a large scale, and establish a reference point for costs at the current state of the art.

Fuel Gas

Gasification of coal in small scale producers is well established and has been widely practiced worldwide. Such gasifiers typically operate at close to atmospheric pressure, use air as the oxygen source, and produce a low Btu gas (LBG) with a fuel value of about 150 Btu/scf. Standard units might be sized to produce about 1.5 billion Btu/day of LBG from 100 tons/day of coal. They are currently being promoted on the basis of favorable economics for localized fuel supply in special circumstances (472207).

Nontraditional Uses

A large amount of research in recent years has been devoted to developing improved routes from syngas to chemicals and fuels. The prime driving force has been the steep rise in the price of oil. However, particularly for oxygenated chemicals such as acetic acid and ethylene glycol, the syngas routes often have an inherent elegance which can also have the potential to translate into economic advantage, the key to which appears to lie in finding highly selective catalyst systems and processing routes.

Conventional Fischer-Tropsch (F-T) technology enables the production of a wide spectrum of products directly from syngas. The F-T mechanism has generally been interpreted in terms of polymerization of a C_1 unit. This would mandate that for species other than methane and methanol, the selectivity is and has to remain relatively low, and such low selectivities do occur in practice. To overcome this limitation much effort has been devoted both to modification of F-T catalysts and to the development of alternative catalysts. An alternative means to improve selectivity has been to use methanol as an intermediate. The downstream processes often use the novel shape-and-size-selective zeolite catalysts. A perspective on recent catalyst developments is given in reference 470082. Below we briefly review the scale and stoichiometries entailed in the developments listed in Table 3.2. The listing is not comprehensive, but covers the major developments that would use syngas on a large scale and appear to have good potential for commercialization.

It is apparent that in general the stoichiometric requirements are for syngases with a H_2:CO ratio of 2:1 or less. Regarding stoichiometry, therefore, partial oxidation of residue and coal gasification processes have an inherent advantage. However, the extent to which some processes might also be able to use CO_2 as well as CO, and be run with nonstoichiometric feedstocks is generally not clear. It is also seen that the scales of operation of individual units are usually below the sizes at which full advantage can be taken of the economies of scale of syngas generation. The latter would favor production complexes which integrate a number of different units using syngas feedstocks.

Acetic Acid and Formic Acid

Since Monsanto introduced the low pressure carbonylation process for acetic acid in 1970 (see PEP Review 78-3-4), industry acceptance of the process has been very rapid. Worldwide about one-third of acetic acid production is now based on this process and most new capacity is expected to follow suit.

The overall reaction is an exothermic one represented by:

$$CH_3OH + CO \longrightarrow CH_3COOH \qquad (3.11)$$

It is conducted at pressures of 400 to 1000 psi with homogeneous iodide promoted rhodium catalysts, in the presence of water. Other conditions and catalysts can favor formation from the same reactants of methyl acetate (itself an intermediate in the acetic acid synthesis), or methyl formate. With similar catalysts and somewhat higher pressures, acetic acid can also be homologated to give higher carboxylic acids such as propionic, butyric, and valeric (472209), e.g.;

$$\underset{}{CH_3COOH + CO + 2H_2} \longrightarrow \underset{\text{propionic acid}}{CH_3CH_2COOH} + H_2O \qquad (3.12)$$

The purity requirements of the feedstocks for acetic acid manufacture are not overly stringent, e.g., typical feed compositions might be:

Methanol Feed	Wt%
Methanol	99.9
Water	0.1
Total	100.0

CO Feed	Vol%
CO	98.0
N_2	1.0
H_2	0.6
CO_2	<5 ppm
CH_4	0.4
Total	100.0

Methyl formate production, on the other hand, appears to be somewhat more sensitive to impurities (see PEP Report 156). The net reaction here is:

$$CH_3OH + CO \longrightarrow HCOOCH_3 \qquad (3.13)$$

This reaction is the basis for the processes for formic acid offered by BASF, Leonard, and Halcon/SD. It takes place under anhydrous conditions in the presence of alkali methoxide catalysts. Pressures used for commercial operation are somewhat higher than for acetic acid manufacture. In a second step the methyl formate is catalytically hydrolyzed to yield formic acid and methanol:

$$HCOOCH_3 + H_2O \longrightarrow HCOOH + CH_3OH \qquad (3.13a)$$

The net reaction therefore consumes only carbon monoxide and water to produce formic acid. One of the main reasons for interest in a direct process for formic acid stems from the trend to switch to the Monsanto process for acetic acid. Formerly the bulk of formic acid was produced as a by-product in the manufacture of acetic acid by the oxidation of butane. Formic acid by a direct process is, of course, made on a much smaller scale than acetic acid, and for optimum economics the CO production would need to be integrated in a complex such as described further below. (A large unit would produce some 44 million lb/yr of formic acid and consume about 1.5 million scfd of CO.)

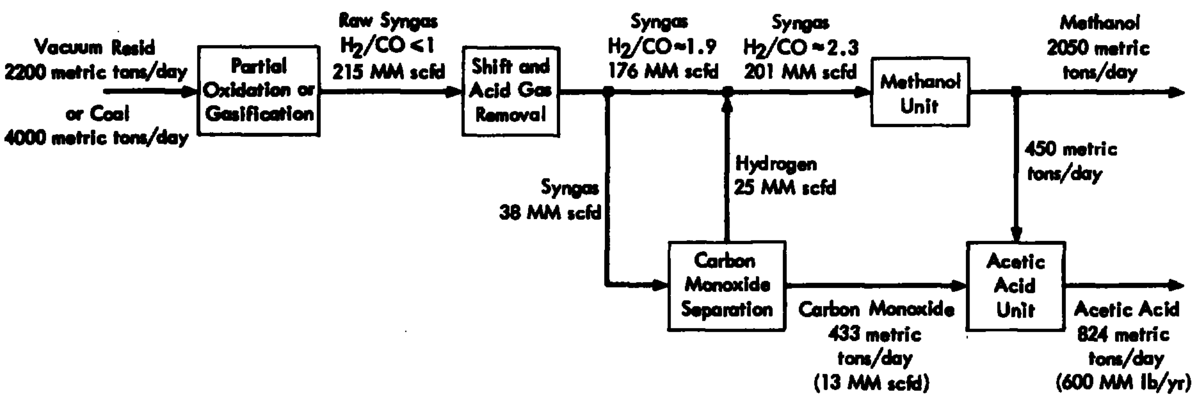
The most recently commissioned grassroots world scale acetic acid plant is that for the Du Pont/USI venture at Deer Park in Texas. In this complex, syngas produced from a heavy sour residue by partial oxidation is used to manufacture both methanol and acetic acid. The acetic acid unit is reportedly rated for some 600 million lb/yr, and would therefore consume about 450 metric tons/day of methanol and 315 million lb/yr (12.8 million scfd) of CO.

If one includes methanol, the overall stoichiometry of equation 3.11 requires hydrogen and CO in a ratio of 1:1. Effective utilization of the syngas is therefore readily achieved if the syngas is produced by gasification of either resid or coal. One possible way of integrating a methanol-acetic acid complex based on such feedstocks is illustrated in Figure 3.3. The flowrates and H_2:CO ratios shown are approximate. The hydrogen stream produced in the CO separation unit can be blended back into the methanol synthesis feed to maintain optimum stoichiometry. Syngas produced by steam reforming of natural gas, on the other hand, is already hydrogen rich. Hence unless there is a chemical use for hydrogen on a site, e.g., refinery processing or ammonia manufacture, any hydrogen separated out might only have fuel value. In such circumstances it could sometimes be more economic to have a separate partial oxidation unit to produce the syngas for CO recovery.

The scheme shown on Figure 3.3 is one for which approximate feedstock costs could be estimated by combining a set of modules from the SYNCOST program. In practice, some cost advantage might be gained by purifying a fraction of the raw syngas separately as feedstock for the CO separation unit.

Figure 3.3

SCHEMATIC OF METHANOL/ACETIC ACID COMPLEX



Acetic Anhydride

New syngas routes to acetic anhydride have received much publicity in recent years, in part because of the decision by Tennessee Eastman to commercialize a new technology using coal based syngas as feedstock (472211). This new route is based on the carbonylation of methyl acetate, which itself can be derived in toto from syngas. The fact that the syngas will be made by gasification of coal is, in a sense, incidental. However, the general interest in the venture has been much intensified by the coal feedstock aspect, and the fact that it will provide the first commercial demonstration of the second generation Texaco gasification technology. The coal based plant at Kingsport, Tennessee, is due to be completed in 1983.

At present, most acetic anhydride is made by the ketene route. In this, acetic acid is cracked to form ketene, which is reacted with another mol of acetic acid to form acetic anhydride. If the acetic acid is made from methanol and carbon monoxide, the ketene route itself can also be considered to be a syngas route. A comparison of the ketene and methyl acetate carbonylation routes is given in the recent PEP report, Bulk Chemicals from Synthesis Gas (No. 146). SRI concluded that the new route compares favorably with the established ketene route.

Both Eastman and Halcon/SD have been active in developing variations of the new process based on carbonylation of methyl acetate. The know-how of both parties was eventually pooled for the commercial venture. Early Halcon patents also describe the use of dimethyl ether as an intermediate, together with methyl acetate, or singly. Later work appears to have focused on methyl acetate. The most active catalyst systems are rhodium based with iodide promoters similar to those for acetic acid synthesis.

The chemistry of the methyl acetate carbonylation is complex and there are several variations of the basic technology. The stoichiometry of the overall sequence starting from syngas can be represented by:

(a) Methanol synthesis--

$$2CO + 4H_2 \longrightarrow 2CH_3OH \qquad (3.3)$$

(b) Acetic acid synthesis--

$$CH_3OH + CO \longrightarrow CH_3COOH \qquad (3.11)$$

(c) Esterification to methyl acetate--

$$CH_3COOH + CH_3OH \longrightarrow CH_3COOCH_3 + H_2O \qquad (3.14)$$

(d) Methyl acetate carbonylation--

$$CH_3COOCH_3 + CO \longrightarrow (CH_3CO)_2O \qquad (3.15)$$

(e) Net reaction to acetic anhydride--

$$4CO + 4H_2 \longrightarrow (CH_3CO)_2O + H_2O \qquad (3.16)$$

The net stoichiometry thus requires carbon monoxide and hydrogen in a 1:1 ratio. The sequence as shown above achieves this indirectly with methanol and carbon monoxide.

Tennessee Eastman uses the anhydride to esterify cellulose. This produces acetic acid and substitutes for step b. Halcon/SD emphasizes that it is also possible to have a manufacturing sequence which entails no acetic acid--the methyl acetate is supplied instead by making twice the amount of anhydride in step d, and recycling half of this to be reacted with methanol (472210):

$$(CH_3CO)_2O + 2CH_3OH \longrightarrow 2CH_3COOCH_3 + H_2O \qquad (3.17)$$

The net stoichiometry remains unchanged.

A world scale plant would manufacture about 500 million lb/yr acetic anhydride. For sequences b through d, such a plant would require some 245 metric tons/day of methanol, 417 metric tons/day of acetic acid, and 235 metric tons/day (about 7 million scfd or 170 million lb/yr) of carbon monoxide. The figures for methanol and carbon monoxide are approximately double if the amounts needed for acetic acid are included.

However, dedicated units would still fall substantially short of world scale capacities for the various intermediate feedstocks; integration with other syngas based units would be of advantage. Apparently, the use of coal rather than natural gas for syngas generation in the Eastman project is a site specific consideration.

Vinyl Acetate

A route to vinyl acetate based on the carbonylation of methyl acetate is being offered by Halcon/SD for commercial application. The technology is related to the acetic anhydride synthesis discussed above. The current conventional route to vinyl acetate is the vapor phase reaction of ethylene and acetic acid.

The overall stoichiometry of the carbonylation route when starting from syngas may be represented by:

(a) Methanol synthesis--

$$2CO + 4H_2 \longrightarrow 2CH_3OH \tag{3.3}$$

(b) Esterification--

$$2CH_3COOH + 2CH_3OH \longrightarrow \underset{\text{methyl acetate}}{2CH_3COOCH_3} + 2H_2O \tag{3.17}$$

(c) Hydrocarbonylation--

$$2CH_3COOCH_3 + 2CO + H_2 \longrightarrow \underset{\substack{\text{ethylidene}\\\text{diacetate}}}{(CH_3COO)_2CHCH_3} + \underset{\substack{\text{acetic}\\\text{acid}}}{CH_3COOH} \tag{3.18}$$

(d) Cracking--

$$(CH_3COO)_2CHCH_3 \longrightarrow CH_3COOH + \underset{\substack{\text{vinyl}\\\text{acetate}}}{CH_3COOCH{:}CH_2} \tag{3.19}$$

(e) Net reaction--

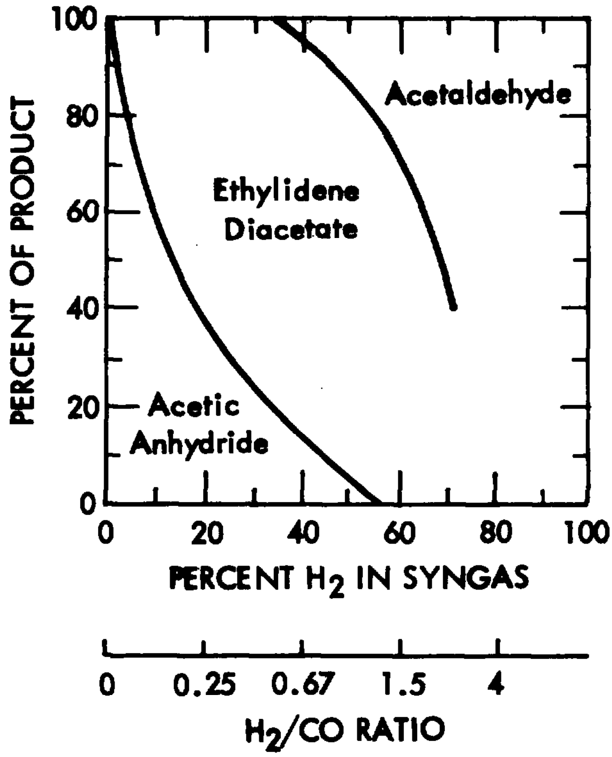
$$4CO + 5H_2 \longrightarrow CH_3COOCH{:}CH_2 + 2H_2O \tag{3.20}$$

The chemistry is complex and no detailed analysis of the reaction mechanisms has been published. The same catalysts (e.g., iodide and phosphene promoted palladium acetate) can be used in the carbonylation step to make both ethylidene diacetate (EDA) and acetic anhydride. The product distribution is then very much influenced by the H_2:CO ratio, as illustrated in Figure 3.4. This also indicates why it is relatively easy to produce acetic anhydride highly selectively, but more difficult to attain high selectivities to EDA or vinyl acetate. A link between acetic anhydride and EDA is that EDA decomposes not only as per equation 3.19, but also to produce anhydride and acetaldehyde:

$$(CH_3COO)_2CHCH_3 \longrightarrow (CH_3CO)_2O + CH_3CHO \qquad (3.21)$$

Figure 3.4

TYPICAL PRODUCT DISTRIBUTIONS IN
REACTION OF METHYL ACETATE WITH SYNGAS



Source: 472208.

The net stoichiometric requirement of the sequence of reactions a through d is for a syngas with a 1.25:1 ratio of hydrogen to carbon monoxide, being used as methanol and a 0.5:1 H_2:CO ratio syngas.

We understand that some of the key patents relating to this technology have as yet not been published. Our screening of the carbonylation route on the information available to date (see PEP Report 146) indicates that, in comparison with the conventional route, the competitiveness of the process at present may be marginal at best. Advantageously priced syngas from a large complex would certainly be required. The evaluation was for a base case unit to produce 500 million lb/yr of vinyl acetate, together with substantial acetaldehyde coproduct. The feedstock requirements were 703 metric tons/day of methanol and some 31 million scfd of syngas with an H_2:CO ratio of 0.58:1.

Ethylene Glycol

Ethylene glycol is currently produced from ethylene by the traditional ethylene oxide hydration route. However, up to 1968 Du Pont produced it commercially via a syngas route, and a variety of syngas routes are now under active development. A direct synthesis is inherently the most attractive, but indirect routes at present show better prospects for commercialization in the medium term.

Direct Route

The stoichiometry of the direct route is enchantingly simple:

$$2CO + 3H_2 \longrightarrow \begin{array}{c} CH_2OH \\ | \\ CH_2OH \end{array} \qquad (3.22)$$

Union Carbide has been prominent in developing such a route, and during the 1970s filed some fifty patents relating to it. The Union Carbide process uses homogeneous rhodium catalysts and is considered to represent a key advance in that it overcomes the selectivity limitations of conventional Fischer-Tropsch catalysis (470082). At optimum conditions a selectivity of 70% to ethylene glycol has been obtained. However, despite its potential attractiveness, a commercially viable technology remains elusive. The main problems relate to the poor activity of the noble metal catalysts (which necessitates high pressures), and to catalyst recovery.

The stoichiometry for this process requires syngas with an H_2:CO ratio of 1:5. A typical world scale facility produces some 400 million lb/yr ethylene glycol and would have a potential syngas requirement of about 66 million scfd.

Glycolic Acid Route

One indirect route is a three step process in which formaldehyde is hydrocarboxylated to glycolic acid, which is then esterified and reduced with hydrogen, the net reaction being:

$$HCHO + 2H_2 + CO \longrightarrow (CH_2OH)_2 \qquad (3.23)$$

This route represents the commercial technology once practiced by Du Pont. In recent years Chevron has patented improvements to the process. However, various screening evaluations to date have indicated that it is unlikely to be competitive at current price relativities, but may have potential over the longer term.

Oxalate Route

Ethylene glycol can be made in two steps from syngas by forming and hydrogenating a dialkyl oxalate. Recently, Union Carbide Corporation and Ube Industries announced the signing of an agreement for joint development of such a route. The most recent PEP evaluation of this found it attractive in comparison with the currently established route entailing hydration of ethylene oxide (see PEP Review 81-2-1, Ethylene Glycol via Oxalate Esters).

Several variations of the oxalate formation have been patented, but the most attractive appears to be a gas phase reaction between carbon monoxide and the methyl ester of nitrous acid over a catalyst of solid palladium on carbon. The total reaction sequence to ethylene glycol may be represented by:

(a) Oxalate synthesis--

$$\underset{\text{methyl nitrite}}{2CO + 2CH_3ONO} \longrightarrow \underset{\text{dimethyl oxalate}}{\begin{array}{l} COOCH_3 \\ | \\ COOCH_3 \end{array}} + \underset{\text{nitric oxide}}{2NO} \qquad (3.24)$$

(b) Nitrite synthesis--

$$2NO + 2CH_3OH + 1/2\ O_2 \longrightarrow 2CH_3ONO + H_2O \qquad (3.25)$$

(c) Hydrogenation--

$$\begin{array}{l} COOCH_3 \\ | \\ COOCH_3 \end{array} + 4H_2 \longrightarrow \begin{array}{l} CH_2OH \\ | \\ CH_2OH \end{array} + 2CH_3OH \qquad (3.26)$$

(d) Net reaction--

$$2CO + 4H_2 + 1/2\ O_2 \longrightarrow \begin{array}{l} CH_2OH \\ | \\ CH_2OH \end{array} + H_2O \qquad (3.27)$$

The stoichiometry therefore requires syngas with an H_2:CO ratio of 2:1, separated into the components.

A 400 million lb/yr plant is estimated to require about 18.5 million scfd of carbon monoxide and 37 million scfd of hydrogen. In addition, the process would consume some 145 metric tons/day of methanol to give by-product methyl formate and dimethyl carbonate.

Ethanol

Research on both direct and indirect synthesis of ethanol from syngas is being actively pursued by a number of companies. Potential large scale end uses are as feedstock for ethylene and as a fuel.

Direct Routes

The direct synthesis is an exothermic reaction which takes place over a number of catalysts:

$$4H_2 + 2CO \longrightarrow CH_3CH_2OH + H_2O \tag{3.28}$$

One such route has been under development by Union Carbide. It entails reaction over a rhodium based catalyst at pressures of 1000 to 2500 psi. The economics of this process were screened in PEP Report 53A and found to be unattractive. The main problems relate to poor selectivity and the large amounts of rhodium catalyst required.

Another possible route can be identified in the patents originating at the Institut Francais du Petrole (IFP). This process uses a copper-cobalt catalyst at moderate pressures ($<$1000 psi) and is in many ways similar to conventional methanol synthesis. The intent of the IFP work appears to be to produce a methanol/butanol gasoline extender. This is achieved by using the IFP process to produce C_4+ alcohols at low conversions and passing unreacted syngas to a conventional methanol synthesis. However, the process can be adjusted to produce ethanol as a primary product. As in methanol synthesis, the CO_2 also reacts directly and via reverse shift to give:

$$6H_2 + 2CO_2 \longrightarrow CH_3CH_2OH + 3H_2O \tag{3.29}$$

Our evaluation was for the substantial scale of 600 million lb/yr. By analogy to methanol synthesis, the design was based on a nonstoichiometric, hydrogen rich feed with an H_2:CO:CO_2 ratio of 7:2:1. The estimated requirement of syngas was about 345 million scfd (basis contained $CO + H_2$). About 1.75 lb of other alcohols are coproduced per lb of ethanol.

We concluded that such a route could become attractive in the 1990s given somewhat optimistic assumptions for coal based chemistry (see the conclusion of this section). However, recent industry feedback indicates that there are serious problems in maintaining catalyst activity in such a system.

Indirect Route

The reaction of methanol with syngas to produce ethanol was discovered by the U.S. Bureau of Mines in the 1950s and is generally referred to as "homologation."

The overall stoichiometry is as follows:

- Methanol synthesis--

$$CO + 2H_2 \longrightarrow CH_3OH \qquad (3.3)$$

- Homologation--

$$CH_3OH + 2H_2 + CO \longrightarrow CH_3CH_2OH + H_2O \qquad (3.30)$$

Thus, a 2:1 ratio syngas is required in each of the steps. The catalysts used in homologation are typically halogen promoted oxo catalysts, and pressures of about 4000 psi are required. The potential of this technology was evaluated in PEP Review 80-1-3 in the context of a syngas route to ethylene. At the given state of the art, the corrosive environment and high pressures of the process resulted in very high capital requirements per unit of product. The prospects for this processes were therefore not highly rated.

Ethylene

Perhaps the most intriguing question is whether ethylene might be commercially produced from syngas or methanol within the next decade. The scale of syngas and methanol plants dedicated to ethylene manufacture would match the largest base case sizes considered in the present report.

PEP Report 146, Bulk Chemicals from Syngas, reviewed and evaluated both a direct route from syngas via modified Fischer-Tropsch synthesis (Ruhrchemie), and an indirect route via steam cracking of methanol (Mobil). Some comments on the potential attractiveness of these routes are given further below.

Direct Route--Modified Fischer-Tropsch

The stoichiometry of the direct synthesis of ethylene from syngas may be represented by:

$$4H_2 + 2CO \longrightarrow C_2H_4 + 2H_2O \tag{3.31}$$

However, the iron based catalysts used for this F-T reaction are also good shift catalysts, so that typically some one-third of the CO shifts to CO_2:

$$CO + H_2O \longrightarrow CO_2 + H_2 \tag{3.1}$$

The net stoichiometry is therefore:

$$3H_2 + 3CO \longrightarrow C_2H_4 + H_2O + CO_2 \tag{3.32}$$

It requires syngas with an H_2:CO ratio of 1:1 rather than the 2:1 ratio needed by the synthesis reaction itself.

At practical temperatures and pressures, ethylene is not the thermodynamically favored product. However, in F-T synthesis, thermodynamic equilibrium is reached slowly and it is possible to limit both chain growth and hydrogenation and thus increase the yield of the short chained olefins by modification of the catalysts, e.g., by promotion with titanium.

The PEP evaluation of the direct synthesis concluded that potentially the direct synthesis would be the most attractive of the various routes. However, this conclusion derived from a design based on laboratory bench scale data. In practice, a loss of selectivity on scale-up appears to be a problem. Considerable uncertainty is associated with this and other assumptions made to arrive at a practical design on a commercial scale.

The evaluation was based on the use of a syngas with an H_2:CO ratio of 0.83. A billion lb/yr ethylene plant was estimated to require 795 million scfd of syngas. Some 1.4 lb of C_3+ coproducts are produced in the process for each lb of ethylene.

Indirect Route—Methanol Homologation

The steps required to produce ethanol were noted above. The dehydration of ethanol is not a new process, and is, in fact, practiced commercially in developing countries such as India and Brazil. The dehydration is endothermic and can be represented by:

$$C_2H_5OH \longrightarrow C_2H_4 + H_2O \tag{3.33}$$

The reaction takes place over silica-alumina and other catalysts. Diethyl ether is formed as an intermediate.

For a 1 billion lb/yr ethylene plant some 320 million scfd of syngas with a 2:1 H_2:CO ratio would be needed to make the required amount of ethanol. The overall process produces relatively small amounts of coproducts. As noted above, our screening evaluations of the process have found it to be unattractive.

Indirect Route—Methanol Cracking

Ethylene is produced from methanol as follows:

$$2CH_3OH \longrightarrow \underset{\text{dimethyl ether}}{CH_3OCH_3} + H_2O \longrightarrow C_2H_4 + 2H_2O \qquad (3.34)$$

The reaction takes place over the new class of molecular-shape-selective zeolite catalysts at low pressures (about 15 psig) and moderate temperatures (about 700°F). In practice the distribution of the light products is somewhat similar to that from gas oil cracking, with ethylene comprising about one-half, and propylene about one-quarter of the weight of hydrocarbons formed. Mobil Oil has been prominent in the development of the basic technology, which is closely related to its methanol-to-gasoline process (MTG). The end products depend in part on the pore size of the zeolite. Gasoline (aromatics) production requires larger pores than does olefins production.

A 1 billion lb/yr ethylene plant would require about 4.8 lb/lb or some 6,600 metric tons/day of methanol. The equivalent 2:1 syngas requirement would be about 530 million scfd. About 1 lb of co-products is produced per lb of ethylene.

Though questions remain about the optimal design, e.g., fluid compared with fixed beds, the development of this technology appears to be well advanced. A commercial plant based on the fixed bed version of the related MTG process is under construction in New Zealand, and a fluid bed MTG plant is being constructed on a pilot scale. Several major companies are developing the smaller pore zeolites preferred for ethylene production. It is thus likely that technology could be ready for commercialization of methanol cracking by the middle of the 1980s. Some comments relating to the probability of this happening are given in the following paragraphs.

Conclusions

In addition to the processes which have traditionally been based on syngas, the Monsanto process for acetic acid has been highly successful, and the Eastman/Halcon technology for acetic anhydride is about to undergo demonstration on a commercial scale.

For the other processes being developed, the economics are generally not competitive at present relative prices of petroleum products and syngas derived from natural gas (basis a trendline uncontrolled price equivalent to that of fuel oil). A major driving force for these developments has been the perception that crude oil prices are likely to continue escalating over the longer term faster on average than the costs of construction and the price of coal. Given this, at some point in time syngas (or methanol) made from coal or low cost natural gas will become a competitive feedstock for manufacture of many of the chemicals noted above. The biggest impact on the industry would be if this were the case regarding production of ethylene.

In PEP Report 146 (Bulk Chemicals from Synthesis Gas) illustrative economics were presented comparing the costs of ethylene production from coal via methanol cracking (dehydration) with the costs of ethylene from gas oil cracking. The scenario used was an "optimistic" one for coal based chemicals, i.e., a 2.5%/yr real escalation in crude oil prices from third quarter of 1980 onward, compared with zero real escalation in capital costs, with coal escalating at 1%/yr in real terms. Also somewhat optimistic values were assigned to the production costs of methanol and syngas from coal. On this basis crossover points were predicted for as early as 1985. (The crossover point is the time at which the value of ethylene from coal equals the value of ethylene from gas oil, value being production cost plus a 25% year pretax ROI in new facilities).

The crossover point is extremely sensitive to the assumption about the relative escalation between capital (construction) costs and crude oil price. This sensitivity derives from two factors. Firstly, the large fraction of the product value deriving from capital investment for coal based routes. Secondly, the contribution of coproduct values to the economics of ethylene manufacture. (The coproducts are assumed to have values related directly to oil price.) Sensitivity to coal price is in relation much smaller.

The more even, or "pessimistic," scenario used for the default value calculations in the present study, assumes no real escalation on crude oil prices until 1985, and a subsequent build-up to 2.5%/yr in 1990 and onward (see Appendix A). Construction costs are assumed to escalate 0.5%/yr faster than inflation. In addition, somewhat higher costs are estimated to be likely for coal based syngases and methanol than were assumed for the evaluations in Report 146. Some very rough calculations indicate that the latter alone would shift the crossover point from 1985 to close to 1990. The more moderate relative escalation of oil prices and capital costs would push the crossover point out some ten more years, close to the year 2000.

