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OUR ENERGY PROBLEM AND THE ROLE OF COAL[a, b]

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b) The views expressed in this paper are those of the author and do not necessarily reflect those of ERDA

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I would like to thank Professor Karadi and hosts of this conference for inviting me to participate in this conference at this beautiful location.

I think it is important to have some feeling for the nature and magnitude of our energy problem and what our alternatives are, before embarking on the role which coal must play for our nation's well being at least until near the end of this century - which is only 23 years from now. In reference to the use of coal, my comment on its importance is made in all due awareness, as a person who grew up with coal furnaces to provide steam heat, with respect to how "dirty" it is.

1. Nature and Magnitude of Our Energy Problem

Our present and near term energy problem arises from two facts;

1. our production of crude oil peaked in 1970 at 9.64 million bbl/D and has gradually decreased to about 8.2 million bbl/D as of mid 1976 (Meyerhoff, 1976) (Table 1). Our imports, in turn, have been increasing, so that by mid 1976, they are about 1/2 of the oil we consume - or $33 billion of imported oil (Table 2);

2. it has been projected that the rate of increase of our energy consumption should continue at the rate we had in the 60's which was a little over 4% (Table 3).

Thus, assuming the oil industry even maintains its present level of production of petroleum, then based on (a) the projections that the U.S. petroleum needs will continually increase at a rate roughly comparable to that in going from 1970 to 1975, (b) we will increase our use of coal, nuclear and other resources, at a reasonable growth rate, where oil is presently used (Tables 4-6), and (c) our imports in 1980 and 1985 will be as forecasted by the United Nations (Table 7), we would still have a very significant shortfall in meeting our petroleum and refined products needs (Table 8). The problem is compounded and due in part to the fact that the world's oil production should peak by 1990, assuming current growth rates, as a result of increasing demand by such countries as Japan, West Germany, and other oil deficient countries. Our problem is further compounded by our increasing balance of payments and tax rebates from the U.S. Treasury - such that by 1980 our oil import bill should increase to

Table 1. U.S. Petroleum Production[a]
(in quads)

Year	Petroleum Production[b] (as crude)
1960	14.7
1965	15.9
1970	19.8
1971	19.3
1972	19.3
1973	18.8
1974	18.5
1975	17.7

a) Reference: Energy Perspectives 2, U. S. Department of the Interior, June 1976

b) Does not include natural gas liquids

Table 2. U.S. Petroleum Consumption and Imports[a]
(in Quads)

	Consumption	Imports	% of Consumption
1969	23.2	5.4	25
1970	29.5	7.1	26
1971	30.6	8.7	31
1972	33.0	11.1	36
1973	34.9	13.4	41
1974	33.4	14.9	45
1975	32.7	15.0	46
1976[b]	36.1	18.2	50

a) Energy Perspectives 2, U.S. Department of the Interior, June 1976

b) A. A. Meyerhoff, American Scientist, 64, 536-541 (1976)

TABLE 3. **U.S. ENERGY CONSUMPTION - 1970-1975 AND PROJECTED VALUES FOR 1980 AND 1985**

(in Quads)

Year	Energy Consumed			
1970	67.1			
1971	68.7			
1972	71.9			
1973	74.7			
1974	73.0			
1975	71.3			
		FEA	BuMines	UN
1980	76[a]	81.6	87.1	86.5
1985	81[a]	98.9	103.5	102.9

a – based on 6% increase in energy consumption (equivalent to 6% increase from 1970 to 1975).

TABLE 4. PETROLEUM AND NATURAL GAS REQUIREMENTS
(in Quads)

Petroleum	1975	1980	1985
–	32.7 (14.9×10^6 bbl/D)	–	–
United Nations	–	41 (18.7×10^6 bbl/D)	46.2 (21.1×10^6 bbl/D)
BuMines	–	41	45.6
FEA	–	35.6	40.9
–	–	40[a]	–

a – Based on 22% increase in consumption in going from 1970 (27 quads) to 1975 (33 quads).

Natural Gas	1975	1980	1985
United Nations	–	22.7	24.2
FEA	–	22.7	24.2
BuMines	–	20.6	20.1
–	20.2	–	–

Petroleum production – 1975: 17.7 quads (8.1×10^6 bbl/D).

TABLE 5. ESTIMATED CONTRIBUTIONS FROM OTHER ENERGY SOURCES

(in Quads)

	1975	1980		1985	
		BuMines	FEA	BuMines	FEA
Coal	13.4	17.2	15.7	21.3	20.6
Nuclear	1.7	4.5	3.9	11.8	8.7
Oil Shale	0	0	0	0.9	0.6
Hydropower and Geothermal	3.1	3.8	3.7	3.8	3.9
Overall (Including Petroleum and Natural Gas)	71.1	87.1	81.6	103.5	98.9

ENERGY PERSPECTIVES 2, U.S. DEPARTMENT OF THE INTERIOR, JUNE 1976

TABLE 6. ESTIMATED CONTRIBUTIONS FROM OTHER ENERGY SOURCES

% INCREASES

	1980 (vs 1975)		1985 (vs Corresponding 1980 Projection)	
	BuMines	FEA	BuMines	FEA
Coal	28%	17%	24%	31%
Nuclear	165%	129%	140%	123%
Hydropower and Geothermal	23%	19%	0%	5%

TABLE 7. PROJECTED PETROLEUM IMPORTS (in Quads)

	1976	1980	1985
–	18.2 (8.3 x 10^6 bbl/D)	–	–
United Nations	–	17.0 (7.7 x 10^6 bbl/D)	20.5 (9.3 x 10^6 bbl/D)
–	–	22[a] (10.0 x 10^6 bbl/D)	28[a] (12.8 x 10^6 bbl/D)
Chase Manhattan Bank	–	–	29.1 (13.3 x 10^6 bbl/D)

[a]Based on 4.9% average annual increase from 1970 (27 quads) to 1976 (36 quads) in total annual consumption of petroleum. Neglects change in U.S. production which declined from 19.8 quads to 17.7 quads from 1970 to 1975.

TABLE 8. PROJECTED "SHORTFALL" IN PETROLEUM NEEDS (in Quads)

	1980	1985
Assuming domestic production holds steady at 1975 level	17.7	17.7
U.N. projected imports for U.S.	17.0	20.5
Total	34.7	38.2
BuMines projected requirements for U.S.	41	45.6
Shortfall	6.3	7.4

$60 billion with a cumulative total expenditure of $225 billion from 1976 - 1980. By 1985, our annual import bill would be about $125 billion, with a cumulative total of $733 billion from 1976 - 1985. This is based on a 60% increase in imports by 1985 vs. 1976 (Energy Report from the Chase Manhattan Bank, September 1976), 8% inflation per year, and a 10% price increase per year for imported petroleum.

Our increasing consumption of oil has also been due in part to various environmental constraints associated with the use of coal in electric power plants and from automotive emission standards which have resulted in increased consumption of gasoline (because of reduction of TEL, lower compression ratio engines, and the requirement for catalytic converters). This is not to say that such environmental protection measures are not desirable - assuming, of course, there has indeed been an overall net protection of the environment and the air we breathe.

2. Dependency on Petroleum

Forty-six percent of our total energy needs in 1975 came from petroleum, with 54% of the latter going to the transportation sector alone (Tables 9 - 10). In the transportation sector, petroleum accounted for 96% of the energy consumed. Furthermore, if one examines the changes in consumption of each fuel/energy source from 1970 to 1975, petroleum not only shows the greatest increase in consumption, but, moreover, its increase (5.9 quads) is greater than the actual increase in our total energy consumption (Δ = 4.1 quads), i.e., its increase more than compensates for the net loss for all other fuels combined (as a result of our decreased consumption of natural gas of 4.3 quads) (Table 11). In other words, the change in our total energy consumption is essentially determined by our use of petroleum.

It is apparent from our declining production of natural gas (which peaked in 1971; Table 12) and petroleum, the slightly increased production of coal ($\sim$ 3% in going from 1970 to 1975), the relatively small contribution of nuclear ($\sim$ 2% of our total energy consumption in 1975), and our increasing imports of petroleum (and refined products) - an increase of over 2 1/2 times in going from 1970 to 1976 - that our energy requirements have been literally locked to the import of petroleum and refined products.

TABLE 9. 1975 U.S. ENERGY CONSUMPTION

	Quads or x 10^{15} Btu	% of Total		
Coal	13.4	19	500×10^6 T/yr	1.36×10^6 T/D
Petroleum	32.6	46	5.43×10^9 bbl/yr	14.9×10^6 bbl/D
Natural Gas	20.6	29	17.2×10^{12} cu ft/yr	47.1×10^9 cu ft/D
Hydropower and Geothermal	3.1	4	3.1×10^8 Mwhr	35,400 Mw
Nuclear	1.65	2	1.65×10^8 Mwhr	18,800 Mw

TABLE 10. **1975 U.S. ENERGY CONSUMPTION**

Energy Source	Household and Commercial	Industrial Sector	Electricity	Transportation	Total
Coal	0.3 quads	4.3 (4.2 for fuel use)	8.8	0.001	13.4 (19%)
Petroleum	5.8 quads (2.8 for distillate fuel use)	5.8 (3.5 for fuel use)	3.3	17.7	32.6 (46%)
Natural Gas	7.5 quads	9.3 (8.6 for fuel use)	3.2	0.6	20.6 (29%)
Hydropower and Geothermal	–	–	3.1	–	3.1 (4%)
Nuclear	–	–	1.65	–	1.65 (2%)
Total	13.6 (19%)	19.4 (27%)	20.05 (28%)	18.3 (26%)	71.35

TABLE 11. U.S. ENERGY CONSUMPTION CHANGES FROM 1970 TO 1975 BY FUEL/ENERGY SOURCE

(in Quads)

	1970	Δ	1975	% Change
Petroleum	26.8	+5.9	32.7	+22
Natural Gas	24.5	-4.3	20.2	-17.5
Coal	12.9	+0.5	13.4	+3.9
Hydropower and Geothermal	2.5	+0.7	3.2	+28.
Nuclear	0.2	+1.45	1.65	+725.
Total	67.0	+4.1	71.1	+6.1

Table 12. U.S. Natural Gas Production (in Quads)[a]

Year	Production[b]
1960	14.1
1965	17.7
1970	24.2
1971	24.81
1972	24.79
1973	24.76
1974	23.69
1975	22.2

a) Energy Perspectives 2, U.S. Department of the Interior, June 1976

b) Includes natural gas liquids

3. U.S. Petroleum Resources

The total U.S. petroleum resources, as of December 31, 1974, was estimated at 144 billion barrels or 864 quads (as crude), Table 13. At the present useage rate of 32.7 quads/year, then with no increase in subsequent years, our resources would last 864/32.7 or 26.4 years, or until the year 2002. At a 4.2% annual increase in consumption, corresponding to our increased consumption of petroleum from 1970 to 1975, our resources would be depleted by 1993. At a 2.5% annual increase in consumption, corresponding to that for the transportation sector from 1970 to 1975, our petroleum resources would be depleted by 1996. All this assumes we would recover the estimated 82 quads of "undiscovered recoverable resources," and we receive no imports.

A more conservative estimate is that if we use our "proved and perspective" reserves of our giant oil fields (where a giant oil field is defined as containing a minimum of 500 million bbl), totaling about 65 billion barrels or 389 quads (Meyerhoff, American Scientist, 1976), to produce all of our petroleum needs at a growth rate of 4.2%/year - without any imports - then this would last until mid 1985 (Table 14).

