4. ECONOMICS OF AMMONIA MANUFACTURE

Ammonia provides the largest single requirement for industrial hydrogen. In the U. S. essentially all ammonia currently produced (about 16 MST/yr) is made by catalytic steam reforming of natural gas or some other light hydrocarbon feed stock. Future shortages of these feed stocks and increases in their prices will provide the incentive for seriously considering coal or residuum as alternative feed stocks for ammonia manufacture.

In this study economics for ammonia manufacture in the 1980-2000 period have been calculated for steam reforming, resid partial oxidation, K-T coal gasification, and new coal gasification. Production cost data for these processes were developed by Chem Systems, Inc. and are presented in Appendix A.

Investments and operating cost data for ammonia plants of 2000 ST/SD capacity are summarized in Table 4.01 and are shown in greater detail in Table 4.02. The production cost data are compared in the diagrams shown in Figure 4.01. These data are further summarized as follows:

Investments and Operating Costs for Ammonia Plants of 2000 ST/SD Capacity

1980 $

	Investment $ Millions 1980 or 2000	Production Cost Including Return, $/ST Ammonia	
		1980	2000
Steam Reforming	180.6	210	248
Resid Partial Oxidation	280.6	248	283
K-T Coal Gasification	395.0	248	248
New Coal Gasification	362.0	227	227

In the year 1980 steam reforming will be the most attractive ammonia producing process because of its substantially lower investment and operating costs. However, by the year 2000 the price of natural gas (or an alternative light hydrocarbon feed stock) will increase substantially thus providing equivalent production costs for reforming and K-T coal gasification. In the year 2000, costs for ammonia production by new coal gasification will be $227/ST compared to $248/ST for both reforming and K-T coal gasification, thereby making it attractive to consider new coal gasification.

It has been assumed that the ammonia plants using new coal gasification would be located in Illinois and Illinois high sulfur coal would be used as the feed stock. This Illinois location provides the lowest cost ammonia manufacture using coal gasification and is in the corn belt, the largest ammonia consuming area of the U. S.

Resid partial oxidation is not competitive in either 1980 or 2000 unless resid feed stock could be purchased at prices substantially below those assumed in this study.

Table 4.03 presents data regarding the sensitivity of ammonia manufacturing costs for the several economic effects previously discussed. These data are compared for reforming and new coal gasification in Table 4.04 for the years 1980 and 2000. In 1980 reforming has an advantage over new coal gasification of \$17 to 26/ST (8-12%). However, by the year 2000 the higher cost of reformer feed stock compared to coal provides an advantage for new coal gasification over reforming of \$5 to 38/ST (2 to 15%).

Plotting the ammonia manufacturing costs for reforming and new coal gasification for the most likely feed stock prices against time shows that the cost with new coal gasification equals that with reforming in the year 1989. After the year 1989, new coal gasification provides lower ammonia manufacturing costs than reforming. This relationship is shown in Figure 4.02. The corresponding data for methanol (Section 5) are also shown in this plot for comparison.

Table 4.05 presents estimates to show new U. S. ammonia manufacturing capacity added during the 1980-2000 period including capacity installed as reforming and new coal gasification. By the year 2000, the U. S. ammonia capacity will be 41.8 M ST/yr; 21.4 M ST/yr will be with new coal gasification and 20.4 M ST/yr will be with reforming. The reformer capacity will require natural gas or some other light hydrocarbon feed stock equivalent to 352,000 B/D of crude. The new coal gasification capacity will replace reformer capacity that would require 370,000 B/D crude equivalent. This saving of hydrocarbon feed stock is discussed further in Section 7.

If the new coal gasification process were available for commercial use, ammonia plants installed with this process would have the overall effect of releasing natural gas or light hydrocarbon feed stock that would be required if the ammonia were produced by reforming. Table 4.06 shows the calculated cost of releasing reformer feed stock by using the new coal gasification process for producing ammonia from Illinois high sulfur coal. When the coal is purchased at its most likely price, the cost of releasing reformer feed is \$3.66/MBtu or \$20.35/bbl crude equivalent. If the coal were purchased at its low price, the corresponding values are \$3.26/MBtu and \$18.13/bbl crude equivalent. The high coal price corresponds to \$4.14/MBtu and \$23.02/bbl crude equivalent. All these values are in excess of the anticipated 1980 price of imported crude (about \$15/bbl) thus confirming that reforming is the preferred ammonia manufacturing process in 1980.

TABLE 4.01

Summary of Investments and Operating Costs for Ammonia Manufacture

All plants are 2000 ST/SD capacity; operation in 1980, 1980 $

	Methane Steam Reforming	Resid Partial Oxidation	Coal Gasification(1) K-T	Coal Gasification(1) New
Investment, $ Millions				
Onsite	116.5	170.6	235.1	209.2
Offsite	64.1	110.0	159.9	152.9
Total	180.6	280.6	395.0	362.1
Cost of feed stock, $/MBtu	3.15	2.35	0.96	0.96
Costs and Charges, $/ST ammonia				
Feed stock	110.39	93.18	38.65	36.13
Other operating costs	4.53	12.01	11.31	10.58
Capital charges(2)	94.91	142.88	197.81	179.94
Total	209.83	248.07	247.77	226.65

(1) Coal gasification plants are located in Illinois and use Illinois high sulfur coal.

(2) Capital charges include maintenance, overhead, insurance property taxes, depreciation, interest on working capital and 20%/year before tax return.

TABLE 4.02

Summary of Economics for Ammonia Manufacture

1980 Operation; 1980$

Process	Methane Reforming		Resid Partial Oxidation		K-T Coal Gasification		New Coal Gasification	
Plant location	Gulf Coast		Gulf Coast		Mid-Continent		Mid-Continent	
Design capacity ST NH_3/Day	2000		2000		2000		2000	
Design capacity ST NH_3/yr x 10^6	0.660		0.660		0.660		0.660	
Feed stock cost at plant	--		$15.00/bbl		$21.80/ton		$21.80/ton	
Feed stock cost at plant $/MBtu	3.35		2.35		0.96		0.95	
Investment, $ Millions								
Onsite	116.5		170.6		235.1		209.2	
Offsite	64.1		110.0		159.9		152.9	
Total plant	180.6		280.6		395.0		362.1	
Working capital	12.6		11.6		5.5		5.1	
Costs and Charges	M$/yr	$/ST	M$/yr	$/ST	M$/yr	$/ST	M$/yr	$/ST
Feed stock	72.860	110.39	61.500	93.18	25.506	38.65	23.849	36.13
Utilities	0.711	1.08	5.046	7.65	4.678	7.09	4.131	6.26
Chemicals and Catalyst	0.800	1.21	0.800	1.21	0.700	1.06	0.700	1.06
Labor and supervision	1.480	2.24	2.082	3.15	2.086	3.16	2.086	3.16
Maintenance (4% onsite)	4.660	7.06	6.824	10.34	9.404	14.25	8.368	12.68
Plant overhead (2.6% onsite)	3.029	4.59	4.436	6.72	6.113	9.26	5.439	8.24
Insurance, property taxes (1.5% total plant)	2.709	4.10	4.209	6.38	5.925	8.98	5.432	8.23
Depreciation (10% onsite + 5% offsite)	14.855	22.51	22.560	34.18	31.505	47.73	28.565	43.28
Interest on working capital (10%)	1.264	1.92	1.157	1.75	0.550	0.83	0.513	0.78
Return on investment (20% total pl.)	36.120	54.73	56.120	85.03	79.000	119.70	72.420	109.73
Total including return	138.488	209.83	164.734	249.59	165.467	250.71	151.503	229.55
Sulfur credit ($50/ton)	--	--	(1.000)	(1.52)	(1.940)	(2.94)	(1.915)	(2.90)
Net cost including return	138.488	209.83	163.734	248.07	163.527	247.77	149.588	226.65

FIGURE 4.01

Ammonia Manufacturing Costs - Midcontinent Location

$/ST - 2000 T/D Plants - 1980 $

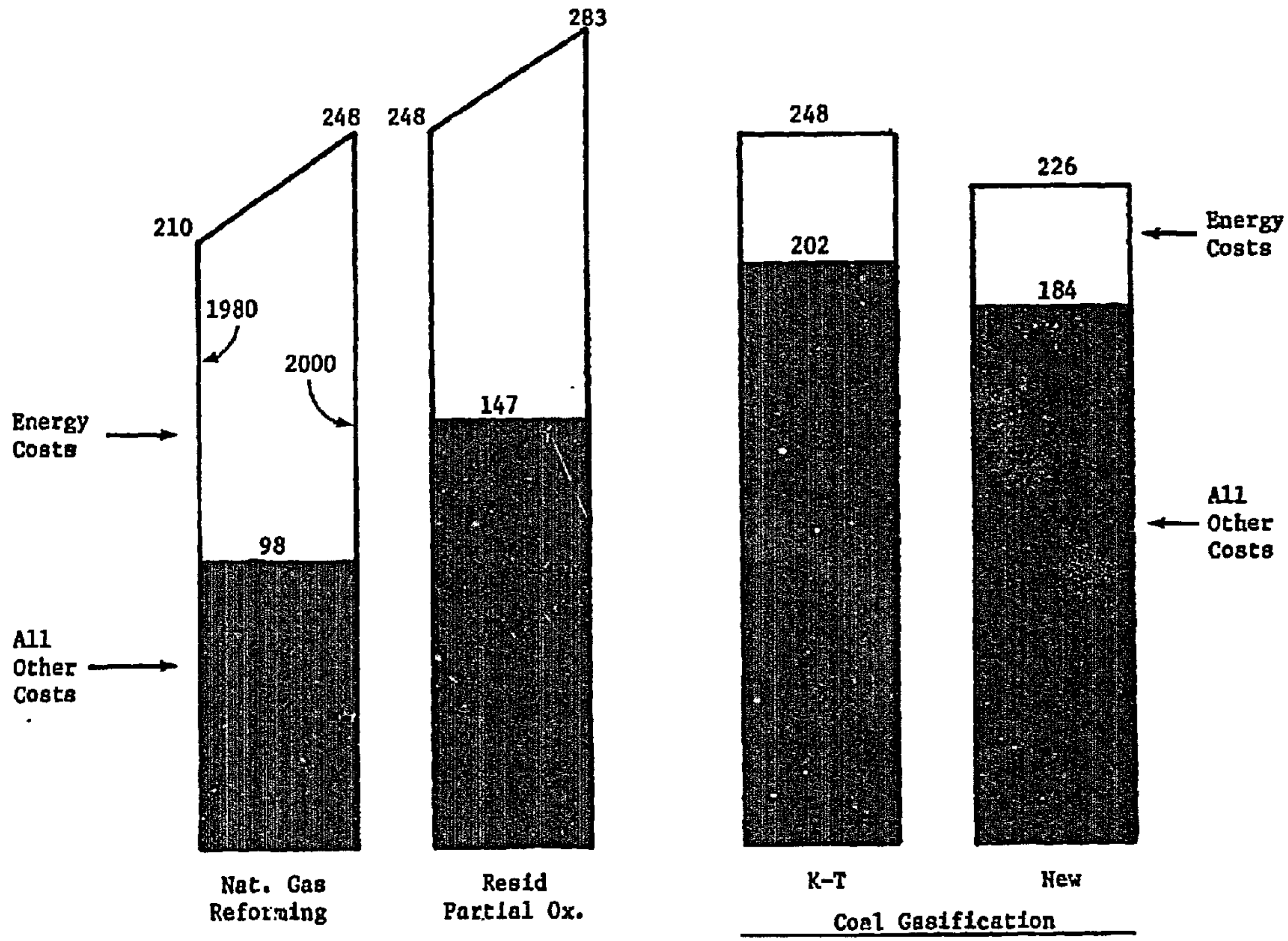

TABLE 4.03

Sensitivities for Ammonia Manufacture

All data are ammonia production costs including
20% below tax return, $/ST, 1980 $

Location	Year	Methane Reforming	Resid Partial Oxid.	Coal Gasification K-T	Coal Gasification New
		All	All	Midcontinent	
Base case - most likely fuel price	1980	210	248	248	227
	2000	248	281	248	227
Base case - high fuel price	1980	219	265	266	244
	2000	260	306	266	244
Base case - low fuel price	1980	187	214	233	213
	2000	218	238	233	213
Additional 10% investment contingency	1980	218	261	265	242
	2000	256	296	265	242
Construction costs escalate 1%/yr. above gen. infl.	2000	269	314	292	267
Construction costs escalate 1%/yr. below gen. infl.	2000	231	257	211	193
Coal prices escalate 1%/yr. above gen. infl.	2000	--	--	258	236
Coal prices escalate 1%/yr. below gen. infl.	2000	--	--	239	219

TABLE 4.04

Sensitivities for Ammonia Manufacture in 2000 ST/SD Plants for Methane Reforming and New Coal Gasification

Midcontinent Location, 1980 $, $/ST

	1980			2000		
	Methane Reforming	New Coal Gasification	Advantage For MR	Methane Reforming	New Coal Gasification	Advantage For MR
Base Case, most likely fuel prices	210	227	17	248	227	-21
Base Case, high fuel prices	219	244	25	260	244	-16
Base Case, low fuel prices	187	213	26	218	213	-5
10% additional investment	218	242	24	256	242	-14
Construction costs escalate +1%/yr.	--	--	--	269	267	-2
Construction costs escalate -1%/yr.	--	--	--	231	193	-38
Coal prices escalate +1%/yr.	--	--	--	248	236	-12
Coal prices escalate -1%/yr.	--	--	--	248	219	-29

FIGURE 4.02

Production Costs, Ammonia and Methanol by Natural Gas Reforming and New Coal Gasification

2000 T/D Plants, Midcontinent Location, 1980 $

Most Likely Feed Stock Prices

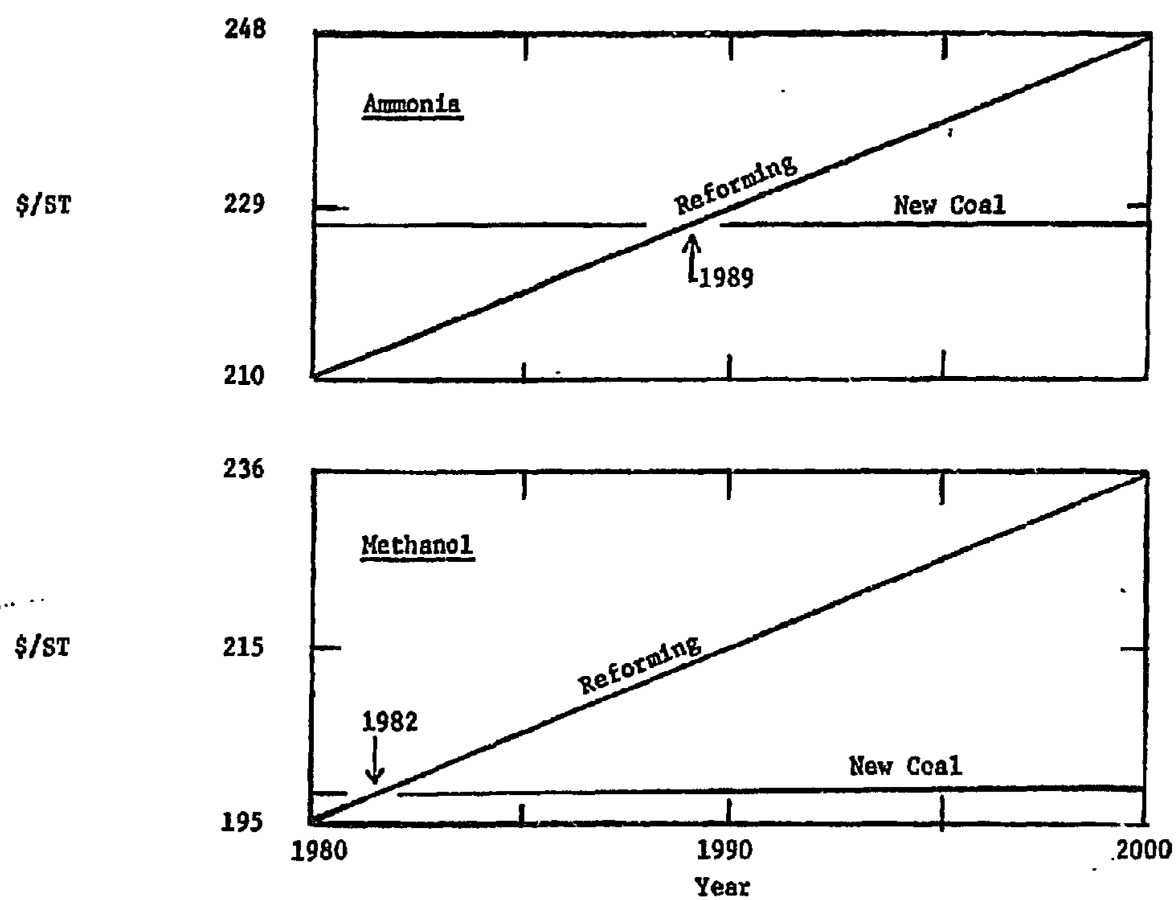

TABLE 4.05

U.S. Ammonia Requirements and Capacity

Year	1975	1980	1985	1990	1995	2000
Ammonia requirements, MST/yr.	16.0	21.3	25.2	30.5	35.7	41.8
Ammonia production cost in new plants, $/ST						
Reforming (1980 $)	--	210	220	229	239	248
New coal (1980 $)	--	--	223	227	227	227
Capacity added, 5 years ending, MST/yr.						
For growth	--	5.3	3.9	5.3	5.2	6.1
For replacement	--	4.0	5.3	6.3	7.6	8.9
Total	--	9.3	9.2	11.6	12.8	15.0
Total, cumulative	--	--	9.2	20.8	33.6	48.6
Reformer capacity added		9.3	9.2	10.0	5.0	3.0
New coal capacity added		--	--	1.6	7.8	12.0
Total		9.3	9.2	11.6	12.8	15.0
Capacity in operation, MST/yr.						
Reformer	16.0	21.3	25.2	28.9	26.3	20.4
New coal	--	--	--	1.6	9.4	21.4
Total	16.0	21.3	25.2	30.5	35.7	41.8
Natural gas equivalent of ammonia production, MB/D crude*						
For reformer ammonia	0.276	0.368	0.435	0.499	0.454	0.352
For new coal ammonia	--	--	--	0.028	0.162	0.370
Total	0.276	0.368	0.435	0.527	0.616	0.722

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* 1.0 ST of ammonia requires 35.045 MBtu of natural gas feed = 6.303 bbl. crude oil.