Such sensitivities and the uncertainties associated with projecting costs, highlight the importance of continuing analysis of alternative scenarios as better defined data become available or as perceptions change. The optimistic (high oil price escalation) scenario was in some ways conservative at the time (early 1981), given oil prices apprcaching $40/barrel (e.g., <u>Chemical Week</u>, Feb. 11, 1981, p. 42). Equally, with the present "oil glut" and recession (mid 1982), the scenario projecting no real oil price escalation before 1985 may overly reflect the mood of the times. Current opinion has, polarized into two extreme schools of economic thought. One group holds that the oil glut is a temporary and artificial phenomenon; the other believes that more than ample supplies are likely for the rest of the century. The difference between the two in terms of where the chemical industry is heading, however, could be the difference between some five coal based ethylene units in place in the United States by the year 2000, and no coal based unit in place by that time.

We should add that a credible crossover point for new facilities is a necessary but not sufficient precondition for coal based facilities to be built. Among other determining factors are the following.

For example, in the United States much of the new ethylene capacity estimated to be added between 1990 and 2000, maybe half or more, will be to replace retired facilities (this could be some 15 billion lb/yr). It might be more attractive to revamp and modernize such facilities for using traditional feedstocks. Secondly, there is typically a lag in switching to new technology, even if such technology has been successfully demonstrated. Because with coal based complexes the risks are high, and the sums of capital placed at risk are very large, strategic problems in arranging financing for such projects may require structural changes in the industry itself.

Complicating the picture is the coming shift in bulk petrochemicals manufacture to areas of low cost feedstocks, namely those possessing associated natural gas for which the alternative use is flaring. Methanol based on low cost gas could equally well be used as a cracking feedstock. Or, new capacity in developed areas could be preempted by capacity for ethylene and derivatives built in areas having cheaper feedstocks. Considering this latter aspect in previous studies, SRI has concluded that the likely impact would be to reduce the rate of new capacity additions by the established producers, but not preempt the addition of new capacity in the developed areas.

Detailed analysis of such strategic considerations is, of course, well outside the scope of the present study. The aim here is to provide a tool for better and more ready quantification, on an ongoing basis, of one piece of the input for such studies, namely, syngas and related costs.

Appendix A

DEFAULT INPUT DATA

SRI's SYNCOST program as submitted to PEP clients contains default data for the years 1980 to 2001. The values, shown in Tables A.1 and A.2 relate to the U.S. Gulf Coast.

For 1980 and 1981 the values are estimates of representative prices, and generally correspond to those used in the 1980 and 1981 editions of the PEP Yearbook. (There are some differences in bases, e.g., for steam.) It should be noted that the natural gas prices are taken as equivalent to medium sulfur fuel oils rather than as the average price actually paid by industrial users.

For 1982 to 1990 we used projections made in late 1981 as part of studies on the effects of natural gas decontrol on chemical prices. The values are "trendline" projections which ignore the ups and downs in the economy. Thus, for example, the values for 1982 are estimates of prices for a scenario in which economic recovery is assumed to have taken place, and thus differ substantially from actual values in mid-1982. An illustration of this is given further below. For convenience "dummy" values are also provided for 1990 onward. These are extrapolations at constant rates of escalation.

The 1982 to 1990 projections are keyed to a scenario in which oil prices (using Saudi marker crude as the reference) are assumed to dip slightly in real terms in 1982 and then stay constant until 1985. Escalation of oil prices in real terms (i.e, over and above general inflation) is then assumed to restart in 1986 and increase to 2.5% per year from 1990 onward. (See Table A.1.) The rationale for such a scenario is discussed further below.

For current dollar prices we assumed that the general level of inflation (as measured by the Gross Domestic Product Deflator) will

Table A.1

SYNCOST DEFAULT VALUES - INDEPENDENT INPUTS

(Current Dollars, U.S. Gulf Coast)

	1980	1981	1982[a]	1983	1984	1985	1986	1987	1988	1989
GDP deflator (1958 = 100)	266.4	289.0	309.2	330.9	354.0	378.8	405.3	433.7	464.1	496.6
GDP inflation % pa	—	8.5	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Multiplier to 1980 $	1.000	0.922	0.861	0.805	0.752	0.703	0.657	0.614	0.574	0.536
Arabian Light f.o.b. ($/B)[c]	28.5	32.0	33.8	36.2	38.7	41.4	45.0	48.9	53.4	58.2
Escalation % pa real	48.3	3.5	(1.16)	—	—	—	1.5	1.5	2.0	2.0
U.S. avg. crude ($/B)	28.1	36.2	38.6	41.2	44.1	47.2	51.8	56.2	61.2	66.7
PEP Cost Index (1958 = 100)	355	400	430	462.3	496.9	534.2	574.3	617.3	663.6	713.4
Wages ($/hr)	15.4	17.5	18.9	20.4	21.9	23.6	25.3	27.1	29.1	31.2
Fuel oil (¢/MM Btu)	440	476	622	705	760	810	885	957	1,040	1,129
HP steam ($/M lb)	7.0	7.7	8.3	8.9	9.5	10.2	10.9	11.7	12.6	13.5
MP steam ($/M lb)	5.9	6.5	7.0	7.5	8.0	8.6	9.2	9.9	10.6	11.4
LP steam ($/M lb)	4.7	5.2	5.6	6.0	6.4	6.9	7.4	7.9	8.5	9.1
Electricity (¢/kwh)	3.4	3.6	4.5	5.0	5.5	5.9	6.6	7.3	8.0	8.8
Clarified water (¢/M gal)	36	41	46	50	54	58	62	67	72	77
Cooling water (¢/M gal)	4.9	5.4	6.2	6.7	7.3	7.9	8.6	9.4	10.2	11.1
Process water (¢/M gal)	60	68	77	83	89	96	103	111	120	129
Natural gas (¢/MM Btu)	400	417	551	609	674	737	827	913	1,013	1,121
Miscellaneous chemicals (-)[d]	0.845	1.000	1.072	1.150	1.235	1.324	1.435	1.547	1.671	1.805
Active carbon (¢/lb)	148	175	188	201	216	232	251	271	292	316
Ash disposal ($/tonne)	4.6	5.0	5.35	5.7	6.1	6.6	7.0	7.5	8.0	8.6
Coal at mine ($/tonne)	28.8	32.3	34.6	37.0	39.6	42.3	45.5	49.0	52.9	57.2
Coal transport ($/tonne)	13.8	15.0	16.0	17.2	18.4	19.7	21.0	22.5	24.1	25.8
Fuel gas (¢/MM Btu)	440	476	622	705	760	810	885	957	1,040	1,129
Higher alcohols (¢/lb)	4.4	4.8	6.2	7.0	7.6	8.1	8.9	9.6	104	11.3
Methanol catalyst (¢/lb)	340	400	430	460	495	530	575	620	670	720
Reforming catalyst (¢/lb)	170	200	215	230	250	265	290	310	335	360
Sulfur (¢/lb)	3.84	4.54	4.87	5.22	5.61	6.01	6.51	7.02	7.59	8.19
Vacuum residue (¢/lb)	5.15	5.65	8.00	9.20	9.8	10.5	11.5	12.5	13.5	14.6

	1990[b]	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
GDP deflator (1958 = 100)	531.3	568.5	608.3	650.9	696.4	745.2	797.4	853.2	912.9	976.8	1,045.2	1,183
GDP inflation % pa	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Multiplier to 1980 $	0.501	0.469	0.438	0.409	0.383	0.357	0.334	0.312	0.292	0.273	0.255	0.238
Arabian Light f.o.b. ($/B)[c]	63.9	70.0	76.8	84.3	92.4	101.4	111.2	121.9	133.7	146.6	160.8	176.4
Escalation % pa real	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
U.S. avg. crude ($/B)	73.1	80.0	87.5	95.8	104.9	114.8	125.7	137.6	150.7	165.0	180.6	197.7
PEP Cost Index (1958 = 100)	766.9	824.4	886.2	952.7	1,024	1,101	1,184	1,272	1,368	1,470	1,581	1,699
Wages ($/hr)	33.4	35.8	38.4	41.1	44.0	47.1	50.4	54.0	57.8	61.8	66.1	70.8
Fuel oil (¢/MM Btu)	1,232	1,346	1,471	1,608	1,757	1,921	2,100	2,297	2,511	2,750	3,010	3,295
HP steam ($/M lb)	14.6	15.6	16.8	18.1	19.4	20.9	22.5	24.2	26.0	27.9	30.0	32.3
MP steam ($/M lb)	12.3	13.2	14.2	15.2	16.4	17.6	18.9	20.4	21.9	23.5	25.3	27.2
LP steam ($/M lb)	9.8	10.5	11.3	12.1	13.1	14.0	15.1	16.2	17.4	18.7	20.1	21.7
Electricity (¢/kwh)	9.7	10.6	11.5	12.6	13.7	14.9	16.3	17.7	19.3	21.1	23.0	25.2
Clarified water (¢/M gal)	83	89	96	103	111	119	128	138	148	159	171	184
Cooling water (¢/M gal)	12.1	13.0	14.1	15.3	16.5	17.9	19.4	21.0	22.7	24.6	26.7	28.9
Process water (¢/M gal)	138	149	160	172	185	199	214	230	247	266	286	307
Natural gas (¢/MM Btu)	1,243	1,358	1,484	1,622	1,773	1,938	2,119	2,316	2,533	2,773	3,036	3,324
Miscellaneous chemicals (-)[d]	1.953	2.112	2.286	2.474	2.677	2.898	3.136	3.394	3.675	3.979	4.309	4.666
Active carbon (¢/lb)	342	370	400	433	468	507	549	594	643	696	754	816
Ash disposal ($/tonne)	9.2	9.8	10.5	11.3	12.0	12.9	13.8	14.8	15.8	16.9	18.1	19.3
Coal at mine ($/tonne)	61.8	66.8	72.2	78.0	84.3	91.1	98.4	106.4	115.0	124.3	134.3	145.1
Coal transport ($/tonne)	27.6	29.5	31.6	33.8	36.1	38.7	41.4	44.3	47.4	50.7	54.2	58.0
Fuel gas (¢/MM Btu)	1,232	1,346	1,471	1,608	1,757	1,921	2,100	2,297	2,511	2,750	3,010	3,295
Higher alcohols (¢/lb)	12.3	13.5	14.7	16.1	17.6	19.2	21.0	23.0	25.1	27.5	30.1	33.0
Methanol catalyst (¢/lb)	780	845	915	990	1,070	1,160	1,255	1,360	1,470	1,590	1,725	1,865
Reforming catalyst (¢/lb)	390	420	460	495	535	580	630	680	735	800	860	930
Sulfur (¢/lb)	8.87	9.59	10.38	11.23	12.15	13.16	14.24	15.41	16.68	18.06	19.56	21.18
Vacuum residue (¢/lb)	15.8	17.2	18.8	20.6	22.5	24.6	26.9	29.4	32.2	35.2	38.5	42.1

(a)Values from 1982 onwards are trend line projections.

(b)Values from 1990 onwards are simple extrapolations.

(c)Oil price values and escalation projections are not used directly, but underpin the projections.

(d)Ratio of price of miscellaneous chemicals in given year to price in 1981.

Table A.2

SYNCOST DEFAULT VALUES - DERIVED INPUTS*

(Current Dollars, U.S. Gulf Coast)

Syncost Raw Mat. Code	Raw Material	1980	1981	1982[j]	1983	1984	1985	1986	1987	1988	1989
3	Carbon dioxide (¢/lb)[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CO_2 ex flue gas (¢/lb)[a]	3.4	3.8	4.1	4.5	4.7	5.2	5.5	6.0	6.5	6.9
11	Hydrogen[b] (¢/mscf)	241	258	321	352	387	421	468	513	565	621
9	Hydrogen (85.4%)[c] (¢/mscf)	143	154	202	228	246	262	287	310	337	366
10	Hydrogen (93%)[d] (¢/mscf)	271	304	326	350	376	403	433	465	500	538
23	Syngas 2.26/C[e] (¢/mscf)	271	304	326	350	376	403	433	465	500	538
25	Syngas 4.9/G[f] (¢/mscf)	195	206	266	294	324	354	396	436	483	533
24	Syngas 3.0/G[g] (¢/mscf)	231	246	309	340	373	407	452	497	547	602
21	Syngas 2.0/G[h] (¢/mscf)	253	270	337	370	407	443	492	540	595	654
22	Syngas 2.0/R[i] (¢/mscf)	256	284	349	389	416	447	485	525	565	610

Syncost Raw Mat. Code	Raw Material	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
3	Carbon dioxide (¢/lb)[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	CO_2 ex flue gas (¢/lb)[a]	7.5	8.0	8.7	9.3	10.1	10.8	11.7	12.6	13.5	14.5
11	Hydrogen[b] (¢/mscf)	684	745	811	883	962	1,047	1,141	1,243	1,355	1,478
9	Hydrogen (85.4%) (¢/mscf)	399	436	477	521	569	622	680	744	814	891
10	Hydrogen (93%) (¢/mscf)	579	623	670	720	774	833	896	963	1,036	1,114
23	Syngas 2.26/C (¢/mscf)	579	623	670	720	774	833	896	963	1,036	1,114
25	Syngas 4.9/G (¢/mscf)	589	643	702	766	837	913	998	1,089	1,190	1,301
24	Syngas 3.0/G (¢/mscf)	664	723	788	859	936	1,020	1,112	1,211	1,321	1,442
21	Syngas 2.0/G (¢/mscf)	721	785	854	931	1,014	1,104	1,204	1,312	1,430	1,560
22	Syngas 2.0/R (¢/mscf)	658	712	773	840	910	988	1,072	1,164	1,264	1,372

Syncost Raw Mat. Code	Raw Material	2000	2001	Program Module
3	Carbon dioxide (¢/lb)[a]	0.0	0.0	—
	CO_2 ex flue gas (¢/lb)[a]	15.7	16.9	28
11	Hydrogen[b] (¢/mscf)	1,612	1,759	21
9	Hydrogen (85.4%) (¢/mscf)	975	1,068	Fuel equiv.
10	Hydrogen (93%) (¢/mscf)	1,199	1,289	Syngas equiv.
23	Syngas 2.26/C (¢/mscf)	1,199	1,289	13
25	Syngas 4.9/G (¢/mscf)	1,423	1,556	14
24	Syngas 3.0/G (¢/mscf)	1,573	1,718	12
21	Syngas 2.0/G (¢/mscf)	1,702	1,858	9
22	Syngas 2.0/R (¢/mscf)	1,490	1,618	10

*All values shown are without G&A.

(a) Zero value is used for default. The value of CO_2 from flue gases is shown for illustration only.

(b) Basis 100 MM scfd production by steam reforming of natural gas.

(c) Value taken as equivalent to fuel value on a Btu basis (HHV).

(d) Valued as syngas (2.26/C) feedstock.

(e) Default capacity 805.3 MM scfd. Syngas 2.26/C refers to syngas with an H_2:CO ratio of 2.26:1 from coal, etc.

(f) Default capacity 264.9 MM scfd.

(g) Default capacity 200.0 MM scfd.

(h) Default capacity 200.0 MM scfd.

(i) Default capacity 200.0 MM scfd.

(j) Values for 1982 onward are trendline projections.

average 7%/yr from 1982 onward. (The percentage increases shown in Table A.1 refer to increases in mid-year values over those of the previous year.)

Plant construction costs (as measured by the PEP Cost Index) are assumed to increase 7.5%/yr from 1982 onward, i.e., a real increase of about 0.5%/yr. As discussed in PEP Review 81-3-1, the average real increase for the 1970s was over 2.5%/yr. Escalation at these high real rates was interpreted as being primarily due to demand pull on equipment prices during surges of construction activity. However, for the 1980s much less major chemical plant construction may be anticipated, and lower or possibly even negative real escalation is therefore likely.

Similarly, wages of plant operators are assumed to increase at only slightly above the general level of inflation. This is again in sharp contrast to the experience of the 1970s when increases averaged some 5%/yr in real terms.

Miscellaneous chemicals and catalysts ("$ prices" relative to 1981) are assumed to increase in price in parallel with the price of the "median" chemical in the PEP 1981 Yearbook, i.e., with a cost component breakdown as follows:

	%
Crude oil related costs	33
Labor related costs	18
Capital related costs	46
Miscellaneous	3
Total	100

The natural gas price trend from 1982 onward is assumed to be determined by interfuel competition with 0.3% sulfur residual oil in a market without price controls. It is thus assumed to increase from about 90% of the projected fuel oil value in 1982, to parity and slightly above in 1990 and the following years.

We established the residual fuel price trend by considering the historical behavior of its margin over crude oil in conjunction with refinery profitability. This margin, on average, declined somewhat during the 1970s and plunged precipitously in 1981. The sharp decline in 1981 of residual oil and other refinery product margins over crude oil was primarily due to the decontrol of the price of crude oil in the United States in the middle of a recession. The U.S. crude price rose to world levels while product prices stayed low. Refinery operating levels had dropped to below 70% of capacity and cash flows turned negative. The forward projections assume that there will be a substantial improvement in prices and margins over those in 1981, but even so, only to a level where a new refinery would show a slightly negative cash flow for the next decade. The margin of residual fuel over crude oil, assumed to have recovered in 1982, is then projected to show a modest decline comparable with the decline in the 1970s. We estimated the price of vacuum residue on the basis of the process economics of delayed coking within the general context of refinery economics noted above. This results in values for the 1980s which are some $3.5/bbl (1981 $) less than the value of high sulfur (3% S) residual fuel oil.

The trend in the price of coal (f.o.b. mine) is assumed to follow the trend of oil prices directionally but at a much attenuated rate of real escalation; zero percent to 1985 and increasing to 1%/yr from 1988 onward. The cost of coal transport is assumed to follow the level of general inflation. Steam costs are based on coal firing and approximated as 50% capital related and 50% coal related in 1981. In contrast to the traditional PEP practice, the numbers for steam costs include illustrative capital charges.

Comparison of Actual and Projected Values

A comparison of the trendline projections with the actual estimates of representative prices on the U.S. Gulf Coast for mid-1982 is shown for a selection of items in Table A.3.

Table A.3

COMPARISON OF PROJECTED AND ACTUAL PRICES FOR 1982

	Trendline Projections, Scenario A	Estimated Actual Values, Scenario B
PEP Cost Index	430	425
Wages ($/hr)*	18.90	19.10
Electricity (¢/kwh)	4.5	4.5
Cooling water (¢/1,000 gal)	6.2	6.09
Process water (¢/1,000 gal)	77.0	73.5
Natural gas (¢/million Btu)	551	320
Miscellaneous chemicals (–)	1.07	0.95
Active carbon (¢/lb)	188	206
Ash disposal ($/tonne)	5.35	5.3
Coal at mine ($/tonne)	34.6	30.0
Coal transport ($/tonne)	16.0	20.0
Fuel gas (¢/million Btu)	622	320
Methanol catalyst (¢/lb)	430	440
Reforming catalyst (¢/lb)	215	200
Sulfur (¢/lb)	4.87	6.29
Vacuum residue (¢/lb)	8.00	5.8

*For plant operating labor, including fringe benefits and shift overlap allowance.

†Escalation factor relative to 1981 for miscellaneous chemicals and catalysts.

The effects on estimated product values are shown in Tables A.4, A.5, and A.6

The substantial differences in the product values calculated for methanol and hydrogen in scenarios A and B are due primarily to the large difference between the projected trendline and actual prices of natural gas. Interestingly the estimated carbon monoxide values are close for both cases. This results because the residue feedstock cost difference is more than counterweighed by the difference in the hydrogen credit.

Reflections on Oil Prices

The world supply/demand balance for oil has developed into the most important single factor in determining not merely chemical feedstock prices but the whole course of the world economy. The first sharp increases in prices imposed by OPEC in 1973/74 led to a worldwide recession and higher rates of inflation. After demand for crude dropped in 1974 and 1975, and supplies came back into balance, the real price of oil leveled off and then declined slightly; the economies of the world picked up; and inflation at least appeared to be coming under control. Then the revolution in Iran, followed by the Iraq-Iran war, cut crude production once again in 1979 and 1980. The crude price almost tripled, the world fell back into recession, and most countries were plagued again with a high rate of inflation. Just as the world economy appeared to arise from this recessionary period in 1981, economic activity, particularly in the United States and Japan, again faded in the second half of 1981. Projections made in late 1981 typically anticipated that world economic activity would begin to quicken in the second half of 1982 and improve moderately during 1983.

There are two extreme schools of economic thought concerning the present "oil glut." One group holds that it is a temporary and artificial phenomenon (e.g., Banks, F. E., Chemical Economy & Engineering Review, April 82); the other believes that ample supplies are likely for the rest of the century (e.g., Brown, W. M., Fortune, Nov. 30, 81).

Table A.4

METHANOL FROM NATURAL GAS
(Module #24)

Capacity: 2,490 Tonnes/Day

	1982	
	Scenario A	Scenario B
Investments (million $)		
Battery limits	166.9	164.9
TOTAL FIXED CAPITAL	228.8	226.1
PEP Cost Index (current $)	430	425
Natural gas ($/million Btu)	5.51	3.20
Variable costs ($/tonne)		
Raw materials	171.64	100.37
By-product credit	(1.02)	(1.02)
Imported utilities	13.80	9.47
PRODUCT VALUE ($/tonne)	308	229

Table A.5

HYDROGEN (97%) FROM NATURAL GAS
(Module #21)

Capacity: 100 Million scfd

	1982	
	Scenario A	Scenario B
Investments (million $)		
Battery limits	46.2	45.7
TOTAL FIXED CAPITAL	61.8	61.1
PEP Cost Index (current $)	430	425
Natural gas ($/million Btu)	5.51	3.20
Variable costs (¢/1,000 scf)		
Raw materials	155.72	91.21
Imported utilities	85.31	52.02
PRODUCT VALUE (¢/1,000 scf)	321	223

Table A.6

CARBON MONOXIDE FROM RESID-DERIVED SYNGAS (H_2:CO = 2.0)
BY CRYOGENIC SEPARATION
(Module #20)

Capacity: 149 Million lb/yr

	1982	
	Scenario A	Scenario B
Investments (million $)		
Battery limits	5.6	5.5
TOTAL FIXED CAPITAL	6.5	6.4
PEP Cost Index (current $)	430	425
Syngas (2.0)/R* ($/1,000 scf)	3.49	2.96
Variable costs (¢/lb)		
Raw materials	14.66	12.45
By-product credit	(8.94)	(6.15)
Imported utilities	0.74	0.74
PRODUCT VALUE (¢/lb)	9.34	9.79

*Syngas (2.0)/R refers to syngas with an H_2:CO ratio of 2:1 made from vacuum residue.

Economists of the first school point to the following factors to support their contention that the surplus of supply over demand is temporary:

- The drop in demand for oil, while partially a function of conservation, has also been a primary result of recessions in the industrial countries.
- The constant risks of war or other disturbances in the Middle East, which connote a high probability of frequent interruptions of oil production in one or another country of the region.
- World consumption of crude during periods of normal economic activity average more than 20 billion barrels of oil per year, which is more than the level of discoveries of new reserves.

These economists expect that in the next 20 years the world will suffer frequent interruptions of oil supplies, and that oil prices will climb faster than general inflation.

Economists of the opposite school believe that the high prices of oil have already moved the world into a new era of energy conservation, and that surpluses of available supply over demand are likely to be with us for years. These economists point to the following factors to support their contention:

- The laws of price elasticity have finally begun to act on demand for oil, as witness the shift in the United States toward small, high-mileage automobiles.
- Crude oil production particularly from non-OPEC less-developed countries will continue to increase and is likely to more than replace any oil production lost by the developed countries, and OPEC's share of oil production is likely to decline slowly but steadily in the future.
- New coal technologies make it convenient to replace heavy fuel oil in existing oil-fired boilers.
- Advances in refinery technology enable the world to produce more light products (naphtha, gasoline, and jet fuel) and less fuel oil, from a barrel of crude.

They project continuing declines in world consumption of oil, with OPEC losing its ability to hold the threat of shortages over the industrial countries; and they believe that world oil prices will increase "little, if at all," through the year 2000, except maybe for periodic inflationary adjustments.

SRI recognizes that the world has finally been forced into patterns that will conserve energy in new ways, and that we are likely to see smaller outputs of energy required to produce a unit of GNP than we grew accustomed to in the prosperous years immediately following World War II. But we also recognize that oil is a finite resource, with one country, Saudi Arabia, holding an effective grip on more than half of the world's exportable supplies. We believe that Saudi Arabia will find that, in the long run, its interests are best served by holding back on supplies in order to achieve oil prices that equate with the prices of competitive energy sources. Since most alternative sources of crude, with the possible exception of tar sands and oil shale, are more expensive than crude at current prices, SRI believes that the price of crude must increase in the long term if OPEC can moderate their supply in line with the demand for crude.

The basic assumptions underlying our projections of economic growth and of oil and gas prices, therefore, can be summarized as follows:

- The world will remain relatively troubled, but there will be few interruptions of oil supplies during the next 20 years as serious as, say, that caused by the Iranian revolution of 1979.
- The major oil producing countries, led by Saudi Arabia, will, in general arrange their levels of production so that supplies are in reasonable balance with demand, and so that prices tend toward equilibrium with other--and particularly with new--energy sources. In the short term, the real price of crude may decline slightly or remain stable until the current oil glut is worked off by both production cutbacks and increased demand brought by improving world-economic activity. Following the glut, the long term real price of crude will increase moderately.

- The industrial countries will continue to find ways to conserve energy, but their demand for primary energy will increase slowly as they achieve moderate economic growth--although rarely at the levels enjoyed in the 1950s and 1960s.
- World financial institutions will find ways to keep recycling the petrodollars, using them mainly to finance the oil imports of the less developed countries.

