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MARKET ASSESSMENT
PETROLEUM MARKETS OUTLOOK-
SUPPORTING REPORTS

JULY 31, 1979

THE PITTSBURG & MIDWAY COAL MINING CO.
DENVER, COLORADO

PREPARED FOR

UNITED STATES DEPARTMENT OF ENERGY
UNDER CONTRACT
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PETROLEUM MARKETS OUTLOOK

PREFACE

This volume consists of a primary report prepared by Sherman H. Clark Associates entitled:The Petroleum Outlook as of June 1979" and two addendum reports. The Sherman Clark report provides valuable insight regarding the projected oil supply/ demand situation, primarily in the United States through the year 2000. The data include projected synthetic fuel contributions and, by inference, the potential need for SRC-II type products can be developed.

Addendum 1, the Data Resources, Inc., U.S. Energy Summary is a review of the U.S. long term energy demand and supply. Addendum 2 provides data on the worldwide availability of coal which could potentially be processed in a SRC-II plant to produce synfuels. These and other data can be used to develop estimates of potential SRC-II production based on feedstock availability.

THE PETROLEUM OUTLOOK AS OF JUNE 1979

Project 7946
June 1979

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1. INTRODUCTION

This report was prepared for Pittsburg and Midway Coal Mining Co., and is ultimately intended for submission to DOE. The objective of the report is to project the world petroleum outlook to 2000, with emphasis on the U.S. situation, but within the perspective of world energy and economic activity. In fact, the oil outlook--supply, demand, and most important, price--is derived by our system of balancing economic growth with energy supply, demand, and price.

A single set of projections is adopted as the "most probable" as of June 1979. Applying a date to the outlook implies that the outlook will change, as it has been changing over the past decade. We believe it is significant that:

- In the early 1970s, we anticipated a rising real price for oil and considered that the true market price in 1973 was at least $5 a barrel (FOB Saudi marker crude) but acknowledged that how much above $5 a barrel was indeterminate. As it turned out, the market price was $10 a barrel.

- In 1974-75, we projected no real increase in the price of oil to 2000.

- In 1976-78, we projected that the real price would escalate at 3% per year to 2000.

- In this June 1979 outlook, we now project rising real prices at 5% to 6% per year on a higher base for 1979. A major cause of this revision is the permanent loss of 2 MMBD of production in Iran, or so the situation there is viewed.

Thus, our expectation on future oil prices has been a progression of still higher projections, caused principally by a stream of disappointments (except in Mexico) in the exploration results in promising new areas. This in turn encourages some members of OPEC to constrain production still further. The last and most serious event is the revolution in Iran with the dramatic decrease in production and the clear indication that 2 MMBD of the reduction is permanent.

The crucial factors on which the projections depend will undoubtedly continue to change. However, the economic feasibility and need for supplementary energy supplies should be based on most probable trends, generally consistent with those presented herein.

No attempt has been made to predict the economic cycle and therefore the volume estimates for 1980 (trend estimates) will more probably be high than low because a world recession has a good probability of occurring. If under these conditions the OPEC price fails to increase in real terms, experience in 1976-79 has well demonstrated that in peak economic years and/or during periods of interrupted supply, the price is increased by much more than 5% to 6%. The trend in price is not likely to be smooth.

The amount of detail in our September 1979 annual report will be much more extensive than the material contained herein and some present imbalances will be resolved. However, oil supply and price projections, and the basic conclusions in this report, are expected to be unaltered.

2. SUMMARY

Tight oil supply, and total energy supply in general, is foreseen for the remainder of this century. The greater the anticipation of this situation, the less tight the supply is likely to be. Future supply appears to be very restricted and through OPEC capable of even greater restriction than has been relied on herein. Policies designed to encourage supply and curtail demand through the price mechanism, as well as existing conservation techniques, appear most likely to accomplish no more than prevent the tightness from becoming even more severe than projected.

The trend in free world crude oil production is predicated on:

- A resource base remaining to be produced of about 1,100 billion barrels (some 10% below the consensus estimate at the 1977 World Energy Conference in Istanbul and reduced from that estimate because of further disappointments in exploration results in new regions).
- Gross reserves additions of 15 billion barrels a year for another decade with a steady decline thereafter.
- A gradual decline in the reserve life index to 25 years and maintenance of the index at the level for as long as possible.
- Related production limits in Iran and Saudi Arabia of 4 MMBD and 8.5 MMBD to 10.5 MMBD respectively.

The supply (and demand) of petroleum that rests primarily on the above evaluation is indicated in Table 1* and in total for the free world amounts to an increase from about 52 MMBD in 1978-79 to 61 MMBD a decade later and remaining at about that level throughout the 1990s. These supply estimates include all the synthetic oil production† that can reasonably be expected by the end of the century. This is considered to be the most realistic outlook based on what is known today. Although other production trends

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* It will be noted in Table 1 that growth in oil demand is projected to be more rapid in the self-sufficient oil regions, as well as to a lesser extent in other developing countries, than is projected in the rest of the free world. These projections reflect the industrial expansion plans of these countries which begin from a relatively small industrial base and also reflect the plans to better the general standard of living for its citizens. Since gas, coal, nuclear, and hydropower are not expected to significantly increase their share of energy supply in these countries, most of the growth in overall energy consumption will have to be met by petroleum products.

† From oil shale, coal, grain, and so forth.

Table 1

PETROLEUM SUPPLY AND DEMAND IN THE FREE WORLD
(MMBD)
1978-2000

	1978	1979	1980	1985	1990	2000
Supply						
OPEC production						
Crude	29.7	30.2	30.1	30.4	30.7	30.1
NGL	0.7	0.8	0.9	2.0	2.5	3.0
Total	30.4	31.0	30.9	32.4	33.3	33.1
Non-OPEC production						
Crude	16.8	18.4	19.6	22.4	22.9	21.6
NGL	2.2	2.2	2.3	2.5	2.5	2.3
Total	19.0	20.6	21.9	24.9	25.4	23.9
Total free world production						
Crude	46.5	48.6	49.8	52.8	53.6	51.7
NGL	2.9	3.0	3.1	4.5	5.0	5.3
Total	49.4	51.6	52.9	57.3	58.6	57.0
Synthetic oil production	--	--	--	0.5	1.3	4.4
Net imports from Soviet Bloc	1.2	0.1	0.5	1.4	1.0	0.0
Processing gain	0.5	0.5	0.5	0.5	0.5	0.5
Total supply	51.1	52.2	53.9	59.7	61.4	61.9
Less increase (decrease) in stocks	(0.3)	0.3	0.8	0.3	0.0	0.0
Free world demand, of which	51.4	51.9	53.1	59.4	61.4	61.9
United States	18.8	18.8	19.1	19.9	20.0	19.2
Canada	1.9	1.9	1.9	2.0	2.0	2.0
Western Europe	14.7	14.3	14.4	15.2	15.3	15.3
Japan	5.4	5.4	5.5	6.0	6.2	6.1
Self-sufficient oil regions	4.8	5.3	5.8	8.2	9.0	10.0
Strong economies	2.6	2.8	2.9	3.7	4.1	4.2
Vulnerable economies	3.2	3.4	3.5	4.4	4.8	5.1

Source: SHCA.

are a realistic possibility, it is important to recognize that the probability of lower availability is as high as the probability of higher oil availability.

After allowing for non-oil energy availability within the constraints of resource base, public acceptance, market acceptance, time required to install capacity, and other pertinent factors, the price trend for oil is derived from the free world supply/demand balance for petroleum as represented by the balance for OPEC oil. Our most probable estimate of availability (average annual production) of OPEC crude oil is 30 MMBD to 32 MMBD, remaining at that level to the end of the century. The emphasis in most if not almost all past studies on this subject has been on the production that OPEC could make available, which has all too readily been converted into a conclusion that OPEC will make increasing supplies available. This was a realistic possibility although the realism is rapidly fading, but such evaluations should have been arrayed against the realistic possibility that OPEC will reduce its production rather than increase it. As the resource remaining to be produced declines and the real price continues to increase for a period of years, OPEC (or some members of OPEC) may conclude that the optimum hydrocarbon policy for their countries is to reduce output gradually over time. There is also the possibility that technical aspects of the reservoirs may force a declining production trend before 2000. Thus, OPEC availability may be only 25 MMBD or even only 20 MMBD by the end of the century.

This tight supply of world oil in general and OPEC oil in particular is expected to force the price of OPEC oil to increase rapidly, which in turn lowers the rate of economic growth. The derivation of the balance is shown in Table 2, which demonstrates that OPEC oil is brought into balance at a rate of real price increase of 5% per year for 1979-1985 and 6% per year for 1985-2000, resulting in an economic growth rate to 1985 of 3.7% per year for the free world and 3% per year for the United States. For 1985-2000 the growth drops to only 2.5% per year for the free world and 1.9% per year for the United States. For the 6-year period 1973-79, the growth rates have been only 3.2% per year for the free world and 2.4% per year for the United States, so while the projected rates appear to be far below the potential, recent experience with rising real oil prices suggests that the projected rates of economic growth are not unrealistically low. It is possible that the post-1985 growth rate for the United States is low by as much as one percentage point. Still, we believe the higher growth in the United States will necessitate lower growth elsewhere in the world because free world growth is constrained by energy supply.

The oil prices resulting from our balance are summarized in Table 3: the FOB Saudi marker crude, the average U.S. refiner acquisition price for total refinery input, and the ex-refinery prices for selected products along the Eastern Seaboard (PAD District I). In 1978 dollars, the U.S. refinery acquisition price increases from $16 a barrel in 1979 to $25 a barrel in 1985

Table 2

DERIVING THE BALANCE OF OIL PRICE WITH ECONOMIC GROWTH
AND SUPPLY/DEMAND FOR OPEC OIL
Balance is at 5% per Year for 1979-1985 and
at 6% per Year for 1985-2000

	Rate of Increase in Marker Price (percent per year)									
	1979-1985					1985-2000				
	0%	1%	3%	5%	7%	0%	1%	3%	5%	7%
GNP (percent per year)										
United States	4.0%	3.9%	3.7%	3.0%	2.5%	3.6%	3.4%	3.0%	2.0%	1.7%
Free world	5.1	4.9	4.4	3.7	3.3	4.8	4.4	3.7	2.8	2.2
Total energy increase (percent per year)										
United States	3.8%	3.0%	2.4%	1.9%	1.7%	2.6%	2.5%	2.1%	1.4%	1.0%
Free world	4.9	4.4	3.8	3.2	2.9	3.7	3.2	2.8	2.0	1.6
Total energy, 1985 (quads)										
United States	101.6	97.1	93.3	90.6	89.6	134.2	130.3	122.9	110.9	104.9
Free world	267.8	259.2	250.1	242.8	237.7	416.9	390.8	366.7	327.9	307.4
Oil demand, 1985 (MMBD)										
United States	48.4	44.4	41.7	39.9	39.4	58.3	55.4	49.4	41.0	38.0
Free world	141.0	133.9	127.0	121.7	117.9	205.8	184.8	166.4	135.5	122.0
Demand for OPEC crude oil, 1985 (MMBD)	40.8	37.2	33.6	30.9	28.9	69.4	59.1	50.0	34.8	28.2
OPEC crude oil supply (MMBD)	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3

Source: SHCA.

Table 3

PROJECTED PETROLEUM PRICES
(Dollars per Barrel)
1979-2000

	1978 Dollars					Actual Dollars				
	1979	1980	1985	1990	2000	1979	1980	1985	1990	2000
Crude oil										
Saudi marker, FOB	$15.41	$16.20	$20.65	$27.63	$49.50	$17.00	$19.65	$37.48	$ 73.72	$285.07
U.S. refiner average acquisition price, all crude and NGL	16.00	17.00	25.00	31.00	53.00	17.65	20.62	45.38	82.71	305.23
U.S. product prices, ex-refinery										
LPG	--*	--*	25.00	30.00	49.00	--*	--*	45.38	80.04	282.19
Gasoline										
Unleaded	23.40	24.40	32.70	38.85	59.95	25.81	29.60	59.36	103.65	345.25
Regular	22.20	23.20	31.00	37.00	59.00	24.49	28.14	56.27	98.72	339.78
Naphtha	21.00	22.00	30.00	36.00	58.00	23.17	26.68	54.46	96.05	334.03
Distillate fuel oil	20.10	21.45	29.15	34.95	56.65	22.17	26.02	52.91	93.25	326.25
Residual fuel oil										
0.3% sulfur	19.65	20.30	28.15	34.00	55.75	21.68	24.62	51.11	90.71	321.07
High sulfur	14.50	15.50	25.00	31.00	53.00	16.00	18.80	45.38	82.71	305.23

* Controlled margins and prices that do not reflect market conditions.

Source: SHCA.

and $53 a barrel in 2000.* The price in 2000 may appear to be high because it is well above the price of $25 to $35 a barrel that is presently needed to make most supplementary energy projects economic. However, we are anticipating that the value of the resources† such as shale oil and coal will increase as the real oil price increases, raising the price needed for economic feasibility. It is also probable that the capital costs of these supplementary projects will continue to increase in real terms. Further, there is a valid question as to how much supply can be elicited by 2000 from all supplemental sources. Figure 1 depicts the price trends in real terms.

The ex-refinery prices incorporate refinery margins that are high by pre-1979 standards but are consistent with those being experienced in 1979. A continuously tight supply of crude oil that basically negates the effect of surplus refining capacity on pricing, is the basis for refinery margins that exceed the 1975-78 experience by several dollars a barrel.

The tight supply of crude oil is also expected to influence the pricing of other petroleum products including petrochemical feedstocks and such feedstocks based on NGL as well. Even though petrochemical and therefore feedstock demand will increase at a low rate in comparison with the past, the tight hydrocarbon supply will lead to rapidly increasing real prices for all feedstocks.

The above price projections are considered to be the most probable but a high degree of probability cannot be assigned. Just how much economic growth the world can achieve at such a rapid rate of real increase in the price of oil is still open to question. But no real

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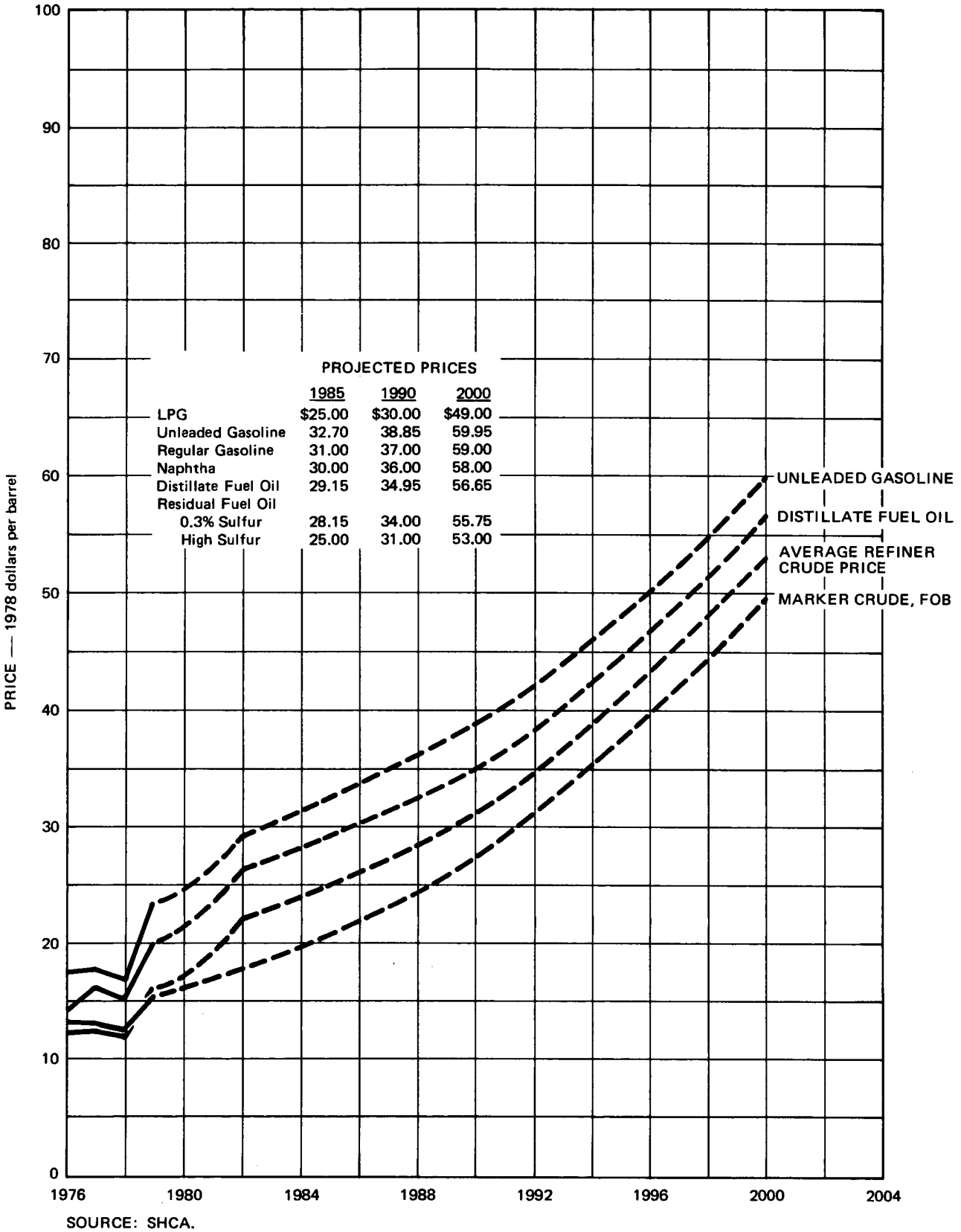
* Decontrol of U.S. oil prices is assumed to be completed by 1982. Decontrol will have a pronounced effect on the average wellhead price of U.S. crude oil and on the average U.S. refinery acquisition price of crude oil. It may have some effect on foreign refining and it may have some effect on U.S. refinery product prices, but there is a great deal of uncertainty as to the precise effect on domestic product prices; in fact, there may not be any. Domestic refineries will, of course, attempt to increase product prices to fully offset the higher dollar per barrel increase in their input costs as compared with the increase incurred by foreign refineries. But we foresee essentially no change in refinery operating rates abroad (in general) and therefore no competitive means of increasing foreign product prices more rapidly than the price of crude oil. Therefore foreign product prices are not likely to escalate more rapidly than crude prices and as U.S. refineries attempt to increase product prices to offset their higher increase in cost of refinery input, foreign products will become increasingly price-attractive and will increase their share of the U.S. market.

† On which supplementary supplies are based.

FIGURE 1 FOB AND U.S. REFINERY PRICES FOR CRUDE AND PRODUCTS: 1976-2000



SOURCE: SHCA.

increase in the price of oil carries a very low probability, less than 10%, and a real rate of increase of 3% per year is considered to be the lowest that can realistically be expected. Real increases considerably exceeding 5% to 6% per year are also realistically possible.

The United States demand for petroleum products is summarized in Table 4 (a complete energy balance is given in Appendix A). Very little growth in demand is now envisaged. It may be possible to obtain somewhat greater foreign supply than we have estimated and that will permit a higher rate of economic growth and oil demand. The only growth projected is in light product demand, although the demand for gasoline increases to a small extent for only a few more years before peaking and then declining. Use of naphtha other than for gasoline has been quite limited to this point and although some growth is expected as a petrochemical feedstock, the petroleum-based feedstocks are expected to be rather diversified by product. Residual fuel oil is expected to decline after 1990 but the future trend will be extremely sensitive to the economic growth rate and the availability and use of gas and coal.

The sources of petroleum supply (Table 5) continue to be heavily dependent on imports, but the low rate of economic growth prevents imports from increasing in volumetric terms. Imports of crude oil will increase from 6.5 MMBD in 1979 to 7.4 MMBD in 2000 while product imports will decline from 1.6 MMBD in 1979 to 0.9 MMBD in 2000. It is conceivable that there will not be a heavier reliance on U.S. refineries since there are foreign refineries (particularly in the Caribbean) already in place that have traditionally served the U.S. market, but we have assumed in this study that U.S. refinery output will expand slowly. Whether U.S. capacity is increased or not, combined volumetric imports of crude and products will be unaffected, but the total cost of imports will be increased by about $3 a barrel (1978 dollars) for the increase in imported products above our estimates.

The total cost of petroleum imports is projected to increase at 5% to 6% per year in real terms, increasing in 1978 dollars from $57 billion in 1979 to $79 billion in 1985 and $162 billion in 2000. As a percent of GNP, they increase from 2.6% in 1979 to 3.1% in 1985 and 4.7% in 2000. Obviously, exports must also increase as a share of GNP (imports in other sectors as a share of GNP can also be expected to increase or remain constant rather than decrease). This is not impossible but it will be difficult to achieve and combined with the massive and increasing debt of the LDC's that must be accommodated in some manner, suggests continuing turbulence in international money markets and a constant threat to the dollar. Under these conditions, inflation is likely to continue to be at a high rate and planning and new capital investment are adversely affected worldwide. However, it is not feasible to project currency exchange rates over the long term. What can be stated unequivocably is that domestic sources of energy carry a value well above the OPEC price because of their favorable influence on the nation's international balance of trade.

Table 4

U.S. DEMAND FOR PETROLEUM PRODUCTS
(MBD)
1979-2000

	1979	1980	1985	1990	2000
LPG*	1,215	1,215	1,509	1,600	1,670
Gasoline total, of which	7,340	7,530	7,455	7,390	7,000
Unleaded	3,020	3,725	5,775	6,650	7,000
Leaded	4,320	3,805	1,680	740	--
Naphtha	305	310	335	350	375
Jet fuel	1,075	1,100	1,225	1,370	1,700
Distillate fuel oil	3,600	3,635	3,775	3,915	4,220
Residual fuel oil total, of which	3,050	3,030	3,105	3,115	1,875
0.5% sulfur	990	1,060	1,400	1,715	875
Other	2,060	1,970	1,705	1,400	1,000
All other products	2,125	2,280	2,166	2,260	2,360
Total	18,800	19,100	19,570	20,000	19,200

* Excludes ethane.

Source: SHCA.

Table 5

U.S. SOURCES OF SUPPLY FOR CRUDE OIL AND PRODUCTS
(MBD)
1979-2000

	United States					PAD District I					PAD District II				
	1979	1980	1985	1990	2000	1979	1980	1985	1990	2000	1979	1980	1985	1990	2000
Crude oil															
Domestic	8,585	8,321	8,633	8,944	7,941	207	201	209	217	193	2,417	2,343	2,431	2,519	2,237
Foreign	6,459	7,108	7,717	7,682	7,390	1,540	1,591	1,658	1,730	1,789	1,439	1,600	1,639	1,580	1,480
Total	15,044	15,429	16,350	16,626	15,331	1,747	1,792	1,867	1,947	1,982	3,856	3,943	4,070	4,099	3,717
NGL--to refineries	397	390	359	301	201	1	1	--	--	--	76	75	69	58	41
Synthetic	--	--	100	300	1,600	--	--	--	7	38	--	--	28	84	448
Processing gain*	562	582	582	582	582	98	98	98	98	98	146	146	146	146	146
Total refinery supply	16,003	16,401	17,391	17,809	17,714	1,846	1,891	1,965	2,052	2,118	4,078	4,164	4,313	4,387	4,352
Other NGL	1,123	1,090	1,011	959	759	38	37	34	29	20	130	127	117	98	68
Gasoline															
Production	7,167†	7,357†	7,397	7,332	6,952	766	810	798	792	752	2,126	2,195	2,198	2,177	2,067
Net imports	173	173	58	58	48	150	150	35	35	25	5	2	1	--	--
Net interdistrict receipts	--	--	--	--	--	1,569	1,590	1,687	1,668	1,583	349	343	311	308	283
Total	7,340	7,530	7,455	7,390	7,000	2,485	2,550	2,520	2,495	2,360	2,480	2,540	2,510	2,485	2,350
Jet fuel															
Production	1,025	1,060	1,205	1,352	1,682	68	70	76	82	94	185	190	205	220	250
Net imports	50	40	20	18	18	21	17	9	8	8	--	--	--	--	--
Net interdistrict receipts	--	--	--	--	--	303	315	362	410	498	30	30	40	55	90
Total	1,075	1,100	1,225	1,370	1,700	392	402	447	500	600	215	220	245	275	340
Distillate fuel oil															
Production	3,423	3,543	3,751	3,891	4,196	470	485	497	555	632	961	986	1,031	1,080	1,175
Net imports	177	92	24	24	24	165	86	23	23	23	--	--	--	--	--
Net interdistrict receipts	--	--	--	--	--	830	904	995	972	975	174	154	154	150	150
Total	3,600	3,635	3,775	3,915	4,220	1,465	1,475	1,515	1,550	1,630	1,135	1,140	1,185	1,230	1,325
Residual fuel oil															
Production	1,813	1,913	2,310	2,405	2,005†	220	230	255	280	240	256	266	290	305	200
Net imports	1,237	1,117	795	710	(55)	1,185	1,070	765	400	--	35	34	15	--	--
Net interdistrict receipts	--	--	--	--	--	195	300	580	920	760	34	25	20	20	--
Total	3,050	3,030	3,105	3,115	1,875	1,600	1,600	1,600	1,600	1,000	325	325	325	325	200

Table 5 (concluded)

	United States					PAD District I					PAD District II				
	1979	1980	1985	1990	2000	1979	1980	1985	1990	2000	1979	1980	1985	1990	2000
All other															
Production	3,728	3,730	3,774	3,725	3,507	348	350	363	372	380	746	748	766	761	719
Net imports	7	75	236	485	898	18	18	18	23	67	64	74	92	128	223
Net interdistrict receipts	--	--	--	--	--	183	184	184	185	178	229	228	222	218	218
Total	3,735	3,805	4,010	4,210	4,405	549	552	565	580	625	1,039	1,050	1,080	1,107	1,160
Total all products															
Production	17,156	17,603	18,437	18,705	18,267	1,872	1,945	1,989	2,081	2,098	4,274	4,385	4,490	4,543	4,411
Net imports	1,644	1,497	1,133	1,295	933	1,539	1,341	850	489	123	104	110	108	128	223
Net interdistrict receipts	--	--	--	--	--	3,080	3,293	3,808	4,155	3,994	816	780	747	751	741
Total	18,800	19,100	19,570	20,000	19,200	6,491	6,579	6,647	6,725	6,215	5,194	5,275	5,345	5,422	5,375

* Includes unfinished oils rerun (net), other hydrocarbons and stock change.
† Includes stock change.

Source: SHCA.

Liquified petroleum gas (LPG) prices and supply/demand are covered in the prior tables. World natural gas liquids (NGL) production (and LPG as well) is expected to increase about 50% by 1985, much more rapidly than crude oil and demand for LPG in the United States is expected to increase. Even though LPG production, particularly in the Middle East, increases rapidly, a distress price should not be expected for several reasons. A tight oil supply in general suggests that no product is likely to face a distress price for long. Markets around the world will absorb whatever is available. More specifically, if a tendency toward surplus supply develops, the surplus will be absorbed in power plant and industrial applications in Japan and Western Europe. Btu equivalence with (more probably some premium over) low sulfur fuel oil prices in those markets will yield a premium for LPG in the U.S. market because LPG transportation costs are much higher than for crude oil. As for supply to the U.S. market, if U.S. demand increases as indicated, all the increase will have to be met by imports because U.S. production from gas plants and refineries is not expected to increase.

Gas supply and use (not demand, because at the prices projected the demand would be much higher) is given in Table 6. Lower 48 production of natural gas holds up well for another year or two as the reserve life index (RLI) continues to drop, but thereafter the decline is fairly steep. Intrastate use declines as power plants in the West South Central states shift to coal and nuclear, but conventional supply to the interstate market also declines. Other sources of supply are indicated, but even though the total gas supply declines gradually over time and the total interstate supply remains about constant, most if not all supplemental sources are vulnerable and the level of supply indicated may well not be realized. This is discussed more fully in Section 8.