Two other scenarios are of interest, viz., that where we use petroleum only for the transportation end-use sector, and that where it is used only for non-fuel uses, such as petrochemicals in particular.

We are currently using 17.7 quads/year or 8.1 million bbl/D of petroleum for the transportation sector. At a growth rate of 2.5%/year, our total petroleum resources of 864 quads (Geological Survey assessment) would last, on this basis, another 32 years or until mid 2008.

According to the other scenario where we would use our petroleum resources only to meet our non-fuel uses, then at a growth rate of 2%/year of our current consumption of 5.3 quads (or 2.4 million bbl/day), our total petroleum resources of 864 quads would last another 73 years or until the year 2049.

4. World Petroleum Resources

Assuming we could import 25% of the free world's proved and perspective reserves of 665 billion bbl (in Canada, Latin America, N. Africa, Greater Europe, the Middle East and the Far East), Table 14, the total proved and perspective reserves available to us then would be 231 billion

Table 13. U.S. Petroleum Resources as of December 31, 1974[a]
(billion barrels)

	Resources: Demonstrated, measured	Resources: Demonstrated, indicated	Resources: Inferred	Resources: Total	Undiscovered Recoverable Resources (statistical mean)	Overall Total
Onshore[b]	31.0	4.3	20.4	55.7	56	111.7
Offshore[b]	3.3	0.3	2.7	6.3	26	32.3
Total	34.3[c]	4.6	23.1	62.0	82	144.0
Total natural gas liquids	6.4	-	6.0	12.4	16	28.4

a) U.S. Geological Survey Circular 725, National Center, Reston, Va., 1975

b) Includes Alaska

c) The API estimated U.S. measured crude oil reserves is 32.7 billion bbl as of December 31, 1975

Table 14. Oil Reserves in Giant Fields (A. Meyerhoff) (as of January 1, 1975)

Oil	Proved & Perspective x 10^9 bbl	Quads	
U.S.A.	64.8	389	
Canada	6.9		
Latin America	59.4		
N. Africa	46.0		China 3.5×10^9 bbl
Greater Europe	20.9		USSR 103.0×10^9 bbl
Middle East	515.1		
Far East	16.5		
Import sources	664.8	3989	

$0.25 \times 3989 = 997$ quads

Total available $= 389 + 997 = 1386$ quads or 231×10^9 bbl

Source: Holmgren & Meyerhoff

barrels or 1386 quads. At a growth rate of 2.4%/year, this would last until the year 2004.

Table 15 shows the petroleum consumption of the world in 1973 (United Nations' data) and the forecasted annual growth rates (Bureau of Mines). At an average annual growth rate of 1.8%, the free world's proved and perspective reserves of 730 billion barrels would run out in 31 years (from 1973) or in the year 2004, thus checking the above estimate. What has been neglected here is an account of the free world's undiscovered recoverable resources which could of course be quite sizeable, as appears to be the case for the U.S. My guess here - and it is purely a guess - is that we are talking about a few additional decades rather than another century.

5. Natural Gas Consumption and Resources

Natural gas consumption in the U.S. amounted to 20.6 quads or 47 billion cu. ft/day in 1975, corresponding to 29% of our total energy consumption. Together with petroleum, this amounted to 75% of our energy consumption. As previously noted, its production peaked in this country in 1971 at 24.8 quads or 56.6 billion cu. ft/day. Nevertheless, it is still being used in substantial quantities as a fuel for industrial use (8.6 quads) and for electric power generation (3.2 quads) or 57% out of 20.6 quads in 1975 (Table 10).

The proved and perspective natural gas reserves in giant fields ($\geq$ 3 trillion cu. ft. of recoverable gas) of the U.S. is estimated at 224 quads or 37.3 billion barrel oil equivalents (B.O.E.), which at a consumption rate of 22 quads/year would last 10 years (1986) (Table 16). According to the U.S. Geological Survey, the measured and inferred reserves, including Alaska and offshore, are estimated at 526 quads which would last 24 years or until the year 2000 (Table 17). The difference in these two estimates corresponds very likely to more difficult to obtain and therefore, more costly natural gas. It is estimated that there is an additional 581 quads of undiscovered recoverable resources which could add another 26 years at the same use rate of 22 quads/year, bringing us to the year 2026. If we import 25% of the free world's proved and perspective reserves (Table 15), we would add another 16 years, leading us to the year 2042. The key assumption here is that we will <u>not</u> be increasing the rate of consumption of natural gas.

Table 15. World Consumption of Petroleum as of 1973
(in Quads)

	Consumption	Projected Annual Growth Rate (thru 1990)[b]
U.S.A.	32.3	2.4%
W. Europe	31.7[a]	0.3%
Japan	11.2[a]	2.8%
Rest of World (other than the Sino-Soviet Bloc)	23.2[a]	1.6%
Total	98.4 (16.4×10^9 bbl)	1.8% (average)
Sino-Soviet Bloc	20.0[a]	3.6%

a) United Nations data

b) Bureau of Mines forecast

Table 16. Free World Natural Gas Reserves (Meyerhoff)

	Proven & Perspective		
	B.O.E. x 10^6	Quads	
U.S.A.	37,324	224	($\approx$ 10 yrs at 22 q/yr)
Canada	3,600	22	
Latin America	4,234	25	
N. Africa	33,356	200	
Greater Europe	22,454	135	
Middle East	148,463	891	
Far East	15,569	93	
Non-U.S. (free world)	227,676	1,366	

$0.25 \times 227{,}676 \times 10^6 = 56{,}919 \times 10^6$ B.O.E. or 342 quads

$\approx$ 15.5 yrs at 22 quads/yr

Table 17. U.S. Recoverable Natural Gas Resources as of January 1975
(in trillion cu. ft.)

	Resources			Undiscovered Recoverable Resources
	Measured	Inferred	Total	
Onshore[a]	201.2	134.1	335.3	377
Offshore[a]	35.9	67.5	103.4	107
Total	237.1[b]	201.6	438.7	484
	(284 quads)	(242 quads)	(526 quads)	(581 quads)
	(13 years)[c]	(11 years)[c]	(24 years)[c]	(26 years)[c]

a) - includes Alaska

b) - The AGA estimated measured reserves is 228.2 x 10^{12} cu. ft. as of Dec. 31, 1975

c) - At a use rate of 22 quads/year

If we could limit our use of natural gas just for the household & commercial end-use sector plus that for non-fuel use in the industrial sector, then at a use rate of 10 quads/year, our total resources of some 1100 quads could last another 100 years.

6. Other Energy Resources Currently Being Used in the U.S.

As previously alluded, although our use of coal currently contributes about 19% of our total energy needs, our consumption of coal has increased only 3.9% overall from 1970 to 1975 (or less than an annual growth rate of 1%). Furthermore, about 66% of its overall consumption was for the electrical end-use sector, i.e., the use where the environmental standards have greatly restricted its growth.

Hydroelectric power provided about 4% of our total energy requirements (or 3.1 quads) and has been at about this figure (2.9 - 3.1 quads) since 1970. Geothermal is generally lumped in with this figure and represents a small fraction of the hydroelectric power.

Finally, nuclear-based electric power generation has increased steadily from 0.2 quads in 1970 to 1.65 quads in 1975, and constituted, as of 1975, 2.3% of our total energy requirements. The growth rate has been increasing but is still disappointingly slow. (It constituted only 8% of our electric power generation capacity in 1975).

7. Some Federal Agency Forecasts of U.S. Energy Requirements

Bureau of Mines/Interior. Their forecasts are shown in Table 18. Key assumptions here are:

1. Our overall energy consumption will increase 4.1%/year from 1975 to 1980, comparable to that from 1960-1970 but considerably greater than the 1.2% from 1970 - 1975.

2. Overall energy consumption is assumed to increase "only" 3.5%/year from 1980 to 1985.

3. U.S. petroleum consumption will increase at an annual rate of 4.6% from 1975 to 1980 which is closer to the growth rate of 4.9% from 1965 to 1970 than the 3.4% rate from 1970 to 1976.

4. On the other hand, from 1980 to 1985 the growth rate in the consumption of petroleum is assumed to be only 2.1%/year.

Table 18. Bureau of Mines/Interior Forecast of 1980 and 1985 Fuel/Energy Requirements (in Quads)

	1975 (actual)	1980	1985
Petroleum			
consumption	32.7	41[a]	45.6[b]
production	17.7	19 (by difference)	17.6 (by difference)
imports	15.0 (46%)	22[c] (54%)	28[c] (61%)
Natural gas	20.2	20.6	20.1
Coal	13.4 Δ = 3.8 q vs 0.5 for 1970-1975	17.2 5% annual growth vs 0.8% for 1970-5	21.3
Nuclear	1.7 Δ = 2.8 q vs 1.45 for 1970-5	4.5 21.5% annual growth rate	11.8
Hydro- & Geothermal	3.1 Δ = 0.7 q vs 0.7 for 1970-5	3.8	3.8
Oil Shale	0	0	0.9 (411,000 B/D crude)
Total	71.1	87.1[d]	103.5[e]
% Contribution by:			
petroleum	46.0	47.0	44.1
natural gas	28.4	23.7	19.4
coal	18.8	19.7	20.6
nuclear	2.4	5.2	11.4
hydro & geotherm.	4.4	4.4	3.7
oil shale	0	0	0.9

Footnotes for Table 18

a) Bureau of Mines assumes a 4.6% annual growth rate from 1975 to 1980

b) Bureau of Mines assumes a 2.1% annual growth rate from 1980 to 1985

c) Assumed annual growth rate is 4.9% comparable to that from 1970 to 1976

d) Bureau of Mines - 4.1% annual growth rate from 1975

e) Bureau of Mines - 3.5% annual growth rate from 1980

5. Assuming our imports will continue to increase at an annual rate of 4.9%, then our petroleum production would have to increase to 19 quads by 1980. Our imports, on the other hand, would continue to increase from 46% of our consumption in 1975 to 61% in 1985.

6. If we use the U.N. forecasts of the available petroleum imports to the U.S. in 1980 of 17.0 quads and in 1985 of 20.5 quads, and we assume U.S. production of petroleum is maintained at 17.7 quads per year in 1980 and 1985, then we would have a petroleum shortfall of 41.0 - (17 + 17.7) = 6.3 quads or 2.9 million bbl/day in 1980 and a shortfall of 45.6 - (20.5 + 17.7) = 7.4 quads or 3.4 million bbl/day in 1985.

7. Coal consumption will increase markedly from 1975 to 1980, corresponding to an increase of 3.8 quads - with a further increase of 4.1 quads from 1980 to 1985 - in spite of only a 0.5 quad increase from 1970 to 1975.

8. Nuclear will increase by 2.8 quads from 1975 to 1980, compared to 1.45 quads from 1970 to 1975, with a 7.3 quad increase from 1980 to 1985.

9. Shale oil crude will make its entry by 1985, corresponding to 0.9% of our overall energy requirements - or 411,000 B/D crude.

10. The overall contribution of oil and gas to our energy requirements will decrease from 74.4% in 1975 to 63.5% in 1985.

Federal Energy Administration. The key features of their forecast, shown in Table 19, are:

1. The total energy growth is more modest, though the % increase is greater from 1980 to 1985 than from 1975 to 1980 - which is still greater than the 1.2% from 1970 to 1975.