APPENDIX B

SYNCOST COMPUTER PROGRAM

B.1 INTRODUCTION

In general evaluations of the various synthesis gas routes to bulk chemicals it is useful to be able to estimate and project the cost of syngases, carbon monoxide, and/or methanol. We have assembled the economics developed earlier in this report into a computer program to estimate syngas costs for a range of years. The program, SYNCOST, calculates production costs (including return on investment) for syngases (H_2/CO ratio 0.75 to 3.0), carbon monoxide, hydrogen, 'raw' syngas, and methanol. The feedstocks available are those investigated in this report: coal, natural gas, and vacuum residue. We have divided the process data developed by PEP into process modules that can be linked by the program in various user-supplied sequences to produce production cost tables for a range of years. The modules available are listed in Table B.1 and are shown schematically in Figure B.1. We have included a

TABLE B.1

AVAILABLE MODULES AND CAPACITIES

MODULE		CAPACITY DEFAULT	MINIMUM		MAXIMUM	
1	SYNGAS(H2/CO=0.75) FROM COAL	802.0	50	-	1600	MMSCFD
2	SYNGAS(H2/CO=1.0) FROM COAL	803.2	50	-	1600	MMSCFD
3	SYNGAS(H2/CO=1.0) FROM NATURAL GAS WITH CO2 IMPORT	97.6	15	-	600	MMSCFD
4	SYNGAS(H2/CO=1.0) FROM SYNGAS(H2/CO=3.0) BY SKIMMING	129.2	40	-	600	MMSCFD
5	SYNGAS(H2/CO=1.0) FROM SYNGAS(H2/CO=2.0) BY SKIMMING	200.0	40	-	760	MMSCFD
6	SYNGAS(H2/CO=1.0) FROM VACUUM RESIDUE	200.0	50	-	600	MMSCFD
7	SYNGAS(H2/CO=1.5) FROM COAL	804.3	50	-	1600	MMSCFD
8	SYNGAS(H2/CO=2.0) FROM COAL	805.0	50	-	1600	MMSCFD
9	SYNGAS(H2/CO=2.0) FROM NATURAL GAS WITH CO2 IMPORT	200.0	40	-	600	MMSCFD
10	SYNGAS(H2/CO=2.0) FROM VACUUM RESIDUE	200.0	50	-	600	MMSCFD
11	SYNGAS(H2/CO=2.0) FROM SYNGAS(H2/CO=3.0) BY SKIMMING	151.5	40	-	880	MMSCFD
12	SYNGAS(H2/CO=3.0) FROM NATURAL GAS WITH CO2 RECYCLE	200.0	40	-	600	MMSCFD
13	METHANOL SYNGAS(H2/CO=2.26) FROM COAL	805.3	50	-	1600	MMSCFD
14	CRUDE SYNGAS(H2/CO=4.92) FROM NATURAL GAS	264.9	90	-	530	MMSCFD
15	CO FROM GAS-DERIVED SYNGAS(H2/CO=3.0) BY COSORB SEPARATION	149.3	70	-	600	MMLB/YR
16	CO FROM GAS-DERIVED SYNGAS(H2/CO=3.0) BY CRYOGENIC SEPARATION	149.3	70	-	600	MMLB/YR
17	CO FROM GAS-DERIVED CRUDE SYNGAS (H2/CO=4.9) BY COSORB SEPARATION	149.3	70	-	600	MMLB/YR
18	CO FROM GAS-DERIVED CRUDE SYNGAS (H2/CO=4.9) BY CRYOGENIC SEPARATION	149.3	70	-	600	MMLB/YR
19	CO FROM COAL-DERIVED METHANOL SYNGAS (H2/CO=2.26) BY COSORB SEPARATION	149.3	70	-	600	MMLB/YR
20	CO FROM RESID-DERIVED SYNGAS(H2/CO=2.0) BY CRYOGENIC SEPARATION	149.3	70	-	600	MMLB/YR
21	HYDROGEN(97%) FROM NATURAL GAS	100.0	8	-	560	MMSCFD
22	HYDROGEN(97%) FROM COAL	200.0	50	-	1560	MMSCFD
23	HYDROGEN(98%) FROM VACUUM RESIDUE	100.0	50	-	1150	MMSCFD
24	METHANOL FROM NATURAL GAS	2490.7	140	-	5000	TONNE/D
25	METHANOL FROM GAS-DERIVED CRUDE SYNGAS(H2/CO=4.9)	2490.7	960	-	5000	TONNE/D
26	METHANOL FROM COAL	10000.0	600	-	20000	TONNE/D
27	METHANOL FROM COAL-DERIVED METHANOL SYNGAS(H2/CO=2.26)	10000.0	600	-	20000	TONNE/D
28	CARBON DIOXIDE FROM FLUE GAS SCRUBBING	870.0	400	-	1750	MMLB/YR

Figure B.1

SYNCOST MODULES

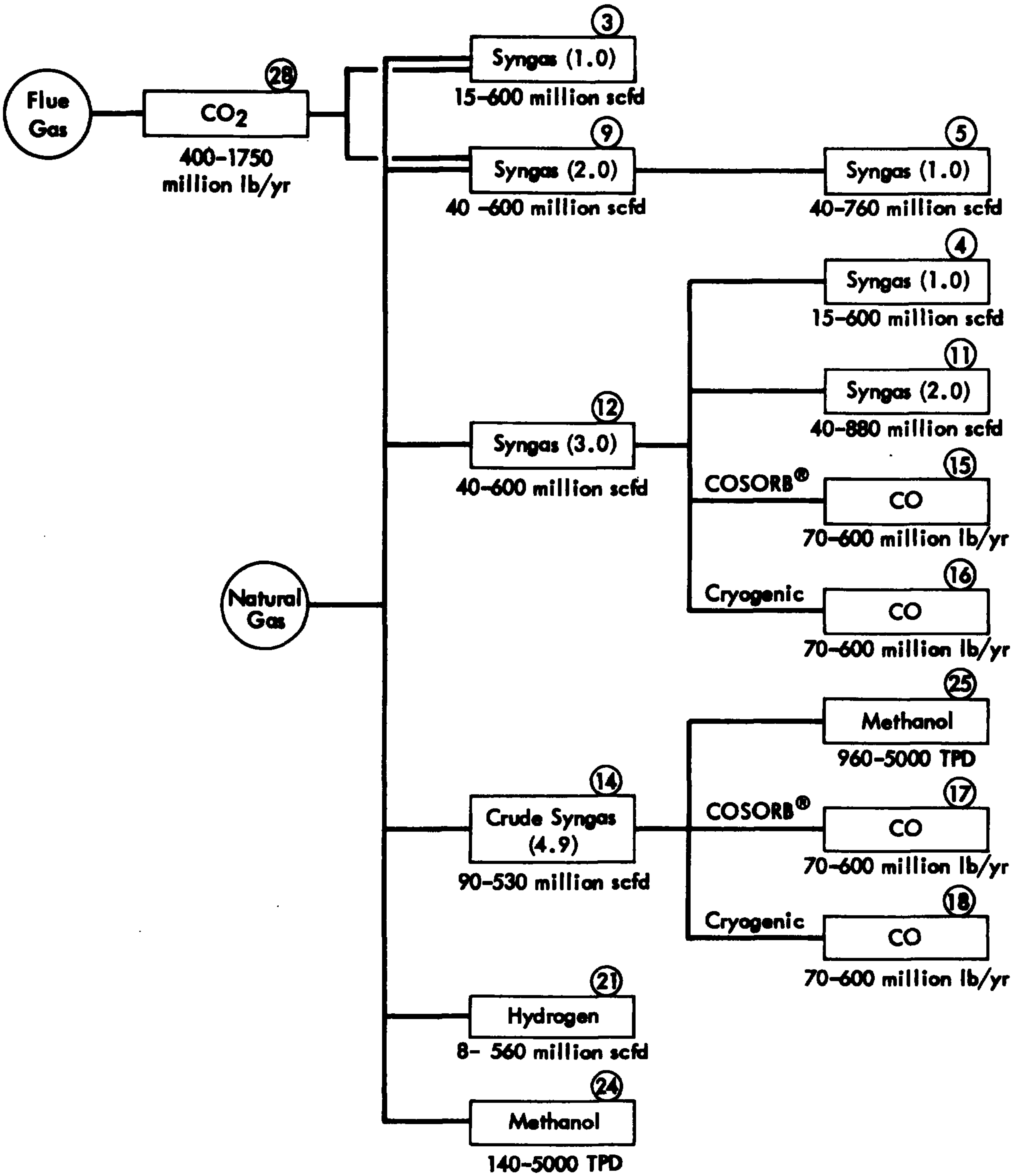
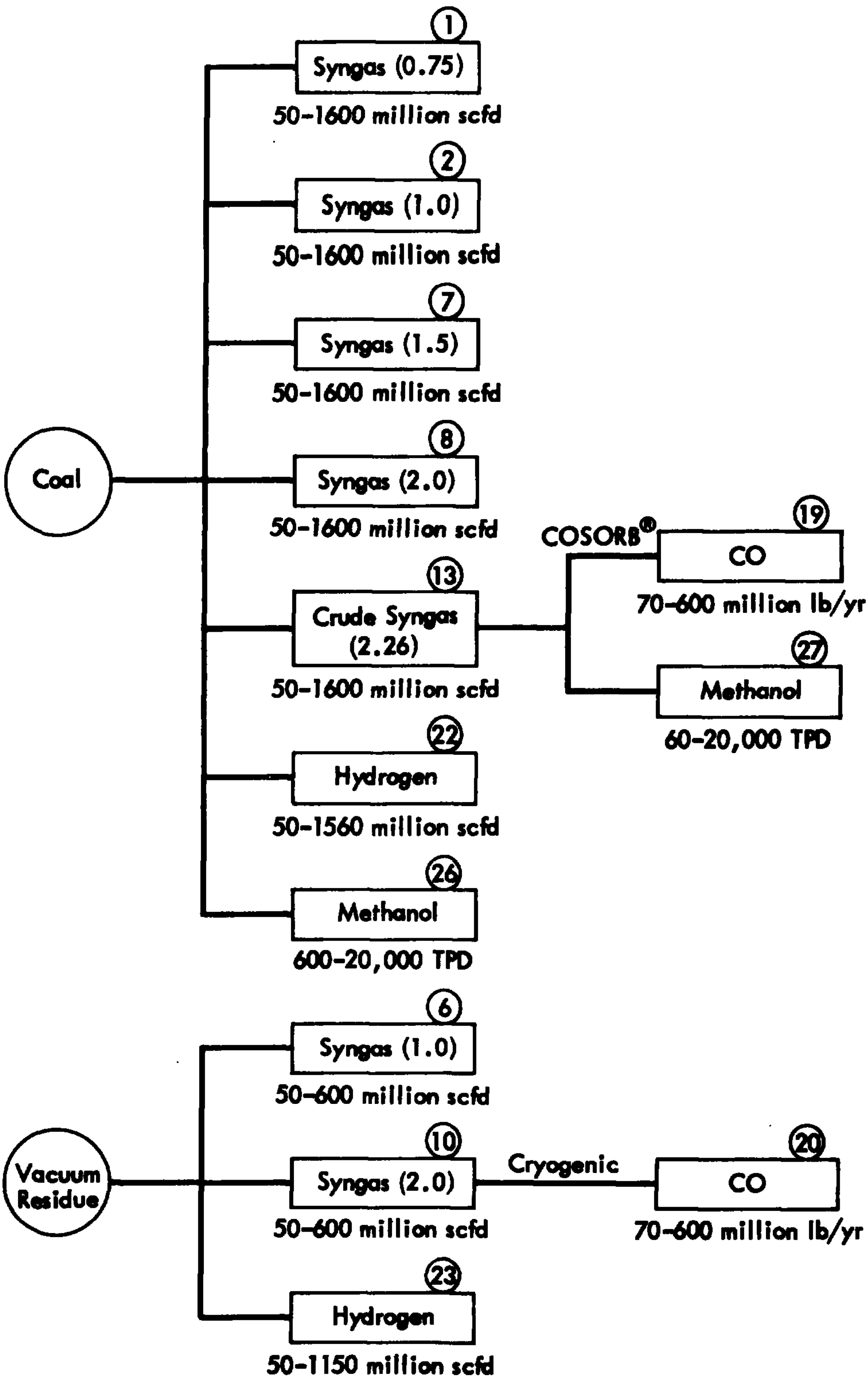


Figure B.1 (Concluded)

SYNCOST MODULES



module for carbon dioxide production from flue gas for use with the syngas modules when imported carbon dioxide is required.

The program calculates the product value (plant gate cost + G&A + return on investment) for any desired set of process modules. The program contains default values for various material and utility costs and operating cost factors, but considerable flexibility in modifying these factors is available. During execution of the program, provision is made for modifying capital investment, cost index, material and utilities costs, return on investment, taxes and insurance, depreciation, maintenance, general and administrative, and overhead factors. The default process and price data may be permanently modified to the user's specifications by changing the two data files attached to the program.

The SYNCOST program runs interactively. The user inputs the desired process sequence and any price or factor modifications at the keyboard in response to computer 'prompts.' The program output can be obtained interactively or it can be saved and printed on a batch device.

The SYNCOST program is written in Fortran 77 and was developed on a VAX 11/782 computer. Storage required is 134K bytes for the source program.

B.2 PROGRAM LOGIC

SRI's SYNCOST program accesses process and price data stored in two data files and interactively prompts the user for information about the process sequences to be run. The program runs multiple process sequences. Each process sequence can consist of one product module and from zero to four "intermediate" modules. The "intermediate" modules need not be related to the product module, but the intermediate process(es) to a particular product can be included to calculate an appropriate raw material price to be used in the product module calculations, e.g., module 12-"Syngas (3.0) from natural gas" would be included in the process sequence as an intermediate to module 11-"Syngas (2.0) from Syngas (3.0)." The syngas (3.0) product value calculated by the program would be used as a raw material cost in the syngas (2.0) calculation. If cost estimates for several unrelated modules are needed, the modules can be grouped in a process sequence as "intermediates" to minimize user keyboard entries.

The product module selection is entered first, followed by the intermediate module selections. Calculations for the intermediate modules are run in the order entered, followed by the product module calculations.

For each process sequence the user must select the years of interest and individual process capacities, and may modify any of the default prices or cost factors. For subsequent process sequences the user has the option of (1) using the entered years/cost factor data from the previous sequence, (2) reentering new years/cost factor data, or (3) using the stored default cost factor values.

Some flexiblity for working with various English and metric units is included in the program. Areas where a choice of units is available are indicated in the program prompts.

The output from each process sequence consists of product value summary tables for the years selected, for each process module. Several printout options are available (see Section B.5). The program is designed primarily for hard copy output. If a CRT device is used for output, some of the tables may be lost.

The user is prompted interactively for input to the program. When input errors are detected by the program, error messages (beginning with '***') are printed and the user is directed to correct the error by reentering the faulty line.

During execution the program creates and uses two direct access process and price data files. These files are deleted upon normal termination.

B.3 INPUT DATA

Input data are supplied by (1) data files containing the basic process data, default prices, and cost factors, and (2) process sequences and data modifications supplied interactively by the user via program prompting.

The data files contain estimated wages, inflation factors, utilities costs, and raw material costs for the years 1980-2001. A list of the default values is shown in Table B.2. Most of these values may be modified interactively.

Interactive Input

For each process sequence the principal input data required are as follows:

a. An integer code corresponding to each process module in the sequence.

b. Capacity of each process (optional).

c. Years for which calculations are required.

d. Type of printout.

e. Cost units in which the product value tables are presented.

f. Choice of printout in current $ or constant $.

Table B.2

Default Utilities and Raw Materials Costs

	0	1	2	3	4	5	6	7	8	9
1-ACTIVE CARBON , C/LB										
80-89	148.00	175.00	188.00	201.00	216.00	232.00	251.00	271.00	292.00	316.00
90-99	342.00	370.00	400.00	433.00	468.00	507.00	549.00	594.00	643.00	696.00
00-01	754.00	816.00								
2-ASH DISPOSAL , $/TONNE										
80-89	4.60	5.00	5.35	5.70	6.10	6.60	7.00	7.50	8.00	8.60
90-99	9.20	9.80	10.50	11.30	12.00	12.90	13.80	14.80	15.80	16.90
00-01	18.10	19.30								
3-CARBON DIOXIDE , C/LB										
80-89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
90-99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
00-01	0.00	0.00								
5-COAL AT MINE , $/TONNE										
80-89	28.80	32.30	34.60	37.00	39.60	42.30	45.50	49.00	52.90	57.20
90-99	61.80	66.80	72.20	78.00	84.30	91.10	98.40	106.40	115.00	124.30
00-01	134.30	145.10								
6-COAL TRANSPORT , $/TONNE										
80-89	13.80	15.00	16.00	17.20	18.40	19.70	21.00	22.50	24.10	25.80
90-99	27.60	29.50	31.60	33.80	36.10	38.70	41.40	44.30	47.40	50.70
00-01	54.20	58.00								
7-FUEL GAS , $/MMBTU										
80-89	4.40	4.76	6.22	7.05	7.60	8.10	8.85	9.57	10.40	11.29
90-99	12.32	13.46	14.71	16.08	17.57	19.21	21.00	22.97	25.11	27.50
00-01	30.10	33.00								
8-HIGHER ALCOHOLS , C/LB										
80-89	4.40	4.80	6.20	7.00	7.60	8.10	8.90	9.60	10.40	11.30
90-99	12.30	13.50	14.70	16.10	17.60	19.20	21.00	23.00	25.10	27.50
00-01	30.10	32.95								
9-HYDROGEN(85.4%) , C/MSCF										
80-89	143.00	154.00	202.00	228.00	246.00	262.00	287.00	310.00	337.00	366.00
90-99	399.00	436.00	477.00	521.00	569.00	622.00	680.00	744.00	814.00	891.00
00-01	975.00	1068.00								
10-HYDROGEN(93%) , C/MSCF										
80-89	271.00	304.00	326.00	350.00	376.00	403.00	433.00	465.00	500.00	538.00
90-99	579.00	623.00	670.00	720.00	774.00	833.00	896.00	963.00	1036.00	1114.00
00-01	1199.00	1289.00								
11-HYDROGEN , C/MSCF										
80-89	241.00	258.00	321.00	352.00	387.00	421.00	468.00	513.00	565.00	621.00
90-99	684.00	745.00	811.00	883.00	962.00	1047.00	1141.00	1243.00	1355.00	1478.00
00-01	1612.00	1759.00								
15-METHANOL CATALYST , C/LB										
80-89	340.00	400.00	430.00	460.00	495.00	530.00	575.00	620.00	670.00	720.00
90-99	780.00	845.00	915.00	990.00	1070.00	1160.00	1255.00	1360.00	1470.00	1590.00
00-01	1725.00	1865.00								
16-MISC. CHEM. & CAT. , $										
80-89	0.85	1.00	1.07	1.15	1.24	1.32	1.43	1.55	1.67	1.80
90-99	1.95	2.11	2.29	2.47	2.68	2.90	3.14	3.39	3.67	3.98
00-01	4.31	4.67								
17-NATURAL GAS , $/MMBTU										
80-89	4.00	4.17	5.51	6.09	6.74	7.37	8.27	9.13	10.13	11.21
90-99	12.43	13.58	14.84	16.22	17.73	19.38	21.19	23.16	25.33	27.73
00-01	30.36	33.24								
18-REFORMING CATALYST , C/LB										
80-89	170.00	200.00	215.00	230.00	250.00	265.00	290.00	310.00	335.00	360.00
90-99	390.00	420.00	460.00	495.00	535.00	580.00	630.00	680.00	735.00	800.00
00-01	860.00	930.00								
20-SULFUR , C/LB										
80-89	3.84	4.54	4.87	5.22	5.61	6.01	6.51	7.02	7.59	8.19
90-99	8.87	9.59	10.38	11.23	12.15	13.16	14.24	15.41	16.68	18.06
00-01	19.56	21.18								
21-SYNGAS(2.0)/G , C/MSCF										
80-89	253.00	270.00	337.00	370.00	407.00	443.00	492.00	540.00	595.00	654.00
90-99	721.00	785.00	854.00	931.00	1014.00	1104.00	1204.00	1312.00	1430.00	1560.00
00-01	1702.00	1858.00								
22-SYNGAS(2.0)/R , C/MSCF										
80-89	256.00	284.00	349.00	389.00	416.00	447.00	485.00	525.00	565.00	610.00
90-99	658.00	712.00	773.00	840.00	910.00	988.00	1072.00	1164.00	1264.00	1372.00
00-01	1490.00	1618.00								
23-SYNGAS(2.26)/C , C/MSCF										
80-89	271.00	304.00	326.00	350.00	376.00	403.00	433.00	465.00	500.00	538.00
90-99	579.00	623.00	670.00	720.00	774.00	833.00	896.00	963.00	1036.00	1114.00
00-01	1199.00	1289.00								
24-SYNGAS(3.0)/G , C/MSCF										
80-89	231.00	246.00	309.00	340.00	373.00	407.00	452.00	497.00	547.00	602.00
90-99	664.00	723.00	788.00	859.00	936.00	1020.00	1112.00	1211.00	1321.00	1442.00
00-01	1573.00	1718.00								
25-SYNGAS(4.9)/G , C/MSCF										
80-89	195.00	206.00	266.00	294.00	324.00	354.00	396.00	436.00	483.00	533.00
90-99	589.00	643.00	702.00	766.00	837.00	913.00	998.00	1089.00	1190.00	1301.00
00-01	1423.00	1556.00								
26-VACUUM RESIDUE , C/LB										
80-89	5.15	5.65	8.00	9.20	9.80	10.50	11.50	12.50	13.50	14.60
90-99	15.80	17.20	18.80	20.60	22.50	24.60	26.90	29.40	32.20	35.20
00-01	38.50	42.10								

Table B.2 (Concluded)

Default Utilities and Raw Materials Costs

	0	1	2	3	4	5	6	7	8	9
COST INDEX:										
80-89	355.0	400.0	430.0	462.3	496.9	534.2	574.3	617.3	663.6	713.4
90-99	766.9	824.4	886.2	952.7	1024.0	1101.0	1184.0	1272.0	1368.0	1470.0
00-01	1581.0	1699.0								
INFLATION FACTOR:										
80-89	1.000	0.922	0.861	0.805	0.752	0.703	0.657	0.614	0.574	0.536
90-99	0.501	0.469	0.438	0.409	0.383	0.357	0.334	0.312	0.292	0.273
00-01	0.255	0.283								
WAGE, $/HR:										
80-89	15.40	17.50	18.90	20.40	21.90	23.60	25.30	27.10	29.10	31.20
90-99	33.40	35.80	38.40	41.10	44.00	47.10	50.40	54.00	57.80	61.80
00-01	66.10	70.80								
NAT. GAS FUEL , $/MMBTU										
80-89	4.00	4.17	5.51	6.09	6.74	7.37	8.27	9.13	10.13	11.21
90-99	12.43	13.58	14.84	16.22	17.73	19.38	21.19	23.16	25.33	27.73
00-01	30.36	33.24								
FUEL OIL , $/MMBTU										
80-89	4.40	4.76	6.22	7.05	7.60	8.10	8.85	9.57	10.40	11.29
90-99	12.32	13.46	14.71	16.08	17.57	19.21	21.00	22.97	25.11	27.50
00-01	30.10	32.95								
HP STEAM , $/MLB										
80-89	7.00	7.70	8.30	8.90	9.50	10.20	10.90	11.70	12.60	13.50
90-99	14.60	15.60	16.80	18.10	19.40	20.90	22.50	24.20	26.00	27.90
00-01	30.00	32.30								
MP STEAM , $/MLB										
80-89	5.90	6.50	7.00	7.50	8.00	8.60	9.20	9.90	10.60	11.40
90-99	12.30	13.20	14.20	15.20	16.40	17.60	18.90	20.40	21.90	23.50
00-01	25.30	27.20								
LP STEAM , $/MLB										
80-89	4.70	5.20	5.60	6.00	6.40	6.90	7.40	7.90	8.50	9.10
90-99	9.80	10.50	11.30	12.10	13.10	14.00	15.10	16.20	17.40	18.70
00-01	20.10	21.70								
ELECTRICITY , C/KWH										
80-89	3.40	3.60	4.50	5.00	5.50	5.90	6.60	7.30	8.00	8.80
90-99	9.70	10.60	11.50	12.60	13.70	14.90	16.30	17.70	19.30	21.10
00-01	23.00	25.20								
CLARIFIED WATER, C/MGAL										
80-89	36.00	41.00	46.00	50.00	54.00	58.00	62.00	67.00	72.00	77.00
90-99	83.00	89.00	96.00	103.00	111.00	119.00	128.00	138.00	148.00	159.00
00-01	171.00	184.00								
COOLING WATER , C/MGAL										
80-89	4.90	5.40	6.20	6.70	7.30	7.90	8.60	9.40	10.20	11.10
90-99	12.10	13.00	14.10	15.30	16.50	17.90	19.40	21.00	22.70	24.60
00-01	26.70	28.90								
PROCESS WATER , C/MGAL										
80-89	60.00	68.00	77.00	83.00	89.00	96.00	103.00	111.00	120.00	129.00
90-99	138.00	149.00	160.00	172.00	185.00	199.00	214.00	230.00	247.00	266.00
00-01	286.00	307.00								

g. Hydrogen by-product value (if processes produce hydrogen).

In addition to the principal input data, the program prompts for several optional modifications to the material and utilities costs and operating cost factors.

Descriptions of the program prompts during execution follow. All input is in free format, i.e. sucessive entries on a line can be separated by a blank or comma and ended with a slash (/).

Q1. 'TYPE 0 TO STOP NOW OR ENTER FEEDSTOCK (1=COAL, 2=NATURAL GAS, 3=VACUUM RESIDUE)?'

Type 0 (zero) to terminate the program, or type the integer representing the desired feedstock.

Q2. 'LIST AVAILABLE MODULES (Y OR N)?'

Type Y(es) to get a list of modules (and capacity ranges) available for the feedstock entered above. Type N(o) for no list.

Q3. 'DO YOU WISH TO USE YOUR YEAR, WAGE, UTILITY COST, BASIS OP COST FACTORS AND RAW MATERIAL PRICE DATA ENTERED FOR THE PREVIOUS PROCESS SEQUENCE (Y OR N)?'

To run another process sequence using the data from the previous sequence, type Y(es). Type N(o) to reset the wage, cost, and factor data to default values and prompt for any modifications. If the Y option is selected, Q4, 5, and 13-21 are suppressed.

Q4. 'NUMBER OF YEARS FOR WHICH ESTIMATES ARE TO BE CALCULATED (MAX=10)?'

Enter the number of years for which calculations are desired. The maximum number of years is 10, but if output is via a screen or terminal device with 80 character width, 5 years is the maximum for readable output.

Q5. 'WHICH YEARS?'

Enter the years for which production cost estimates are required, e.g., 1981,1982,1983,1984,1985. The years need not be contiguous.

NOTE: The program has default data for 1980-2001. If years are selected outside this range, the appropriate data must be entered for cost index (Q14a), wage (Q14b), utilities costs (Q14d-k), and raw material costs (Q17).

Q6. 'PRODUCT MODULE?'

Enter the integer code for the product module desired (see Table B.1). The product module is entered first even though it is the last module for which calculations are done in any process sequence.

NOTE: The product value for this module includes G&A,S,R cost. The G&A cost can be suppressed by entering a negative integer code for the product module.

Q7. "RUN BASE CASE, WITH DEFAULT VALUES FOR ALL MODULES IN PROCESS SEQUENCE (Y OR N)?"

Type Y(es) to run the process sequence with the default capacities, output units, material and utility costs, and cost factors supplied by the program (see Tables B.1 and B.2). Type N(o) to override capacity and any of the various cost and factor default data. When the "default" option is selected the plant capacities of the various related modules are automatically matched by the program. If the Y option is selected, Q8 and 12-21 are suppressed.

Q8. "ENTER CAPACITY, FOLLOWED BY UNIT (DEFAULT=xxxx) (1=MMSCFD, 2=MMBTU/HR, 3=MMLB/YR, 4=TONNE/DAY)",

e.g. 5000.,4 for a 5000 tonne/day plant.

The entered capacity is used for each of the specified years. Type a / (slash) to use the default capacity listed.

NOTE: If there are several modules in a process sequence, the user must match the capacities of the related modules.

Q9. "LIST INTERMEDIATE MODULES (Y OR N)?"

Type Y(es) for a list of intermediate modules required for the chosen product module. The list will include the modules which calculate costs for raw materials used by the product module. Type N(o) for no list.

Q10. "INTERMEDIATE MODULE?"

Enter the integer code for the intermediate module desired, or enter / (slash) if no intermediate module(s) is desired.

If the product module has related "intermediate" modules (listed in Q9), the module(s) may be included here as "intermediates." The product value calculated by the program for each "intermediate" is entered into the price file and is used as a raw material price in the product module calculation. If the related intermediate module is not included in the process sequence, either the default raw material price or one entered by the user is used in the product module calculation.

Any unrelated modules may be grouped and entered here and run as part of a process sequence for convenience. This minimizes keyboard entries. For example, to get cost estimates for four different unrelated modules, it is more efficient to run them all in one process sequence as a product module and three "intermediates" rather than running four separate process sequences of one product module each.

NOTES: G&A,S,R cost is not included in the intermediate module costs. To include G&A cost, enter a negative integer code for the intermediate module.

Q11. "ENTER CAPACITY, FOLLOWED BY UNIT (1=MMSCFD, 2=MMBTU/HR, 3=MMLB/YR, 4=TONNE/DAY)"

Enter the capacity for the selected intermediate module, or type / (slash) for the default capacity. The capacities of related modules are automatically matched only if the user selects the default capacity for all modules. Otherwise, the user must match the capacities of any related modules.

NOTE: Q10 and Q11 are repeated four times so that up to four intermediate modules may be run with the product module to create a process sequence.

Q12. "TYPE OF PRINTOUT DESIRED (0=FULL, 1=ABBREVIATED, 2=SHORT)?"

0= two pages of printout for each process module including (1) a variable cost detail for the first year selected and (2) a full table of product value vs. year for each process module.

NOTE: If a CRT terminal device is used for output, the first page of printout may be lost.

1= a full table of product value vs. year for each process module.

2= a short table of product value vs. year for each process module. Investment, raw material, by-product, and utility costs, and product value are included.

Q13. "LIST DEFAULT UNIT COST VALUES? (Y OR N)"

Type Y(es) for a list of all default values for 1980-2001 for cost index, inflation factor, hourly wage, and utilities costs. Type N(o) for no list. Default values are shown in Table B.2.

Q14. "DO YOU WISH TO ENTER UNIT COST DATA FOR THE SELECTED YEARS?(Y OR N)"

Type Y(es) to override any of the default data for cost index, hourly wage or utilities costs for the years of interest.

a. "COST INDEXES?"

Enter the cost indexes for the years selected in Q5. An entry of blank or zero for any year causes the default values to be used. Enter / (slash) to use all default values. For example, if 1981,1982,1983,1984,1985 was entered for Q5 and the default cost indexes are 400,430,462.3,496.9,534.2 then

350.,,450./ will result in

1981	1982	1983	1984	1985
350	430	450	496.9	534.2

b. "LABOR COST (US $/HR)?"

