Appendix A

PROJECTIONS OF GNP, AND SOURCES AND USES OF FUNDS

Table A-1

GROSS NATIONAL PRODUCT -- HISTORICAL AND PROJECTIONS TO 2000
(Billions of Dollars)

Historical	Current Dollars	Constant 1973 Dollars	Gross National Product Deflator 1973 = 100
1967	$ 790	$1,060	74.7
1968	860	1,100	78.1
1969	920	1,130	82.0
1970	970	1,130	86.4
1971	1,050	1,160	90.8
1972	1,160	1,220	94.9
1973	1,300	1,300	100.0
1974	1,397	1,267	110.3
Average annual change 1967-1974	8.5%	3.3%	5.0%
Projections			
1975	1,480	1,220	121
1980	2,340	1,590	147
1985	3,560	1,890	188
1990	5,420	2,260	240
1995	8,270	2,700	306
2000	12,590	3,220	391

Sources: Historical data. Constant 1973 dollars were obtained from Survey of Current Business, Bureau of Economic Analysis, Sept. 2974, p. 6, Table A; current dollars are from Table 1, various issues. Deflators were derived by dividing current dollars by 1973 constant dollars.

Projections. Real GNP was projected at an annual growth rate of 3.6 percent, taking off from 1974. The deflators were projected at 5 percent annually for the period 1975-2000. Current GNP was obtained by multiplying real GNP by deflators.

Table A-2

SOURCES OF FUNDS--HISTORICAL DATA AND PROJECTIONS TO 2000
(Billions of Current Dollars)

Historical	Business Savings*	Personal Savings	Net Foreign Investment
1967	$ 93	$ 40	$ 2.2
1968	97	38	-0.3
1969	97	38	-0.9
1970	97	55	1.2
1971	110	61	-2.1
1972	126	53	-9.1
1973	137	74	0.1
Projections			
1975	165	65	20
1980	249	95	40
1985	378	139	0
1990	574	218	0
1995	872	342	0
2000	1,326	535	0
Cumulative 1975-2000	14,639	5,696	300

*Business savings is equivalent to the sum of undistributed corporate profits, corporate inventory valuation adjustment, corporate and noncorporate capital consumption allowances, and wage accruals less disbursements in the Survey of Current Business.

- Business savings

Sources: Historical. Survey of Current Business, National Income and Product Table 15, various issues.

Projections. The equation 3.5 + 0.105 (GNP) was used to project business savings. (See Reference 3.)

(continued)

Table A-2 (concluded)

- Personal savings

Sources: Historical. Survey of Current Business, National Income and Product, Table 10, various issues.

Projections. Personal savings was projected using a ratio of personal savings to GNP (on a sliding scale of 0.0425-0.039 for 1975-1985 and 0.039-0.0425 from 1985-2000). (See Reference 3.)

- Net foreign investment

Sources: Historical. Survey of Current Business, National Income and Product, Table 12, various issues.

Projections. Net foreign investment (NFI), which historically has fluctuated around zero, is assumed to increase to \$20 billion in 1975, to continue to grow, reaching a high of \$40 billion in 1980, and then to fall to zero again by 1985. The sharp rise in NFI expected over the 1975-85 period is due to recycling of "petro-dollars." In 1975, it is estimated that OPEC surplus revenues (i.e., the difference between oil exports and total imports) will be about \$65 billion. Currently, about 31 percent of these funds are returning to the United States. OPEC surplus revenues are expected to increase to about \$130 billion by 1980, and assuming the 31 percent share for the United States persists, a NFI in 1980 of about \$40 billion results. NFI is anticipated to decline steadily between 1980 and 1985 as the dollar value of imports to OPEC countries gradually overtakes the dollar value of oil exports. By 1985 it is assumed that the oil surplus will disappear.

Table A-3

BUSINESS FIXED INVESTMENT*--HISTORICAL AND PROJECTIONS TO 2000
(Billions of Dollars)

Historical	Current Dollars	Constant 1973 Dollars	Business Fixed Investment Deflator 1973 = 100
1967	$ 88	$ 106	78.5
1968	89	110	81.1
1969	99	116	85.0
1970	101	113	89.7
1971	106	111	95.1
1972	117	121	96.3
1973	137	137	100.0
1974	149	136	109.4
Average annual change 1967-1973	8.6%	4.3%	4.1%
Projections			
1975	167	142	118
1980	273	181	151
1985	446	232	192
1990	686	280	245
1995	1,055	337	313
2000	1,623	407	399
Cumulative 1975-2000	17,413	6,775	

*Business fixed investment is equivalent to nonresidential fixed investment in the Survey of Current Business.

Sources: Historical data. Survey of Current Business, National Income and Product, Table 1 (various issues) for current dollars; Table 16 for deflators. 1958 base year deflators were converted to 1973 base year by dividing deflators by the year 1973 deflator. Constant 1973 dollars were obtained by dividing current dollars by the deflators.

(continued)

Table A-3 (concluded)

Projections. Current dollars were projected at an annual growth rate of 10.3 percent for the period 1975-1985 and 9 percent from 1985-2000. Deflators were projected using an average ratio (0.9588) of business fixed investment deflators to GNP deflators (1958 = 100) and converted to a 1973 base year. Constant 1973 dollars were calculated by dividing current dollars by the deflators.

Table A-4

RESIDENTIAL CONSTRUCTION*--HISTORICAL AND PROJECTIONS TO 2000
(Billions of Dollars)

Historical	Current Dollars	Constant 1973 Dollars	Residential Construction Deflator 1973 = 100
1967	$ 25	$ 36	70.7
1968	30	40	74.6
1969	32	40	79.2
1970	31	39	80.4
1971	43	51	84.2
1972	54	60	90.5
1973	57	57	100.0
Average annual change 1967-1973	14.7%	8.3%	6.0%
Projections			
1975	58	53	109
1980	88	63	139
1985	135	76	178
1990	205	90	227
1995	312	108	290
2000	475	129	370
Cumulative 1975-2000	5,223	2,224	

*Residential construction is equivalent to residential structures fixed investment in the Survey of Current Business.

Sources: Historical. Current dollars are from Survey of Current Business, National Income and Product, Table 1, various issues. Deflators (1958 = 100) from Table 16 were converted to 1973 base year and divided into current dollars to obtain constant 1973 dollars.

(continued)

Table A-4 (concluded)

Projections. Projections of constant prices were made by taking an average ratio (0.0354) of residential construction (1958 prices) to GNP (1958 prices) for the years 1967-1973 and multiplying by real GNP projections for 1975-2000. Deflators were projected by the same method (using average ratio of deflators) and converted to a 1973 base year. Current dollars were obtained by multiplying constant dollars by the deflators.