TABLE 4.06

Cost of Releasing Natural Gas Feed Stock for Ammonia Manufacture by New Coal Gasification

1980 operation, 1980 $

Price of Illinois High Sulfur Coal, $/Ton	14.82	21.80	30.80
Price of Illinois High Sulfur Coal, $/MBtu	0.65	0.96	1.35
<u>Costs for Producing Ammonia $/ST</u>			
Total cost - new coal process	213	227	244
Deduct reforming costs exclusive of feedstock	99	99	99
Cost of releasing 35.04 MBtu of natural gas	114	128	145
Cost of releasing natural gas feed, $/MBtu	3.26	3.66	4.14
Cost of releasing natural gas feed, $/bbl crude equiv.	18.13	20.35	23.02

5. ECONOMICS OF METHANOL MANUFACTURE

Essentially all methanol manufactured in the U. S. is produced by catalytic steam reforming of natural gas or some other light hydrocarbon feed stock. However, a large methanol plant was recently announced for the Houston ship channel area will employ resid partial oxidation. Future shortages of natural gas and other light hydrocarbon feed stocks will encourage the consideration of resid and coal as alternative feed stocks.

As was done for ammonia manufacture, economics for methanol manufacture for the 1980-2000 period have been calculated for steam reforming, resid partial oxidation, K-T coal gasification and new coal gasification. Production cost data for these processes were developed by Chem Systems, Inc. and are presented in Appendix A.

Investments and operating cost data for methanol plants of 2000 ST/SD capacity are summarized in Table 5.01 and are shown in greater detail in Table 5.02. The production cost data are compared in Figure 5.01. These data are further summarized as follows:

Investments and Operating Costs for Methanol Plants of 2000 ST/SD Capacity

1980 $

	Investment $ Millions 1980 or 2000	Production Cost Including Return, $/ST Methanol 1980	2000
Steam Reforming	135.3	195	236
Resid Partial oxidation	231.1	221	255
K-T coal gasification	350.4	226	226
New coal gasification	310.1	198	198

In the year 1980 steam reforming will be the most attractive methanol process because of its low investment and low operating costs. However, by the year 2000, production costs for methanol manufacture by the new coal process will be substantially below those for reforming or resid partial oxidation. Predicted methanol manufacturing costs for the year 2000 will be $198/ST for the new coal process compared to $236/ST for reforming.

Methanol plants using the new coal process will be located in geographical areas where low cost high Btu coal is available and methanol markets can be serviced with low transportation costs. These requirements would correspond to plants being located in the East Coast area or possibly the Midcontinent area. The economics shown above assume the coal based plant is located in Illinois and would use Illinois high sulfur coal as feed stock.

Resid partial oxidation is not competitive in either 1980 or 2000 unless resid feed stock could be purchased at prices substantially below those assumed in this study.

Table 5.03 presents data to show the sensitivity of methanol manufacturing costs for the several economic effects previously described. These data for reforming and new coal gasification are compared in Table 5.04 for the years 1980 and 2000. In 1980 reforming has a small advantage over new coal gasification of $3 to 14/ST (2 to 7%). By the year 2000 new coal gasification has an advantage over reforming of $18 to 53/ST (8 to 22%).

Plotting the methanol manufacturing cost (most likely feed stock prices) for reforming and new coal gasification against time shows the two processes provide equal costs in the year 1982. After 1982, the cost with new coal is less than for reforming. This relationship is shown in Figure 5.02. The corresponding data for ammonia manufacture (Section 4) are shown in this plot for comparison.

Table 5.05 presents estimates to show the new U. S. methanol capacity added during the 1980-2000 period including capacity installed as reforming and as new coal gasification. By the year 2000 the U. S. methanol capacity will be 15.3 million ST/yr; 13.2 million ST/yr will employ new coal gasification and 2.1 will be with reforming. The reformer capacity will require natural gas or another light hydrocarbon feed stock equivalent to 37,000 B/D of crude. The new coal gasification capacity will replace reformer capacity that would require 230,000 B/D of crude equivalent. This saving is discussed further in Section 7.

Table 5.06 shows the calculated cost of releasing reformer feed stock by using the new coal gasification process for producing methanol using Illinois high sulfur coal. When the coal is purchased at its most likely price the cost of releasing reformer feed is $3.22/MBtu or $17.90/bbl crude equivalent. The corresponding data are $2.85/MBtu and $15.85/bbl for the low coal price and $3.67/MBtu and $20.41/bbl for the high coal price. These values are somewhat in excess of the anticipated price of imported crude (about $15/bbl), thus confirming that reforming is the more attractive methanol manufacturing process in 1980.

TABLE 5.01

Summary of Investments and Operating Costs for Methanol Manufacture

All plants are 2000 ST/SD capacity; operation in 1980; 1980 $

	Methane Steam Reforming	Resid Partial Oxidation	Coal Gasification[1] K-T	Coal Gasification[1] New
Investment, $ Millions				
Onsite	87.9	137.9	206.1	175.2
Offsite	47.4	93.3	144.3	134.9
Total	135.3	231.1	350.4	310.1
Cost of feed stock, $/MBtu	3.15	2.35	0.96	0.96
Costs and Charges, $/ST Methanol				
Feed stock	111.68	93.18	37.46	35.01
Other operating costs	11.69	10.32	10.26	9.49
Capital charges[2]	71.84	117.24	177.86	153.35
Total	195.21	220.74	225.58	197.85

(1) Coal gasification plants are located in Illinois and use Illinois high sulfur coal.
(2) Capital charges include maintenance, overhead, insurance, property taxes, depreciation, interest on working capital, and 20%/year before tax return.

TABLE 5.02

Summary of Economics for Methanol Manufacture

1980 Operation; 1980 $

Process / Plant Location	Methane Reforming Gulf Coast		Resid Partial Oxidation Gulf Coast		K-T Coal Gasification Mid-Continent		New Coal Gasification Mid-Continent	
Design capacity ST CH_3OH/day	2000		2000		2000		2000	
Design capacity ST CH_3OH/year x 10^6	0.660		0.660		0.660		0.660	
Feed stock cost at plant	--		$15.00/bbl		$21.80/ton		$21.80/ton	
Feed stock cost at plant $/MBtu	3.15		2.35		0.96		0.96	
Investment, $ Millions								
Onsite	87.9		137.9		206.1		175.2	
Offsite	47.4		93.3		144.3		134.9	
Total plant	135.3		231.1		350.4		310.1	
Working capital	13.6		11.4		5.2		4.9	
Costs and Charges	M$/yr	$/ST	M$/yr	$/ST	M$/yr	$/ST	M$/yr	$/ST
Feed stock	73.710	111.68	61.500	93.18	24.721	37.46	23.108	35.01
Utilities	4.090	6.20	3.933	5.96	4.235	6.42	3.732	5.65
Chemicals and catalyst	2.147	3.25	0.800	1.21	0.450	0.68	0.450	0.68
Labor and supervision	1.480	2.24	2.082	3.15	2.086	3.16	2.086	3.16
Maintenance (4% onsite)	3.516	5.33	5.516	8.36	8.244	12.49	7.008	10.62
Plant overhead (2.6% onsite)	2.285	3.46	3.585	5.43	5.359	8.12	4.555	6.90
Insurance, property taxes (1.5% total plant)	2.030	3.08	3.467	5.25	5.256	7.96	4.652	7.05
Depreciation (10% onsite + 5% offsite)	11.160	16.91	18.455	27.96	27.825	42.16	24.265	36.77
Interest on working capital (10%)	1.357	2.06	1.139	1.73	0.525	0.80	0.490	0.74
Return on onvestment (20% tot. plant)	27.060	41.00	46.220	70.03	72.080	109.21	62.020	93.97
Total including return	128.835	195.21	146.697	222.26	150.781	228.46	132.366	200.55
Sulfur credit ($50/ton)	--	--	(1.000)	(1.52)	(1.900)	(2.88)	(1.780)	(2.70)
Net cost including return	128.835	195.21	145.697	220.74	148.881	225.58	130.586	197.85

FIGURE 5.01

Methanol Manufacturing Costs - Midcontinent Location

\$/ST - 2000 T/D Plants - 1980 \$

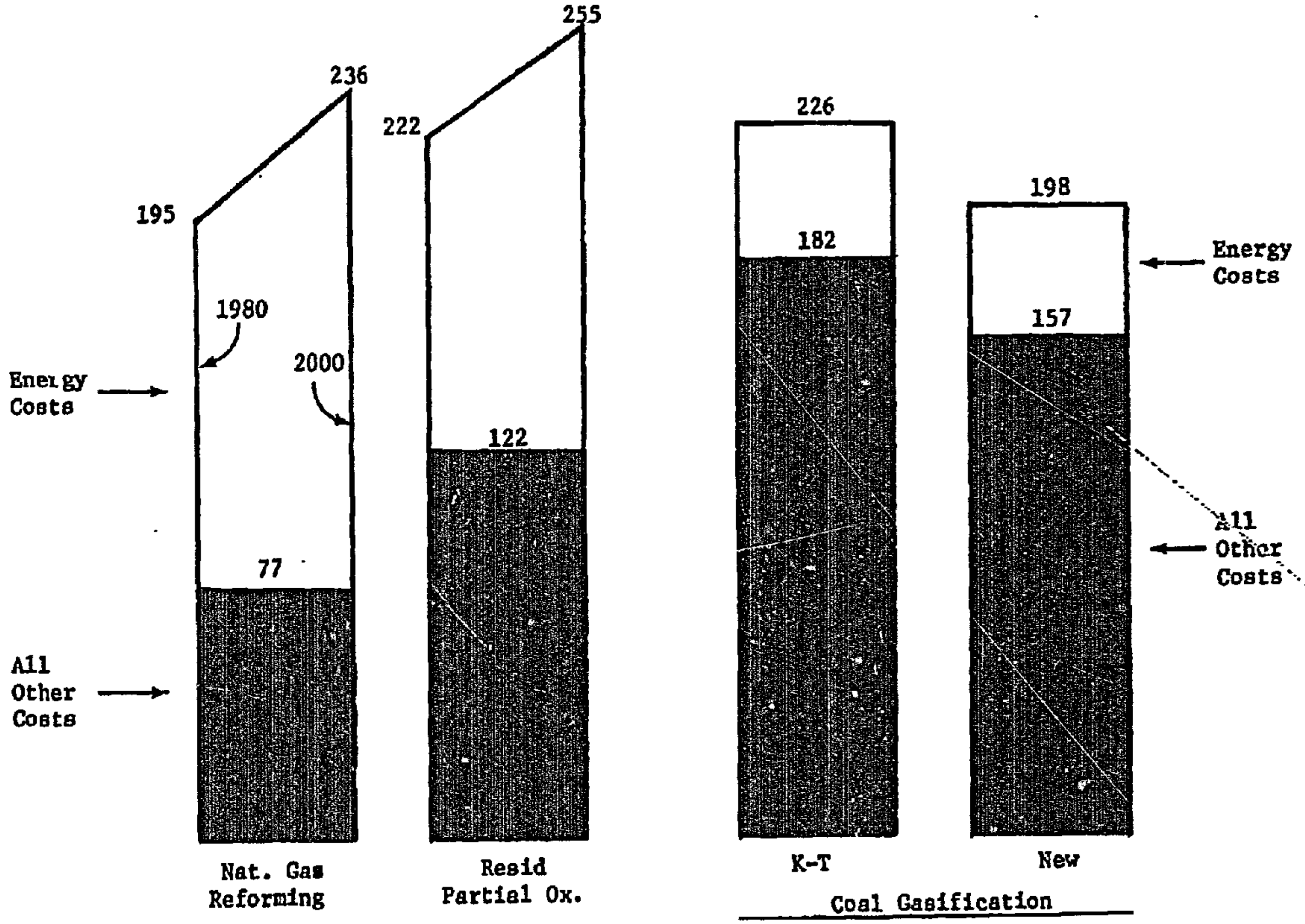


TABLE 5.03

Sensitivities for Methanol Manufacture

All data are methanol production costs including
20% before tax return, $/ST, 1980 $

	Year	Methane Reforming	Resid Partial Oxid.	Coal Gasification K-T	Coal Gasification New
Location		All	All	Midcontinent	
Base case - most likely fuel price	1980	195	221	226	198
	2000	236	255	226	198
Base case - high fuel price	1980	205	237	243	214
	2000	249	277	243	214
Base case - low fuel price	1980	171	187	211	185
	2000	203	210	211	185
Additional 10% investment contingency	1980	202	231	241	211
	2000	242	265	241	211
Construction costs escalate 1%/yr. above gen. infl.	2000	251	280	265	232
Construction costs escalate 1%/yr. below gen. infl.	2000	223	233	193	170
Coal prices escalate 1%/yr. above gen. infl.	2000	--	--	235	207
Coal prices escalate 1%/yr. below gen. infl.	2000	--	--	218	190

TABLE 5.04

Sensitivities for Methanol Manufacture in 2000 ST/SD Plants for Methane Reforming and New Coal Gasification

Midcontinent Location, 1980 $, $/ST

	1980			2000		
	Methane Reforming	New Coal Gasification	Advantage For MR	Methane Reforming	New Coal Gasification	Advantage for MR
Base Case, most likely fuel prices	195	198	3	236	198	-38
Base Case, high fuel prices	205	214	9	249	214	-35
Base Case, low fuel prices	171	185	14	203	185	-18
10% additional investment	202	211	9	242	211	-31
Construction costs escalate +1%/yr.	--	--	--	251	232	-19
Construction costs escalate -1%/yr.	--	--	--	223	170	-53
Coal prices escalate +1%/yr.	--	--	--	236	207	-29
Coal prices escalate -1%/yr.	--	--	--	236	190	-46

FIGURE 5.02

PRODUCTION COSTS, AMMONIA AND METHANOL
BY NATURAL GAS REFORMING AND NEW COAL GASIFICATION

2000 T/D Plants, Midcontinent Location, 1980 $

Most Likely Feed Stock Prices

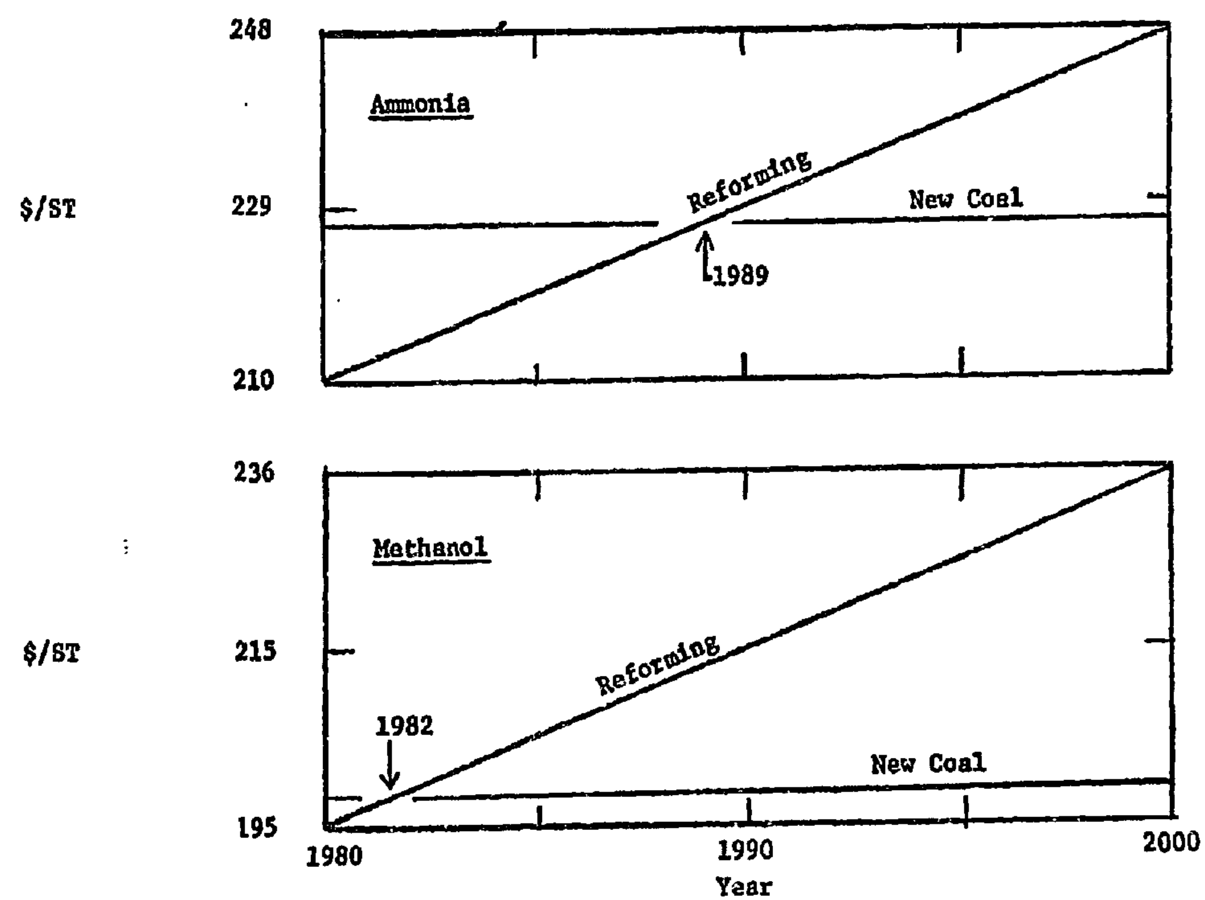


TABLE 5.05

U.S. Methanol Requirements and Capacity

Year	1975	1980	1985	1990	1995	2000
Methanol requirements, MST/yr.	3.8	5.3	6.6	9.5	12.1	15.3
Methanol production cost in new plants, $/ST						
Reforming (1980 $)	--	195	205	216	226	236
New coal (1980 $)	--	198	198	198	198	198
Capacity added, 5 years ending, MST/yr.						
For growth	--	1.5	1.3	2.9	2.6	3.2
For replacement	--	0.9	1.3	1.6	2.4	3.0
Total		2.4	2.6	4.5	5.0	6.2
Reformer capacity added	--	2.4	1.6	1.5	1.0	1.0
New coal capacity added	--	--	1.0	3.0	4.0	5.2
Total		2.4	2.6	4.5	5.0	6.2
Capacity in operation, MST/yr.						
Reformer	3.8	5.3	5.6	5.5	4.1	2.1
New Coal	--	--	1.0	4.0	8.0	13.2
Total	3.8	5.3	6.6	9.5	12.1	15.3
Natural gas equivalent of methanol production, MB/D crude*						
For reformer ammonia	0.066	0.093	0.098	0.096	0.072	0.037
For new coal ammonia	--	--	0.017	0.070	0.140	0.230
Total	0.066	0.093	0.115	0.166	0.212	0.267

-----

* 1.0 ST of methanol requires 35.455×10^6 Btu of feed = 6.38 bbl. of crude oil.

TABLE 5.06

Cost of Releasing Natural Gas Feed Stock for Methanol Manufacture by New Coal Gasification

1980 Operation, 1980 $

Price of Illinois High Sulfur Coal, $/Ton	14.82	21.80	30.80
" " " " " " , $/MBtu	0.65	0.96	1.35
Costs for Producing Methanol, $/ST			
Total cost, new coal process	185	198	214
Deduct reforming costs exclusive of feed	84	84	84
Cost of releasing 35.45 MBtu of natural gas	101	114	130
Cost of releasing natural gas feed, $/MBtu	2.85	3.22	3.67
" " " " " " , $/bbl crude equiv.	15.85	17.90	20.41

6. ECONOMICS FOR SMALL USER HYDROGEN

Requirements for hydrogen for the various small uses were discussed previously in Section 1 including Tables 1.11, 1.12, 1.13, and Figure 1.01.