Enter the hourly wage for each of the selected years. A blank entry for any year causes the default value to be used. Enter / (slash) to use all default values.

c. "INFLATION FACTOR?"

Enter the inflation factor for the selected years. The inflation factor is used in converting current $ to constant $.

d. "Utilities xx COST, PRECEDED BY COST UNITS..."

21d-k. Enter the utility costs for the selected years, preceded by the appropriate cost unit code. A blank entry for any year causes the default value to be used. Enter / (slash) to use all default values.

For example, 6,4.20,4.30,4.50/

will enter $4.20 /MMBTU for 1981, $4.30/MMBTU for 1982, $4.50/MMBTU for 1983, and default values for the remaining years.

NOTE: The natural gas cost must be entered as a raw material cost (Material Code #17) in Q16 below.

Q15. "LIST RAW MATERIAL CODES AND PRICES (Y OR N)?"

Enter Y(es) for a complete listing of all default raw material prices for 1980-2001. The units shown are the units used by the program. (The default codes and prices are shown in Table B.2).

Q16. 'DO YOU WISH TO ENTER RAW MATERIAL COSTS (Y OR N)?'

Enter Y(es) to override any of the default raw material costs.

Q17. 'THE FOLLOWING UNITS MAY BE USED:
0=$, 1=C/LB, 3=C/MSCF, 6=$/MMBTU, 7=$/TONNE, 8=$/MNM3
ENTER MATERIAL CODE, UNIT, PRICES FOR THE SELECTED YEARS:
CODE, UNIT, PRICES?'

Enter the raw material code, price unit code, and the prices for each of the selected years. A blank entry for any year causes the default value to be used. Type / (slash) to terminate the entry for any raw material or to terminate the raw material price entries.

For example, 26,1,,9.0,9.5/

will enter 9.0 and 9.5 c/lb costs in 1982 and 1983 respectively for vacuum residue, and default values for the remaining years.

Q18. 'module xx PRODUCES HYDROGEN COPRODUCT- PLEASE ENTER THE VALUES FOR THE SELECTED YEARS FOR HYDROGEN IN C/MSCF OF CONTAINED HYDROGEN. (DEFAULT VALUES ARE USED OTHERWISE)'

Enter the hydrogen value in the units requested. A blank entry for any year causes the default value to be used. Type / (slash) to terminate the entry. The prices entered here are used for the by-product credit.

Q19. 'LIST NEWLY ENTERED PRICES (Y OR N)?'

Type Y(es) to list the raw material prices just entered.

Q20. 'DO YOU WISH TO ENTER BASIC OPERATING COST FACTORS (Y OR N)'?

Type Y(es) to override any of the default values for control laboratory, operating supplies, taxes and insurance, depreciation, G&A,S,R, before-tax return on investment, and location factors.

20 a-g. Enter a value, or / (slash) to use the default value.

The investments for all modules in a process sequence are multiplied by the location factor (default value = 1.0). It can be used to modify the default investment data to a non-U.S. location, or to temporarily adjust the investments by the entered factor.

Q21. 'COST UNITS FOR module xx?' (1=C/MSCF, 2=$/MMBTU, 3=C/LB, 4=$/TONNE,5=$/MNM3, 6=$/TON-CAL, 7=C/KG, 8=C/GAL):'

Enter the integer code corresponding to the cost units desired for the production cost summary table printout.

NOTE: Not all listed units are available for each module. The program indicates when the selected units cannot be used and prompts for another choice.

Q22. "PRINT COSTS IN CURRENT $ (DEFAULT,ENTER /) OR IN CONSTANT $ (ENTER YEAR)?"

By default the production cost tables are printed out in current $. Enter a / (slash) for current $ printout. If a year is entered here (in the range 1980-2001) the production costs are printed in constant $ for the year entered. (The variable cost table is printed out for the year in which the constant $ option is chosen.)

Q23. "OVERRIDE MAINTENANCE LABOR, MATERIAL AND OVERHEAD FACTORS FOR module xx (Y OR N)?"

Type Y(es) to override the maintenance and overhead default factors for the listed module.

23a-c. Enter the appropriate factor or type / (slash) to use the default value.

NOTE: The maintenance labor, material, and operating supplies factors are specific to each process module. Any entries here are for the listed module only.

Data Files

The basic process data and default price data are stored in two files which are read by the SYNCOST program via logical units 3 (process data) and 4 (price data). The program stores the data in direct access files and retrieves the data via logical units 1 (process data) and 2 (price data).

The data are stored in list-directed or "free format" form (sucessive entries on a line are separated by commas) and can be modified before execution of the program by a user familiar with file editing.

Process Data File

The process data file (Section B.6) contains capacity, material and utilities consumptions, and investment data for the process modules. The following is a list of the process data file format, by line:

line number

1		module number
2		module title, 40 characters/line maximum
3		"
4	a	cost index
	b	type of investment calculation (see note 1)
	c1	battery limits investment at base capacity
	d1	capacity exponent for scale-down

	e1	capacity exponent for scale-up
	f1	-
	g1	-
or		
	d2	A coefficients used in 3rd order fit
	e2	B of battery limits investment to
	f2	C capacity (c): $BLI=A+Bc+Cc^2+Dc^3$
	g2	D
5	a1	total fixed capital at base capacity
	b1	capacity exponent for scale-down
	c1	capacity exponent for scale-up
	d1	-
	e1	-
or		
	b2	A coefficents used in 3rd order fit
	c2	B of total fixed capital to capacity (c)
	d2	C $TFC=A+Bc+Cc^2+Dc^3$
	e2	D
6	a	unit of capacity (1=MMSCFD, 2=MMBTU/HR, 3=MMLB/YR, 4=TONNE/DAY)
	b	base capacity
	c	stream factor (fraction of time on-stream)
	d	equivalent methanol capacity factor for natural gas processes only (see note 2)
7	a	raw material code (See Table B.2)
	b	raw material unit consumption
	c	consumption units (0=$, 1=LB, 3=MSCF, 5=MGAL

		6=MMBTU, 7=TONNE, 9=MLB)
	d	chemical name (optional)
		Repeat line 7 for each raw material or by-product (maximum of 7 entries)
8		999/
9	a	number of operators at base capacity
	b	integer code for method used to scale number of operators to desired capacity (see note 3)
	c	maintenance labor, %BLI
	d	maintenance materials, %BLI
	e	plant overhead, % total labor
10	a	upper capacity cutoff for utilities consumptions (see note 4)
	b	natural gas fuel unit consumption, mmBtu
	c	fuel oil unit consumption, mmBtu
	d	high press. steam unit consumption, 1,000 lb
	e	medium press. steam unit consumption, 1,000 lb
	f	low press. steam unit consumption, 1,000 lb
	g	electricity unit consumption, kwh
	h	clarified water unit consumption, 1,000 gal
	i	cooling water unit consumption, 1,000 gal
	j	process water unit consumption, 1,000 gal
11		same as line 10 (see note 4)
12		same as line 10 (see note 4)
13	a	product code (for saving the calculated product value in price file, see note 5)
	b	product name (enclosed in apostrophes)
	c	MMBTU/MSCF of product

d SCF/LB of product

e LB/GAL of product

f BTU/LB of product

g minimum plant capacity allowed (same units as base capacity (line 6b))

h maximum plant capacity allowed

i default capacity (to be used for default calculation option)

NOTES:

(1) The investment (I) may be scaled to different capacities in three ways (c = capacity, cb = base capacity, Ib = base investment):

Type 1-(used for coal-based processes)

for $c \leq cb$
$I = A+Bc+Cc^2+Dc^3$
for $c > cb$
I = Ib x (c/cb)**0.95

Type 2- (used for natural gas-based processes)

for $c \leq cb$
$I = Ib \times (A+BE+CE^2+DE^3)$
where E is the equivalent methanol capacity (see note 2)
for $c > cb$
I = Ib x (c/cb)**0.9

Type 3-(used for vacuum residue-based cases)

for $c \leq cb$
I = Ib x (c/cb)**scale-down exponent
for $c > cb$
I = Ib x (c/cb)**scale-up exponent

(2) Equivalent methanol capacity factor, E = 2500/equivalent amount of product produced from a 2500 MTPD methanol reformer. For example, 302.8 MMSCFD Syngas 1.0 can be produced in a 2500 MTPD methanol

reformer, so E=2500/302.8=8.26.

(3) The number of operators can be scaled to different capacities as follows (c = capacity, cb = base capacity):

Code 0-for natural gas and vacuum residue modules:

for c $\leqslant$ cb
#op = # op at base capacity
for c > cb
#op = #op(base) x (c/cb)**0.95

Codes 1-4

The number of operators is expressed as a function of capacity (# op = $A+Bc+Cc^2+Dc^3$; capacity, c is expressed in 1,000 tonnes/day). 1 is used for methanol from coal, 2 for syngases from coal, 3 for methanol from coal syngas, and 4 for hydrogen from coal.

(4) In the natural gas modules, for some plants, the utilities unit consumptions are a function of plant size. The capacity entered here is the maximum capacity at which the utilities consumptions on this line apply. There are provisions for up to 3 utilities consumption ranges on lines 10, 11, and 12, listed in order of decreasing capacity. If the utilities unit consumption is independent of capacity, the capacity entered on line 10 should be a large number, e.g. 1.E6, and lines 11 and 12 lines should contain a / (slash).

(5) If the product number code is entered here, the calculated product value for this module is temporarily entered into the price file and can be used in other modules for the duration of the terminal session.

Up to 12 additional modules can be added to the process data file by following this format. The raw materials used must follow the existing codes in the price file or additional raw material codes must be added to the price file by the user. The price unit and consumption units must match.

Price Data File

The price data file (Section B.6) contains data for all the raw materials and by-products used in the process modules. Up to 50 raw materials and by-products may be used. In addition to the raw material prices, the file contains: cost index, inflation factors, hourly wages, and utilities costs estimated for 1980-2001. Data is in list-directed or "free format" form with sucessive entries on a line separated by commas. The format of this file is as follows.

<u>line number</u>

1	number of years for which data is included (maximum = 22)
2	years for which data is included
3	'PCI', cost index values for each year
4	'INFL FAC', inflation factor for each year (used in constant \$/current \$ conversion)
5	'WAGE', hourly wage (\$/hr) for each year
6	'GAS', natural gas costs (\$/mmBtu)
7	'FUEL', fuel oil costs (\$/mmBtu)
8	'HP STEAM', costs (\$/1000 lb)
9	'MP STEAM', costs (\$/1000 lb)
10	'LP STEAM', costs (\$/1000 lb)
11	'ELECT', electricity costs (c/kwh)
12	'CLARIFIED H20', costs (c/1000 gal)
13	'COOLING H20', costs (c/1000 gal)

14 'PROCESS H2O', costs (c/1000 gal)

15-end

a material code number (see Table B.2)

b material name (enclosed in apostrophes)

c price unit code (0=$, 1=C/LB, 3=C/MSCF, 6=$/MMBTU, 7=$/TONNE, 8=$/MNM3)

d prices for each year

B.4 PRODUCT VALUE CALCULATION

SRI's SYNCOST program calculates product value by the same techniques that are used for PEP reports. The product value is defined as net plant gate cost (including depreciation) plus general, administrative, sales, and research costs plus a 25%/yr pretax return on total fixed capital. The production costs generally do not include any allowance for shipping, i.e. they represent bulk costs, f.o.b. plant. The various elements of the product value calculation are discussed below.

Plant Capacity

The plant capacity figure refers to the annual production rate that can be achieved in a plant that operates continuously about 90% of the time. The capacity is expressed on a contained basis. For syngas modules, the capacity refers to CO + H2 content.

Investments

The battery limits investment is an estimate of the installed major process equipment costs including allowances for engineering, field expenses, overhead, and contractor's costs. The total fixed capital includes the total investment in battery limits, utilities and tankage, waste disposal, and general service facilities. Working capital and start-up costs are not included in the investment figures. The total fixed capital figures also exclude the cost of land, site development, and royalties or licenses. 'Overnight' construction is assumed. Investment data for each process has been estimated at a base capacity and cost index. The investments are updated to the years of interest by means of the PEP Cost Index (1958 = 100) and investments are scaled to other capacities either by using derived capacity exponents or from investment vs. capacity correlations.

Raw Materials

Raw material prices generally do not include delivery or shipping costs (except as noted). All prices and consumptions are expressed on a contained basis.

Operators

The number of operators shown is an estimate for a well instrumented plant. For natural gas and vacuum residue modules we assumed that the number of operators is independent of capacity up to the base capacity and is scaled in proportion to the capacity thereafter. For coal modules, the number of operators is expressed as a function of capacity. The hourly wage is expressed as $/hour actually worked, including fringe benefits and shift overlap.

Utilities

The utilities costs reflect both operating and capital costs (where appropriate). Utilities consumptions are expressed on a contained basis.

Maintenance

Maintenance costs are generally estimated at 1.5-3%/year of the battery limits investment for maintenance labor and 1.5-3%/year for maintenance supplies.

Control Laboratory

Control laboratory labor and operating supplies are estimated at 20% and 10% (default values) respectively of operating labor costs.

Plant Overhead

Plant overhead is estimated as 80% (default value) of total labor for natural gas and vacuum residue-based processes and 30% (default value) of total labor for coal-based processes.

Taxes and Insurance

Taxes and insurance (excluding income tax) are estimated at 2%/year (default value) of total fixed capital.

General, Administrative, Sales, and Research

The general, administrative, sales and research (G&A,S,R) costs are lumped together and taken as 3% (default value) of the product sales. Product sales are based on the computed product value plus the value of the by-products, if any. The G&A,S,R costs are applied only to the final product in any process sequence (unless specified otherwise by the user).

Depreciation

Depreciation is estimated as 10%/year (default value) of total fixed capital.

Return on Investment

The before-tax return on investment is taken as 25%/year (default value) of the total fixed capital.

Interest on Working Capital

Interest on working capital is not included in the product value.

Sample Run 1

```
RUN SYNCOST


WELCOME TO THE SYNCOST PROGRAM FOR ESTIMATING COSTS
OF SYNTHESIS GASES, CARBON MONOXIDE, HYDROGEN AND METHANOL.
ALL CONSUMPTIONS AND COSTS ARE EXPRESSED ON A CONTAINED BASIS.
ADDITIONAL INFORMATION ABOUT THE PROCESSES MAY BE FOUND
IN SRI INTERNATIONAL PROCESS ECONOMIC PROGRAM REPORT 148.



Q1.  TYPE 0 TO STOP NOW OR
ENTER FEEDSTOCK:  1=COAL, 2=NATURAL GAS, 3=VAC. RESIDUE?
1
Q2. LIST AVAILABLE MODULES (Y OR N)?
Y
FEEDSTOCK:  COAL
MODULES AVAILABLE:
   1-SYNGAS(H2/CO=0.75) FROM COAL
     (    50.- 1600.MMSCFD  )
   2-SYNGAS(H2/CO=1.0) FROM COAL
     (    50.- 1600.MMSCFD  )
   7-SYNGAS(H2/CO=1.5) FROM COAL
     (    50.- 1600.MMSCFD  )
   8-SYNGAS(H2/CO=2.0) FROM COAL
     (    50.- 1600.MMSCFD  )
  13-METHANOL SYNGAS(H2/CO=2.26) FROM COAL
     (    50.- 1600.MMSCFD  )
  19-CO FROM COAL-DERIVED METHANOL SYNGAS (H2/CO=2.26) BY COSORB
     (    70.-  600.MMLB/YR )
  22-HYDROGEN(97%) FROM COAL
     (    50.- 1560.MMSCFD  )
  26-METHANOL FROM COAL
     (  600.-20000.TONNE/D )
  27-METHANOL FROM COAL-DERIVED METHANOL SYNGAS(H2/CO=2.26)
     (  600.-20000.TONNE/D )
Q4. NUMBER OF YEARS FOR WHICH ESTIMATES ARE TO BE CALCULATED(MAX=10)?
3
Q5. WHICH YEARS?
1982,1983,1984
Q6. PRODUCT MODULE?
27
Q7. RUN BASE CASE, WITH DEFAULT VALUES FOR ALL
 MODULES IN THE PROCESS SEQUENCE (Y OR N)?
Y
Q10. INTERMEDIATE MODULE?
13
Q10. INTERMEDIATE MODULE?
/
Q12. TYPE OF PRINTOUT DESIRED, (0=FULL, 1=ABBREVIATED 2=SHORT)?
0
```

METHANOL SYNGAS(H2/CO=2.26) FROM COAL (MODULE #13)

805.30 MMSCFD

VARIABLE COST SUMMARY FOR 1982

	UNIT COST	CONSUMPTION PER MSCF	C/MSCF
RAW MATERIALS			
COAL AT MINE	34.60$/TONNE	0.0186	64.49
COAL TRANSPORT	16.00$/TONNE	0.0186	29.82
ASH DISPOSAL	5.35$/TONNE	0.0019	1.00
MISC. CHEM. & CAT.			0.66
			95.97
BY PRODUCTS			
SULFUR	4.87C/LB	(1.2570)	(6.12)
			(6.12)
IMPORTED UTILITIES			
HP STEAM	8.30$/MLB	0.0076	6.31
ELECTRICITY	4.50C/KWH	(0.0825)	(0.37)
CLARIFIED WATER	46.00C/MGAL	0.0151	0.70
			6.64
TOTAL VARIABLE COSTS			96.49

Output from Sample Run 1

"Full" and "Abbreviated" printout options

METHANOL SYNGAS(H2/CO=2.26) FROM COAL (MODULE #13)

805.30 MMSCFD

**COSTS SHOWN IN CURRENT $

	1982	1983	1984
INVESTMENTS (MM$)			
BATTERY LIMITS(BLI)	1197.9	1287.9	1384.3
TOTAL FIXED CAPITAL(TFC)	1463.7	1573.7	1691.5
COST INDEX(CURRENT $)	430.0	462.3	496.9
COAL AT MINE ($/TONNE)	34.60	37.00	39.60
PRODUCTION COST, C/MSCF			
RAW MATERIALS	95.97	102.80	110.00
BY-PRODUCT CREDIT	(6.12)	(6.56)	(7.05)
IMPORTED UTILITIES	6.64	7.11	7.59
VARIABLE COSTS	96.49	103.35	110.54
OPERATING LABOR(42.0/SHIFT)	2.63	2.84	3.05
MAINTENANCE LABOR(1.6% BLI)	7.25	7.79	8.37
CONTROL LAB LABOR(20.0% OP LABOR)	0.53	0.57	0.61
TOTAL DIRECT LABOR	10.41	11.20	12.03
MAINTENANCE MATERIALS(2.4% BLI)	10.87	11.68	12.56
OPERATING SUPPLIES(10.0%OP LABOR)	0.26	0.28	0.31
	11.13	11.96	12.87
PLANT OVERHEAD(30.0% TOTAL LABOR)	3.12	3.36	3.61
TAXES AND INSURANCE(2.0% TFC)	11.07	11.90	12.79
DEPRECIATION(10.0% TFC)	55.33	59.49	63.94
	69.52	74.75	80.34
SUBTOTAL: PLANT GATE COST	187.55	201.26	215.78
ROI BEFORE TAXES(25.0% TFC)	138.32	148.72	159.85
PRODUCT VALUE(PV), C/MSCF	325.87	349.98	375.63

METHANOL FROM COAL-DERIVED (MODULE #27)
METHANOL SYNGAS(H2/CO=2.26)

10000.00 TONNE/D

VARIABLE COST SUMMARY FOR 1982

	UNIT COST	CONSUMPTION PER TONNE	$/TONNE
RAW MATERIALS			
SYNGAS(2.26)/C	3.26$/MSCF	80.5000	262.33
METHANOL CATALYST	4.30$/LB	0.4000	1.72
MISC. CHEM. & CAT.			0.11
			264.16
IMPORTED UTILITIES			
HP STEAM	8.30$/MLB	(0.6100)	(5.06)
ELECTRICITY	4.50C/KWH	6.6300	0.30
CLARIFIED WATER	46.00C/MGAL	0.1500	0.07
			(4.69)
TOTAL VARIABLE COSTS			259.47

Output from Sample Run 1

"Full" and "Abbreviated" printout options

METHANOL FROM COAL-DERIVED (MODULE #27)
METHANOL SYNGAS(H2/CO=2.26)

10000.00 TONNE/D

**COSTS SHOWN IN CURRENT $

	1982	1983	1984
INVESTMENTS (MM$)			
BATTERY LIMITS(BLI)	169.9	182.6	196.3
TOTAL FIXED CAPITAL(TFC)	236.5	254.3	273.3
COST INDEX(CURRENT $)	430.0	462.3	496.9
SYNGAS(2.26)/C ($/MSCF)	3.26	3.50	3.76
PRODUCTION COST, $/TONNE			
RAW MATERIALS	264.16	283.68	304.48
IMPORTED UTILITIES	(4.69)	(5.02)	(5.36)
VARIABLE COSTS	259.47	278.66	299.12
OPERATING LABOR(20.0/SHIFT)	1.01	1.09	1.17
MAINTENANCE LABOR(1.6% BLI)	0.83	0.89	0.96
CONTROL LAB LABOR(20.0% OP LABOR)	0.20	0.22	0.23
TOTAL DIRECT LABOR	2.04	2.20	2.36
MAINTENANCE MATERIALS(2.4% BLI)	1.24	1.33	1.43
OPERATING SUPPLIES(10.0%OP LABOR)	0.10	0.11	0.12
	1.34	1.44	1.55
PLANT OVERHEAD(30.0% TOTAL LABOR)	0.61	0.66	0.71
TAXES AND INSURANCE(2.0% TFC)	1.44	1.55	1.66
DEPRECIATION(10.0% TFC)	7.20	7.74	8.32
	9.25	9.95	10.69
SUBTOTAL: PLANT GATE COST	272.10	292.25	313.72
G&A, SALES, RESEARCH(3.0% PV)	8.97	9.64	10.35
ROI BEFORE TAXES(25.0% TFC)	18.00	19.35	20.80
PRODUCT VALUE(PV), $/TONNE	299.07	321.24	344.87

"Short" printout option

METHANOL SYNGAS(H2/CO=2.26) FROM COAL (MODULE #13)

805.30 MMSCFD

**COSTS SHOWN IN CURRENT $

		1982	1983	1984
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)		1197.9	1287.9	1384.3
TOTAL FIXED CAPITAL(TFC)		1463.7	1573.7	1691.5
COST INDEX(CURRENT $)		430.0	462.3	496.9
COAL AT MINE	($/TONNE)	34.60	37.00	39.60
RAW MATERIALS		95.97	102.80	110.00
BY-PRODUCT CREDIT		(6.12)	(6.56)	(7.05)
IMPORTED UTILITIES		6.64	7.11	7.59
PRODUCT VALUE(PV), C/MSCF		325.87	349.98	375.63

METHANOL FROM COAL-DERIVED (MODULE #27)
METHANOL SYNGAS(H2/CO=2.26)

10000.00 TONNE/D

**COSTS SHOWN IN CURRENT $

		1982	1983	1984
INVESTMENTS (MM$)				
BATTERY LIMITS(BLI)		169.9	182.6	196.3
TOTAL FIXED CAPITAL(TFC)		236.5	254.3	273.3
COST INDEX(CURRENT $)		430.0	462.3	496.9
SYNGAS(2.26)/C	($/MSCF)	3.26	3.50	3.76
RAW MATERIALS		264.16	283.68	304.48
IMPORTED UTILITIES		(4.69)	(5.02)	(5.36)
PRODUCT VALUE(PV), $/TONNE		299.07	321.24	344.87