Table A-5

SELECTED USES OF FUNDS--HISTORICAL AND PROJECTIONS TO 2000
(Billions of Current Dollars)

Historical	Inventory Investment*	Federal Deficit	Credit Agency Borrowing	State and Local Borrowing†
1967	$ 7.4	$12.7	$ 8.2	$ 1.8
1968	7.3	5.2	7.7	1.5
1969	8.5	-9.2 (surplus)	8.6	0.6
1970	4.9	12.9	--	-2.8 (surplus)
1971	3.6	21.7	--	-4.8 (surplus)
1972	8.5	17.5	--	-12.3 (surplus)
1973	15.4	5.6	9.5	-9.2 (surplus)
Projections				
1975	12	4	10	3
1980	18	4	10	3
1985	27	4	10	3
1990	41	4	15	5
1995	63	4	15	5
2000	96	4	15	5
Cumulative 1975-2000	1,053	91	335	103

*Inventory investment is equivalent to change in business inventories in the Survey of Current Business.

- Inventory investment

Sources: Historical. Survey of Current Business, National Income and Product, Table 1, various issues.

Projections. Current dollars were projected by taking an average ratio (0.0076) of inventory investment to GNP for the period 1967-1973 and multiplying by projected GNP in current dollars.

- Federal deficit

Sources: Historical. Survey of Current Business, National Income and Product, Table 13, various issues.

Projections. The federal deficit is assumed to average about $3.5 billion per year over the 1975-2000 period the same as the average for the nonwar years of 1954-1963. This projection was used in the New York Stock Exchange study for the 1975-1985 period and is assumed to continue in the 1985-2000 period. It is important to recognize that the $3.5 billion annual deficit projected for 1975 is only an average over the 1975-2000 period. The actual deficit in 1975 may be anywhere between $50 and $80 billion because the economy is current in a recession. However, part of the 1975 deficit is expected to be offset in future years by a government surplus when the economy is operating close to full employment again.

(continued)

Table A-5 (concluded)

- Credit agency borrowing

Sources: Historical. *Federal Reserve Bulletin*, Total New Issues table under Federally Sponsored Credit Agencies, various issues.

Projections. Credit agency borrowing is taken from the New York Stock Exchange study over the 1975-1985 period and extrapolated to year 2000.

- State and local borrowing

†State and local borrowing is equivalent to state and local surplus or deficit in the Survey of Current Business.

Sources: Historical. *Survey of Current Business*, National Income and Product, Table 14, various issues.

Projections. These projections are taken from the New York Stock Exchange study for the 1975-1985 period and extrapolated to 2000.

Appendix B

PROJECTIONS OF CAPITAL INVESTMENT IN THE OIL AND GAS INDUSTRY

The capital investments in the five categories of energy investment shown in Table 8-3 were projected using the data through 1985 from Hass, Stone and Mitchell in Financing the Energy Industry (FEI),[8] and converted into 1973 constant dollars using the deflator from Table A-3.

Table B-1

ENERGY INDUSTRY INVESTMENT FOR 1975, 1980, AND 1985 FOR HG1
(Billions of Constant Dollars)

	1970 Dollars			1973 Dollars		
Energy Sector	1975	1980	1985	1975	1980	1985
Domestic petroleum and natural gas production and refining, excluding chemical plants	$12.0	$17.0	$22.0	$13.4	$19.0	$24.5
Electric utilities, including nuclear capacity	18.6	26.8	37.6	20.7	29.9	41.9
Natural gas pipelines and distribution	4.0	4.0	4.0	4.5	4.5	4.5
Coal production	1.5	1.5	1.5	1.7	1.7	1.7
Nuclear fuel production	0.0	1.4	1.4	0.0	1.6	1.6
Totals	$36.1	$50.7	$60.5	$40.3	$56.7	$74.2

To obtain investment in the domestic petroleum industry without synthetic fuels, it was assumed that energy output per dollar invested is identical for conventional petroleum and synthetic fuels.

The ratio of energy output from conventional oil and gas, and synthetic gas from coal (including conversion losses) to energy output from conventional oil and gas, and synthetic liquid fuels from coal and oil shale from the HG1 scenario (Table B-2) was used to scale down the investment in conventional oil and gas plus synthetic from FEI to exclude synthetic liquid fuels. It is assumed that the investment schedule from FEI, Table 6-1, applied to the HG1 scenario shown in Table B-2. The resulting investment in 1973 constant dollars under HG1 for the domestic petroleum industry fuel is:

1975	$13.4 billion
1980	18.2
1985	23.0

These projections are used for the HG1 projections through 1985 shown in Table 8-3. The investment requirements for HG1 through 2000 and the investment requirement for HG2 and HG3 shown in Table 8-3 and for TF1 shown in Table 8-5 are generated by <u>scaling</u> the HG1 investment. First, HG1 is extended to 2000 based on the ratio of energy output in 1990, 1995, and 2000 to energy output for 1985. For other scenarios, the HG1 investment figure was scaled using the ratio of energy output relative to the HG1 energy output for the same category and year. Table B-2 shows the energy outputs from the various energy investment categories which are used for the scaling. Table B-3 gives the annual investment requirements for the maximum credible implementation scenario.

Table B-2

ENERGY SUPPLY SCENARIOS
(Quadrillion Btu)*

	Actual	HG1		HG2		HG3		TF1	
	1973	1985	2000	1985	2000	1985	2000	1985	2000
Domestic Oil and Gas									
Domestic oil (no synthetics)	22	32	40	32	34	27	27	30	36
Domestic gas	23	29	37	29	31	26	27	27	32
Synthetic gas from coal	0	1	3	1	3	1	3	0	1
Conversion losses, coal to synthetic gas	0	0.5	1.5	0.5	2	0	1.5	0	1
Total domestic gas and oil†	45	63	82	63	70	54	59	57	60
Natural Gas for Distribution									
Domestic gas	23	29	37	29	31	26	22	27	32
Synthetic gas	0	1	3	1	3	1	3	0	1
Imported gas	1	1	0	1	2	4	5	1	0
Total gas consumption†	24	31	40	31	36	31	35	28	33
Nuclear fuel produced†	1	10	40	12	50	10	40	8	11
Coal production† (excluding use for liquid synthetics)	13	25	33	23	33	20	38	16	22
Energy input to electricity generation‡	21	41	85	41	85	41	85	29	42

*Note a quadrillion (10^{15}) Btu is about 10^{18} J.
†Reference 1, Tables 3 and 13.
‡Reference 1, Tables F-2, F-3.

Table B-3

INVESTMENT REQUIREMENTS FOR SYNTHETIC FUELS UNDER THE MAXIMUM CREDIBLE IMPLEMENTATION SCENARIO

Year	Billions of 1973 Dollars
1975	$0.0
1980	0.7
1985	2.6
1990	5.6
1995	7.2
2000	9.0

Appendix C

PROJECTIONS OF CASH FLOW FOR THE PETROLEUM AND GAS INDUSTRY

The following gives financial accounting relationships used to derive cash flow for the petroleum and gas industry, summarized from Hass, Stone and Mitchell,[8] Appendix B and Table 3-4.