2. The increase in petroleum consumption is considerably smaller than the Bureau of Mines projection, viz., 1.7%/yr from 1975 to 1980, though the % annual increase from 1980 to 1985 is greater, viz. 2.8%/yr, than the Bureau of Mines figure of 2.1% for the latter period.

3. Petroleum production would steadily increase, assuming the United Nations' figures for imports. On the other hand, if it remained constant at 17.7 quads, there would

Table 19. FEA Forecast of 1980 and 1985 Fuel/Energy Requirements for the U.S. (in Quads)

	1975 (actual)	1980	1985
Petroleum			
consumption	32.7	35.6	40.9
production	17.7	18.6 (by diff.)	20.4 (by diff.)
imports	15.0 (46%)	17.0 (U.N.) (48%)	20.5 (U.N.) (50%)
Natural gas	20.2 $\Delta = 2.5$ q	22.7	24.2
Coal	13.4 $\Delta = 2.3$ q	15.7 (3.2% annual increase)	20.6 (5.6% annual increase)
Nuclear	1.7 $\Delta = 2.2$ q	3.9	8.7
Hydro- & Geothermal	3.1 $\Delta = 0.6$ q	3.7	3.9
Oil Shale	0	0	0.6 (274,000 B/D)
Total	71.1	81.6 (2.8% annual increase from 1975)	98.9 (3.9% annual increase from 1980)
% Contribution by:			
petroleum	46.0	43.6	41.4
natural gas	28.4	27.8	24.5
coal	18.8	19.2	20.8
nuclear	2.4	4.8	8.8
hydro & geotherm.	4.4	4.5	3.9
oil shale	0	0	0.6

be a shortfall of 0.9 quads of petroleum in 1980 and a shortfall of 2.7 quads or 1.2 million bbl/day in 1985.

4. Natural gas production & consumption would increase significantly - in contrast to the Bureau of Mines forecast.

5. Coal consumption would increase more slowly from 1975 to 1980 and then increase at a faster rate from 1980 to 1985.

6. Nuclear use would increase more slowly through 1985, being 3.1 quads less than the Bureau of Mines forecast for 1985.

7. Shale oil would make a somewhat more modest entry in 1985 than the Bureau of Mines forecast.

8. Except for the increased domestic production of petroleum & natural gas, the FEA forecasts are in general more conservative than the Bureau of Mines forecasts.

ERDA Goals. According to the recent "National Plan for Energy Research, Development, and Demonstration" it is stated that "the primary responsibility for bringing into use new technologies for energy conservation and expanding domestic energy production," ... and "for developing and bringing into use the technology needed to fulfill our energy needs" rests with the private sector. Accordingly, ERDA makes no forecasts on energy requirements and how these requirements will be met through its program in the official national plan for energy research, development, & demonstration. It does, however, indicate the potential impact in the year 2000 of "technologies now available" ... "in any scenario measured in terms of additional oil which would have to be marketed if the technology were not implemented." These figures are shown in Table 20. It is seen that coal and nuclear contribute the most but their total is still only 36.4%. If we add oil & gas, oil shale, synthetic fuels from coal, and the savings from improved transportation efficiency, industrial energy use, and conservation, we get an additional 40.8%. In volume 2 of its plan (reference 5), ERDA specifies objectives for some of the technologies - including specific energy targets. These are shown in Table 21. It is seen from these two tables that the technologies and fuel/energy options are manifold and highly diverse in contrast to current fuel/energy systems. A valid point that can be raised is whether we

Table 20. Maximum Impact in Year 2000 of Technologies now Available. ERDA 76-1. Reference 4.

	Quads	%
oil and gas	13.6	9.4
oil shale	7.3	5.1
geothermal	4.3	3.0
solar electric	3.1	2.1
breeder reactors	3.1	2.1
coal	24.5	17.0
waste materials to energy	4.9	3.4
gaseous & liquid fuels from coal	14.0	9.7
fuels from biomass	1.4	1.0
nuclear converter reactors	28.0	19.4
energy convers. efficiency	2.6	1.8
electric power transmission & distribution	1.4	1.0
solar-thermal	5.9	4.1
waste heat	4.9	3.4
electric transport	1.3	0.9
transportation efficiency	9.0	6.2
industrial energy efficiency	8.0	5.5
conservation in bldgs & consumer products	7.1	4.9
Total	144.4 quads	100%

Table 21. ERDA Projections for the Various Technologies ERDA 76-1. Reference 5. (in Quads)

	1985	2000
Synthetic liquid fuels from coal	0	3.8
SNG	0	6.8
Low Btu gas	0	1.8
Advanced power cycles	0	2 - 4
Coal combustion in place of oil and gas	0	6 - 8
Enhanced oil production	1	-
Enhanced gas production	1	-
Oil Shale	-	-
In-situ gasification	0	3 - 4
Solar thermal	0.3	4.3
Solar electric	.006-.018	2.1 - 4.2
Wind energy conversion	.018-.036	1.4 - 2.5
Biomass fuels	0.2	2 - 5
Geothermal	0.1	0.5 - 1
Total	2.62 - 2.65	33.7 - 45.4

can marshall the R&D and financial resources to develop and commercialize so many technologies.

8. End-Use Sectors

As mentioned above, our energy requirements in the foreseeable future through 1985 are literally locked to the import of petroleum (as crude and refined products) - unless we can come up with a more imaginative approach to this crucial problem. If we don't, the question that can be raised is whether we will simply have the financial resources to develop the longer range options such as indicated in the ERDA plans. It would seem to this writer that we should become more pragmatic in the selection of those "options" which can have a meaningful impact on our energy problem - especially in the near term. Along this view, since our costly imports are reflected largely by their useage, the petroleum/end-use sectors are then the key to our current energy problem. This is then followed in priority by our use of natural gas - which is the next fuel in short supply in this country.

Transportation End-Use Sector. Petroleum consumption here increased from 15.6 quads to 17.7 quads from 1970 to 1975 (or an increase of 13.5%), with a peak use of 18.0 quads in 1973 (Table 22). The 17.7 quads represents 96% of the energy consumed for this sector as petroleum (gasoline, diesel oil, and jet fuel), corresponding to 8.1 million bbl/day as crude. The increase of 13.5% more fuel (as crude) for this sector is considerably greater than the increase in our population during this period which was about 4% (or an increase of about 8.3 million people; U.S. census 1970 = 206.5 million; U.S. census 1975 = 214.8 million) (Table 23). This would certainly appear to be an area for decreased consumption via more efficient fuel use and other conservation measures, such as mass transit.

In addition to various conservation measures which are very much required here from a fuel economy standpoint as well as from an environmental standpoint, it is important for our nation to (1) increase its domestic production capability to retard exhorbitant import costs (Marshall, Chemtech, 1976), and (2) to displace the use of petroleum products such as distillate fuels and low sulfur fuel oil from the other end-use sectors,especially for electrical power generation, to this sector, so that a far greater fraction of our crude is converted to transportation fuels. This would be preferred from a national interest

TABLE 22. ENERGY CONSUMPTION IN TRANSPORTATION SECTOR

x 10^{15} Btu (Quads)

	1970	1971	1972	1973	1974	1975
Petroleum	15.6	16.2	17.1	18.0	17.6	17.7
Natural Gas	0.7	0.8	0.8	0.7	0.7	0.6
Electricity	0.016	0.017	0.017	0.015	0.019	0.019
Coal	0.008	0.006	0.004	0.003	0.002	0.001
Total	16.4	17.0	17.9	18.8	18.3	18.4

TABLE 23. U.S. POPULATION

Year	Population	Increase
1970	206.5 Million	–
1971	208.5	0.97%
1972	210.1	0.77
1973	211.6	0.75
1974	213.2	0.76
1975	214.8	0.75

standpoint for various reasons - especially for the immediate future, like until 1982, than the production of synthetic gasoline from coal (when subsidized by the Government). One can certainly foresee other alternatives, such as electric cars, but this is even further away in my view than synthetic gasoline from coal from a practical standpoint - even with the environmental problems associated with a synfuels industry.

Electrical End-Use Sector. The total energy consumed here increased from 16.2 to 20.1 quads (or 24%) from 1970 to 1975 (Table 24).

The fuel used here consisted of 3.3 quads of petroleum (1.5 million bbl/day), and 3.2 quads of natural gas (2.67 trillion cu. ft/yr or 7.3 billion cu. ft/day); the total petroleum and natural gas being 5.5 quads or 27% of the total energy required here (including hydropower, geothermal, and nuclear).

I believe it is important to (1) reduce and eventually eliminate the use of such premium hydrocarbons, as petroleum and natural gas, from this sector; (2) to accelerate the construction of nuclear-based electric power plants; and (3) to take up the "slack" - which should be quite significant via the use of coal, predicated on sensible environmental standards. This is especially important if we go over more and more to the use of electric power, as I believe we should, to meet the energy requirements in the other end-use sectors. In reference to environmental standards, I am not suggesting any blatant disregard of such standards - merely that we be very judicious in applying such standards across the board for every power plant. Consideration should be given to tailoring the emission standards to the plant sites in question and their prevailing meteorological conditions (H. C. Hottel, Chem. Eng. Prog., 1973; W. J. Coppoc, Chem. Eng. Prog., 1973).

The growth of nuclear-based electric power plants has been disappointingly slow, in my opinion, and should be markedly accelerated. I say this as a person who only 4 years ago had mixed feelings about the use of nuclear. It is now my view that it is important here from a national need standpoint, with all factors considered (safety, national security, environmental aspects, and cost), to have this end-use sector be based 100% on nuclear power as soon as possible. Simultaneously, the difference between total demand and

TABLE 24. ENERGY CONSUMPTION - ELECTRICAL SECTOR $\times 10^{15}$ Btu (Quads)

	1970	1971	1972	1973	1974	1975
Coal	7.3	7.3	7.8	8.6	8.5	8.8
Natural Gas	4.0	4.1	4.1	3.7	3.5	3.2
Petroleum	2.1	2.5	3.1	3.7	3.5	3.3
Hydropower	2.7	2.9	2.9	3.0	3.3	3.1
Nuclear	0.2	0.4	0.6	0.9	1.2	1.65
Total	16.2	17.3	18.6	19.8	20.0	20.1

output from nuclear should be based more on coal and less on petroleum and natural gas, which are premium hydrocarbon resources.

Household and Commercial Use Sector. We consumed here 13.6 quads of energy as natural gas, oil, and coal, or 19% of the total energy consumed; of which 7.5 quads was as natural gas (which was 55% of the energy for this sector) and 5.8 quads or 2.7 million bbl/day of petroleum (which was 43% of the energy for this sector) (Table 25). In other words, this sector was petroleum, as well as natural gas intensive.

It would be desirable to reduce the consumption of fuel oil for this sector by (1) shifting more to electrical heating based on coal-fired and nuclear-based electric power plants, and (2) shifting in the near term from petroleum fuels to natural gas - with, however, greater conservation measures across the board for space heating.

Industrial End-Use Sector. We consumed here for process heating and non-fuel uses, such as coke for steel and petrochemicals, 19.4 quads of energy or 27% of the total energy consumed; of which 9.3 quads or 48% was as natural gas, 5.8 quads or 30% as petroleum, and 4.3 quads or 22% was as coal (Table 26). The natural gas and oil requirements for fuel use amounted to 12.1 quads, made up of 20 billion cu. ft./day of natural gas and 1.6 million bbl/D of low sulfur fuel oil.

It would be desirable to back out the use of natural gas and oil here as fuels via, for example, increased conservation measures, e.g., more efficient combustion, use of coal as a fuel oil extender, and use of a synthetic fuel gas and/or low sulfur synthetic fuel oil from coal.