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C****SYNCOST- JANUARY 10, 1983
C*    A PROGRAM FOR ESTIMATING SYNTHESIS GAS, CARBON MONOXIDE,
C*    HYDROGEN AND METHANOL COSTS.  FEEDSTOCKS AVAILABLE ARE
C*    COAL, NATURAL GAS AND RESIDUAL OIL.  THE PROGRAM RUNS
C*    IN CONJUNCTION WITH TWO DATA FILES- CHEMICAL AND UTILITY
C*    PRICES (UNIT 4) AND  PROCESS DATA (UNIT 3).
C*
C*    TABLES DISPLAYING UP TO 10 YEARS OF PRODUCTION COSTS CAN
C*    BE GENERATED.
C*
C*    USER-SUPPLIED INPUT IS INTERACTIVE (IN RESPONSE TO
C*    PROGRAM PROMPTS).
C**
C**DEFINITIONS
C**
C**NON-SUBSCRIPTED VARIABLES
C**
C*  BLA        BATTERY LIMITS INVESTMENT CALCULATION FACTOR
C*  BLB        BATTERY LIMITS INVESTMENT CALCULATION FACTOR
C*  BLC        BATTERY LIMITS INVESTMENT CALCULATION FACTOR
C*  BLD        BATTERY LIMITS INVESTMENT CALCULATION FACTOR
C*  BLIP       BATTERY LIMITS INVESTMENT (MM$) IN PROCESS FILE
C*  CAPB       BASE CAPACITY OF DATA IN PROCESS FILE
C*  CAPD       DEFAULT CAPACITY USED IN CALCULATIONS
C*  CAPMAX     MAXIMUM CAPACITY ALLOWED FOR PROCESS CALCULATIONS
C*  CAPMIN     MINIMUM CAPACITY ALLOWED FOR PROCESS CALCULATIONS
C*  CAPS       CAPACITY REQUESTED BY USER
C*  CF1        CONVERSION FACTOR, MMBTU/MSCF
C*  CF2        CONVERSION FACTOR, SCF/LB
C*  CF3        CONVERSION FACTOR, LB/GAL
C*  CF4        CONVERSION FACTOR, BTU/LB
C*  CYR        YEARLY CAPACITY
C*  EQMETH     EQUIVALENT METHANOL CAPACITY FACTOR
C*  F1         CONSUMPTION CONVERSION FACTOR
C*  F2         COST CONVERSION FACTOR
C*  FLOC       LOCATION FACTOR FOR INVESTMENTS
C*  I1         INTEGER CODE FOR COST UNITS USED FOR PRINTOUT
C*  ICAPP      USER-REQUESTED PRODUCT MODULE CAPACITY UNITS
C*  ICS        INTEGER CODE FOR CAPACITY UNITS SELECTED BY USER
C*  ICUNP      INTEGER CODE FOR CAPACITY UNITS IN PROCESS FILE
C*  IDOL       YEAR FOR WHICH CONSTANT DOLLAR CALUCATIONS DONE
C*  IERR       ERROR FLAG DURING MATERIAL PRICE CONVERSIONS
C*  IFY        ARRAY SUBSCRIPT CORRESPONDING TO YEAR CHOSEN FOR
C*               CONSTANT $ CALCULATIONS
C*  IP         INTEGER CODE FOR UNITS OF CAPACITY
C*  IPFLAG     TYPE OF PRINTOUT
C*  IPUN       CODE FOR MATERIAL PRICE UNITS, EG. 1=C/LB
C*  IU         ARRAY INDEX FOR UTILITIES
C*  IUN        CODE FOR UTILITIES PRICES, EG. 6=$/MMBTU
C*  IY         ARRAY INDEX FOR YEAR
C*  IYP        ARRAY SUBSCRIPT FOR YEAR USED FOR VARIABLE COST PRINTOUT
C*  L1         I/O UNIT 1- DIRECT ACCESS FILE FOR PRICE DATA
C*  L2         I/O UNIT 2- DIRECT ACCESS FILE FOR PROCESS DATA
C*  L3         I/O UNIT 3- INPUT PROCESS DATA
C*  L4         I/O UNIT 4- INPUT PRICE DATA
C*  L5         I/O UNIT 5- INTERACTIVE INPUT
C*  L6         I/O UNIT 6- INTERACTIVE OUTPUT
C*  L7         I/O UNIT 7- COST TABLES OUTPUT
C*  MLS        CODE FOR OPERATING LABOR SCALING CALCULATION
C*  MODNP      PRODUCT MODULE NUMBER
C*  NAME       RAW MATERIAL (OR BY-PRODUCT) NAME
C*  NBP        NUMBER OF BY-PRODUCTS
C*  NEWRUN     FLAG INDICATING FIRST OR SUBSEQUENT PROCESS SEQUENCE
C*  NF         TYPE OF FEEDSTOCK: 1=COAL, 2=GAS, 3=RESID
C*  NH         HYDROGEN RECORD NUMBER IN PRICE FILE
C*  NI         CODE FOR METHOD OF SCALING INVESTMENT TO
C*               REQUESTED CAPACITY
C*  NMAT       NUMBER OF RAW MATERIALS AND BY-PRODUCTS IN PROCESS
C*  NMOD       NUMBER OF PROCESS MODULES IN PROCESS SEQUENCE
C*  NN         RAW MATERIAL RECORD NUMBER ( IN PRICE FILE)
C*  NPRICE     NUMBER OF RAW MATERIAL PRICES ENTERED BY USER
C*  NPROD      PRODUCT CODE (CORRESPONDS TO RECORD NUMBER IN PRICE FILE)
C*  NUM        RAW MATERIAL CODE FOR PRICES ENTERED BY USER
C*  NYEAR      NUMBER OF YEARS FOR WHICH CALCULATIONS ARE TO BE DONE
C*  NYEARD     NUMBER OF YEARS FOR WHICH DATA IS STORED IN PRICE FILE
C*  OSE        ON-STREAM EFFICIENCY
C*  PCAP       PRODUCT MODULE CAPACITY REQUESTED BY USER
C*  PCIP       COST INDEX OF INVESTMENT DATA IN PROCESS FILE
C*  PCL        CONTROL LAB, % OF OPERATING LABOR
C*  PCLD       DEFAULT VALUE, CONTROL LAB, % OF OPERATING LABOR
C*  PDP        DEPRECIATION, %TFC
C*  PDPD       DEFAULT DEPRECIATION, % TFC
C*  PGA        GENERAL, ADMIN, SALES, RESEARCH, % OF PRODUCT VALUE
C*               USED FOR CALCULATION
C*  PGAD       DEFAULT GENERAL, ADMIN, SALES, RESEARCH
C*  PGAP       GENERAL, ADMIN, SALES, RESEARCH, % OF PRODUCT VALUE
C*  PMLP       MAINTENANCE LABOR, % BLI
C*  PMMP       MAINTENANCE MATERIALS, % BLI
C*  POS        OPERATING SUPPLIES, % OPERATING LABOR
C*  POSD       DEFAULT OPERATING SUPPLIES, % OPERATING LABOR
C*  PPOP       PLANT OVERHEAD, % TOTAL LABOR
C*  PRI        RETURN ON INVESTMENT, % TFC
C*  PRID       DEFAULT RETURN ON INVESTMENT, % TFC
C*  PROD       PRODUCT NAME
C*  PTI        TAXES AND INSURANCE, % TFC
C*  PTID       DEFAULT TAXES AND INSURANCE, % TFC
C*  PUNM1      PRICE UNITS OF MAJOR RAW MATERIAL IN PROCESS
C*  READAL     LOGICAL FLAG USED TO SKIP VARIOUS INPUT WHEN DEFAULT
C*               OPTION CHOSEN
C*  TCA        TOTAL FIXED CAPITAL INVESTMENT CALCULATION FACTORS
C*  TCB        TOTAL FIXED CAPITAL INVESTMENT CALCULATION FACTORS
C*  TCC        TOTAL FIXED CAPITAL INVESTMENT CALCULATION FACTORS
C*  TCD        TOTAL FIXED CAPITAL INVESTMENT CALCULATION FACTORS
C*  TFCP       TOTAL FIXED CAPITAL (MM$) IN PROCESS DATA FILE
C*  TITLE1     PROCESS TITLE
C*  TITLE2     PROCESS TITLE
C*  TOP        NUMBER OF OPERATORS AT BASE CAPACITY
C*  TOPR       NUMBER OF OPERATORS SCALED TO REQUESTED CAPACITY
C*  YEARFL     LOGICAL FLAG- TRUE IF REQUESTED YEARS ARE OUTSIDE
C*               DEFAULT RANGE
C*  YORN       YES OR NO ANSWER TO INPUT PROMPTS
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C*
C**SUBSCRIPTED VARIABLES
C*  BLI(N)       BATTERY LIMITS INVESTMENT IN NTH YEAR (MM$)
C*  BPC(N)       BY-PRODUCT VALUE IN NTH YEAR
C*  CAP(M)       USER-REQUESTED CAPACITY FOR MTH PROCESS IN SEQUENCE
C*  CAPU         UPPER CAPACITY CUTOFF FOR UTILITIES CONSUMPTION
C*  CAPUN        CAPACITY UNITS, EG. 'MMSCFD'
C*  CONS(K)      UNIT CONSUMPTION OF RAW MATERIAL K
C*  COSTUN       COST UNITS, EG. 'C/MSCF'
C*  DEP(N)       DEPRECIATION IN NTH YEAR
C*  DFAC(N)      CURRENT $ TO CONSTANT $ CONVERSION FACTOR FOR NTH YEAR
C*  DUMM         DUMMY ARRAY
C*  FINF(N)      INFLATION FACTOR IN NTH YEAR
C*  FINFD        DEFAULT ARRAY OF INFLATION FACTORS
C*  GA(N)        GENERAL, ADMIN., SALES, RESEARCH COSTS IN NTH YEAR
C*  ICAPUN(M)    CODE FOR CAPACITY UNITS FOR MTH PROCESS
C*  IPRUN        CODE FOR MATERIAL PRICE UNITS
C*  IUF          CODE FOR ALLOWABLE UTILITIES UNITS
C*  IUNUT        CODE FOR UTILITIES UNITS USED IN PROCESS FILE
C*  IYEAR(N)     NTH YEAR REQUESTED BY USER
C*  IYEARD       DEFAULT YEARS IN DATA FILE
C*  MAT(K)       INTEGER CODE FOR KTH RAW MATERIAL IN PROCESS
C*  MNAME(K)     NAME OF KTH RAW MATERIAL IN PROCESS
C*  MODH(M)      CODE FOR HYDROGEN BY-PRODUCT PRODUCED IN MODULUE M
C*  MODN(M)      MTH MODULE IN PROCESS SEQUENCE
C*  MUN(K)       UNITS OF CONSUMPTION OF KTH RAW MATERIAL IN PROCESS
C*  NEWPR        NEW RAW MATERIAL PRICES SUPPLIED BY USER
C*  PCI(N)       COST INDEX IN NTH YEAR
C*  PCID         DEFAULT ARRAY OF COST INDEXES
C*  PO(N)        PLANT OVERHEAD IN NTH YEAR
C*  PR(N)        RAW MATERIAL PRICE SUPPLIED BY USER FOR NTH YEAR
C*  PRCAP(M)     CAPACITY RANGE OF MTH MODULE
C*  PRICE(N,K)   PRICE OF RAW MATERIAL K IN NTH YEAR
C*  PRICED       DEFAULT ARRAY OF RAW MATERIAL PRICES
C*  PRM1(N)      PRICE OF MAJOR RAW MATERIAL IN PROCESS FOR NTH YEAR
C*  PRNAME(M)    PROCESS TITLE FOR PROCESS M
C*  PUNIT        PRICE UNITS, EG. 'C/LB'
C*  PV(N)        PRODUCT VALUE IN NTH YEAR
C*  RMC(N)       RAW MATERIAL COSTS IN NTH YEAR
C*  ROI(N)       RETURN ON INVESTMENT IN NTH YEAR
C*  TCL(N)       CONTROL LAB LABOR COST IN NTH YEAR
C*  TFC(N)       TOTAL FIXED CAPITAL IN NTH YEAR (MM$)
C*  TI(N)        TAXES AND INSURANCE IN NTH YEAR
C*  TML(N)       MAINTENANCE LABOR IN NTH YEAR
C*  TMM(N)       MAINTENANCE MATERIAL IN NTH YEAR
C*  TOL(N)       OPERATING LABOR IN NTH YEAR
C*  TOS(N)       OPERATING SUPPLIES IN NTH YEAR
C*  TTL(N)       TOTAL LABOR IN NTH YEAR
C*  UNOUT        PRODUCTION COST UNITS, EG. 'C/MSCF'
C*  UTC(N)       UTILITIES COSTS IN NTH YEAR
C*  UTCON(K)     UTILITIES CONSUMPTION OF UTILITY K AT REQUESTED CAPACITY
C*  UTCOMP(K,L)  UTILITIES CONSUMPTION OF UTILITY K FOR CAPACITY RANGE L
C*  UTFORM       ALLOWABLE UTILITIES UNITS
C*  UTIL(N,K)    UTILITIES COST FOR UTILITY K IN NTH YEAR
C*  UTILD        DEFAULT UTILITIES COSTS
C*  UTNAME       UTILITY NAMES
C*  UTUN(K)      COST UNITS FOR UTILITY K
C*  WAGE(N)      HOURLY WAGE ($/HR) IN NTH YEAR
C*  WAGED        DEFAULT HOURLY WAGE
C*
      DIMENSION CAP(5),IUF(9),PR(10),NEWPR(50),DUMM(12),
     1ICAPUN(5),IUNUT(9),MODN(5),MODH(40),PRICED(22),FINF(10)
      LOGICAL YEARFL,READAL
      CHARACTER YORN*1,   NAME*20, PUNM1*7 , MNAME(8)*20,
     1UTNAME(9)*15, UNOUT(8)*7,PUNIT(11)*7,COSTUN(8)*7,
     2CAPUN(4)*8, TITLE1*40, TITLE2*40, UTFORM(5)*44,
     3PRNAME(40)*60, PROD*16, PRCAP(40)*21, UTUN(9)*7
      COMMON/IO/L1,L2,L3,L4,L5,L6,L7,IPFLAG
      COMMON/DEFAULT/NYEARD,PCID(22),WAGED(22),FINFD(22)
      COMMON/YEARS/NYEAR,IYEAR(10),IYEARD(22),IDOL,DFAC(10)
      COMMON/YDAT/PRICE(10,50),PCI(10),WAGE(10)
      COMMON/CAPCTY/CAPC,CYR,I1,CAPS,ICS
      COMMON/PERCNT/PCL,PDP,PTI,POS,PRI,PGA
      COMMON/OPCOST/GA(10),DEP(10),TI(10),TML(10),TMM(10),TTL(10),
     1TCL(10),PO(10),ROI(10),RMC(10),UTC(10),TOS(10),PV(10),BPC(10)
     2,TOL(10),TOPR,F1,F2,BLI(10),TFC(10),NBP,PRM1(10)
      COMMON/UCHAR/UTNAME,UTUN
      COMMON/CHAR/PRNAME,PRCAP
      COMMON/UTLTY/UTIL(10,9),UTILD(22,9)
      COMMON/PRDAT/CAPB,ICUMP,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,OSE,MLS,
     1TCA,TCB,TCC,TCD,NMAT,MAT(8),CONS(8),TOP,NPROD,PMLP,PMMP,PPOP
     2,IPRUN(8),MUN(8),CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,FLOC,EQMETH,
     3CAPU(3),UTCON(9),UTCOMP(9,3),CAPD
      COMMON/PCHAR/MNAME,TITLE1,TITLE2,PROD,UNOUT,PUNIT,COSTUN,CAPUN
     1,PUNM1
      DATA UTNAME/'NAT. GAS FUEL', 'FUEL OIL', 'HP STEAM',
     1'MP STEAM', 'LP STEAM', 'ELECTRICITY', 'CLARIFIED WATER',
     2'COOLING WATER', 'PROCESS WATER'/
      DATA IUNUT/6,6,9,9,9,0,5,5,5/
      DATA CAPUN/'MMSCFD','MMBTU/HR','MMLB/YR','TONNE/D'/
      DATA PUNIT/'$','C/LB','C/KG','C/MSCF','C/NM3','C/MGAL','$/MMBTU',
     1'$/TONNE','$/MNM3','$/MLB','$/T-CAL'/
      DATA UNOUT/'MSCF','MMBTU','LB','TONNE','MNM3','TON-CAL','KG',
     1'GAL'/
      DATA COSTUN/'C/MSCF','$/MMBTU','C/LB','$/TONNE','$/MNM3',
     1'$/T-CAL', 'C/KG','C/GAL'/
      DATA PCLD,PDPD,PTID,POSD,PRID,PGAD/20.,10.,2.,10.,25.,3./
      DATA IUF/1,1,2,2,2,3,4,4,4/
      DATA UTFORM/' 6=US $/MMBTU OR 10=US $/TON-CAL',
     1' 9=US $/1000 LB OR 7=US $/1000 KG', ' 11=US C/KWH',
     2' 5=US C/1000 GAL OR 4=US C/CU M',' '/
      DATA UTUN/'$/MMBTU','$/MMBTU','$/MLB','$/MLB','$/MLB','C/KWH',
     1'C/MGAL','C/MGAL','C/MGAL'/
      DATA MODH/3*0,2*11,5*0,11,3*0,11,11,9,11,10,11,20*0/
C**  DEFINE LOGICAL UNITS
      L1=1
      L2=2
      L3=3
      L4=4
      L5=5
      L6=6
      L7=7
```