Assets

$$TA(t) = TA(t-1) + \Delta CA(t) + \Delta OA(t) + INV(t) - DEP(t)$$

where

t = year

$TA(t)$ = total assets in year t.

$\Delta CA(t)$ = change in cash assets $(CA(t))$ from the previous year.

$\Delta OA(t)$ = change in other assets $(OA(t))$ from the previous year.

$INV(t)$ = investment in year t.

$DEP(t)$ = depreciation on total assets in year t.

and

$CA(t) = a\ TA(t) \qquad a = 0.32$

$DEP(t) = d\ TA(t-1) \quad d = 0.064$

$OA(t) = \phi\ TA(t) \qquad \phi = 0.08$

then

$$TA(t) = \frac{(1-a-\phi-d)\ TA(t-1) + INV(t)}{1-a-\phi}$$

$$TA(t) = \frac{0.54\ TA(t-1) + INV(t)}{0.60}$$

The base year taken was 1973, and total assets were derived from total fixed assets given by Reference 4, excluding chemical plants and pipelines, of \$48.3 billion. The total assets for 1973 are therefore \$80 billion.

Total Financing

TF(t), total financing, is defined as

$$TF(t) = TA(t) - CL(t) - OL(t)$$

where

$CL(t)$ = current liabilities in year t.

$OL(t)$ = other liabilities in year t.

and

$$CL(t) = c\ TA(t), \quad c = 0.20$$

$$OL(t) = \alpha\ TA(t), \quad \alpha = 0.24$$

then

$$TF(t) = (1-c-\alpha)\ TA(t)$$

$$= 0.56\ TA(t)$$

Cash Flow

Sources (cash flow in) = uses (cash flow out)

Cash flow in = NIAT(t) + DEP(t) + net new borrowings

where

NIAT(t) = net income after taxes

New borrowings = net new debt financing issued plus new equity financing (all common stock-assuming no preferred stock).

$NIAT(t) = 0.10\ TF(t)$

assuming a 10% rate of return after taxes on total financing

$DEP(t) = 0.064\ TA(t-1)$

Cash flow out $= INV(t) + DIV(t)$

$INV(t)$ = annual investment

$DIV(t)$ = dividend payments on common shareholder equity

$DIV(t) = PO \cdot ECS(t)$

PO = dividend payout rate

$= 0.50$

$ECS(t)$ = equity share of the total financing

$= 0.10\ TF(t) - 0.08\ DEBT(t)$

$DEBT$ = total debt financing in year t.

$= 0.04\ TF(t)$ (assumes a constant debt/equity ratio).

Table C-1

ANNUAL INVESTMENT SCHEDULE FOR HG1
(Billions of 1973 Dollars)

Year	HG1 (no synthetic liquid fuels)	HG1 (with MCIS synthetic fuels)
1973	$ 9.8	$ 9.8
74	12.0	12.0
1975	13.0	13.0
76	14.0	14.2
77	15.0	15.3
78	16.0	16.5
79	17.0	17.6
1980	18.0	18.7
81	19.0	20.1
82	20.0	21.5
83	21.0	22.8
84	22.0	24.2
1985	23.0	25.6
86	23.4	26.6
87	23.8	27.6
88	24.2	28.6
89	24.6	29.8
1990	25.0	30.6
91	25.6	31.4
92	26.2	32.4
93	26.8	33.4
94	27.4	34.3
1995	28.0	35.2
96	28.4	36.0
97	28.8	36.7
98	29.2	37.5
99	29.6	38.2
2000	30.0	39.0

Sources: Table 8-3 and Table 6-8 (in Chapter 6).

Table C-2

HG1 CASH FLOW--NO INFLATION
(Billions of 1973 Dollars)

Year	Cash Flow In: NIAT(t)	Cash Flow In: DEP(t)	Cash Flow In: New Borrowings	Cash Flow Out: INV(t)	Cash Flow Out: DIV(t)	Cash Flow Out: Excess Funds
			No Synthetic Fuels			
1975	$ 5.9	$ 5.9	$3.6	$13	$ 2.4	
1980	9.6	10.1	2.1	18	3.8	
1985	13.8	14.8		23	5.5	$ 0.1
1990	17.5	19.2		25	7.0	4.7
1995	20.6	22.8		28	8.2	7.2
2000	23.4	26.1		30	9.3	10.2
	With Maximum Credible Implementation Scenario Synthetic Fuels					
1975	5.9	5.9	3.6	13	2.4	
1980	9.9	10.3	2.5	18.7	4.0	
1985	14.7	15.6	1.2	25.6	5.9	
1990	19.7	21.4		30.6	7.9	2.6
1995	24.4	26.9		35.2	9.8	6.3
2000	28.8	32.0		39.0	11.5	10.3

Table C-3

HG1 CASH FLOW--5 PERCENT ANNUAL INFLATION
(Billions of Current Dollars)

Year	Cash Flow In: NIAT(t)	Cash Flow In: DEP(t)	Cash Flow In: New Borrowings	Cash Flow Out: INV	Cash Flow Out: DIV
			No Synthetic Fuels		
1975	$ 6.0	$ 6.0	$ 4.7	$ 14.3	$ 2.4
1980	11.6	11.7	6.6	25.3	4.6
1985	20.3	20.9	8.2	41.3	8.1
1990	31.6	33.3	5.0	57.3	12.6
1995	46.3	49.1	5.0	81.9	18.5
2000	65.8	70.3	2.2	112	26.3
		With Maximum Credible Implementation Scenario Synthetic Fuels			
1975	6.0	6.0	4.7	14.3	2.4
1980	11.9	11.9	7.3	26.3	4.8
1985	21.7	22.1	10.9	46.0	8.7
1990	36.1	37.5	10.9	70.1	14.4
1995	55.8	58.7	10.8	103.0	22.3
2000	82.4	87.4	9.2	146.0	33.0

Table C-1

HG1 CASH FLOW--8 PERCENT ANNUAL INFLATION
(Billions of Current Dollars)

Year	Cash Flow In: NIAT(t)	Cash Flow In: DEP(t)	Cash Flow In: New Borrowings	Cash Flow Out: INV	Cash Flow Out: DIV
			No Synthetic Fuels		
1975	$ 6.1	$ 6.0	$ 5.5	$ 15.2	$ 2.4
1980	13.0	12.9	10.1	30.8	5.2
1985	25.7	25.8	16.7	57.9	10.3
1990	45.4	46.7	18.6	92.5	18.2
1995	76.0	78.5	28.1	152.2	30.4
2000	123.4	128.3	37.7	240	49.4
	With Maximum Credible Implementation Scenario Synthetic Fuels				
1975	6.1	6.0	5.5	15.2	2.4
1980	13.3	13.1	10.9	32.0	5.3
1985	28.0	27.5	20.0	64.5	11.0
1990	52.2	52.9	28.8	113	20.9
1995	92.2	94.3	41.8	191.4	36.9
2000	155.4	160.4	57.9	311.5	62.2