9. Meeting Our Energy Needs

In discussing this issue, I believe it should be treated in a sequential manner as follows:

1st, our immediate problem and possible solutions - through 1982,

2nd, the use of "swing" fuel/energy resources from 1980 and on, and finally

3rd, longer range solutions - encompassing the inexhaustible energy options - from 1990 and on.

TABLE 25. ENERGY CONSUMPTION - HOUSEHOLD & COMMERCIAL SECTOR

Quads (10^{15} Btu)

	1970	1971	1972	1973	1974	1975
Natural Gas	7.1	7.4	7.6	7.3	7.5	7.5
Petroleum	6.5	6.4	6.7	6.7	6.1	5.8
Coal	0.4	0.4	0.3	0.3	0.3	0.3
Electricity Distributed	3.0	3.2	3.5	3.7	3.7	3.8
Total	17.0	17.4	18.1	18.0	17.6	17.3

TABLE 26. ENERGY CONSUMPTION - INDUSTRIAL SECTOR
x 10^{15} Btu (or Quads)

	1970	1971	1972	1973	1974	1975[b]
Natural Gas	10.2 (9.5)[a]	10.6 (9.9)	10.6 (9.9)	10.1 (9.3)	10.3 (9.6)	9.3 (8.6)
Petroleum	5.3 (3.3)	5.2 (3.2)	5.8 (3.5)	6.2 (3.8)	6.1 (3.7)	5.8 (3.5)
Coal	5.0 (4.9)	4.3 (4.2)	4.2 (4.1)	4.3 (4.2)	4.3 (4.2)	4.3 (4.2)
Electricity Purchased	2.2	2.3	2.5	2.6	2.7	2.7
Total	22.6 (19.8)	22.4 (19.6)	23.1 (20.0)	23.3 (20.0)	23.4 (20.2)	22.1 (19.0)

a — ( ) as fuel

b — preliminary figures

In order to address this issue in definitive terms, it is obviously important to develop specific targets for specific times or dates. This can be based on current fuel/energy uses and projecting these to future dates based on previous increases in the rate of energy consumption, production, and imports for petroleum, natural gas, coal, nuclear, hydro- and geothermal power, as more or less shown in Table 18 and to a lesser extent in Table 19. This approach is essentially equivalent to a laissez-faire policy of our government in the area of energy, as was the case for the water problem in the arid part of the U.S.A. and the national desalination research program - in spite of the prestigous report & recommendations by the National Academy of Sciences - National Research Council (Reference 9). A somewhat different view, which I favor, is that in such a vitally important area as energy, which is of national importance, it is up to our government to formulate, promote, and <u>implement</u> a national energy policy - including full scale commercialization. The underlying premise of such an approach is that if this area had real economic incentive private industry would do it alone. Since it does not, because of the high business risk and capital costs, then in view of the national need here the Federal government must assume responsibility for seeing to it that the vital needs here for our nation are met. The role of private industry is then the vehicle by means of which the Federal government's responsibility is carried out. Taxpayers' money should be spent with the same care, if not greater, then private industry spends corporate funds of its stockholders. This does not negate longer range research. It merely places it in an order of national priority relevant to the overall near and longer range problem with the judicious selection of even the longer range approaches which should be expected to have a "payout."

The first hurdle we must overcome is the difference between what we consume and what we produce; in other words, our current major dependence on foreign oil. This should be our <u>initial</u> goal in our national energy policy. It does <u>not</u> mean doing away with all imports. It does mean, however, that our nation must shoulder a greater responsibility for self-reliance in such a critical area as energy for our well-being as well as for the world.

In projecting our energy requirements for 1980 and 1985, it is important to first note that the actual % annual increase in energy consumption was <u>1.2%</u> during 1970-1975 (Table 27). This projects out to a requirement of 76 quads for 1980 and 81 quads in 1985. If we <u>increase</u> our domestic

TABLE 27. U.S. ENERGY CONSUMPTION & CHANGES IN THE RATE OF INCREASE

Year	Amount (Quads)	% Annual Increase (During 5 Year Period)
1960	44.6	—
1965	53.3	3.7
1970	67.1	4.7
1975	71.3	1.2

production capability of petroleum by 1980 to the 1970 level of 19.8 quads (corresponding to a 2.25% annual increase from 1975 to 1980), and we reduce our total petroleum needs to 25.5 quads (corresponding to about 4.5% decrease per year from 1975 to 1980) our required imports would drop to 5.7 quads or 2.6 million bbl/D. The numbers shown in Table 28 are based on these and other assumptions, which I believe are not unreasonable, to indicate a desired target for our fuel/energy consumption needs by end-use sector. What is obviously required is such a definitive goal arrived at by due consultation with the private sector (oil companies, utilities, et al), state governments, and an appropriately designated federal steering committee - which may be akin to the Petroleum Administration for War during the early 40's.

Specific approaches aimed alleviating the immediate near term problem and thereby providing time for the introduction of the newer energy options in a more cost effective manner are, as summarized in Table 29, as follows:

1. Increase domestic production capability of crude oil to 19.8 quads or greater by 1980 via various incentives to do so - coupled possibly with disincentives for imports. This goal, I believe, is extremely important from a logistic supply/national security standpoint - without which we may not have the financial resources to implement the newer and longer lasting fuel/energy options such as synthetic fuels, solar, and nuclear fusion. Hopefully, we could begin to reduce at an increasing rate our production of crude by 1982 as we accelerate the implementation of the swing fuel/energy options based primarily on the direct utilization of coal and synthetic fuels, coupled with conservation measures.

2. Introduce various measures for conserving petroleum in all end-use sectors.

3. Initiate phase-out of use of oil and gas in electrical sector.

4. Extend use of oil via coal/oil slurries for process heating in industrial sector and where possible for electric power generation.

5. Initiate greater use of electricity for household and commercial sector to displace oil and where possible, gas.

6. Increase electric power generating capacity via coal and nuclear.

TABLE 28. A TARGET FUEL/ENERGY USE PATTERN FOR 1980
(in Quads)

	Household and Commercial		Industrial		Electrical		Transportation		Total	
	1975	1980	1975	1980	1975	1980	1975	1980	1975	1980
Petroleum	5.8	3.9	5.8	4.5	3.3	1.6	17.7	15.5	32.6	25.5
Natural Gas	7.5	7.0	9.3	8.7	3.2	1.6	0.6	0.6	20.6	17.9
Coal	0.3	1.3	4.3	6.0	8.8	11.4	0.001	0.001	13.4	18.7
Electricity Distributed/ Purchased	(3.8)	(4.8)	(2.7)	(3.2)	–	–	(0.019)	(0.2)		
Nuclear	–	–			1.65	4.5	–	–	1.65	4.5
Hydropower and Geothermal	–	–			3.1	3.8	–	–	3.1	3.8
Total	13.6	12.2	19.4	19.2	20.1	22.9	18.3	16.1	71.4	70.4

Table 29. <u>Approaches Relevant to Immediate Problem</u>

- Increase domestic production of crude oil
- Conserve petroleum in all end-use sectors
- Phase out use of oil and gas in electrical sector
- Extend use of oil via coal/oil slurries for industrial & electrical sectors
- Increase use of electricity for household & commercial sector to displace oil & where possible, gas
- Increase electric power generating capacity via coal & nuclear

In reference to the second measure, we must make a concerted effort to reduce our petroleum consumption in all end use sectors, including that for the transportation sector which currently consumes 54.3% of our total petroleum needs. For this purpose, we should carefully review the emission standards to see how realistic they are. Ultimately, I would hope we go over to electric cars - but we may not get the chance to do so if we spend all our financial resources at one time on all the fine things we want - including an illusionary pristine environment. The word "illusionary" is used within the context that one cannot produce or consume a fuel without some undesirable effect on the environment. The environmental impact will also be greater, as the amount and rate of fuel production and consumption is increased - which is in essence a manifestation of the second law of thermodynamics and the basis of irreversible thermodynamics (Fig. 1).

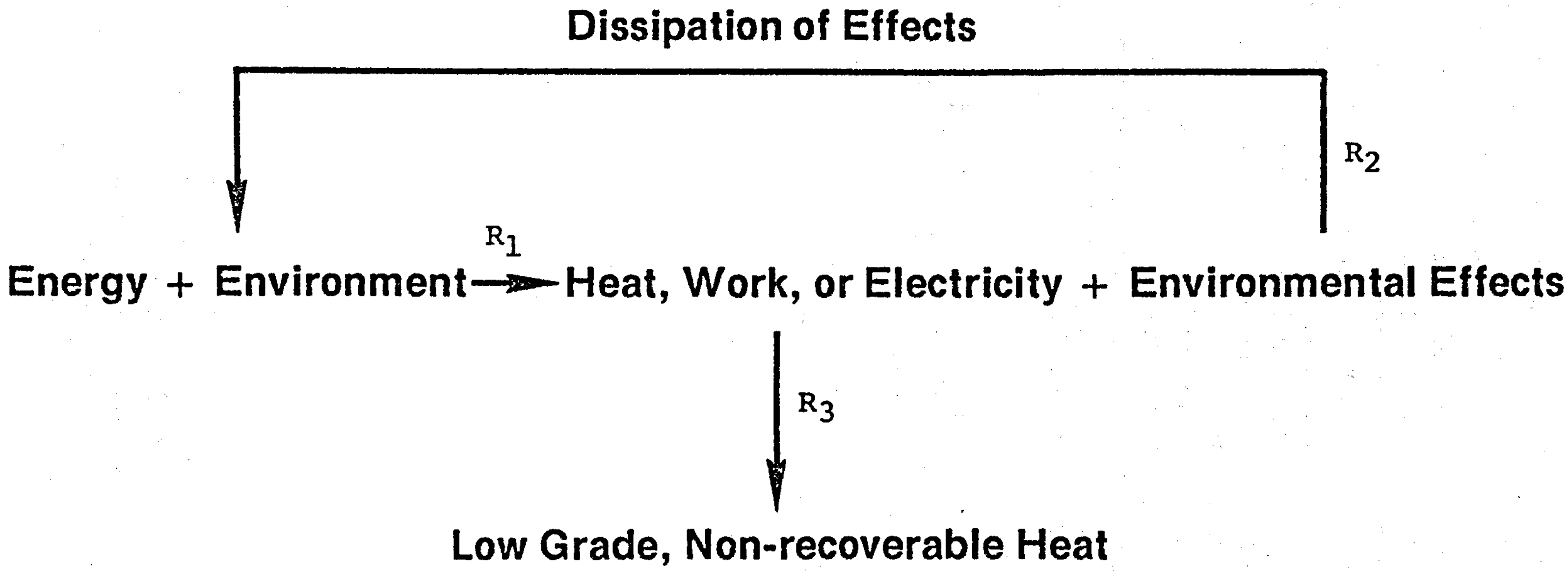
The next timeframe starting in the vicinity of 1980, which may be referred to as the "swing" fuel/energy era, would permit us to reduce our petroleum imports still further, and gradually phase us into the longer lasting ans so-called permanent energy systems, viz., solar and nuclear fusion. The latter would be aimed at restricting our use of such premium hydrocarbon resources as petroleum, natural gas, and eventually coal for non-fuel uses, such as petrochemicals, medicinals, plastics, fibers, lubricants, etc. I will not discuss here the longer term energy options, with the exception of synthetic fuels which, I believe, could and should enter the picture significantly by the mid 80's.