Table 6

GAS SUPPLY AND USE IN THE UNITED STATES AND SELECTED REGIONS
(Bcf)
1979-2000

	United States						New England and Middle Atlantic						East North Central					
	1979	1980	1982	1985	1990	2000	1979	1980	1982	1985	1990	2000	1979	1980	1982	1985	1990	2000
Supply																		
Interstate*	10,460	10,375	9,200	7,950	5,870	3,060	1,770	1,775	1,670	1,532	1,160	600	3,740	3,700	3,590	3,000	2,250	1,200
Intrastate*	8,100	8,000	7,600	7,000	6,500	6,000												
SNG	365	375	502	400	400	400	98	102	102	102	102	102	230	233	250	250	250	250
Canada	950	1,000	1,200	1,101	927	1,000	11	11	20	20	20	20	250	250	300	260	250	260
Mexico	0	0	700	700	700	1,000	0	0	116	116	116	130	0	0	35	36	36	60
LNG	310	408	565	1,565	2,065	2,465	96	127	127	350	400	600	50	84	90	300	500	800
Coal gas	0	0	0	500	1,000	2,000	0	0	0	10	307	768	0	0	0	414	709	1,350
North Slope and other	0	0	0	0	700	2,000	0	0	0	0	75	100	0	0	0	0	265	400
Total supply	20,185	20,158	19,767	19,216	18,162	17,925	1,975	2,015	2,035	2,120	2,180	2,320	4,270	4,267	4,265	4,260	4,260	4,320
Total interstate†	12,085	12,158	12,167	12,216	11,665	11,925												
Usage																		
Residential	4,985	4,995	5,055	5,140	5,235	5,425	930	945	990	1,040	1,110	1,210	1,570	1,595	1,640	1,715	1,810	2,000
Commercial	2,705	2,810	2,935	3,070	3,215	3,410	430	445	485	530	580	670	765	797	830	870	925	975
Industrial	6,445	6,350	6,245	6,385	6,370	6,120	505	515	480	470	410	360	1,705	1,645	1,585	1,475	1,325	1,145
Power plants	2,500	2,450	2,050	1,100	500	500	30	30	--	--	--	--	20	20	--	--	--	--
Other	3,550	3,553	3,482	3,221	2,842	2,470	80	80	80	80	80	80	210	210	210	200	200	200
Total usage	20,185	20,158	19,767	19,216	18,162	17,925	1,975	2,015	2,035	2,120	2,180	2,320	4,270	4,267	4,265	4,260	4,260	4,320

* NGL that is extracted has been eliminated from the production estimates.
† Equals total supply less intrastate.

Source: SHCA.

3. INTERRELATIONSHIPS--ECONOMIC ACTIVITY, ENERGY, PRICE

The purpose of this section is to derive the balance among economic activity and energy supply, demand, and price. Our analysis is empirically-based and to that end, the price elasticity exhibited in 1974-76 (and preliminarily in 1977) is first examined in some detail.

Price Elasticity of Energy Demand

Energy prices have been increasing in real terms since the 1973 oil embargo and our world evaluation points to further real increases, so that the effect of price on the demand for energy and each of its components has become a critical factor in energy projections. That price has some effect is now beyond question, and while the magnitude of the effect in recent years can be measured, the future influence of price is open to debate for several reasons:

- The empirical basis is very limited as yet; within the five-year 1974-78 period, one year (1974) was during the oil embargo and energy usage was thereby distorted, 1975 was a recession year which also causes some distortion in energy/economy relationships, and consumption data for 1978 are not yet reported by state and must be approximated.

- Energy legislation pertaining to conservation will have some effect on demand independent of price. While it may be argued that such legislation will be a complete substitute for the price mechanism, nothing could be further from the truth. The reasonable position is that both conservation and price have their separate influence and again the question concerns how much influence is involved.

- Even though the price effects in 1974-78 are measured, the future degree of influence will not necessarily be the same. Some analysts have argued that real price increases will have an initial effect on demand, after which the demand for energy will prove to be quite resistant to further price changes. The more telling evidence from numerous econometric studies demonstrates that with capital intensive markets as in energy usage, the effect of price changes is small at first but increases over time.

- Finally, with respect to interfuel competition, there is no empirical basis in the 1974-78 period because gas sales were constrained by lack of supply.

These facts suggest to us that the empirical analysis has its limitations but is nevertheless essential for "point of departure" purposes if for no other reason, that reasoning and judgment must continue to supplement the empirical base, and that the market must be evaluated carefully every year for new evidence, new signs of future trends.

A demand equation includes at least three terms*: a variable relating to some form of broad economic indicator such as personal income, a variable relating to the price of the commodity, and a variable relating to relative prices of competing commodities if the demand for one form of energy, such as gas, is being analyzed. The latter term drops out if the equation is concerned with total energy use in a particular sector, such as residential consumption. The price effect is isolated in the price variable(s) and the measurement of the effect is given in a portion of the term that is called "elasticity," a dimensionless parameter that is simply the ratio of the percentage change in demand attributable to a change in price divided by that percentage change in price. Thus, if a 10% increase in price causes a 10% reduction in demand, the elasticity is -10%/+10% or -1.0†, which is called unitary elasticity. If the absolute ratio is greater than 1.0 (e.g., -1.5 or -2.0), the demand is called price elastic because price has a pronounced effect; if the absolute ratio is less than 1.0 (e.g., -0.3), the demand is called price inelastic because demand decreases by a smaller percentage than the percentage increase in price.

Table 7 summarizes U.S. energy price escalation in recent years by region and application and Table 8 gives the price elasticity of demand by sector and census region for 1974-76, with an approximation on a national basis for 1977. Price increases have been irregular and rather widely varying by region, use, and form of energy. For all energy in the United States, the average rate of real increase was 21.4% in 1974, 8.1% in 1975, 1.8% in 1976, and 2.5% in 1977.

National trends in energy use plotted against the relevent economic indicators that in the past have proven to be closely related are given in Figures 2 through 5. The straight lines identified as "1960-73 trend" represent the extrapolated trends that might have been expected had the past relationships continued in the future within a framework of no real increases in energy prices, the situation that generally prevailed during the pre-embargo 1960-73 period. With rising real prices however, energy consumption has been reduced and the adopted lines indicate in our judgment as to how great a reduction from past trends may be expected in the future. For example, in 1985 and at a projected income level of about 1,650 billion dollars (1976), residential consumption assuming continuation of the 1960-73 trend and with no real price increases would approach 20 quads. At the same income level, but with real price increases, residential consumption is expected to be less than 15 quads (Figure 2). The effect of rising real prices in the residential market is thus to reduce consumption in 1985 by roughly 20% from

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* There may be other terms for temperature adjustment or other factors.

† Demand elasticities are almost invariably negative.

Table 7

RATE OF REAL PRICE INCREASE IN U.S. ENERGY BY END USE AND REGION
(Index 1972 = 100)
1972-1977

	1972	1973	1974	1975	1976	Prel. 1977
New England						
Residential						
Oil	1.00	1.11	1.51	1.53	1.53	1.61
Gas	1.00	1.00	1.03	1.11	1.17	1.13
Electricity	1.00	0.99	1.18	1.21	1.16	1.13
Total	1.00	1.07	1.35	1.39	1.38	1.40
Commercial						
Oil	1.00	1.16	2.35	2.24	2.08	2.29
Gas	1.00	1.00	1.06	1.15	1.30	1.27
Electricity	1.00	0.98	1.24	1.24	1.20	1.17
Total	1.00	1.03	1.48	1.62	1.59	1.58
Industrial	1.00	1.04	1.69	1.74	1.60	1.67
Gasoline	1.00	1.02	1.23	1.19	1.17	1.16
Middle Atlantic						
Residential						
Oil	1.00	1.08	1.56	1.53	1.54	1.68
Gas	1.00	1.00	1.02	1.13	1.22	1.24
Electricity	1.00	1.00	1.17	1.19	1.18	1.15
Total	1.00	1.06	1.30	1.35	1.37	1.41
Commercial						
Oil	1.00	1.12	1.88	1.64	1.65	1.84
Gas	1.00	0.99	1.03	1.20	1.31	1.34
Electricity	1.00	0.98	1.23	1.24	1.23	1.21
Total	1.00	1.05	1.42	1.55	1.50	1.50
Industrial	1.00	0.98	1.41	1.51	1.46	1.51
Gasoline	1.00	0.99	1.23	1.17	1.14	1.13
East North Central						
Residential						
Oil	1.00	1.08	1.54	1.53	1.57	1.72
Gas	1.00	1.00	1.01	1.10	1.22	1.31
Electricity	1.00	0.97	0.99	1.04	1.06	1.05
Total	1.00	1.04	1.15	1.22	1.29	1.34
Commercial						
Oil	1.00	1.13	1.56	1.69	1.90	2.12
Gas	1.00	1.00	1.02	1.19	1.36	1.51
Electricity	1.00	0.97	1.01	1.08	1.09	1.09
Total	1.00	1.02	1.08	1.22	1.30	1.35
Industrial	1.00	0.99	1.14	1.35	1.46	1.53
Gasoline	1.00	1.04	1.27	1.27	1.20	1.21
West North Central						
Residential						
Oil	1.00	1.09	1.60	1.53	1.56	1.69
Gas	1.00	0.99	0.98	1.03	1.13	1.24
Electricity	1.00	0.94	0.91	0.93	0.97	0.99
Total	1.00	1.03	1.13	1.16	1.23	1.30
Commercial						
Oil	1.00	1.13	1.65	1.74	1.78	1.95
Gas	1.00	1.01	1.02	1.09	1.25	1.48
Electricity	1.00	0.95	0.93	0.97	1.02	1.04
Total	1.00	1.04	1.04	1.12	1.22	1.31
Industrial	1.00	0.95	1.00	1.21	1.33	1.49
Gasoline	1.00	1.03	1.24	1.26	1.26	1.25

Table 7 (continued)

	1972	1973	1974	1975	1976	Prel. 1977.
South Atlantic						
Residential						
Oil	1.00	1.06	1.55	1.43	1.49	1.64
Gas	1.00	0.98	0.96	1.05	1.12	1.16
Electricity	1.00	0.98	1.10	1.18	1.20	1.21
Total	1.00	1.04	1.26	1.35	1.40	1.44
Commercial						
Oil	1.00	1.09	2.19	2.23	2.10	2.34
Gas	1.00	0.98	1.02	1.13	1.22	1.31
Electricity	1.00	0.98	1.15	1.25	1.24	1.26
Total	1.00	1.01	1.23	1.38	1.39	1.43
Industrial	1.00	0.99	1.33	1.59	1.63	1.73
Gasoline	1.00	0.99	1.20	1.19	1.17	1.16
East South Central						
Residential						
Oil	1.00	1.07	1.56	1.46	1.50	1.66
Gas	1.00	1.00	1.01	1.00	1.10	1.17
Electricity	1.00	1.01	1.05	1.16	1.23	1.26
Total	1.00	1.05	1.17	1.26	1.34	1.40
Commercial						
Gas	1.00	1.10	1.68	1.64	1.62	1.80
Oil	1.00	0.98	1.00	1.09	1.27	1.41
Electricity	1.00	0.91	0.94	0.97	1.01	1.03
Total	1.00	1.02	1.08	1.22	1.33	1.39
Industrial	1.00	0.99	1.11	1.45	1.68	1.81
Gasoline	1.00	1.01	1.22	1.20	1.20	1.22
West South Central						
Residential						
Oil	1.00	1.08	1.63	1.59	1.62	1.75
Gas	1.00	0.98	1.00	1.13	1.33	1.41
Electricity	1.00	0.97	0.99	1.03	1.14	1.15
Total	1.00	1.00	1.10	1.18	1.35	1.39
Commercial						
Oil	1.00	1.13	1.52	1.85	1.89	2.07
Gas	1.00	1.03	1.15	1.44	1.76	1.92
Electricity	1.00	0.96	0.98	1.10	1.18	1.21
Total	1.00	1.02	1.07	1.29	1.50	1.55
Industrial	1.00	1.04	1.40	1.79	2.07	2.28
Gasoline	1.00	0.99	1.21	1.26	1.25	1.25
Mountain						
Residential						
Oil	1.00	1.03	1.54	1.57	1.60	1.67
Gas	1.00	1.01	1.04	1.08	1.15	1.20
Electricity	1.00	0.97	0.95	1.05	1.08	1.09
Total	1.00	1.05	1.15	1.21	1.25	1.28
Commercial						
Oil	1.00	1.17	1.61	1.86	1.82	1.92
Gas	1.00	1.01	1.06	1.23	1.35	1.51
Electricity	1.00	0.95	0.93	1.08	1.09	1.09
Total	1.00	1.01	1.05	1.20	1.21	1.25
Industrial	1.00	1.03	1.14	1.45	1.55	1.71
Gasoline	1.00	1.03	1.24	1.27	1.25	1.24

Table 7 (concluded)

	1972	1973	1974	1975	1976	Prel. 1977
Pacific*						
Residential						
Oil	1.00	1.02	1.46	1.40	1.46	1.51
Gas	1.00	1.01	1.08	1.13	1.21	1.40
Electricity	1.00	1.00	1.08	1.07	1.08	1.09
Total	1.00	1.01	1.16	1.15	1.22	1.29
Commercial						
Oil	1.00	1.41	2.26	2.39	2.35	2.31
Gas	1.00	1.00	1.04	1.22	1.42	1.70
Electricity	1.00	1.01	1.15	1.15	1.19	1.20
Total	1.00	1.00	1.14	1.18	1.30	1.35
Industrial	1.00	1.01	1.28	1.50	1.77	1.93
Gasoline	1.00	1.04	1.27	1.29	1.27	1.26
Total United States*						
Residential						
Oil	1.00	1.08	1.55	1.51	1.54	1.66
Gas	1.00	1.00	1.01	1.09	1.19	1.27
Electricity	1.00	0.98	1.05	1.10	1.12	1.12
Total	1.00	1.04	1.21	1.26	1.32	1.36
Commercial						
Oil	1.00	1.13	1.84	1.82	1.84	2.03
Gas	1.00	1.00	1.03	1.18	1.35	1.48
Electricity	1.00	0.97	1.09	1.13	1.14	1.16
Total	1.00	1.03	1.18	1.29	1.35	1.40
Industrial	1.00	0.99	1.25	1.49	1.61	1.72
Gasoline	1.00	1.01	1.24	1.23	1.21	1.20
Total energy*	1.00	1.02	1.24	1.34	1.36	1.40

* Excluding Alaska and Hawaii.

Source: SHCA.

Table 8

ESTIMATED PRICE ELASTICITY OF U.S. DEMAND FOR ENERGY
BY CENSUS REGION AND APPLICATION
(All Numbers are Negative)
1974-1977

	Residential										Commercial											
	Gasoline		Total		Gas Use per Customer		Oil		Electricity		Total		Gas Use per Customer		Oil		Electricity		Total Electricity		Total Industrial	
	1975	1976	1975	1976	1975	1976	1975	1976	1975	1976	1975	1976	1975	1976	1975	1976	1975	1976	1975	1976	1975	1976
Census Region																						
New England	--	--	0.0	--	--	--	0.1	--	--	--	0.3	0.3	0.5	0.6	0.4	0.4	--	0.0	--	0.0	0.2	0.0
Middle Atlantic	0.3	0.2	0.1	0.2	0.5	0.4	0.1	0.1	--	--	0.3	0.3	0.4	--	0.7	0.8	--	0.1	0.0	0.1	0.4	0.3
East North Central	0.0	0.1	0.1	0.0	0.5	0.3	0.0	--	--	--	0.2	0.4	0.4	0.5	0.1	0.1	--	0.1	--	--	0.3	0.2
West North Central	0.1	--	0.2	--	2.2	0.2	0.2	0.0	--	--	0.4	0.1	1.4	0.4	0.3	0.2	--	--	--	--	0.3	0.2
South Atlantic	0.3	0.4	0.3	0.4	1.7	0.5	0.5	0.5	0.4	0.7	0.4	0.5	0.4	0.4	0.3	0.4	0.5	0.8	0.4	0.6	0.3	0.2
East South Central	0.2	0.4	0.4	0.5	--	0.9	0.4	0.5	0.5	0.8	0.3	0.4	1.4	0.3	--	0.3	--	--	--	--	0.2	0.2
West South Central	0.2	0.3	0.6	0.6	0.2	0.4	0.4	0.5	--	2.0	1.2	0.9	0.6	0.5	0.2	0.3	5.5	1.3	3.3	1.6	0.3	0.2
Mountain	0.5	0.6	0.6	0.8	0.7	--	0.3	0.3	0.7	1.0	0.8	0.8	0.6	0.2	0.0	0.1	1.7	2.4	0.1	0.2	0.2	0.2
Pacific*	0.2	0.2	0.7	0.7	0.5	0.8	0.8	0.6	0.6	1.2	0.8	0.8	0.4	0.4	0.4	0.4	1.2	1.2	0.7	0.7	0.3	0.1
Total United States*	0.1	0.2	0.2	0.2	0.8	0.4	0.2	0.1	0.0	0.5	0.5	0.5	0.6	0.4	0.4	0.5	0.4	0.7	0.2	0.3	0.2	0.2

	United States			
	1974	1975	1976	1977
Jet fuel	0.3	0.3	0.4	0.4
Gasoline	0.2	0.1	0.2	0.4
Total transportation	0.2	0.2	0.2	0.4
Feedstocks	0.3	0.4	0.4	0.4
Residential	0.3	0.2	0.2	0.3
Commercial	0.5	0.5	0.5	0.5
Industrial	0.3	0.2	0.2	0.1
Electricity	0.2	0.2	0.3	0.5
Total energy	0.1	0.1	0.2	0.3

* Excluding Alaska and Hawaii.

Source: SHCA.

FIGURE 2 U.S. RESIDENTIAL, COMMERCIAL AND ELECTRICITY CONSUMPTION VERSUS DISPOSABLE INCOME

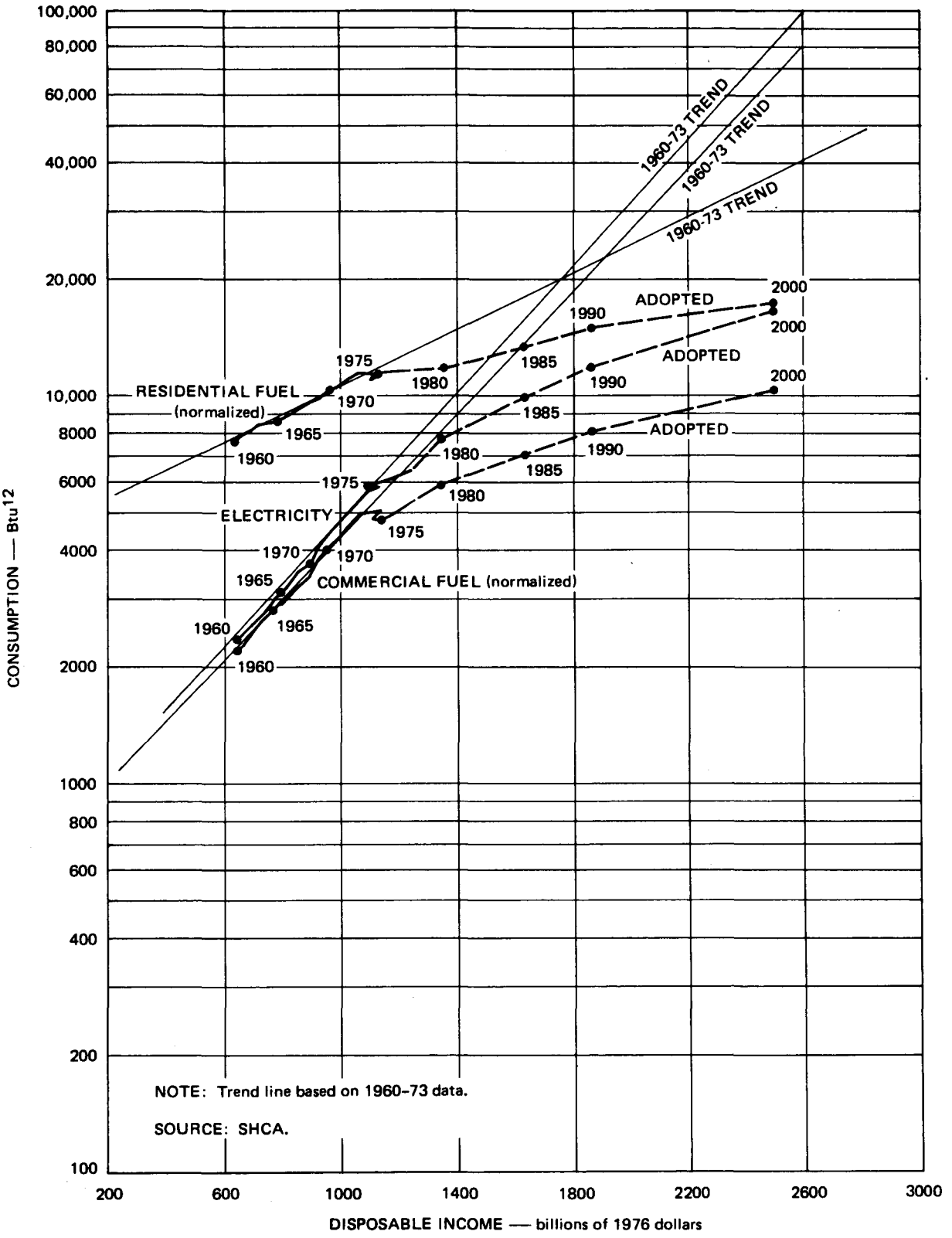


FIGURE 3 U.S. GASOLINE AND TOTAL TRANSPORTATION ENERGY USE VERSUS DISPOSABLE INCOME

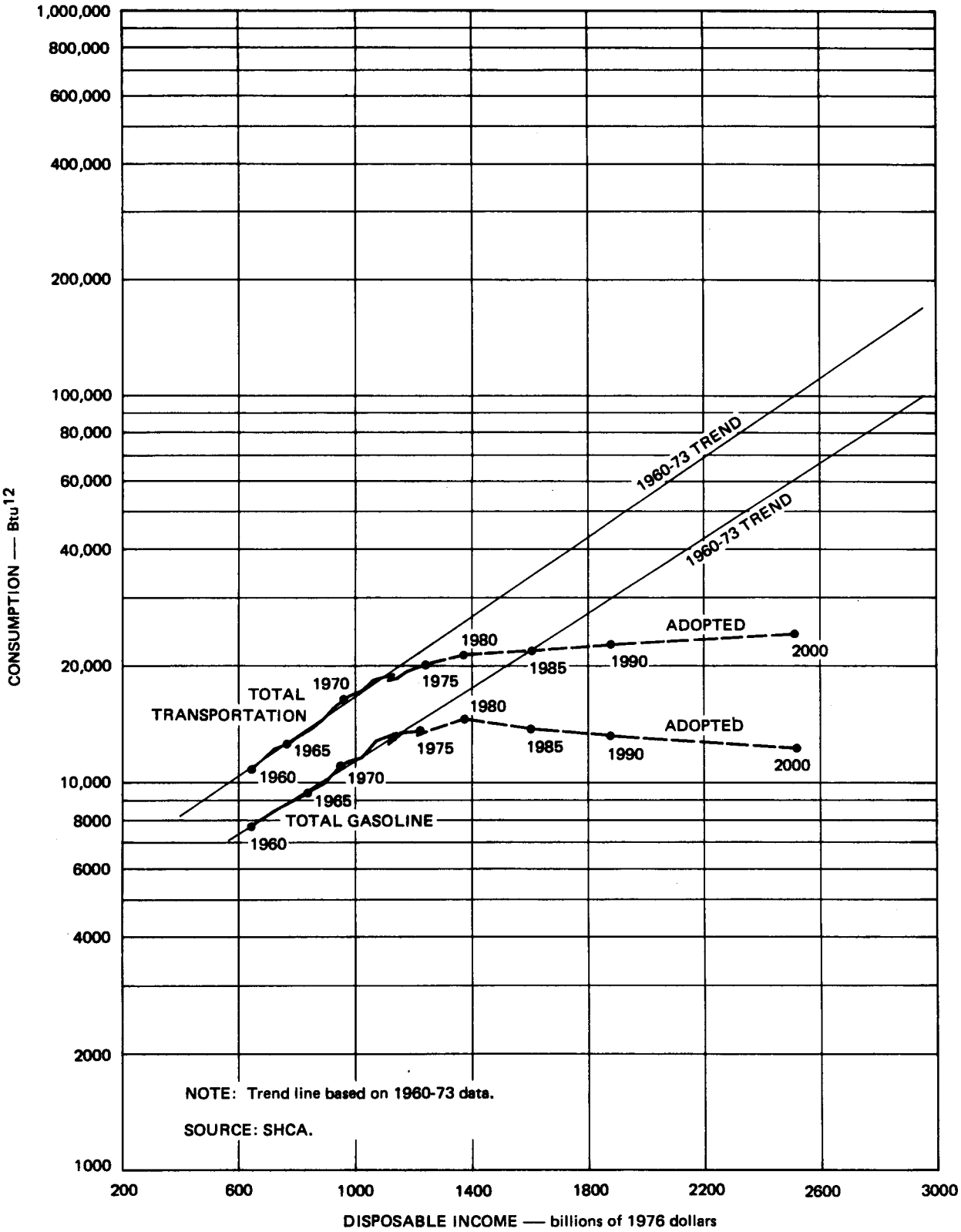


FIGURE 4 U.S. INDUSTRIAL ENERGY VERSUS VALUE ADDED

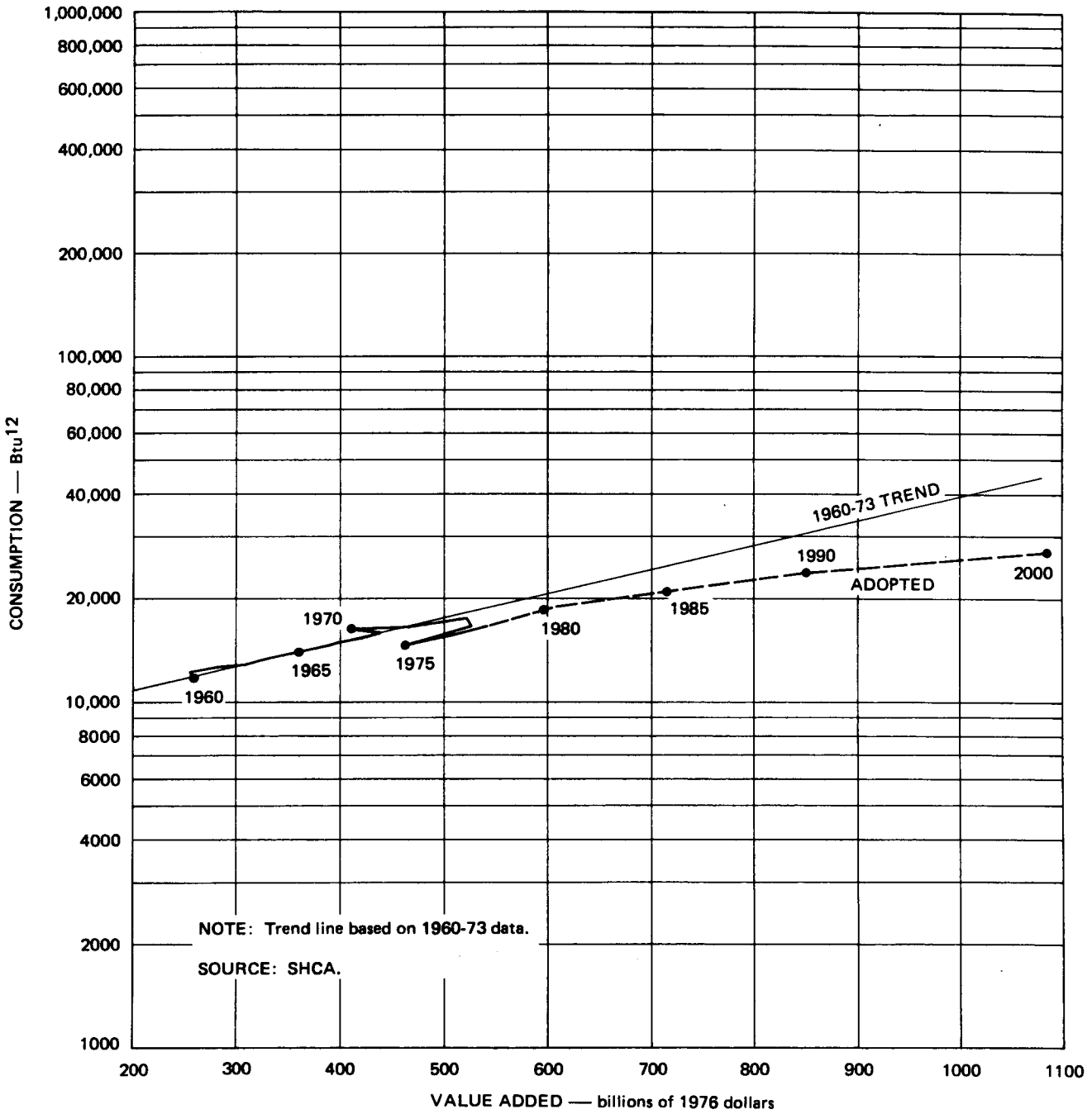
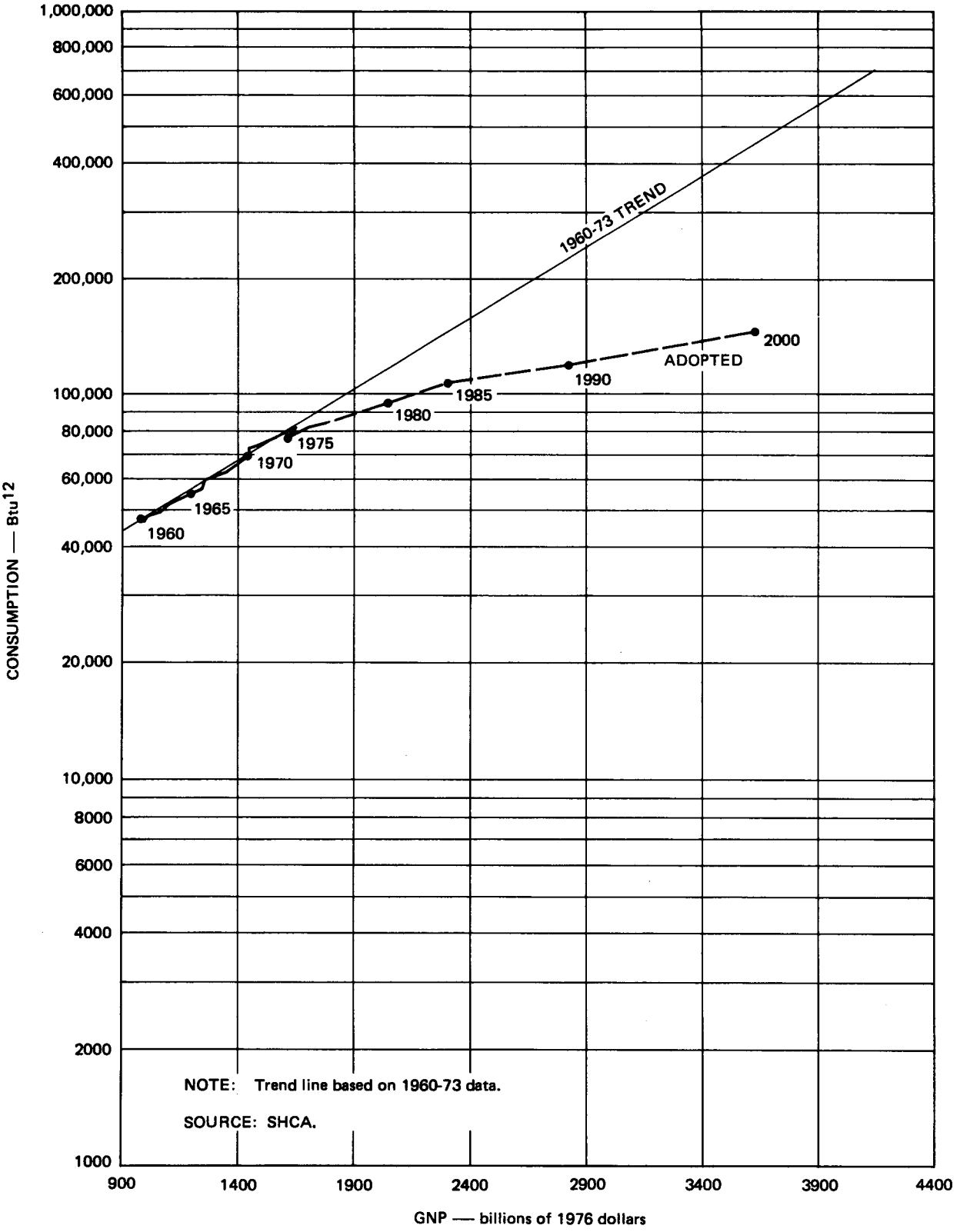


FIGURE 5 U.S. ENERGY CONSUMPTION VERSUS GNP



what it might otherwise have been had there been no real increases in price. Thus, although total income remains unchanged, the same dollar buys less energy and less money is available for other discretionary purchases. As a partial offset, therefore, some degree of energy conservation (i.e., reduction in consumption) can be expected; and of course, such a reduction has already been experienced.