The consumer who requires a "small" quantity of hydrogen in the range of 1000 to 1.0 million SCF/D has several choices for procuring his hydrogen supply. If his facility is near a large hydrogen producer he may arrange to purchase hydrogen for over the fence pipe line delivery. If this cannot be done, he would consider the purchase of hydrogen from an industrial gas producer with delivery by truck either as a gas in pressurized cylinders or as liquid hydrogen. Since hydrogen purchased by truck delivery is rather expensive, another choice would be to install a steam reformer or water electrolyzer as a hydrogen manufacturing facility and use either natural gas, LPG, or electricity as the energy source. It is beyond the scope of this report to show the economics for these choices for all geographical locations. However, the general range of costs that apply to these choices are discussed so as to provide general guidance.

Economics data for steam reforming in 100 MSCF/SD plants are presented in Section 3 (Table 3.02). Economics data for small capacity reformers is discussed in Reference 22. Data from this reference have been adjusted to 1980 operation and 1980 $ using the feed stock and other values used previously for calculating the economics of large reformers. These data for small reformers are presented in Table 6.01. The unit investment cost for these small reformers increases substantially as plant size is decreased:

0.100 MSCF/SD	-	$68.81/MBtu/yr
0.480 MSCF/SD	-	24.81/MBtu/yr
2.400 MSCF/SD	-	9.92/MBtu/yr
100 MSCF/SD	-	5.55/MBtu/yr

Labor costs for operating small reformer plants have a large effect on total production costs. The data shown in Table 6.01 assume each of these small reformers is operated essentially unattended (0.15 to 0.26 operator/shift). If one full time operator were required the total cost for hydrogen would be as follows:

0.100 MSCF/SD	-	$37.94/MBtu
0.480 MSCF/SD	-	20.77/MBtu
2.40 MSCF/SD	-	10.12/MBtu

The investment in SPE electrolysis plants should be essentially constant at $200/kw. Production cost data for small capacity SPE electrolysis plants have been calculated as shown in Table 6.02. It was also assumed that these plants would operate essentially unattended. If one full time operator per shift were required, the electrolytic hydrogen costs would be as follows:

0.100 MSCF/SD - $44.38/MBtu
0.480 MSCF/SD - 19.68/MBtu
2.40 MSCF/SD - 14.37/MBtu

Currently available electrolysis plants cost about $500/kw rather than $200/kw projected for the SPE process. Electrolytic hydrogen from currently available electrolysis plants will cost about $6.00/MBtu more than that from SPE electrolysis plants.

Current costs (late 1976) for hydrogen purchased for truck delivery have been converted to 1980 $ using a 5%/yr escalation rate. These costs are plotted in Figure 6.01 along with the costs including return for manufacturing hydrogen by reforming and SPE electrolysis.

In the requirement range up to about 50,000 SCF/day it is probably more attractive to purchase hydrogen for truck delivery than to manufacture it on site, assuming the dealer does not have to truck it more than about 50 miles. Purchased hydrogen will cost about $100/MBtu at the rate of 100 SCF/day and will decrease to $25-40/MBtu for 100,000 SCF/day.

For requirements in the range of 50,000 to 500,000 SCF/day, SPE electrolysis would provide the lowest cost assuming this process were available. Costs with SPE electrolysis would be in the range of $15-20/MBtu. Above 500,000 SCF/day reforming using either natural gas or LPG feed stock is probably the most attractive system ($6 to 15/MBtu). However, the cost and availability of natural gas and LPG feed stock varies considerably from one geographical area to another.

Many small hydrogen users consume hydrogen only a few hours per day. Reforming is not attractive under these circumstances since these plants require several hours to achieve economic, steady operation.

This small user hydrogen market will be supplied by either reforming, new coal gasification through pipeline or tank truck delivery from an ammonia or methanol plant, or electrolysis during the 1980-2000 period. The quantities supplied by each system have been predicted as shown in Table 6.03. These data (also plotted in Figure 6.02) assume that the small user hydrogen market will grow at 5%/yr during the 1975-2000 period and that electrolysis would gradually increase its percentage of the total from the current 17% to 25% by the year 2000. It was also assumed that coal gasification would start supplying hydrogen to the small user market in 1990 and would provide 30% of the total by the year 2000. In the year 2000, supplies for the small user hydrogen market are predicted to be:

	MBtu/yr x 10^6	MSCF/day
By reforming	37	310
By new coal gasification	25	210
By electrolysis	21	180
Total	83	700

TABLE 6.01

Economics of Hydrogen Manufacture in Small Reformers*

1980 Operation, 1980 $

Hydrogen capacity, MSCF/SD	0.100	0.480	2.400
" " , kSCF/hr	4.17	20.0	100.0
" " , MSCF/yr	33.0	158.4	792
" " , MBtu/yr x 10^6	0.0109	0.0524	0.262
Operating days per year	330	330	330
" hours per year	7920	7920	7920
Operators per shift	0.15	0.20	0.26
Investment, $ Millions			
Onsite	0.600	1.04	2.08
Offsite	0.150	0.26	0.52
Total	0.750	1.30	2.60
% contingency in investments	10	10	10
$/MBtu/yr	68.81	24.81	9.92
Working capital, $ thousands	18	57	241
Costs & Charges, $/MBtu product			
Natural gas @ $3.15/MBtu	5.09	5.09	5.09
Utilities	0.08	0.08	0.08
Labor and supervision	4.68	1.32	0.34
Maintenance (4% of onsites)	2.20	0.80	0.32
Plant overhead (2.6% of onsites)	1.47	0.52	0.21
Insurance, property taxes (1.5% of total)	1.01	0.38	0.15
Depreciation (10% onsites, 5% offsites)	6.24	2.23	0.89
Interest on working capital (10%/yr)	0.18	0.11	0.09
Return on investment (20%/yr)	13.76	4.96	1.98
Total	34.71	15.49	9.15
Total Cost, $/kscf	11.42	5.13	3.03

TABLE 6.02

Economics of Hydrogen Manufacture - SPE Electrolysis

1980 Operation, 1980 $

Hydrogen capacity, MSCF/SD	0.100	0.480	2.400
" " , kSCF/hr	4.17	20.0	100.0
" " , MSCF/yr	33.0	158.4	792
" " , MBtu/yr x 10^6	0.0109	0.0524	0.262
Operating days per year	330	330	330
" hours per year	7920	7920	7920
Operators per shift	0.15	0.20	0.26
Thermal efficiency, %	77.6	77.6	77.6
Investment, $ Millions			
Onsite	0.065	0.310	1.550
Offsite	0.016	0.080	0.390
Total	0.081	0.390	1.940
Investment, $/MBtu/yr	7.43	7.43	7.43
" , $/kw product	200	200	200
Working capital, $ thousands	25	89	401
Costs and Charges, $/MBtu product			
Electricity @ $0.027/kwhr	10.19	10.19	10.19
Other utilities	0.07	0.07	0.07
Labor and supervision	4.68	1.32	0.34
Maintenance (4% of onsites)	0.24	0.24	0.24
Plant overhead (2.6% of onsites)	0.15	0.15	0.15
Insurance, property taxes (1.5% of total)	0.11	0.11	0.11
Depreciation (10% onsite, 5% offsite)	0.67	0.67	0.67
Interest on working capital (10%/yr)	0.27	0.17	0.15
Return on investment, 20%/yr	1.48	1.48	1.48
Total	17.86	14.40	13.40
Total Cost, $/kscf	5.80	4.68	4.36

FIGURE 6.01

Hydrogen Costs by Reforming, Electrolysis and Truck Delivery vs. Quantity Required

1980 Operation, 1980 $

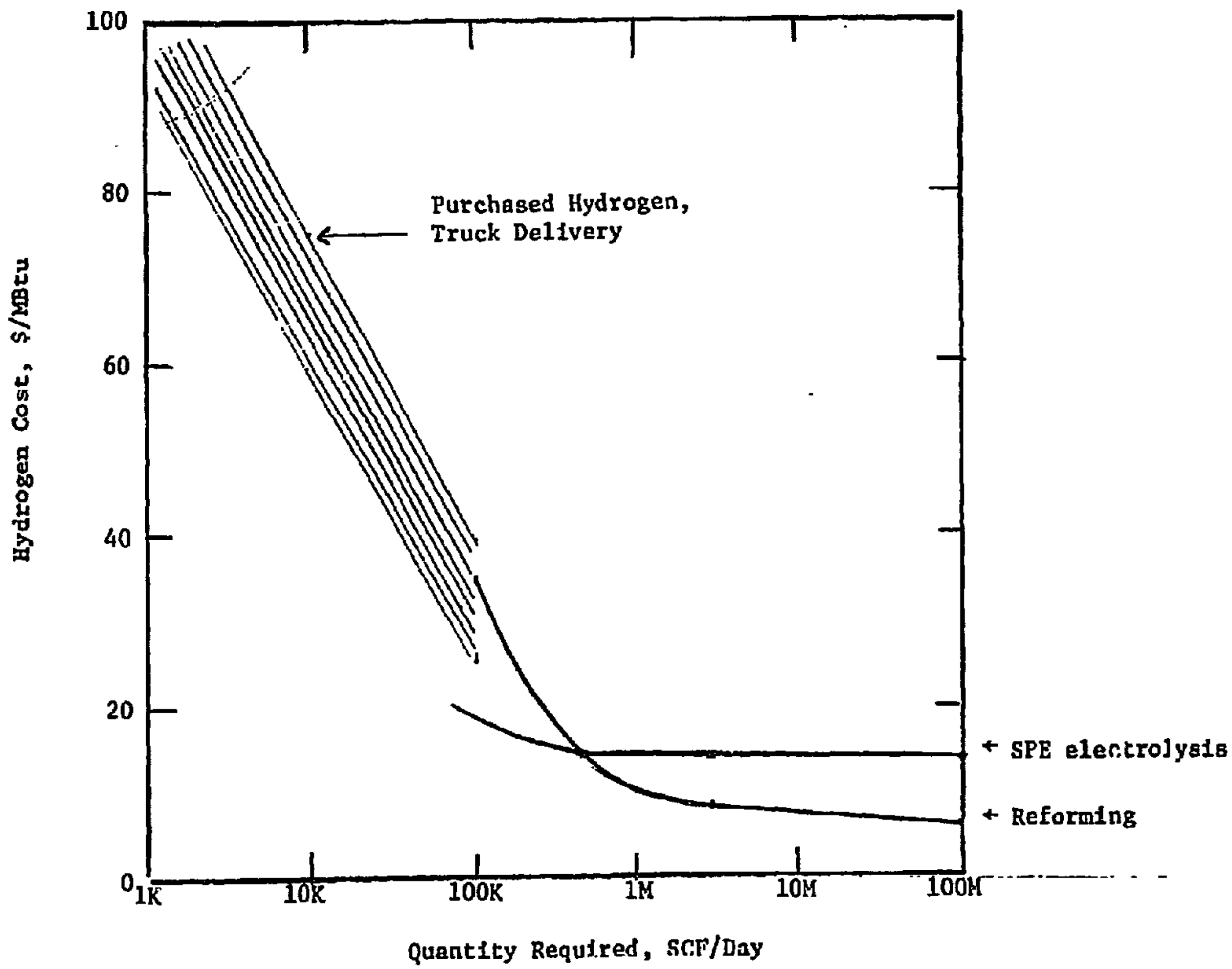


TABLE 6.03

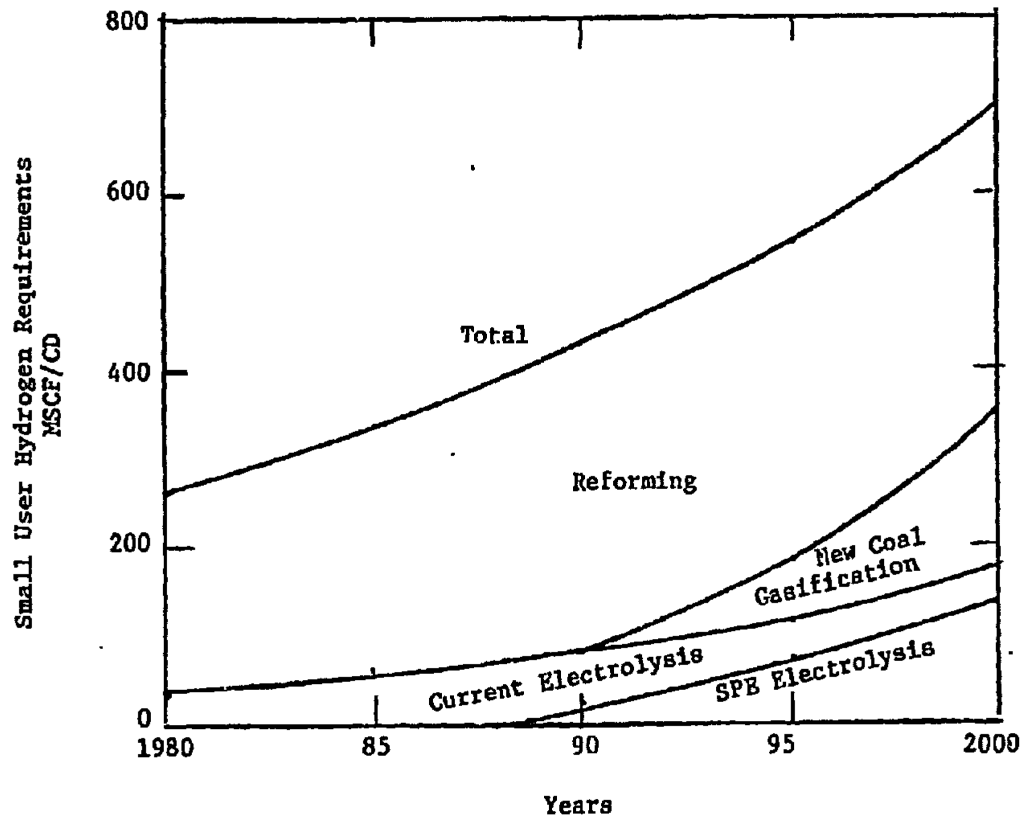
Requirements and Capacity for U.S. Small User Hydrogen

Year	1975	1980	1985	1990	1995	2000
Small user hydrogen requirements, MSCF/CD	202	261	337	430	548	700
Capacity Added, 5 years ending, MSCF/CD						
For growth	-	59	76	93	118	152
For replacement	-	50	65	65	65	66
Total	-	109	141	158	183	218
Reformer capacity added	-	109	114	124	65	47
New coal " "	-	-	-	-	70	105
Current electrolysis capacity added	-	3	27	9	-	-
SPE " " "	-	-	-	25	48	66
Total	-	112	141	158	183	218
Capacity in Operation, MSCF/CD						
Refomer	170	226	284	352	361	350
New coal	-	-	-	-	70	175
Current electrolysis	32	35	53	53	44	36
SPE "	-	-	-	25	73	139
Total	202	261	337	430	548	700
Natural gas equivalent of small user hydrogen production, k B/D crude equivalent*						
Reformer hydrogen	14.2	18.9	23.7	29.5	30.2	29.3
New coal "	-	-	-	-	5.8	14.6
Current electrolysis hydrogen	2.7	2.9	4.4	4.4	3.7	3.0
SPE " "	-	-	-	2.1	6.1	11.6
Total	16.9	21.8	28.1	36.0	45.8	58.5

*Assuming this hydrogen is produced by steam reforming and that 1.0 MSCF hydrogen requires natural gas equivalent to 83.6 bbl. crude.

FIGURE 6.02

Processes Used in Production of U. S. Requirements for Small User Hydrogen



7. POTENTIAL SAVINGS OF NATURAL GAS

As has been explained in Sections 4, 5, and 6, some of the ammonia, methanol and small user hydrogen will likely be produced by the new coal gasification process starting about 1985. After 1985, hydrocarbon feed stocks will become more expensive than coal and the use of coal gasification will increase.

The economics data presented in Section 3 indicate that new coal gasification is likely not to be attractive for refinery hydrogen production during the 1980-2000 period.

Economics data for ammonia, methanol and small user hydrogen were used in Sections 4, 5, and 6 to estimate the new capacity that is likely to be built using the new coal process. From these estimates of new coal capacity, the quantities of natural gas feed stock saved by the new coal process have been calculated as is discussed in the following paragraphs. These data are summarized in Table 7.01 and are further summarized as follows:

Natural Gas Feed Stock Saved by New Coal Gasification Process, 1990-2000

Year	1990	2000
Natural gas required if all production were by reforming, kB/D crude equiv.		
Refinery hydrogen	273	395
Ammonia	527	722
Methanol	166	267
Small user hydrogen	36	59
Total	1002	1443
Natural gas saved by new coal gasification, kB/D crude equiv.		
Refinery hydrogen	—	—
Ammonia	28	370
Methanol	70	230
Small user hydrogen	—	15
Total	98	615
Saving, % of total	10	43

By 1990 the new coal process will likely save natural gas equivalent to 98,000 B/D crude equivalent or about 10% of the natural gas feed stock required for all the industrial hydrogen production. Afterward the use of new coal gasification will increase until in the year 2000 it will save natural gas equivalent to 615,000 B/D of crude or 43% of the total natural gas feed stock requirement.

Table 7.02 shows the annual production of refinery hydrogen, ammonia, methanol and small user hydrogen during the 1980-2000 period and the corresponding requirements for natural gas feed stock assuming reforming were used to provide 100% of the industrial hydrogen production.

Table 7.03 shows the quantities of ammonia, methanol, and small user hydrogen that is likely to be produced by new coal gasification. Also shown in this table are the quantities of natural gas saved each year by the new coal process. These data are also shown in Figure 7.01.

The coal required to manufacture these annual quantities of ammonia, methanol, and small user hydrogen are shown in Table 7.04. In 1990 the coal required is 9.1 MST/yr. In the year 2000 this requirement is 58 MST/yr.

The electricity required to produce the small user hydrogen manufactured by electrolysis is shown in Table 7.05. In 1980 the electricity is estimated to be 1.6 billion kwhr/yr. By 1990 this requirement is estimated to be 3.5 billion kwhr/yr and in the year 2000 the estimate is 7.9 billion kwhr/yr. These estimates assume the total U. S. small user hydrogen market will grow at 5%/yr during the 1975-2000 period and that electrolysis will supply 16% of this production in 1975 increasing to 25% in the year 2000. Electricity required to produce this hydrogen was estimated using 77.6% thermal efficiency throughout the entire period. If this efficiency were 90%, the electricity required in the year 2000 would be 6.8 billion kwhr instead of 7.9 billion kwhr shown in the table.

The investment required to install the reformer and new coal gasification capacity during the 1980-2000 period is shown in Table 7.06. Substantially more capital will be required to build the new coal gasification capacity than would be required if all the new capacity were installed as reformer plants. If only reforming were used, the new capacity during this 20 year period would require an investment of $20.7 billion. However, the reformer and new coal capacity shown by these estimates will require an investment of $30.4 billion. The new coal capacity requires $9.7 billion more capital than would be required if only reforming were used. These investment data are expressed as 1980 $.