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9--MARKET PENETRATION OF SYNTHETIC LIQUID FUELS--THE KEY ROLE OF THE DECISION-MAKING PROCESS LEADING TO DEPLOYMENT

By Edward M. Dickson

A. Introduction

For most new product offerings, the manufacturer is properly concerned with obtaining an estimate of the share of the market that his new product may capture. It would seem appropriate, therefore, to ask what fraction of the consumer market gasoline produced from oil shale, for example, might ultimately capture. However, discussions with energy industry experts* and stakeholders† have revealed that the question of market penetration of the final consumer product is less fundamental to the impact study than is the question of how and why decisions to deploy synthetic liquid fuel production technologies will be made.

B. Synthetic Liquid Fuels and the Natural Petroleum System

The nature of the synthetic fuel production processes and of the existing fuel production and distribution infrastructure with which synthetic fuels must mesh is at the root of this. Figure 9-1 shows a simplified block representation of a synthetic fuels production process and Figure 9-2 shows a simplified representation of the existing automotive fuels production system. Two markets are involved in both cases:

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*Exxon Research and Engineering and Stanford Research Institute.
†Atlantic Richfield, Shell Oil, Carter Oil (a subsidiary of Exxon), Texaco, and Chase Manhattan Bank.

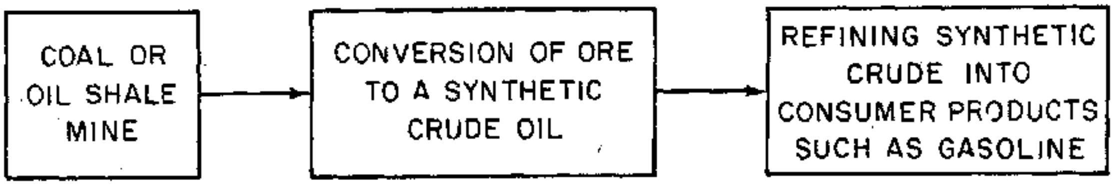

FIGURE 9-1. SYNTHETIC LIQUID FUELS PRODUCTION SYSTEM

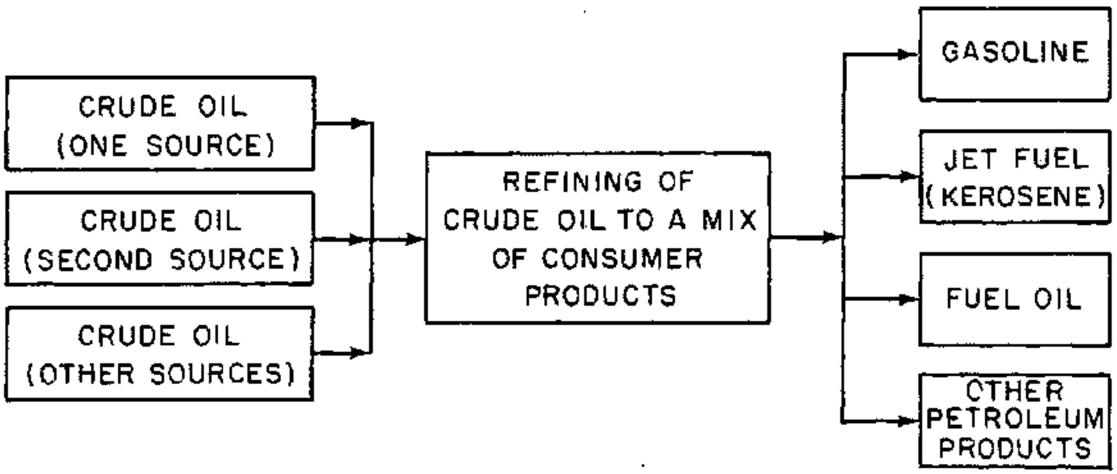

FIGURE 9-2. NATURAL PETROLEUM PRODUCTS PRODUCTION SYSTEM

crude oils and refined products. The synthetic fuels and natural petroleum fuels systems could be joined or could compete at either of the two points.

If the two systems were to join in the market for refined products, there could be two alternative market forms (not mutually exclusive):

(1) The synthetic gasoline could be sold separately through a distinct distribution system in direct competition with conventional gasoline.

(2) The synthetic and conventional gasolines could be mixed together to be marketed and sold through the existing distribution system.

Both alternatives allow the possibility of either new or established corporate entities, with no previous association with the automotive fuels market, making and selling synthetic gasoline. The first alternative would require creation of a new marketing network and competitive pricing of the product. Since it is expected that synthetic gasoline cannot be made as cheaply as conventional gasoline,[1] this market will be difficult to enter competitively. The second alternative avoids the establishment of a new network and expenditures on advertising, and allows the product to be sold at the average price of all the inputs that are blended together, rather than at the actual marginal price of the synthetic gasoline. Of course, if the synthetic gasoline were to cost more to produce than the conventional gasoline, there would be little enthusiasm for using this cost averaging mechanism to create a market for synthetic gasoline. Nevertheless, provided that synthetic gasoline did not cost too much more than conventional gasoline and that it was not too large a share of the total product to be marketed, the second alternative would offer this "roll-in" mechanism that could be employed if a fallback proved necessary because of a poor business decision. However, if the synthetic gasoline were produced by organizations outside the existing natural petroleum based industry, such synthetic gasoline would have to wholesale competitively with conventional gasoline before existing oil companies could be expected to purchase it and absorb it in their existing marketing system.

The first alternative, the competitive approach of a fully integrated synthetic fuel company, is clearly the more risky course and because of the very strong position of existing oil companies in the automotive fuels marketplace there has been apparently no serious contemplation of this approach of potential corporate producers outside this existing industry. Indeed, for excellent reasons that are rooted in the chemical engineering of the processes, even the second alternative, the consumer product blending approach, has not been taken seriously even by those corporations* expressing interest in synthetic liquid fuels.