All U.S. elasticities are in the range of -0.1 to -0.3, with the exception of gasoline in 1977 which is -0.5. The 1976-77 elasticities, and particularly those of 1977, show modest increases over the 1974-75 experience and create a question as to the possibility of further increases. Gasoline, for example, with the mandated mileage standards and interpretation of these data as price-induced effects (which they are not), is likely to attain a price elasticity of -0.9 by the mid-1980s, although part of this is attributable to a shift to diesel fuel; if the elasticity were measured on automotive fuel in total, the result would be about -0.5. However, in other sectors, we expect the price elasticity to reach and maintain about -0.3, which generally requires substantial capital investment as opposed to much of the "easy" prior achievement through reduced thermostat settings and similar energy-conserving efforts.

The elasticity for total energy is difficult to develop because of the number of different price trends for each fuel and application, but our approximation by year is:

1974	-0.2
1975	-0.2
1976	-0.2
1977	-0.3

The graph plotted in Figure 5 demonstrates these results and our adopted trend in U.S. energy demand is consistent with an overall price elasticity of -0.3.

The price elasticity of energy supply is also estimated to be quite low. In a Canadian study in early 1975, we estimated oil and gas production elasticity at 0.1 to 0.2 for the first five years, increasing to 0.3 in the tenth year and to 0.5 in the twentieth year. The response in the United States is of comparable magnitude and certainly the world response in the past five years cannot be interpreted as any higher. Moreover, this elasticity is measured in terms of net'to the producer; if measured in terms of total price, including government take of all kinds, the elasticity is well below 0.1.

With U.S. coal's known resource base, it would be all too easy to conclude that coal supply is highly elastic. However, the environment within which the coal industry has been operating (and will continue to operate) precludes high elasticity. The availability and price of competing fuels permit the price of coal to increase appreciably and so all "costs" have increased precipitously including labor, equipment, the cost of coal

properties, and government take. Meeting the environmental stipulations on coal mining has also increased costs through lower productivity and greater requirements for equipment. The net result is a low price elasticity of about 0.2 to 0.3 (e.g., a 20% increase in production since 1973 versus a doubling in the real mine price). The elasticity may increase further to a modest extent, but we expect that a doubling in coal output will require at least a quadrupling in real mine price (0.5 elasticity).

Non-Oil Energy Availability

Supply elasticity is low for all forms of energy, but supply elasticity is by no means the only factor that dictates the supply available. Energy production facilities are invariably capital intensive, generally require 5 to 10 years to install, and are rarely built unless an economic market for their output is identified--in some cases such as coal mines, a long term sales contract for most of the mine capacity is essential. Thus, the demand for the energy source dictates close to the maximum supply likely to be made available. In turn, the demand may be limited even though the price of the energy source is most attractive vis a vis competing forms of energy because air pollution or other regulations may prevent the use of that form of energy or the cost of conversion of the energy using facilities and equipment may make conversion uneconomic. Still another constraint is the inability to use non-oil sources of energy for almost all transportation applications.

In some cases, supply is limited by the resource base, which is the case for most coal production in Western Europe and to some extent for gas production in the United States. Moreover, the U.S. field price is stipulated for the next 6 to 8 years and is independent of the price of oil so that different rates of escalation in the oil price will have virtually no effect on U.S. gas production. Canadian gas production is market constrained and is almost independent of the rate of increase in the oil price (over the probable range in escalation) and world gas availability in the form of LNG is heavily constrained by market and/or government acceptance (or rejection) in the developed countries, independent of the oil price. New economically feasible hydroelectric sites are very limited in the United States, as well as in other developed countries. Nuclear power faces an uncertain future because of safety and environmental considerations. Other sources of energy such as solar, hopefully can make important contributions to the energy supply, but no significant amounts can be expected for some time and in order to materialize, government subsidies of one kind or another undoubtedly will have to be relied on.

Even non-OPEC oil availability is considered to be independent of the future rate of escalation in the OPEC price (over the probable range of escalation) because the net to the producer is controlled in all countries and does not generally escalate with the price. In addition, access to new areas for exploration is also controlled, generally independent of the oil price.

For all of the above reasons and others not mentioned, our balancing procedure relies (with one exception) on a single projection for gas, coal, hydro, and nuclear, as well as for non-OPEC oil, at all rates of escalation in the OPEC oil price. The exception is coal, and the variation in availability and use of this resource as a function of the oil price is the opposite of common expectations because the more rapid the escalation in OPEC's price for oil, the less coal is used in the balancing system. The reason for this anomoly is that the more rapidly the real oil price increases the slower the economic growth and therefore the slower the growth in coal usage (primarily industrial and electric power generation). Substitution of coal for oil is essentially independent of the coal/oil price ratio and so the lower growth in industrial energy use and fuel input to power plants almost directly lowers the growth in coal usage.

There are other reasons why coal consumption may be limited despite its dominance in overall fossil fuel reserves and its cost and siting advantages as compared with petroleum and nuclear fuels in industrial and power plant applications. While economics should increasingly favor coal over oil in major end-use applications, several problems exist. These include:

- Coal transportation equipment is expected to represent a limiting factor, i.e., railroad cars and tracks, docking facilities, and ocean freighters. In the United States, for example, the railroad track system is in poor condition and most existing tracks need replacement (or reinforcement to accommodate 100 to 120 ton rail cars). The current rate of replacement of old tracks, construction of new tracks, and ordering of new railroad cars would not support even the coal quantities projected.

- Ocean shipping of coal is expected to increase dramatically between now and 1985 and should continue to grow at least through the mid-1990s. There is some doubt as to whether coal freighter tonnages, port handling, and coal storage facilties will be adequate to accommodate demand.

- Coking coal, mainly for use in steelmaking, represents about 25% of the current coal consumption in the free world. In addition to the expected slow growth of the steel industry in general (and resulting slow growth for coking coal in steelmaking), technological progress is being made in reducing coal requirements per unit of steel produced (direct reduction, one-heat process). New steel mills are therefore likely to use reduced levels of coking coal. High quality coking coal may be replaced with low grade steam coal in some processes.

- The opening of new mines has been slowed by long delivery times for heavy mining equipment. Although aided by lagging demand for mining equipment for many metallic and nonmetallic minerals (demand for copper, zinc, aluminum, and other minerals has been at low levels for the past few years and demand for mining equipment for new copper, zinc, or bauxite mines is therefore soft), delivery

times in the United States have remained at two to three years. If the demand for metallic and nonmetallic minerals should begin to pick up again, an aggravation of this situation can be expected.

- The use of coal in many applications is not likely to increase. In residential and small commercial applications, the handling and storage of coal is too inconvenient to offset any possible price advantages. In many commercial and industrial applications coal is also not likely to replace oil or gas because some processes cannot be adapted to coal use (in direct heat applications, gas or distillate oil is usually needed), because the cost of equipment conversion cannot be offset by savings in energy cost (particularly considering the likely long term price development of oil and coal), because plants simply do not have available the significantly greater storage and handling area required by the use of coal, and because clean air legislation in many areas makes the use of coal almost impossible in all but the largest plants, where the substantial investments in ash removal and desulfurization facilities can be spread over a sufficiently large quantity of coal input.

The estimates for each source of energy are given in the balancing tables.

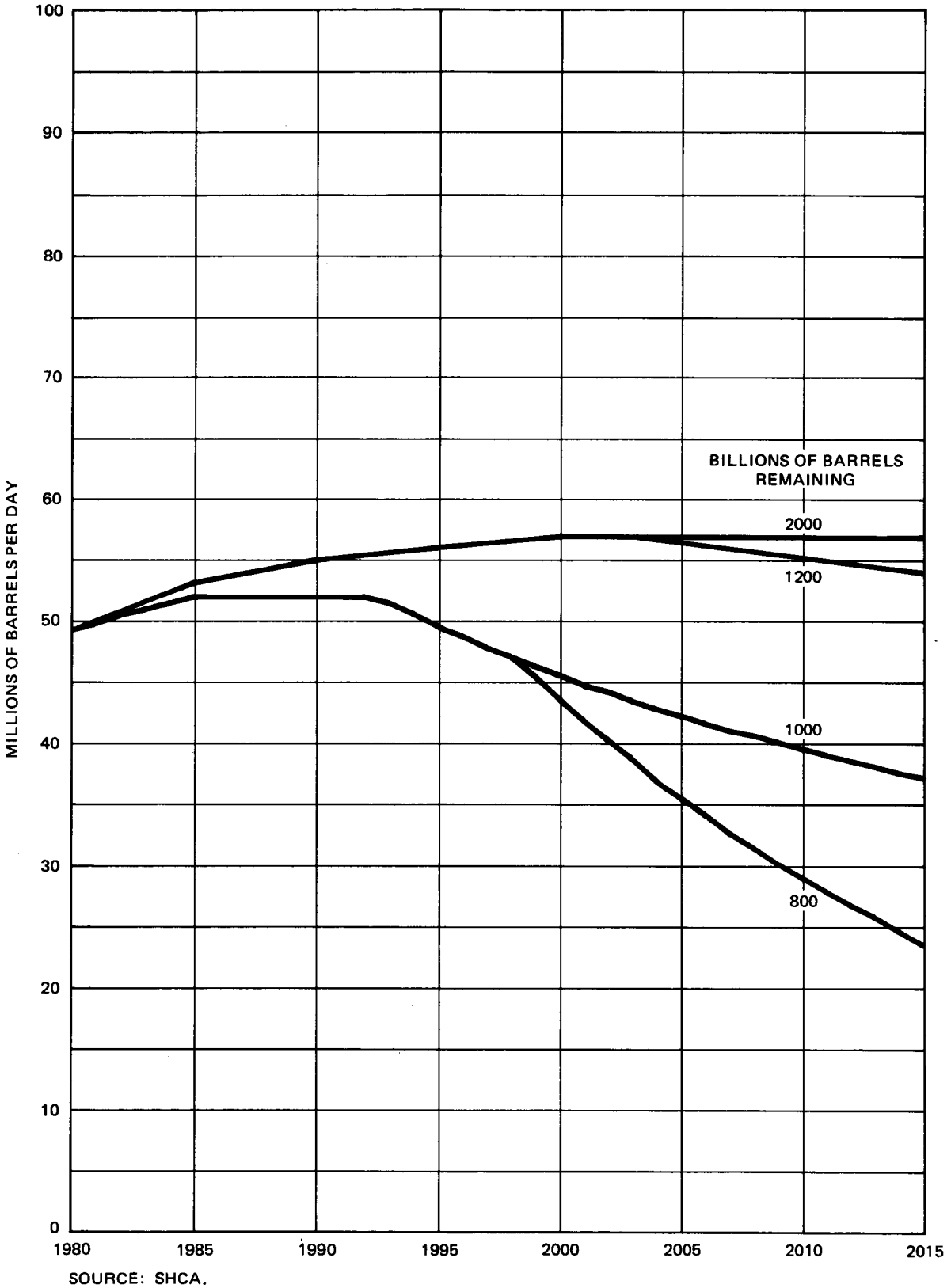
Oil Availability

Resource Base

Figure 6 provides production-time profiles for conventional crude oil in the free world based on four different estimates of the remaining recoverable resource base combined with specific estimates of availability by country for the next 5 to 10 years. The remaining resource base varies from 800 to 2,000 billion barrels. The consensus estimate at the mid-1977 World Energy Conference in Istanbul was 1,200 billion barrels but the lack of new discoveries in the past two years, except in Mexico, tends to lower the probability-based estimate; we now consider that 1,100 billion barrels of conventional crude oil remaining to be produced yields the most realistic production-time profile.

There is no single production-time profile for a given resource base. However, the recent crisis in Iran appears to have ended the long debate over the availability of OPEC crude. It is now obvious that a high reserve life index will be maintained, with all countries within OPEC imposing limits on average annual production. This has been our position for the past three years and the only change that is clearly necessary as a result of the revolution in Iran is to reduce the production in that country to 4 MMBD from our former estimate of 6 MMBD. There is still a valid debate as to the ultimate limit in Saudi Arabia, which accounts for some of the variation in free world production. The lower trend assumes 8.5 MMBD while the higher trend assumes 10.5 MMBD. Although capacity is being expanded to 12 MMBD, production cannot be expected to be maintained at that level at all times, nor can the world oil industry operate at 100% of available

FIGURE 6 FREE WORLD PRODUCTION OF CONVENTIONAL CRUDE OIL: 1980-2015



SOURCE: SHCA.

production every day of every year. The 8.5 MMBD average, with 12 MMBD available for peak months and approaching 12 MMBD in peak years is considered to be the most realistic for planning purposes.

The remainder of the variation in the production trends is due to non-OPEC oil availability and is attributable to the resource base remaining to be found. But the resource base has almost no effect on the production trend for the next decade; there is limited potential variation during this period because production potential is fairly well identified and the long lead times from discovery to production limit the variation likely to be experienced.

The free world production of crude for each of the resource base estimates is as follows (in billions of barrels remaining)*:

	800	1,000	1,200	2,000
1978	46.7	46.7	46.7	46.7
1980	48.8	48.8	48.8	48.8
1985	52.0	52.0	53.5	53.5
1990	52.0	52.0	55.0	55.0
2000	43.0	45.5	56.5	56.5

The range in 1990 is only 3 MMBD, but the range in 2000 is 13.5 MMBD, with our most probable estimate toward the low end of the range rather than at a midpoint. Even under the high resource base estimate, production of crude oil will not increase by more than 20% from the 1978 level and in the probable trend the peak occurs in only 6 more years at only 10% above the 1978 actual.

Production

Production in the non-OPEC and OPEC countries is given in Tables 9 and 10 respectively, and the detailed all-inclusive production by country of the free world for crude oil, NGL, and synthetic oil (oil shale, tar sands, heavy oil, and oil from coal) to 2000 is given in Table 11.

It is difficult to be highly optimistic about non-OPEC production of petroleum, and in fact our present estimates are the lowest we have ever published. While the pre-embargo decline has been reversed and production is projected to increase further, the projected increase is quite limited in magnitude. Mexico's production projection has been increased to allow for more NGL output and Canada's outlook has improved because of the West Pembina developments and the move toward development of the substantial

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* As noted earlier, our production projections are predicated on a resource base of about 1,100 billion barrels.

Table 9

NON-OPEC PRODUCTION OF PETROLEUM*
(MMBD)
1975-2000

	1975	1976	1977	1978	1979	1980	1982	1985	1990	2000
United States										
Lower 48	9.8	9.6	9.4	9.1	8.7	8.4	7.7	8.0	8.0	7.5
North Slope	0.0	0.0	0.3	1.0	1.2	1.2	1.6	1.6	1.8	3.0
Other Alaska	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.5	0.7	
Total†	10.0	9.7	9.9	10.3	10.1	9.8	9.5	10.1	10.5	10.5
Canada‡	1.7	1.6	1.6	1.6	1.7	1.8	1.9	2.0	2.0	2.0
Western Europe	0.6	1.0	1.5	1.9	2.5	3.0	3.6	4.0	4.0	4.0
Latin America										
Mexico	0.8	0.9	1.1	1.3	1.8	2.2	2.6	3.0	3.5	3.7
Argentina	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
Colombia	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Trinidad	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Brazil§	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.2
Peru	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Bolivia	--	--	--	--	0.1	0.1	0.1	0.1	0.1	0.1
Other	--	--	--	--	--	0.1	0.2	0.2	0.2	0.2
Total	1.9	1.9	2.2	2.5	3.1	3.7	4.2	4.8	5.3	5.4
Africa										
Angola■	0.2	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Egypt	0.2	0.3	0.4	0.5	0.5	0.6	0.8	1.0	1.0	1.0
Tunisia	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Other♦	--	0.1	0.1	0.1	0.3	0.4	0.5	0.5	0.5	0.5
Total	0.5	0.6	0.8	0.9	1.1	1.4	1.7	1.9	1.9	1.9
Middle East										
Bahrain	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0
Oman	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4
Syria	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.4	0.4	0.4
Other	0.1	--	--	--	--	--	0.1	0.1	0.1	0.1
Total	0.7	0.7	0.6	0.6	0.7	0.7	0.9	0.9	0.9	0.9
Pacific Basin										
Malaysia**	0.3	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.7	0.7
Australia, New Zealand††	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4
Other	0.2	0.3	0.3	0.3	0.4	0.5	0.5	0.5	0.5	0.5
Total	1.0	1.2	1.2	1.3	1.4	1.5	1.5	1.5	1.6	1.6
Free World										
Non-OPEC production	16.4	16.7	17.8	19.1	20.6	21.9	23.3	25.2	26.2	26.3

Note: Totals may not add due to rounding.

* Includes NGL.

† Includes synthetic oil production of 100,000 barrels per day in 1985, 300,000 barrels per day in 1990, and 1,600,000 barrels per day in 2000.

‡ Includes synthetic oil production of 300,000 barrels per day in 1985, 600,000 barrels per day in 1990, and 900,000 barrels per day in 2000.

§ Excludes synthetic oil production from shale in Brazil of 20,000 barrels per day in 1985, 40,000 barrels per day in 1990, and 80,000 barrels per day in 2000.

■ Includes Cabinda.

♦ Excludes synthetic oil production from coal in South Africa of 50,000 barrels per day in 1985, 100,000 barrels per day in 1990, and 300,000 barrels per day in 2000.

** Includes Brunei.

†† Excludes synthetic oil production from coal in Australia of 100,000 barrels per day in 1990 and 300,000 barrels per day in 2000.

Source: SHCA.

Table 10

CRUDE OIL PRODUCTION IN THE OPEC COUNTRIES
(MBD)
1973-2000

	Abu Dhabi	Dubai	Iraq	Iran	Kuwait	Qatar	Saudi Arabia*	Sharjah	Algeria	Libya	Nigeria	Gabon	Indonesia†	Venezuela‡	Ecuador	Total
Crude oil																
1973	1,298	220	1,964	5,861	3,024	570	7,597	--	1,070	2,187	2,053	147	1,324	3,364	204	30,883
1974	1,412	239	1,850	6,026	2,546	518	8,480	--	986	1,491	2,256	177	1,396	2,976	153	30,506
1975	1,403	254	2,240	5,350	2,055	441	7,075	38	946	1,488	1,787	200	1,313	2,345	160	27,095
1976	1,590	315	2,159	5,883	2,150	487	8,580	37	1,050	1,906	2,050	214	1,500	2,290	187	30,398
1977	1,680	320	2,150	5,650	1,877	350	9,128	30	990	2,050	2,020	225	1,690	2,280	180	30,620
1978	1,448	362	2,629	5,204	2,096	482	8,291	22	1,225	1,976	1,907	225	1,636	2,163	202	29,868
1979																
1st quarter	1,455	358	3,233	1,165	2,501	490	9,780	13	1,225	2,150	2,435	225	1,618	2,346	238	29,232
2nd quarter	1,350	360	3,300	4,000	2,500	550	8,800	20	1,230	2,100	2,410	230	1,600	2,390	210	31,050
3rd quarter	1,400	360	3,300	4,000	2,000	550	9,000	20	1,230	2,000	2,300	230	1,600	2,300	220	30,510
4th quarter	1,400	360	3,300	4,000	2,000	550	8,500	20	1,200	2,000	2,300	230	1,600	2,200	220	29,880
Year	1,401	360	3,283	3,291	2,250	535	9,020	18	1,221	2,063	2,361	229	1,604	2,309	222	30,167
1980	1,450	350	3,500	4,000	2,000	500	8,500	20	1,200	2,000	2,400	220	1,550	2,200	200	30,090
1982	1,450	350	3,500	4,000	2,000	500	8,870	20	1,200	2,000	2,400	220	1,500	2,100	200	30,310
1985	1,450	350	3,500	4,000	2,000	500	9,000	20	1,100	2,000	2,400	220	1,600	2,100	200	30,440
1990	1,450	350	4,000	4,000	2,000	400	9,000	20	1,000	2,000	2,400	220	1,600	2,100	200	30,740
2000	1,450	350	4,000	4,000	2,000	300	9,000	20	900	2,000	2,400	220	1,600	1,700	200	30,140
Natural gas liquids																
1973	--	--	--	40	60	--	90	--	30	35	--	--	--	90	--	345
1974	--	--	--	45	50	5	130	--	50	20	--	--	--	85	--	385
1975	--	--	--	45	50	10	140	--	50	25	--	--	--	75	--	395
1976	--	--	--	45	50	10	185	--	65	40	--	--	10	75	--	480
1977	15	--	5	40	55	5	215	--	75	40	--	--	10	80	--	540
1978	20	10	5	45	75	5	250	--	165	40	--	--	30	80	--	725
1979	20	10	5	40	85	5	275	--	180	40	--	--	30	90	--	780
1980	20	10	5	50	100	5	300	--	200	40	--	--	30	90	--	850
1982	45	20	20	80	100	150	400	--	260	40	--	--	50	100	--	1,265
1985	150	50	170	100	100	200	600	--	360	60	--	--	70	100	--	1,960
1990	150	50	240	150	100	200	800	--	440	80	100	--	100	100	10	2,520
2000	200	100	300	200	100	200	800	--	480	80	200	--	200	100	10	2,970

Table 10 (concluded)

	Abu Dhabi	Dubai	Iraq	Iran	Kuwait*	Qatar	Saudi Arabia*	Sharjah	Algeria	Libya	Nigeria	Gabon	Indonesia†	Venezuela‡	Ecuador	Total
Total petroleum																
1973	1,298	220	1,964	5,901	3,084	570	7,687	--	1,100	2,222	2,053	147	1,324	3,454	204	31,228
1974	1,412	239	1,850	6,071	2,596	523	8,610	--	1,036	1,511	2,256	177	1,396	3,061	153	30,891
1975	1,403	254	2,240	5,395	2,105	451	7,215	38	996	1,513	1,787	200	1,313	2,420	160	27,490
1976	1,590	315	2,159	5,928	2,200	497	8,765	37	115	1,946	2,050	214	1,510	2,365	187	30,878
1977	1,695	320	2,155	5,690	1,932	355	9,343	30	1,065	2,090	2,020	225	1,700	2,360	180	31,160
1978	1,468	372	2,634	5,249	2,171	487	8,541	22	1,390	2,016	1,907	225	1,666	2,243	202	30,593
1979	1,421	370	3,288	3,331	2,325	540	9,295	18	1,401	2,103	2,361	229	1,634	2,399	222	30,947
1980	1,470	360	3,505	4,050	2,100	505	8,800	20	1,400	2,040	2,400	220	1,580	2,290	200	30,940
1982	1,495	370	3,520	4,080	2,100	650	9,270	20	1,460	2,040	2,400	220	1,550	2,200	200	31,575
1985	1,600	400	3,670	4,100	2,100	700	9,600	20	1,460	2,060	2,400	220	1,670	2,200	200	32,400
1990	1,600	400	4,240	4,150	2,100	600	9,800	20	1,440	2,080	2,500	220	1,700	2,200	210	33,260
2000	1,650	450	4,300	4,200	2,100	500	9,800	20	1,380	2,080	2,600	220	1,800	1,800	210	33,110

Note: Totals may not add due to rounding.
* Includes Neutral Zone.
† Excludes synthetic oil production from coal in Indonesia of 100,000 barrels per day in 1990 and 300,000 barrels per day in 2000.
‡ Excludes synthetic oil production from coal in Venezuela of 100,000 barrels per day in 1990 and 1 million barrels per day in 2000. Also excludes heavy oil production.

Sources: Crude oil, 1973-77--The Petroleum Publishing Co., International Petroleum Encyclopedia, 1978. 1978--The Oil and Gas Journal, various issues.
NGL, 1973-78--CIA, International Energy Biweekly Statistical Review, various issues.
Projections--SHCA.