TABLE 7.01

Summary of Natural Gas Requirements and Natural Gas Saved by New Coal Process

Year	1975	1980	1985	1990	1995	2000
Industrial Hydrogen Production						
Refinery hydrogen, MSCF/CD	1385	1780	2400	3260	3924	4725
Ammonia, MST/yr	16.0	21.3	25.2	30.5	35.7	41.8
Methanol, MST/yr	3.8	5.3	6.6	9.5	12.1	15.3
Small user hydrogen, MSCF/CD	202	261	337	430	548	700
Natural Gas Required if Used for 100% of Production, k B/D crude equivalent						
Refinery hydrogen	116	149	201	273	328	395
Ammonia	276	368	435	527	616	722
Methanol	67	93	115	166	212	267
Small user hydrogen	17	22	28	36	46	59
Total	476	632	779	1002	1202	1443
Natural Gas Saved by New Coal Gasification, k B/D crude equivalent						
Refinery hydrogen	-	-	-	-	-	-
Ammonia	-	-	-	28	162	370
Methanol	-	-	17	70	140	230
Small user hydrogen	-	-	-	-	6	15
Total	-	-	17	98	308	615

TABLE 7.02

Natural Gas Feed Stock Required if All Industrial Hydrogen is Manufactured by Natural Gas Reforming

	Total Industrial Hydrogen Production				Natural Gas Feed Stock Required if All Industrial Hydrogen Were Produced by Reforming B/D crude equivalent x 10^3				
Year	Refinery Hydrogen MSCF/CD	Ammonia MST/yr	Methanol MST/yr	Small User Hydrogen MSCF/CD	Refinery Hydrogen	Ammonia	Methanol	Small User Hydrogen	Total
1980	1780	21.3	5.3	261	149	368	93	22	632
81	1904	22.1	5.6	276	159	382	98	23	662
82	2028	22.9	5.8	291	170	395	101	24	690
83	2152	23.6	6.1	307	180	408	107	26	721
84	2276	24.4	6.3	322	190	421	110	27	748
85	2400	25.2	6.6	337	201	435	115	28	779
86	2572	26.3	7.2	356	215	454	126	30	825
87	2744	27.3	7.8	374	229	471	136	31	867
88	2916	28.4	8.3	392	244	490	145	33	912
89	3088	29.4	8.9	411	258	508	156	34	956
90	3260	30.5	9.5	430	273	527	166	36	1002
91	3383	31.5	10.0	454	283	544	174	38	1039
92	3511	32.6	10.5	477	294	563	184	40	1081
93	3643	33.6	11.1	501	305	580	194	42	1121
94	3781	34.7	11.6	524	316	599	203	44	1162
95	3924	35.7	12.1	548	328	616	212	46	1202
96	4072	36.9	12.7	578	340	637	222	48	1247
97	4226	38.1	13.4	609	353	658	234	51	1296
98	4386	39.4	14.0	639	367	680	245	53	1345
99	4552	40.6	14.7	669	381	701	257	56	1395
2000	4725	41.8	15.3	700	395	722	267	59	1443
Total Bbl x 10^6*	--	--	--	--	2054	4073	1294	289	7710

*During 1980-2000 period.

TABLE 7.03

Natural Gas Feedstock Saved by New Coal Gasification for Manufacture of Ammonia, Methanol, and Small User Hydrogen

Year	Manufactured by New Coal Process			Natural Gas Feedstock Saved by Use of New Coal Process, B/CD x 10^3 crude equiv.			
	Ammonia MST/yr	Methanol MST/yr	Small User Hydrogen MSCF/CD	For Ammonia	For Methanol	For Small User Hydrogen	Total
1985	-	1.0	-	-	17	-	17
86	-	1.6	-	-	28	-	28
87	-	2.2	-	-	38	-	38
88	-	2.8	-	-	49	-	49
89	-	3.4	-	-	59	-	59
90	1.6	4.0	0	28	70	-	98
91	3.1	4.8	12	54	84	1.0	139
92	4.6	5.6	25	80	98	2.1	180
93	6.1	6.4	40	105	112	3.3	220
94	7.6	7.2	55	131	125	4.6	261
95	9.4	8.0	70	162	140	5.8	308
96	11.8	9.0	84	204	157	7.0	368
97	14.2	10.1	101	246	176	8.4	430
98	16.6	11.1	121	287	193	10.0	490
99	19.0	12.2	145	328	213	12.0	553
2000	21.4	13.2	175	370	230	14.5	615
Total*	-	-	-	728	653	25	1406

*Million bbl during the 1985-2000 period.

FIGURE 7.01

Potential for Replacing Natural Gas Feed With Coal for Manufacture of Ammonia, Methanol and Small User Hydrogen

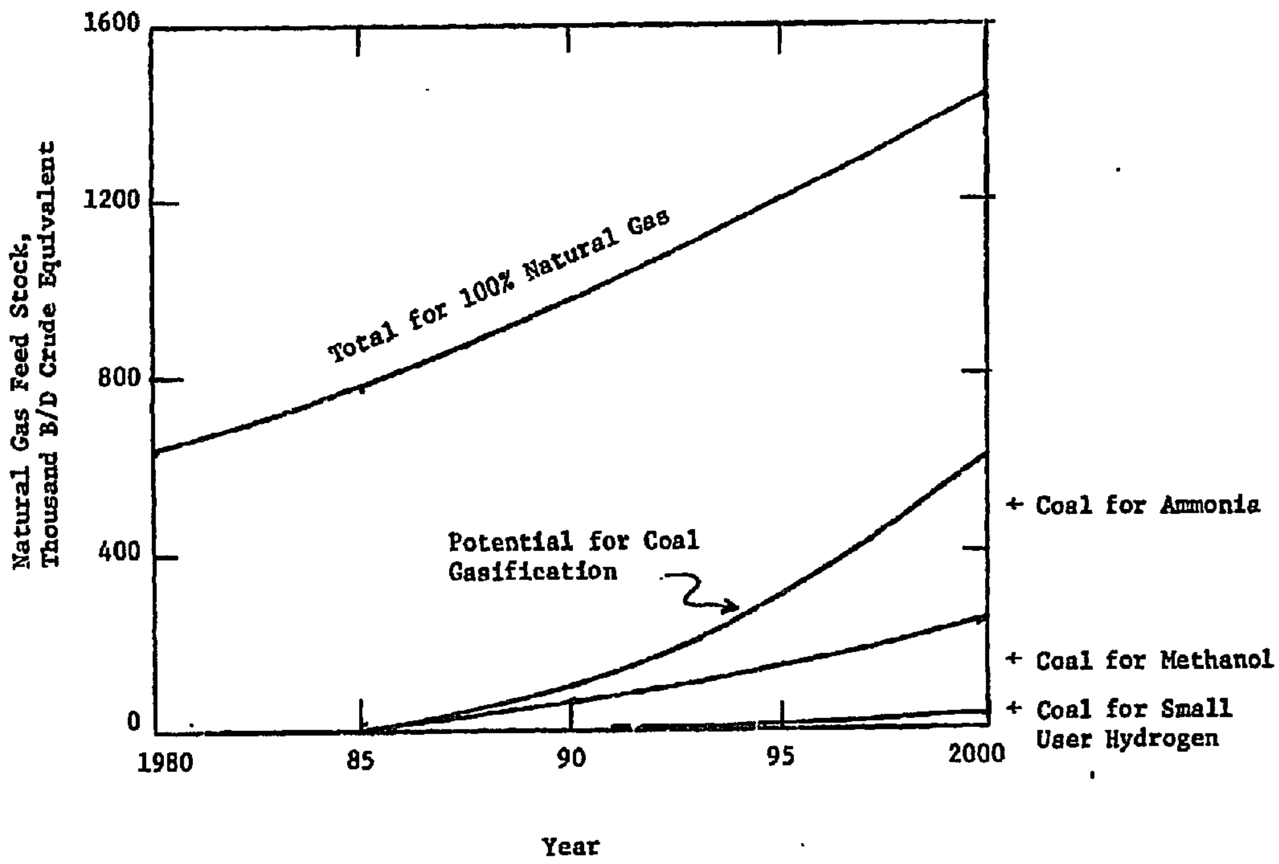


TABLE 7.04

Coal Feed Stock Required for New Coal Gasification

	Manufactured by New Coal Process			Coal Required for New Coal Plants MST/yr(1)			
Year	Ammonia MST/yr	Methanol MST/yr	Small User Hydrogen MSCF/CD	For Ammonia	For Methanol	For Small User Hydrogen	Total
1985	-	1.0	-	-	1.6	-	1.6
86	-	1.6	-	-	2.6	-	2.6
87	-	2.2	-	-	3.5	-	3.5
88	-	2.8	-	-	4.5	-	4.5
89	-	3.4	-	-	5.5	-	5.5
90	1.6	4.0	-	2.7	6.4	-	9.1
91	3.1	4.8	12	5.1	7.7	0.10	12.9
92	4.6	5.6	25	7.6	9.0	0.20	16.8
93	6.1	6.4	40	10.1	10.3	0.32	20.7
94	7.6	7.2	55	12.6	11.6	0.44	24.6
95	9.4	8.0	70	15.6	12.8	0.57	29.0
96	11.8	9.0	84	19.6	14.4	0.68	34.7
97	14.2	10.1	101	23.5	16.2	0.82	40.5
98	16.6	11.1	121	27.5	17.8	0.98	46.3
99	19.0	12.2	145	31.5	19.6	1.17	52.3
2000	21.4	13.2	175	35.5	21.2	1.41	58.1
Total	-	-	-	191	165	7	363

(1) Assumes Illinois high sulfur coal is used, 1.0 ST NH_3 requires 1.657 ST coal; 1.0 ST methanol requires 1.606 ST coal; 1.0 MSCF H_2 requires 22.1 tons coal.

TABLE 7.05

Electricity Required for U.S. Electrolytic Hydrogen Production

Year	Electrolytic Hydrogen Production		Electricity Required	Year	Electrolytic Hydrogen Production		Electricity Required
	MBtu/yr x 10^6	MSCF/CD	kwhr/yr x 10^9		MBtu/yr x 10^6	MSCF/CD	kwhr/yr x 10^9
1965*	4.2	35	1.59	1984	5.8	49	2.19
66*	4.5	38	1.70	85	6.3	53	2.38
67*	4.8	40	1.81	86	6.9	58	2.60
68*	4.5	38	1.70	87	7.5	63	2.83
69*	4.8	40	1.81	88	8.0	68	3.02
70*	3.8	32	1.43	89	8.7	73	3.28
71	3.8	32	1.43	90	9.3	78	3.51
72	3.8	32	1.43	91	10.2	86	3.85
73	3.8	32	1.43	92	11.2	94	4.23
74	3.8	32	1.43	93	12.0	101	4.53
75	3.8	32	1.43	94	13.0	109	4.91
76	3.9	33	1.47	95	13.9	117	5.25
77	3.9	33	1.47	96	15.4	129	5.81
78	4.0	34	1.51	97	16.7	140	6.30
79	4.0	34	1.51	98	18.1	152	6.83
80	4.2	35	1.58	99	19.4	163	7.32
81	4.6	39	1.74	2000	20.8	175	7.85
82	5.0	42	1.89				
83	5.5	46	2.08				

*Data reported by Bureau of Census. Other data are estaimtes.

TABLE 7.06

Additional Investment Required for New Coal Gasification Plants Over That Required for Natural Gas Reforming

	Refinery Hydrogen	Ammonia	Methanol	Small User Hydrogen	Total
New Capacity Installed, 1980-2000					
Measuring units	MSCF/CD	MST/yr	MST/yr	MSCF/CD	-
By natural gas reforming	4725	27.2	5.1	350	-
By new coal	-	21.4	13.2	175	-
Total	4725	48.6	18.3	525	-
Investment, $M/unit (1980 $)					
Natural gas reforming	0.692	273.6	205.0	0.692	-
New coal	2.472	548.6	470.0	2.472	-
Investment During 1980-2000 Period if All Capacity Were Nat. Gas Reforming, $M	3270	13296	3751	363	20680
Investment (Actual), 1980-2000 Period, $M					
Natural gas reforming	3270	7442	1046	242	12000
New coal	0	11740	6204	433	18377
Total	3270	19182	7250	675	30377
Additional Investment Required for New Coal Capacity, $M	-	5886	3499	312	9697

8. ERDA INCENTIVES

An objective of several ERDA programs is to reduce the U.S. consumption of natural gas and liquid hydrocarbons through the development of systems using coal or nuclear fuels. Reducing hydrocarbon consumption by such procedures would maintain the productivity of the U.S. industrial system and would reduce the requirements for imported petroleum. The production of industrial hydrogen provides an opportunity to reduce the consumption of hydrocarbon fuels through the substitution of coal and/or nuclear fuels. Two specific opportunities for accomplishing this change are (1) to produce ammonia and methanol by coal gasification rather than by steam reforming, and (2) to produce hydrogen for the small user market by electrolysis rather than by steam reforming.

The economics data developed in this study and discussed in the preceding sections provide a means of estimating the economic savings that would occur in converting from a reforming oriented hydrogen economy to one based on coal and/or nuclear fuel. The present (1977) value of future earnings for plants using the new coal process for manufacturing ammonia and methanol have been calculated. These savings discounted to 1977 are those realized during the first 20 years of operation of all new coal gasification plants installed in the 1985-2000 period, when these future earnings are discounted to 1977 using a discount factor of 10%/year. Details of this calculation for methanol plants are shown in Table 8.02 for (1) the base case situation (most likely fuel price); (2) the high fuel price case; and (3) the low fuel price case.

The 1977 savings represented by these future plants are summarized in Table 8.01. For the base case (first line) the 1977 value of these future earnings are \$647M for methanol and \$561M for ammonia making a total of \$1208M. For the several sensitivities (next 8 lines), the total is \$1280M maximum and \$597M minimum. It is likely that the commercial use of the new coal process should provide future earnings corresponding to a 1977 value of \$500-1200M.

ERDA should, therefore, determine what is needed to accelerate the commercial use of the new coal gasification process. It is beyond the scope of this study to identify the program needed to accelerate the new coal program. It is likely that the developers of this improved gasification process are doing all that can be done to speed up the development. However, if the development of the improved gasification process could be assisted by an early demonstration plant, ERDA should consider sponsoring with industry on a cost sharing basis a demonstration of the process.

The development of an improved electrolyzer such as the SPE system would lower the investment and decrease the electricity requirements compared to electrolysis systems currently available. The data shown in Table 3.12 indicate that the cost including 20%/yr before tax return for hydrogen produced with the improved process might be about \$8.00/MBtu less than that for the current electrolysis system. To be conservative, the present value of future savings for the improved electrolysis system were calculated assuming a saving of \$5.00/MBtu. This saving of \$5.00/MBtu has been used for the electrolysis plants projected for the small user hydrogen market as is shown by Table 6.02.

Table 8.03 shows the details of calculating the present (1977) value of future savings for SPE electrolysis capacity installed according to the schedule shown in Table 6.03. The savings were calculated for SPE plants installed during the 1988-2000 period over their entire 20 year life. The annual savings were discounted to 1977 by using discount factors for 10%/year.

The 1977 value of these future savings is $152 million. This figure does not include any savings that may accrue in using the SPE process for new uses not considered in this study such as for conversion of off-peak nuclear or hydro electricity to hydrogen, or utilization of remote hydro power, or ocean thermal energy for hydrogen manufacture.

It is beyond the scope of this study to determine what work should be conducted to accelerate the development of an improved electrolysis process. It is clear that an improved process capable of reducing the investment in electrolysis plants by say 50% and increase the thermal efficiency to say 90% would provide a substantial incentive for using electrolysis rather than steam reforming as the source of small user hydrogen. Such an improved electrolysis system would also be useful for hydrogen generation for new uses not considered in this study.

TABLE 8.01

Summary of Discounted Values of Future Savings for
Use of New Coal Process for Methanol and Ammonia Manufacture

	For Methanol	For Ammonia	Methanol + Ammonia
Present Value* of Future Savings for Plants Installed in 1985-2000 Period, $ Millions			
Base Case (most likely feedstock prices)	647	561	1208
High Fuel Prices	609	481	1090
Low Fuel Prices	356	241	597
Additional 10% Investment	584	454	1038
Construction costs escalate 1%/yr above gen infl.	458	220	678
" " " 1%/yr below " "	606	580	1186
Coal prices escalate 1%/yr above gen. infl.	577	413	990
" " " 1%/yr below " "	681	599	1280

*Future savings are discounted to 1976 using a discount factor of 10%/yr.