Before embarking on a discussion of the role of coal, a few additional words appear in order in reference to our need for increased petroleum production, as well as a few words relating to natural gas production and useage.

10. Petroleum and Natural Gas Needs

From a short or near term standpoint, viz., 1977-1982, there is an urgent need for increasing markedly the production of petroleum in the U.S. Appropriate incentives for doing so and/or disincentives for imports are urgently required from the standpoint of (1) national security, (2) to greatly decrease our vulnerability to international blackmail, via, for example, oil embargos, and (3) to begin to move away from the highly inflationary and costly tax depletions our nation suffers because of out critical dependence on foreign oil.

Fig. 1. Interaction of Energy and the Environment



R_1, R_2, and R_3 are the rates of the respective processes. As R_1 increases, R_2 will decrease and R_3 will increase, based on entropy considerations.

In reference to our import of oil, it has been pointed out that we will be faced with a "mammoth and dangerous pollution problem or face very high costs for the prevention and cleanup of (such) coastal pollution" (10). It has been documented that 95% of the spillage of oil by man results from the overall tankerage operation - with minimal spillage occurring from blowouts from offshore wells. Such environmental problems of potential disastrous ecological effects may well dwarf our current concerns over emissions from various domestic energy producing and consuming sources.

As discussed above, we appear to be somewhat better off in the case of our natural gas resources. However, we are still talking here of a decade or two relative to petroleum. Based on our current useage rate - which appears to have tapered off - it appears from a conservation standpoint that our current production rate is more than adequate. In each case, i.e., for petroleum and natural gas, what is urgently needed are conservation measures in their use or in particular for what they are being used for.

The research needs here relate to:

1. more efficient utilization of natural gas for residential heating;

2. more efficient use of gasoline in engines. This requires careful re-examination of the tail pipe emission standards and their validity (including the need for reducing or eliminating the use of TEL in gasoline) vis-a-vis the net effect on the environment, after considering the various tradeoffs associated with the use of catalytic converters and "lead-free" gasoline. A primary objective should be to reduce the number of cars and energy consumption/capita here rather than to seek methods (which are invariably inefficient, very costly, and even of questionable net environmental benefit) to enable the use of more automobiles per capita and greater gasoline consumption/person; and

3. enhanced recovery of petroleum. This is an area which industry can pretty well handle by itself, given the right motivation.

I would now like to discuss some major considerations associated with (a) the direct utilization of coal and (b) conversion of coal and oil shale to synthetic fuels - which comprise in conjunction with the increased use of nuclear (fission) for electric power generation our major swing fuel/energy options. This does not mean to say that solar thermal cannot make a significant contribution in this mid timeframe via solar heating especially in the sunnier, more spacious regions of our country like the deep south, and western part of the country.

11. Role of Coal

Resource Base. It is estimated by the Bureau of Mines that the U.S. has 437 billion tons of demonstrated (measured and indicated) reserves, equivalent to 10,020 quads (average Btu/lb = 11,500). Approximately 199 billion tons have a sulfur content < 1% (with about 80% of this located west of the Mississippi River) Table 30. Of the 437 billion tons, 203 billion tons are east of the Mississippi River, and 234 billion tons are west of the Mississippi River. Approximately one-half of the coal west of the Mississippi would be surface mined. Essentially all (195 billion tons) of the sub-bituminous coal and lignite is located west of the Mississippi River (Table 31).

Assuming 50% recoverability, this resource would last 250 years at a useage rate of 20 quads/year. At a useage rate of 40 quads/yr, the resource would last 125 years. It is thus a viable energy resource for maximum effective utilization for at least the next 50 years. In other words, at a fifty-fifty split between nuclear and coal to meet all of our energy needs (via direct combustion and conversion to synthetic fuels in place of natural gas and petroleum), it could take care of us for the next 50 years at an average total energy consumption of 80 quads/yr (split equally between coal and nuclear). Our energy needs will no doubt be considerably greater than 80 quads/year fifty years from now, but other energy sources such as solar should also contribute significantly by then. Hopefully, nuclear fusion will also be with us by then and coal can then be used primarily as a chemical feedstock.

Overview on the Role of Coal. As I see it, the role of coal should be as follows:

1. to continue its current role throughout all end-use sectors, including, for example, production of coke for steel manufacture plus coal tar-derived chemicals,

2. increased use as such for electric power generation and in the form of coal/oil slurries, where possible, to extend the use of oil in this sector,

TABLE 30. DEMONSTRATED U.S. COAL RESERVES BY SULFUR CONTENT

(billion (short) tons)

	<1% S	1–3% S	>3% S	Unknown	Total
Underground Mining	126	60	74	40	300
Surface Mining	73	34	19	11	137
Total	199	94	93	51	437*

*Equivalent to 10,020 Quads

TABLE 31. DEMONSTRATED U.S. COAL RESERVES BY COAL TYPE

(billion tons)

	Anthracite	Bituminous	Subbituminous	Lignite	Total
Surface	0	41	68	28	137
Underground	7	193	100	0	300
Total	7	234	168	28	437

3. as a feedstock for the production of substitite (synthetic) fuels to supplement and displace natural gas and especially petroleum - which may be considered as premium raw materials for use in the production of petro-chemicals - until the "permanent" energy sources, viz., solar and nuclear (especially fusion) provide sufficiently cheap electric power for use in all end-use sectors, except where carbon is needed as a raw material, and

4. eventual use as a primary feedstock for chemicals, including coke.

Assuming the use of nuclear for electric power generation is greatly accelerated - as it must be - then the use of coal for electric power generation would peak before the turn of the century, hopefully by 1985 or 1990 at the latest, and its primary use could be devoted to synthetic fuels.

In the interim, synthetic fuel gas (~300 Btu/cu. ft) from coal for process heating and possibly low sulfur synthetic boiler fuels from coal could begin to make a significant contribution by 1985, like 1-2 quads (or 10-20 plants, each equivalent to 50,000 bbl/D low sulfur fuel oil or 825 million cu. ft/day of intermediate Btu fuel gas (300 Btu/cu. ft), requiring 15,000 T/D of coal/plant or 55-110 million tons/year of coal = 1.5-3.0 quads of coal), if construction of these plants could be underway by 1978.

Substitute natural gas (SNG) from coal and distillate fuels (including synthetic gasoline) from coal and possibly from oil shale could begin to make a similar contribution by 1990, if plant construction was initiated by 1981 or 1982.

Synthetic fuel plants capable of providing a variable slate of readily marketable products ranging from fuel gas, SNG, a liquid boiler fuel, and distillate fuels for transportation, whose mix could be varied by season and need, would offer a desirable flexibility, high on-stream factor, and possibly the best overall economics. The construction of such plants, instead of the above single product plants, would obviously have to be seriously considered. It is my personal view that we can and should move forward aggressively in this mode as soon as possible, so that the entire product slate mentioned above could make a significant contribution to our energy needs, especially for the transportation sector, by 1985. Geography obviously plays a role but I believe it is preferable, and in the long run more economical, to be able to transport such synthetic fuels across our country than from some country half way around the world.

12. Direct Utilization

Direct utilization by combustion provides the most efficient utilization of coal for energy production. The major problem here has been one of environmental constraints ranging from its mining to combustion.

Specific needs and approaches to increasing the direct utilization of coal, listed in what I consider to be of decreasing importance in meeting our energy needs are, as summarized in Table 32, as follows:

1. Modification of stack gas emission standards based on factual evidence for the site in question to permit increased use of coal, plus research to define the longer term effects of emissions, under various realistic conditions, on man, plant life, etc.

2. Use of coal/oil slurries in pumpable form for process heating; research to define conditions for use and effectiveness.

3. Increased production of coal plus development of more efficient and environmentally acceptable methods of mining, e.g., hydraulic mining.

4. Development of more efficient & economical methods for transporting coal from mine site to power plant, e.g., coal/water slurry pipelines.

5. More extensive use of Western low sulfur coals.

6. Blending of low sulfur coals with high sulfur coals to reduce the sulfur content to an acceptable level, where needed.

7. Drying of lignite (which contains 35-40% moisture) down to 5-10% moisture to make its transportation costs/Btu more attractive.

8. Development of more efficient, economical, and environmentally acceptable coal preparation/beneficiation processes to reduce the pyritic sulfur from high sulfur coals to a more acceptable level.

Stack gas cleanup is confronted at present with a major problem associated with the disposal of the aqueous wastes, containing for example, calcium sulfate and flyash, which

TABLE 32. **DIRECT UTILIZATION OF COAL-NEEDS & APPROACHES**

- Modification of Stack Gas Emission Standards
- Use of Coal/Oil Slurries
- Increased Production of Coal
- More Efficient Transportation of Coal
- Western Low Sulfur Coals
- Blending Low and High Sulfur Coals
- Drying of Lignite for Transportation
- More Effective Coal Preparation/Beneficiation Processes

limits its wide-spread use. Regenerative processes, such as based on the use of ammonium sulfite, with the production of a more concentrated SO_2 gaseous effluent, which can be reduced to elemental sulfur, appears to overcome the calcium sulfate disposal problem but is more complex and of questionable reliability. Such processes are also not conducive to the most efficient operation of a power plant. In either case, a key feature, at present, of the use of coal for power plants, is that such plants can be constructed roughly twice as fast as a nuclear-based plant of equivalent electrical power output, for example, in 4-5 years vs. 6-8 years.

Fluidized-bed combustion involving the use of limestone or limestone/dolomite as a scavenger for the SO_2 is still unproven from a practical standpoint. It offers the advantages of higher heat transfer rates, smaller size, lower NO_x emissions, and the output of a dry solid waste. The disadvantages are the higher cost of such equipment (compared to conventional boilers), fouling of the heat transfer tubes contained within the fluid-bed combustor with reduced heat transfer and operational upsets, probable erosion and corrosion of these heat transfer tubes, and the unresolved problem associated with the disposal of the $CaSO_4/MgSO_4$/ash wastes. It is therefore questionable whether this technology as presently known will be viable.

It is apparent that where water is scarce and it is required in conjunction with the coal mining, beneficiation, and conveyance, or where a water or land resource may be severely affected, then water availability will be a major limiting factor. This should not be viewed, however, in every instance, as an insurmountable problem. Effective water management should be employed regardless of whether water is relatively scarce or in abundant supply.

13. <u>Synthetic Fuels from Coal and Oil Shale</u>

This can be broken down simply into three areas, viz.,

1. in-situ gasification of coal,

2. synthetic fuels from coal, and

3. liquid fuels, especially JP-3 jet fuel, from oil shale.

In-situ gasification, although well known, still offers the challenge for very high production rates of a fuel gas at relatively low capital cost. There are here also potential environmental problems. In brief, a strong R&D program is currently being supported in this area by ERDA-Fossil Energy, with demonstration tests currently underway. It is still too early to forecast the outcome of this work.

In reference to the second topic, coal conversion will eventually be needed for chemical feedstocks, specifically C_2-C_4 hydrocarbons and BTX's, which provide the basis of the modern petrochemical/chemical industry. From a shorter term standpoint, e.g., by 1980, we should aggressively pursue the commercialization of those synthetic fuels which can displace petroleum and to a lesser extent natural gas, with minimum economic impact. These would appear to be an intermediate Btu fuel gas (~300 Btu/cu ft) and a No. 4 fuel oil, each for process heating.