Table 11

WORLD CRUDE OIL AND NATURAL GAS LIQUIDS PRODUCTION
(MBD)
1976-2000

	1976			1977			1978			1979			1980			1982			1985				1990				2000			
	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Synthetic	Total	Crude	NGL	Synthetic	Total	Crude	NGL	Synthetic	Total
United States	8,132	1,604	9,736	8,245	1,618	9,863	8,701	1,557	10,268	8,585	1,515	10,100	8,321	1,479	9,800	8,057	1,443	9,500	8,633	1,367	100	10,100	8,944	1,256	300	10,500	7,941	959	1,600	10,500
Canada	1,307	287	1,594	1,321	288	1,609	1,314*	264	1,578	1,402*	298	1,700	1,502*	298	1,800	1,584*	316	1,900	1,355	345	300	2,000	999	401	600	2,000	699	401	900	2,000
Western Europe	951	70	1,021	1,432	85	1,517	1,797	110	1,907	2,349	151	2,500	2,833	167	3,000	3,371	229	3,600	3,700	300	--	4,000	3,700	300	--	4,000	3,700	300	--	4,000
Japan	12	--	12	10	--	10	10	--	10	10	--	10	10	--	10	10	--	10	10	--	--	10	10	--	--	10	10	--	--	10
Africa																														
Self-sufficient oil regions																														
Algeria	1,050	65	1,115	990	75	1,065	1,225	165	1,390	1,221	180	1,401	1,200	200	1,400	1,200	260	1,460	1,100	360	--	1,460	1,000	440	--	1,440	900	480	--	1,380
Libya	1,906	40	1,946	2,050	40	2,090	1,976	40	2,016	2,063	40	2,103	2,000	40	2,040	2,000	40	2,040	2,000	60	--	2,060	2,000	80	--	2,080	2,000	80	--	2,080
Nigeria	2,050	--	2,050	2,020	--	2,020	1,907	--	1,907	2,361	--	2,361	2,400	--	2,400	2,400	--	2,400	2,400	--	--	2,400	2,400	100	--	2,500	2,400	200	--	2,600
Angola/Cabinda	108	--	108	195	--	195	166	--	166	200	--	200	300	--	300	300	--	300	300	--	--	300	300	--	--	300	300	--	--	300
Egypt	328	--	328	450	--	450	484	--	484	500	--	500	600	--	600	800	--	800	1,000	--	--	1,000	1,000	--	--	1,000	1,000	--	--	1,000
Tunisia	73	--	73	87	--	87	100	--	100	100	--	100	100	--	100	100	--	100	100	--	--	100	100	--	--	100	100	--	--	100
Gabon	214	--	214	225	--	225	225	--	225	229	--	229	220	--	220	220	--	220	220	--	--	220	220	--	--	220	220	--	--	220
Total	5,729	105	5,834	6,017	115	6,132	6,083	205	6,288	6,674	220	6,894	6,820	240	7,060	7,020	300	7,320	7,120	420	--	7,540	7,020	620	--	7,640	6,920	760	--	7,680
Strong economies																														
South Africa	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	50	50	--	--	100	100	--	--	300	300
Vulnerable economies																														
Other	58	--	58	59	--	59	57	--	57	300	--	300	400	--	400	500	--	500	500	--	--	500	500	--	--	500	500	--	--	500
Total Africa	5,787	105	5,892	6,076	115	6,191	6,140	205	6,345	6,974	220	7,194	7,220	240	7,460	7,520	300	7,820	7,620	420	50	8,090	7,520	620	100	8,240	7,420	760	300	8,480
Middle East																														
Self-sufficient oil regions																														
Saudi Arabia	8,580	185	8,765	9,128	215	9,343	8,291	250	8,541	9,020	275	9,295	8,500	300	8,800	8,870	400	9,270	9,000	600	--	9,600	9,000	800	--	9,800	9,000	800	--	9,800
Iran	5,883	45	5,928	5,650	40	5,690	5,204	45	5,249	3,291	40	3,331	4,000	50	4,050	4,000	80	4,080	4,000	100	--	4,100	4,000	150	--	4,150	4,000	200	--	4,200
Kuwait	2,140	50	2,200	1,877	55	1,932	2,096	75	2,171	2,250	85	2,335	2,000	100	2,100	2,100	100	2,100	2,000	100	--	2,100	2,000	100	--	2,100	2,000	100	--	2,100
Iraq	2,159	--	2,159	2,150	5	2,155	2,629	5	2,634	3,283	5	3,288	3,500	5	3,505	3,500	20	3,520	3,500	170	--	3,670	4,000	240	--	4,240	4,000	300	--	4,300
Abu Dhabi	1,590	--	1,590	1,680	15	1,695	1,448	20	1,468	1,401	20	1,421	1,450	20	1,470	1,450	45	1,495		150	--	1,600	1,450	150	--	1,600	1,450	200	--	1,650
Bahrain	58	--	58	54	--	54	53	--	53	50	--	50	40	--	40	30	--	30	20	--	--	20	--	--	--	--	--	--	--	--
Dubai	315	--	315	320	--	320	362	10	372	360	10	370	350	10	360	350	20	370	350	50	--	400	350	50	--	400	350	100	--	450
Oman	368	--	368	350	--	350	315	--	315	400	--	400	400	--	400	400	--	400	400	--	--	400	400	--	--	400	400	--	--	400
Qatar	487	10	497	350	5	355	482	5	487	535	5	540	500	5	505	500	150	650	500	200	--	700	400	200	--	600	300	200	--	500
Syria	175	--	175	200	--	200	190	--	190	200	--	200	300	--	300	400	--	400	400	--	--	400	400	--	--	400	400	--	--	400
Other	38	--	38	31	--	31	33	--	33	25	--	25	25	--	25	125	--	125	125	--	--	125	125	--	--	125	125	--	--	125
Total Middle East	21,803	290	22,093	21,790	335	22,125	21,103	410	21,513	20,815	440	21,255	21,065	490	21,555	21,625	815	22,440	21,745	1,370	--	23,115	22,125	1,690	--	23,815	22,025	1,900	--	23,925
Pacific Basin																														
Self-sufficient oil regions																														
Indonesia	1,500	10	1,510	1,690	10	1,700	1,636	30	1,666	1,600	30	1,630	1,550	30	1,580	1,500	50	1,550	1,600	70	--	1,670	1,600	100	100	1,800	1,600	200	200	2,000
Malaysia/Brunei	361	--	361	397	--	397	454	--	454	500	--	500	500	--	500	590	10	600	580	20	--	600	670	30	--	700	660	40	--	700
Total	1,861	10	1,871	2,087	10	2,097	2,090	30	2,120	2,100	30	2,130	2,050	30	2,080	2,090	60	2,150	2,180	90	--	2,270	2,270	130	100	2,500	2,260	240	200	2,700
Strong economies																														
Australia	430	50	480	430	55	485	432	60	492	440	60	500	440	60	500	320	80	400	300	100	--	400	300	100	100	500	300	100	300	700
New Zealand, Singapore, Taiwan, and Hong Kong	14	--	14	20	--	20	5	--	5	100	--	100	150	--	150	200	--	200	200	--	--	200	200	--	--	200	200	--	--	200
Total	444	50	494	450	55	505	437	60	497	540	60	600	590	60	650	520	80	600	500	100	--	600	500	100	100	700	500	100	300	900
Vulnerable economies																														
Other	208	25	233	233	30	263	261	30	291	270	30	300	270	30	300	270	30	300	270	30	--	300	270	30	--	300	270	30	--	300
Total Pacific Basin	2,513	85	2,598	2,770	95	2,865	2,788	120	2,908	2,910	120	3,030	2,910	120	3,030	2,880	170	3,050	2,950	220	--	3,170	3,040	260	200	3,500	3,030	370	500	3,900
Latin America																														
Self-sufficient oil regions																														
Venezuela	2,290	75	2,365	2,280	80	2,360	2,163	80	2,243	2,309	90	2,399	2,200	90	2,290	2,100	100	2,200	2,100	100	--	2,200	2,100	100	100	2,300	1,700	100	1,000	2,800
Argentina	390	35	425	440	35	475	451	35	486	450	35	485	465	35	500	465	35	500	550	50	--	600	550	50	--	600	550	50	--	600
Colombia	147	--	147	140	--	140	142	--	142	140	--	140	140	--	140	140	--	140	140	--	--	140	140	--	--	140	140	--	--	140
Ecuador	187	--	187	180	--	180	202	--	202	222	--	222	200	--	200	200	--	200	200	--	--	200	200	10	--	210	200	10	--	210
Mexico	831	95	926	990	105	1,095	1,207	135	1,342	1,647	153	1,800	2,000	200	2,200	2,390	210	2,600	2,760	240	--	3,000	3,230	270	--	3,500	3,335	365	--	3,700
Trinidad and Tobago	224	--	224	230	--	230	234	--	234	300	--	300	300	--	300	300	--	300	270	30	--	300	270	30	--	300	270	30	--	300
Total	4,069	205	4,274	4,260	220	4,480	4,399	250	4,649	5,068	278	5,346	5,305	325	5,630	5,595	345	5,940	6,020	420	--	6,440	6,490	460	100	7,050	6,195	555	1,000	7,750

Table 11 (concluded)

	1976			1977			1978			1979			1980			1982			1985				1990				2000			
	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Total	Crude	NGL	Syn-thetic	Total	Crude	NGL	Syn-thetic	Total	Crude	NGL	Syn-thetic	Total
Latin America (cont.)																														
Strong economies																														
Brazil	171	--	171	162	--	162	164	--	164	200	--	200	200	--	200 *	200	--	200	280	--	20	300	260	--	40	300	220	--	80	300
Vulnerable economies																														
Peru	75	--	75	90	--	90	156	--	156	200	--	200	200	--	200	200	--	200	200	--	--	200	200	--	--	200	200	--	--	200
Bolivia	41	--	41	35	--	35	34	--	34	100	--	100	100	--	100	100	--	100	100	--	--	100	100	--	--	100	100	--	--	100
Other	24	10	34	22	10	32	19	10	29	30	10	40	90	10	100	180	20	200	180	20	--	200	180	20	--	200	180	20	--	200
Total	140	10	150	147	10	157	209	10	219	330	10	340	390	10	400	480	20	500	480	20	--	500	480	20	--	500	480	20	--	500
Total Latin America	4,380	215	4,595	4,569	230	4,799	4,772	260	5,032	5,598	288	5,886	5,895	335	6,230	6,275	365	6,640	6,780	440	20	7,240	7,230	480	140	7,850	6,895	575	1,080	8,550
Free world	44,885	2,656	47,541	46,213	2,766	48,979	46,625	2,936	49,561	48,643	3,032	51,675	49,756	3,129	52,885	51,322	3,638	54,960	52,793	4,462	470	57,725	53,568	5,007	1,340	59,915	51,720	5,265	4,380	61,365

* Canadian production of synthetic crude oil (in MBD) is as follows: 1978, 60; 1979, 100; 1980, 125; and 1982, 225.

Sources: United States--1976-77, U.S. Department of Energy, Energy Information Administration, Energy Data Reports, Petroleum Statement, Annual (formerly by U.S. Department of the Interior, Mineral Industry Surveys), various years. 1978, estimated from U.S. Department of Energy, Energy Information Administration, Energy Data Reports, Petroleum Statement, Monthly and Monthly Energy Review, various monthly issues.
Canada--1976-77, Statistics Canada, Crude Petroleum and Natural Gas Production, various monthly issues. 1978--estimate from Oilweek, February 12, 1979.
All other countries--Crude oil--1976-77, Petroleum Publishing Co., International Petroleum Encyclopedia, 1977 and 1978. 1978, The Oil and Gas Journal, various monthly issues. NGL--1976-78, Central Intelligence Agency, International Energy Statistical Review, March 7, 1979.

All countries--1979-2000, SHCA.

heavy oil resources. The outlook for the frontier areas, however, has not improved and projected production for Western Europe has been scaled back once again because of tightened controls on profitability and indications of moves toward production controls. The outlook in the United States is not much better than it was a couple of years ago although the potential is probably in excess of our projection. (Canada may also have a greater production capacity than our adopted forecast but the currently known potential is all high in cost.)

In the detail for all countries, synthetic oil production is now estimated separately and for the free world amounts to about one-half million barrels per day in 1985, 1.3 MMBD in 1990 and 4.4 MMBD in 2000. This production includes shale oil and some oil from coal in the United States, tar sands and heavy oil in Canada, heavy oil in Venezuela, shale oil in Brazil, and oil from coal in South Africa and Australia. In some of these countries, the potential is well in excess of the estimate but the distribution of each resource as a function of cost is not known and in general the high cost suggests a rather slow development.

Taking NGL and synthetic oil production (shale oil, tar sands, heavy oil, and oil from coal) into account as well as net imports from the Soviet Bloc, total oil availability is projected to be (in MMBD):

	Crude Oil	NGL	Synthetic	Total Free World Production	Net Imports From Soviet Bloc	Processing Gain	Total Free World Availability
1978	46.5	2.9	--	49.4	1.2	0.5	51.1
1980	49.8	3.1	--	52.9	0.5	0.5	53.9
1982	51.3	3.6	--	54.9	1.2	0.5	56.2
1985	52.8	4.5	0.5	57.8	1.4	0.5	59.7
1990	53.6	5.0	1.3	59.9	1.0	0.5	61.4
2000	51.7	5.3	4.4	61.4	0.0	0.5	61.9

The probable range of net imports from the Soviet Bloc is zero to 1.4 MMBD; we have dropped the net imports for the next few years, raised them for the intermediate term as imports from the PRC become significant and reduced them back to zero by 2000. Conventional crude production is consistent with a remaining resource base in the free world of about 1,100 billion barrels.

Total oil availability peaks in about a decade at less than 60 MMBD, only 9 MMBD (18%) higher than in 1978. The post-1990 decline would be much steeper if synthetic oil were not counted on, and the 4.4 MMBD of synthetic production by 2000 must be viewed as optimistic. This magnitude is also considered to be independent of the price of crude oil, so long as the real price rises at more than 3% per year.

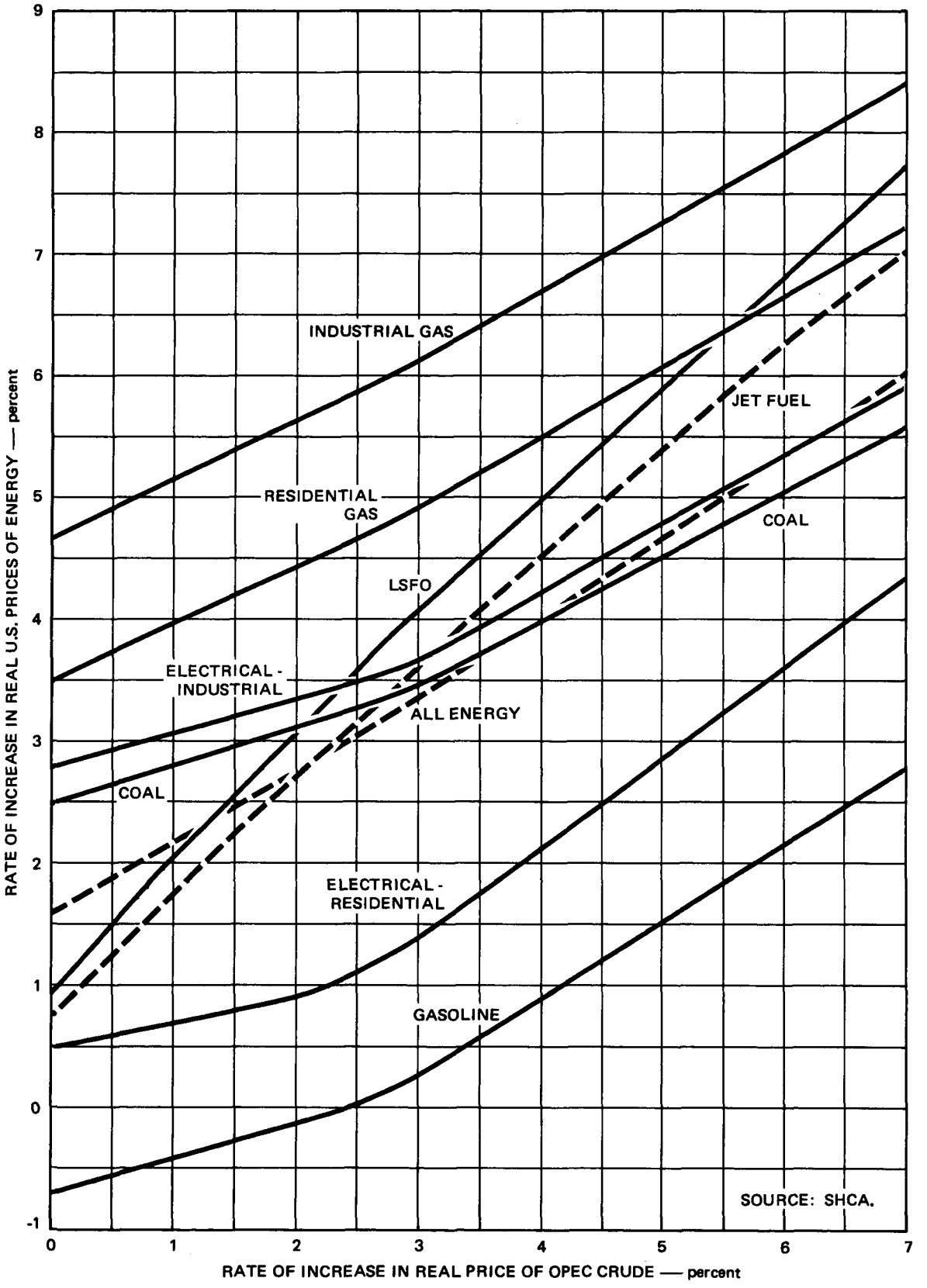
Another linkage needed to relate the price elasticity estimates and the price escalation of OPEC crude is the effect that OPEC's price trend has on U.S. energy price, assuming no change in taxes (Figure 7). It is our position that OPEC's price trend affects the price trend for every form of energy. While all prices are not equalized for equivalent functions, there is strong pressure for them to converge. OPEC's price trend affects the costs of producing and transporting natural gas, LNG, coal, electricity, and of course all forms of oil. The U.S. government can attempt to minimize these effects, but we believe little can be done. For example, the effect of limiting the price escalation of both upper and lower tier oil is to lower U.S. oil production which is then offset by an increase in imports and the consumer prices for oil products will still increase along with the increase in the OPEC crude oil price. Similarly, the U.S. government can fix the escalation in the field price of gas, making it independent of the OPEC price, but the rate of increase in OPEC's price will be reflected in increases in gas production costs and decreases in the exploration effort and resulting production. This means either lower load factors resulting in higher consumer prices or more supplementary supplies at a higher price than for traditional supplies and, again, higher consumer prices.

The relationship demonstrates that over the next decade, average U.S. consumer prices for energy will increase by almost 3% per year (real) even if there is no further increase in OPEC's real price. If OPEC's price increases by 3% per year in real terms, on average to 1990, U.S. energy prices will average almost a 5% per year real increase. If OPEC's rate of increase were 7% per year, U.S. energy on average would increase at about the same rate. It is a highly complex relationship.

Although it is difficult to conceive of the price of any one commodity influencing economic growth, historical evidence supports the thesis that the price of oil does have an effect; however, factors other than the price of oil could have been the cause. A direct analysis of the relationship between oil revenue and total economic activity also fails to identify the importance of the oil price. For example, consider the approximate data on free world economic activity and crude oil revenues:

	Billions of Dollars		
	1976 Level	Annual Increment	Comment
Gross free world product	$4,769	$477	Assumes 5% real growth and 5% inflation
Crude oil	200	10	2+ million barrels per day of annual growth
Crude oil price increase			
5%		10	
10		20	
15		30	
20		40	
25		50	

FIGURE 7 RELATIONSHIPS BETWEEN OPEC PRICE AND U.S. ENERGY CONSUMER PRICES: 1976-1990



Crude oil sales account for 4% to 5% of gross free world product and from 4% to 12% of the incremental increase in GNP, for a 5% to 25% increase in the price. These shares are large for a single commodity, but taken alone they tend to indicate that a large price increase can be accommodated. Moreover, all goods and services seem to be increasing in price and the effect of a large increase in the price of oil on the overall inflation rate does not appear to be significant enough to curtail economic growth.

This is not the way to evaluate the effect. International trade in crude oil exceeds $140 billion a year. Annual trade in iron ore is only about $5 billion and the most important finished product, automobiles, amounts to about $25 billion. This provides a better perspective as to oil's significance. To evaluate the effect of an increase in the price of oil, it is essential to consider all elements of its impact and to consider them from the standpoint of their effect on economic growth, which is only 5% or 6% at a maximum and the effective range of consideration is zero to 6%. In other words, very little change is required to alter the growth rate by several percent. It is also important to conduct a dynamic analysis rather than consider a single price increase, because even before the adjustment from one price increase is completed, another price increase may be imposed.

The major elements affecting economic growth, as the price of oil is increased, are:

- The rate of inflation is increased. A 10% price increase may add only 0.5 percentage points to the rate of inflation but for the bulk of the labor force the increase in personal income will not offset this additional inflation and real personal income will increase more slowly than with no price increase. The increase in consumer spending will be that much less, and if the price increase is too large, a reduction in confidence may increase the savings rate and further reduce consumer spending.

- OPEC's imports are already at an approximate maximum in the short term (i.e., for the next year). Therefore, exports to OPEC do not increase to offset the increased cost of oil imports from OPEC. Because of the increased payments to OPEC, less funds are actually available for trade and the result could even be a decline in international trade, excluding the value of oil.

- The more favorable monetary balance within OPEC requires greater deficits in most importing countries, but with the deficits varying widely in relative importance to each country. In many cases, the deficits are on top of an already massive cumulative deficit. One consequence of these deficits is further adjustments in all exchange rates. This creates more nationalistic tendencies and has an adverse effect on world trade.

- Company planners tend to lower their forecasts of demand for their products, particularly in energy intensive goods. The lowered expectation leads to deferred or cancelled capital expenditures.

If the price increase is so high that confidence is undermined, expenditures will be further reduced.

- Tax revenues increase more slowly, resulting in pressures to reduce government expenditures. Passage of state and local bond issues becomes more difficult.

- Reduced spending in all sectors slows the increase in employment, further reducing the growth in real personal income and therefore in consumer spending.

- An increased OPEC price leads to higher prices for a portion of all other energy supply immediately and for a larger portion eventually. This further increases inflation.

- There are no offsetting factors or at least none have been identified as yet.

- The result is rather astounding. On the surface, the maximum effect one would expect from an increased payment to OPEC is a commensurate reduction in economic growth; e.g., a $10 billion annual increase would lower free world economic growth by $10 billion or 0.2%, and there are reasons to expect the impact to be even less. But when all the effects are traced through, a $10 billion increase could have 5 to 10 times that impact on economic growth. Moreover, the greater the price increase, the greater the multiplier effect, primarily because of the confidence factor. The latter is accentuated by the ritual of OPEC price deliberations, the step-function type of increase rather than a gradual adjustment, and the continuous stream of publicity on the subject. The effect may be summarized as follows for free world economic growth in 1976-80 and OPEC price increases as a function of the price increase:

Rate of Increase in Real Price (%/yr)	Increase in Actual Dollars per Barrel	Billions of Dollars			Multiplier Effect*
		Increase in OPEC Revenues	Real Growth in GWP	Loss of Growth in GWP	
0%	$0.60	$ 7	$260	$ 0	0
1	0.70	8	240	20	2.5
3	1.00	11	200	60	5.5
5	1.20	13	50	210	16
7	1.45	16	0	260	16+

* Loss of growth in gross world product divided by increase in OPEC revenues.

The Balance

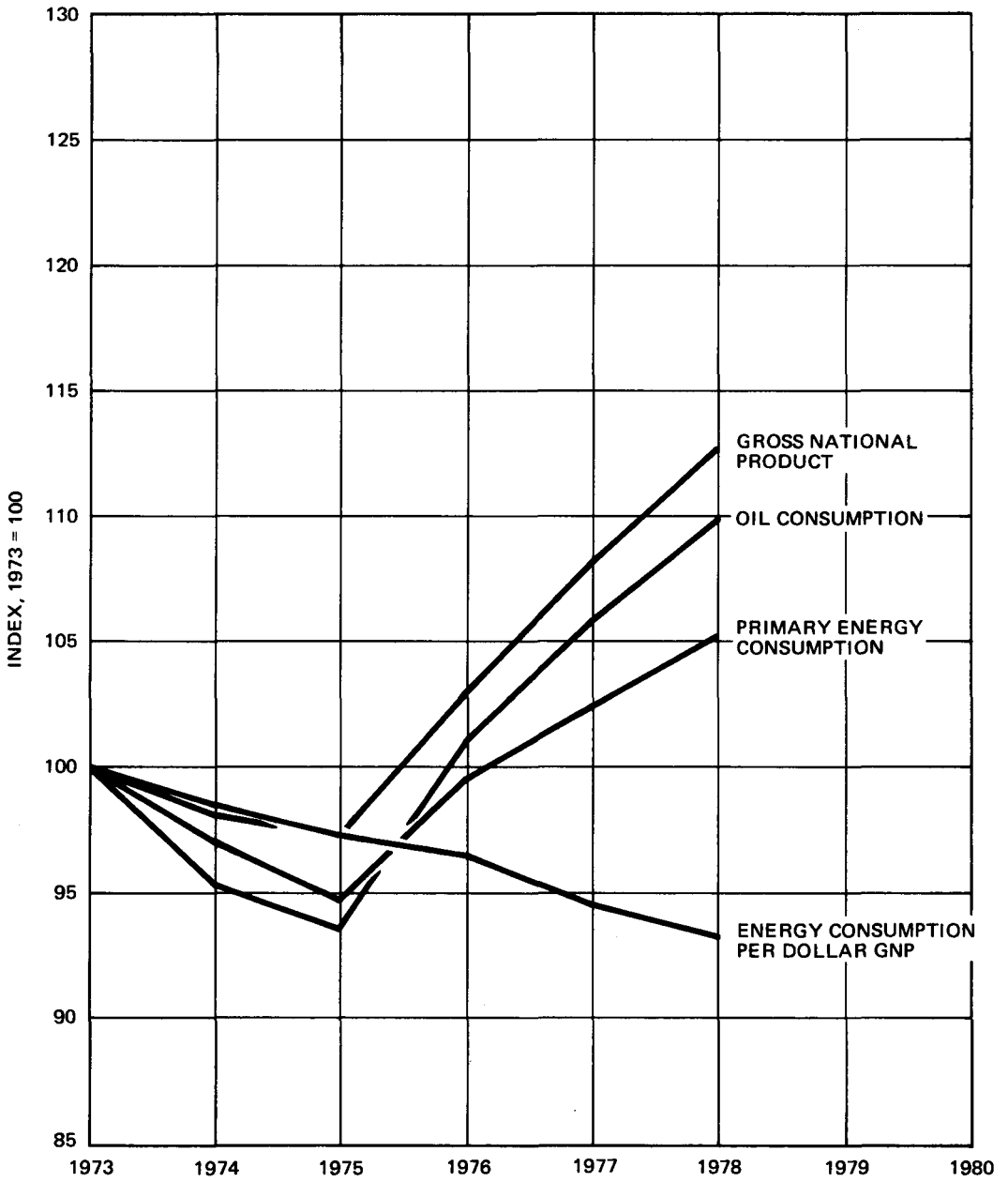
The rate at which OPEC's price increases generally affects the world's consumer prices for energy, but not in all instances. For the United States, the relationship is as was shown in Figure 7. In most of the rest of the world the relationship is quite direct, but within OPEC (and some other self-sufficient oil regions such as Mexico), the consumer prices for energy have been held far below the world price and are expected to be constrained for another five to ten years. In such countries, the growth in energy demand can be expected to parallel the growth in economic activity during this period.

For most countries, the price of energy has slowed the growth in energy demand more markedly than in GNP. The 1973-78 trends (with 1973 equal to 100) in free world (Figure 8) economic activity, total energy and oil consumption, the energy/GNP ratio, and OPEC production demonstrate the gradual divergence in the trends over the six-year period; it is apparent that the average annual growth rate is very low (zero for OPEC oil). The U.S. trends (Figure 9) are comparable although U.S. economic recovery has been stronger than for the free world in total and hence total energy and oil consumption have also grown more. But the divergence in the trends is also present. The decline in the energy/GNP ratio (Btu per dollar) by only a few percent can be a little misleading because it seems to imply very little change. However, note that a GNP growth rate of 2% per year for four years and an energy growth rate of 1% per year for four years will yield a ratio of energy to GNP in the fourth year of 0.96 while the ratio of the growth rates is only 0.5. If the ratio of the growth rates is 0.75, the energy/GNP ratio in the fourth year would be about 0.98. With a 4% per year growth rate in GNP and a 3% per year growth rate for energy use (0.75 ratio in the growth rates or a price elasticity of about -0.3) over 10 and 20 years, the energy/GNP ratio would drop to 0.91 in the tenth year and to 0.82 in the twentieth year. In time, the effect is appreciable even with low elasticity.