TABLE 8.02 (Page 1 of 2)

Discounted Value of Future Savings for Methanol Production Using New Coal Gasification Process

1980 $ Discounted to 1976

Year	Discount Factor(1)	New Coal Installed Capacity, MST/yr: Added During Yr.	New Coal Installed Capacity, MST/yr: Cumulative	Base Case - Most Likely Fuel Prices: Reforming or K-T* $/ST	Base Case - Most Likely Fuel Prices: New Coal Gasification $/ST	Base Case - Most Likely Fuel Prices: Saving $/ST	Savings, $M/yr: Current	Savings, $M/yr: Discounted
1985	0.424	1.0	1.0	205.2	198.0	7.2	7.2	3.05
86	0.386	0.6	1.6	207.3		9.3	14.9	5.74
87	0.350	0.6	2.2	211.4		13.4	29.5	10.32
88	0.319	0.6	2.8	213.4		15.4	43.1	13.76
89	0.290	0.6	3.4	215.5		17.5	59.5	17.26
90	0.253	0.6	4.0	217.6		19.6	78.4	20.62
91	0.239	0.8	4.8	219.6		21.6	103.7	24.78
92	0.218	0.8	5.6	221.6		23.6	132.1	28.81
93	0.198	0.8	6.4	223.7		25.7	164.5	32.57
94	0.180	0.8	7.2	225.8		27.8	200.2	36.03
95	0.164	0.8	8.0	226.0*		28.0	224.0	36.74
96	0.149	1.0	9.0				252.0	37.55
97	0.135	1.1	10.1				282.8	38.18
98	0.123	1.0	11.1				310.8	38.23
99	0.112	1.1	12.2				341.6	38.26
2000	0.102	1.0	13.2				369.6	37.70
2001	0.092	-	13.2				369.6	34.00
2	0.084	-	13.2				369.6	31.05
3	0.076	-	13.2				369.6	28.09
4	0.069	-	13.2				369.6	25.50
5	0.063	-1.0	12.2				341.6	21.52
6	0.057	-0.6	11.6				324.8	18.51
7	0.052	-0.6	11.0				308.0	16.02
8	0.047	-0.6	10.4				291.2	13.69
9	0.043	-0.6	9.8				274.4	11.80
10	0.039	-0.6	9.2				257.6	10.05
11	0.036	-0.8	8.4				235.2	8.47
12	0.032	-0.8	7.6				212.8	6.81
13	0.029	-0.8	6.8				190.4	5.52
14	0.027	-0.8	6.0				168.0	4.53
15	0.024	-0.8	5.2				145.6	3.49
16	0.022	-1.0	4.2				117.6	2.59
17	0.020	-1.1	3.1				86.8	1.74
18	0.018	-1.0	2.1				58.8	1.06
19	0.017	-1.1	1.0				28.0	0.48
2020	0.015	-1.0	0				0	0
Total	-	-	-	-	-	-	7133.1	664.52

*Value for K-T

TABLE 8.02 (Page 2 of 2)

Discounted Value of Future Savings for Methanol Production Using New Coal Gasification Process

1980 $ Discounted to 1976

	High Fuel Price Case					Low Fuel Price Case				
	Reforming or K-T $/ST	New Coal Gasification $/ST	Saving $/ST	Savings, $M/yr Current	Savings, $M/yr Discounted	Reforming or K-T $/ST	New Coal Gasification $/ST	Saving $/ST	Savings, $M/yr Current	Savings, $M/yr Discounte
1985	216.0	214.0	2.0	2.0	0.85	179.0	185.0	-	-	-
86	218.2		4.2	6.7	2.59	180.6		-	-	-
87	220.4		6.4	14.1	4.93	182.2		-	-	-
88	222.6		8.6	24.1	7.68	183.8		-	-	-
89	224.8		10.8	36.7	10.65	185.4		0.4	1.4	0.39
90	227.0		1[illegible].0	52.0	13.68	187.0		2.0	8.0	2.10
91	229.2		15.2	73.0	17.44	188.6		3.6	17.3	4.13
92	231.4		17.4	97.4	21.24	190.2		5.2	29.1	6.35
93	233.6		19.6	125.4	24.84	191.8		6.8	43.5	8.62
94	235.8		21.8	157.0	28.25	193.4		8.4	60.5	10.89
95	238.0		24.0	192.0	31.49	195.0		10.0	80.0	13.12
96	240.2		26.2	235.8	35.13	196.6		11.6	104.4	15.56
97	242.4		28.4	286.3	38.72	198.2		13.2	133.3	18.00
98	243.0*		29.0	321.9	39.59	199.8		14.8	164.3	20.21
99				353.8	39.63	201.4		16.4	200.1	22.41
2000				382.8	39.05	203.0		18.0	237.6	24.24
2001				382.8	35.22	204.6		19.6	258.7	23.80
2				382.8	32.16	206.2		21.2	279.8	23.51
3				382.8	29.09	207.8		22.8	301.0	22.89
4				382.8	26.41	209.4		24.4	322.1	22.22
5				353.8	22.29	211.0*		26.0	317.2	19.98
6				336.4	19.17				301.6	17.19
7				319.0	16.59				286.0	14.87
8				301.6	14.18				270.4	12.71
9				284.2	12.22				254.8	10.96
10				266.8	10.41				239.2	9.33
11				243.6	8.77				218.4	7.86
12				220.4	7.05				197.6	6.32
13				197.2	5.72				176.8	5.13
14				174.0	4.70				156.0	4.21
15				150.8	3.62				135.2	3.24
16				121.8	2.68				109.2	2.40
17				89.9	1.80				80.6	1.61
18				60.9	1.10				54.6	0.98
19				29.0	0.49				26.0	0.44
20				0	0				0	0
Total				7042.1	609.43				5064.7	355.65

*Value for K-T

TABLE 8.03

Discounted Value of Future Savings for SPE Electrolysis Technology Over Current Electrolysis Technology

1980 $ Discounted to 1977

Year	Discount Factor(1)	SPE Electrolysis Capacity, MSCF/CD Added	SPE Electrolysis Capacity, MSCF/CD Cumulative	Savings, $M/yr(2) Current	Savings, $M/yr(2) Discounted
1985	0.467	-	-		
86	0.424	-	-		
87	0.386	-	-		
88	0.350	8	8	4.74	1.66
89	0.319	8	16	9.47	3.02
90	0.290	9	25	14.80	4.29
91	0.263	10	35	20.72	5.45
92	0.239	9	44	26.05	6.23
93	0.218	10	54	31.97	6.97
94	0.198	9	63	37.30	7.38
95	0.180	10	73	43.22	7.78
96	0.164	13	86	50.91	8.35
97	0.149	13	99	58.61	8.73
98	0.135	14	113	66.90	9.03
99	0.123	13	126	74.59	9.17
2000	0.112	13	139	82.29	9.22
2001	0.102	-	139	82.29	8.39
2	0.092	-	139	82.29	7.57
3	0.084	-	139	82.29	6.91
4	0.076	-	139	82.29	6.25
5	0.069	-	139	82.29	5.68
6	0.063	-	139	82.29	5.18
7	0.057	-	139	82.29	4.69
8	0.052	-8	131	77.55	4.03
9	0.047	-8	123	72.82	3.42
10	0.043	-9	114	67.49	2.90
11	0.039	-10	104	61.57	2.40
12	0.036	-9	95	56.24	2.02
13	0.032	-10	85	50.32	1.61
14	0.029	-9	76	44.99	1.30
15	0.027	-10	66	39.07	1.05
16	0.024	-13	53	31.38	0.75
17	0.022	-13	40	23.68	0.52
18	0.020	-14	26	15.39	0.31
19	0.018	-13	13	7.70	0.14
2020	0.017	-13	0	0	0
Total				1646	152

(1) At 10%/yr to 1977.

(2) Assumes SPE electrolysis saves $5.00/MBtu over current electrolysis technology or 1.0 MSCF/CD = $0.592 x 10^6/yr saving.

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APPENDIX A

Cost of Production Estimates
For
Hydrogen, Ammonia and Methanol

A Study for Exxon Research
and Engineering Company

CHEM SYSTEMS INC.
747 Third Avenue
New York, New York 10017

October 21, 1976

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BASIS FOR ECONOMIC CALCULATIONS

For this study all investment costs are presented in mid-1980 (July, 1980) dollars in consideration of the following factors:

- No commercial-sized coal based plant now presently planned could be built and ready for operation much before 1980.
- Expressing 1980 economics on a 1976 basis could result in apparent future costs lower than 1976 costs which could, in our view, be a misleading comparison.

General Rate of Inflation

Based on the slow recovery the United States is making from the recent recession and the slowdown in inflationary rates of the past two years, we have assumed that inflation will still continue at a moderate to high rate through 1980 (7.0% per year).

Capital Cost Escalation

During the past two to three years, the United States has experienced a phenomenon in engineering and construction costs that has never been encountered previously. Equipment and material costs escalated rapidly. Fabricators and vendors of these bulk materials were, for a long period of time, refusing to offer firm price quotations. Final costs were geared to date of delivery rather than date of purchase.

It was not uncommon for prices to increase from 1 to 2% per month between date of purchase order and date of equipment delivery. In addition, material shortages also plagued the construction industry. In many instances, availability and assuredness of supply became more important than price. This situation radically changed the engineering construction business for refinery, chemical, and petrochemical plants. Engineering contractors no longer bid on a lump sum basis. Even on a cost plus basis, clients were told to include large contingencies in their budget figures because of continually escalating material costs.

In the past few months, this situation has eased somewhat but certainly conditions have not returned to what they were several years ago. In view of this situation, we have assumed that process plant investments will escalate at 2 percentage points greater than the general inflation rate, i.e., 9% per year. Historically the gap has been 1.7 percentage points.

Plant Capacity, On-Stream Factor, and Location

The following capacities, on-stream factors, and locations were assumed for the thirteen (13) plants analyzed in this study:

	Capacity	On-Stream Factor	Location
Production of Hydrogen			
1. Coal Gasification - Illinois #6 Coal, Koppers-Totzek Process	100 MSCFD	330 days/yr	U.S. Mid-Cont. (Mine Mouth)
2. Coal Gasification - Illinois #6 Coal, Pressurized Koppers-Totzek Type Process	100 MSCFD	330 days/yr	U.S. Mid-Cont. (Mine Mouth)
3. Partial Oxidation of Residual Fuel Oil	100 MSCFD	330 days/yr	U.S. Gulf Coast
4. Steam Reforming of Natural Gas	100 MSCFD	330 days/yr	U.S. Gulf Coast
5. Electrolysis of Water - Solid Polymer Electrolyte Electrolytic Cell	100 MSCFD	330 days/yr	U.S. Gulf Coast
Production of Ammonia			
6. Coal Gasification - Illinois #6 Coal, Koppers-Totzek Process	2000 STPD	330 days/yr	U.S. Mid-Cont. (Mine Mouth)
7. Coal Gasification - Illinois #6 Coal, Pressurized Koppers-Totzek Type Process	2000 STPD	330 days/yr	U.S. Mid-Cont. (Mine Mouth)
8. Partial Oxidation of Residual Fuel Oil	2000 STPD	330 days/yr	U.S. Gulf Coast
9. Steam Reforming of Natural Gas	2000 STPD	330 days/yr	U.S. Gulf Coast
Production of Methanol			
10. Coal Gasification - Illinois #6 Coal, Koppers-Totzek Process	2000 STPD	330 days/yr	U.S. Mid-Cont. (Mine Mouth)
11. Coal Gasification - Illinois #6 Coal, Pressurized Koppers-Totzek Type Process	2000 STPD	330 days/yr	U.S. Mid-Cont. (Mine Mouth)
12. Partial Oxidation of Residual Fuel Oil	2000 STPD	330 days/yr	U.S. Gulf Coast
13. Steam Reforming of Natural Gas	2000 STPD	330 days/yr	U.S. Gulf Coast

In addition, for the coal sensitivity analysis, the Western coal gasification plants were assumed to be located at the Western coal mine.

Location Factors

In any economic analyses the geographic location of the plant may cause variations in capital costs. Based on Chem Systems' estimates of construction cost factors, taking into account weather conditions, labor rates, labor productivity, transportation costs, etc., investment location factors have been estimated for the following areas:

U.S. Gulf Coast	1.00
U.S. Mid-Continent	1.10
Chicago	1.15
Philadelphia	1.20
Western Coal Mine	1.15 - 1.20
West Coast	1.10 - 1.15

Battery Limits Capital Cost (BLCC)

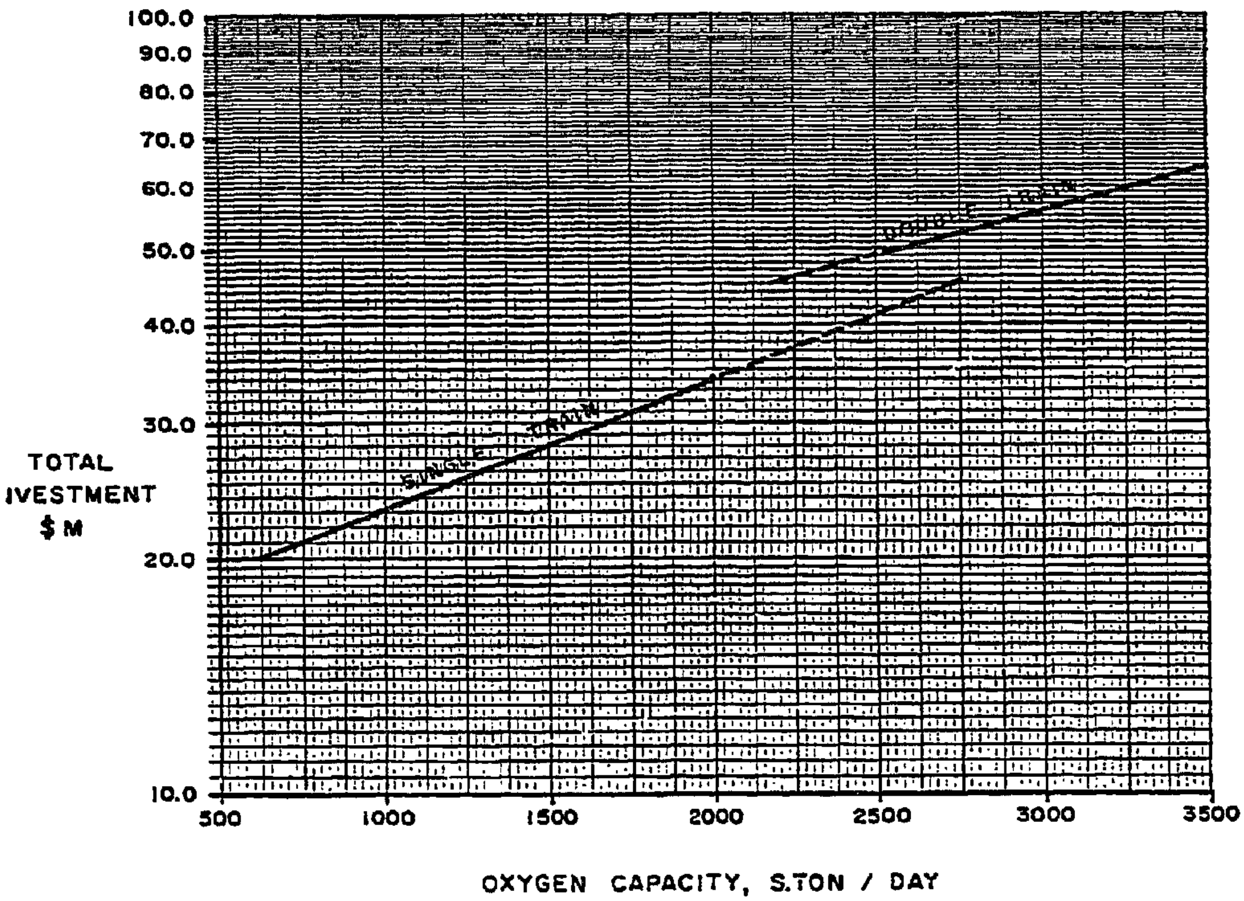
Investment costs have been based on several sources of information available to Chem Systems. These include capital estimates developed for other internal studies, plus cost data obtained from contractors for hydrogen, ammonia, and methanol plants. This has provided us with a wide source of capital cost data, and we have used our judgment in soliciting what we feel represents the most reasonable estimates to work up battery limits capital costs for the various plants being considered.

The battery limits capital cost represents an "instantaneous" cost for a plant starting up in 1980 with an "overnight" construction period. Therefore, estimation of project costs during construction, interest on borrowed monies during construction, and inflationary effects during construction are eliminated from our analysis.

FIGURE 1

OXYGEN PLANT INVESTMENT COST VS. CAPACITY

(99.5% O_2 @ 500 PSIG)
1980 COSTS IN 1980 DOLLARS



CHEM SYSTEMS INC.
PROJECT NO. 6 9 7 DATE

For this study it has been assumed that any air separation plant required would be part of the battery limits capital cost. The 1980 investment for oxygen plants as a function of capacity is shown in Figure 1. The following utility requirements have been estimated per ton of oxygen required.

	99.5% O_2 @ 500 psig	99.5% O_2 @ 50 psig
Power, KWH	435	325
Cooling Water MGal	36.5	36.5
Process Water MGal	1.2	1.2

In the partial oxidation and coal-based plants larger power users have been put on turbine drive with the net required high pressure steam generated in oil (for partial oxidation plants) or coal-fired (for coal-based plants) boilers. Similarly, large power users in the natural gas-based plants have been put on turbine drive, but since these plants are net exporters of high pressure steam, there is no need for steam boilers. Extraction turbines are used to provide any medium pressure steam required. The heat rate used to convert HP steam to electrical power is 10,300 BTU/KWH, and the boiler efficiency is 85% on HHV for the large boilers required.

Instead of converting large power users from motor to turbine-drive, the HP steam raised could be used to produce electricity in an inside-battery limits (ISBL) power plant, but the small size of the power generating facilities make this approach uneconomical. Thus, the HP steam drives these large users directly without intervening and more costly electrical generation. It should be noted that a small amount of electrical power is still required for users which cannot be placed on turbine-drive.

The electrolysis process for the production of hydrogen requires no steam.

Offsites Costs

Sufficient data were available to directly estimate the offsites costs for the plants based on steam-methane reforming. Since these plants are net exporters of steam, no inclusion of a steam system capital cost is made. Also, cooling water is charged as a direct operating cost under utilities and is not capitalized for the steam-methane plants.

For the partial oxidation and coal-based plants, we have estimated offsites costs as the sum of the following:

(1) 30% of battery limits cost - This allows for storage, waste disposal facilities, general and administrative facilities, etc.

(2) Steam system capital cost - This cost includes stack gas scrubbing equipment plus ash and dust collection equipment for the coal-based plants. The production cost analysis sheets show the amount of steam generated with the note "internal."

(3) Cooling water system capital cost - This provides a complete system including cooling tower, circulatory pumps, additive injection, etc. The quantities of cooling water circulated have been estimated and noted on the production cost analysis sheets with the note "internal."

Working Capital

The amount of working capital usually depends upon arrangements for payments on feedstock purchases and product sales, and on storage volumes maintained for both. In our 1980 production cost analysis, we have used one month storage of major feedstocks at cost, (excluding gaseous feedstocks) and one month's accounts receivables to estimate working capital. Working capital is considered as borrowed capital and only interest charges, at 10%, are included in the overall production cost.

Utility Costs

Utility costs have been estimated in 1980 for three different areas in the United States and are summarized in Table I.

TABLE I

UTILITY COSTS AT SELECTED LOCATIONS

Illinois Area	Unit	1980¢/Unit
Illinois Coal (11,390 BTU/lb)	M BTU	92
Power (Coal Based)	KWH	2.7
Cooling Water	KGal	5.3
Steam (600 psig, 750°F, ex coal)	Klbs	250
Steam (1500 psig, 900°F, ex coal)	Klbs	260
BFW	Kgal	85
Process Water	Kgal	55

Montana/Wyoming Area	Unit	1980¢/Unit
Mont./Wy. Coal (8500 BTU/lb)	M BTU	47
Power (Coal-based)	KWH	2.0
Cooling Water	Kgal	4.6
Steam (600 psig 750°F, ex coal)	Klbs	115
Steam (1500 psig, 900°F, ex coal)	Klbs	120
BFW	Kgal	80
Process Water	Kgal	50

Gulf Coast Area	Unit	1980¢/Unit
Mont./Wy Coal (delivered)	M BTU	98
Fuel Oil	M BTU	317
Gas, New	M BTU	315
Gas, Average	M BTU	150
Power (From mix of fuels)	KWH	2.7
Cooling Water	Kgal	5.3
Steam (600 psig, 750°F, ex oil)	Klbs	500
Steam (1500 psig, 900°F, ex oil)	Klbs	525
BFW	Kgal	85
Process Water	Kgal	55

Labor and Related Costs

Operating labor costs have been projected to escalate at 8.0% per year through 1980.

The following annual salaries have been estimated for 1980:

Shift Operators	$21,500
Shift Foremen	24,200
Supervisors	28,800

The total number of laborers has been estimated by multiplying the men per shift by 4.6 and rounding to the next higher whole number. This assumes a 40 hour average work week and 48 work weeks per year.

Our production cost analysis has been divided into labor related and capital related categories to allow for easy comparison among alternate technologies. Labor related costs, in addition to direct labor charges, include a part of maintenance and general plant overhead. These costs have been assumed at 100% of direct labor costs.