The product mix shown as a single refinery output in Figure 9-2 results not simply from the consumer demand for diverse products, but also from the nature of crude oil and the chemistry and engineering associated with its processing. Crude oil consists of a mixture of hydrocarbon molecules that cover a wide range of physical and chemical properties. The first step in refining is the distillation of the oil into its various components (fractions). Some of these are processed fairly directly into consumer products while other components that are present in quantities that exceed their market demand are chemically altered into products that are in more demand. Although it would be possible to convert crude oil entirely into a gasoline product, this would entail so much chemical reforming that it would be economically prohibitive as well as costly in terms of process energy (largely supplied from the petroleum stream itself). Consequently, it is standard practice to design modern, large refineries so that they can be tuned to yield an optimal product mix for any (sensible) blend of crude inputs.†

Because it is standard for refineries to accept and utilize a blend of crude inputs and the natural intermediate output of a synthetic liquid fuels plant is a synthetic crude oil rather than refined product, the

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*Such as a large chemical company.
†Some old, small refineries do, however, accept crude from a single field. These represent an historical artifact.

the corporate interests and governmental research elements involved in synthetic liquid fuels development have emphasized joining the synthetic liquid fuels and the existing fuels system at the synthetic crude node rather than at the synthetic consumer product node. The natural industry approach to synthetic liquid fuels is to produce a synthetic crude and to add that product to the pool of all available crudes. Thus, the key market is not the consumer market but is the intra-industry market for crude oil.

Once this mixture occurs, of course, it is extremely unlikely that, on an atom-to-atom basis, the carbon derived from either the fossil coal or oil shale deposits would actually all be consumed in the form of automotive fuel. Instead, as in a game of musical chairs, a carbon atom previously destined to become fuel oil might end up as kerosene, while an atom previously headed for kerosene might end up as gasoline, and the atom from the coal or oil shale might end up as fuel oil. Thus, whether the coal or oil shale is made straight into gasoline or into a syncrude that is blended with natural crudes, the net result is the same: Development of coal or oil shale resources has resulted in gasoline being made available. In either event, the consumer would be no more aware that any given purchase of gasoline came from coal or oil shale than he is now aware whether his gasoline came from domestic or foreign crude, or from a particular oil field.

Depiction of the series of synthetic fuels product events as a single chain from coal to gasoline is a useful heuristic device to demonstrate that coal or oil shale could provide energy for automotive uses, but this device does not reflect reality adequately to serve as a basis for impact analysis. Through discussion with people well informed about the petroleum industry and with energy industry stakeholders, the SRI study team has verified that the key element is the process by which decisions will be made to produce synthetic crudes. Once these decisions are made, synthetic crude will become available for blending into the pool of total crude and this, in turn, will facilitate the production of automotive fuels. A key element in the decision to deploy synthetic liquid fuels technology will be the decision maker's perception of the risks of synthetic crude production compared with his perception of the risks of alternative investments in conventional crude exploration and production. Moreover, both of these alternatives will be compared to investment opportunities outside the fuels arena.

The petroleum business is inherently very complex, but myriad governmental regulations make it even more complex. Nevertheless, the analysis below captures the essential features, although not the nuances, of the decision-making process concerning synthetic liquid fuels. Corporate stakeholders have verified that the major thrust of the description is correct.

C. Common Misconceptions About the Petroleum Industry

Before the decision-making process can be discussed properly, it is essential to dispose of some commonly held misconceptions about the oil industry.

First, there is no single price for crude oil. There are many sources of crude oil, each possessing different chemical and physical properties--some more highly valued than others. For example, some oils are rich in the less viscous hydrocarbons and are called "light," while others are rich in more viscous hydrocarbons (such as asphalt or bitumen) and are termed "heavy;" some oils have low sulfur content (less than 1 percent) and are called "sweet," while others with higher sulfur content are called "sour." In general, American refiners prefer the light, sweet crudes because these can most easily and economically be used to produce the mix of products desired by American consumers; their use

also permits environmental standards to be met most readily. Consequently, there are price differentials for crude oils of different qualities; at the extreme, these variations approach \$2 per barrel (\$12/m^3).*
The common practice of referring to the market price of crude oil is merely a shorthand for speaking of a representative price of a major crude oil or of the government controlled price of domestic crude.

Second, there is no single cost of producting natural crude oil. Since there are many wells (some 500,000 in the United States at the end of 1973) in many different fields at different stages of depletion, producing oils of many different qualities, recovery costs are highly variable. Some fields are self-pressured and the oil flows to the surface naturally, while some wells require pumping. Wells that produce less than 10 B/D (1.6 m^3/D) are termed "stripper wells." In 1973, nearly 14,000 stripper wells became uneconomic to operate and were closed down; the size of this number shows that many stripper wells are on the verge of being phased out at any given time. Many wells are very old but still producing; for these, the exploration and development costs have been fully written off long ago so only operating costs are now pertinent. Clearly, therefore, the costs of producing crude oil vary widely, and thus so does oil well profitability.

Third, the market for crude oil is far from a "free market," owing to the cartel of the Organization of Petroleum Exporting Countries (OPEC) and complicated federal government price controls.[1] For example, "old" oil comes both from new wells and from increased production from old

*The raw oil shale and coal syncrudes can be upgraded to superb quality (sweet and light) and, therefore, could command a premium price over most natural crudes.

wells,* and can be sold at whatever the market will bear. There is also "released" oil, that is, old oil that has been reclassified as new in accord with a government exploration incentive that allows reclassification of one barrel of old oil for each barrel of new oil produced. Stripper wells are exempt from the "old" classification. The complex price structure is further complicated by an "entitlements" program by which the federal government guarantees to all refiners the equivalent of an equal percentage access to low price old oil. Companies with ownership or contract rights to old oil in excess of the industry average must purchase entitlements from companies with less old oil than the average. By this strategem, the government seeks to spread the blow of the suddenly higher cost of imported oil over all petroleum companies. These governmental interventions were temporary expedients stimulated by the Arab oil embargo; they are subject to change at any time.

D. Example of the Decision-Making Process

The recent rise in world oil prices caused by the strong position of the OPEC cartel is an excellent example of the decision-making process concerning synthetic crude. The description that follows is simplified; in particular, the extreme complications caused by U.S. oil price regulations and the entitlements program are suppressed in the interest of providing a readily intelligible picture of the decision-making process.

Figure 9-3 is a snapshot in time that shows a hypothetical† curve depicting the spectrum of natural crude oil production costs, relative

*Relative to the pertinent monthly reference period in 1972 for each producing property.

†The shape of the curve and the breadth do not represent actual data. Such data is proprietary to the producer and therefore not available to this study.