In the balancing tables (Table 12 for the derivation of the 1985 balance and the 1979-85 rate of increase in the OPEC price, and Table 13 for the 2000 balance and the 1985-2000 rate of increase in the OPEC price), the price elasticity of demand for each region is based largely on 1974-78 experience but allowing for some increase for longer term effects, and the elasticity varies from -0.25 to -0.5 depending on the region and the time period. Actual, or estimated actual data for 1976-79 are provided and then for 1985 or 2000 the economic growth rate and energy growth rate and use by form of energy by country or region of the free world is estimated for each of five different rates of increase in the OPEC price. Note that the 2000 balance is dependent on the adopted results for 1985; i.e., the 1979-85 trends are first derived and the trends for the succeeding period are dependent on them.

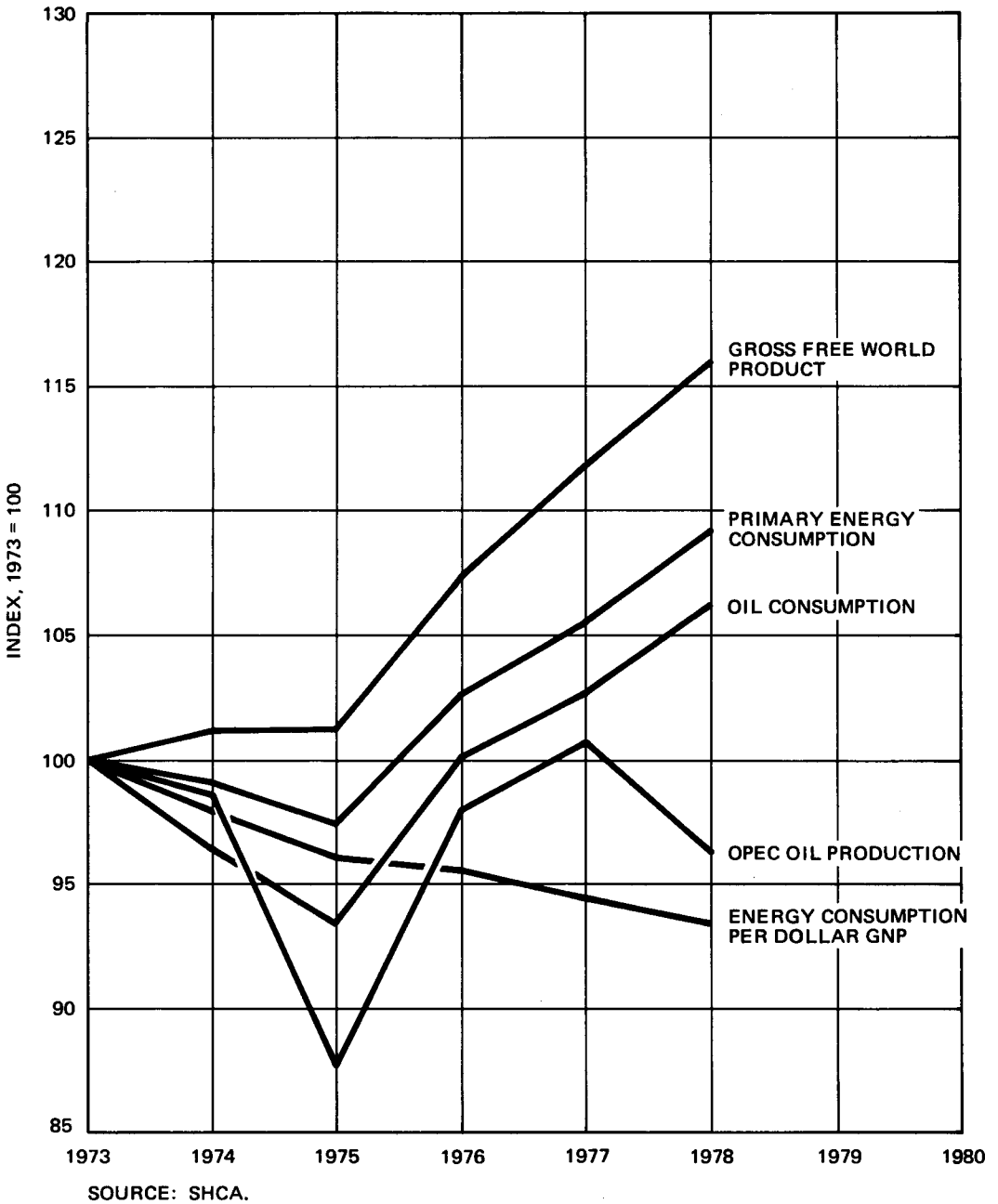
Oil use is derived from the projected total energy demand, less the use of all non-oil forms of energy.

FIGURE 8 TRENDS IN U.S. ECONOMIC GROWTH AND ENERGY USE: 1973-1978



SOURCE: SHCA.

FIGURE 9 TRENDS IN FREE WORLD ECONOMIC GROWTH AND ENERGY USE: 1973-1978



SOURCE: SHCA.

Table 12

EFFECT OF CRUDE OIL PRICE INCREASES ON ECONOMIC GROWTH AND ENERGY CONSUMPTION IN THE FREE WORLD: 1976-1985

					Rate of Real Increase in OPEC Oil Price									
					0% per Year		1% per Year		3% per Year		5% per Year		7% per Year	
	1976	1977	1978	1979	1979-85 (percent per year)	1985	1979-85 (percent per year)	1985	1979-85 (percent per year)	1985	1979-85 (percent per year)	1985	1979-85 (percent per year)	1985
OPEC oil price (actual dollars)	$11.51	$12.30	$12.70	$17.00	6.5%	$26.48	7.6%	$28.11	9.7%	$31.61	11.8%	$35.48	14.0%	$39.74
OPEC oil price (1978 dollars)	13.11	13.20	12.70	15.41	0.0	15.41	1.0	16.36	3.0	18.40	5.0	20.65	7.0	23.13
Rate of U.S. energy price increase					1.6		2.2		3.3		4.7		6.0	
GNP rate of increase (percent per year)														
Free world	5.7%	4.4%	4.0%	3.4%	5.1%		4.9%		4.4%		3.7%		3.3%	
United States	6.0	4.9	3.9	2.0	4.0		3.9		3.7		3.0		2.5	
Canada	5.0	2.3	3.8	4.0	4.0		3.9		3.7		3.5		3.0	
Western Europe	4.3	2.2	2.6	3.3	4.6		4.4		3.9		3.3		2.8	
Japan	6.3	6.5	5.3	5.0	6.3		6.0		5.3		4.4		3.6	
Self-sufficient oil regions	10.8	9.6	8.8	8.8	8.6		8.2		8.0		8.0		7.8	
Strong economies	6.3	4.8	3.8	4.5	7.0		6.8		6.0		5.5		5.0	
Vulnerable economies	4.1	2.5	3.7	3.7	6.0		5.0		4.5		4.0		3.5	
Total primary energy increase (percent per year)														
Free world	4.8%	2.6%	3.7%	3.0%	4.9%		4.4%		3.8%		3.2%		2.9%	
United States	5.3	2.6	2.2	2.1	3.8		3.0		2.4		1.9		1.7	
Canada	4.3	2.5	3.5	3.4	3.8		3.6		3.3		3.0		2.5	
Western Europe	5.8	1.1	3.3	2.8	4.4		4.0		3.5		2.8		2.4	
Japan	3.6	1.9	4.9	4.6	6.0		5.5		4.7		4.0		3.0	
Self-sufficient oil regions	4.9	8.6	10.1	6.5	9.2		8.8		8.6		8.5		8.2	
Strong economies	3.4	5.2	5.9	3.7	7.0		6.8		5.5		5.0		4.5	
Vulnerable economies	0.9	1.7	5.1	1.6	5.5		4.5		4.0		3.5		3.0	
Total primary energy (quads)														
Free world	182.9	187.7	194.7	200.5		267.8		259.2		250.1		242.8		237.7
United States	75.7	77.7	79.4	81.1		101.6		97.1		93.3		90.6		89.6
Canada	8.3	8.5	8.8	9.1		11.4		11.3		11.1		10.9		10.6
Western Europe	50.5	51.0	52.7	54.2		70.2		68.6		66.6		64.0		62.5
Japan	14.3	14.6	15.3	16.0		22.7		22.1		21.1		20.2		19.1
Self-sufficient oil regions	12.8	13.9	15.3	16.3		27.7		27.1		26.7		26.6		26.3
Strong economies	9.7	10.2	10.8	11.2		16.8		16.6		15.4		15.0		14.6
Vulnerable economies	11.6	11.8	12.4	12.6		17.4		16.4		15.9		15.5		15.0
Gas														
Free world	33.1	33.9	35.3	36.8		42.9		42.9		42.9		42.9		42.9
United States	21.0	21.0	20.9	20.9		19.9		19.9		19.9		19.9		19.9
Canada	1.6	1.7	1.8	2.0		2.4		2.4		2.4		2.4		2.4
Western Europe	6.4	6.6	7.2	7.6		9.9		9.9		9.9		9.9		9.9
Japan	0.4	0.5	0.7	1.0		2.5		2.5		2.5		2.5		2.5
Self-sufficient oil regions	3.1	3.4	3.8	4.2		6.4		6.4		6.4		6.4		6.4
Strong economies	0.3	0.3	0.4	0.6		1.2		1.2		1.2		1.2		1.2
Vulnerable economies	0.3	0.4	0.5	0.5		0.6		0.6		0.6		0.6		0.6

Table 12 (concluded)

					Rate of Real Increase in OPEC Oil Price									
					0% per Year		1% per Year		3% per Year		5% per Year		7% per Year	
	1976	1977	1978	1979	1979-85 (percent per year)	1985	1979-85 (percent per year)	1985	1979-85 (percent per year)	1985	1979-85 (percent per year)	1985	1979-85 (percent per year)	1985
Solid fuels														
Free world	34.6	35.2	35.6	36.5		50.5		49.0		46.8		44.8		43.5
United States	13.8	14.2	14.3	15.0		23.0		22.5		21.4		20.5		20.0
Canada	0.7	0.7	0.7	0.7		1.2		1.1		1.0		1.0		1.0
Western Europe	10.6	10.5	10.5	10.4		13.0		12.6		12.1		11.8		11.5
Japan	2.3	2.3	2.4	2.5		3.2		3.1		3.0		2.9		2.8
Self-sufficient oil regions	0.4	0.4	0.4	0.4		0.6		0.6		0.6		0.5		0.5
Strong economies	3.2	3.4	3.5	3.6		4.5		4.3		4.1		3.9		3.7
Vulnerable economies	3.6	3.7	3.8	3.9		5.0		4.8		4.6		4.2		4.0
Hydroelectric and nuclear														
Free world	16.9	17.8	19.9	21.8		33.4		33.4		33.4		33.4		33.4
United States	5.2	5.2	6.2	6.9		10.3		10.3		10.3		10.3		10.3
Canada	2.4	2.4	2.5	2.7		3.5		3.5		3.5		3.5		3.5
Western Europe	5.1	5.9	6.4	6.9		11.5		11.5		11.5		11.5		11.5
Japan	1.3	1.2	1.4	1.6		2.6		2.6		2.6		2.6		2.6
Self-sufficient oil regions	0.7	0.7	0.8	0.9		1.5		1.5		1.5		1.5		1.5
Strong economies	1.2	1.3	1.4	1.5		2.3		2.3		2.3		2.3		2.3
Vulnerable economies	1.1	1.1	1.2	1.3		1.7		1.7		1.7		1.7		1.7
Oil														
Free world	98.3	100.8	103.9	105.4		141.0		133.9		127.0		121.7		117.9
United States	35.7	37.3	38.0	38.2		48.4		44.4		41.7		39.9		39.4
Canada	3.7	3.8	3.8	3.8		4.3		4.3		4.2		4.0		3.7
Western Europe	28.4	28.0	28.6	29.1		35.8		34.6		33.1		30.8		29.6
Japan	10.3	10.6	10.8	11.0		14.4		13.9		13.0		12.2		11.2
Self-sufficient oil regions	8.6	9.3	10.3	10.8		19.2		18.6		18.2		18.2		17.9
Strong economies	5.0	5.2	5.5	5.6		8.8		8.8		7.8		7.6		7.4
Vulnerable economies	6.6	6.6	6.9	6.9		10.1		9.3		9.0		9.0		8.7

Source: SHCA.

Table 13

EFFECT OF CRUDE OIL PRICE INCREASES ON ECONOMIC GROWTH AND ENERGY CONSUMPTION IN THE FREE WORLD: 1985-2000
(Based on 1985 Balance)

		Rate of Real Increase in OPEC Oil Price									
		0% per Year		1% per Year		3% per Year		5% per Year		7% per Year	
	1985	1985-2000 (percent per year)	2000	1985-2000 (percent per year)	2000	1985-2000 (percent per year)	2000	1985-2000 (percent per year)	2000	1985-2000 (percent per year)	2000
OPEC oil price (actual dollars)	$35.48	5.5%	$121.16	6.6%	$140.53	8.7%	$188.76	10.8%	$251.90	12.9%	$334.34
OPEC oil price (1978 dollars)	20.65	0.0	20.65	1.0	23.95	3.0	32.17	5.0	42.93	7.0	56.97
Rate of U.S. energy price increase		1.0		1.5		3.0		5.0		7.0	
GNP rate of increase (percent per year)											
Free world		4.8		4.4		3.7		2.8		2.2	
United States		3.6		3.4		3.0		2.0		1.7	
Canada		3.7		3.6		3.5		3.0		2.5	
Western Europe		4.0		3.6		3.3		2.5		2.0	
Japan		5.3		4.8		4.4		3.6		3.0	
Self-sufficient oil regions		8.6		8.2		8.0		6.0		5.0	
Strong economies		6.6		6.3		5.5		4.0		3.3	
Vulnerable economies		6.0		5.5		4.0		3.0		2.5	
Total primary energy increase (percent per year)											
Free world		3.7		3.2		2.8		2.0		1.6	
United States		2.6		2.5		2.1		1.4		1.0	
Canada		2.8		2.7		2.6		2.2		1.9	
Western Europe		3.0		2.6		2.3		1.8		1.5	
Japan		4.2		3.7		3.3		2.8		2.4	
Self-sufficient oil regions		6.3		5.1		4.8		3.2		2.4	
Strong economies		5.3		5.0		4.0		2.8		2.4	
Vulnerable economies		4.5		4.0		3.0		2.3		1.7	
Total primary energy (quads)											
Free world	242.8		416.9		390.8		366.7		327.9		307.4
United States	90.6		134.2		130.3		122.9		110.9		104.9
Canada	10.9		16.5		16.3		16.0		15.1		14.4
Western Europe	64.0		99.7		94.1		90.0		84.3		80.3
Japan	20.2		37.4		34.8		32.9		30.4		28.8
Self-sufficient oil regions	26.6		66.6		56.2		53.8		42.7		37.7
Strong economies	15.0		32.5		31.2		27.0		22.8		21.3
Vulnerable economies	15.5		30.0		27.9		24.1		21.7		20.0

Table 13 (concluded)

		Rate of Real Increase in OPEC Oil Price									
		0% per Year		1% per Year		3% per Year		5% per Year		7% per Year	
	1985	1985-2000 (percent per year)	2000	1985-2000 (percent per year)	2000	1985-2000 (percent per year)	2000	1985-2000 (percent per year)	2000	1985-2000 (percent per year)	2000
Gas											
Free world	42.9		51.4		51.4		51.4		51.4		51.4
United States	19.9		18.6		18.6		18.6		18.6		18.6
Canada	2.4		3.3		3.3		3.3		3.3		3.3
Western Europe	9.9		9.3		9.3		9.3		9.3		9.3
Japan	2.5		4.4		4.4		4.4		4.4		4.4
Self-sufficient oil regions	6.4		12.8		12.8		12.8		12.8		12.8
Strong economies	1.2		2.2		2.2		2.2		2.2		2.2
Vulnerable economies	0.6		0.8		0.8		0.8		0.8		0.8
Solid fuels											
Free world	44.8		95.1		90.0		84.3		76.4		69.4
United States	20.5		43.0		42.0		40.6		37.0		34.0
Canada	1.0		2.1		2.0		1.7		1.5		1.3
Western Europe	11.8		24.0		22.5		21.4		19.0		17.0
Japan	2.9		9.0		8.0		7.0		6.0		5.4
Self-sufficient oil regions	0.5		1.3		1.0		0.7		0.7		0.7
Strong economies	3.9		8.0		7.5		7.0		6.5		6.0
Vulnerable economies	4.2		7.7		7.0		5.9		5.7		5.0
Hydroelectric and nuclear											
Free world	33.4		64.6		64.6		64.6		64.6		64.6
United States	10.3		14.3		14.3		14.3		14.3		14.3
Canada	3.5		5.8		5.8		5.8		5.8		5.8
Western Europe	11.5		24.0		24.0		24.0		24.0		24.0
Japan	2.6		7.0		7.0		7.0		7.0		7.0
Self-sufficient oil regions	1.5		4.2		4.2		4.2		4.2		4.2
Strong economies	2.3		5.1		5.1		5.1		5.1		5.1
Vulnerable economies	1.7		4.2		4.2		4.2		4.2		4.2
Oil											
Free world	121.7		205.8		184.8		166.4		135.5		122.0
United States	39.9		58.3		55.4		49.4		41.0		38.0
Canada	4.0		5.3		5.2		5.2		4.5		4.0
Western Europe	30.8		42.4		38.3		35.3		32.0		30.0
Japan	12.2		17.0		15.4		14.5		13.0		12.0
Self-sufficient oil regions	18.2		48.3		38.2		36.1		25.0		20.0
Strong economies	7.6		17.2		16.4		12.7		9.0		8.0
Vulnerable economies	9.0		17.3		15.9		13.2		11.0		10.0

Source: SHCA.

The final step in the balancing is to convert the oil use in quads for each rate of increase in the oil price, to barrels per day and then derive the demand for OPEC crude by subtracting all other available supplies as in Table 14.* This provides the demand schedules for OPEC crude (using rate of increase in the price rather than the absolute price), which are plotted in Figure 10 along with the band of expected supply from OPEC. We have adopted a balance at the following points:

	1979-85	1985	1985-2000	2000
Rate of increase in price (percent per year)	5%		6%	
Rate of increase in GNP†	3.7		3.0	
Free world oil demand (MMBD)		59.8		61.9
OPEC crude production (MMBD)		30.4		30.1

The free world oil demand and sources of supply are given in Table 15 and the demand by region in Table 16.

Potential Variation in the Results

The above results are considered to be the most probable; the probability for various rates of increase in the oil price are estimated as follows:

Annual Rate of Increase	Probability
0%	<10%
3	30
5.6	40
>6	>20

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* It will be noted that synthetic oil production is the same at each level of price increase. There is only so much that can be accomplished during the next 20 years or so in view of the several constraints and lengthy time needed to fully develop each of the necessary sequential steps culminating in full commercial operation. Some of the constraints are solving the environmental and siting problems, acquiring all the necessary regulatory permits, overcoming probable legal challenges, and obtaining capital financing, etc.

† Gross free world product.

Table 14

DERIVATION OF DEMAND FOR OPEC CRUDE OIL IN 1985 AND 2000 AS A FUNCTION OF RATE OF INCREASE IN MARKER CRUDE PRICE (MBD)

	Rate of Real Increase in Marker Price, 1979-85 (percent per year)				
	0%	1%	3%	5%	7%
1985					
Free world demand	69,340	65,850	62,460	59,850	57,980
Increase in stocks	800	600	450	300	250
Total supply required	70,140	66,450	62,910	60,150	58,230
Non-OPEC supply					
Net imports from Soviet Bloc	1,200	1,200	1,200	1,200	1,200
Non-OPEC production	25,200	25,200	25,200	25,200	25,200
Processing gain	500	500	500	500	500
Synthetic oil production	400	400	400	400	400
Total	27,300	27,300	27,300	27,300	27,300
OPEC crude and NGL supply required	42,840	39,150	35,610	32,850	30,930
Less OPEC NGL production	2,000	2,000	2,000	2,000	2,000
Demand for OPEC crude oil	40,840	37,150	33,610	30,850	28,930
2000					
Free world demand	101,200	90,880	81,830	66,640	60,000
Increase in stocks	0	0	0	0	0
Total supply required	101,200	90,880	81,830	66,640	60,000
Non-OPEC supply					
Net imports from Soviet Bloc	0	0	0	0	0
Non-OPEC production	23,900	23,900	23,900	23,900	23,900
Processing gain	500	500	500	500	500
Synthetic oil production	4,400	4,400	4,400	4,400	4,400
Total	28,800	28,800	28,800	28,800	28,800
OPEC crude and NGL supply required	72,400	62,080	53,030	37,840	31,200
Less OPEC NGL production	3,000	3,000	3,000	3,000	3,000
Demand for OPEC crude oil	69,400	59,080	50,030	34,840	28,200

Source: SHCA.

FIGURE 10 DEMAND FOR AND SUPPLY OF OPEC CRUDE OIL

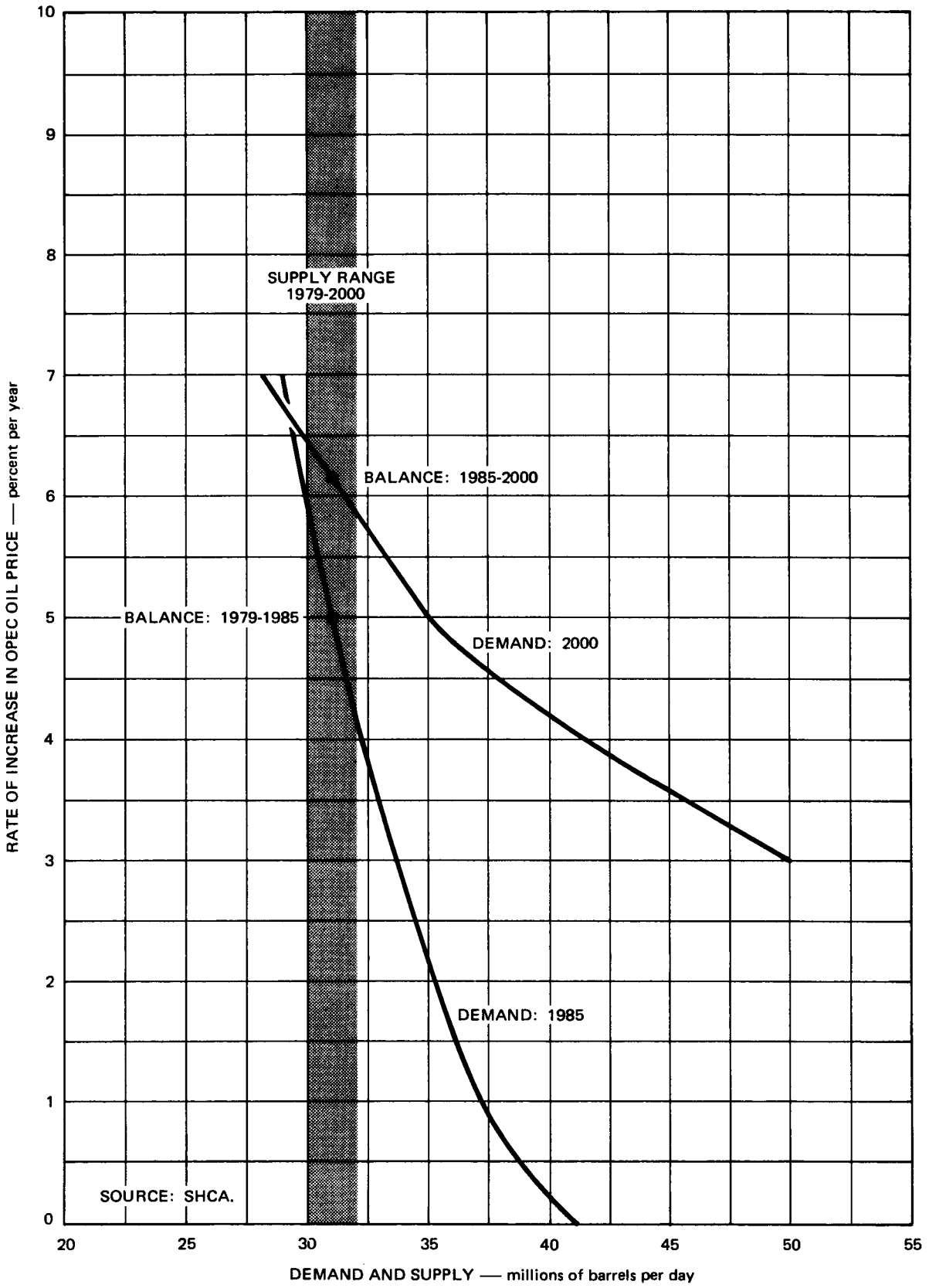

Table 15

FREE WORLD PETROLEUM DEMAND AND BROAD SOURCES OF SUPPLY
(MMBD)
1977-2000

	1977	1978	1979	1980	1982	1985	1990	2000
Demand	49.9	51.4	51.9	53.1	55.4	59.4	61.4	61.9
Increase (decrease) in stocks	1.3	(0.3)	0.3	0.8	0.8	0.3	0.0	0.0
Total supply required	51.2	51.1	52.2	53.9	56.2	59.7	61.4	61.9
Sources of supply								
Free world production								
OPEC								
Crude oil	31.1	29.7	30.2	30.1	30.3	30.4	30.7	30.1
NGL	0.6	0.7	0.8	0.9	1.3	2.0	2.5	3.0
Total	31.7	30.4	31.0	30.9	31.6	32.4	33.3	33.1
Non-OPEC								
Crude oil	15.6	16.8	18.4	19.6	21.0	22.4	22.9	21.6
NGL	2.2	2.2	2.2	2.3	2.3	2.5	2.5	2.3
Total	17.8	19.0	20.6	21.9	23.3	24.9	25.4	23.9
Total								
Crude oil	46.7	46.5	48.6	49.8	51.3	52.8	53.6	51.7
NGL	2.8	2.9	3.0	3.1	3.6	4.5	5.0	5.3
Total	49.5	49.4	51.6	52.9	54.9	57.3	58.6	57.0
Synthetic crude	0.0	0.0	0.0	0.0	0.0	0.5	1.3	4.4
Net imports from Soviet Bloc	1.2	1.2	0.1	0.5	0.8	1.4	1.0	0.0
Processing gain	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Total supply	51.2	51.1	52.2	53.9	56.2	59.7	61.4	61.9

Source: SHCA.

Table 16

FREE WORLD OIL DEMAND
(MBD)
1979-2000

	1979	1980	1982	1985	1990	2000
United States	18,800	19,100	19,300	19,570	20,000	19,200
Canada	1,870	1,900	1,950	1,970	2,000	1,950
Western Europe	14,300	14,400	14,600	15,150	15,300	15,300
Japan	5,400	5,500	5,700	6,000	6,200	6,150
Self-sufficient oil regions	5,300	5,800	6,900	8,550	9,000	10,000
Strong economies	2,760	2,900	3,150	3,730	4,100	4,200
Vulnerable economies	3,400	3,500	3,800	4,430	4,800	5,100
Total	51,830	53,100	55,400	59,400	61,400	61,900

Source: SHCA.

It is not realistic to place a band of high and low estimates around the basic projection because the divergence is so large as to be meaningless. Pressure for even higher rates of increase are very high because all available supply is used every year, which suggests that OPEC will attempt to achieve rates of price increase that will result in less than full utilization of available supply. On the low side, oil discoveries may accelerate, and other forms of energy may be relied on to a greater extent than anticipated, and in the ultimate a much lower rate of economic growth may result from energy and other imbalances, even to the point of a world depression. But from the standpoint of justifying supplemental supplies, a high rate of escalation in the oil price should be relied on if everything possible is to be done to prevent energy from being the cause of a world depression or war.

4. OIL PRICES

The focus of this section is on petroleum prices in the United States, with emphasis on product prices at the refinery along the Eastern Seaboard. However, it should be realized that the extremely high prices for crude oil will tend to mask the locational differences in product prices, which are essentially attributable to differences in transportation costs. Thus, the projected refinery prices are within a few percent of the refinery prices at any U.S. location.