CAPITAL RELATED EXPENSES

This includes all items related to the plant investment. The following percentages have been assumed:

Maintenance	4.0% of battery limits capital cost
General Plant Overhead	2.6% of battery limits capital cost
Insurance and Property Taxes	1.5% of Total Fixed Investment (BLCC + Off-sites)
Depreciation	10.0% battery limits capital cost plus 5% off-site cost
Interest	10% of Working Capital

Contingency

Based upon suggestions from Exxon, the following contingency factors have been applied to the capital cost estimates:

Steam-Methane Reforming	1.10
Partial Oxidation of Residual Fuel Oil	1.10
Coal Gasification (Koppers-Totzek)	1.15
Coal Gasification (New Process)	1.20
Electrolysis (Solid Polymer Electrolyte)	1.30

Return on Investment

In order to estimate sales or transfer price, we include a gross return before taxes of 20% on the Total Fixed investment. This assumes full equity financing of all projects.

Hydrogen

The Koppers-Totzek process was chosen as being typical of existing coal gasification processes which could be utilized to manufacture hydrogen. The low methane yield from the gasifier makes the gasifier effluent suitable for hydrogen production by adding process equipment for shift conversion, CO_2 removal, and final carbon oxides removal (methanation).

Figure 2 is a block flow diagram depicting the major steps in the production of hydrogen, ammonia, or methanol from coal.

Table 2 is a production cost analysis for manufacturing 100 MSCFD hydrogen via a totally integrated K-T gasification process. The battery limits capital cost for this project (including 15% contingency) can be delineated as follows:

	$M (Mid 1980)	Percent
K-T Synthesis Gas Production (Incl. O_2 Plant)	106.4	72.5
Shift Conversion and Methanation	16.7	11.4
CO_2 Removal	23.6	16.1
Total	146.7	100.0

The hydrogen cost plus return on these bases is about 311¢/KSCF with coal priced at $21/ton.

The K-T gasifiers, as well as the compression cost of the synthesis gas produced to 450 psig, represent a considerable portion of the overall investment requirements. Therefore, a "new" or "second generation" gasification process should offer significant cost advantages, if it possesses the following characteristics:

Figure 2

Block Flow Diagram

Hydrogen, Ammonia, or Methanol

Via K-T or New Coal Gasification

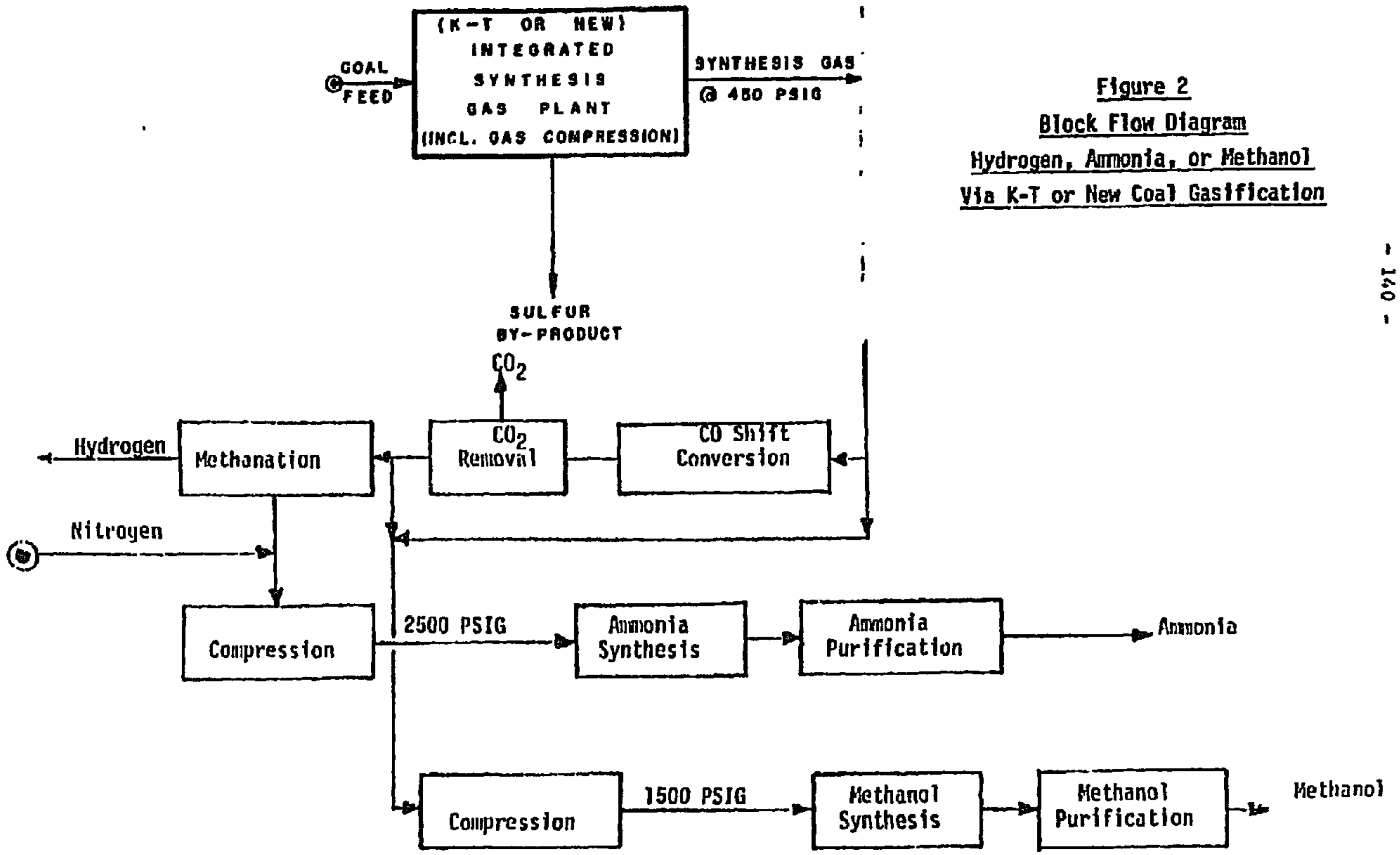


TABLE 2

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

HYDROGEN VIA KOPPERS-TOTZEK COAL GASIFICATION WITH INTEGRATED OXYGEN PLANT

*Incluues 15% Contingency

Plant Hydrogen Via Koppers-Totzek Coal Gasification
Location U.S. Mid Cont. Mid-1980
Capacity 100 MSCF/Day
Production Rate 33,000 M SCF/Year

	$ M
*Battery Limits Capital Cost	146.7
*Offsites Capital Cost	99.7
Total Fixed Investment	246.4
Working Capital	11.0
Total Fixed & Working Capital	257.4

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST
Illinois Coal (HHV=11,390 Btu/Lb.)	786,000	Ton	21.00	16,500,000	¢/KSCF
TOTAL RAW MATERIALS COST				16,500,000	50.00
UTILITIES					
Power	11,428,000	KWH	0.027	309,000	
Cooling Water	35,857,000	K Gal.	Internal		
Process Water	2,514,000	K Gal.	0.55	1,383,000	
Fuel		MBtu			
Steam	2,357,000	K Lbs.	Internal		
Stack Gas Clean-Up	"		0.35	825,000	
TOTAL UTILITIES COST				2,517,000	7.63
LABOR & RELATED	Men/Shift		Total Men		
Labor @ $21,500	7		30	645,000	
Supervision @ -- Foreman $28,800/24,200	1		1/5	150,000	
Direct & General Plant Overhead @ 100% L + S				796,000	
TOTAL LABOR & RELATED COST				$1,591,000	4.82
CAPITAL RELATED					
Maintenance	4.0% BLCC			5,868,000	
General Plant Overhead	2.6 % BLCC			3,814,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			3,696,000	
Depreciation	10.0% BLCC + 5% Offsites			19,655,000	
Interest	10.0% on Working Capital			1,100,000	
TOTAL CAPITAL-RELATED EXPENSES				34,133,000	103.43
BY-PRODUCT CREDIT					
Sulfur	26,400	Ton	50	1,320,000	
TOTAL BY-PRODUCT CREDIT				(1,320,000)	(4.00)
TOTAL COST OF PRODUCTION				53,421,000	161.88
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				49,280,000	149.33
TOTAL COST PLUS RETURN				$102,701,000	311.21

- Pressure operation: in the range of 300 to 500 psi.
- High productivity: capable of handling 2500 tons per day of coal feed and producing 100 to 150 MSCFD per gasifier.
- High temperature operation, ca. 2000°F to minimize methane content.
- High carbon utilization.

Koppers is engaged in a joint effort with Shell Development to design the K-T gasifier to operate at approximately 450 psig and achieve the above objectives.

Table 3 is a production cost analysis for manufacturing 100 MSCFD of hydrogen via a totally integrated "new" coal gasification process. The battery limits capital costs (including 20% contingency) can be delineated as follows:

	\$M (Mid-1980)	Percent
New Synthesis Gas Production (Incl. O_2 Plant)	82.1	67.1
Shift Conversion and Methanation	16.7	13.6
CO_2 Removal	23.6	19.3
TOTAL	122.4	100.0

The hydrogen transfer price on these bases is about 260¢/KSCF or a potential savings of about 16% over hydrogen via existing K-T technology.

TABLE 3

CHEM SYSTEMS
PRODUCTION COST ANALYSIS

HYDROGEN VIA "NEW" COAL GASIFICATION PROCESS WITH INTEGRATED OXYGEN PLANT

*Includes 20% Contingency

Plant Hydrogen Via New Coal Gasification Process
Location U.S. Mid Cont. Mid-1980
Capacity 100 MSCF/Day
Production Rate 33,000 MSCF/Year

	$ M
*Battery Limits Capital Cost	122.4
*Offsites Capital Cost	77.7
Total Fixed Investment	200.1
Working Capital	10.0
Total Fixed & Working Capital	210.1

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST
Illinois Coal (HHV = 11,390 Btu/Lb)	729,000	Ton	21.00	15,309,000	¢/KSCF
TOTAL RAW MATERIALS COST				15,309,000	46.39
UTILITIES					
Power	11,428,000	KWH	0.027	309,000	
Cooling Water	32,000,000	KGal.	Internal		
Process Water	2,243,000	KGal.	0.55	1,234,000	
Fuel		MBtu			
Steam	1,429,000	KLbs.	Internal		
Stack Gas Clean-Up	"		0.35	500,000	
TOTAL UTILITIES COST				2,043,000	6.19
LABOR & RELATED	Men/Shift		Total Men		
Labor @ $21,500	7		30	645,000	
Supervision @ Foreman $28,800/24,200	1		1/5	150,000	
Direct & General Plant Overhead @ 100% L + S				796,000	
TOTAL LABOR & RELATED COST				1,591,000	4.82
CAPITAL RELATED					
Maintenance	4.0% BLCC			4,896,000	
General Plant Overhead	2.6 % BLCC			3,182,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			3,002,000	
Depreciation	10.0% BLCC + 5% Offsites			16,125,000	
Interest	10.0% on Working Capital			1,000,000	
TOTAL CAPITAL-RELATED EXPENSES				28,205,000	85.47
BY-PRODUCT CREDIT					
Sulfur	24,300	Ton	50	1,215,000	
TOTAL BY-PRODUCT CREDIT				(1,215,000)	(3.68)
TOTAL COST OF PRODUCTION				45,933,000	139.19
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				40,020,000	121.27
TOTAL COST PLUS RETURN				$85,953,000	260.46

Hydrogen production based upon coal gasification can be compared against production via:

- Partial Oxidation of Residual Fuel Oil
- Steam Reforming of Methane
- Electrolysis of Water

Figure 3 is a block flow diagram showing the various process options available in partial oxidation. Certain basic processing steps must be accomplished and can be classified as:

- Gasification
- Cooling
- Carbon Removal
- Sulfur Removal

If hydrogen is the desired product, then additional processing steps are required:

- Shift Conversion
- Carbon Dioxide Removal
- Final Carbon Oxides Removal

Table 4 is a production cost analysis for a 100 M SCFD plant. With residual fuel oil valued at a 1980 price of $15 per barrel, the hydrogen transfer price is estimated at about 263¢/KSCF.

Figure 4 is a block flow diagram depicting the major steps in producing H_2 via conventional steam-methane reforming, and Table 5 is a production cost analysis for a 100 M SCFD plant. With natural gas valued at a 1980 price of $3.15/M Btu, the hydrogen transfer price is estimated at about 200¢/KSCF.

Figure 3
Block Flow Diagram
Hydrogen, Ammonia, or Methanol
Via Partial Oxidation

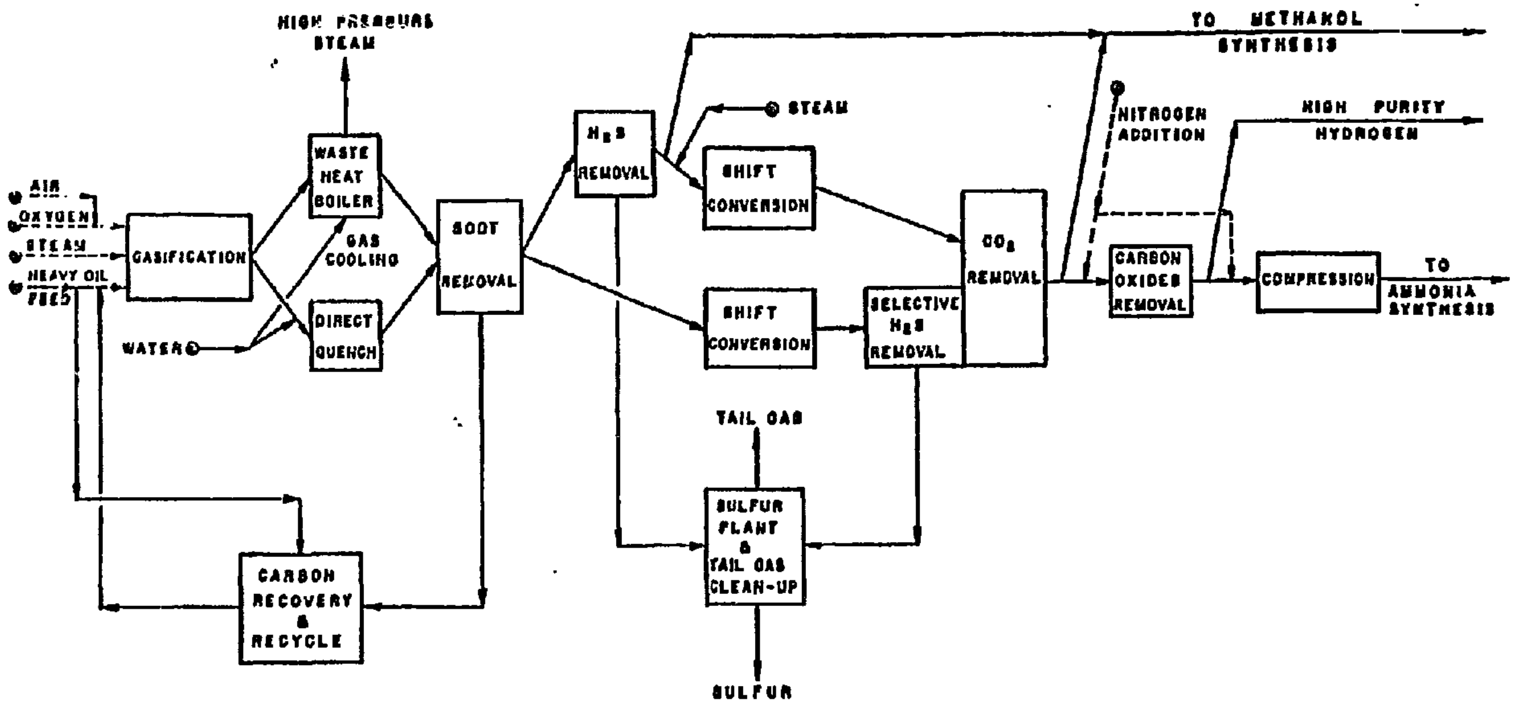


TABLE 4

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

HYDROGEN VIA PARTIAL OXIDATION WITH INTEGRATED OXYGEN PRODUCTION

*Includes 10% Contingency

		$ M
Plant Hydrogen Via Partial Oxidation	*Battery Limits Capital Cost	93.9
	*Offsites Capital Cost	65.4
Location U.S. Gulf Coast Mid 1980	Total Fixed Investment	159.3
Capacity 100 M SCFD	Working Capital	10.0
Production Rate 33,000 MSCF/Yr	Total Fixed & Working Capital	169.3

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST
Residual Fuel Oil	2,013,000	Bbl	15.00	$ 30,195,000	¢/KSCF
TOTAL RAW MATERIALS COST				30,195,000	91.50
UTILITIES					
Power	11,285,000	KWH	0.27	307,000	
Cooling Water	28,694,000	KGal.	Internal		
Process Water	964,000	KGal.	.55	530,000	
Fuel		MBtu			
Steam	1,065,000	KLbs.	Internal		
Stack Gas Clean-up	"	"	0.35	373,000	
TOTAL UTILITIES COST				1,210,000	3.67
LABOR & RELATED	Men/Shift		Total Men		
Labor @ $21,500	6		26	559,000	
Supervision @ $24,200/28,800	2		9/1	247,000	
Direct & General Plant Overhead @ 100% L + S				806,000	
TOTAL LABOR & RELATED COST				1,612,000	4.88
CAPITAL RELATED					
Maintenance	4.0% BLCC			3,756,000	
General Plant Overhead	2.6 % BLCC			2,441,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			2,390,000	
Depreciation	10.0% BLCC + 5% Offsites			12,660,000	
Interest	10.0% on Working Capital			1,000,000	
TOTAL CAPITAL-RELATED EXPENSES				22,247,000	67.42
BY-PRODUCT CREDIT					
Sulfur	10,000	Tons	50	500,000	
TOTAL BY-PRODUCT CREDIT				(500,000)	(1.52)
TOTAL COST OF PRODUCTION				54,764,000	165.95
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				31,860,000	96.55
TOTAL COST PLUS RETURN				$86,624,000	262.50