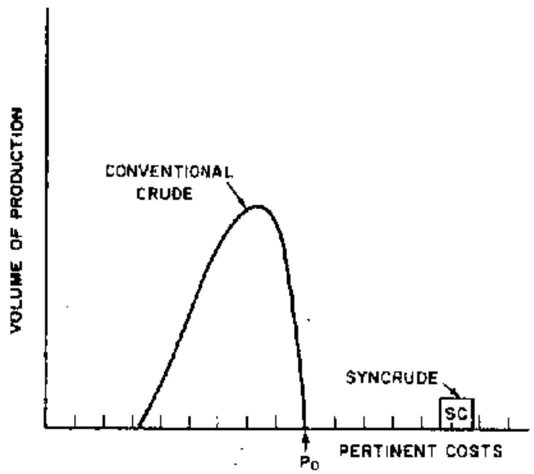

FIGURE 9-3 EARLY 1973 PERCEPTION OF A HYPOTHETICAL SYNCRUDE PLANT BEGINNING TO PRODUCE IN 1973

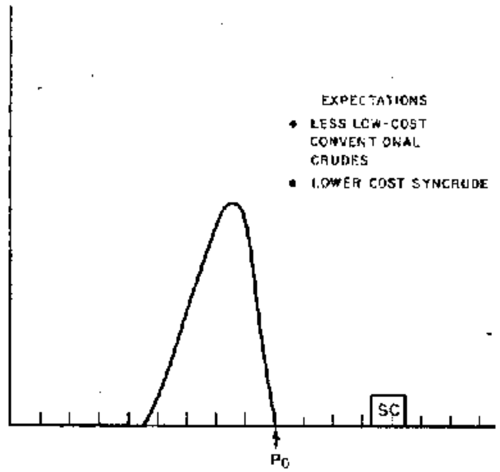

FIGURE 9-4 EARLY 1973 PERCEPTION OF A SYNCRUDE PLANT BROUGHT ON STREAM IN 1980

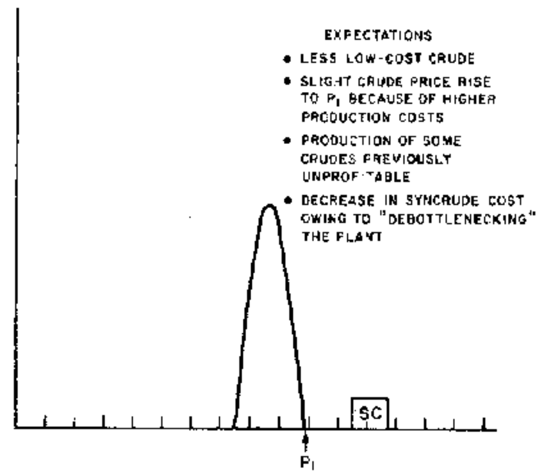

FIGURE 9-5 EARLY 1973 PERCEPTION OF THE 1985 STATUS OF A SYNCRUDE PLANT BROUGHT ON STREAM IN 1980

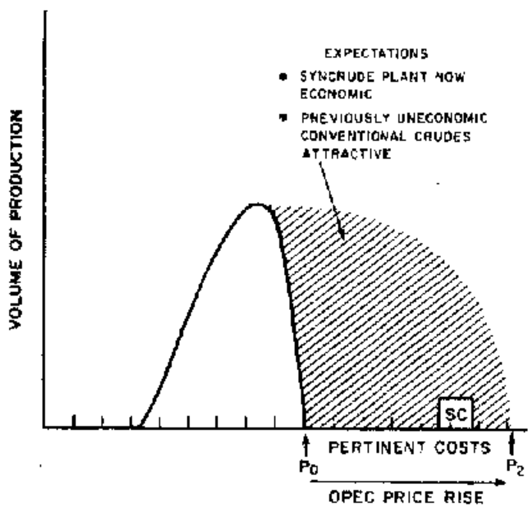

FIGURE 9-6. LATE 1973 PERCEPTION OF THE HYPOTHETICAL SYNCRUDE PLANT PRODUCING IN 1973

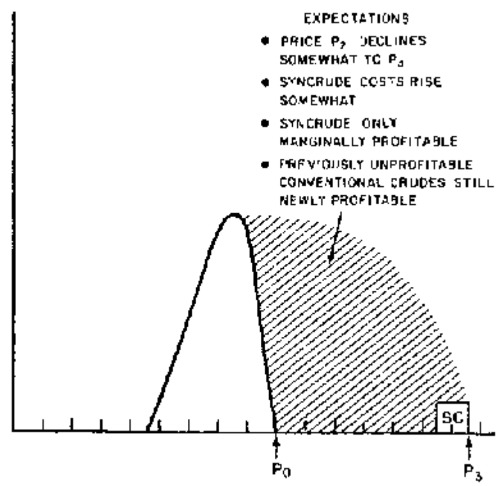

FIGURE 9-7 MID-1974 PERCEPTION OF A HYPOTHETICAL 1974 SYNCRUDE PLANT, AFTER EXAMINATION OF INVESTMENT COSTS

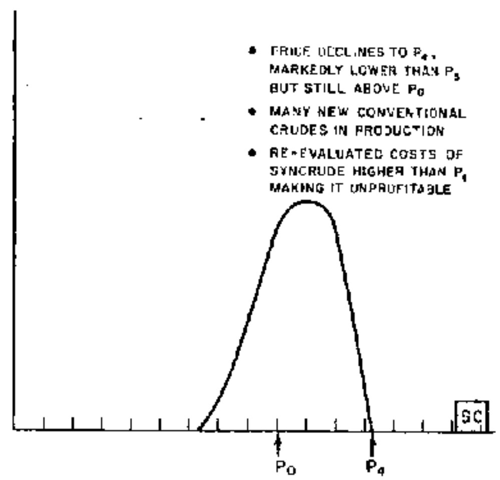

FIGURE 9-8. LATE 1974–EARLY 1975 PERCEPTION OF SYNCRUDE PLANT ON STREAM IN 1980

to the average market price, P_o, for crude oil. The portion just to the left of P_o is largely composed of stripper wells. Whenever the pertinent costs of a particular well rise above P_o, that well is shut down. During the lifetime of a well, or ensemble of wells, producing from a particular field, the tendency is for the costs to be at the leftward end of the spectrum when the well or field is young and progressively shift to the right as production rate declines with increasing depletion until finally the wells enter the category of stripper wells. Figure 9-3 also shows how a hypothetical, newly producing commercial-scale syncrude plant would have looked to a decision maker in early 1973. At that time there was no actual producing syncrude plant, but if there had been, it would have represented the technology at 1965, when its design would have begun. In early 1973, the best estimates for the syncrude plant showed that production would cost considerably more than the going crude oil market price, and, hence, the plant would have lost money. In 1973, then, it was apparent that petroleum companies had made the correct decision years earlier when they chose not to build syncrude plants.

Figure 9-4 shows how, in early 1973, the same decision maker would have perceived a syncrude project begun that year but not scheduled to produce crude until 1980. Thus, the curves represent his perception of the state of affairs that would pertain in 1980. First, the conventional crude production spectrum would have narrowed somewhat as the easier-to-find-and-produce conventional crudes were depleted, thereby eliminating the lowest cost crudes (at the farthest left portion of the production spectrum). The price, P_o, was left essentially unchanged, because the weight of the historical evidence favored basically a stable price expectation for crude oil. Although the production cost for syncrude is shown to be slightly lower than in Figure 9-3 (because there would have been some improvement in technology), the costs were still expected to exceed the market price in 1980; consequently, in early 1973 the decision still would have been not to build a syncrude plant.