Crude Oil

The derivation of Saudi marker crude oil prices (Table 17) was furnished in the last section. Basically, the real price for marker crude oil is projected to increase rapidly--at 5% per year, from the 1979 base, to 1985 and at 6% per year from 1985-2000 because of a very tight crude oil supply. The tight supply results from a combination of factors that tend to reinforce each other. First, OPEC cannot be expected to make supply available much above the current level. The arguments relating to OPEC's need for foreign currency simply have no merit when all other factors are considered. Second, the remaining resource base for conventional crude oil does not appear to be very large and the non-OPEC free world resource base in particular appears to be extremely limited. Non-OPEC production is expanding, but there have been many disappointments in new exploration areas in this decade, and peaking of conventional production now appears to be probable within five to ten years. While production in Mexico and some other countries may increase, production in other countries will decrease. Third, other energy sources, including synthetic oil, are not available or are not politically acceptable in sufficient quantities soon enough to provide the growth in total energy supply needed to prevent oil prices from increasing rapidly. Moreover, synthetic oil costs are equal to or higher than the projected oil prices for at least the next decade. Finally, conservation without adverse economic impact is not expected to meet such a massive challenge because OPEC can readily reduce output as rapidly as conservation can reduce demand and so the net result is that the balance in economic growth and energy is at a low rate of economic growth and a high rate of escalation in the price of oil. Precedent in the 1973-79 period has been fully taken into consideration in all factors. Arguing this analysis, as has been prevalent, merely ensures that the price escalation will be even higher.

FOB prices for other crudes reflect transportation and quality differentials, with the latter responsible for most of the variation. The quality differentials are volatile and are, we believe, basically

Table 17

FOB AND DELIVERED U.S. PRICES OF SELECTED CRUDE OILS*
(U.S. Dollars per Barrel)
1979-2000

	1978 Dollars					Actual Dollars				
	1979	1980	1985	1990	2000	1979	1980	1985	1990	2000
FOB										
Saudi marker	$15.41	$16.20	$20.65	$27.63	$49.50	$17.00	$19.65	$37.48	$73.72	$285.07
UAE	17.00	17.00	21.50	28.50	50.00	18.75	20.62	39.02	76.04	287.95
Iran	17.00	17.00	21.50	28.50	50.00	18.75	20.62	39.02	76.04	287.95
Algeria	22.00	22.00	27.00	32.00	54.00	24.27	26.69	49.00	85.38	310.99
Libya	22.00	22.00	27.00	32.00	54.00	24.27	26.69	49.00	85.38	310.99
Nigeria	22.00	22.00	27.00	32.00	54.00	24.27	26.69	49.00	85.38	310.99
Indonesia	20.00	20.00	26.50	31.50	53.50	22.06	24.26	48.10	84.04	308.11
Venezuela	17.00	17.00	20.00	28.00	49.50	18.75	20.62	36.30	74.70	285.07
Canada	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.
Mexico	18.50	18.50	23.00	30.00	51.50	20.41	22.44	41.74	80.04	296.59
Refiner acquisition price										
Saudi marker	17.00	17.70	22.25	29.50	51.50	18.75	21.47	40.38	78.71	296.59
UAE	18.50	18.50	23.10	30.25	52.00	20.41	22.44	41.93	80.71	299.47
Iran	18.50	18.50	23.10	30.25	52.00	20.41	22.44	41.93	80.71	299.47
Algeria	23.00	23.00	28.00	33.00	55.00	25.37	27.90	50.82	88.04	316.74
Libya	23.00	23.00	28.00	33.00	55.00	25.37	27.90	50.82	88.04	316.74
Nigeria	23.00	23.00	28.00	33.00	55.00	25.37	27.90	50.82	88.04	316.74
Indonesia	21.50	21.00	28.00	33.00	55.00	23.71	25.47	50.82	88.04	316.74
Venezuela	17.75	17.75	20.75	28.75	50.25	19.58	21.53	37.66	76.70	289.39
Canada	18.50	18.50	23.00	31.00	52.00	20.41	22.44	41.74	82.71	299.47
Mexico	19.00	19.00	23.50	30.50	52.00	20.96	23.05	42.65	81.37	299.47
U.S. crude	12.20	15.00	25.00	31.00	53.00	13.46	18.20	45.38	82.71	305.23
Average acquisition price	16.00	17.00	25.00	31.00	53.00	17.65	20.62	45.38	82.71	305.23

n.a. - not applicable.
* U.S. East Coast.

Source: SHCA.

unpredictable because of the large number of variables involved* and the unpredictability of a number of these factors. Therefore with a continuing tightness foreseen in crude oil supply, our quality differentials are predicated on the assumption that higher quality crudes will remain in tightest supply (all net increase in production will be in heavier crudes).†

The refiner acquisition price assumes that U.S. import duties on crude oil will remain as in 1978, and are further predicated on high differentials for quality crudes as discussed above but on continually depressed tanker rates that increase in real terms only because of the rising real cost of bunker fuel. The tanker rates could not possibly be lower whereas eventual rationalization of the industry could lead to an increase in the refiner acquisition price of as much as 75 cents a barrel (1978 dollars). The import duty, fees, and tariffs could be only slightly lower (5 cents to 10 cents a barrel in actual dollars) but more probably will at least remain the same in constant dollars with a good chance of a real increase. The quality differentials are not likely to be higher than estimated (except for limited time periods) but could average as much as $3 a barrel lower. The price of U.S. crude is based on the Administration's plan for complete decontrol by 1982. One additional factor could affect the average refinery acquisition price: the composition by source of the U.S. crude runs, which could affect the average in either direction.

Given the FOB prices, the potential variation in the average refiner acquisition price is roughly +$2.00 per barrel and -$4.00 per barrel if all factors operated in the same direction, but some of these factors will more likely vary in opposite directions and the realistic range is considered to be ±$1 per barrel. The potential variation in the Saudi marker price is of much greater importance.

Oil Price Decontrol

The announced decontrol of U.S. crude oil prices by September 1981 will have a pronounced effect on the average wellhead price of U.S. crude oil and on the average U.S. refinery acquisition price of crude oil in 1980-82 and to a lesser extent in 1983-85. It may have some effect on

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* E.g., air pollution regulations worldwide, refinery fuel oil desulfurization capacity and cracking capacity, availability of crude oil by range of sulfur content and gravity, and relative and absolute demand for light and heavy products which in turn becomes a function of economic activity by region and composition.

† Although light crude oil production will increase in some locations such as the North Sea, the total increase from these sources will no more than offset the decline in light crude production in other locations such as the United States (Kansas, Louisiana, etc.).

foreign refining and it may have some effect on U.S. refinery product prices, but there is a great deal of uncertainty as to the effect, if any, and it is likely to be another year and a half before any evidence is available.

The average price of domestic crude oil will more than double in less than three years. This is a major adjustment and a major change from our previous reports, representing almost an $8 per barrel increase from our early 1979 estimate for 1982. The refinery acquisition price for total input, at $24 a barrel in 1983 is more than $5 a barrel higher than our early 1979 estimate. But refiners are facing the question of how much higher product prices will be. We are not at all sure of the answer.

Over the next three years, domestic refineries will experience an $11 per barrel increase in cost of refinery input while foreign refineries will experience an $8 per barrel increase. Domestic refineries will of course attempt to increase product prices to fully offset the $11 per barrel increase in their input costs. But we foresee essentially no change in refinery operating rates abroad (in general) and therefore no competitive means of increasing foreign product prices more rapidly than the price of crude oil. A very tight crude oil supply could alter this situation, but if Iran sustains production at 4 MMBD, the slow world economy should yield a demand for OPEC crude of 28 to 30 MMBD, and at this level, stocks can be maintained and all refiners should be able to obtain an adequate crude supply. Therefore, foreign product prices are not likely to escalate more rapidly than crude prices and as U.S. refiners attempt to increase product prices to offset their higher increase in cost of refinery input, foreign products will become increasingly price-attractive and will increase their share of the U.S. market. However, while foreign refineries are operating at less than 70% of capacity, the light fractions in the crude supply and refinery cracking capacity are fully utilized. Some increase in light fraction supply will occur as North Sea production increases and there is about 1 MMBD of cracking capacity being installed in European refineries (but none in Caribbean refineries to date). The resulting increase in light product supply from these sources should do no more than meet growing European demand as well as offset the net reduction in light fractions caused by the loss of 2 MMBD of Iranian crude that is offset by increased production of heavier crudes. Thus, for the next two or three years, during the time required to install more cracking capacity, it is doubtful that foreign refiners can materially increase their share of the U.S. light product market--particularly gasoline--and therefore they are not likely to prevent U.S. light product prices from escalating to fully offset the rising cost of U.S. refinery input. But product price escalation for heavy products, including low sulfur heavy fuel oil, is likely to follow the escalation in foreign crude prices only, and within three to five years the U.S. prices for light products will be subjected to downward adjustment (in relation to crude prices due to foreign competition.

Before continuing to other topics, it may be of significance to speculate as to the reason for the Administration's sudden reversal of position on crude oil price decontrol. With no inside information whatever, we see the reasoning as follows. The DOE has, we believe, continued until recently to rely on the view of the majority of analysts*, both inside and outside the government, that the real price of crude oil would not increase in real terms until after the middle to late 1980s, if then. This, they felt, gave them ample time to develop alternatives without moving rapidly. According to recent testimony before Congress by the Secretary of DOE, the DOE has now drastically reduced its projection of middle to late 1980s availability of OPEC crude from 44 MMBD to 37 MMBD (which is still much too high by our estimates), and with that reduction in oil availability it stands to reason that DOE now foresees a rising real price for crude oil from here on. We believe the DOE models (and the DRI model which is also relied on) project no growth in U.S. petroleum demand if crude oil prices increase at 3% per year in real terms, because their cross-sectional analysis will invariably yield a higher price elasticity of demand than we have derived through time series analysis alone. Under these conditions, the Administration would revise its policy, encouraging more crude oil supply through price decontrol and discouraging refining, because additional capacity would not be needed if there were no further increase in petroleum demand. In fact, the Administration has even eliminated import duties et al for a brief period, so that the small protection afforded U.S. refiners has been abandoned, and this concession could be extended indefinitely.

But the question is whether the Administration will see a need for additional U.S. refining capacity and whether they will impose a differential duty between products and crude of $1 to $3 a barrel, and if so, when? In our judgment, a differential duty is not likely to be imposed until refinery margins are squeezed to such an extent that some independent refiners are forced out of business, and this is not likely to happen for three to five years. Thus new refinery investment in the United States, particularly for grass roots refineries, will be very difficult to justify and U.S. refining capacity is likely to increase more slowly as a result of the new U.S. policy.

Product Prices

Ex-refinery prices for petroleum products are a function of the refinery acquisition price for crude oil combined with refinery margins (Table 18). The latter are based on the supply-demand balance for each product (and relative differences in the balance for each product) on a worldwide basis, combined with U.S. import duties, tariffs, and fees.

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* See, for example, Energy, An Uncertain Future--An Analysis of Energy Projections Through 1990, Committee on Energy and Natural Resources, U.S. Senate.

Table 18

MARGINS AND PRODUCT PRICES EX-REFINERY U.S. EAST COAST*
(Dollars per Barrel)
1979-2000

	1978 Dollars					Actual Dollars				
	1979	1980	1985	1990	2000	1979	1980	1985	1990	2000
Crude oil acquisition price	$16.00	$17.00	$25.00	$31.00	$53.00	$17.65	$20.62	$45.38	$ 82.71	$305.23
Refinery margins										
LPG	--†	--†	0	-1.00	-4.00	--†	--†	0	(2.67)	(23.04)
Unleaded gasoline	7.40	7.40	7.70	7.85	6.95	8.16	8.98	13.98	20.94	40.02
Regular gasoline	6.20	6.20	6.00	6.00	6.00	6.84	7.52	10.89	16.01	34.55
Naphtha	5.00	5.00	5.00	5.00	5.00	5.52	6.06	9.08	13.34	28.80
Distillate fuel oil	4.10	4.45	4.15	3.95	3.65	4.52	5.40	7.53	10.54	21.02
Residual fuel oil										
0.3% sulfur	3.65	3.30	3.15	3.00	2.75	4.03	4.00	5.72	8.00	15.84
High sulfur	(1.50)	(1.50)	0	0	0	(1.65)	(1.82)	0	0	0
Ex-refinery prices										
LPG	--†	--†	25.00	30.00	49.00	--†	--†	45.38	80.04	282.19
Unleaded gasoline	23.40	24.40	32.70	38.85	59.95	25.81	29.60	59.36	103.65	345.25
Regular gasoline	22.20	23.20	31.00	37.00	59.00	24.49	28.14	56.27	98.72	339.78
Naphtha	21.00	22.00	30.00	36.00	58.00	23.17	26.68	54.46	96.05	334.03
Distillate fuel oil	20.10	21.45	29.15	34.95	56.65	22.17	26.02	52.91	93.25	326.25
Residual fuel oil										
0.3% sulfur	19.65	20.30	28.15	34.00	55.75	21.68	24.62	51.11	90.71	321.07
High sulfur	14.50	15.50	25.00	31.00	53.00	16.00	18.80	45.38	82.71	305.23

* Estimated average for all transactions.
† Controlled margins and prices that do not reflect actual market conditions.

Source: SHCA.

We have assumed that U.S. product prices will not be controlled and that duties, etc., will be approximately 80 cents a barrel (in 1978 dollars). Protection of U.S. refiners may require an increase to $2 to $3 a barrel whereas political pressure from eastern states may force the duties, etc., to be eliminated and imports even subsidized (as at present for fuel oil, by granting entitlements). Thus, the potential range in margins (and refinery prices due to these factors alone) is several dollars a barrel. When all factors are taken into consideration, including the OPEC price for crude oil, we estimate that there is a greater probability of higher prices than projected rather than lower, at least through 1990 because supplementary sources are expected to require a price at least as high as the 1985-90 level and these sources may well require the 2000 price by that time as the value of the resources on which these supplies depend rise in real terms.

The refinery margins are consistent with margins prevailing in 1979 but are well above actuals in 1975-78. Tight crude supply is expected to lead to the maintenance of high refinery margins because tight crude supply generally indicates tight product supply. The only product that might realistically tend to be in chronic surplus is high sulfur fuel oil, in which case the refinery margin would be negative by several dollars a barrel. A tight supply would probably result in a slightly positive margin. We have taken an intermediate position on this product, and have used a zero margin (the negative margin in 1979-80 is due to the effect of entitlements for imported fuel oil on the domestic price).

The margin on unleaded gasoline would be even higher today without controls, but demand pressures on this product should ease by 1985 as demand and required supply peak. The differential between unleaded and regular has characteristically been 2 cents a gallon but without controls the refinery differential is expected to increase to at least 3 to 4 cents a gallon, supported both by differences in cost and supply/demand balance (declining demand for regular gasoline, with the decline in capacity to produce lagging the demand).

Considering the premium characteristics for LPG, its price per barrel in the table may appear to be low because it is equal to or lower than the price for high sulfur residual fuel oil. However, LPG contains only about two-thirds the Btu per barrel of heavy fuel oil and so the price per Btu is projected to carry a 16% premium over the price of distillate fuel oil at the refinery. Because LPG distribution costs are higher than for fuel oil, the premium at the consumer level is even higher. The gas processing plant price of LPG in the West South Central states would be several cents a gallon lower than the East Coast refinery price, but a plant in the East North Central or Middle Atlantic census region would receive a price comparable to the East Coast refinery price.

A later section deals with the supply and usage characteristics of LPG. World refinery production of LPG is not expected to increase very much and may not increase at all because the increase in crude runs is so small that it tends to be offset by a gradual reduction in the average

gravity of crude runs that concomitantly contain less LPG. U.S. gas processing plant production is expected to decline as natural gas production declines and LPG production may well decline more rapidly than natural gas because gas production at greater depth is becoming a larger share of the total and this production is dryer; i.e., it contains less LPG and other liquids. Therefore, total U.S. production will decline (there has already been a 15% decline from the 1973 peak) from 1.1 MMBD in 1978 to 770 MBD by 2000. Imports will have to offset this decline and meet any growth in U.S. demand, but for the free world in total there is expected to be an increase in production from all sources of 1.7 MMBD by 2000 (from 2.9 MMBD in 1978 to 4.6 MMBD in 2000), and so foreign sources should be able to meet U.S. import requirements. However, a distress price should not be expected because the Middle Eastern producers will insist on rough price equivalence with distillate fuel oil at the source and have the power to adjust the supply and/or market appropriately to maintain the price at the desired level. Transportation costs on LPG are much higher than on crude oil, and Japan in particular, but also Western Europe is closer to the Middle East than is the United States. Any tendency toward surplus supply in relation to traditional markets will lead to a substantial increase in LPG use as a power plant (and industrial) fuel, particularly in Japan, at a small premium over fuel oil. But with the much higher LPG transportation cost to U.S. markets, the premium over fuel oil becomes about 16%. Our estimated increase in demand is from 1.2 MMBD in 1979 to 1.7 MMBD in 2000; the projected price premium is consistent with the product's premium in the past, during which some increase in demand has been experienced. Whether the projected increase in demand at the price premium will actually be experienced is questionable, but whether or not usage proves to be lower than estimated, the price premium should still be anticipated because nearer markets (to the Middle East) will absorb (at our projected price) any quantities that the U.S. market cannot handle.

LPG is a propane-butane mix. Projected prices of propane and butane, in relation to LPG are estimated as follows (in 1978 dollars per barrel):

	1985	1990	2000
LPG	$25.00	$30.00	$49.00
Propane	26.00	31.50	51.00
Normal butane	24.00	28.50	47.00
Isobutane	27.00	33.00	53.00

Both propane and isobutane have a value over straight fuel value in the LPG mix as a feedstock and a gasoline additive respectively. The specific long term price relationships among these products should be viewed as quite tentative because of the extreme complexity in forecasting their supply/demand balance.

Ethane is produced with natural gas and may or may not be extracted. Ethane is not shipped any distance and so total U.S. supply is limited

almost completely to quantities extracted from U.S. natural gas production. Some deeper extraction is possible but as gas production declines and becomes leaner, total U.S. ethane supply is expected to decline (i.e., from 1985 to 2000; there could be some increase over the next two to three years). With ethane-based ethylene plants already in place, ethane supply can be expected to be tight and the price should reflect that tightness. The fuel value is dictated by the field price of natural gas, which for the "new" gas category is estimated as follows (in 1978 cents per MMBtu and 1978 dollars per barrel of naphtha equivalent, in comparison with naphtha):

	Ethane Fuel Value			Naphtha	
	Cents per MMBtu	Dollars per Barrel		Cents per MMBtu	Dollars per Barrel
		Ethane	Naphtha Equivalent		
1985	259¢	$ 7.59	$12.95	600¢	$30
1990	525	15.35	26.25	710	36
2000	868	25.43	43.40	1,160	58

With a tight supply, ethane is much more likely to carry a price closer to naphtha, which is the alternative feedstock for ethylene, and in fact could be priced higher than naphtha because plant costs using ethane are lower, conversion to naphtha in existing ethane-based ethylene plants is costly, and there will not be a sufficient supply of ethane to provide feedstock to all existing plants. On the other hand, the restricted movement of ethane and its much lower fuel value in relation to the naphtha price suggests that ethane should approximately track naphtha prices, with its price therefore estimated as follows (in 1978 dollars):

	Cents per MMBtu	Dollars per Barrel of Ethane
1985	600¢	$17.60
1990	710	20.80
2000	1,160	34.00

5. U.S. OIL DEMAND

The projections of U.S. oil demand in this study* (Table 19) are the lowest we have ever prepared, and for 1985-2000 are several million barrels per day below the projections made only a year ago. In effect, the loss of 2 MMBD of Iranian production is allocated totally to an equivalent downward adjustment in the U.S. market. Actually, our free world production and total supply have been adjusted downward to an even greater extent, as discussed earlier, due to a more critical evaluation of future supply and the exclusion of a category of "other" supply that although unidentifiable we hoped would be discovered and developed. The downward adjustment is attributable almost completely to a lower projection of economic growth, which is also the lowest we have ever adopted for a base case ("most probable"). GNP is projected at 3% per year to 1985 and 1.9% per year thereafter; the latter rate is extremely low, not much above the growth rate in the potential labor force if increasing numbers of women continue to seek employment as in the past few decades and as they are most likely to do with the static real incomes per capita that are implied by the low economic growth rate. The 3% per year growth rate to 1985 may seem respectable but it is almost a percentage point below the rate that was enjoyed for about a quarter of a century through 1973 and the projected rate is from a low recession year base (1979). Further it follows a 6-year period in which growth has been below average (thus, the 1973-75 growth is only 2.7% per year). This is not a very satisfactory method of limiting oil demand and imports.

We are not counting on any greater gas supply than we did a year ago and there is substantial risk that the supply we are counting on will not materialize, as discussed in a later section. DOE/ERA have not certificated a single supplementary gas project and thereby have discouraged the development of other projects. Most available LNG may well go to Western Europe and Japan because of the U.S. government's posture. Thus, if gas supply is less than projected, the pressure to increase oil demand and imports will be greater and the U.S. market may in effect outbid other regions (e.g., by not providing increased loans to LDC's to finance economic growth that will require increased oil imports). However, we believe it is more probable that failure to introduce supplementary gas supply in sufficient quantities will lower the economic growth rate a little further. Zero economic growth appears to be almost within our grasp; with just a little harder effort, the apparent goal of certain groups will be attained.

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* As derived within our overall energy balance by end use (Appendix A) which in turn was derived within our economic activity and energy supply, demand, and price balancing system.

Table 19

DEMAND FOR PETROLEUM PRODUCTS IN THE UNITED STATES
AND IN PAD DISTRICTS I AND II
(MBD)
1978-2000

	1978	1979	1980	1982	1985	1990	2000
United States							
LPG*	1,219	1,215	1,215	1,330	1,509	1,600	1,670
Gasoline total, of which	7,453	7,340	7,530	7,585	7,455	7,390	7,000
Unleaded	2,521	3,020	3,725	4,840	5,775	6,650	7,000
Leaded	4,932	4,320	3,805	2,745	1,680	740	--
Naphtha	300	305	310	320	335	350	375
Jet fuel	1,060	1,075	1,100	1,150	1,225	1,370	1,700
Distillate fuel oil	3,592	3,600	3,635	3,690	3,775	3,915	4,220
Residual fuel oil total, of which	3,021	3,050	3,030	2,990	3,105	3,115	1,875
0.5% sulfur	877	990	1,060	1,165	1,400	1,715	875
Other	2,144	2,060	1,970	1,825	1,705	1,400	1,000
All other products	2,182	2,125	2,280	2,235	2,166	2,260	2,360
Total	18,827	18,800	19,100	19,300	19,570	20,000	19,200
PAD District I							
LPG	193	194	195	197	200	205	215
Gasoline total, of which	2,521	2,485	2,550	2,565	2,520	2,495	2,360
Unleaded	854	1,020	1,260	1,635	1,955	2,245	2,360
Leaded	1,667	1,465	1,290	930	565	250	--
Naphtha	29	30	30	30	30	30	30
Jet fuel	387	392	402	420	447	500	620
Distillate fuel oil	1,460	1,465	1,475	1,490	1,515	1,550	1,630
Residual fuel oil total, of which	1,587	1,600	1,600	1,600	1,600	1,600	1,000
0.5% sulfur	503	520	560	625	720	880	450
Other	1,084	1,080	1,040	975	880	720	550
All other products	323	325	327	330	335	345	360
Total	6,500	6,491	6,579	6,632	6,647	6,725	6,215
PAD District II							
LPG	460	465	470	475	480	490	510
Gasoline total, of which	2,516	2,480	2,540	2,555	2,510	2,485	2,350
Unleaded	852	1,015	1,255	1,630	1,945	2,235	2,350
Leaded	1,664	1,465	1,285	925	565	250	--
Naphtha	43	44	45	47	50	55	60
Jet fuel	212	215	220	230	245	275	340
Distillate fuel oil	1,136	1,135	1,140	1,155	1,185	1,230	1,325
Residual fuel oil total, of which	323	325	325	325	325	325	200
0.5% sulfur	21	25	35	65	100	165	95
Other	302	300	290	260	225	160	105
All other products	529	530	535	540	550	562	590
Total	5,219	5,194	5,275	5,327	5,345	5,422	5,375

* Excludes ethane.

Source: SHCA.

Our nuclear projections have been reduced once again; no new nuclear plants are assumed to be put in place in the 1980s. This may turn around but it is not likely, at least for several years, and there is a better chance that our adopted estimates are too high because some known plants may be cancelled and the capacity factor may be lower on average because of extended downtime for repairs, etc. Increased relative reliance on coal will offset the lesser reliance on nuclear, but slower economic growth lessens the growth in demand for total power generation. In the industrial market, the recently enacted FUA appears to have had no effect on industrial conversion to coal, and our evaluation of the act is that it will continue to have no effect. Perhaps new measures will be introduced but the complexity of the problem, the environmental issues and constraints, and the enormous cost of conversion for most industrial plants suggests that a major increase in the industrial use of coal is not to be expected. We could be low on coal use for this reason and therefore high on oil, but the other factors (nuclear, gas, and economic growth) contain a greater bias toward underestimation than overestimation and so the projection of total oil demand is considered to be "most probable".

Oil has always been considered the swing fuel, meeting whatever requirements are left after utilizing all other available/acceptable/economic sources of energy, with total energy requirements related to the economic growth projections that were arrived at independently. As in Section 3, our present procedure is to derive the economic growth that will be permitted by the energy supply available since the resulting economic growth is so much below the economic potential that should exist if energy supplies were ample and real prices increased only modestly (1% to 3% per year). Therefore, in effect the projection of oil demand is dictated by the estimate of supply available. Economic growth, or the degree thereof, will now provide the "swing".

Total demand is projected to increase very little over the next twenty years, peaking in about 1990 at 20 MMBD (versus 18.8 MMBD in 1978), and declining thereafter to reach 19.2 MMBD in 2000, only 2% above the 1978 level. It should be recognized that there is an appreciable potential margin of error in absolute terms, amounting to plus or minus several million barrels per day in average years, without taking into consideration the effect of a depression. A high degree of precision in this forecast is literally impossible because there are too many factors involved, each having much uncertainty.

Past and projected shifts in oil's share of its various end-use markets are as tabulated below (total oil in a particular market as a percent of total energy):

	1960	1973	1980	1990
Residential	35%	29%	27%	24%
Commercial	37	26	20	13
Industrial	28	25	30	28
Power plants	7	18	15	10
Transportation*	94	95	96	97
Other†	35	48	42	46
Total primary energy	44	46	47	42

The projected residential and commercial shares of market are consistent with the past trends and reflect gas and electricity's preferential position. Oil has lost market share in the industrial market, but because of lack of availability of gas supply and the probable inability of coal to significantly increase market position‡ (at least for another decade or so), oil's share is expected to increase somewhat. Except along the Eastern Seaboard and in California, oil has not been a major factor in the power plant market. Over time, its position is expected to deteriorate at the expense of coal (and possibly nuclear later on). The transportation market is virtually all supplied by oil and is likely to continue to be so.§ Any penetration by electric vehicles will be minimal during the time period considered in this report. Overall, oil is expected to at least maintain its share of the overall energy market into the early 1980s. Because of loss of market after 1980 in the residential, commercial, and industrial sectors, oil's overall share also declines.

The projections for the principal petroleum product are discussed below.

LPG

The demand for LPG (excluding ethane) by end use is projected as follows (in MBD):

	1978	1985	1990	2000
Residential	350	352	352	352
Commercial	116	120	120	120
Industrial	68	68	68	68
Transportation	75	79	81	85
Raw materials	270	515	596	664
Gasoline production	239	245	243	231
Miscellaneous	101	130	140	150
Total	1,219	1,509	1,600	1,670

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* Includes military use.
† Raw materials and miscellaneous uses.
‡ For reasons cited earlier.
§ Except for the non-competitive use of gas for pipeline fuel.

The projections are generally consistent with recent trends. The main growth sector is in raw materials use, but this is open to question. Other products may be substituted for LPG because of the price premium for LPG and the concern over reliance on imports of this specialized product.

Gasoline

Automotive Sector

Automotive gasoline consumption now accounts for about 73% of total motor gasoline consumption. Historic and projected U.S. automotive fuel summary statistics are presented in Table 20. The expected growth rate in automotive gasoline consumption is shown below (in average annual percent):

1960-1973	5.0%	1978-1980	-0.4%	1982-1990	-0.5%
1973-1978	1.2	1980-1982	-0.1	1990-2000	-0.7

It is clear from the above data that the adjustments made by the American motoring public and U.S. Government to the 1974 oil embargo have caused a severe and abrupt shift in gasoline consumption patterns. The supply shortages and price increases experienced during the embargo period are expected to be rekindled to a somewhat lesser extent over the next two to three years--causing a premature peaking out in U.S. auto gasoline usage after 1978 at around 5,340 MBD. The declining trend in automotive gasoline consumption after 1982 is largely a result of government mandated new car fuel efficiencies, a growing proportion of diesel powered automobiles, and reduced growth in the number of cars on the road.