In the selection of a process for a synthetic fuel, it is imperative to consider the fate of the gas, liquid, and solid waste process streams, including aqueous streams, and fugitive emissions in the design of the overall process. The case of stack gas cleanup and fluid-bed combustion are examples of processes which were not adequately considered from an overall systems standpoint. The transfer of SO_2 from a gaseous emission - which may be rapidly dissipated to a harmless concentration at ground level - to an aqueous or solid waste such as $CaSO_4$ and/or $MgSO_4$ plus coal ash still results in an undesirable to troublesome problem which may very well be more serious than the SO_2 emissions problem - from the standpoint of overall persistence, dissemination, and progressively increasing contamination of our water and food-chain resources, specifically in terms of land management, our water resources and contamination thereof, agriculture (from the undesired waste water runoff or drainage), and marine life. Accordingly, the conversion process of choice should involve nothing but steam/air/or hydrogen, in conjunction with the coal. All other materials, such as catalysts, acid gas cleanup absorbents, etc., should be continually recycled within the overall process.

In reference to the processes themselves, they may be considered in terms of whether they have already been carried out on a large scale, such as gasification via the McDowell-Wellmann or Lurgi counterflow moving bed processes, Babcock & Wilcox or K/T entrained flow gasification, SASOL Fischer-Tropsch, or Bergius direct liquefaction (referred to as 1st generation processes); at a developmental pilot plant scale, such as the HYGAS, CO_2-Acceptor, Synthane, Texaco partial oxidation entrained flow, COGAS, or the BIGAS gasification processes - all of which are higher throughput or have other improved features over the 1st generation processes, or in the case of liquefaction the COED, Consol CSF, SRC, Gulf CCL, SRC-II, H-Coal, Synthoil, or Exxon's H-Donor Solvent process; or finally the so-called 3rd generation advanced processes which are at the bench scale of R&D, such as Exxon's catalytic gasification process, flash hydropyrolysis, zinc chloride hydrocracking process, or Mobil's methanol to high octane gasoline process. The latter processes and others still in the research stage offer the opportunity of considerably higher throughput rates, smaller plants, higher efficiencies, and lower capital costs.

The synthetic fuels and processes listed in order of need and readiness for immediate to near future commercialization are as follows:

1. Intermediate Btu fuel gas and SNG

Each of these products could be used to displace natural gas for process heating or fuel oil for new or increased capacity industrial processes. Specific synthetic gaseous fuel processes here include:

a. McDowell-Wellman or Lurgi counterflow moving bed process,

b. Babcock & Wilcox or Texaco partial oxidation entrained upflow processes, and

c. K/T atmospheric pressure tangential entrained flow process.

In general, the thermal efficiencies range from 65-80% with a 250×10^9 Btu/day plant ($\sim$ 0.1 quad/yr) costing about $1 billion. This means that if we are to supply about 4 quads of a synthetic fuel gas for the industrial sector by say 1985, which may represent about 50% of the requirements, we would need 40 such plants costing $40 billion. This would, in turn, conserve 4 quads of natural gas and/or low sulfur fuel oil from petroleum.

2. Low sulfur fuel oil, intermediate Btu fuel gas, and electric power

A plant capable of producing these products would be the FMC COED-based pyrolysis complex. The basic liquefaction process involves a temperature-staged fluid bed carbonization of coal at atmospheric pressure and temperatures ranging from 600°F in the 1st stage to 1500°F in the final 4th char combustion stage (to provide the heat for the process, to produce about 1.3 bbl of low sulfur fuel oil (comparable to a No. 4 fuel oil) per ton of ROM coal (after mild hydrodesulfurization of the pyrolysis syncrude oil), 9000 cu. ft of an intermediate Btu fuel gas (of about 650 Btu/cu.ft) per ton of coal, and about 0.55 tons of char per ton of coal. The char would be gasified to supply (a) the hydrogen for hydrodesulfurization of the syncrude oil, and (b) intermediate Btu gas for process heating and for electric power generation. Predicted thermal efficiency for the process portion of the plant is estimated at 58% for the production of the syncrude and clean fuel gases as feed to electrical power generation. Thus, a 25,000 T/D plant could produce about 30,000 B/D of low sulfur fuel oil plus about 850 MW of electric power at an estimated fixed capital cost of about $1.3 billion, with the fuel oil priced at $6/bbl and power at 4¢ per kilowatt-hr (kwhr) to break even (zero discounted cash flow rate of return (DCF)) (Ref. 11). Such a process which produces a char in excess of that needed for the production of hydrogen, fuel gas, and/or electrical power for the plant to be self-sufficient, and where the char offers only a marginal economic incentive as a boiler fuel feedstock versus the starting coal itself, is at an obvious disadvantage in competing with a process that is otherwise comparable in economics but does not have this requisite marketing burden. However, this process could be implemented now to produce a synthetic fuel oil as a substitute for a petroleum-derived fuel oil. For the case of financing by a 65/35 debt-equity ratio, with interest at 9%, and to yield a 12% DCF, the required selling price for the fuel oil would be $35/bbl, with across the fence power export priced at 4¢/kwhr. However, the requirement for a DCF above zero can be seriously questioned for a plant and operation fully subsidized by the government. To produce 5 quads/year of such a low sulfur fuel oil for the industrial sector, as well as 5.6 quads of electric power, we would require 75 such plants at an overall capital cost of about $98 billion.

3. Low sulfur, solid boiler fuel-solvent refined coal (SRC)

The SRC process of the Pittsburg & Midway Coal Mining Co. (PAMCO), now owned by Gulf Oil, which has been successfully piloted at a scale of 40 T/D at Tacoma, Washington, produces about 4 barrel oil equivalents (BOE) of solvent refined coal ($\sim$ 75% yield), roughly equivalent to a No. 6 fuel oil, per ton of coal (Kentucky coal No. 9, H/C ratio $\approx$ 0.85). The SRC has a heating value of 16,000 Btu/lb, m.p. ~ 350°F (with dec.), contains <0.1%, <0.8% sulfur, and has a H/C ratio of about 0.80. The process involves a relatively mild hydroextraction of coal at 725 - 780°F, 1500 psig hydrogen, and consumes about 2% hydrogen by weight of the coal (MF basis, high volatile B bituminous) primarily for hydrocracking, hydrodesulfurization, and deoxygenation. Some light liquids (H/C ~ 1.3) and methane are also produced which account for the hydrogen consumption. (Ref. 12).

To produce 5 quads of such a low sulfur, solid boiler fuel, we would require 19 plants, each 30,000 T/D coal feed rate; at a cost of roughly $19 billion. Based on mid 1973 prices, the projected selling price was approximately $1.25/million Btu or $7.50/BOE - based on a 12% DCF, a debt-equity ratio of 75/25, an interest rate of 9%, and $7.25 coal price/ton (Ref. 13).

4. Low sulfur fuel oil or liquid syncrude feedstock

The SRC-II process, also of Gulf Oil, which will be run in the 40 T/D pilot plant at Tacoma, after some modifications - scheduled for February 1977, involves hydroliquefaction of coal in one step at 750 - 800°F/2000 psi hydrogen to produce directly a distillate product comprised of a naphtha cut and No. 2 to 6 fuel oils. All gas products are consumed in the plant as fuel and/or for production of hydrogen. Vacuum bottoms from the liquefaction stage are recycled in part and, in part, withdrawn with the ash, which may be coked to produce additional syncrude, some gas, and coke. The latter may be gasified to produce fuel gas for the process and/or syngas for hydrogen production for the process. Approximately 4% hydrogen is consumed by weight of the coal (MF basis), with about 3.5 - 4 bbl of liquid fuel produced overall per ton of coal (MAF basis). The estimated capital cost is $11,000 per daily barrel, or for a 100,000 bbl/D plant, the overall capital cost (exclusive of the mine) would be $1.1 billion (Ref. 14). The estimated price of the liquid fuel is $2.00/million Btu or $12/bbl at a 0% DCF. At a 12% DCF, 65/35 debt/equity ratio at 9% interest, the estimated selling price would have to be $3.30/million Btu or $19.80/bbl (Ref. 11).

For 5 quads of this fuel, one would require 23 such plants at a cost of $25 billion.

Two other processes which should be mentioned here are the H-Coal process, operated in the syncrude mode, and the Exxon Donor Solvent (EDS) process. The latter resembles, in part, the Consol CSF process except that it is operated at higher hydrogen pressures and produces a distillate fuel oil rather than a non-distillate "extract" type fuel oil (which requires less hydrogen than the EDS process). In the case of the non-distillate extract-type boiler fuels, a major effort is curently underway to develop a more economical process than rotary drum filtration for separation of the pyrite-containing ash; major effort being focused on solvent precipitation/ash agglomeration and on elevated temperature/pressure solvent extraction processes. Scaleup of the H-Coal process from 2 T/D to 600 T/D and of the EDS process from 1 T/D to 250 T/D are currently planned. They appear, therefore, considerably down the road than the SRC-II process, and the bottom line regarding their economic incentive is, therefore, not yet clear.

5. Gasoline and distillate fuel coproduct processes

a. Refining of SRC-II Syncrude

It has been estimated (Ref. 15) that the syncrude from this process or related processes, such as the Consol CSF or Exxon Donor Solvent process, could be refined by essentially conventional petroleum refining technology to yield 3.4 bbl of 100 RO gasoline per ton of MAF coal at a capital cost of $7000 per daily barrel. On this basis, the estimated overall capital cost for producing 100 RO gasoline from coal via the SRC-II process would be roughly $18,000 per daily barrel. It is assumed that the refining could be carried out in a fixed bed mode, involving three unit processes, (1) hydrotreating to remove residual sulfur and nitrogen, (2) hydrocracking to naphtha, and (3) mild catalytic reforming of the hydrocracker naphtha. Most or all of the hydrogen requirements would be obtained by steam reforming of the byproduct gas. It was also assumed that the coal extract feed contained only 7% by weight of hydrogen - which appears to be on the low side for the SRC-II syncrude. Thus, the hydrogen requirements may be less than assumed for conversion of such a syncrude to synthetic gasoline.

To provide 10 quads of gasoline in this mode by 1990, which - with a dedicated conservation effort initiated in the late 70's - could represent as much as 80% of our motor fuel requirements in 1990, we would require 50 (fifty) such plants at a total capital cost of $90 billion (in 1976 dollars). This cost would obviously increase by 1990, with inflation, according to the degree of our imports, etc.

b. Indirect Liquefaction

The 2nd type process involves indirect liquefaction, entailing gasification of coal to produce synthesis gas, followed by its conversion in one or more steps to hydrocarbon liquids. Three cases are worth citing here.

1st - The SASOL Fischer-Tropsch (F/T) plant in South Africa. The most recent version of this process, referred to as the SASOL-II process, incorporates "Synthol" reactors, involving fluidized bed catalytic conversion of synthesis gas to liquid products. This plant is designed to produce 50,000 bbl/D of refined liquids at a total capital cost of about $1.8 billion (Ref. 16).

In a preliminary economic estimate made in 1973, for a process to produce 100,000 bbl per day of fuel oil plus 1.7 billion cu. ft/day of SNG from 137,500 T/day of high sulfur coal, the capital cost was estimated at $3.8 billion or roughly $10,000 per BOE (Ref. 17). The estimated selling price was $1.40/million Btu at 0% DCF or $2.35/million Btu at a 12% DCF, 65/35 debt/equity financing at 9% interest.