Figure 9-5 represents the same decision maker's perception of 1985--still from his vantage point in 1973. All the trends described for Figure 9-4 continued and this led to an expectation that there might be a slight price increase in crude (to P_1), reflecting the increased difficulty of providing the supply. Nevertheless, a syncrude plant scheduled to begin production in 1985 still looked like a poor investment.

Then, however, OPEC initiated a series of stunning price increases for crude oil, which opened an unprecedented gap between the then-operational production spectrum and the new crude oil market price, P_2. This event is shown in Figure 9-6, which shows that from a late 1973 vantage point it suddenly looked as if the hypothetical syncrude plant of Figure 9-3 (producing in 1973) would then be profitable if only it had been built. The sudden price increase, however, also meant that many conventional crude production possibilities, which had previously been unprofitable, would now also be profitable if only they were in operation. In fact, any activity and activities in the range of production costs between P_0 and P_2 now could be taken seriously as profitable investment opportunities. Thus, during the initial period following the OPEC price rises, the price rise stimulated interest in many new sources of crude oil--including synthetics and advanced recovery techniques from old fields.

Often, alternatives that seem very unattractive after only a coarse analysis are set aside without performing a more costly, more refined analysis. This was largely true of the analysis of synthetic crude plants. As shown in Figure 9-7, between late 1973 and mid-1974, when the possible syncrude investment option was examined more closely, cost estimates were revised upwards, and once again it appeared that a syncrude investment would be only marginally profitable. This conclusion was enhanced by the prospect that the OPEC price would not hold at P_2 and would shift downward somewhat, to at least P_3. Thus, within the spectrum of new options lying in the range P_0 to P_3, syncrude seemed to be one of the costlier crudes to produce and therefore one of the least profitable. Moreover, there seemed to be many conventional crude exploration and production opportunities that could still be undertaken that would be more profitable than production of syncrude. Indeed, even some previously shut down stripper wells could justifiably be returned to operational status. Moreover, many difficult conventional crude production activities such as deep offshore, arctic offshore, and tertiary recovery might all prove profitable.

By late 1974 and early 1975, reevaluation of the expectations of the future and the costs of options had improved further. Figure 9-8 indicates how the same decision maker generally thought the situation would appear in 1980. First, the syncrude plant was found to produce an even (slightly) more costly product than last thought, and conviction that the OPEC price would fall to P_4 grew stronger. Thus, once again, syncrude looked like it would lose money. In addition, the conviction that much more conventional crude could be produced at costs between P_0 to P_4 led to rekindled interest in extensions of the conventional approach to oil production and away from the temporary, but heady, enthusiasm for syncrudes. Important to this rekindled interest was the fact that the decision maker felt more comfortable with the historical conventional approach than he did with the syncrude approach to obtaining his supplies of crude.

It must be emphasized that the above analysis concerns <u>commercial</u> scale plants, not demonstration or pilot plants, and not research and development activities. All of these activities are in progress and will continue in spite of unfavorable expectations for commercial plants.

Indeed, there may be so much publicity given to pilot or demonstration plants built to further the research and development efforts that the public could easily leap to the premature conclusion that the day of synthetic fuels had dawned. The tempo of research and development activity will, of course, be modulated by the decision maker's expectation of when synthetic fuels will be competitive with future alternatives.

E. Comparison of the Risks

Besides a straightforward (although difficult to calculate) comparison of the relative profitability of alternative ways to gain new crude supplies based on the pertinent costs of production and market price, other factors enter into the decision-making process. Foremost among these is the risk involved.

Building a synthetic crude plant, although it requires much capital and complex engineering, carries very little risk concerning the ultimate existence of the product. In that respect the risk is very much like an oil refinery or a chemical plant where the major risk is the likelihood of a misestimate of the cost of the feedstock and of making the product, not the actual existence of the product. Thus, a synthetic crude plant very much resembles many other manufacturing type activities. Basically, there is a single decision to "go ahead" and there are no major intermediate decision exit points between the start and the finish.

Exploring and developing oil resources, by contrast, involves risks of a completely different nature, and there are several crucial intermediate decision exit points between the initial exploration go-ahead and the actual production of oil. First, there are geological explorations to determine formations likely to contain commercially significant accumulations of oil and gas. Second, based on these geological data, there are decisions to be made about whether and where to drill. Third, based on the findings of the exploration wells, there are decisions to be made about whether the discoveries (if any) are sufficiently large to justify drilling of production wells. At each decision-making juncture there are risks associated with proceeding to the next juncture, but it is important that there be a series of exit points should the project begin to look unfavorable.

The salient feature of the synthetic crude plant risk* is the uncertainty in production costs, while the major risk* in oil exploration investments is the actual presence of the oil. As conventional production shifts increasingly to offshore areas and distant, unfamiliar, hostile environments (e.g., Alaska, or deep waters of the outer continental shelf), experience on which decision makers can base their estimates of the inherent risks diminishes. Ultimately, rational investors will decide that the risks of oil exploration exceed the risks of synthetic fuels production--but today there is much disagreement over when synthetic fuels will become commercially competitive.

In a very real sense, the world has just embarked on an oil exploration experiment. Never before has there been such a large sudden jump in the market price of crude oil. As a result, there is no historical experience to show how much additional oil can really be located and produced under the stimulus of such an incentive. By 1980 the indications will be strong and by 1985 the results of this experiment will be

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*The comparison of risks on just the basis of crude production is incomplete because much of the natural gas used in the United States is found associated with oil, thus there is a byproduct credit involved; similarly synthetic crude plants also produce byproducts with value such as gas (which may however be consumed internally to power the plant), sulfur, and ammonia.

known. The success rate of finding and producing new oil will have a profound effect on decision makers concerned with synthetic crude because, as shown in Figures 9-3 to 9-8, their perception of the future of conventional petroleum strongly affects their perception of the need and profitability of synthetic fuels.

Besides risks associated with the nature of the fuel production methods themselves, there are substantial uncertainties about the institutional setting. In particular, corporate interests in the petroleum business translate uncertainties about governmental policies into risks. Examples of uncertainties affecting the decision-making process and the sphere of influence include:

Federal Government

- Domestic and international actions to establish a stable crude oil market price.
- Future domestic oil price regulations.
- Environmental regulations on extraction of coal by strip mining, oil shale refuse disposal, and production of oil from offshore leases.
- Resource leasing policies.
- Environmental restrictions that affect direct burning of coal and oil (mainly control of sulfur compound emissions).
- Policies concerning the degree of energy independence to be achieved.
- Policies affecting the development of alternative energy technologies.*

*Since oil is the "swing fuel," or the one that has historically taken up the slack in the availability of other energy forms, the role of oil is especially sensitive to the total national energy mix, or interfuel balance.