Implicit growth in the total number of automobiles on the road between 1960 and 2000 is shown below (in average annual percent per year):

1960-1973	3.5%
1973-1976	1.8
1976-1982	2.5
1982-1990	1.8
1990-2000	1.2

Reasons for the anticipated slower growth in the number of cars on the road include lower projected population growth and approaching saturation of licensed drivers to the total driving-age population. Table 21 presents historic and projected data for the U.S. driving-age population, number of licensed drivers, and total passenger cars on the road. Because of a slowing growth rate in the driving-age population and approaching saturation of the licensed driving-age population (it was assumed that 6% to the driving-age population will never be licensed due to those too old to drive, institutionalized persons, and the disabled) the overall annual growth rate

Table 20

U.S. PASSENGER CAR SUMMARY STATISTICS
1960-2000

	Passenger Cars in Use (millions)			Average Miles Traveled per Vehicle	Total Vehicle Travel (billions of miles)			Average Fleet Miles per Gallon		Gasoline Fuel Consumption		Diesel Fuel Consumption	
	Gasoline	Diesel	Total		Gasoline	Diesel	Total	Gasoline	Diesel	Millions of Gallons	MBD	Millions of Gallons	MBD
1960	57.1	--	57.1	10,298	588	--	588	14.3	--	41,169	2,686	--	--
1961	58.9	--	58.9	10,272	605	--	605	14.4	--	42,033	2,742	--	--
1962	60.9	--	60.9	10,328	629	--	629	14.4	--	43,771	2,855	--	--
1963	63.1	--	63.1	10,157	645	--	645	14.3	--	45,246	2,951	--	--
1964	66.1	--	66.1	10,257	678	--	678	14.3	--	47,567	3,103	--	--
1965	68.9	--	68.9	10,246	706	--	706	14.1	--	50,206	3,275	--	--
1966	71.3	--	71.3	10,498	745	--	745	14.0	--	53,220	3,472	--	--
1967	73.0	--	73.0	10,493	766	--	766	13.9	--	55,007	3,588	--	--
1968	75.4	--	75.4	10,690	806	--	806	13.8	--	58,413	3,810	--	--
1969	78.5	--	78.5	10,878	850	--	850	13.6	--	62,325	4,066	--	--
1970	80.4	--	80.4	11,082	891	--	891	13.6	--	65,649	4,282	--	--
1971	83.1	--	83.1	11,300	939	--	939	13.6	--	69,213	4,515	--	--
1972	86.4	--	86.4	11,412	986	--	986	13.4	--	74,718	4,874	--	--
1973	89.8	--	89.8	11,325	1,017	--	1,017	13.0	--	77,619	5,063	--	--
1974	92.6	n.a.	92.6	10,702	991	n.a.	991	13.4	n.a.	73,770	4,812	n.a.	n.a.
1975	95.2	n.a.	95.2	10,798	1,028	n.a.	1,028	13.5	n.a.	76,010	4,958	n.a.	n.a.
1976	97.8	n.a.	97.8	10,982	1,074	n.a.	1,074	13.7	n.a.	78,291	5,107	n.a.	n.a.
1977	99.8	0.1	99.9	11,202	1,118	1	1,119	13.9	24.0	80,225	5,233	40	3
1978	102.6	0.3	102.9	11,344	1,163	3	1,166	14.1	24.0	82,475	5,380	143	9
1979	105.5	0.5	106.0	11,024	1,163	4	1,168	14.4	24.0	80,758	5,268	208	14
1980	108.1	0.8	108.9	11,055	1,195	9	1,204	14.6	24.0	81,847	5,339	375	24
1982	112.1	1.6	113.7	11,151	1,250	18	1,268	15.3	24.0	81,724	5,331	750	49
1985	118.3	2.8	121.1	11,268	1,333	32	1,365	16.8	24.0	79,333	5,175	1,333	87
1990	126.1	5.3	131.4	11,395	1,437	61	1,498	18.3	26.0	78,520	5,122	2,542	166
2000	137.0	11.3	148.3	11,745	1,609	131	1,740	22.0	28.0	73,139	4,771	5,458	356

Sources: 1960-77--U.S. Department of Transportation, Highway Statistics, various issues.
1978-2000--SHCA.

Table 21

U.S. DRIVING AGE POPULATION, LICENSED DRIVERS, AND TOTAL CARS IN USE 1970-2000

	Population 15 Years Old and Over (millions)	Licensed Drivers (millions)	Percent of Licensed Population 15 and Over	Passenger Cars in Use (millions)	Passenger Cars in Use per 100 Licensed Drivers
1970	147.0	111.5	75.9%	80.4%	72.1%
1971	149.5	114.4	76.5	83.1	72.6
1972	152.2	118.4	77.8	86.4	73.0
1973	154.7	121.5	78.5	89.8	73.9
1974	157.3	125.4	79.7	92.6	73.8
1975	159.9	129.8	81.2	95.2	73.3
1976	162.6	134.0	82.4	97.8	73.0
1977	165.2	138.1	83.6	97.9	72.3
1978	167.1	141.7	84.8	102.9	72.6
1979	169.0	145.3	86.0	106.0	73.0
1980	170.9	148.9	87.1	108.9	73.1
1982	173.9	154.8	89.0	113.7	73.4
1985	178.6	162.5	91.0	121.1	74.5
1990	185.4	174.3	94.0	131.4	75.4
2000	201.9	189.8	94.0	148.3	78.1

Sources: SHCA.

in U.S. licensed drivers between 1978 and 2000 is projected to be only 1.3%, which compares with a 3% annual rate between 1950 and 1970. Passenger cars in use per 100 licensed drivers, which grew from 65.4 in 1960 to 72.6 in 1978, is forecast to grow to 78.1 in 2000.

A major unknown variable in automotive gasoline demand forecasting is the penetration of diesel-fueled cars in the new car market. General Motors, for example, is planning to market diesels at up to 20% to 25% of its total 1985 fleet (1 million to 1.3 million autos) partially as a move toward satisfying EPA fuel economy standards in 1985. The strong consumer response to the GM, Volkswagen, Mercedes-Benz, and Peugeot diesel models over the past several years would indicate that such a large penetration of diesels probably could be achieved. The one major problem of emissions regulations, however, could potentially restrain diesel growth. The Environmental Protection Agency has proposed maximum particulate emissions of 0.6 grams per mile for 1981 models and 0.2 grams per mile for 1983 cars. At present, it appears that there is no way for diesel manufacturers to meet these requirements within this time frame. SHCA has assumed that diesel growth will amount to over 300,000 units per year between 1978 and 1982, about 425,000 units per year between 1982 and 1985, and upwards to 650,000 units per year between 1985 and 2000, when diesels will represent about 7.6% of the total vehicle fleet.

Assuming a continued moderate growth in average travel per vehicle, from around 11,300 miles in 1978 to 11,450 miles in 2000, total vehicle travel is expected to increase from about 1.17 billion miles in 1978 to 1.74 billion miles in 2000. The tabulation below demonstrates this growth in terms of miles driven per licensed driver (in thousand of miles per driver):

1960	6,739
1965	7,167
1970	7,991
1976	8,015
1978	8,229
1979	8,039
1980	8,086
1982	8,191
1985	8,400
1990	8,594
2000	9,168

Average fleet miles per gallon decreased from 14.4 in 1961 to 13.0 in 1973 following the market trend toward larger, higher performance new vehicles during that time period. In the future, the major factor in overall fuel efficiency will be federal regulations. Average fleet new car fuel efficiency standards as presented in the Energy Policy and Conservation Act of 1975 and implemented by Secretary of Transportation Brock Adams in 1977 are as follows (in miles per gallon):

1978	18.0
1979	19.0
1980	20.0
1981	22.0
1982	24.0
1983	26.0
1984	27.0
1985	27.5

In this study, it is assumed that new in-use car mileages for gasoline-powered vehicles will be about 16% lower than legislated standards because of current laboratory testing methods employed by the EPA and because in-use mileages for new cars over the first year of operation can be expected to deteriorate somewhat with the level of tuning from the first day of purchase. Additionally, gasoline-powered vehicles will be averaged in with more efficient diesel-powered vehicles to meet the proposed new car standards. It was also assumed that required mileages would remain constant after 1985. Taking into consideration assumed new car fuel efficiency levels and the historic scrappage rate of older vehicles, the average total fleet level increases from 14.1 in 1978 to 22.0 by 2000.

Total gasoline usage per vehicle is expected to develop as follows (in gallons per automobile):

	Total Vehicles (gasoline and diesel)	Gasoline Powered Vehicles
1960	721	721
1965	729	729
1970	817	864
1973	864	864
1975	798	798
1976	801	801
1977	803	804
1978	802	804
1979	762	765
1980	752	757
1982	719	729
1985	655	671
1990	598	623
2000	493	534

Trucks

Truck gasoline use accounted for approximately 22% of total gasoline demand in 1978. Factors affecting truck gasoline demand include rapid growth in the number of single unit trucks (6.8% annually between 1970 and

1978), a trend toward increased numbers of diesel single unit trucks and a phase-out of gasoline-powered combination trucks, and Department of Transportation fuel economy standards for domestically produced light trucks and vans with gross vehicle weight ratings of up to 8,500 pounds. DOT fuel economy standards, which originally called for ratings of 19.2 mpg in 1980 and 20.5 mpg in 1981, were reduced in March of 1978 to 16 mpg for two-wheel-drive trucks and 14 mpg for four-wheel-drive trucks in 1980, and 18 mpg and 15.5 mpg in 1981 for two-wheel-drive trucks and four-wheel-drive trucks respectively.

Historic and projected summary statistics for U.S. trucks are presented in Table 22. Growth in the number of registered single unit trucks is expected to develop as follows (in average annual percent per year):

1965-1973	5.93%	1978-1982	5.47%
1973-1976	6.14	1982-1990	2.81
1976-1978	6.47	1990-2000	1.75

Throughout the projection period, truck growth is forecast to remain above that of automobile growth, as has been the historic trend.

Average truck fuel economy for single unit trucks is expected to in-increase from about 10.5 mpg currently to only about 13.5 mpg by 1990. Because trucks normally have a longer road life than autos and fuel efficiency standards for trucks are less severe than those for autos, gains in fuel efficiency are expected to be much more modest for trucks vis a vis autos.

The percentage of gasoline to total truck fuel consumption (including diesel) decreased from an estimated 83% in 1965 to about 71% by 1977. As the gasoline-powered combination trucks are expected to virtually phase out of the truck fleet by the mid-1980s and diesel-powered single unit trucks continue to increase their overall market share, the percentage of truck gasoline consumption is expected to decrease to 66% by 1982 and to 51% by 2000. As a result of these factors, total truck gasoline demand should develop as follows (in MBD):

1976	1,684
1977	1,753
1978	1,846
1980	1,956
1982	2,025
1985	2,033
1990	2,000
2000	1,907

Table 22

U.S. TRUCK SUMMARY STATISTICS
1965-2000

	Number of Trucks Registered (thousands)			Average Travel per Vehicle (miles)			Total Vehicle Travel (billions of miles)			Average Fleet Miles per Gallon			Fuel Consumption (millions of gallons)			Total Fuel Consumption (MBD)	Percent of Total Fuel Consumption		Total Fuel Consumption (MBD)	
	Single Unit (1)	Combination (2)	Total (3)	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)	(1)	(2)	(3)		Gasoline	Diesel	Gasoline	Diesel
1965	14,008	787	14,795	10,003	39,795	11,587	140	31	171	10.37	4.82	8.58	13,504	6,431	19,935	1,300	81.6%	18.4%	1,061	239
1966	14,694	823	15,517	9,588	40,112	11,207	141	33	174	10.34	4.87	8.52	13,636	6,779	20,415	1,332	79.4	20.6	1,058	274
1967	15,363	830	16,193	9,598	42,176	11,268	147	35	182	10.16	4.86	8.40	14,470	7,203	21,673	1,414	79.0	21.0	1,117	297
1968	16,124	871	16,995	9,857	43,229	11,571	159	38	197	10.14	4.87	8.39	15,674	7,808	23,482	1,532	77.9	22.1	1,194	338
1969	16,942	929	17,781	9,871	42,453	11,565	167	39	206	10.10	4.76	8.33	16,528	8,199	24,727	1,613	76.4	23.6	1,232	381
1970	17,788	960	18,748	9,807	41,903	11,450	175	40	215	10.15	4.78	8.40	17,237	8,363	25,600	1,670	75.6	24.4	1,262	408
1971	18,828	974	19,802	9,794	43,779	11,465	184	43	227	10.10	4.85	8.38	18,221	8,865	27,086	1,767	73.8	26.2	1,304	463
1972	20,249	990	21,239	10,525	47,084	12,229	213	47	260	9.63	5.47	8.46	22,118	8,600	30,718	2,004	68.5	31.5	1,373	631
1973	22,205	1,028	23,233	9,868	46,716	11,538	219	48	267	9.62	5.42	8.45	22,755	8,860	31,615	2,062	70.1	29.9	1,445	617
1974	23,545	1,085	24,630	8,981	51,667	10,861	211	56	267	9.99	5.54	8.55	21,125	10,101	31,226	2,037	70.1	29.9	1,427	610
1975	24,645	1,131	25,776	8,882	49,125	10,648	219	55	274	10.01	5.63	8.66	21,868	9,764	31,632	2,063	71.1	28.9	1,467	596
1976	26,554	1,225	27,779	9,369	48,297	11,086	249	59	408	9.99	5.38	8.58	24,915	10,975	35,890	2,341	71.9	28.1	1,684	657
1977	28,298	1,264	29,562	9,400	50,206	11,145	266	63	329	10,13	5.38	8.67	26,255	11,709	37,964	2,476	70.8	29.2	1,753	723
1978	30,100	1,340	31,440	9,410	51,009	11,183	286	69	350	10.25	5.45	8.63	27,902	12,646	40,548	2,645	69.8	30.2	1,846	799
1979	32,176	1,394	33,570	9,210	51,141	10,951	296	71	367	10.50	5.54	8.94	28,222	12,816	41,038	2,677	69.1	30.9	1,850	827
1980	34,107	1,443	35,550	9,500	51,274	11,196	324	74	398	10.60	5.55	9.07	30,566	13,333	43,899	2,864	68.3	31.7	1,956	908
1982	37,246	1,531	38,777	9,650	51,540	11,304	359	79	438	11.00	5.60	9.37	32,636	14,107	46,743	3,049	66.4	33.6	2,025	1,024
1985	41,294	1,661	42,955	9,800	51,942	11,430	405	86	491	12.00	5.75	10.08	33,750	14,957	48,707	3,177	64.0	36.0	2,033	1,144
1990	46,721	1,880	48,601	10,000	52,619	11,649	467	99	566	13.60	6.00	11.08	34,593	16,500	51,093	3,333	60.0	40.0	2,000	1,333
2000	55,573	2,290	57,863	10,200	54,000	11,933	567	124	691	15.00	6.35	12.05	37,800	19,528	57,328	3,740	51.0	49.0	1,907	1,833

Source: SHCA.

Table 23 presents trends in per capita highway travel and vehicle ownership for autos and single unit trucks over the period 1965-2000. Ownership of autos and single unit trucks, which increased from 84.1 to 92.8 vehicles for every 100 licensed drivers between 1965 and 1977, is expected to increase to 96.0 by 1980, 99.9 by 1985, and 107.4 vehicles per 100 licensed drivers by 2000. Growth in vehicle ownership per licensed driver is assumed to slow down in the future as auto and single-unit truck ownership per driver begins to exceed one vehicle.

Total auto and single-unit truck mile driver per licensed driver increased from 8,589 miles in 1965 to 10,029 miles in 1977, a 1.3% rate, and are projected to increase at 1.0% rate between 1977 and 1985, and a 0.7% rate between 1985 and 2000. Even with the expected future decline in licensed driver vehicle travel growth, the average driver is assumed by SHCA to amass 20% more mileage in 2000 than was the case in 1977. Because of forecast real growth in gasoline prices, and the fact that there would be an expected upper limit on per capita driving patterns, the 20% increase in driver travel is contingent upon increased leisure time, vehicle fuel efficiencies, per capita income, and driver conveniences in 2000 vis a vis today.

Aviation, Motorcycle, Bus, and Off-Highway Gasoline Use

In 1977, total gasoline consumption in the aviation, motorcycle, bus, and off-highway categories accounted for less than 4% of overall gasoline use. Aviation gasoline consumption, which stood at around 55 MBD in 1970, declined to 39 MBD by 1975, and has since increased to around 41 MBD. Aviation gasoline demand is expected to continue increasing only modestly to about 46 MBD by 1985. Growth in motorcycle gasoline demand increased rapidly from 1965 through 1973 (about 23% per year), but has shown no major growth since 1974 and appears to have leveled off at around 29 MBD. While total bus fuel consumption has increased modestly since 1973, most of the increased usage has been in diesel fuel. Diesels are expected to increase their share of the bus population in the future, and bus gasoline demand is expected to remain constant at about 30 MBD. As has been the case with aviation, motorcycle, and bus gasoline consumption, off-highway gasoline use has shown little growth in recent years and is expected to grow only moderately in the future.

Total

Table 24 shows expected growth in total gasoline demand, which is expected to peak at about 7.6 MMBD between 1980 and 1982 and to decline to 7.5 MMBD by 1985, 7.4 MMBD by 1990, and 7.0 MMBD by 2000.

Naphtha

The U.S. reliance on naphtha for uses other than for gasoline has been very minimal to date because other petrochemical feedstocks have

Table 23

TRENDS IN PER CAPITA HIGHWAY TRAVEL AND
VEHICLE OWNERSHIP FOR AUTOS AND SINGLE UNIT TRUCKS
1965-2000

	Population 15 and Over (millions)	Licensed Drivers (millions)	Vehicles in Use (millions)			Vehicle-Miles Driven (millions)			Licensed Drivers per 100 Population 15 and Over	Vehicles in Use per 100 Licensed Drivers			Vehicle-Miles Driven per Licensed Drivers		
			Autos	Single Unit Trucks	Total	Autos	Single Unit Trucks	Total		Autos	Single Unit Trucks	Total	Autos	Single Unit Trucks	Total
1965	132.2	98.5	58.9	14.0	82.9	706	140	846	74.5	69.9	14.2	84.1	7,168	1,421	8,589
1970	147.0	111.5	80.4	17.8	98.2	891	175	1,066	75.9	72.1	16.0	88.1	7,991	1,570	9,561
1971	149.5	114.4	83.1	18.8	101.9	939	184	1,123	76.5	72.6	16.4	89.0	8,208	1,608	9,816
1972	152.2	118.4	86.4	20.2	106.6	986	213	1,199	77.8	73.0	17.1	90.1	8,328	1,799	10,127
1973	154.7	121.5	89.8	22.2	112.0	1,017	219	1,236	78.5	73.9	18.3	92.2	8,370	1,802	10,172
1974	157.3	125.4	92.6	23.5	116.1	991	211	1,202	79.7	73.8	18.7	92.5	7,903	1,683	9,586
1975	159.9	129.8	95.2	24.6	119.8	1,028	219	1,247	81.2	73.3	19.0	92.3	7,920	1,687	9,607
1976	162.6	134.0	97.8	26.6	124.4	1,074	249	1,323	82.4	73.0	19.9	92.9	8,015	1,858	9,873
1977	165.2	138.1	99.9	28.3	128.2	1,119	266	1,385	83.6	72.3	20.5	92.8	8,103	1,926	10,029
1978	167.1	141.7	102.9	30.1	133.0	1,166	286	1,452	84.8	72.6	21.2	93.8	8,229	2,018	10,247
1979	169.0	145.3	106.0	32.2	138.2	1,168	296	1,464	86.0	73.0	22.2	95.2	8,039	2,037	10,076
1980	170.9	148.9	108.9	34.1	143.0	1,204	324	1,528	87.1	73.1	22.9	96.0	8,086	2,176	10,262
1982	173.9	154.8	113.7	37.2	150.9	1,268	359	1,627	89.0	73.4	24.0	97.4	8,191	2,319	10,510
1985	178.6	162.5	121.1	41.3	162.4	1,365	405	1,770	91.0	74.5	25.4	99.9	8,400	2,492	10,892
1990	185.4	174.3	131.4	46.7	178.1	1,498	467	1,965	94.0	75.4	26.8	102.2	8,594	2,679	11,274
2000	201.9	189.8	148.3	55.6	203.9	1,740	567	2,307	94.0	78.1	29.3	107.4	9,168	2,987	12,155

Source: SHCA.

Table 24

U.S. MOTOR GASOLINE DEMAND
(MBD)
1965-2000

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1982	1985	1990	2000
Highway																				
Automobile	3,275	3,472	3,588	3,810	4,066	4,282	4,515	4,874	5,063	4,812	4,958	5,107	5,223	5,380	5,268	5,339	5,331	5,175	5,122	4,771
Motorcycle	5	6	7	7	8	9	20	22	26	29	29	29	29	29	29	29	29	29	29	29
Bus	28	28	29	29	30	31	31	29	31	27	27	28	29	30	30	30	30	30	30	30
Truck	1,061	1,058	1,117	1,194	1,232	1,262	1,304	1,373	1,445	1,427	1,467	1,684	1,753	1,846	1,850	1,956	2,025	2,033	2,000	1,907
Subtotal	4,369	4,564	4,741	5,040	5,336	5,584	5,870	6,298	6,565	6,295	6,481	6,848	7,044	7,285	7,442	7,564	7,550	7,357	7,231	6,677
Off-highway																				
Aviation	120	105	90	84	70	55	49	46	45	44	39	37	38	40	41	42	43	46	50	60
Other	224	244	217	235	190	200	144	96	110	243	193	130	133	127	122	126	132	142	159	203
Total	4,713	4,913	5,048	5,359	5,596	5,839	6,063	6,440	6,720	6,582	6,713	7,015	7,215	7,452	7,340	7,530	7,590	7,455	7,390	7,000

Source: SHCA.

been available in this country. Naphtha demand carries a high degree of uncertainty, comparable to that for LPG (propane, butane) as a feedstock. Our estimated, rather flat demand over the next 20 years is the lowest likely to be achieved (whereas LPG is the highest). We have adopted a low estimate because of the need for naphtha for gasoline and the higher feedstock requirement for unleaded gasoline that keeps the total feedstock requirement increasing into the 1990s even though gasoline demand flattens in the early 1980s. This demand for naphtha (and other international factors*) will keep the price high, and since new petrochemical plants can be increasingly expected to be designed to utilize a wide range of feedstocks, naphtha is not expected to be utilized as much as other, less expensive products.

Jet Fuel

Air transportation is adversely affected by a rapid increase in the price of jet fuel, but the industry has demonstrated an ability to offset, or partially offset the higher cost by use of larger, more efficient planes and by achieving higher load factors through a combination of scheduling and rate design. Our projection of demand is consistent with the price elasticity evidenced to date and the projected price of jet fuel. However, even though the growth rate in demand is low, we assign more probability to a lower trend than to a higher trend because the future prices are formidable.

Fuel Oil

The demand for distillate fuel oil (including diesel fuel) is expected to increase through 2000 because of its versatility. Use in combined-cycle plants, trucks, and increasingly in autos, should assure continued growth even though residential, commercial, and industrial demand remains flat, or declines. But no growth is included for heavy fuel oil and in fact we drop the demand rather steeply after 1990.† Demand by application for both fuels is (in MBD):

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* Tendency toward lower average gravity of world crude runs with lower natural fraction of naphtha and other light products, plus more rapid relative growth of light products (versus heavy products) worldwide and the growth in requirements abroad for naphtha as a feedstock.

† This is due to the sharp reduction in power plant use after 1990 which we assume is displaced by coal (and/or possibly nuclear if all its problems can be overcome by then).

	Distillate			Residual		
	1985	1990	2000	1985	1990	2000
Residential	1,120	1,075	935	--	--	--
Commercial	350	305	235	55	45	35
Industrial	345	340	300	1,105	1,135	1,135
Power plants	235	280	325	1,550	1,540	330
Transportation	1,440	1,625	2,130	335	335	315
Other	285	290	295	60	60	60
Total	3,775	3,915	4,220	3,105	3,115	1,875

Both distillate and residual fuel oil needs are quite sensitive to the economic growth rate (particularly the latter) as well as to the availability and/or ability to rely on gas, coal, and nuclear. As such, demand can be quite volatile and the long term trend is subject to a higher degree of uncertainty than for other products. In 1978, low sulfur fuel oil represented only about 30% of total residual fuel oil demand. By 1990, its share is expected to increase to 55%. The estimated composition by end use in 1990 is as tabulated below (in MBD):

	Low Sulfur (0.5% or less)	High Sulfur (greater than 0.5%)	Total
Commercial	30	15	45
Industrial	570	565	1,135
Power plants	1,100	440	1,540
Transportation	0	335	335
Other	0	60	60
Total	1,715	1,400	3,115

Other Products

The remainder of the barrel includes lubes and greases, asphalt, coke, and many other products of small magnitude. The projection of about a 10% increase over the next 20 years is consistent with but somewhat below the 1973-78 trend.

Districts I and II

Petroleum demand in Districts I and II (Table 19) is expected to be essentially flat, although both jet fuel and distillate fuel oil increase somewhat. Both naphtha and LPG demand could be affected (increased) by location, in those districts, of petrochemical plants that rely on naphtha and/or LPG.

6. WORLD AND U.S. NATURAL GAS LIQUIDS

The production and use of LPG amount to about 3 MMBD or some 6% of the total free world petroleum requirement of 51 MMBD. At the consumer level, LPG has characteristically sold at a premium over natural gas and other oil products. Yet consumption has increased about 50% since 1968 and is now about 100 MBD above the 1973 peak. There is no question that the potential availability of LPG can increase quite rapidly, much faster than the projected production of crude oil. It is our position that this supply will be fully utilized and that the prices in the United States will remain at a premium (in terms of Btu value) in relation to the price of fuel oil at the consumer level.

Supply

Natural gas liquids (NGL) consist of ethane, LPG (butane, propane, and isobutane), pentanes, natural gasoline and other finished products, and plant condensate. In addition, LPG and ethane are also produced in refinery operations as by-products of the fractionation of crude oil. The supply of NGL in the United States and its composition for the period 1965 through 1978 is shown in Table 25, and summarized in Table 26 for the year 1977 in order to provide perspective as to the relative importance of the various NGL supply elements. As can be noted, LPG constitutes about 60% of total NGL supply with the remaining supply being split approximately even between the ethane component and the natural gasoline, plant condensate, and other finished products component. In 1977, 75% of total NGL supply came from gas processing plants, 16% from refinery production, and 9% from imports. This compares with the 1965 and 1970 breakdowns as follows (percent of total supply):

	1965	1970
Gas processing plants	79%	80%
Refinery production	20	17
Imports	1	3
Total	100%	100%

Thus, NGL imports have become relatively more important over time in the overall U.S. supply situation. This trend is not only expected to continue but to quicken since production from gas processing plants will decline in conjunction with the projected decline in lower 48 state gas production and since little growth is foreseen in refinery production of NGL.

Table 25

U.S. SUPPLY OF NATURAL GAS LIQUIDS AND LIQUEFIED REFINERY GASES
(Thousands of Barrels per Day)
1965-1978

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978*
Production														
Gas processing														
Ethane	73	82	101	125	173	201	221	276	296	323	337	365	397	398
LP-gases														
Propane	372	409	465	504	535	555	581	587	583	566	550	518	510	490
Butane	170	192	207	216	237	239	243	242	243	239	233	223	219	209
Butane/propane mix	24	36	42	34	16	16	11	10	10	8	7	7	7	6
Isobutane	67	73	80	81	74	84	88	92	92	92	90	82	81	76
Total LP-gases	633	710	794	835	862	894	923	931	928	905	880	830	817	781
Natural gas†	356	356	382	404	423	452	453	427	443	405	367	353	356	351
Finished products and others‡	119	136	132	140	117	113	96	81	70	56	49	46	46	38
Total natural gas liquids	1,181	1,284	1,409	1,504	1,575	1,660	1,693	1,715	1,737	1,689	1,633	1,594	1,616	1,568
Refinery														
Liquefied refinery gas	293	291	306	323	313	319	331	332	350	321	300	325	334	340
Ethane					25	26	25	25	25	17	11	15	19	13
Total refinery liquids	293	291	306	323	338	345	356	357	375	338	311	340	353	353
Total production of NGL and LRG	1,474	1,575	1,715	1,827	1,913	2,005	2,049	2,072	2,112	2,027	1,944	1,934	1,969	1,921
Imports														
LPG	21	29	27	32	35	52	71	89	132	123	112	130	161	n.a.
Natural gasoline and plant condensate	--	--	--	--	--	6	37	86	108	89	74	67	42	n.a.
Total	21	29	27	32	35	58	108	175	240	212	186	197	203	n.a.
Exports														
LPG	21	22	25	29	35	27	26	32	27	25	26	25	18	n.a.
Natural gasoline and plant condensate	--	--	--	--	--	--	--	--	--	--	--	--	--	n.a.
Total	21	22	25	29	35	27	26	32	27	25	26	25	18	n.a.
Domestic availability of NGL and LRG	1,474	1,582	1,717	1,830	1,913	2,036	2,131	2,215	2,325	2,214	2,104	2,106	2,154	n.a.
Stock changes														
Ethane	1	2	66	34	(47)	(3)	6	10	(6)	(1)	7	18	4	n.a.
LPG	1	12				24	70	(35)	41	39	21	(35)	51	n.a.
Natural gasoline and plant condensate	2	(2)	3	(1)	--	3	(2)	--	5	(1)	--	--	1	n.a.
Total	4	12	69	33	(47)	24	74	(25)	40	37	28	(17)	56	n.a.
Domestic disappearance of NGL and LRG	1,470	1,570	1,648	1,797	1,960	2,012	2,057	2,240	2,285	2,177	2,076	2,123	2,098	n.a.