2nd - Recent work done at Mobil R&D, supported largely by ERDA, has shown that unfractionated or crude methanol can be essentially quantitatively converted, via a proprietary zeolite catalyst, to produce directly hydrocarbons, comprised of 4% LPG and 96% of C_5^+ gasoline, 92-94 RON. It has been estimated that the capital cost for a plant starting with coal to produce gasoline in this mode (via gasification to syngas, conversion to methanol, and conversion of the latter to gasoline) would run about $27,000 per daily barrel (Ref. 18). A 50,000 bbl/D plant starting with coal would thus cost about $1.4 billion. This compares favorably with the SASOL-II process, neglecting byproduct credit from the latter. On a Btu basis, on the other hand, it does not appear as attractive as the coproduct case involving fuel oil and SNG.

3rd - A more recent conceptual design of an advanced Fischer-Tropsch process by Ralph M. Parsons Company (Ref. 19) incorporates an entrained flow gasifier operating at elevated pressure, such as the BIGAS gasifier; extended catalyst surface reactors (Ref. 20), with efficient heat transfer and utilization for the F/T and methanation unit processes; and recovery of the heats of reaction as high temperature steam to drive the compressors for the oxygen plant and for electric power generation. The proposed process would produce SNG, synthetic liquids (including gasoline), and electric power. The overall yield would be about 3.3 barrel-oil -equivalent of crude oil per ton of coal, comprised of LPG, naphtha, diesel fuel, fuel oil, and oxygenates. The overall thermal efficiency of the process would be about 70% (vs about 56% for the SASOL-I plant). The capital cost per daily BOE is estimated at $20,400, with a 30,000 T/D coal conversion plant producing 50,000 B/D of liquid products, 260×10^6 cu.ft/D of SNG, and 140 Mw of electric power for sale, estimated to cost $1.7 billion.

In summary, it would appear from these preliminary estimates that the direct liquefaction route to gasoline, such as via the SRC-II process, offers the most potential. However, the Fischer-Tropsch variations offer nearer term potential. Further, the Mobil methanol route and Parson's advanced F/T complex appear to offer significant cost advantages vs the SASOL plants. The relative economic incentives of these newer indirect liquefaction processes are not entirely clear and require a more careful comparative evaluation, including a sensitivity analysis to scaleup.

Conversion of Oil Shale to Syncrude, Liquid Boiler Fuel, and Distillate Fuels

Fifteen to 33 gal of a black syncrude per ton of oil shale can be obtained by pyrolysis of various oil shales (0.36 - 0.78 bbl/T of oil shale). Retorting of the oil shale is carried out at about 900°F, requiring a heat input of about 300 Btu/lb of shale, to produce the syncrude shale oil which has a H/C ratio of about 1.6. Perhaps the best example of this process is the TOSCO II process which has been field tested in a 1000 ton/day semiworks plant located near Grand Valley, Colorado (Ref. 21). The syncrude contains some particulate matter which must be removed prior to fixed bed hydrofining. Nitrogen removal constitutes a prime problem associated with the processing of shale oil but it appears that this can be decreased to acceptable levels for hydrocracking and hydroforming, by catalytic hydrotreating in two stages which simultaneously reduces the sulfur content, which may run close to 1%; reduces aromatics - especially in the form of heterocyclic nitrogen compounds (where the nitrogen may be about 2%); raises its API gravity; and lowers its pour point. Thus, a Parahoe shale oil has been hydrotreated in a single stage to reduce the nitrogen content from about 2% to less than 1000 ppm (95% removal) to produce an odorless yellow oil which should be suitable for direct use as a bunker fuel oil or conventional refining to distillate fuels, ranging from light distillates, synthetic gasoline, and/or JP-3 jet fuel (Ref. 22).

The principal problem has been in the mining of the oil shale in an environmentally acceptable manner. Pyrolytic retorting of the latter (above ground), besides producing the syncrude, produces a voluminous residue which is considerably greater in volume than the original oil shale removed from the ground. Accordingly, this excess must be appropriately disposed of. In order to reduce the overall environmental impact of surface and underground mining of oil shale, an effort is being made to develop in-situ processes, e.g., Occidental Oil Co. process. However, this also involves removal of like 1/3rd of the shale rock at various levels beneath the ground to allow for the explosive fracturing of the adjacent shale layers, followed by initiating the in-situ retorting process, as well as to allow room for the expanded spent shale. The shale that is removed may be retorted above the ground but this spent shale must still be disposed of, with the result that there may be little difference in the volume of spent shale that cannot be returned to the mined area. Other problems or concerns associated with in-situ processing include (a) maintaining the retorting process throughout the layers of underground shale, (b) localizing the process without permeation of gases through the artificially created shale rock walls for the "in-situ retort," which may have permeability, and (c) the cost of having movable auxiliary equipment (pumps, piping, process control equipment, etc.) above the in-situ site for transport from one site to another site over the area of land for continuous in-situ production. It is hoped, of course, that these concerns can be satisfactorily resolved via additional research. Until then, however, above the ground retorting of mined shale provides the only practical route to shale oil. Disposal of spent shale is an environmental problem in either case, but this would certainly appear to be a resolvable problem for many sites where there is ample, otherwise uneconomically utilized, land.

14. Overview of Synthetic Fuel Prospects

I believe the above examples suffice to indicate the present potential of synthetic fuels processes. With an aggressive research program - to be distinguished from a development program - I believe it is possible to obtain significant improvements in existing processes, as well as new and advanced processes. The time for such an aggressive effort is now - especially in view of the relatively low cost of such research - rather than to wait and later require a crash program to remedy difficult, if not impossible problems.

At the same time we should proceed with the commercialization of certain selected processes which have been successfully piloted, since we can certainly expect gross increases in the cost of such projects, with an ever increasing tight cash flow situation and inflation as a result of our continually expanding balance of payments abroad.

The major American synthetic fuel processes are summarized in Tables 33 and 34; the capital and product costs in Table 35; and an overview of various fuel/energy systems based on coal and oil shale, and their potential in Table 36.

15. Water Requirements

General Considerations. One can expect that the water requirements and associated environmental problems for gasification processes will be greater than those for the lower temperature direct hydroliquefaction processes. The water requirements for indirect liquefaction processes, e.g., Fischer-Tropsch (F/T) type processes, should be similar to those for gasification processes, while those for pyrolysis processes should be intermediate between the gasification and direct liquefaction processes.

The reason for the greater water requirements for gasification processes stems primarily from the higher temperatures involved, viz., 1600 - 1800°F vs 700 - 800°F for direct liquefaction processes, requiring greater amounts of water for cooling the producer gas and for washing this gas to remove tars and particulate matter. High temperature entrained flow processes, such as K-T (Koppers-Totzek) which is operated at a flame temperature of 2700°F, will require greater volumes of water for cooling the product gas (with, of course, heat recovery), but the degree of contamination and hence washing of the synthesis gas should be less compared to a producer gas, such as from the Lurgi or McDowell-Wellmann type gasifier. Cooling water will undoubtedly be recycled but there will be evaporative losses and some blowdown of the higher boiling concentrate. In going from an intermediate Btu gas or producer gas to SNG, additional cooling water is required for the highly exothermic methanation reaction.

In the case of direct hydroliquefaction, many of the contaminants, such as phenolics and tars present in the producer gas from a gasification process will be reduced during hydroliquefaction. Residuals will be present in a non-distillate boiler fuel and combusted during use or removed during hydrofining of the syncrude for a more premium distillate fuel.

Table 33. GASIFICATION PROCESSES

DESCRIPTION	PRODUCT	STATUS
∘ McDOWELL WELLMANN/BuMINES - MORGANTOWN STIRRED FIXED BED GASIFIER USING AIR OR O_2 PLUS STEAM (ATM TO 300 PSI)	∘ INTERMED. Btu GAS ∘ SYNTHESIS GAS ∘ SNG	CAN SPECIFY AND PURCHASE
∘ TEXACO PARTIAL OXIDATION-ENTRAINED FLOW GASIFICATION WITH AIR OR O_2 PLUS STEAM (500 PSI)	∘ INTERMED. Btu GAS ∘ SYNTHESIS GAS ∘ SNG	" "
∘ BABCOCK & WILCOX - ENTRAINED UPFLOW GASIFICATION WITH AIR OR O_2 PLUS STEAM (ATM TO 50 PSI)	∘ INTERMED. Btu GAS ∘ SYNTHESIS GAS	" "
∘ BCR - 2 STAGE ENTRAINED FLOW GASIFICATION WITH O_2 AND STEAM (1000 PSI)	∘ SYNTHESIS GAS ∘ SNG	120 T/D PILOT PLANT, HOMER CITY, PA.
∘ BuMINES-PITTSBURGH - SYNTHANE-FLUID BED GASIFICATION WITH O_2 AND STEAM (1000 PSI)	∘ SNG	75 T/D PILOT PLANT, BRUCETON, PENNSYLVANIA

Table 34. LIQUEFACTION PROCESSES

PROCESS DESCRIPTION	PRODUCT	STATUS
∘ FMC-COED PROCESS. STAGED FLUID-BED CARBONIZATION PROCESS (ATM PRESSURE)	∘ NO. 4 FUEL OIL ∘ FUEL GAS ∘ ELECTRIC POWER	SUCCESSFULLY PILOTED AT 36 T/D SCALE. PRINCETON, N.J.
∘ GULF OIL/PAMCO - SRC PROCESS. HYDRO-EXTRACTION PROCESS. 1500 PSI H_2	∘ LOW SULFUR SOLID FUEL	SUCCESSFULLY PILOTED AT 40 T/D SCALE. TACOMA, WASH.
∘ GULF OIL. SRC-II PROCESS. MODERATE PRESSURE HYDROLIQUEFACTION PROCESS. 1500-2000 PSI H_2	∘ NAPHTHA ∘ NO. 2 - NO. 6 FUEL OILS ∘ SYNCRUDE	MODIFIED 40 T/D PILOT PLANT AT TACOMA
∘ RALPH M. PARSONS MODIFIED FISCHER-TROPSCH COMPLEX	∘ SNG ∘ DISTILLATE FUELS ∘ ELECTRIC POWER	ENGINEERING DESIGN

LIQUEFACTION PROCESSES (CONT'D)

PROCESS DESCRIPTION	PRODUCT	STATUS
○ MOBIL - METHANOL FROM COAL TO HIGH OCTANE GASOLINE PROCESS	○ HIGH OCTANE GASOLINE	COMPLETED BENCH SCALE RESEARCH
○ HRI - H-COAL/EBULLATED BED CATALYTIC HYDRO-LIQUEFACTION (2500 PSI)	○ LOW SULFUR BOILER FUEL ○ SYNCRUDE	COMPLETED PDU STAGE
○ EXXON - DONOR SOLVENT HYDROLIQUEFACTION PROCESS (2000 PSI)	○ LIQUID BOILER FUEL ○ SYNCRUDE	" "
○ BuMINES/SYNTHOIL PROCESS - TURBULENT FLOW "CATALYTIC" HYDROLIQUEFACTION (2500 PSI)	○ LOW SULFUR BOILER FUEL	10 T/D PDU AT BRUCETON, PA.
○ GULF OIL - CCL PROCESS. SEGMENTED FIXED BED CATALYTIC HYDROLIQUEFACTION (2500 PSI)	○ NAPHTHA ○ FUEL OILS ○ SYNCRUDE	PDU STAGE NEAR COMPLETION

LIQUEFACTION PROCESSES (CONT'D)