```
      NEWRUN=1
C**   OPEN PRICE AND PROCESS DATA FILES FOR DIRECT ACCESS
      OPEN(L1,ACCESS='DIRECT',RECL=29,STATUS='NEW')
      OPEN(L2,ACCESS='DIRECT',RECL=108,STATUS='NEW')
C**   SET UP PROCESS DATA FILE AND MATERIAL PRICE FILE
C**    L1=PRICE FILE
C**    L2=PROCESS DATA FILE
      CALL DATAF
      WRITE(L6,800)
 50   WRITE(L6,801)
      READ(L5,*,END=1000) NF
C**   CHECK FOR JOB END
      IF(NF.EQ.0) GO TO 1000
      WRITE(L6,805)
      READ(L5,822,END=1000) YORN
      IF(YORN.EQ.'Y') CALL PLIST(NF)
C**   READ IN DESIRED MODULES AND CAPACITIES
C**
C**   ZERO MODULE DATA AND FACTORS
      ICAPP=0
      DO M=1,5
        CAP(M)=0.
        ICAPUN(M)=0
        MODN(M)=0
      ENDDO
      PCAP=0.
C** CHECK FOR USING PREVIOUSLY ENTERED YEAR,WAGE,UTILITY DATA
      IF(NEWRUN.EQ.0) THEN
        WRITE(L6,877)
        READ(L5,822) YORN
      END IF
 80   IF(YORN.NE.'Y'.OR.NEWRUN.EQ.1) THEN
        NYEAR=0
        DO IY=1,10
          WAGE(IY)=-.00001
          PCI(IY)=-.00001
          IYEAR(IY)=0
          FINF(IY)=-.00001
          DO IU=1,9
            UTIL(IY,IU)=-.00001
          ENDDO
          DO K=1,50
            PRICE(IY,K)=-.00001
          ENDDO
        ENDDO
        PRI=-0.00001
        PBP=-0.00001
        PGAP=-0.00001
        PTI=-0.00001
        PCL=-0.00001
        POS=-0.00001
        IDOL=0
        FLOC=1.
C*    READ IN YEARS
        WRITE(L6,810)
        READ(L5,*) NYEAR
        NYEAR=MIN0(NYEAR,10)
        WRITE(L6,809)
        READ(L5,*) (IYEAR(IY),IY=1,NYEAR)
      END IF
C**   CHECK TO SEE IF YEARS ARE ENTERED
      IF(NYEAR.EQ.0) THEN
        YORN='N'
        GO TO 80
      END IF
 100  WRITE(L6,803)
C** SELECT PRODUCT MODULE/CAPACITY
      READ(L5,*) MODNP
      NEWRUN=0
      IF(MODNP.GT.50) THEN
        WRITE(L6,802)
        GO TO 100
      END IF
C**   RUN BASE CASES, USING DEFAULTS?
      WRITE(L6,871)
      READ(L5,822)YORN
      READAL=.TRUE.
      IF(YORN.EQ.'Y') READAL=.FALSE.
      NMOD=1
      IF(READAL) THEN
        READ(L2,REC=ABS(MODNP))TITLE1,TITLE2,DUMM,IP,CAPD,CAPB
        IF(CAPD.LT.0.001) CAPD=CAPB
        WRITE(L6,806) CAPD,CAPUN(IP)
 109    READ(L5,*,ERR=110,END=111)PCAP,ICAPP
        GO TO 111
 110    CALL ERROR(*109)
 111    IF(ICAPP.EQ.0) ICAPP=1
        WRITE(L6,804)
        READ(L5,822) YORN
        IF(YORN.EQ.'Y')CALL FPLIST(MODNP)
      END IF
C** SELECT INTERMEDIATE MODULES/CAPACITIES
 120  NMOD=1
      DO M=1,4
 140    WRITE(L6,808)
        READ(L5,*,END=150) MODN(M)
        IF(MODN(M).EQ.0) GO TO 150
        IF(READAL) THEN
          READ(L2,REC=(ABS(MODN(M))))TITLE1,TITLE2,DUMM,IP,CAPD,CAPB
          IF(CAPD.LT.0.001) CAPD=CAPB
          WRITE(L6,806)CAPD,CAPUN(IP)
 145      READ(L5,*,ERR=146,END=147) CAP(M),ICAPUN(M)
          GO TO 147
 146      CALL ERROR(*145)
 147      IF(ICAPUN(M).EQ.0) ICAPUN(M)=1
        END IF
        NMOD=M+1
      ENDDO
C**   SET PRODUCT MODULE AS LAST MODULE IN CHAIN
C** NEGATIVE MODULE CODE SUPPRESSES G+A CALCULATION
 150  MODN(NMOD)=-MODNP
      ICAPUN(NMOD)=ICAPP
```

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      CAP(NMOD)=PCAP
C** SELECT PRINTOUT OPTIONS
      WRITE(L6,852)
      READ(L5,*)IPFLAG
      YORN='N'
      YEARFL=.FALSE.
C** CHECK FOR YEARS OUTSIDE DEFAULT YEARS
      DO IY=1,NYEAR
        IF(IYEAR(IY).LT.IYEARD(1).OR.IYEAR(IY).GT.IYEARD(NYEARD)) THEN
          WRITE(L6,884) IYEAR(IY)
          YEARFL=.TRUE.
        END IF
      ENDDO
C* USER INPUT OF UNIT COSTS FOR GIVEN YEARS
      IF(YEARFL) GO TO 201
C**  PRINT OUT DEFAULT UNIT COSTS IF DESIRED
 200  IF(READAL)THEN
        WRITE(L6,860)
        READ(L5,822) YORN
        IF(YORN.EQ.'Y') THEN
          WRITE(L6,861)(I,I=0,9)
          WRITE(L6,862) (PCID(IY),IY=1,22)
          WRITE(L6,882) (FINFD(IY),IY=1,22)
          WRITE(L6,863) (WAGED(IY),IY=1,22)
          DO IU=1,9
            WRITE(L6,864) UTNAME(IU),UTUN(IU),(UTILD(IY,IU),IY=1,22)
          ENDDO
        END IF
        WRITE(L6,812)
        READ(L5,822) YORN
      END IF
 201  IF(YORN.EQ.'Y'.OR.YEARFL.AND.READAL) THEN
        WRITE(L6,813)
C** ENTER COST INDEX FOR GIVEN YEARS
 202    READ(L5,*,END=205,ERR=203) (PCI(IY),IY=1,NYEAR)
        GO TO 205
 203    CALL ERROR(*202)
 205    CALL DEFAULT(PCID,PCI)
C**  ENTER INFLATION FACTOR
 207    WRITE (L6,817)
 210    READ(L5,*,END=215,ERR=213) (FINF(IY),IY=1,NYEAR)
        GO TO 215
 213    CALL ERROR (*210)
 215    CALL DEFAULT(FINFD,FINF)
 217    WRITE(L6,815)
C**  ENTER WAGES FOR GIVEN YEARS
 220    READ(L5,*,END=230,ERR=221) (WAGE(IY),IY=1,NYEAR)
        GO TO 230
 221    CALL ERROR(*220)
 230    CALL DEFAULT(WAGED,WAGE)
C**  ENTER UTILITIES COSTS FOR GIVEN YEARS
        WRITE(L6,878)
        DO IU=2,9
          IUN=0
 235      WRITE(L6,816) UTNAME(IU)
          WRITE(L6,870) UTFORM(IUF(IU))
 236      READ(L5,*,END=240,ERR=237) IUN,(UTIL(IY,IU),IY=1,NYEAR)
          IF(IUN.EQ.0) GO TO 240
          GO TO 238
 237      CALL ERROR(*236)
C**  CONVERT UNITS IF NECESSARY
 238      IERR=0
          IF(IU.NE.6) CALL CONVERT(IUN,IUNUT(IU),UTIL(1,IU),IERR)
          IF(IERR.NE.0) THEN
            WRITE(L6,807)
            GO TO 235
          END IF
C**  SET DEFAULT VALUES IF NECESSARY
 240      CALL DEFAULT(UTILD(1,IU),UTIL(1,IU))
 250    ENDDO
      ELSE
C**  SET DEFAULT VALUES FOR PCI, WAGES, UTILITIES COSTS
        CALL DEFAULT(PCID,PCI)
        CALL DEFAULT(WAGED,WAGE)
        CALL DEFAULT(FINFD,FINF)
        DO IU=1,9
          CALL DEFAULT(UTILD(1,IU),UTIL(1,IU))
        ENDDO
      END IF
      NPRICE=0
 430  IF(READAL.OR.YEARFL)THEN
C** PRINT OUT LIST OF RAW MATERIAL CODES IF DESIRED
        WRITE(L6,865)
        READ(L5,822) YORN
        IF(YORN.EQ.'Y') THEN
          WRITE(L6,869)(I,I=0,9)
          DO I=1,50
            NN=0
            READ(L1,REC=I,ERR=436) NN,NAME,IUN,PRICED
            IF(NN.NE.0)
     1      WRITE(L6,866) I,NAME,PUNIT(IUN+1),(PRICED(J),J=1,22)
 436      ENDDO
        END IF
C*  ENTER RAW MATERIAL COSTS
        WRITE(L6,849)
        READ(L5,822)YORN
        IF(YORN.EQ.'Y') THEN
          WRITE(L6,851)
          WRITE(L6,850)
          DO I=1,50
            NUM=0
            WRITE(L6,876)
            DO IY=1,NYEAR
              PR(IY)=-.0001
            ENDDO
 440        READ(L5,*,END=444,ERR=441) NUM,IUN,(PR(IY),IY=1,NYEAR)
            IF(NUM.EQ.0) GO TO 444
            GO TO 442
 441        CALL ERROR(*440)

 442        READ(L1,REC=NUM) NN,NAME,IPUN,PRICED
C**  CONVERT PRICES IF NECESSARY
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          IERR=0
          IF(IUN.NE.IPUN)CALL CONVERT(IUN,IPUN,PR,IERR)
          IF(IERR.NE.0) THEN
            WRITE(L6,859) PUNIT(IUN+1),NUM,PUNIT(IPUN+1)
            GO TO 440
          END IF
C**  SET DEFAULT PRICES WHERE NECESSARY
          CALL DEFAULT(PRICED,PR)
          NPRICE=NPRICE+1
          NEWPR(NPRICE)=NUM
          DO K=1,NYEAR
            PRICE(K,NUM)=PR(K)
C**  SET NAT. GAS FUEL COST = NAT. GAS FEEDSTOCK PRICE
            IF(NUM.EQ.17) UTIL(K,1)=PR(K)
          ENDDO
        ENDDO
 444  END IF
      CALL DEFAULT (UTILD(1,1),UTIL(1,1))
C**  READ IN HYDROGEN CREDIT VALUE IF NECESSARY
 450  DO M=1,NMOD
        NH=MODH(ABS(MODN(M)))
        IF(NH.NE.0) THEN
          READ(L1,REC=NH)NH,NAME,IPUN,PRICED
          WRITE(L6,811) PRNAME(ABS(MODN(M))),NAME,PUNIT(IPUN+1)
          DO IY=1,NYEAR
            PR(IY)=-.0001
          ENDDO
 460      READ(L5,*,END=500,ERR=461) (PR(IY),IY=1,NYEAR)
          GO TO 462
 461      CALL ERROR(*460)
C**  SET DEFAULT PRICES WHERE NECESSARY
 462      CALL DEFAULT(PRICED,PR)
          NPRICE=NPRICE+1
          NEWPR(NPRICE)=NH
          DO IY=1,NYEAR
            PRICE(IY,NH)=PR(IY)
          ENDDO
          GO TO 500
        END IF
      ENDDO
C**  PRINT OUT NEWLY ENTERED PRICES
 500  IF(NPRICE.NE.0) THEN
        WRITE(L6,814)
        READ(L5,822) YORN
        IF(YORN.EQ.'Y') THEN
          WRITE(L6,879) (IYEAR(IY),IY=1,NYEAR)
          DO I=1,NPRICE
            NN=NEWPR(I)
            READ(L1,REC=NN) NN,NAME,IUN
            WRITE(L6,880) NAME,PUNIT(IUN+1),(PRICE(K,NN),K=1,NYEAR)
          ENDDO
        END IF
      ENDIF
C**  READ IN BASIC OPERATING COST FACTORS
      WRITE(L6,840)
      READ(L5,822) YORN
      IF(YORN.EQ.'Y') THEN
        WRITE(L6,842)PCLD
        READ(L5,*,END=501) PCL
 501    WRITE(L6,843) POSD
        READ(L5,*,END=502) POS
 502    WRITE(L6,845) PTID
        READ(L5,*,END=503) PTI
 503    WRITE(L6,846) PDPD
        READ(L5,*,END=504)PDP
 504    WRITE(L6,847) PGAD
        READ(L5,*,END=505) PGAP
 505    WRITE(L6,848) PRID
        READ(L5,*,END=506) PRI
C**  READ IN LOCATION FACTOR FOR INVESTMENT (1.0=DEFAULT)
 506    WRITE(L6,856)
        READ(L5,*,END=508) FLOC
 508  END IF
      END IF
C** SET DEFAULT VALUES FOR BASIC OPERATING COST FACTORS WHERE NECESSARY
      IF(PCL.LT.0.) PCL=PCLD
      IF(POS.LT.0.) POS=POSD
      IF(PTI.LT.0.) PTI=PTID
      IF(PDP.LT.0.) PDP=PDPD
      IF(PGAP.LT.0.) PGAP=PGAD
      IF(PRI.LT.0.) PRI=PRID
      IF(FLOC.LT.0.001) FLOC=1.0
C**  CALCULATE OPERATING COSTS FOR EACH SELECTED PROCESS MODULE
      DO M=1,NMOD
C**  GET PROCESS DATA
        CALL PROCIN(ABS(MODN(M)))
        I1=ICUNP
        IDOL=0
        IF(READAL)THEN
C**  SELECT COST UNITS
          WRITE(L6,853) PROD
          READ(L5,*)I1
          IF(.NOT.YEARFL) THEN
C**  CHECK FOR CURRENT $ OR CONSTANT $ PRINTOUT
C**  IF YEARS OUTSIDE DEFAULT RANGE- CURRENT $ PRINTOUT ONLY
 5081         WRITE(L6,881)IYEARD(1),IYEARD(NYEARD)
              READ(L5,*,END=509) IDOL
              IF(IDOL.NE.0) THEN
                IF(IDOL.LT.IYEARD(1).OR.IDOL.GT.IYEARD(NYEARD)) THEN
                  WRITE(L6,883) IDOL
                  GO TO 5081
                END IF
              END IF
 509      END IF
          WRITE(L6,872) PROD
          READ(L5,822)YORN
C**  CHECK FOR OVERRIDE OF MAINT LAB,MATL AND OVERHEAD FACTORS
          IF(YORN.EQ.'Y') THEN
            WRITE(L6,873) PMLP
            READ(L5,*,END=510) PMLP
 510        WRITE(L6,874) PMMP
            READ(L5,*,END=512) PMMP
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 512      WRITE(L6,875) PPOP
          READ(L5,*,END=514) PPOP
 514    END IF
      END IF
C** SET DEFAULT CAPACITY IF NO USER-SUPPLIED CAPACITY
 520  IF(CAP(M).EQ.0.) THEN

        CAPC=CAPD
        CAPS=CAPD
        ICS=ICUNP
        GO TO (559,569,579,580) ICS
C**  CONVERT DESIRED CAPACITY TO STANDARD UNITS
      ELSE
        CAPS=CAP(M)
        ICS=ICAPUN(M)
        CAPC=0.
        GO TO ( 550,560,570,580) ICUNP
 550    GO TO (552,554,556,558) ICAPUN(M)
C**  CAPC=DESIRED CAPACITY CONVERTED TO UNITS USED IN MODULE
C**  CYR=YEARLY CAPACITY (IN MSCF, MMBTU, LB, OR TONNE)
C**  CONVERT TO MMSCFD
 552    CAPC=CAP(M)
        GO TO 559
 554    IF(CF1.NE.0.)  CAPC=CAP(M)*24./(CF1*1000.)
        GO TO 559
 556    CAPC=CAP(M)*CF2/(OSE*365.)
        GO TO 559
 558    CAPC=CAP(M)*CF2/453.59
 559    CYR=CAPC*365000.*OSE
        GO TO 590
 560    GO TO (562,564,566,568) ICAPUN(M)
C**  CONVERT TO MMBTU/HR
 562    CAPC=CAP(M)*1000.*CF1/24.
        GO TO 569
 564    CAPC=CAP(M)
        GO TO 569
 566    CAPC=CAP(M)*CF1*CF2/(OSE*8.760)
        GO TO 569
 568    CAPC=CAP(M)*CF4/10886.
 569    CYR=CAPC*24.*365.*OSE
        GO TO 590
 570    GO TO (572,574,576,578) ICAPUN(M)
C**  CONVERT TO MMLB/YR
 572    IF(CF2.NE.0.)  CAPC=CAP(M)*365.*OSE/CF2
        GO TO 579
 574    IF(CF1.NE.0.0.AND.CF2.NE.0.)  CAPC=CAP(M)*OSE*8.76/(CF1*CF2)
        GO TO 579
 576    CAPC=CAP(M)
        GO TO 579
 578    CAPC=CAP(M)*OSE/1.2427
 579    CYR=CAPC*1.E6
        GO TO 590
 580    GO TO (582,584,586,588) ICAPUN(M)
C**  CONVERT TO TONNE/DAY
 582    IF(CF2.NE.0.)  CAPC=CAP(M)*453.59/CF2
        GO TO 589
 584    IF(CF4.NE.0.)  CAPC=CAP(M)*10886./CF4
        GO TO 589
 586    CAPC=CAP(M)*1.2427/OSE
        GO TO 589
 588    CAPC=CAP(M)
 589    CYR=CAPC*365.*OSE
 590    IF(CAPC.EQ.0.) THEN
          WRITE(L6,855) CAPS, CAPUN(ICS),PROD
          WRITE(L6,806)
          READ(L5,*) CAP(M),ICAPUN(M)
          GO TO 520
        END IF
C** CHECK FOR CAPACITY OUTSIDE RANGE
        IF(CAPC.GT.CAPMAX.OR.CAPC.LT.CAPMIN) THEN
          WRITE(L6,857) CAP(M),CAPUN(ICS),CAPMIN,CAPMAX,CAPUN(ICUNP)
          WRITE(L6,806) CAPD,CAPUN(ICUNP)
          READ(L5,*) CAP(M),ICAPUN(M)
          IF(CAP(M).LT.0.) GO TO 600
          GO TO 520
        END IF
      END IF
C**  CALCULATE CONVERSION FACTORS FOR COST PRINTOUTS
C**  CALCULATE G+A FOR PRODUCT MODULE ONLY OR WHEN NEGATIVE MODULE CODE
 596  IF(MODN(M).LT.0) THEN
        PGA=PGAP
      ELSE
        PGA=0.
      END IF
      CALL CSTPER(ICUNP,I1,F1,F2)
      IF(F1.EQ.0.) THEN
        WRITE(L6,854) COSTUN(I1), PROD
        WRITE(L6,853) PROD
        READ(L5,*) I1
        GO TO 596
      END IF
C**  SELECT UTILITIES CONSUMPTION BASED ON CAPACITY
      DO I=3,1,-1
        IF(CAPC.LT.CAPU(I)) THEN
          DO J=1,9
            UTCON(J)=UTCONP(J,I)
          ENDDO
          GO TO 595
        END IF
      ENDDO
 595  CONTINUE
C**ASSIGN YEAR FOR VARIABLE COST PRINTOUT
      IYP=1
      DO IY=1,NYEAR
        IF(IYEAR(IY).EQ.IDOL) IYP=IY
      ENDDO
C**  CALCULATE COSTS FOR EACH YEAR
      IFY=IDOL-1980+1
      DO IY=1,NYEAR
C**  CALCULATE CURRENT$/CONSTANT$ CONVERSION FACTOR
        DFAC(IY)=1.
        IF(IDOL.NE.0) DFAC(IY)=FINF(IY)/FINFD(IFY)
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C** CALCULATE RAW MATERIAL AND BY-PRODUCT COSTS
          CALL MATL(IY,IYP,ABS(MODN(M)))
C** CALCULATE LABOR COSTS
          CALL LABOR(IY)
C** CALCULATE UTILITY COSTS
          CALL UTILTY(IY,IYP)
C** CALCULATE INVESTMENT RELATED COSTS AND OP COSTS
          CALL INVCAL(IY)
        ENDDO
C** PRINT OUT OPERATING COST TABLE
        CALL PCOST(ABS(MODN(M)))
C** STORE PRODUCT VALUE FOR FUTURE USE
        IF(NPROD.NE.0) THEN
          DO IY=1,NYEAR
C** CONVERT PRICE TO UNITS USED IN PROCESS MODULES
            PRICE(IY,NPROD)=PV(IY)/(F1*F2)
          ENDDO
        END IF
        WRITE(L6,858) PRNAME(ABS(MODN(M)))
 600  ENDDO
      GO TO 50
C** FORMATS---------
 800  FORMAT(///,' WELCOME TO THE SYNCOST PROGRAM FOR ESTIMATING COSTS',
     1/,' OF SYNTHESIS GASES, CARBON MONOXIDE, HYDROGEN AND METHANOL.',
     2/,' ALL CONSUMPTIONS AND COSTS ARE EXPRESSED ON A ',
     3'CONTAINED BASIS.',/,' ADDITIONAL INFORMATION ABOUT THE',
     4' PROCESSES MAY BE FOUND',/' IN SRI INTERNATIONAL PROCESS ',
     5'ECONOMIC PROGRAM REPORT 148.')
 801  FORMAT(/////,' Q1.  TYPE 0 TO STOP NOW OR',/,
     2' ENTER FEEDSTOCK:  1=COAL, 2=NATURAL GAS, 3=VAC. RESIDUE?  ')
 802  FORMAT(' ***BAD PRODUCT NUMBER-TRY AGAIN')
 803  FORMAT(' Q6. PRODUCT MODULE?  ')
 804  FORMAT(' Q9. LIST INTERMEDIATE MODULES?(Y OR N) ')
 805  FORMAT(' Q2. LIST AVAILABLE MODULES (Y OR N)?  ')
 806  FORMAT(' Q8(11). ENTER CAPACITY, FOLLOWED BY UNIT (DEFAULT: ',
     1F10.2,A8,')',/
     12X,'(1=MMSCFD, 2=MMBTU/HR, 3=MMLB/YR, 4=TONNE/DAY):  ')
 807  FORMAT(' ***UNIT ERROR-PLEASE REENTER')
 808  FORMAT(' Q10. INTERMEDIATE MODULE?  ')
 809  FORMAT(' Q5. WHICH YEARS?  ')
 810  FORMAT(' Q4. NUMBER OF YEARS FOR WHICH ESTIMATES ARE TO BE',
     1' CALCULATED(MAX=10)?  ')
 811  FORMAT(/' Q18. ',A,' PRODUCES',/,'   HYDROGEN COPRODUCT.',
     1'   PLEASE ENTER THE VALUES FOR THE SELECTED YEARS FOR',/,
     23X,A,' IN ',A,' OF CONTAINED HYDROGEN.',/,
     3'   (DEFAULT VALUES ARE USED OTHERWISE)',/,' ?')
 812  FORMAT(' Q14. DO YOU WISH TO ENTER UNIT COST DATA FOR THE ',
     1'SELECTED YEARS? (Y OR N)  ')
 813  FORMAT(' Q14A. COST INDEXES ?',/)
 814  FORMAT(' Q19. LIST NEWLY ENTERED PRICES?(Y OR N) ')
 815  FORMAT(' Q14B. LABOR COST (US$/HR)?',/)
 816  FORMAT(' Q14D-K. ',A,' COST, PRECEDED BY COST UNITS,')
 817  FORMAT(' Q14C. INFLATION FACTOR?',/)
 822  FORMAT(A)
 840  FORMAT(' Q20. DO YOU WISH TO ENTER BASIC OPERATING COST FACTORS?',
     1'(Y OR N) ')
 842  FORMAT(' Q20A. CONTROL LAB LABOR, %OP LABOR (DEFAULT=',F5.2,')? ')
 843  FORMAT(' Q20B. OPERATING SUPPLIES, %OP LABOR (DEFAULT=',F5.2,')?')
 845  FORMAT(' Q20C. TAXES AND INSURANCE, %TFC (DEFAULT=',F5.2,')?  ')
 846  FORMAT(' Q20D. DEPRECIATION, %TFC (DEFAULT=',F5.2,')?  ')
 847  FORMAT(' Q20E. G&A,S,R, % PRODUCT VALUE (DEFAULT=',F5.2,')?  ')
 848  FORMAT(' Q20F. ROI(BEFORE-TAX), %TFC (DEFAULT=',F5.2,')?  ')
 849  FORMAT(' Q16. DO YOU WISH TO ENTER RAW MATERIAL COSTS?(Y OR N) ')
 850  FORMAT(' Q17. ENTER MATERIAL CODE, UNIT, PRICES FOR THE SELECTED',
     1' YEARS:',/,'  (TYPE / TO END)',/)
 851  FORMAT(' THE FOLLOWING UNITS MAY BE USED:  ',/,
     1' 0=$, 1=C/LB, 3=C/MSCF, 6=$/MMBTU, 7=$/TONNE, 8=$/MNM3')
 852  FORMAT(' Q12. TYPE OF PRINTOUT DESIRED, (0=FULL, 1=ABBREVIATED',
     1' 2=SHORT)?  ')
 853  FORMAT(//,' Q21. COST UNITS FOR ',A,'-',/,
     1' (1=C/MSCF, 2=$/MMBTU, 3=C/LB, 4=$/TONNE, 5=$/MNM3, '
     2,/,'   6=$/TON-CAL, 7=C/KG, 8=C/GAL):  ')
 854  FORMAT(' ***THE SELECTED COST UNITS, ',A7,', CANNOT BE ',
     1'CALCULATED',/,'   FROM THE PROCESS DATA FOR ',A,/,
     2'   PLEASE SELECT DIFFERENT UNITS.')
 855  FORMAT(/,' ***THE SELECTED CAPACITY ',F10.2,A8, 'CANNOT BE',
     1/,' CALCULATED FROM THE PROCESS DATA FOR ',A,/,' PLEASE ',
     2'SELECT DIFFERENT UNITS.')
 856  FORMAT(' Q20G. LOCATION FACTOR FOR INVESTMENT DATA',
     1' (DEFAULT=1.0)?  ')
 857  FORMAT(' ***THE SELECTED CAPACITY ',F10.2,A8,' IS OUTSIDE THE'
     1' ALLOWABLE RANGE',/,4X,'OF',F10.2,'-',F10.2,A8,/,
     2'    REENTER CAPACITY BELOW OR TYPE -1.,0 TO SKIP THIS PROCESS.')
 858  FORMAT(' CALCULATIONS COMPLETE FOR ',A)
 859  FORMAT(' ***THE SELECTED PRICE UNITS ',A,' FOR MATERIAL ',
     1I3,/4X,'CANNOT BE CONVERTED TO THE UNITS USED BY THE ',
     2'PROCESS MODULE (',A,')',/4X,'PLEASE REENTER PRICE DATA.')
 860  FORMAT(' Q13. LIST DEFAULT UNIT COST VALUES?(Y OR N)  ')
 861  FORMAT(/' DEFAULT VALUES:',/8X,10(I6,1X),/11X,10('----',3X))
 862  FORMAT(' COST INDEX:',/,'   80-89',10F7.1,/,'   90-99',10F7.1,
     1/,'   00-01',2F7.1)
 863  FORMAT(' WAGE, $/HR:',/,'   80-89',10F7.2,/,'   90-99',10F7.2,
     1/,'   00-01',2F7.2)
 864  FORMAT(1X,A15,', ',A,/,'   80-89',10F7.2,/,'   90-99',10F7.2,
     1/,'   00-01',2F7.2)
 865  FORMAT(' Q15. LIST RAW MATERIAL CODES AND PRICES?(Y OR N)  ')
 866  FORMAT(1X,I2,'-',A20,',',A11,/,'   80-89',10F7.2,/,'   90-99',
     110F7.2,/,'   00-01',2F7.2)
 869  FORMAT(/' RAW MATERIAL CODES AND DEFAULT PRICES:',
     1/,8X,10(I6,1X),/11X,10('----',3X))
 870  FORMAT(A,'?',/)
 871  FORMAT(' Q7. RUN BASE CASE, WITH DEFAULT VALUES FOR ALL',
     1'  MODULES IN THE PROCESS SEQUENCE (Y OR N)?  ')
 872  FORMAT(' Q23. OVERRIDE MAINTENANCE LABOR, MATERIAL AND OVERHEAD ',
     1'FACTORS',/,'   FOR ',A,' (Y OR N)?  ')
 873  FORMAT(' Q23A. MAINTENANCE LABOR, %BLI (DEFAULT=',F5.2,')? ')
 874  FORMAT(' Q23B. MAINTENANCE MATL, %BLI (DEFAULT=',F5.2,')? ')
 875  FORMAT(' Q23C. PLANT OVERHEAD, % TOTAL LABOR (DEFAULT=',F5.2,')?')
 876  FORMAT(' CODE, UNIT, PRICES?')
 877  FORMAT(' Q3. DO YOU WISH TO USE YOUR YEAR, WAGE, UTILITY COST,',
     1' BASIC OP COST FACTORS AND',/'    RAW MATERIAL PRICE DATA',
     2' ENTERED FOR THE PREVIOUS PROCESS SEQUENCE? (Y OR N) ')
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878  FORMAT(' NATURAL GAS FUEL COST MAY BE ENTERED LATER--',
    1'  AS RAW MATERIAL #17',/1X)
879  FORMAT(36X,10I9)
880  FORMAT(1X,A24,A11,2X,10(F7.2,2X))
881  FORMAT(' Q22. PRINT COSTS IN CURRENT $ (DEFAULT, TYPE/) OR',
    1' IN CONSTANT $ (ENTER YEAR)?',/,
    2'      (YEAR MUST BE WITHIN RANGE ',I4,'-',I4,')')
882  FORMAT(' INFLATION FACTOR:',/,'   80-89',10F7.3,/,'   90-99',
    110F7.3,/,'   00-01',2F7.3)
883  FORMAT(' ***PROGRAM CANNOT CALCULATE CONSTANT $ FOR ',I4)
884  FORMAT(' NOTE: THE SELECTED YEAR ',I4,' IS OUTSIDE THE ',
    1' DEFAULT RANGE.',/' YOU MUST ENTER COST INDEX, LABOR ',
    2'RATE, UTILITIES AND RAW MATERIAL COSTS BELOW')
1000 CLOSE(L1,STATUS='DELETE')
     CLOSE(L2,STATUS='DELETE')
     STOP
     END
C**
C**
     SUBROUTINE CONVERT(NIN,NOUT,A,IERR)
C**GET CONVERSION FACTOR TO CONVERT INPUT PRICE UNITS(NIN) TO
C**  1=C/LB, 2=C/KG, 3=C/MSCF, 4=C/M3, 5=C/MGAL, 6=$/MMBTU,
C**  7=$/TONNE, 8=$/MNM3, 9=$/MLB, 10=$/TON-CAL
C**  OUTPUT PRICE UNITS(NOUT)
C**  CONVERT ARRAY A BY USING APPROPRIATE FACTOR
     DIMENSION FACT(100)
     DIMENSION A(10)
     COMMON/YEARS/NYEAR,IYEAR(10)
     DATA FACT/1.,2.2046,4*0.,22.046,0.,10.,0.,.4536,1.,4*0.,10.,0.,
    14.536,3*0.,1.,.037326,3*0.,.37326,4*0.,26.791,1.,3.7854,2*0.,
    210.,5*0.,.2642,1.,2*0.,2.642,7*0.,1.,3*0.,.0039685,.04536,.1,4*0.,
    31.,0.,.4536,3*0.,2.6788,.1,.37854,2*0.,1.,2*0.,.1,.22046,4*0.,
    42.2046,0.,1.,6*0.,251.98,3*0.,1./
C**  DETERMINE INTEGER CORRESPONDING TO INPUT/OUTPUT UNITS
     IERR=0
     IF(NIN.EQ.0) THEN
       IERR=2
       RETURN
     END IF
     IF(NIN.EQ.NOUT) THEN
       RETURN
     END IF
C** FLAG ERROR
     IF(NOUT.EQ.0) THEN
       IERR=1
       RETURN
     END IF
     K=NOUT+10*(NIN-1)
     FACTOR=FACT(K)
     IF(FACTOR.EQ.0.) THEN
       IERR=2
       RETURN
     END IF
     DO I=1,NYEAR
       A(I)=FACTOR*A(I)
     ENDDO
     RETURN
     END
C**
C**
     SUBROUTINE CSTPER(N1,N2,F1,F2)
C**  CONVERT COST TO REQUESTED UNITS
C**  N1=UNITS IN PROCESS MODULE
C**  N2=REQUESTED UNITS
C**   1=MSCF, 2=MMBTU, 3=LB, 4=TONNE, 5=MNM3, 6=TON-CAL, 7=KG, 8=GAL
C**  F1=CONSUMPTION CONVERSION FACTOR
C**  F2=COST CONVERSION FACTOR
C**   CF1=MMBTU/MSCF
C**   CF2=SCF/LB
C**   CF3=LB/GAL
C**   CF4=BTU/LB
     COMMON/PRDAT/CAPB,ICUNP,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,OSE,MLS,
    1TCA,TCB,TCC,TCD,NMAT,MAT(8),CONS(8),TOP,NPROD,PMLP,PMMP,PPDP
    2,IPRUN(8),MUN(8),CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,FLOC,EQMETH,
    3CAPU(3),UTCON(9),UTCONP(9,3),CAPD
     F1=0.
     F2=1.
     GO TO (100,200,300,400) N1
100  GO TO (110,120,130,140,150,160,170,180)N2
C**  CONVERT FROM MSCF
110  F1=1.
     RETURN
120  IF(CF1.NE.0.) F1=1./CF1
     F2=0.01
     RETURN
130  F1=CF2*0.001
     RETURN
140  F1=2.2046*CF2
     F2=0.01
     RETURN
150  F1=37.326
     F2=0.01
     RETURN
160  IF(CF1.NE.0.) F1=.003968/CF1
     F2=0.01
     RETURN
170  F1=CF2*.00220458
     RETURN
180  F1=0.
     RETURN
200  GO TO (210,220,230,240,250,260,270,280)N2
C**  CONVERT FROM MMBTU
210  F1=CF1
     RETURN
220  F1=1.
     F2=0.01
     RETURN
230  F1=CF1*CF2*0.001
     RETURN
240  F1=.0022046*CF4
     F2=0.01
     RETURN
```

```
250  F1=CF1*37.326
     F2=0.01
     RETURN
260  F1=.003968
     F2=0.01
     RETURN
270  F1=CF1*CF2*.00220458
     RETURN
280  F1=1.E6*CF3*CF4
     RETURN
300  GO TO (310,320,330,340,350,360,370,380)N2
C**  CONVERT FROM LB
310  IF(CF2.NE.0.) F1=1000./CF2
     RETURN
320  IF(CF1*CF2.NE.0.) F1=1000./(CF1*CF2)
     F2=0.01
     RETURN
330  F1=1.
     RETURN
340  F1=2204.6
     F2=0.01
     RETURN
350  IF(CF2.NE.0.) F1=37326./CF2
     F2=0.01
     RETURN
360  IF(CF1*CF2.NE.0.) F1=3.968/(CF1*CF2)
     F2=0.01
     RETURN
370  F1=2.20458
     RETURN
380  F1=CF3
     RETURN
400  GO TO (410,420,430,440,450,460,470,480) N2
C**  CONVERT FROM TONNE
410  IF(CF2.NE.0.) F1=0.45359/CF2
     RETURN
420  IF(CF4.NE.0.) F1=453.597/CF4
     F2=0.01
     RETURN
430  F1=.0004536
     RETURN
440  F1=1.0
     F2=0.01
     RETURN
450  IF(CF2.NE.0.) F1=16.931/CF2
     F2=0.01
     RETURN
460  F1=1.7999/CF4
     F2=0.01
     RETURN
470  F1=0.001
     RETURN
480  F1=CF3/2204.6
     RETURN
     END
C**
```

```
C**
      SUBROUTINE DATAF
C**  READ IN AND SET UP FOR DIRECT ACCESS MATERIAL PRICE FILE AND
C**    PROCESS MODULE DATA FILE
C**   UNIT L1=MATERIAL PRICE FILE (DIRECT ACCESS)
C**   UNIT L2= PROCESS MODULE DATA FILE (DIRECT ACCESS)
C**   UNIT L3= PROCESS DATA INPUT
C**   UNIT L4= PRICE DATA INPUT
      CHARACTER MNAME*20,TITLE1*40,TITLE2*40,PROD*16,CAPUN(4)*8,
     1PRNAME(40)*60,PRCAP(40)*21,PROCESS*80