Figure 4

Block Flow Diagram

Hydrogen Via Conventional

Steam-Methane Reforming

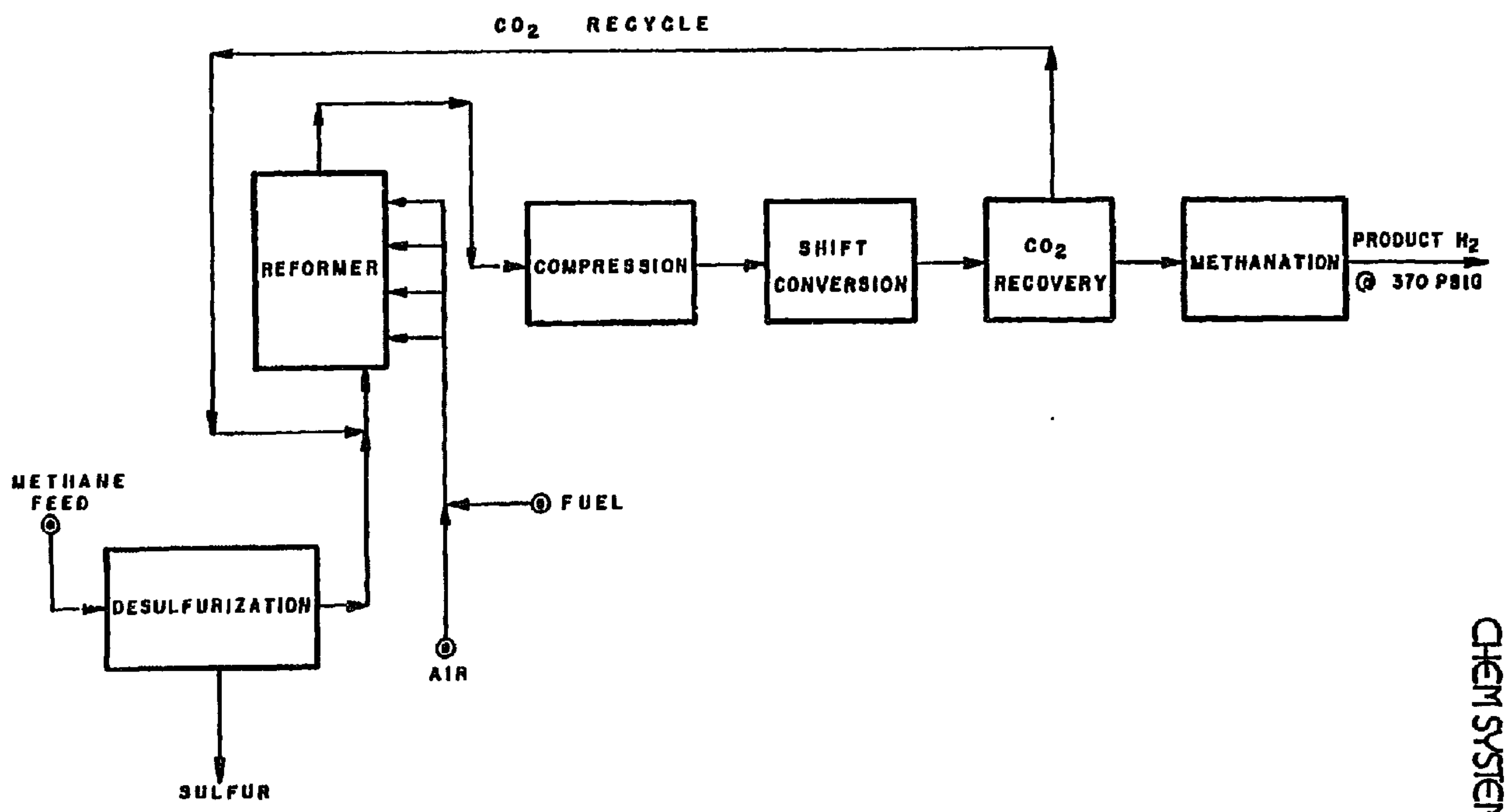


TABLE 5

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

HYDROGEN VIA CONVENTIONAL STEAM-METHANE REFORMING

* Includes 10% Contingency

			$ M
Plant	Hydrogen Via Conventional Steam-Methane Reforming	Battery Limits Capital Cost	41.3
Location	Gulf Coast, Mid-1980	Offsites Capital Cost	21.3
Capacity	100 MSCF/Day	Total Fixed Investment	62.6
Production Rate	33,000 M SCF/Yr	Working Capital	6.0
		Total Fixed & Working Capital	68.6

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST
Natural Gas	15,142,000	MBtu	3.15	47,699,000	¢/KSCF
TOTAL RAW MATERIALS COST				47,699,000	144.54
UTILITIES					
Power	34,428,000	KWH	0.027	930,000	
Cooling Water	4,429,000	KGal.	0.053	234,000	
Process Water	315,000	KGal.	0.55	173,000	
Fuel		MBtu.			
Steam	(1,122,000)	KLbs.	5.00	(5,610,000)	
TOTAL UTILITIES COST				(4,273,000)	(12.95)
LABOR & RELATED	Men/Shift		Total Men		
Labor @ 10 men @ $21,500				215,000	
Supervision @ Foreman 1/4 Men $28,800/$24,200				126,000	
Direct & General Plant Overhead @ 100% L + S				341,000	
TOTAL LABOR & RELATED COST				682,000	2.07
CAPITAL RELATED					
Maintenance	4.0% BLCC			1,652,000	
General Plant Overhead	2.6 % BLCC			1,074,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			939,000	
Depreciation	10.0% BLCC + 5% Offsites			5,195,000	
Interest	10.0% on Working Capital			600,000	
TOTAL CAPITAL-RELATED EXPENSES				9,460,000	28.67
BY-PRODUCT CREDIT					
TOTAL BY-PRODUCT CREDIT					
TOTAL COST OF PRODUCTION				53,568,000	162.33
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				12,520,000	37.94
TOTAL COST PLUS RETURN				66,088,000	200.27

Production cost estimates for hydrogen manufacture via electrolysis have been developed for "new" developing technology as represented by General Electric's Solid Polymer Electrolyte Process (see Figure 5).

Table 6 summarizes the production cost for 100 M SCFD of H_2 using GE's SPE system. Battery limits capital cost is based upon a recent GE estimate for a 58 MW unit to start up in 1980. Since the unit we are considering is roughly six times as large as the estimate module, the supply voltage for our unit will probably range up to 1000 volts, if available, rather than the 500 volt electrical source used in the estimate.

The battery limits capital for this plant (including 30% contingency) can be delineated as follows:

	$M (Mid-1980)	Percent
Electrolysis Module	7.1	10.5
Power Conversion and Switch Gear	37.4	55.4
Ancillary Equipment (See Figure 5)	15.8	23.4
Installation	7.2	10.7
TOTAL	67.5	100.0

Offsites facilities have been estimated at only 20% since this is not a conventional petrochemical plant and neither feed nor product storage are required.

The cost of electrical power is the key item in determining the overall cost of hydrogen via electrolysis. At a value of 2.7¢/KWH (an average 1980 value based on a mix of nuclear, fossil fuel and hydroelectric plants), the estimated hydrogen transfer price is about 374¢/KSCF.

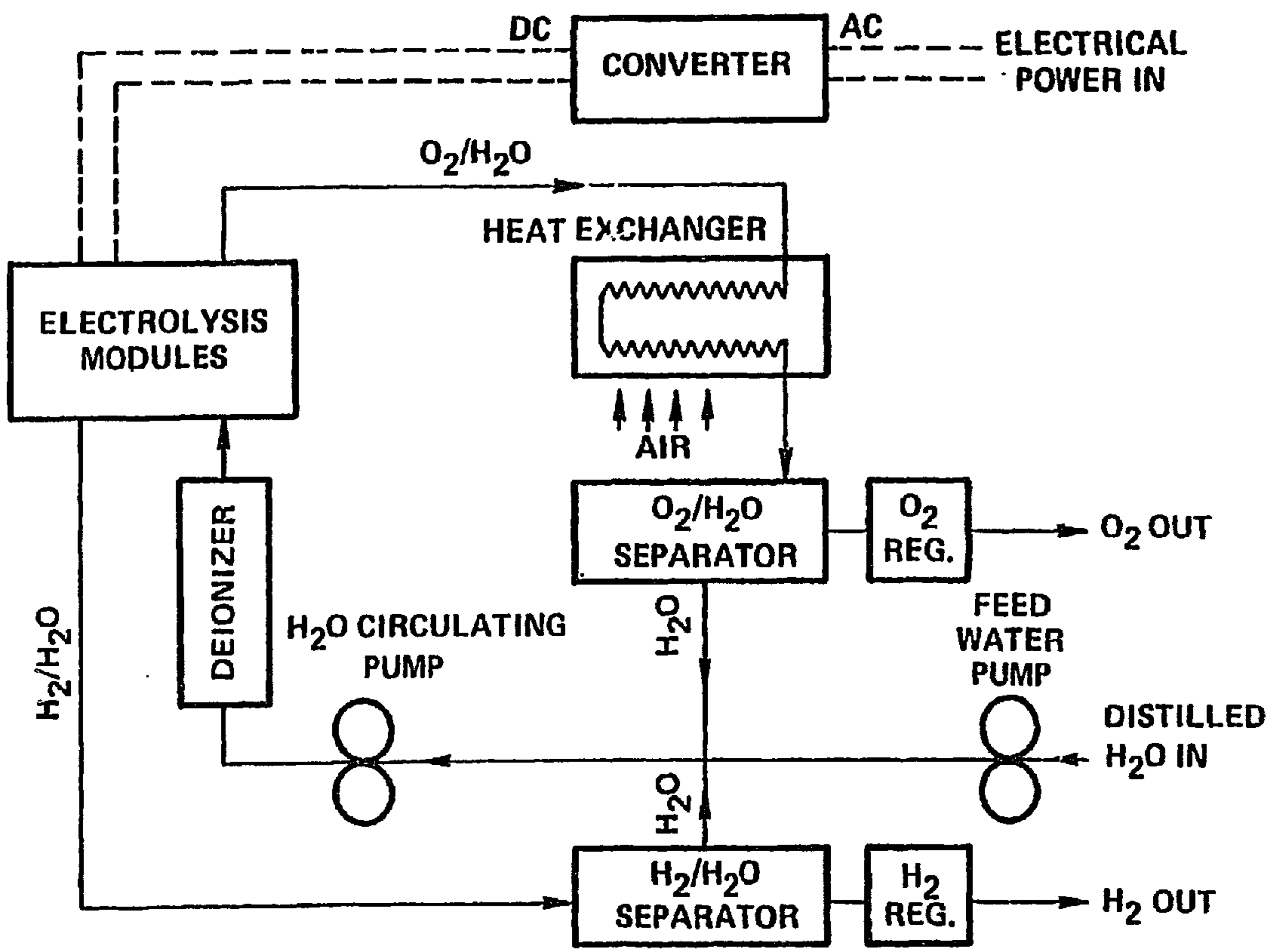


FIGURE 5. SIMPLIFIED SPE ELECTROLYTIC H_2 GENERATING PLANT SCHEMATIC

TABLE 6

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

HYDROGEN AT 450 PSIG VIA NEW ELECTROLYTIC PROCESS

(SOLID POLYMER ELECTROLYTE ELECTROLYTIC CELL)

* Includes 20% Contingency

			$ M
Plant	Hydrogen Via New Electrolytic Process	*Battery Limits Capital Cost	67.5
		*Offsites Capital Cost	13.5
Location	U.S. Gulf Coast Mid-1980	Total Fixed Investment	81.0
Capacity	100 M SCFD	Working Capital	11.0
Production Rate	33,000 MSCF/Yr	Total Fixed & Working Capital	92.0

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST ¢/KSCF
Process Water	190,000	KGal	.55	105,000	
TOTAL RAW MATERIALS COST				105,000	0.32
UTILITIES					
Power	4,008,228,000	KWH	.027	108,222,000	
Cooling Water	12,000,000	K Gal.	0.053	636,000	
Process Water		K Gal.			
Fuel		MBTU			
Steam		K Lbs.			
TOTAL UTILITIES COST				108,858,000	329.87
LABOR & RELATED	Men/Shift		Total Men		
Labor @ $21,500			10	215,000	
Supervision @ 28,800			3	86,000	
Direct & General Plant Overhead @ 100% L + S				301,000	
TOTAL LABOR & RELATED COST				602,000	1.82
CAPITAL RELATED					
Maintenance	4.0% BLCC			2,700,000	
General Plant Overhead	2.6 % BLCC			1,755,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			1,215,000	
Depreciation	10.0% BLCC + 5% Offsites			7,425,000	
Interest	10.0% on Working Capital			1,100,000	
TOTAL CAPITAL-RELATED EXPENSES				14,195,000	43.02
BY-PRODUCT CREDIT					
Oxygen	696,000	Ton	24	(16,704,000)	
TOTAL BY-PRODUCT CREDIT				(16,704,000)	(50.62)
TOTAL COST OF PRODUCTION				107,056,000	324.41
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				16,200,000	49.09
TOTAL COST PLUS RETURN				123,256,000	373.50

Table 7 shows that the use of low sulfur, lower priced Western coals does not reduce the cost of hydrogen via the gasification route but actually increases it by 3 to 4%. Although there are savings in raw material costs based upon the price differential between Western and Eastern coals and also capital savings in sulfur recovery equipment, these savings are more than offset by increased costs for coal handling and drying of the lower heating value, higher moisture Western coal. Note that the four plants are assumed to be mine-mouth and equipped with stack gas scrubbing equipment.

TABLE 7

Hydrogen Via Coal Gasification - Coal Sensitivity Analysis

	Illinois Coal @ $21/ton		Montana/Wyoming Coal @ $8/ton	
	Total Fixed Investment $M	Transfer Price ¢/MSCF	Total Fixed Investment $M	Transfer Price ¢/MSCF
K-T Coal Gasification	246.4	311.21	269.0	320.47
"New" Coal Gasification	200.1	260.46	223.5	270.16

Ammonia

The same processing steps described previously under hydrogen production via coal gasification are required in ammonia production. In addition, an ammonia synthesis loop is included, preceded by a nitrogen wash or methanation step to remove residual carbon oxides (see Figure 2). We have assumed that conventional ammonia synthesis technology (ca. 2500 psig) is utilized.

Table 8 shows a cost of production analysis for a 2000 short ton per day ammonia plant for synthesis gas generated in K-T gasifiers. Table 9 shows the same production cost analysis for a 2000 short ton per day plant using a "new" coal gasification process. At this capacity level, the "new" technology offers a potential savings of about 9%. on the ammonia cost plus return.

Ammonia production based on coal gasification can be compared against production via:

- Partial Oxidation of Residual Fuel Oil
- Steam Reforming of Methane

If ammonia is the desired product from a partial oxidation unit then additional processing steps must be added to the partial oxidation based hydrogen plant (See Figure 3).

- Nitrogen Addition
- Compression to Desired Gas Pressure
- Ammonia Synthesis and Purification

Table 10 shows the production cost analysis for a 2000 ton per day ammonia plant using partial oxidation of a high sulfur residual oil. The estimated transfer price is about 249$/ton.

TABLE 8

CHEM SYSTEMS
PRODUCTION COST ANALYSIS

AMMONIA FROM A K-T COAL GASIFICATION PROCESS

*Includes 15% Contingency

Plant	Ammonia Via Koppers-Totzek Coal Gasification
Location	U.S. Mid Cont. - 1980
Capacity	2,000 Short Tons/Day
Production Rate	660,000 ST/Yr

	$ M
*Battery Limits Capital Cost	235.1
*Offsites Capital Cost	159.9
Total Fixed Investment	395.0
Working Capital	15.0
Total Fixed & Working Capital	410.0

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST
Illinois Coal (HHV=11,?30 Btu/Lb)	1,170,000	Tons	21.00	$ 24,570,000	$/T
Catalyst and Chemicals				700,000	
TOTAL RAW MATERIALS COST				$ 25,270,000	38.29
UTILITIES					
Power	24,500,000	KWH	0.027	662,000	
Cooling Water	64,840,000	KGal.	Internal	-	
Process Water	4,540,000	KGal.	0.55	2,497,000	
Fuel		MBTU			
Steam	4,340,000	KLbs.	Internal	-	
Stack Gas Clean-up	"	"	0.35	1,519,000	
TOTAL UTILITIES COST				4,678,000	7.09
LABOR & RELATED	Men/Shift		Total Men		
Labor @ $21,500	8		37	796,000	
Supervision @ $28,800/24,200	2		1/9	247,000	
Direct & General Plant Overhead @ 100% L + S				1,043,000	
TOTAL LABOR & RELATED COST				$ 2,086,000	3.16
CAPITAL RELATED					
Maintenance	4.0% BLCC			9,404,000	
General Plant Overhead	2.6% BLCC			6,113,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			5,925,000	
Depreciation	10.0% BLCC + 5% Offsites			31,505,000	
Interest	10.0% on Working Capital			1,500,000	
TOTAL CAPITAL-RELATED EXPENSES				54,447,000	82.49
BY-PRODUCT CREDIT					
Sulfur	38,800	Tons	50	1,940,000	
TOTAL BY-PRODUCT CREDIT				($ 1,940,000)	(2.94)
TOTAL COST OF PRODUCTION				84,541,000	128.09
RETURN ON TOTAL FIXED INVESTMENT @ 20%				79 000,000	119.69
TOTAL COST PLUS RETURN				$163,541,000	$247.78

TABLE 9

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

AMMONIA FROM A "NEW" COAL GASIFICATION PROCESS

*Includes 20% Contingency

				$ MM
Plant	Ammonia Via "New" Coal Gasification Process		*Battery Limits Capital Cost	209.2
Location	U.S. Mid Cont. 1980		*Offsites Capital Cost	152.9
Capacity	2,000 Short Tons/Day		Total Fixed Investment	362.1
Production Rate	660,000 ST/Yr		Working Capital	14.0
			Total Fixed & Working Capital	'76.1

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST
Illinois Coal (HHV=11,390 Btu/Lb)	1,094,000	Tons	21.00	$ 22,974,000	$/T
Catalyst and Chemicals				700,000	
TOTAL RAW MATERIALS COST				$ 23,674,000	35.87
UTILITIES					
Power	24,500,000	KWH	0.027	662,000	
Cooling Water	60,200,000	KGal.	Internal	-	
Process Water	4,220,000	KGal.	0.55	2,321,000	
Fuel		MBTU			
Steam	3,280,000	KLbs.	Internal	-	
Stack Gas Clean-up	"	"	0.35	1,148,000	
TOTAL UTILITIES COST				4,131,000	6.26
LABOR & RELATED		Men/Shift	Total Men		
Labor @ $21,500		8	37	796,000	
Supervision @ $24,200/28,800		2	9/1	247,000	
Direct & General Plant Overhead @ 100% L + S				1,043,000	
TOTAL LABOR & RELATED COST				$ 2,086,000	3.16
CAPITAL RELATED					
Maintenance	4.0% BLCC			8,363,000	
General Plant Overhead	2.6% BLCC			5,439,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			5,432,000	
Depreciation	10.0% BLCC + 5% Offsites			28,565,000	
Interest	10.0% on Working Capital			1,400,000	
TOTAL CAPITAL-RELATED EXPENSES				49,204,000	74.55
BY-PRODUCT CREDIT					
Sulfur	38,300	Tons	50	1,915,000	
TOTAL BY-PRODUCT CREDIT				($ 1,915,000)	(2.90)
TOTAL COST OF PRODUCTION				77,180,000	116.94
RETURN ON TOTAL FIXED INVESTMENT @ 20%				72,420,000	109.73
TOTAL COST PLUS RETURN				149,600,000	226.67

TABLE 10

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

AMMONIA VIA PARTIAL OXIDATION WITH INTEGRATED OXYGEN PRODUCTION

*Includes 10% Contingency

			$ M
Plant	Ammonia Via Partial Oxidation	*Battery Limits Capital Cost	170.6
		*Offsites Capital Cost	110.0
Location	U.S. Gulf Coast, Mid-1980	Total Fixed Investment	280.6
Capacity	2000 Short Tons/Day	Working Capital	18.0
Production Rate	660,000 Tons/Yr	Total Fixed & Working Capital	298.6

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST
Residual Fuel Oil	4,100,000	Bbl	15.00	61,500,000	$/Ton
Catalyst and Chemicals				800,000	
TOTAL RAW MATERIALS COST				62,300,000	94.39
UTILITIES					
Power	13,200,000	KWH	0.027	356,000	
Cooling Water	72,451,000	KGal.	Internal		
Process Water	6,780,000	KGal.	0.55	3,731,000	
Fuel		MBTU			
Steam	2,740,000	KLbs.	Internal		
Stack Gas Clean-Up	"	"	0.35	959,000	
TOTAL UTILITIES COST				5,046,000	7.65
LABOR & RELATED	Men/Shift		Total Men		
Labor @ $21,500	7		30	645,000	
Supervision @ $24,200/28,800	3		14/2	396,000	
Direct & General Plant Overhead @ 100% L + S				1,041,000	
TOTAL LABOR & RELATED COST				$2,082,000	3.16
CAPITAL RELATED					
Maintenance	4.0% BLCC			6,824,000	
General Plant Overhead	2.6 % BLCC			4,436,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			4,209,000	
Depreciation	10.0% BLCC + 5% Offsites			22,560,000	
Interest	10.0% on Working Capital			1,800,000	
TOTAL CAPITAL-RELATED EXPENSES				39,829,000	60.34
BY-PRODUCT CREDIT					
Sulfur	20,000	Tons	50	(1,000,000)	
TOTAL BY-PRODUCT CREDIT				($1,000,000)	(1.52)
TOTAL COST OF PRODUCTION				108,257,000	164.02
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				56,120,000	85.03
TOTAL COST PLUS RETURN				164,377,000	249.05

The production cost analysis for the production of ammonia (2000 STPD) via steam methane reforming is presented in Table 11. The estimated transfer price is about 210 $/ton.