PROCESS DESCRIPTION	PRODUCT	STATUS
° BuMINES/COSTEAM PROCESS - HYDROLIQUEFACTION OF LIGNITE WITH SYN GAS AT 3000 PSI	° NO. 6 BOILER FUEL	PDU STAGE

Table 35. Summary of Capital and Product Costs of Key Synthetic Fuel Processes

Process	Capital Cost[a]	Product Cost
• Various gasification processes for SNG	\$24,000	\$3.00-3.50[b]
• COED plant complex for low sulfur fuel oil	\$20,300	\$6.00/bbl[c] 35.00/bbl[d]
• SRC process for SRC	\$8500	\$7.50/bbl[d]
• SRC-II for syncrude	\$11,000	12.00/bbl[c] 19.80/bbl[d]
• SRC-II/Refining to distillate fuel, including gasoline	\$18,000	-
• SASOL-II	\$36,000	-
• Mobil methanol to gasoline	\$27,000	-
• Parsons advanced F/T	\$20,400	8.70/bbl[c] 15.00/bbl[d]

a - capital cost/(6 million Btu/D)

b - product cost/million Btu --- average gas cost by the utility financing method

c - at 0% DCF

d - at 12% DCF, 65/35 debt/equity, 9% interest

Table 36. Summary of Fuel/Energy Systems Based On Coal and Oil Shale and Assessment of Potential Application[a]

Fuel/Energy System	Resource Base	Potential
1. a) Direct combustion for electric power	low sulfur coal	good
b) Extending coal via slurries for process heating & electric power	mod. sulfur coal	good
c) Blending with low sulfur coals for electric power	moderate to high sulfur coal	good
2. Hot low Btu gas for electric power	high sulfur coal	poor
3. Intermed. Btu fuel gas for process & space heating & electric power	high sulfur coal	good
4. Solvent refined coal for electric power	high sulfur coal	questionable
5. Low sulfur fuel oil	high sulfur coal	good
6. Jet fuel for aircraft	oil shale coal	good fair
7. Diesel fuel for trucks, ships, & railroads	oil shale coal	good good
8. Synthetic gasoline	oil shale coal	questionable good
9. Light distillate fuels for gas turbine/peak power use	coal oil shale	good good
10. Fluidized bed combustion for electric power	high sulfur coal	poor
11. In-situ gasification for low to intermed. Btu gas	coal	poor
12. In-situ pyrolysis of oil shale for shale oil	oil shale	poor

a) based on present state-of-the-art

In each case, hydrogen sulfide and ammonia will be present in the gaseous process streams but these should be more readily removed, with lower water requirements, from the less voluminous gaseous byproducts from the direct hydroliquefaction processes. In other words, the gas cleanup operations should require less water and/or result in smaller volumes of gas cleanup waste streams to be recycled or requiring treatment.

Gasification Processes

The water requirements here are for an SNG plant which should be greater than that for the production of an intermediate Btu gas or synthesis gas, as indicated above.

The process water requirements for a steam/oxygen blown gasification process will depend upon (a) that recovered from the run-of-the-mine (ROM) coal upon drying to a given level prior to gasification, (b) the moisture level in the charged coal, (c) whether the coal is fed as an aqueous slurry or not, (d) the water consumed in the steam/devolatilized coal reaction to produce CO, CO_2, H_2, etc., (e) the amount of coal required in the combustion zone or partial oxidation stage to provide heat for process and the amount of water so produced, (f) the amount of water required for quenching and washing the raw producer gas to remove tar, particulate matter, etc., and that recovered from the treatment of the dirty water, and (g) the net water consumed in the shift conversion of CO to raise the H_2/CO ratio to somewhat greater than three for the methanation reaction, and that recovered from the methanation stage after condensing the water from the wet SNG product. An estimate of the process water consumption is from 1043 gal/min. (Ref. 23) to 1742 gal/min. (Ref. 24) for a 250 million cu. ft/day SNG plant requiring a total coal feed of about 25,600 T/D (Ref. 24).

It may be noted that for the coal referred to in reference 23, about 34% of it is as fixed carbon. At a feed rate of 22,000 T/D to the gasifier, some 866 lb-mol/min of fixed carbon would be fed, which, in turn, would require 1877 gal/min of water as steam for gasification. An appreciable amount of water is also required for the quenching and washing of the hot raw gas from the gasifier. Efficient cleanup of this waste water process stream would enable an appreciable reduction of the consumptive water requirements for the process. Other factors which would reduce the water or steam requirements include the formation of water from (1) the water content of the coal feed, (2) combustion of some of the coal in the lower combustion zone of the gasifier,

(3) from organic oxygen and hydrogen in the coal, and
(4) incomplete reaction of the fixed carbon.

For a lignite containing originally 35% by weight water, dried to 5% moisture content, and fed at a rate of 25,000 T/D, 1834 gal/min of water would be available from the original lignite which could be converted to steam for the gasification reaction.

It is estimated that 396 gallons/min of water are required for boiler water feed makeup - presumably because of blowdown of the boiler concentrate. By far the largest water requirements, however, are for cooling water makeup as a result of evaporative losses. This is estimated at 20,178 gal/min for a bituminous or subbituminous coal (Ref. 24), based on a 5% loss of the total cooling water circulated, viz., about 403,560 gal/min or 1.24 acre ft/min. With partial air cooling, the cooling water makeup is estimated at 9020 gal/min or 14,522 AF/yr, which corresponds to a 2.2% loss of the total cooling water circulated. The total consumptive water requirements on this basis is 1742 + 396 + 9020 = 11,158 gal/min or 17,964 AF/yr. For lignite, the corresponding estimate is 9446 gal/min or 15,208 AF/yr, the difference corresponding roughly to the water available from a lignite containing 35% by weight water.

According to the Fluor estimate (Ref. 23) - based on information obtained from Lurgi for a coal more akin to lignite, the cooling water makeup is estimated as only 3968 gal/min or 6390 AF/yr, giving a total consumptive water requirement of 1043 + 3968 = 5011 gal/min or 8080 AF/yr.

In summary, the total water circulated in a 250 million cu. ft/day SNG plant is estimated at 1.2 AF/min, with a net water draw (from, for example, a river) of 5000 - 9400 gal/min or 8000 - 15,200 AF/yr for a lignite based plant, and 11,000 gal/min or 18,000 AF/yr for a corresponding bituminous or subbituminous based SNG plant.

Direct Liquefaction

A similar estimate has been made by Ralph M. Parsons Co. (Ref. 25) of the water requirements for a liquefaction demonstration plant to produce a low sulfur fuel oil which is based on the SRC process but includes hydrotreating of the latter to produce the low sulfur fuel oil and gasification of coal or residue to provide the hydrogen and fuel gas requirements for the liquefaction plant. Based on their numbers, a 42,000 bbl/D plant, which is roughly equivalent to a 250 million cu. ft/day SNG plant on a Btu fuel output basis (assuming 6 million Btu/bbl of fuel oil), would consume 410 gal/min of water for the unit processes (presumably largely for the gasification plant to produce the hydrogen), 715 gal/min of boiler feed makeup water, and 4500 gal/min of cooling water makeup. Assuming partial air cooling is used to reduce the evaporative water losses by 25%, the latter should be capable of being reduced to 3400 gal/min. The overall consumptive water requirements would then be 410 + 715 + 3400 ≈ 4500 gal/min or 7300 AF/yr. The consumptive water requirements for such a direct liquefaction plant for a low sulfur fuel oil is thus about 40% of that for an SNG plant based on a bituminous or subbituminous coal feed.

In a recent conceptual design (Ref. 26) for a commercial scale oil/gas plant based on the SRC-II process, for a low sulfur fuel oil, and a two-stage slagging gasifier, based on data published by the Bituminous Coal Research Co. for the BIGAS process, for generating SNG and syngas (for hydrogen production for the SRC-II hydroliquefaction process), 34,700 T/D of coal would be converted into 11,310 T/D of low sulfur (0.5 wt.%) fuel oil (430 billion Btu/D), 3940 T/D of SNG (180 billion Btu/D), 1290 T/D of naphtha (50 billion Btu/D), 940 T/D of LPG (40 billion Btu/D), (with an overall Btu content of the liquids being 527 billion Btu/D, equivalent to 87,800 bbl/D), 1250 T/D of sulfur, and 90 T/D of ammonia. The overall Btu fuel production (including that of the SNG) would thus be about 700 billion Btu/D or 117,000 BOE/D. The process water input (derived from the water treatment and supply plant) is estimated at 970 gal/min. Cooling water makeup was estimated at 14,515 gal/min (of which 11,200 gal/min is as evaporative losses, 440 gal/min as "drift," and 2875 gal/min as blowdown), the boiler feed-water makeup as 2910 gal/min (150 gal/min as blowdown), and 75 gal/min as waste water from the deionizer. Cleanup of the deionizer water, cooling tower blowdown, and boiler blowdown is estimated to return 3100 gal/min, so that the net water draw from a river is 17,500 - 3100 = 14,400 gal/min. For a 42,000 BOE/D plant this would correspond to (when scaled down linearly) 5170 gal/min or 8322 AF/yr.

Advanced Fischer Tropsch Plant Case

For a conceptual advanced F/T plant (Ref. 19), based on feeding 40,000 T/D ROM coal to produce 525 billion Btu/D, equivalent to 87,500 BOE/D, of energy products, consisting of 260 million cu. ft/D of SNG and 50,000 bbl/D of liquid products (comprised of LPG, naphtha, diesel fuel, fuel oil, and alcohols) plus 140 megawatts of excess power for sale (beyond that required for the plant), it was estimated that

(1) approximately 1500 gal/min of water would be consumed in the process, (2) approximately 12,000 gal/min are required as makeup water feed for the overall plant, and (3) the water requirements could be reduced by approximately 75% by use of air coolers for site locations where water supply is critical. Translated to a 42,000 BOE/D plant the consumptive water requirements would range from 0.48(1500 + 12,000) = 6480 gal/min to 0.48(1500 + 3000) = 2160 gal/min, depending upon the degree of air cooling to reduce evaporative losses. The projected water draw from a river for the overall conceptualized commercial plant was 12,000 gal/min, or for a 42,000 BOE/D plant this would amount to 5760 gal/min or 9274 AF/yr - with less than 1% returned to the river from the process areas.

In summary, the decreasing trend in the water requirements for an SNG plant, F/T plant, a gas/oil complex, and a liquid fuel oil plant, are thus in agreement with what one would predict from the gross energy inputs and operating temperatures of the major unit processes.

16. Role of the Federal Government

A basic fact that is frequently overlooked (or avoided), from a business standpoint, is that if a product or process for a given product has significant economic potential in the foreseeable future (like within 10-15 years), private industry will undoubtedly do the required R&D for its commercialization. It follows that the only sound basis for the Government to support R&D is based on national need, such as -

- to meet a pressing current or imminent national emergency
- national preparedness in case of an emergency
- to improve the health, education, and welfare - including environmental problems - of our people, and
- basic research in support of these general and specific practical objectives.

In addition, for areas where the R&D is technology oriented, it is necessary that the mission include the construction of "commercial scale" plants useful to the public - just as local governments do for municipal sewage disposal. Otherwise, such R&D supported by the Government leads nowhere. I recognize that there may be some exceptions to such a generalization, but such offshoots are hardly a justification for the expenditure of federal funds.

Our country is now long overdue in fulfilling its responsibility in the area of energy. I hope that we can soon have some tangible goals, such as suggested in this paper, and that you who are in the water resources/planning field will work with us as a team member to meet these goals which are in the best interest of our nation.

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