      DIMENSION PRICED(22),MAT(8),CONS(8),UTCONP(9,3),MUN(8),CAPU(3)
      COMMON/IO/L1,L2,L3,L4,L5,L6,L7,IPFLAG
      COMMON/DEFAULT/NYEARD,PCID(22),WAGED(22),FINFD(22)
      COMMON/UTLTY/UTIL(10,9),UTILD(22,9)
      COMMON/YEARS/NYEAR,IYEAR(10),IYEARD(22),IDOL,DFAC(10)
      COMMON/CHAR/PRNAME,PRCAP
      DATA CAPUN/'MMSCFD','MMBTU/HR','MMLB/YR','TONNE/D'/
C**  READ IN DEFAULT DATA
      READ(L4,*) NYEARD
      READ(L4,*) (IYEARD(IY),IY=1,NYEARD)
      READ(L4,*) MNAME,(PCID(IY),IY=1,NYEARD)
      READ(L4,*) MNAME,(FINFD(IY),IY=1,NYEARD)
      READ(L4,*) MNAME,(WAGED(IY),IY=1,NYEARD)
      DO IU=1,9
        READ(L4,*) MNAME,(UTILD(IY,IU),IY=1,NYEARD)
      ENDDO
C**  READ IN MATERIAL PRICES
 50   IPRUN=0
      DO I=1,22
        PRICED(I)=0.
      ENDDO
      READ(L4,*,END=90) MATNO,MNAME,IPRUN,PRICED
C**  CREATE DIRECT ACCESS RECORD OF PRICE DATA
      WRITE(L1,REC=MATNO) MATNO,MNAME,IPRUN,PRICED
      GO TO 50
C**  ZERO VARIABLES
 90   DO I=1,40
        PRNAME(I)=' '
        PRCAP(I)=' '
      ENDDO
 100  DO J=1,8
        MAT(J)=0
        CONS(J)=0.
        MUN(J)=0
      ENDDO
      DO I=1,3
        CAPU(I)=0.
        DO J=1,9
          UTCONP(J,I)=0.
        ENDDO
      ENDDO
      MPROD=0
      CF1=0.
      CF2=0.
      CF3=0.
      CF4=0.
```

```
      BLA=0.
      BLB=0.
      BLC=0.
      BLD=0.
      TCA=0.
      TCB=0.
      TCC=0.
      TCD=0.
      BLIP=0.
      TFCP=0.
      EQMETH=0.
      CAPMIN=0.
      CAPMAX=0.
      CAPD=0.
      TITLE1=' '
      TITLE2=' '
C**  READ IN PROCESS DATA FROM UNIT L3
      READ(L3,*,END=200) NREC
      READ(L3,*) TITLE1
      READ(L3,*) TITLE2
      PROCESS=TITLE1(1:40)//' '//TITLE2(1:39)
      DO J=10,79
        I=J
        K=80
 110    IF(PROCESS(I:I).EQ.' '.AND.PROCESS(I+1:I+1).EQ.' ') THEN
          PROCESS(I:K)=PROCESS(I+1:K)//' '
          K=K-1
          IF(K.GT.I) GO TO 110
        END IF
      ENDDO
      PRNAME(NREC)=PROCESS(1:60)
      READ(L3,*) PCIP,NI,BLIP,BLA,BLB,BLC,BLD
      READ(L3,*)TFCP,TCA,TCB,TCC,TCD
      READ(L3,*) ICUMP,CAPB,OSE,EQMETH
      DO J=1,8
        READ(L3,*) MAT(J),CONS(J),MUN(J)
        IF(MAT(J).EQ.999) GO TO 120
        NMAT=J
      ENDDO
 120  READ(L3,*) TOP,MLS,PMLP,PMMP,PPOP
      DO I=1,3
        READ(L3,*) CAPU(I),(UTCOMP(J,I),J=1,9)
      ENDDO
      READ(L3,*) NPROD,PROD,CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,CAPD
      WRITE(PRCAP(NREC),2) CAPMIN,CAPMAX,CAPUN(ICUMP)
C**  CREATE DIRECT-ACCESS RECORD OF PROCESS DATA
      WRITE(L2,REC=NREC)TITLE1,TITLE2,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,
     1TCA,TCB,TCC,TCD,ICUMP,CAPD,CAPB,OSE,EQMETH,NMAT,(MAT(J),CONS(J),
     2MUN(J),J=1,8),TOP,MLS,PMLP,PMMP,PPOP,CAPU,((UTCOMP(J,I),
     3J=1,9),I=1,3),NPROD,PROD,CF1,CF2,CF3,CF4,CAPMIN,CAPMAX
      GO TO 100
 200  RETURN
 2    FORMAT(F6.0,'-',F6.0,A8)
      END
C**
C**
      SUBROUTINE DEFAULT(A,B)
C**  A=DEFAULT DATA ARRAY(FUNCTION OF  1980-2001)
C**  B=OUTPUT ARRAY(FUNCTION OF USER-SELECTED YEARS)
C**  FILL IN DATA IN ARRAY B FROM DEFAULT DATA (ARRAY A) AS
C**  AFUNCTION OF YEAR
      DIMENSION A(22),B(10)
      COMMON/YEARS/NYEAR,IYEAR(10),IYEARD(22),IDOL,DFAC(10)
      DO IY=1,NYEAR
        IYY=IYEAR(IY)-IYEARD(1)+1
        IF(B(IY).LT.0.0) B(IY)=A(IYY)
      ENDDO
      RETURN
      END
C**
C**
      SUBROUTINE ERROR(*)
      COMMON/IO/L1,L2,L3,L4,L5,L6,L7,IPFLAG
      WRITE(L6,1)
      RETURN 1
 1    FORMAT(' ***DATA ENTRY ERROR-PLEASE REENTER LINE',/,' ?')
      END
C**
C**
      SUBROUTINE FPLIST(N)
C** PRINT OUT LIST OF REQUIRED INTERMEDIATE MODULES
      COMMON/IO/L1,L2,L3,L4,L5,L6,L7
      DIMENSION LST(2,40)
      CHARACTER PRNAME(40)*60,PRCAP(40)*21
      COMMON/CHAR/PRNAME,PRCAP
      DATA LST/0,0,0,0,28,0,12,0,9,28,0,0,0,0,0,0,28,0,0,0,
     112,0,0,0,0,0,0,0,12,0,12,0,14,0,14,0,13,0,10,0,0,0,0,0,0,
     20,0,0,0,14,0,0,0,13,0,0,0,24*0/
      WRITE(L6,1) PRNAME(N)
      I=1
      IF(LST(1,N).EQ.0) THEN
        WRITE(L6,3)
        RETURN
      END IF
      DO WHILE (LST(I,N).NE.0)
        NN=LST(I,N)
        WRITE(L6,2) NN,PRNAME(NN),PRCAP(NN)
        I=I+1
      ENDDO
      RETURN
 1    FORMAT(1X,A,/3X,'REQUIRED INTERMEDIATE MODULES:')
 2    FORMAT(5X,I2,'-',A,/,3X,'(',A,')')
 3    FORMAT('+',35X,'NONE')
      END
C**
C**
      SUBROUTINE INVCAL(IY)
C** CALCULATE INVESTMENT, INVESTMENT-RELATED COSTS AND
C** PRODUCT VALUES
      COMMON/YEARS/NYEAR,IYEAR(10)
      COMMON/YDAT/PRICE(10,50),PCI(10),WAGE(10)
      COMMON/CAPCTY/CAPC,CYR
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```
      COMMON/PERCNT/PCL,PDP,PTI,POS,PRI,PGA
      COMMON/DPCOST/GA(10),DEP(10),TI(10),TML(10),TMM(10),TTL(10),
     1TCL(10),PO(10),ROI(10),RMC(10),UTC(10),TOS(10),PV(10),BPC(10)
     2,TOL(10),TOPR,F1,F2,BLI(10),TFC(10),NBP,PRM1(10)
      COMMON/PRDAT/CAPB,ICUNP,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,OSE,MLS,
     1TCA,TCB,TCC,TCD,NMAT,MAT(8),CONS(8),TOP,NPROD,PMLP,PMMP,PPOP
     2,IPRUN(8),MUN(8),CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,FLOC,EQMETH,
     3CAPU(3),UTCON(9),UTCONP(9,3),CAPD
      R1=CAPC/CAPB
      R2=PCI(IY)/PCIP
C** INVESTMENT IN MM$
C** SCALE INVESTMENT TO DESIRED CAPACITY AND COST INDEX
C** GOTO APPROPRIATE INVESTMENT VS. CAPACITY ALGORITHM
      GO TO (100,200,300)NI
C** COAL CASES
 100  IF(CAPC.LE.CAPB)THEN
C**  3RD ORDER FIT OF INVESTMENT VS. CAPACITY
        BLI(IY)=(BLA+CAPC*(BLB+CAPC*(BLC+CAPC*BLD)))*R2
        TFC(IY)=(TCA+CAPC*(TCB+CAPC*(TCC+CAPC*TCD)))*R2
      ELSE
        BLI(IY)=(R1**0.95)*BLIP*R2
        OFF=R2*(TFCP-BLIP)*(R1**0.75)
        TFC(IY)=BLI(IY)+OFF
      END IF
      GO TO 40
C** NATURAL GAS CASES
C**  REPLICATE IF CAPACITY GT BASE CAPACITY
 200  BLEU=0.9
      TCEU=0.9
      IF(CAPC.GT.CAPB) GO TO 10
      EQCAP=EQMETH*CAPC
C**  3RD ORDER FIT OF INVEST/BASE INVEST VS. EQUIVALENT METHANOL CAPACITY
      CF=.07688+EQCAP*(5.399E-4+EQCAP*(EQCAP*1.915E-11-1.161E-7))
      BLI(IY)=CF*BLIP*R2
      TFC(IY)=CF*TFCP*R2
      GO TO 40
 300  BLEU=BLB
      BLED=BLA
      TCEU=TCB
      TCED=TCA
      IF(CAPC-CAPB)30,20,10
C**  INVESTMENT SCALED VIA CAPACITY EXPONENT
C**  SCALE UP
 10   BLI(IY)=(R1**BLEU)*BLIP*R2
      TFC(IY)=(R1**TCEU)*TFCP*R2
      GO TO 40
 20   BLI(IY)=BLIP*R2
      TFC(IY)=TFCP*R2
      GO TO 40
C**  SCALE DOWN
 30   BLI(IY)=(R1**BLED)*BLIP*R2
      TFC(IY)=(R1**TCED)*TFCP*R2
C**  CALCULATE DEPRECIATION
 40   FACTOR=F1*F2
C**  ROUND INVESTMENTS
      BLI(IY)=0.1*AINT(FLOC*BLI(IY)*10.+0.5)
      TFC(IY)=0.1*AINT(FLOC*TFC(IY)*10.+0.5)
      DEP(IY)=ROUND(FACTOR*PDP*TFC(IY)*1.E6/CYR)
C**  TAXES AND INSURANCE
      TI(IY)=ROUND(FACTOR*PTI*TFC(IY)*1.E6/CYR)
C**  MAINTENANCE LABOR AND MAINTENANCE MATERIAL
      TML(IY)=ROUND(FACTOR*PMLP*BLI(IY)*1.E6/CYR)
      TMM(IY)=ROUND(FACTOR*PMMP*BLI(IY)*1.E6/CYR)
C**  TOTAL LABOR
      TTL(IY)=TOL(IY)+TCL(IY)+TML(IY)
C**  PLANT OVERHEAD
      PO(IY)=ROUND(PPOP*0.01*TTL(IY))
C**  RETURN ON INVESTMENT
      ROI(IY)=ROUND(FACTOR*PRI*TFC(IY)*1.E6/CYR)
      COST=RMC(IY)+TTL(IY)+UTC(IY)+TMM(IY)+TOS(IY)+PO(IY)+
     1ROI(IY)+DEP(IY)+TI(IY)
C** G&A, SALES, RESEARCH
      GA(IY)=ROUND(PGA/(100-PGA)*COST)
C**  PRODUCT VALUE
      PV(IY)=COST+GA(IY)+BPC(IY)
      RETURN
      END
C**
C**
      SUBROUTINE LABOR(IY)
C** CALCULATE LABOR AND LABOR-RELATED COSTS
      COMMON/YDAT/PRICE(10,50),PCI(10),WAGE(10)
      COMMON/PERCNT/PCL,PDP,PTI,POS,PRI,PGA
      COMMON/CAPCTY/CAPC,CYR
      COMMON/DPCOST/GA(10),DEP(10),TI(10),TML(10),TMM(10),TTL(10),
     1TCL(10),PO(10),ROI(10),RMC(10),UTC(10),TOS(10),PV(10),BPC(10)
     2,TOL(10),TOPR,F1,F2,BLI(10),TFC(10),NBP,PRM1(10)
      COMMON/PRDAT/CAPB,ICUNP,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,OSE,MLS,
     1TCA,TCB,TCC,TCD,NMAT,MAT(8),CONS(8),TOP,NPROD,PMLP,PMMP,PPOP
     2,IPRUN(8),MUN(8),CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,FLOC,EQMETH,
     3CAPU(3),UTCON(9),UTCONP(9,3),CAPD
C**  SCALE NUMBER OF OPERATORS TO DESIRED CAPACITY
      IF(IY.EQ.1) THEN
        TOPR=0.
        GO TO (10,20,30,40,50) MLS+1
C**  NAT GAS AND RESID
 10     TOPR=TOP
        IF(CAPC.GT.CAPB) TOPR=AINT(TOP*(CAPC/CAPB)**0.95+0.5)
        GO TO 60
C**  METHANOL FROM COAL
 20     C=.001*CAPC
        TOPR=AINT(18.309+C*(1.436+C*(.425-C*.0127)))
        GO TO 60
C**  SYNGAS FROM COAL
 30     C=CAPC
        TOPR=AINT(13.119+C*(.02546+C*(1.181E-6+C*1.612E-8)))
        GO TO 60
C**  METHANOL FROM COAL SYNGAS
 40     C=.001*CAPC
        TOPR=AINT(5.69+C*(-.6008+C*(.4174-C*.0209)))
        GO TO 60
C**  HYDROGEN FROM COAL
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 50      C=CAPC
         TOPR=AINT(13.653+C*(.0332+C*(7.97E-7+C*1.355E-8)))
       END IF
C**   OPERATING LABOR
 60    TOL(IY)=ROUND(F1*F2*TOPR*WAGE(IY)*876000./CYR)
C**   CONTROL LABORATORY
       TCL(IY)=ROUND(PCL*TOL(IY)*0.01)
C**   OPERATING SUPPLIES
       TOS(IY)=ROUND(POS*TOL(IY)*0.01)
       RETURN
       END
C**
C**
       SUBROUTINE MATL(IY,IYP,MN)
C** GET MATERIAL PRICES AND CALCULATE MATERIAL-RELATED COSTS
       DIMENSION COST(8)
       CHARACTER MNAME(8)*20,UNOUT(8)*7,COSTUN(8)*7,PUNIT(11)*7
      1,CAPUN(4)*8,TITLE1*40,TITLE2*40, PUN*7,PROD*16,PUNM1*7
       LOGICAL IPRNT
       COMMON/IO/L1,L2,L3,L4,L5,L6,L7,IPFLAG
       COMMON/YEARS/NYEAR,IYEAR(10),IYEARD(22),IDOL,DFAC(10)
       COMMON/YDAT/PRICE(10,50),PCI(10),WAGE(10)
       COMMON/CAPCTY/CAPC,CYR,I1,CAPS,ICS
       COMMON/OPCOST/GA(10),DEP(10),TI(10),TML(10),TMM(10),TTL(10),
      1TCL(10),PO(10),ROI(10),RMC(10),UTC(10),TOS(10),PV(10),BPC(10)
      2,TOL(10),TOPR,F1,F2,BLI(10),TFC(10),NBP,PRM1(10)
       COMMON/PRDAT/CAPB,ICUMP,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,OSE,MLS,
      1TCA,TCB,TCC,TCB,NMAT,MAT(8),CONS(8),TOP,NPROD,PMLP,PMMP,PPOP
      2,IPRUN(8),MUN(8),CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,FLOC,EQMETH,
      3CAPU(3),UTCON(9),UTCOMP(9,3),CAPD
       COMMON/PCHAR/MNAME,TITLE1,TITLE2,PROD,UNOUT,PUNIT,COSTUN,CAPUN
      1,PUNM1
       IPRNT=.FALSE.
       IF(IY.EQ.IYP.AND.IPFLAG.EQ.0) IPRNT=.TRUE.
       NBP=0
       BPC(IY)=0.
       RMC(IY)=0.
C**   PRINT OUT VARIABLE COST SUMMARY TABLE
       IF(IPRNT) THEN
         WRITE(L7,9) TITLE1,MN,TITLE2,CAPS,CAPUN(ICS)
         WRITE(L7,1) IYEAR(IYP), UNOUT(I1),COSTUN(I1)
       ENDIF
C**   CALCULATE MATERIAL AND BY-PRODUCT COSTS
       DO J=1,NMAT
         MATNO=MAT(J)
C**   CONVERT $ TO CENTS IF NECESSARY TO GET COST IN CENTS
         F3=1.
         IF(IPRUN(J).GT.5) F3=100.
         COST(J)=ROUND(F2*F3*PRICE(IY,MATNO)*CONS(J)*F1)
         IF(CONS(J).GT.0.) THEN
           IF(MUN(J).NE.0) THEN
C**   CONVERT UNIT PRICE TO $ IF NECESSARY FOR PRINTOUT
               PRICEP=PRICE(IYP,MATNO)
               PRICEM=PRICE(IY,MAT(1))
               PUN=PUNIT(IPRUN(J)+1)
               IF(PUN(1:1).EQ.'C'.AND.PRICE(1,MATNO).GT.99.99) THEN
                 PRICEP=PRICEP*0.01
                 IF(J.EQ.1) PRICEM=PRICEM*0.01
                 PUN(1:1)='$'
               END IF
C**   STORE MAJOR MATERIAL PRICE FOR SUMMARY PRINTOUT
               IF(J.EQ.1) THEN
                 PRM1(IY)=PRICEM
                 IF(IY.EQ.1) WRITE(PUNM1,10)PUN
               END IF
 10            FORMAT(A)
               IF(IPRNT) WRITE(L7,2) MNAME(J),PRICEP,PUN,CONS(J)*F1,COST(J)
             ELSE
               IF(IPRNT) WRITE(L7,3) MNAME(J),COST(J)
               IF(J.EQ.1) PRM1(IY)=0.
             END IF
             RMC(IY)=RMC(IY)+COST(J)
           ELSE
             BPC(IY)=BPC(IY)+COST(J)
             NBP=NBP+1
           END IF
         ENDDO
         IF(IPRNT) WRITE(L7,4) RMC(IYP)
C**   PRINT OUT BY-PRODUCT COSTS FOR YEAR IYP
         IF(IPRNT.AND.NBP.NE.0) THEN
           WRITE(L7,5)
           DO J=1,NMAT
             IF(CONS(J).LT.0.) THEN
               IF(MUN(J).NE.0) THEN
C**   CONVERT UNIT PRICE TO $ IF NECESSARY FOR PRINTOUT
                 PRICEP=PRICE(IYP,MAT(J))
                 PUN=PUNIT(IPRUN(J)+1)
                 IF(PUN(1:1).EQ.'C'.AND.PRICEP.GT.99.99) THEN
                   PRICEP=PRICEP*0.01
                   PUN(1:1)='$'
                 END IF
                 IF(IPRNT) WRITE(L7,6) MNAME(J),PRICEP,PUN
      1          ,    ABS(CONS(J)*F1),ABS(COST(J))
               ELSE
                 IF(IPRNT) WRITE(L7,7) MNAME(J),ABS(COST(J))
               END IF
             END IF
           ENDDO
           IF(IPRNT.AND.NBP.GE.1) WRITE(L7,8) ABS(BPC(IYP))
         END IF
 1       FORMAT(10X,'VARIABLE COST SUMMARY FOR ',I4,//42X,'CONSUMPTION',
        1/29X,'UNIT COST',5X,'PER ',A7,3X,A7,/29X,'---------',4X,
        2'-----------',4X,'-------',/,' RAW MATERIALS')
 2       FORMAT(3X,A20,4X,F6.2,A7,3X,F8.4,6X,F7.2)
 3       FORMAT(3X,A20,33X,F8.2)
 4       FORMAT(57X,'_______',/57X,F7.2)
 5       FORMAT(/,' BY PRODUCTS')
 6       FORMAT(3X,A20,4X,F6.2,A7,2X,'(',F8.4,')',4X,'(',F7.2,')')
 7       FORMAT(3X,A20,33X,'(',F7.2,')')
 8       FORMAT(57X,'-------',/55X,'(',F8.2,')')
 9       FORMAT(1H1,A40,5X,'(MODULE #',I2,')',/1X,A40,//1X,F10.2,1X,A8,//)
         RETURN
```

```
      END
C**
C**
      SUBROUTINE PAREN(A,AC)
C** PUT PARENTHESES AROUND NEGATIVE CONSUMPTIONS OR COSTS
      DIMENSION A(10)
      COMMON/YEARS/NYEAR,IYEAR(10)
      CHARACTER AC(10)*9
      DO IY=1,NYEAR
        AC(IY)='         '
        WRITE(AC(IY),1) ABS(A(IY))
 1      FORMAT(1X,F7.2,1X)
        IF(A(IY).LT.0.) THEN
          MM=2
          DO M=2,4
            IF(AC(IY)(M:M).EQ.' ') MM=MM+1
          ENDDO
          IF(MM.EQ.2) THEN
            AC(IY)='9'//AC(IY)(2:8)//')'
          ELSE
            AC(IY)=AC(IY)(1:MM-2)//'('//AC(IY)(MM:8)//')'
          END IF
        END IF
      ENDDO
      RETURN
      END
C**
C**
      SUBROUTINE PCOST(MN)
C** PRINT OUT OPERATING COST TABLE
      CHARACTER ULINE*20,COSTUN(8)*7,MNAME(8)*20,PUNIT(11)*7,UNOUT(8)*7
     1,TITLE1*40,TITLE2*40,CAPUN(4)*8,PUNM1*7,PROD*16, CC(10)*9
      DIMENSION CDOL(10)
      COMMON/IO/L1,L2,L3,L4,L5,L6,L7,IPFLAG
      COMMON/YEARS/NYEAR,IYEAR(10),IYEARD(22),IDOL,DFAC(10)
      COMMON/YDAT/PRICE(10,50),PCI(10),WAGE(10)
      COMMON/PERCNT/PCL,PDP,PTI,POS,PRI,PGA
      COMMON/PCHAR/MNAME,TITLE1,TITLE2,PROD,UNOUT,PUNIT,COSTUN,CAPUN
     1,PUNM1
      COMMON/CAPCTY/CAPC,CYR,I1,CAPS,ICS
      COMMON/PRDAT/CAPB,ICUNP,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,OSE,MLS,
     1TCA,TCB,TCC,TCD,NMAT,MAT(8),CONS(8),TOP,NPROD,PMLP,PMMP,PPOP
     2,IPRUN(8),MUN(8),CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,FLOC,EQMETH,
     3CAPU(3),UTCON(9),UTCONP(9,3),CAPD
      COMMON/OPCOST/GA(10),DEP(10),TI(10),TML(10),TMM(10),TTL(10),
     1TCL(10),PO(10),ROI(10),RMC(10),UTC(10),TOS(10),PV(10),BPC(10)
     2,TOL(10),TOPR,F1,F2,BLI(10),TFC(10),NBP,PRM1(10)
      LOGICAL IPRNT
      DIMENSION COST(10),TCOST(10)
C** SET UP PRINTOUT CONTROL
      IPRNT=.FALSE.
      IF(IPFLAG.LT.2) IPRNT=.TRUE.
      WRITE(L7,22) TITLE1,MN,TITLE2,CAPS,CAPUN(ICS)
      IF(FLOC.NE.1.0) WRITE(L6,28) FLOC
      IF(IDOL.NE.0) THEN
        WRITE(L7,29) IDOL
      ELSE
        WRITE(L7,30)
      END IF
      WRITE(L7,1) (IYEAR(IY),IY=1,NYEAR)
      WRITE(ULINE,2) NYEAR
      WRITE(L7,ULINE)
C** PRINT INVESTMENTS
      WRITE(L7,26)
      WRITE(L7,23) (BLI(IY)*DFAC(IY),IY=1,NYEAR)
      WRITE(L7,24) (TFC(IY)*DFAC(IY),IY=1,NYEAR)
      WRITE(L7,25) (PCI(IY),IY=1,NYEAR)
C** PRINT MAJOR RAW MATERIAL COST
C** DFAC SCALES OUTPUT TO CONSTANT $
      IF(PRM1(1).NE.0.0) WRITE(L7,27) MNAME(1),PUNM1,(PRM1(IY)*DFAC(IY),
     1IY=1,NYEAR)
      IF(IPRNT) WRITE(L7,3) COSTUN(I1)
C** PRINT RAW MATERIAL/BY-PRODUCT COSTS
      WRITE(L7,4) (RMC(IY)*DFAC(IY),IY=1,NYEAR)
      IF(NBP.NE.0) THEN
        DO IY=1,NYEAR
          CDOL(IY)=BPC(IY)*DFAC(IY)
        ENDDO
        CALL PAREN(CDOL,CC)
        WRITE(L7,5) (CC(IY),IY=1,NYEAR)
      END IF
      DO IY=1,NYEAR
        CDOL(IY)=UTC(IY)*DFAC(IY)
      ENDDO
C** PRINT UTILITIES COSTS
      CALL PAREN(CDOL,CC)
      WRITE(L7,6) (CC(IY),IY=1,NYEAR)
      DO IY=1,NYEAR
        COST(IY)=(RMC(IY)+BPC(IY)+UTC(IY))*DFAC(IY)
        TCOST(IY)=COST(IY)
      ENDDO
      IF(IPRNT) THEN
        WRITE(L7,ULINE)
        WRITE(L7,7) (COST(IY),IY=1,NYEAR)
C** PRINT LABOR COSTS
        WRITE(L7,8) TOPR,(TOL(IY)*DFAC(IY),IY=1,NYEAR)
        WRITE(L7,9) PMLP,(TML(IY)*DFAC(IY),IY=1,NYEAR)
        WRITE(L7,10) PCL,(TCL(IY)*DFAC(IY),IY=1,NYEAR)
      END IF
      DO IY=1,NYEAR
        COST(IY)=(TOL(IY)+TML(IY)+TCL(IY))*DFAC(IY)
        TCOST(IY)=TCOST(IY)+COST(IY)
      ENDDO
C** PRINT OPERATING SUPPLIES, MAINTENANCE MATERIALS COSTS
      IF(IPRNT) THEN
        WRITE(L7,ULINE)
        WRITE(L7,11) (COST(IY),IY=1,NYEAR)
        WRITE(L7,12) PMMP,(TMM(IY)*DFAC(IY),IY=1,NYEAR)
        WRITE(L7,13) POS,(TOS(IY)*DFAC(IY),IY=1,NYEAR)
      END IF
      DO IY=1,NYEAR
        COST(IY)=(TMM(IY)+TOS(IY))*DFAC(IY)
```

```
        TCOST(IY)=TCOST(IY)+COST(IY)
      ENDDO
C**  PRINT PLANT OVERHEAD, TAXES+ INSUR. AND DEPRECIATION COSTS
      IF(IPRNT) THEN
        WRITE(L7,ULINE)
        WRITE(L7,14) (COST(IY),IY=1,NYEAR)
        WRITE(L7,15) PPOP,(PO(IY)*DFAC(IY),IY=1,NYEAR)
        WRITE(L7,16) PTI,(TI(IY)*DFAC(IY),IY=1,NYEAR)
        WRITE(L7,17) PDP,(DEP(IY)*DFAC(IY),IY=1,NYEAR)
        WRITE(L7,ULINE)
      END IF
      DO IY=1,NYEAR
        COST(IY)=(PO(IY)+TI(IY)+DEP(IY))*DFAC(IY)
        TCOST(IY)=TCOST(IY)+COST(IY)
      ENDDO
      IF(IPRNT) THEN
        WRITE(L7,14) (COST(IY),IY=1,NYEAR)
        CALL PAREN(TCOST,CC)
        WRITE(L7,18) (CC(IY),IY=1,NYEAR)
C**  PRINT G + A COST
        IF(PGA.NE.0.)WRITE(L7,19) PGA,(GA(IY)*DFAC(IY),IY=1,NYEAR)
C**  PRINT RETURN ON INVESTMENT
        WRITE(L7,20) PRI,(ROI(IY)*DFAC(IY),IY=1,NYEAR)
        WRITE(L7,ULINE)
      END IF
      DO IY=1,NYEAR
        CDOL(IY)=PV(IY)*DFAC(IY)
      ENDDO
      CALL PAREN(CDOL,CC)
C**  PRINT PRODUCT VALUE
       WRITE(L7,21) COSTUN(I1), (CC(IY),IY=1,NYEAR)
C**  FORMATS
 1    FORMAT(//40X,10(I4,5X))
 2    FORMAT('(40X,',I2,'(''----'',5X))')
 3    FORMAT(//' PRODUCTION COST, ',A)
 4    FORMAT(/,'  RAW MATERIALS',20X,10F9.2)
 5    FORMAT('  BY-PRODUCT CREDIT',17X,10A9)
 6    FORMAT('  IMPORTED UTILITIES',16X,10A9)
 7    FORMAT('     VARIABLE COSTS',16X,10F9.2)
 8    FORMAT(/,'  OPERATING LABOR(',F5.1,'/SHIFT)',5X,10F9.2)
 9    FORMAT('  MAINTENANCE LABOR(',F3.1,'% BLI)',6X,10F9.2)
 10   FORMAT('  CONTROL LAB LABOR(',F4.1,'% OP LABOR)',10F9.2)
 11   FORMAT('     TOTAL DIRECT LABOR',12X,10F9.2)
 12   FORMAT(/,'  MAINTENANCE MATERIALS(',F3.1,'% BLI)',2X,10F9.2)
 13   FORMAT('  OPERATING SUPPLIES(',F4.1,'%OP LABOR)',10F9.2)
 14   FORMAT(35X,10F9.2)
 15   FORMAT(/,'  PLANT OVERHEAD(',F4.1,'% TOTAL LABOR)',10F9.2)
 16   FORMAT('  TAXES AND INSURANCE(',F4.1,'% TFC)',3X,10F9.2)
 17   FORMAT('  DEPRECIATION(',F4.1,'% TFC)',10X,10F9.2)
 18   FORMAT(/' SUBTOTAL:  PLANT GATE COST',9X,10A9)
 19   FORMAT(/'  G&A, SALES, RESEARCH(',F4.1,'% PV)',3X,10F9.2)
 20   FORMAT(/'  ROI BEFORE TAXES(',F4.1,'% TFC)',6X,10F9.2)
 21   FORMAT(' PRODUCT VALUE(PV), ',A7,9X,10A9)
 22   FORMAT(1H1,A40,5X,'(MODULE #',I2,')',/1X,A40,//1X,F10.2,1X,A8,/)
 23   FORMAT('  BATTERY LIMITS(BLI)',14X,10F9.1)
 24   FORMAT('  TOTAL FIXED CAPITAL(TFC)',9X,10F9.1)
 25   FORMAT(/,' COST INDEX(CURRENT $)',13X,10F9.1)
 26   FORMAT(' INVESTMENTS (MM$)')
 27   FORMAT(/4X,A20,'(',A7,')',2X,10F9.2)
 28   FORMAT(//,' LOCATION FACTOR:  ',F6.3)
 29   FORMAT(' **COSTS SHOWN IN CONSTANT ',I4,' $')
 30   FORMAT(' **COSTS SHOWN IN CURRENT $')
      RETURN
      END
C**
C**
      SUBROUTINE PLIST(NF)
C**  PRINT A LIST OF PRODUCTS
      CHARACTER PRNAME(40)*60,PRCAP(40)*21
     1,FEED(3)*12
      COMMON/IO/L1,L2,L3,L4,L5,L6,L7
      COMMON/CHAR/PRNAME,PRCAP
      DIMENSION NUMPR(20,3)
      DATA FEED/'COAL','NATURAL GAS','VACUUM RESIDUE'/
      DATA NUMPR/1,2,7,8,13,19,22,26,27,11*0,
     13,4,5,9,11,12,14,15,16,17,18,21,24,25,28,5*0,
     210,6,23,20,16*0/
      I=1
      WRITE(L6,2) FEED(NF)
      DO WHILE (NUMPR(I,NF).NE.0)
        NN=NUMPR(I,NF)
        WRITE(L6,1) NN,PRNAME(NN),PRCAP(NN)
        I=I+1
      ENDDO
      RETURN
 1    FORMAT(3X,I2,'-',A,/6X,'(',A,')')
 2    FORMAT(' FEEDSTOCK:  ',A,/1X,'MODULES AVAILABLE:')
 3    FORMAT(5X,A)
      END
C**
C**
      SUBROUTINE PROCIN(M)
C** GET PROCESS DATA FOR MODULE M
      CHARACTER TITLE1*40,TITLE2*40,MNAME(8)*20,PROD*16
      DIMENSION PRICED(22)
      COMMON/IO/L1,L2,L3,L4,L5,L6,L7
      COMMON/YDAT/PRICE(10,50),PCI(10),WAGE(10)
      COMMON/PCHAR/MNAME,TITLE1,TITLE2,PROD
      COMMON/PRDAT/CAPB,ICUNP,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,OSE,MLS,
     1TCA,TCB,TCC,TCD,NMAT,MAT(8),CONS(8),TOP,NPROD,PMLP,PMMP,PPOP
     2,IPRUN(8),MUN(8),CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,FLOC,EQMETH,
     3CAPU(3),UTCON(9),UTCONP(9,3),CAPD
C**   READ IN PROCESS DATA
C**  ZERO ARRAYS
 100  DO I=1,8
        MAT(I)=0
        CONS(I)=0.
        MUN(I)=' '
      ENDDO
C**  READ IN REQUIRED PROCESS DATA
 300  READ(L2,REC=M) TITLE1,TITLE2,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,
     1TCA,TCB,TCC,TCD,ICUNP,CAPD,CAPB,OSE,EQMETH,NMAT,(MAT(J),CONS(J),
```

```
     2MUN(J),J=1,8),TOP,MLS,PMLP,PMMP,PPOP,CAPU,((UTCONP(J,I),J=1,9)
     3,I=1,3),NPROD,PROD,CF1,CF2,CF3,CF4,CAPMIN,CAPMAX
C**  SET DEFAULT CAPACITY = BASE CAPACITY IF NO DEFAULT CAP ENTERED
      IF(CAPD.LE.0.001) CAPD=CAPB
      DO J=1,NMAT
        MATNO=MAT(J)
        READ(L1,REC=MATNO) MM,MNAME(J),IPRUN(J),PRICED
C**  GET DEFAULT RAW MATERIAL PRICE IF NO USER-SUPPLIED VALUE
        CALL DEFAULT(PRICED,PRICE(1,MATNO))
      ENDDO
      RETURN
      END
C**
C**
      SUBROUTINE UTILTY(IY,IYP)
C**  CALCULATE UTILITY COSTS
      CHARACTER UTNAME(9)*15, UTUN(9)*7
      LOGICAL IPRNT
      COMMON/IO/L1,L2,L3,L4,L5,L6,L7,IPFLAG
      COMMON/UCHAR/UTNAME,UTUN
      COMMON/YEARS/NYEAR,IYEAR(10),IYEARD(22),IDOL,DFAC(10)
      COMMON/OPCOST/GA(10),DEP(10),TI(10),TML(10),TMM(10),TTL(10),
     1TCL(10),PO(10),ROI(10),RMC(10),UTC(10),TOS(10),PV(10),BPC(10)
     2,TOL(10),TOPR,F1,F2,BLI(10),TFC(10),NBP,PRM1(10)
      COMMON/PRDAT/CAPB,ICUMP,PCIP,NI,BLIP,BLA,BLB,BLC,BLD,TFCP,OSE,M
     1TCA,TCB,TCC,TCD,NMAT,MAT(8),CONS(8),TOP,NPROD,PMLP,PMMP,PPOP
     2,IPRUN(8),MUN(8),CF1,CF2,CF3,CF4,CAPMIN,CAPMAX,FLOC,EQMETH,
     3CAPU(3),UTCON(9),UTCONP(9,3),CAPD
      COMMON/UTLTY/UTIL(10,9),UTILD(22,9)
      IPRNT=.FALSE.
      IF(IY.EQ.IYP.AND.IPFLAG.EQ.0) IPRNT=.TRUE.
      IF(IPRNT) WRITE(L7,1)
      UTC(IY)=0.
      DO K=1,9
        F3=1.
        IF(K.LE.5) F3=100.
        COST=ROUND(F2*F3*UTCON(K)*F1*UTIL(IY,K))
        IF(IPRNT.AND.ABS(UTCON(K)).GT.0.000001) THEN
          IF(UTCON(K).GT.0.) THEN
C**  PRINT UTILITY PRICE, CONSUMPTION, COST
            WRITE(L7,2) UTNAME(K),UTIL(IY,K),UTUN(K),UTCON(K)*F1,COST
          ELSE
            WRITE(L7,5) UTNAME(K),UTIL(IY,K),UTUN(K),ABS(UTCON(K)*F1),
     1      ABS(COST)
          END IF
        END IF
        UTC(IY)=UTC(IY)+COST
      ENDDO
      IF(IPRNT) THEN
        IF(UTC(IYP).GT.0.) THEN
          WRITE(L7,3) UTC(IYP)
        ELSE
          WRITE(L7,6) ABS(UTC(IYP))
        END IF
      END IF
C**  CALCULATE TOTAL VARIABLE COSTS
      TVC=RMC(IY)+BPC(IY)+UTC(IY)
      IF(IPRNT) THEN
        IF(TVC.GT.0.) THEN
          WRITE(L7,4) TVC
        ELSE
          WRITE(L7,7) ABS(TVC)
        END IF
      END IF
      RETURN
    1 FORMAT(/,' IMPORTED UTILITIES',/)
    2 FORMAT(3X,A15,9X,F6.2,A7,3X,F8.4,6X,F7.2)
    3 FORMAT(57X,'-------',/57X,F7.2)
    4 FORMAT(//,'   TOTAL VARIABLE COSTS',33X,F8.2)
    5 FORMAT(3X,A15,9X,F6.2,A7,2X,'(',F8.4,')',4X,'(',F7.2,')')
    6 FORMAT(57X,'-------',/56X,'(',F7.2,')')
    7 FORMAT(//,'   TOTAL VARIABLE COSTS',32X,'(',F8.2,')')
      END
C**
C**
      FUNCTION ROUND(X)
C** ROUND TO NEAREST HUNDRETH
      ROUND=SIGN(0.01,X)*AINT(ABS(X)*100.+0.5)
      RETURN
      END
```