- Rate of inflation.*
- Stability of governmental policies and regulations.

State Governments

- Growth policies.
- Water allocation policies in the energy resource-rich portion of the West.
- Environmental restrictions on development.
- Stability of state policies.

Foreign Governments

- Stability of foreign ownership rights, export policies, and taxes.
- OPEC price-setting actions.

Perhaps the most crucial risk element--recurring over and over again in discussions with synthetic fuels corporate stakeholders--was the one of stability of governmental policies.[3] When there is expectation that policies will be stable, even when the policies are unfavorable to the stakeholder and greatly restrict their freedom of action, there is a feeling that the investment decisions can be made with a tolerable degree of risk.

*Rapid inflation increases risks of investment in capital intensive projects for several reasons: First, the continual escalation of costs during construction diminishes the purchasing power of the initial financing. Second, because depreciation is based on the initial (book) value of the plant but the depreciation tax deductions are always in current dollars, the capital actually recovered fails to meet the true replacement costs.

F. Comparison of Economic Risk

The investment in synthetic crude oil plants is very large--of the order of $0.5 to 1 billion (in 1973 dollars) for a production of 100,000 B/D (16,000 m^3/D). The size of this investment can be compared to the net worth of the corporations that might make the investment and the size of alternative crude production investments.

Data obtained from a standard financial reference[4] concerning oil company assets are shown in Table 9-1. A decision to invest $0.5 to 1 billion in a synthetic crude plant is a very grave event for even the largest companies. For example, such an investment would amount to some 4 to 7 percent of Exxon's net worth in 1973, and 25 to 50 percent of Phillips' net worth in 1973. To contemplate having such a large fraction of their shareholders equity riding on such a risky single project is especially sobering to the smaller companies, and not taken lightly by the large ones either.

Table 9-1

ASSETS OF SELECTED MAJOR OIL COMPANIES, DEC. 31, 1973
(Billions of Dollars)

Company	Gross Assets	Net Worth
Exxon	25.1	13.7
Gulf	10.1	5.6
Mobil	10.7	5.7
Phillips	3.6	2.0
Shell	5.4	3.1
Standard of California	9.1	5.8
Standard of Indiana	7.0	4.1
Standard of Ohio	2.0	1.1
Sun Oil	3.4	1.9
Texaco	13.6	8.0
Atlantic Richfield	5.1	3.1

Source: Reference 4.

By contrast, the investment in individual exploration and development projects for conventional crude oil, although considerable, is not as large. Moreover, the step-by-step decision process allows several exit points. For example, a 3-company consortium obtained offshore drilling rights in 6 contiguous tracts off the Florida Panhandle. On the basis of geophysical exploration by many companies, this region had been expected to be a large producer of oil. The $632 million cost[5] of rights to explore this so-called Destin Anticline is summarized in Table 9-2. This bid is about 10 times as large as the usual successful lease bid. Exxon is reported to have spent $15 million drilling 7 dry holes.[6,7] Other companies, drilling in the vicinity, have also failed to strike meaningful accumulations of oil. The consortium has surrendered the leases and will have to write off a $632 million lease bid.[7] This example illustrates that while oil exploration is costly and carries the risk of complete failure, the initial stakes of even an extreme example are not as high as with synthetic crudes.

Table 9-2

OFFSHORE LEASES IN THE DESTIN AREA OFF
FLORIDA'S PANHANDLE
(Millions of Dollars)

Company	Share
Exxon	311
Mobile	211
Champlin	111
Total*	632

*Total does not add because of rounding.

Source: Reference 5.

It is noteworthy that for large contemporary conventional crude activities, such as the Destin venture, companies find it prudent to spread the risk by forming consortia. The same approach has been applied to the development of the tar sands resource in Canada and to the development of oil shale technology and oil shale lease bids (Table 9-3). Besides spreading the risk, this group approach allows the smaller oil companies to participate. Naturally, however, the participation of several companies complicates the decision-making process because they do not possess common perceptions of the future and the risk to each differs in proportion to their total assets. However, coal leases are not, generally, being acquired by consortia, apparently because, unlike oil shale, there are many alternative uses of coal besides liquid fuels, and, therefore, the risks are much smaller.

If the disappointing Destin exploration experience in the eastern Gulf of Mexico should be repeated in other frontier offshore areas--where much of the future domestic oil is expected to originate--corporate decision makers will reevaluate the relative attractiveness of the gamble on conventional exploration compared to synthetic crude production. This would result from their reevaluating the expected marginal cost of new conventional crude and its effect on the market price. Added to the comparison between the future of domestic crude discovery and production and synthetic fuels is the future of foreign activity in conventional crude. Most oil companies feel that worldwide there is still much oil to be developed, but after recent experiences with nationalization they must weigh the risk of foreign investment against those of domestic investment--including synthetic crude. Companies now generally insist on higher rates of return in foreign countries where political instabilities threaten their investments.

Foreign governments affect the decisions of U.S. oil companies in another important way. As Figure 9-8 showed, any activity that could

Table 9-3

GROUP PARTICIPATION IN OIL SHALE LEASES AND VENTURES

Oil Shale Leases	Share (percent)
Colorado-a	
Gulf	50
Standard of Indiana	50
Colorado-b	
Atlantic Richfield	25
TOSCO	25
Ashland	25
Shell	25
Utah-a*	
Phillips	50
Sun	50
Utah-b*	
White River Oil Shale	
Sun	33
Phillips	33
Standard Oil of Ohio	33
Colony Development (as of July 1974)	
Atlantic-Richfield (ARCO)	25
Shell	25
TOSCO	25
Ashland	25

*To be operated jointly.

produce a crude at a cost between P_0 and P_4 would prove profitable. Yet, if companies commit investment capital to these activities they run the risk of OPEC cutting the price of their oil, thereby pulling the rug out from under the investments that produce crude at a cost above the new price. The fear of this possibility inhibits investments in synthetic crudes.

G. The Decision-Making Climate for Synthetic Liquid Fuels

Published information and our discussions with corporate stakeholders revealed that today the indicated poor profitability (even loss) of synthetic crudes, coupled with guarded optimism about the success of redoubled efforts to find new reserves of conventional crude, tip the scales against deployment of commercial synthetic crude production facilities. The outlook for decisions being made to go ahead with synthetic liquid fuels is very poor without either direct risk mitigation or indirect risk mitigation through the stabilization of policy and, most probably, some concomitant--direct or indirect--economic subsidy.[2] A high level of synthetic liquid fuels production will probably not be attainable without the creation of strong incentives; with a governmental hands-off policy, it is most likely that hardly any synthetic liquid fuels will be produced in this century.

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