Table 12 shows that the use of low sulfur, lower priced Western coals does not reduce the cost of ammonia via the gasification route, but increases it by 1 to 2%. Again, the four plants are assumed to be mine mouth and equipped with stack gas scrubbing equipment. Similar to the hydrogen-coal sensitivity analysis, this increase in ammonia cost is the result of increased costs for coal handling and drying of the lower heating value, higher moisture Western coal.

TABLE 12

Ammonia Via Coal, Gasification - Coal Sensitivity Analysis

	Illinois Coal @ $21/ton		Montana/Wyoming Coal @ $8/ton	
	Total Fixed Investment $M	Transfer Price $/Ton	Total Fixed Investment $M	Transfer Price $/Ton
K-T Coal Gasification	395.0	247.78	422 2	250.97
"New" Coal Gasification	362.1	226.67	390.4	231.36

TABLE 11

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

AMMONIA BY STEAM-METHANE REFORMING

*Includes 10% Contingency

Plant	Ammonia by Steam-Methane Reforming		$ M
Location	U.S. Gulf Coast - 1980	* Battery Limits Capital Cost	116.5
Capacity	2000 ST/SD	* Offsites Capital Cost	64.1
Production Rate	660,000 ST/Yr	Total Fixed Investment	180.6
		Working Capital	11.0
		Total Fixed & Working Capital	191.6

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST
Natural Gas	23,130,000	MBTU	3.15	72,860,000	$/T
Catalyst and Chemicals				800,000	
TOTAL RAW MATERIALS COST				73,660,000	111.60
UTILITIES					
Power	60,600,000	KWH	.027	1,622,000	
Cooling Water	63,171,000	KGal.	.053	3,349,000	
Process Water	140,000	KGal.	0.55	77,000	
Fuel		MBTU			
Steam	(867,000)	KLbs.	5.00	(4,337,000)	
TOTAL UTILITIES COST				$ 711,000	1.08
LABOR & RELATED	Men/Shift		Total Men		
Labor @ $21,500			25	538,000	
Supervision @ $28,800			7	202,000	
Direct & General Plant Overhead @ 100% L + S				740,000	
TOTAL LABOR & RELATED COST				1,480,000	2.23
CAPITAL RELATED					
Maintenance	4.0% BLCC			4,660,000	
General Plant Overhead	2.6 % BLCC			3,029,000	
Insurance, Property Taxes	1.5% Total Fixed Investment			2,709,000	
Depreciation	10.0% BLCC + 5% Offsites			14,855,000	
Interest	10.0% on Working Capital			1,100,000	
TOTAL CAPITAL-RELATED EXPENSES				26,353,000	39.93
BY-PRODUCT CREDIT					
TOTAL BY-PRODUCT CREDIT					
TOTAL COST OF PRODUCTION				102,204,000	154.84
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				36,120,000	54.73
TOTAL COST PLUS RETURN				$138,324,000	209.57

Methanol

Methanol production via coal gasification is similar to that for ammonia except that the synthesis gas, following clean-up and sulfur removal, is adjusted to the proper hydrogen to carbon monoxide ratio by sending only part of the stream to a shift conversion step (See Figure 2). Some carbon dioxide is removed and the total synthesis gas stream is compressed to the methanol synthesis pressure. ICI (100 ATM) methanol technology is assumed for this step.

Table 13 shows a production cost analysis for a 2000 short ton per day methanol plant using Koppers-Totzek technology. Table 14 shows a production cost analysis for a 2000 short ton per day plant using a "new" coal gasification process. The "new" coal gasification technology offers potential savings of about 12% on the methanol cost plus return.

As in the case of ammonia production, partial oxidation of heavy residual oil and steam methane reforming are considered as alternative processes for methanol production in the U.S. Table 15 shows the production cost analysis for a 2000 ton per day methanol plant using partial oxidation of a high sulfur residual oil. The estimated transfer price is about 74¢/gal.

The production cost analysis for the production of methanol (2000 STPD) via steam methane reforming is presented in Table 16. The estimated transfer price is about 64¢/gal.

TABLE 13

CHEM SYSTEMS
PRODUCTION COST ANALYSIS
METHANOL VIA KC-PERS-TOTZEK COAL GASIFICATION

Plant Methanol Via Koppers-Totzek Coal Gasification
Location U.S. Mid Continent-1980
Capacity 2,000 Short Tons/Day
Production Rate 660,000 Tons/Yr

*Includes 15% Contingency

	$ M
*Battery Limits Capital Cost	206.1
*Offsites Capital Cost	144.3
Total Fixed Investment	350.4
Working Capital	14.0
Total Fixed & Working Capital	364.4

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST S/T	UNIT COST ¢ Gal
Illinois Coal (HHV = 11,390 Btu/Lb.)	1,134,000	Tons	21.00	23,814,000		
Catalyst and Chemicals				450,000		
TOTAL RAW MATERIALS COST				24,264,000	36.76	12.25
UTILITIES						
Power	23,000,000	KWH	0.027	621,000		
Cooling Water	59,200,000	KGal.	Internal			
Process Water	4,140,000	KGal.	0.55	2,277,000		
Fuel		MBtu				
Steam	3,820,000	KLbs.	Internal			
Stack Gas Clean-Up	"	"	0.35	1,337,000		
TOTAL UTILITIES COST				4,235,000	6.42	2.14
LABOR & RELATED	Men/Shift		Total Men			
Labor @ $21,500	7		37	796,000		
Supervision @ $24,200/28,800	2		9/1	247,000		
Direct & General Plant Overhead @ 100% L + S				1,043,000		
TOTAL LABOR & RELATED COST				2,086,000	3.16	1.05
CAPITAL RELATED						
Maintenance	4.0% BLCC			8,244,000		
General Plant Overhead	2.6 % BLCC			5,359,000		
Insurance, Property Taxes	1.5% Total Fixed Investment			5,256,000		
Depreciation	10.0% BLCC + 5% Offsites			27,825,000		
Interest	10.0% on Working Capital			1,400,000		
TOTAL CAPITAL-RELATED EXPENSES				48,084,000	72.85	24.29
BY-PRODUCT CREDIT						
Sulfur	38,000	Tons	50	1,900,000		
TOTAL BY-PRODUCT CREDIT				(1,900,000)	(2.88)	(.96)
TOTAL COST OF PRODUCTION				76,769,000	116.31	38.77
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				70,080,000	106.18	35.39
TOTAL COST PLUS RETURN				$146,849,000	222.49	74.16

TABLE 14

CHEM SYSTEMS
PRODUCTION COST ANALYSIS

METHANOL VIA "NEW" COAL GASIFICATION

*Includes 20% Contingency

			$ M
Plant	Methanol Via "New" Coal Gasification	*Battery Limits Capital Cost	175.2
Location	U.S. Mid Cont. - 1980	*Offsites Capital Cost	134.9
Capacity	2,000 Short Tons/Day	Total Fixed Investment	310.1
Production Rate	660,000 Tons/Yr	Working Capital	13.0
		Total Fixed & Working Capital	323.1

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST $/T	UNIT COST ¢ Gal.
Illinois Coal (HHV=11,390 Btu/Lb.)	1,060,000	Tons	21.00	$ 22,260,000		
Catalyst and Chemicals				450,000		
TOTAL RAW MATERIALS COST				$ 22,710,000	34.41	11.47
UTILITIES						
Power	23,000,000	KWH	0.27	$ 621,000		
Cooling Water	55,800,000	KGal.	Internal	-		
Process Water	3,900,000	KGal.	0.55	2,145,000		
Fuel		MBTU				
Steam	2,760,000	KLbs.	Internal	-		
Stack Gas Clean-up	"	"	0.35	966,000		
TOTAL UTILITIES COST				3,732,000	5.65	1.89
LABOR & RELATED	Men/Shift		Total Men			
Labor @ $21,500	7		37	$ 796,000		
Supervision @ $24,200/28,800	2		9/1	247,000		
Direct & General Plant Overhead @ 100% L + S				1,043,000		
TOTAL LABOR & RELATED COST				$ 2,086,000	3.16	1.05
CAPITAL RELATED						
Maintenance	4.0% BLCC			$ 7,008,000		
General Plant Overhead	2.6% BLCC			4,555,000		
Insurance, Property Taxes	1.5% Total Fixed Investment			4,652,000		
Depreciation	10.0% BLCC + 5% Offsites			24,265,000		
Interest	10.0% on Working Capital			1,300,000		
TOTAL CAPITAL—RELATED EXPENSES				40,480,000	61.33	20.44
BY-PRODUCT CREDIT						
Sulfur	35,600	Tons	50	$ 1,780,000		
TOTAL BY-PRODUCT CREDIT				($ 1,780,000)	(2.70)	(0.90)
TOTAL COST OF PRODUCTION				$ 67,228,000	101.85	33.95
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				62,020,000	93.97	31.32
TOTAL COST PLUS RETURN				$129,248,000	195.82	65.27

TABLE 15

CHEM SYSTEMS
PRODUCTION COST ANALYSIS

METHANOL VIA PARTIAL OXIDATION WITH INTEGRATED OXYGEN PRODUCTION

*Includes 10% Contingency

			$ M
Plant	Methanol Via Partial Oxidation	*Battery Limits Capital Cost	137.8
		*Offsites Capital Cost	93.3
Location	U.S. Gulf Coast Mid-1980	Total Fixed Investment	231.1
Capacity	2000 Short Tons/Day	Working Capital	17.0
Production Rate	660,000 Tons/Yr	Total Fixed & Working Capital	248.1

RAW MATERIALS	QUANTITY	UNIT	PRICE, $	ANNUAL COST, $	UNIT COST $/T	UNIT COST ¢/Gal
Residual Fuel Oil	4,100,000	Bbl		61,500,000		
Catalyst and Chemicals				800,000		
TOTAL RAW MATERIALS COST				62,300,000	94.39	31.46
UTILITIES						
Power	6,666,000	KWH	.027	179,000		
Cooling Water	54,400,000	K Gal.	Internal			
Process Water	5,080,000	K Gal.	0.55	2,795,000		
Fuel		MBTU				
Steam	2,740,000	K Lbs.	Internal			
Stack Gas Clean-Up	"	"	0.35	959,000		
TOTAL UTILITIES COST				3,933,000	5.96	1.99
LABOR & RELATED	Men/Shift		Total Men			
Labor @ $21,500	6		30	645,000		
Supervision @ $24,200/28,800	2		14/2	396,000		
Direct & General Plant Overhead @ 100% L + S				1,041,000		
TOTAL LABOR & RELATED COST				2,082,000	3.15	1.06
CAPITAL RELATED						
Maintenance	4.0% BLCC			5,512,000		
General Plant Overhead	2.6 % BLCC			3,583,000		
Insurance, Property Taxes	1.5% Total Fixed Investment			3,467,000		
Depreciation	10.0% BLCC + 5% Offsites			18,445,000		
Interest	10.0% on Working Capital			1,700,000		
TOTAL CAPITAL-RELATED EXPENSES				32,707,000	49.56	16.51
BY-PRODUCT CREDIT						
Sulfur	20,000	Tons	5.00	1,000,000		
TOTAL BY-PRODUCT CREDIT				(1,000,000)	(1.52)	(0.51)
TOTAL COST OF PRODUCTION				100,022,000	151.54	50.51
RETURN ON TOTAL FIXED INVESTMENT @ 20%				46,220,000	70.03	23.34
TOTAL COST PLUS RETURN				146,242,000	221.57	73.85

TABLE 16

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

METHANOL BY STEAM-METHANE REFORMING

*Includes 10% Contingency

			$ M
Plant	Methanol by Steam-Methane Reforming	*Battery Limits Capital Cost	86.1
		*Offsites Capital Cost	47.4
Location	U.S. Gulf Coast - 1980	Total Fixed Investment	133.5
Capacity	2000 ST/SD	Working Capital	10.0
Production Rate	660,000 ST/Yr	Total Fixed & Working Capital	143.5

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST S/T	UNIT COST ¢/Gal
Natural Gas	23,400,000	MBTU	3.15	73,710,000		
CO_2	4,150,000	KSCF	Nil	Nil		
Catalyst and Chemicals				1,400,000		
TOTAL RAW MATERIALS COST				75,110,000	113.80	37.93
UTILITIES						
Power	51,027,000	KWH	.027	1,378,000		
Cooling Water	40,411,000	KGal.	.053	2,142,000		
Process Water	140,000	KGal.	0.55	77,000		
Fuel		MBTU				
Steam		KLbs.				
TOTAL UTILITIES COST				3,597,000	5.45	1.82
LABOR & RELATED	Men/Shift		Total Men			
Labor @ $21,500			25	538,000		
Supervision @ $28,800			7	202,000		
Direct & General Plant Overhead @ 100% L + S				740,000		
TOTAL LABOR & RELATED COST				1,480,000	2.23	0.74
CAPITAL RELATED						
Maintenance	4.0% BLCC			3,444,000		
General Plant Overhead	2.6 % BLCC			2,239,000		
Insurance, Property Taxes	1.5% Total Fixed Investment			2,003,000		
Depreciation	10.0% BLCC + 5% Offsites			10,980,000		
Interest	10.0% on Working Capital			1,000,000		
TOTAL CAPITAL-RELATED EXPENSES				19,666,000	29.80	9.92
BY-PRODUCT CREDIT						
None						
TOTAL BY-PRODUCT CREDIT						
TOTAL COST OF PRODUCTION				99,853,000	151.28	50.41
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				26,700,000	40.45	13.48
TOTAL COST PLUS RETURN				126,553,000	191.73	63.89

Synthesis gas produced from steam methane reforming is typically a mixture of carbon monoxide, carbon dioxide, and hydrogen, with the conversion to methanol following the equations:

$$CO + 2H_2 \longrightarrow CH_3OH$$
$$CO_2 + 3H_2 \longrightarrow CH_3OH + H_2O$$

Since methane is richer in hydrogen than is ideal, CO_2 is normally added to the feed to balance the excess hydrogen. Thus, methanol producers have traditionally located their plants not only close to cheap natural gas sources but also adjacent to ammonia plants where CO_2 would be available cost-free.

Thus, Table 16 shows no charge for the CO_2 raw material. However, it is possible that a methanol plant could be built in an area where cost-free CO_2 is not available. Table 17 presents a production cost analysis for such a case. The estimated transfer price is about 65¢/gal.

TABLE 17

CHEM SYSTEMS

PRODUCTION COST ANALYSIS

METHANOL BY STEAM-METHANE REFORMING
(No Captive CO_2)

*Includes 10% contingency

			$ M
Plant Methanol by Steam-Methane Reforming		*Battery Limits Capital Cost	87.9
		*Offsites Capital Cost	47.4
Location U.S. Gulf Coast - 1980		Total Fixed Investment	135.3
Capacity 2000 ST/SD		Working Capital	10.0
Production Rate 660,000 ST/Yr		Total Fixed & Working Capital	145.3

RAW MATERIALS	QUANTITY	UNIT	PRICE,$	ANNUAL COST,$	UNIT COST $/T	¢/Gal
Natural Gas	23,400,000	MBTU	3.15	73,710,000		
CO_2	4,150,000	KSCF	0.18	747,000		
Catalyst and Chemicals				1,400,000		
TOTAL RAW MATERIALS COST				75,857,000	114.93	38.31
UTILITIES						
Power	69,296,000	KWH	.027	1,871,000		
Cooling Water	40,411,000	KGal.	.053	2,142,000		
Process Water	140,000	KGal.	0.55	77,000		
Fuel		MBTU				
Steam		KLbs.				
TOTAL UTILITIES COST				4,090,000	6.20	2.07
LABOR & RELATED	Men/Shift		Total Men			
Labor @ $21,500			25	538,000		
Supervision @ $28,800			7	202,000		
Direct & General Plant Overhead @ 100% L + S				740,000		
TOTAL LABOR & RELATED COST				1,480,000	2.23	0.74
CAPITAL RELATED						
Maintenance	4.0% BLCC			3,516,000		
General Plant Overhead	2.6 % BLCC			2,285,000		
Insurance, Property Taxes	1.5% Total Fixed Investment			2,030,000		
Depreciation	10.0% BLCC + 5% Offsites			11,160,000		
Interest	10.0% on Working Capital			1,000,000		
TOTAL CAPITAL-RELATED EXPENSES				$19,991,000	30.29	10.08
BY-PRODUCT CREDIT						
None						
TOTAL BY-PRODUCT CREDIT						
TOTAL COST OF PRODUCTION				101,418,000	153.65	51.20
RETURN ON TOTAL FIXED INVESTMENT @ 20 %				27,060,000	41.00	13.56
TOTAL COST PLUS RETURN				$128,478,000	194.65	64.86

Table 18 shows that the use of low sulfur, lower priced, Western coals does not reduce the cost of methanol via the gasification route, but increases it by 1 to 3%. Again, the four plants are assumed to be mine mouth and equipped with stack gas scrubbing equipment. Similar to the hydrogen and ammonia-coal sensitivity analyses, this increase in methanol cost is the result of increased costs for coal handling and drying of the lower heating value, higher moisture Western coal.

TABLE 18

Methanol Via Coal Gasification - Coal Sensitivity Analysis

	Illinois Coal @ $21/ton		Montana/Wyoming Coal @ $8/ton	
	Total Fixed Investment $M	Transfer Price ¢/Gal	Total Fixed Investment $M	Transfer Price ¢/Gal
K-T Coal Gasification	350.4	74.16	377.2	75.33
"New"Coal Gasification	310.1	65.27	338.3	67.47