PROCESS DATA FILE

```
1
'SYNGAS(H2/CO=0.75) FROM COAL'
'      '
400.,1,1053.00,0.34412E+02,0.16372E+01,-.10466E-02,0.73388E-06
1292.00,0.60346E+02,0.20484E+01,-.14351E-02,0.99221E-06
1,802.,0.9,0.
5,.01868,7,'COAL AT MINE'
6,.01868,7,'COAL TRANSPORT'
2,.00186,7,'ASH DISPOSAL'
16,.514,0,'MISC. CHEMICALS'
20,-1.257,1,'SULFUR'
999/
24.,2,1.6,2.4,30.
1.E6,,,.012,,,-.181,.01483/
0./
0./
0,'SYNGAS(0.75)/C',.326,22.5,,,50.,1600.,0.
2
'SYNGAS(H2/CO=1.0) FROM COAL'
'      '
400.,1,1073.00,0.35467E+02,0.16554E+01,-.10470E-02,0.73959E-06
1315.00,0.61036E+02,0.20778E+01,-.14578E-02,0.10133E-05
1,803.2,0.9,0.
5,.01866,7,'COAL AT MINE'
6,.01866,7,'COAL TRANSPORT'
2,.00186,7,'ASH DISPOSAL'
16,.542,0,'MISC. CHEMICALS'
20,-1.257,1,'SULFUR'
999/
24.,2,1.6,2.4,30.
1.E6,,,.011,,,-.153,.01491/
0./
0./
0,'SYNGAS(1.0)/C',0.327,25.3,,,50.,1600.,0.
3
'SYNGAS(H2/CO=1.0) FROM NATURAL GAS'
'WITH CO2 IMPORT'
400.,2, 200.20,0.,0.,0.,0.
 247.60,0.,0.,0.,0.
1,302.8,0.9,8.26
17,.254,6,'NATURAL GAS'
3,27.85,1,'CARBON DIOXIDE'
16,2.59,0,'MISC. CHEM. & CAT.'
999/
4.,0,1.5,1.5,80.
1.E6,.230,,,,.0502,1.277,,.741,.00749,
100.,.245,,,,.0502,1.277,,.741,.00749,
50.,.261,,,.04999,-.0609,5.57,,.741,.00749,
0,'SYNGAS(1.0)/G',.327,25.3,,,15.,600.,97.6
4,
'SYNGAS(H2/CO=1.0) FROM SYNGAS(H2/CO=3.0)'
'BY SKIMMING'
400.,3,  26.72,0.75000E+00,0.90000E+00,0.,0.
  26.77,0.75000E+00,0.90000E+00,0.,0.
1,141.7,0.9,0.
24,2.05,3,'SYNGAS(3.0)/G'
11,-.97,3,'HYDROGEN'
999/
0.,0,1.5,1.5,80.
1.E6,.00126,,,,,1.524/
0./
0./
0,'SYNGAS(1.0)/GS',.327,25.3,,,40.,600.,129.2
5
'SYNGAS(H2/CO=1.0) FROM SYNGAS(H2/CO=2.0)'
'BY SKIMMING'
400.,3,  18.81,0.75000E+00,0.90000E+00,0.,0.
  18.85,0.75000E+00,0.90000E+00,0.,0.
1,190.,0.9,0.
21,1.548,3,'SYNGAS(2.0)/G'
11,-.48,3,'HYDROGEN'
999/
0.,0,1.5,1.5,80.
1.E6,.000647,,,,,1.503/
0./
0./
0,'SYNGAS(1.0)/GS',.327,25.3,,,40.,760.,200.
6
'SYNGAS(H2/CO=1.0) FROM VACUUM RESIDUE'
'      '
400.,3, 232.00,0.80000E+00,0.90000E+00,0.,0.
 306.00,0.80000E+00,0.90000E+00,0.,0.
1,298.3,0.9,0.
26,22.96,1,'VACUUM RESIDUE'
16,.46,0,'MISC. CHEMICALS'
20,-1.36,1,'SULFUR'
999/
8.,0,1.5,1.5,80.
1.E6,,,-.004,,,.694,,.098,.0091,
0./
0./
0.,'SYNGAS(1.0)/R'.327,25.3,,,50.,600.,200.
7
'SYNGAS(H2/CO=1.5) FROM COAL'
'      '
400.,1,1095.00,0.35967E+02,0.16796E+01,-.10388E-02,0.73067E-06
1340.00,0.55578E+02,0.22333E+01,-.18473E-02,0.13135E-05
1,804.3,0.9,0.
5,.01864,7,'COAL AT MINE'
6,.01864,7,'COAL TRANSPORT'
2,.00186,7,'ASH DISPOSAL'
16,.581,0,'MISC. CHEMICALS'
20,-1.257,1,'SULFUR'
999/
24.,2,1.6,2.4,30.
1.E6,,,.009,,,-.116,.01502/
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0./
0./
0,'SYNGAS(1.5)/C',.327,30.6,,,50.,1600.,0.
8
'SYNGAS(H2/CO=2.0) FROM COAL'
'    '
400.,1,1109.00,0.37248E+02,0.16907E+01,-.10350E-02,0.73150E-06
1356.00,0.63829E+02,0.21144E+01,-.14196E-02,0.97727E-06
1,805.,0.9,0.
5,.01864,7,'COAL AT MINE'
6,.01864,7,'COAL TRANSPORT'
2,.00186,7,'ASH DISPOSAL'
16,.607,0,'MISC. CHEMICALS'
20,-1.257,1,'SULFUR'
999/
24.,2,1.6,2.4,30.
1.E6,,,.008,,,-.091,.01509/
0./
0./
0,'SYNGAS(2.0)/C',.327,35.58,,,50.,1600.,0.
9
'SYNGAS(H2/CO=2.0) FROM NATURAL GAS'
'WITH CO2 IMPORT'
400.,2, 117.80,0.,0.,0.,0.
 158.50,0.,0.,0.,0.
1,294.6,0.9,8.49
17,.261,6,'NATURAL GAS'
3,8.96,1,'CARBON DIOXIDE'
16,1.23,0,'MISC. CHEMICALS'
999/
4.,0,1.5,1.5,80.
1.E6,.188,,,,,1.202,,.319,.00637
100.,.198,,,,,1.202,,.319,.00637
0./
21,'SYNGAS(2.0)/G',.327,35.58,,,40.,600.,200.
10
'SYNGAS(H2/CO=2.0) FROM VACUUM RESIDUE'
'    '
400.,3, 243.00,0.80000E+00,0.90000E+00,0.,0.
 328.00,0.80000E+00,0.90000E+00,0.,0.
1,295.9,0.9,0.
26,22.41,1,'VACUUM RESIDUE'
16,.51,0,'MISC. CHEMICALS'
20,-1.32,1,'SULFUR'
999/
8.,0,1.5,1.5,80.
1.E6,,,.0104,,,.862,,.116,.0082,
0./
0./
22,'SYNGAS(2.0)/R',.327,35.58,,,50.,600.,200.
11
'SYNGAS(H2/CO=2.0) FROM SYNGAS(H2/CO=3.0)'
'BY SKIMMING'
400.,3,  11.83,0.75000E+00,0.90000E+00,0.,0.
  11.87,0.75000E+00,0.90000E+00,0.,0.
1,220.5,0.9,0.
24,1.32,3,'SYNGAS(3.0)/G'
11,-.3193,3,'HYDROGEN'
999/
0.,0,1.5,1.5,80.
1.E6,.000394,,,,,.933/
0./
0./
0,'SYNGAS(2.0)/GS',.327,35.58,,,40.,880.,151.5
12
'SYNGAS(H2/CO=3.0) FROM NATURAL GAS'
'WITH CO2 RECYCLE'
400.,2,  98.20,0.,0.,0.,0.
 130.90,0.,0.,0.,0.
1,290.5,0.9,8.6
17,.265,6,'NATURAL GAS'
16,.90,0,'MISC. CHEMICALS'
999/
4.,0,1.5,1.5,80.
1.E6,.160,,,,,1.018,,.223,.00645
0./
0./
24,'SYNGAS(3.0)/G',.324,44.64,,,40.,600.,200.
13
'METHANOL SYNGAS(H2/CO=2.26) FROM COAL'
'    '
400.,1,1114.00,0.38025E+02,0.16960E+01,-.10364E-02,0.73274E-06
1362.00,0.64853E+02,0.21130E+01,-.14000E-02,0.96331E-06
1,805.3,0.9,0.
5,.01864,7,'COAL AT MINE'
6,.01864,7,'COAL TRANSPORT'
2,.00186,7,'ASH DISPOSAL'
16,.616,0,'MISC. CHEMICALS'
20,-1.257,1,'SULFUR'
999/
24.,2,1.6,2.4,30.
1.E6,,,.0076,,,-.0825,.01512/
0./
0./
23,'SYNGAS(2.26)/C',.327,38.03,,,50.,1600.,0.
14
'CRUDE SYNGAS(H2/CO=4.92)'
'FROM NATURAL GAS'
400.,2,  73.60,0.,0.,0.,0.
  92.80,0.,0.,0.,0.
1,264.9,0.9,9.44
17,.308,6,'NATURAL GAS'
16,.33,0,'MISC. CHEM. & CAT.'
999/
2.,0,1.5,1.5,80.
1.E6,.1256,,-.04609,.02082,,.717,,.00473,.00283
0./
0./
25,'SYNGAS(4.9)/G',.323,59.37,,,90.,530.,0.
15
'CO FROM GAS-DERIVED SYNGAS(H2/CO=3.0)'
'BY COSORB SEPARATION'
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400.,3,   8.60,0.64000E+00,0.65000E+00,0.,0.
   9.68,0.65000E+00,0.65000E+00,0.,0.
3,149.3,0.9,0.
24,.0539,3,'SYNGAS(3.0)/G'
16,.13,0,'MISC. CHEMICALS'
11,-.040,3,'HYDROGEN'
7,-.0000871,6,'FUEL GAS'
999/
2.,0,2.,2.,80.
1.E6,,,,,.00103,.12,,.003/
0./
0./
0,'CARBON MONOXIDE',.322,13.55,,,70.,600.,0.
16
'CO FROM GAS-DERIVED SYNGAS(H2/CO=3.0)'
'BY CRYOGENIC SEPARATION'
400.,3,   4.80,0.58000E+00,0.60000E+00,0.,0.
   5.50,0.60000E+00,0.60000E+00,0.,0.
3,149.3,0.9,0.
24,.0541,3,'SYNGAS(3.0)/G'
16,.05,0,'MISC. CHEMICALS'
11,-.0393,3,'HYDROGEN'
7,-.000496,6,'FUEL GAS'
999/
2.,0,2.,2.,80.
1.E6,,,,,,.197,,.00121/
0./
0./
0,'CARBON MONOXIDE',.322,13.55,,,70.,600.,0.
17
'CO FROM GAS-DERIVED CRUDE SYNGAS'
'(H2/CO=4.9) BY COSORB SEPARATION'
400.,3,  10.40,0.66000E+00,0.65000E+00,0.,0.
  13.62,0.65000E+00,0.65000E+00,0.,0.
3,149.3,.9/
25,.0846,3,'SYNGAS(4.9)/G'
16,.155,0,'MISC. CHEMICALS'
9,-.0699,3,'HYDROGEN(85.4%)'
999/
2.,0,2.,2.,80.
1.E6,,,,,.00125,.166,,.00362/
0./
0./
0,'CARBON MONOXIDE',.322,13.55,,,70.,600.,0.
18
'CO FROM GAS-DERIVED CRUDE SYNGAS'
'(H2/CO=4.9) BY CRYOGENIC SEPARATION'
400.,3,  17.90,0.65000E+00,0.65000E+00,0.,0.
  19.34,0.65000E+00,0.65000E+00,0.,0.
3,149.3,0.9,0.
25,.0891,3,'SYNGAS(4.9)/G'
16,.21,0,'MISC. CHEMICALS'
3,-.913,1,'CARBON DIOXIDE'
11,-.0712,3,'HYDROGEN'
7,-.00394,6,'FUEL GAS'
999/
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4.,0,2.,2.,80.
1.E6,,,,,.00116,.353,,.0192/
0./
0./
0,'CARBON MONOXIDE',.322,13.55,,,70.,600.,0.
19
'CO FROM COAL-DERIVED METHANOL SYNGAS'
'(H2/CO=2.26) BY COSORB SEPARATION'
400.,3,   8.40,0.64000E+00,0.65000E+00,0.,0.
   9.38,0.65000E+00,0.65000E+00,0.,0.
3,149.3,0.9,0.
23,.04446,3,'SYNGAS(2.26)/C'
16,.13,0,'MISC. CHEMICALS'
10,-.0306,3,'HYDROGEN(93%)'
999/
2.,0,2.,2.,80.
1.E6,,,,,.00103,.12,,.003/
0./
0./
0,'CARBON MONOXIDE',.322,13.55,,,70.,600.,0.
20
'CO FROM RESID-DERIVED SYNGAS(H2/CO=2.0)'
'BY CRYOGENIC SEPARATION'
400.,3,   5.20,0.61000E+00,0.60000E+00,0.,0.
   6.00,0.60000E+00,0.60000E+00,0.,0.
3,149.3,.9/
22,.0419,3,'SYNGAS(2.0)/R'
16,.04,0,'MISC. CHEMICALS'
11,-.0271,3,'HYDROGEN'
7,-.000378,6,'FUEL GAS'
999/
2.,0,2.,2.,80.
1.E6,,,,,,.163,,.00123/
0./
0./
0,'CARBON MONOXIDE',.322,13.55,,,70.,600.,0.
21
'HYDROGEN(97%) FROM NATURAL GAS'
'  '
400.,2,  88.90,0.,0.,0.,0.
 118.80,0.,0.,0.,0.
1,276.9,0.9,9.030
17,.278,6,'NATURAL GAS'
16,2.37,0,'MISC. CHEMICALS'
999/
4.,0,1.5,1.5,80.
1.E6,.144,,-.0544,.0544,.0134,.838,,.202,.0067
57.8,.155,,-.0544,.0544,.0134,.838,,.202,.0067
0./
0,'HYDROGEN/G',.324,189.7,,,8.,560.,100.
22
'HYDROGEN(97%) FROM COAL'
'  '
400.,1,1239.00,0.41353E+02,0.19328E+01,-.12143E-02,0.89958E-06
1503.00,0.69783E+02,0.24180E+01,-.17154E-02,0.12404E-05
1,781.,0.9,0.
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5,.01919,7,'COAL AT MINE'
6,.01919,7,'COAL TRANSPORT'
2,.00192,7,'ASH DISPOSAL'
16,1.532,0,'MISC. CHEMICALS'
20,-1.257,1,'SULFUR'
999/
27.,4,1.6,2.4,30.
1.E6,,,.0163,,-.0169,.0307,.016/
0./
0./
0,'HYDROGEN/C',.324,189.7,,,50.,1560.,200.
23
'HYDROGEN(98%) FROM VACUUM RESIDUE'
'     '

400.,3, 273.00,0.80000E+00,0.90000E+00,0.,0.
 368.00,0.80000E+00,0.90000E+00,0.,0.
1,286.1,0.9,0.
26,23.25,1,'VACUUM RESIDUE'
16,.79,0,'MISC. CHEMICALS'
20,-1.38,1,'SULFUR'
999/
8.,0,1.5,1.5,80.
1.E6,,,.0622,,,1.265,,.172,.00859
0./
0./
0,'HYDROGEN/R',.324,189.7,,,50.,1150.,100.
24
'METHANOL FROM NATURAL GAS'
'     '

400.,2, 155.20,0.,0.,0.,0.
 212.80,0.,0.,0.,0.
4,2490.7,0.9,1.0037
17,30.86,6,'NATURAL GAS'
1,.022,1,'ACTIVE CARBON'
18,.154,1,'REFORMING CATALYST'
15,.287,1,'METHANOL CATALYST'
8,-16.47,1,'HIGHER ALCOHOLS'
999/
6.,0,1.5,1.5,80.
1.E6,1.87,,,,,33.07,,28.66,.298
500.,2.76,,,,,33.07,,28.66,.298
0./
0,'METHANOL/G',,,6.6,9690.,140.,5000.,0.
25
'METHANOL FROM GAS-DERIVED'
'CRUDE SYNGAS(H2/CO=4.9)'
400.,2,  81.70,0.,0.,0.,0.
 120.00,0.,0.,0.,0.
4,2490.7,0.9,1.0037
25,106.5,3,'SYNGAS(4.9)/G'
15,.154,1,'METHANOL CATALYST'
8,-16.47,1,'HIGHER ALCOHOLS'
999/
4,0,1.5,1.5,80.
1.E6,-13.35,,4.89,-2.21,,-42.99,,28.44/
0./
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0./
0,'METHANOL/G',,,6.6,9690.,960.,5000.,0.
26
'METHANOL FROM COAL'
'     '

400.,1,1272.00,0.46252E+02,0.14685E+00,-.54413E-05,0.30184E-09
1582.00,0.77769E+02,0.18624E+00,-.75195E-05,0.39421E-09
4,10000.,0.9,0.
5,1.5,7,'COAL AT MINE'
6,1.5,7,'COAL TRANSPORT'
2,.15,7,'ASH DISPOSAL'
15,.4,1,'METHANOL CATALYST'
16,60.,0,'MISC. CHEMICALS'
20,-101.4,1,'SULFUR'
999/
34.,1,1.6,2.4,30.
1.E6,,,,,,,,1.37/
0./
0./
0,'METHANOL/C',,,6.6,9690.,600.,20000.,0.
27
'METHANOL FROM COAL-DERIVED'
'METHANOL SYNGAS(H2/CO=2.26)'
400.,1, 158.00,0.87600E+01,0.11502E-01,0.91045E-06,-.56825E-10
 220.00,0.13210E+02,0.17057E-01,0.12712E-05,-.90901E-10
4,10000.,0.9,0.
23,80.5,3,'SYNGAS(2.26)/C'
15,.4,1,'METHANOL CATALYST'
16,10.,0,'MISC. CHEMICALS'
999/
10.,3,1.6,2.4,30.
1.E6,,,-.61,,,6.63,.15/
0./
0./
0,'METHANOL/C',,,6.6,9690.,600.,20000.,0.
28
'CARBON DIOXIDE FROM FLUE GAS SCRUBBING'
'     '

400.,3,  30.10,0.85000E+00,0.90000E+00,0.,0.
  43.65,0.85000E+00,0.90000E+00,0.,0.
3,870.,.9/
16,.05,0,'MISC. CHEM. & CAT.'
999/
2.,0,1.5,1.5,80.
1.E6,,,,,.00236,.091,,.0157/
0./
0./
3,'CARBON DIOXIDE',,8.63,,,400.,1750.,0.
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PRICE DATA FILE

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22
1980,1981,1982,1983,1984,1985,1986,1987,1988,1989,1990,1991,1992,1993,1994,
1995,1996,1997,1998,1999,2000,2001/
'PCI', 355.0, 400.0, 430.0, 462.3, 496.9, 534.2, 574.3, 617.3, 663.6, 713.4,
 766.9, 824.4, 886.2, 952.7,1024.0,1101.0,1184.0,1272.0,1368.0,1470.0,
1581.0,1699.0/
'INFL FAC',1.,.922,.861,.805,.752,.703,.657,.614,.574,.536,
,501,.469,.438,.409,.383,.357,.334,.312,.292,.273,.255,.283
'WAGE',15.4,17.5,18.9,20.4,21.9,23.6,25.3,27.1,29.1,31.2,
33.4,35.8,38.4,41.1,44.0,47.1,50.4,54.0,57.8,61.8,
66.1,70.8/
'GAS',4.00,4.17,5.51,6.09,6.74,7.37,8.27,9.13,10.13,11.21,
  12.43,13.58,14.84,16.22,17.73,19.38,21.19,23.16,25.33,27.73,
  30.36,33.24/
'FUEL',4.40,4.76,6.22,7.05,7.60,8.10,8.85,9.57,10.40,11.29,
  12.32,13.46,14.71,16.08,17.57,19.21,21.00,22.97,25.11,27.50,
  30.10,32.95/
'HP STEAM',7.00,7.70,8.30,8.90,9.50,10.20,10.90,11.70,12.60,13.50,
14.60,15.60,16.80,18.10,19.40,20.90,22.50,24.20,26.00,27.90,
30.00,32.30/
'MP STEAM',5.90,6.50,7.00,7.50,8.00,8.60,9.20,9.90,10.60,11.40,
  12.30,13.20,14.20,15.20,16.40,17.60,18.90,20.40,21.90,23.50,
  25.30,27.20/
'LP STEAM',4.70,5.20,5.60,6.00,6.40,6.90,7.40,7.90,8.50,9.10,
   9.80,10.5,11.3,12.1,13.1,14.0,15.1,16.2,17.4,18.7,
  20.1,21.7/
'ELECT',3.40,3.60,4.50,5.00,5.50,5.90,6.60,7.30,8.00,8.80,
 9.70,10.60,11.50,12.60,13.70,14.90,16.30,17.70,19.30,21.10,
  23.00,25.20/
'CLARIFIED H2O',36.00,41.00,46.00,50.00,54.00,58.00,62.00,67.00,72.00,77.00,
  83.00,89.00,96.00,103.00,111.00,119.00,128.00,138.00,148.00,159.00,
 171.00,184.00/
'COOLING H2O',4.90,5.40,6.20,6.70,7.30,7.90,8.60,9.40,10.20,11.10,
  12.10,13.00,14.10,15.30,16.50,17.90,19.40,21.00,22.70,24.60,
  26.70,28.90/
'PROCESS H2O',60.00,68.00,77.00,83.00,89.00,96.00,103.00,111.00,120.00,129.00,
 138.00,149.00,160.00,172.00,185.00,199.00,214.00,230.00,247.00,266.00,
 286.00,307.00/
1,'ACTIVE CARBON',1,148.,175.,188.,201.,216.,232.,251.,271.,292.,316.,342.,370.,
400.,433.,468.,507.,549.,594.,643.,696.,754.,816.
2,'ASH DISPOSAL',7,4.6,5.0,5.35,5.7,6.1,6.6,7.,7.5,8.,8.6,9.2,9.8,10.5,11.3,12.,
12.9,13.8,14.8,15.8,16.9,18.1,19.3
3,'CARBON DIOXIDE',1/
5,'COAL AT MINE',7,28.8,32.3,34.6,37.,39.6,42.3,45.5,49.,52.9,57.2,61.8,66.8,72.2,
78.,84.3,91.1,98.4,106.4,115.,124.3,134.3,145.1
6,'COAL TRANSPORT',7,13.8,15.,16.,17.2,18.4,19.7,21.,22.5,24.1,25.8,27.6,29.5,31.6,
33.8,36.1,38.7,41.4,44.3,47.4,50.7,54.2,58.
7,'FUEL GAS',6,4.4,4.76,6.22,7.05,7.6,8.1,8.85,9.57,10.4,11.29,12.32,13.46,14.71,
16.08,17.57,19.21,21.,22.97,25.11,27.5,30.1,33.
8,'HIGHER ALCOHOLS',1,4.4,4.8,6.2,7.,7.6,8.1,8.9,9.6,10.4,11.3,12.3,13.5,14.7,16.1,
17.6,19.2,21.,23.,25.1,27.5,30.1,32.95
9,'HYDROGEN(85.4%)',3,143.,154.,202.,228.,246.,262.,287.,310.,337.,366.,
399.,436.,477.,521.,569.,622.,680.,744.,814.,891.,975.,1068.
10,'HYDROGEN(93%)',3,271.,304.,326.,350.,376.,403.,433.,465.,500.,538.,
579.,623.,670.,720.,774.,833.,896.,963.,1036.,1114.,1199.,1289.
11,'HYDROGEN',3,241.,258.,321.,352.,387.,421.,468.,513.,565.,621.,
684.,745.,811.,883.,962.,1047.,1141.,1243.,1355.,1478.,1612.,1759.
15,'METHANOL CATALYST',1,340.,400.,430.,460.,495.,530.,575.,620.,670.,720.,780.,
845.,915.,990.,1070.,1160.,1255.,1360.,1470.,1590.,1725.,1865.
16,'MISC. CHEM. & CAT.',0,.845,1.,1.07,1.15,1.235,1.324,1.435,1.547,1.671,1.805,
1.953,2.112,2.286,2.474,2.677,2.898,3.136,3.394,3.675,3.979,4.309,4.666
17,'NATURAL GAS',6,4.0,4.17,5.51,6.09,6.74,7.37,8.27,9.13,10.13,
11.21,12.43,13.58,14.84,16.22,17.73,19.38,21.19,23.16,25.33,27.73,
30.36,33.24
18,'REFORMING CATALYST',1,170.,200.,215.,230.,250.,265.,290.,310.,335.,360.,
390.,420.,460.,495.,535.,580.,630.,680.,735.,800.,860.,930.
20,'SULFUR',1,3.84,4.54,4.87,5.22,5.61,6.01,6.51,7.02,7.59,8.19,8.87,
9.59,10.38,11.23,12.15,13.16,14.24,15.41,16.68,18.06,19.56,21.18
21,'SYNGAS(2.0)/G',3,253.,270.,337.,370.,407.,443.,492.,540.,595.,654.,
721.,785.,854.,931.,1014.,1104.,1204.,1312.,1430.,1560.,1702.,1858.
22,'SYNGAS(2.0)/R',3,256.,284.,349.,389.,416.,447.,485.,525.,565.,610.,
658.,712.,773.,840.,910.,988.,1072.,1164.,1264.,1372.,1490.,1618.
23,'SYNGAS(2.26)/C',3,271.,304.,326.,350.,376.,403.,433.,465.,500.,538.,
579.,623.,670.,720.,774.,833.,896.,963.,1036.,1114.,1199.,1289.
24,'SYNGAS(3.0)/G',3,231.,246.,309.,340.,373.,407.,452.,497.,547.,602.,
664.,723.,788.,859.,936.,1020.,1112.,1211.,1321.,1442.,1573.,1718.
25,'SYNGAS(4.9)/G',3,195.,206.,266.,294.,324.,354.,396.,436.,483.,533.,
589.,643.,702.,766.,837.,913.,998.,1089.,1190.,1301.,1423.,1556.
26,'VACUUM RESIDUE',1,5.15,5.65,8.,9.2,9.8,10.5,11.5,12.5,13.5,14.6,15.8,
17.2,18.8,20.6,22.5,24.6,26.9,29.4,32.2,35.2,38.5,42.1
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