* Preliminary.
† Including isopentane.
‡ Including plant condensate.
Sources: Oil and Gas Journal, January 30, 1978 and January 29, 1979; Bureau of Mines, Mineral Industry Surveys, Minerals Yearbook and Petroleum Statement, Annual, 1976 and 1977.

Table 26

RELATIVE IMPORTANCE OF
VARIOUS ELEMENTS OF NGL SUPPLY
(MBD and Percent of Total)

	Volume	Percent of Total
Ethane		
Gas processing plants	397	18%
Refineries	19	1
Imports	--	--
From stocks	--	--
Subtotal	416	19
LPG		
Gas processing plants	817	38
Refineries	334	15
Imports	161	8
From stocks	--	--
Subtotal	1,312	61
Natural gasoline, isopentane, and plant condensate		
Gas processing plants	399	18
Imports	42	2
From stocks	--	--
Subtotal	441	20
Total NGL		
Gas processing plants	1,613	75
Refineries	353	16
Imports	203	9
From stocks	--	--
Total	2,169	100%

Source: DOE, Energy Data Reports, PAD District Supply/Demand Annual, prepared Feb. 8, 1979.

The future supply of NGL depends on the following factors:

- Recovery of LPG from refinery operations
- Refinery throughput
- Quantity of natural gas processed at gas processing plants
- Chemical composition and liquids content of the natural gas processed
- Recovery rates of NGL at gas processing plants

In addition, transportation, handling, and storage facilities could impact on interregional movements at any given time, but these factors have not been taken into account in this assessment because such supply constraints can be offset within a few years of their occurrence. The major supply factors are discussed below.

Refinery Production of LPG

The recovery of LPG from refinery operations in 1975-77 is shown for OECD countries in Table 27. The wide range from about 9 barrels of LPG per thousand barrels of oil throughput in Norway to over 40 barrels in Germany and Turkey is apparent. The major developed countries, however, show a closer correspondence: 20 to 22 barrels in the United States, 30 to 32 barrels in Japan, and 31 to 33 barrels in Western Europe as a whole. The weighted average recovery amount has been about 26 barrels of LPG per thousand barrels of oil throughput for all OECD countries combined, over the 1975-77 period.

Estimated free world petroleum consumption, refinery throughput, and LPG production in refineries for 1973 through 2000 are given in Table 28. The increasing difference between oil consumption and refinery throughput reflects the growing production of NGL. Refinery production will barely grow at all because of the slow growth in petroleum demand and refinery runs, plus a gradual shift toward heavier crudes containing less LPG. The increase in LPG production is from 1.3 MMBD currently to 1.4 MMBD in 2000. Except for a modest increase in Western Europe, all of the increase is expected in the non-developed self-sufficient oil regions. The declining trends that are expected in refinery yield of LPG are indicated below for selected years (LPG refinery production as a percent of total refinery throughput):

Table 27

REFINERY THROUGHPUT AND LPG PRODUCTION IN OECD COUNTRIES: 1975-1977

	Crude Oil Refinery Intake						Refinery LPG Production						Barrels of LPG per Thousands of Barrels of Oil Throughput		
	Thousands of Metric Tons			Millions of Barrels			Thousands of Metric Tons			Thousands of Barrels					
	1975	1976	1977	1975	1976	1977	1975	1976	1977	1975	1976	1977	1975	1976	1977
European area															
Austria	8,248	9,319	8,759	60.2	68.0	63.9	86	96	102	1,014.8	1,132.8	1,203.6	16.9	16.7	18.8
Belgium	29,266	29,371	36,466	213.6	214.4	266.2	356	304	508	4,200.8	3,587.2	5,994.4	19.7	16.7	22.5
Denmark	8,086	8,215	8,212	59.0	60.0	59.9	97	95	119	1,144.6	1,121.0	1,404.2	19.4	18.7	19.7
Finland	8,593	10,982	11,868	62.7	80.2	86.6	85	87	100	1,003.0	1,026.6	1,180.0	16.0	12.8	13.6
France	109,050	121,902	119,911	796.1	889.9	875.4	2,658	2,789	2,868	31,364.4	32,910.2	33,842.4	39.4	37.0	38.7
Germany	98,652	109,987	107,775	720.2	802.9	786.8	2,284	3,135	2,759	26,951.2	36,993.0	32,556.2	37.4	46.1	41.4
Greece	11,627	11,099	10,552	84.9	81.0	77.0	132	137	128	1,557.6	1,616.6	1,510.4	18.3	20.0	19.6
Iceland	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Ireland	2,574	1,944	2,298	18.8	14.2	16.8	38	24	23	448.4	283.2	271.4	23.9	19.9	16.2
Italy	100,897	106,017	108,130	736.5	773.9	789.3	2,161	2,332	2,327	25,499.8	27,517.6	27,458.6	34.6	35.6	34.8
Luxembourg	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Netherlands	57,034	65,085	60,850	416.3	475.1	444.2	899	1,052	1,020	10,608.2	12,413.6	12,036.0	25.5	26.1	27.1
Norway	7,660	8,458	8,134	55.9	61.7	59.4	41	30	45	483.8	354.0	531.0	8.7	5.7	8.9
Portugal	5,661	5,811	5,880	41.3	42.4	42.9	127	127	143	1,498.6	1,498.6	1,687.4	36.3	35.3	39.3
Spain	44,199	51,616	47,533	322.6	376.8	347.0	999	1,107	1,066	11,788.2	13,062.6	12,578.8	36.5	34.7	36.3
Sweden	11,575	14,692	15,024	84.5	107.3	109.7	132	153	158	1,557.6	1,805.4	1,864.4	18.4	16.8	17.0
Switzerland	4,690	4,911	4,593	34.2	35.9	33.5	88	62	85	1,038.4	731.6	1,003.0	30.4	20.4	29.9
Turkey	13,046	13,487	14,489	95.2	98.4	105.8	295	347	393	3,481.0	4,094.6	4,637.4	36.6	41.6	43.8
United Kingdom	93,579	97,784	93,615	683.1	713.8	683.4	1,447	1,575	1,539	17,074.6	18,585.0	18,160.2	25.0	26.0	26.6
Total and average	614,437	670,680	664,089	4,485.1	4,895.9	4,847.8	11,925	13,452	13,383	140,715.0	158,733.6	157,919.4	31.4	32.4	32.6
Western Hemisphere area															
Canada	84,988	85,108	89,612	620.4	621.3	654.2	785	615	692	9,263.0	7,257.0	8,165.6	18.9	11.7	12.5
United States	677,955	726,866	784,999	4,949.1	5,306.1	5,730.5	9,266	9,744	9,780	109,338.8	114,979.2	115,404.0	22.1	21.7	20.1
Australia	27,181	28,020	29,657	198.4	204.5	216.5	337	338	383	3,976.6	3,988.4	4,519.4	20.0	19.5	20.9
Japan	219,331	230,134	233,298	1,601.1	1,680.0	1,703.1	4,390	4,344	4,339	51,802.0	51,259.2	51,202.2	32.4	30.5	30.1
New Zealand	3,005	3,517	3,268	21.9	25.7	23.9	--	--	--	--	--	--	--	--	--
Total OECD area	1,626,897	1,744,325	1,804,923	11,876.0	12,733.5	13,176.0	26,703	28,493	28,577	315,095.4	336,217.4	337,208.6	26.5	26.4	25.6

Note: Conversion factors--crude equals 7.3 barrels per metric ton; LPG equals 11.8 barrels per metric ton.

Source: Calculated by SHCA from OECD Oil Statistics, 1975-1977.

Table 28

ESTIMATED FREE WORLD PETROLEUM CONSUMPTION, REFINERY THROUGHPUT, AND LPG PRODUCTION IN REFINERIES 1973-2000

	1973	1974	1975	1976	1977	1978	1979	1980	1982	1985	1990	1995	2000
Petroleum consumption (millions of barrels per day)													
United States	17.3	16.6	16.3	17.3	18.5	18.8	18.8	19.1	19.3	19.6	20.0	19.6	19.2
Canada	1.8	1.8	1.7	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0
Japan	5.4	5.3	4.9	5.3	5.5	5.6	5.4	5.5	5.7	6.0	6.2	6.2	6.2
Western Europe	15.2	14.3	13.5	14.5	14.2	14.3	14.3	14.4	14.6	15.2	15.3	15.3	15.3
Other	8.4	8.5	8.8	9.3	9.6	10.0	10.5	11.0	12.0	13.6	13.6	13.6	13.6
Total free world	48.1	46.5	45.2	48.7	49.8	51.3	51.8	53.1	55.4	59.4	61.4	61.7	61.9
Refinery throughput (millions of barrels per day)													
United States	13.4	13.0	13.2	13.7	14.4	15.2	15.5	15.9	16.3	16.9	17.3	17.3	17.2
Canada	1.8	1.8	1.7	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0
Japan	4.8	4.7	4.4	4.7	5.0	5.3	5.3	5.4	5.6	5.9	6.1	6.1	6.1
Western Europe	14.7	14.2	12.2	14.1	13.8	13.9	13.9	14.0	14.2	14.8	14.8	14.8	14.8
Other	13.0	12.2	13.1	13.2	13.5	13.9	14.4	15.8	16.3	17.3	18.5	18.8	18.8
Total free world	47.7	45.9	44.6	47.6	48.6	50.2	50.8	53.0	54.4	56.9	58.7	59.0	58.9
LPG production in refineries (thousands of barrels per day)													
United States	350	320	299	325	334	340	330	330	330	330	330	330	330
Canada	22	24	25	20	22	22	22	22	22	22	22	22	22
Japan	203	190	142	140	140	140	140	140	140	140	140	140	140
Western Europe	426	379	384	435	433	435	435	440	440	450	450	450	450
Other	390	366	393	393	395	400	405	440	445	460	470	470	470
Total free world	1,391	1,279	1,263	1,313	1,324	1,337	1,332	1,372	1,377	1,402	1,412	1,412	1,412

Note: 1973-75 refinery throughput from Bureau of Mines, International Petroleum Annual 1973-1975. Figures denote total output of refined products.

Source: SHCA.

	1973	1985	2000
United States	2.6%	2.0%	1.9%
Canada	1.2	0.7	0.7
Japan	4.2	2.4	2.3
Western Europe	2.9	3.0	3.0
Other free world	3.0	2.7	2.5
Total	2.9	2.5	2.4

Liquids Production from Gas Processing Plants

Table 29 shows 1978 capacity and production data for gas processing plants in each country of the free world. As would be expected, the United States is the dominate country in capacity and production, as shown below (region as percent of total free world):

	Plant Capacity	Plant Production
United States	65%	64%
Canada	13	8
Western Europe	6	1
Africa	7	11
Middle East	2	4
Far East	1	3
Latin America	6	9
Total	100%	100%

Plant operating rates (in 1978) are as tabulated below, surplus capacity is evident:

United States	64%
Canada	62
Western Europe	76
Africa	74
Middle East	80
Far East	63
Latin America	80
Free world	67

Table 30 records the reported expansion plans for natural gas liquids plants in the Middle East. If all materialize, production from this region alone will increase by over 2 MMBD. Although product detail is not reported for all the plants, the LPG component can be expected to account for over one-half of total NGL output. Expansion plans by country are summarized below (total planned output in MBD):

Table 29

GAS PROCESSING PLANTS IN THE WORLD--CAPACITY AND PRODUCTION DATA, 1978

	Number of Plants	MMcfd		Production (MBD)								
		Gas Capacity	Gas Throughput	Ethane	Propane	Isobutane	Normal or Unsplit Butane	LP-Gas Mix	Raw NGL Mix	Natural Gasoline	Other	Total Products
Developed countries												
Canada	225	14,126	8,808	9	48	6	25	12	31	69	19	219
Western Europe												
Austria	2	4	4	--	--	--	--	--	--	--	--	--
Germany	5	444	434	--	--	--	--	--	--	--	--	--
Italy	8	4,167	2,763	--	--	--	--	3	--	19	--	22
United Kingdom	2	2,150	1,959	--	--	--	--	--	3	--	--	3
Total Western Europe	17	6,765	5,160	--	--	--	--	3	3	19	--	25
United States	762	69,818	44,974	169	260	36	103	31	878	122	136	1,735
Total developed countries	1,004	90,709	58,942	178	308	42	128	46	912	210	155	1,979
Developing countries												
Self-sufficient oil regions												
Africa												
Algeria	4	5,335	4,268	--	--	--	--	15	--	--	130	145
Egypt	3	400	145	--	--	--	--	1	--	4	--	5
Libya	7	1,851	1,227	--	--	--	--	--	1	133	13	147
Total Africa	14	7,586	5,640	--	--	--	--	16	1	137	143	297
Far East												
Indonesia	1	126	105	--	4	--	2	--	--	--	--	6
Latin America												
Argentina	6	287	212	--	2	1	--	--	--	1	--	4
Ecuador	2	--	--	--	--	--	--	--	--	--	--	--
Mexico	9	2,669	2,440	31	130	--	--	--	--	--	--	161
Venezuela	18	2,548	1,665	--	4	--	3	3	37	3	--	50
Total Latin America	35	5,504	4,317	31	136	1	3	3	37	4	--	215
Middle East												
Iran	1	150	140	--	4	--	2	--	4	--	--	10
Kuwait	1	150	110	--	20	--	18	--	--	15	--	53
Saudi Arabia	3	1,300	1,040	--	--	--	--	--	31	--	--	31
Abu Dhabi	1	560	448	--	13	--	8	--	--	2	--	23
Total Middle East	6	2,160	1,738	--	37	--	28	--	35	17	--	117
Total self-sufficient oil regions	56	15,376	11,800	31	177	1	33	19	73	158	143	635

Table 29 (concluded)

	Plants	MMcfd Gas Capacity	MMcfd Gas Throughput	Production (MBD) Ethane	Propane	Isobutane	Normal or Unsplit Butane	LP-Gas Mix	Raw NGL Mix	Natural Gasoline	Other	Total Products
Strong economies												
Australia	1	810	457	11	26	--	28	--	--	--	12	77
Brazil	2	120	125	--	--	--	--	--	6	--	--	6
New Zealand	1	96	54	--	--	--	--	--	--	--	--	--
Taiwan	3	188	152	2	--	--	--	3	--	1	--	6
Total strong economies	7	1,214	788	13	26	--	28	3	6	1	12	89
Vulnerable economies												
Other Far East												
Pakistan	1	25	15	--	--	--	--	--	--	--	--	--
Other Latin America												
Bolivia	2	474	380	--	--	--	--	--	1	--	--	1
Chile	2	490	439	--	5	--	3	--	--	3	--	11
Domincan Republic	1	3	1	--	--	--	--	--	--	--	6	6
Total Other Latin America	5	967	820	--	5	--	3	--	1	3	6	18
Total vulnerable economies	6	992	835	--	5	--	3	--	1	3	6	18
Total developing countries	69	17,582	13,423	44	208	1	64	22	80	162	161	742
Total free world	10,073	108,291	72,365	222	516	43	192	68	992	372	316	2,721
Sino-Soviet Bloc	14	967	648	--	1	--	3	--	2	4	6	16
Total world	10,087	109,258	73,013	222	517	43	195	68	994	376	322	2,737

Source: Oil and Gas Journal, June 25, 1979.

Table 30

REPORTED EXPANSION PLANS OF NATURAL GAS LIQUIDS PROCESSING PLANTS IN THE MIDDLE EAST

Country and Company	Input	Output (MBD)*							Estimated Completion Date
		Ethane	Propane	Butane	Condensate	Natural Gasoline	Light Naphtha	Total	
Abu Dhabi									
Abu Dhabi Gas Liquefaction Co.	913 MMcfd		33	50	75			158	September 1980
Abu Dhabi Gas Industries	Not given							150	Late 1981
Abu Dhabi National Oil Co.	Not given							185	Not given
Bahrain									
Bahrain National Oil Co.	100 MMcfd		3	2		4		9	January 1980
Iran									
Iran-Japan Petrochemical Co.	Not given							102	1979
Kuwait									
Kuwait Oil Co.	1,680 MMcfd		117	62		49		228	October 1979
Qatar									
Qatar Gas Co.								3	1980
Qatar Gas Co.								93	Not given
Qatar Gas Co.								85	1984
Saudi Arabia									
Aramco	270 MBD	100	90	40			30	260	Under construction
Shedgun	1,470 MMcfd							305	1980
Uthmaniyah	1,430 MMcfd							325	Not given
Yanbu	270 MBD	110	90	40	—	30	—	270	Planning stage
Total†		210	333	194	75	83	30	2,173	

* Converted from metric tons on the basis of 11.6 barrels per metric ton.
† For individual products, totals include only those plants for which product data are given.

Sources: Oil and Gas Journal, Petroleum Economist, and International Petroleum Times, various issues.

Abu Dhabi	493
Bahrain	9
Iran	102
Kuwait	228
Qatar	181
Saudi Arabia	1,160
Total	2,173

In addition to expansion plans identified in Table 30, other developing countries that have announced new or expanded facilities include Algeria (several projects), Argentina, Bolivia, Brazil, Mexico, Nigeria, Venezuela, and Yugoslavia. The combination of current surplus capacity plus planned new and expanded facilities suggest that surplus capacity will continue. It is likely therefore, that voluntary cutback of capacity expansion and/or rescheduling of capacity additions will occur.

Historical and projected marketed production of natural gas and extraction of NGL as well as LPG's share of that total is shown in Table 31 by region of the free world. NGL production will depend on marketed (processed) production of natural gas, although in some countries, particularly those that vent or flare a substantial portion of their associated gas production, liquids may be extracted before the residue gas is flared or reinjected; this extraction would particularly apply to the heavier fractions. Whereas a high proportion of the gross production is marketed in the developed countries, the marketed production is quite small in proportion to gross production in the developing countries, as indicated in the tabulation to follow.* It is in these developing areas that the greatest potential for additional gas liquids production exists.

Africa	37%
Middle East	28
Latin America (Venezuela)	37

The NGL production is consistent with planned expansion of plant capacity but there is still an appreciable potential margin of error in the NGL production estimates and in the LPG share. Directionally, however, the rapid growth as compared with total petroleum supply is assured. The average gas liquids recovery in the free world is expected to increase from about 29 barrels per million cubic feet in 1978 to 40 barrels per million cubic feet in 1990; the production of gas liquids will then increase faster than the marketed production of natural gas. Growth rates compare as follows (in percent per year):

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* For the year 1976, the latest year for which such data are available.

Table 31

FREE WORLD NATURAL GAS LIQUIDS AND LPG PRODUCTION IN GAS PROCESSING PLANTS
1975-2000

	Marketed Natural Gas Production (millions of cubic feet per day)	NGL Recovery (barrels per millions of cubic feet)	NGL Production (thousands of barrels per day)	LPG Share (percent)	LPG Production (thousands of barrels per day)
1975					
United States	55,093	29.6	1,633	53.9%	880
Canada	8,464	36.3	307	50.5	155
Western Europe	16,383	1.9	31	32.3	10
Middle East	3,930	59.5	234	71.4	167
Africa	2,078	31.3	65	3.1	2
Latin America	4,592	46.6	214	71.5	153
Far East, Southeast Asia, and Oceania	2,423	26.4	64	4.7	3
Total free world	92,963	27.4	2,548	53.8	1,370
1976					
United States	54,664	29.4	1,608	51.7	832
Canada	8,404	34.3	288	53.8	155
Western Europe	17,212	2.1	37	24.3	9
Middle East	4,084	70.5	288	21.9	63
Africa	2,482	27.4	68	0.0	--
Latin America	4,715	44.1	208	45.7	95
Far East, Southeast Asia, and Oceania	3,312	23.9	79	3.8	3
Total free world	94,873	27.2	2,576	44.9	1,157
1977					
United States	54,589	28.9	1,580	51.7	817
Canada	8,816	33.1	292	54.2	159
Western Europe	17,397	6.9	120	43.0	52
Middle East	4,490	74.6	335	75.0	251
Africa	2,633	51.3	135	26.4	36
Latin America	4,910	46.8	230	73.9	170
Far East, Southeast Asia, and Oceania	3,828	28.7	110	81.1	89
Total free world	96,663	29.0	2,802	56.2	1,574
1978					
United States	53,512	29.3	1,567	49.8	781
Canada	9,258	28.5	264	54.0	143
Western Europe	19,219	5.7	110	44.6	49
Middle East	5,479	74.8	410	75.0	307
Africa	3,329	61.6	205	30.3	62
Latin America	5,373	48.4	260	73.3	191
Far East, Southeast Asia, and Oceania	4,529	26.5	120	79.0	95
Total free world	100,699	29.2	2,936	55.4	1,628
1979					
United States	53,500	28.3	1,515	47.6	721
Canada	9,874	30.2	298	54.0	161
Western Europe	20,619	7.3	151	46.3	70
Middle East	4,600	95.7	440	75.0	330
Africa	4,112	53.5	220	34.8	77
Latin America	5,678	50.7	288	72.6	209
Far East, Southeast Asia, and Oceania	5,200	23.1	120	77.0	93
Total free world	103,583	29.3	3,032	54.8	1,661
1980					
United States	53,000	27.9	1,479	46.3	685
Canada	10,299	28.9	298	53.0	158
Western Europe	21,428	7.8	167	48.0	80
Middle East	5,400	90.7	490	75.0	368
Africa	5,077	47.3	240	40.0	96
Latin America	7,504	44.6	335	72.0	241
Far East, Southeast Asia, and Oceania	6,000	20.0	120	75.0	90
Total free world	108,708	28.8	3,129	54.9	1,718

Table 31 (concluded)

	Marketed Natural Gas Production (millions of cubic feet per day)	NGL Recovery (barrels per millions of cubic feet)	NGL Production (thousands of barrels per day)	LPG Share (percent)	LPG Production (thousands of barrels per day)
1982					
United States	48,000	30.1	1,443	46.0%	664
Canada	10,167	31.1	316	52.0	164
Western Europe	22,000	10.4	229	49.0	112
Middle East	7,100	114.8	815	75.0	612
Africa	7,523	39.9	300	43.7	131
Latin America	8,838	41.3	365	71.0	259
Far East, Southeast Asia, and Oceania	7,380	23.0	170	73.0	124
Total free world	111,008	32.8	3,638	56.8	2,066
1985					
United States	43,400	31.5	1,367	46.0	629
Canada	10,288	33.5	345	52.0	179
Western Europe	23,340	12.9	300	50.0	150
Middle East	11,200	122.3	1,370	75.0	1,029
Africa	11,748	35.8	420	50.0	210
Latin America	10,726	41.0	440	70.0	308
Far East, Southeast Asia, and Oceania	9,300	23.7	220	70.0	154
Total free world	120,002	37.2	4,462	59.6	2,659
1990					
United States	35,900	35.0	1,256	46.0	577
Canada	11,532	34.8	401	52.0	208
Western Europe	22,529	13.3	300	50.0	150
Middle East	15,000	112.7	1,690	68.0	1,149
Africa	14,164	43.8	620	60.0	372
Latin America	13,784	34.8	480	70.0	336
Far East, Southeast Asia, and Oceania	12,000	21.7	260	70.0	182
Total free world	124,909	40.1	5,007	59.4	2,974
2000					
United States	26,300	36.4	959	46.0	441
Canada	11,800	34.0	401	52.0	209
Western Europe	20,668	14.5	300	50.0	150
Middle East	19,000	100.0	1,900	68.0	1,293
Africa	14,293	53.2	760	60.0	456
Latin America	17,249	33.3	575	70.0	403
Far East, Southeast Asia, and Oceania	14,000	26.4	370	70.0	259
Total free world	123,310	42.7	5,265	61.0	3,211

Source: SHCA.

	1978-85	1985-90	1990-2000
Marketed production of natural gas	2.5%	0.8%	(0.1%)
NGL production	6.2	2.3	1.0
LPG production	7.3	2.3	1.5

Incremental increase in NGL production between 1978 and 2000 is set forth below (in MBD). Also shown is the share of total increase (in percent):

	Increase in MBD	Share of Increase (percent)
United States	(608)	--
Canada	137	5%
Western Europe	190	6
Middle East	1,490	51
Africa	555	19
Latin America	315	11
Far East	250	8
Total net increase	2,329	
Total increase	2,937	100%

Thus, over 50% is expected to originate in the Middle East with an additional 20% or so expected in the self-sufficient oil countries in Africa (mainly Algeria). It will be noted that the projected increase in NGL production of 1,490 MBD in the Middle East compares with that region's reported expansion plans of 2,173 MBD NGL output (Table 30). This would indicate a capacity utilization of only 69% (with no allowance for any later planned facilities). In our judgment, not all the reported NGL capacity addition plans will be fully implemented. However, if production in the Middle East does exceed by an appreciable amount our estimates as given in Table 31, accompanying price weakness is not likely. As noted earlier in Section 4, a distress price should not be expected because the Middle East producers will insist on rough price equivalence with distillate fuel oil at the source and they have the power to adjust the supply and/or market appropriately to maintain the price at the desired level. Any tendency toward surplus supply in relation to traditional markets will lead to a substantial increase in LPG use as a power plant and industrial fuel, particularly in Japan, at a small premium over fuel oil.

Table 32 summarizes our projections of LPG production by region and by source in the free world.

Table 32

LPG PRODUCTION BY REGION AND SOURCE
(Thousands of Barrels per Day)
1973-2000

	1973	1974	1975	1976	1977	1978	1979	1980	1982	1985	1990	2000
United States												
Refineries	350	320	299	325	334	340	330	330	330	330	330	330
Gas plants	928	905	880	832	817	781	721	685	664	629	577	441
Total	1,278	1,225	1,179	1,157	1,151	1,121	1,051	1,015	994	959	907	771
Canada												
Refineries	22	24	25	20	22	22	22	22	22	22	22	22
Gas plants	152	151	155	155	159	143	161	158	164	179	208	209
Total	174	175	180	175	181	165	183	180	186	201	230	231
Western Europe												
Refineries	426	379	384	435	433	435	435	440	440	450	450	450
Gas plants	15	15	10	9	52	49	70	80	112	150	150	150
Total	441	394	394	444	485	484	505	520	552	600	600	600
Japan												
Refineries	203	190	142	140	140	140	140	140	140	140	140	140
Gas plants	0	0	0	0	0	0	0	0	0	0	0	0
Total	203	190	142	140	140	140	140	140	140	140	140	140
Other free world												
Refineries	390	366	393	393	395	400	405	440	445	460	470	470
Gas plants	309	349	325	161	546	655	709	795	1,126	1,701	2,039	2,411
Total	699	715	718	554	941	1,055	1,114	1,235	1,571	2,161	2,509	2,881
Total												
Refineries	1,391	1,279	1,243	1,313	1,324	1,337	1,332	1,372	1,377	1,402	1,412	1,412
Gas plants	1,404	1,420	1,370	1,157	1,574	1,628	1,661	1,718	2,066	2,659	2,974	3,211
Total	2,795	2,699	2,613	2,470	2,898	2,965	2,993	3,090	3,443	4,061	4,386	4,623

Source: SHCA.

Supply/Disposition Balances

Table 33 provides the detail on the supply/disposition balance in the United States. As will be noted, little growth in LPG demand is foreseen except for use as a raw material, mainly in the chemical industry and for miscellaneous uses including feedstock for SNG plants. Past and projected growth rates implicit in our projections are tabulated below (in annual percent change):

	1975-78	1978-85	1985-90
Residential	0.7%	0.0%	0.0%
Commercial	0.3	0.5	0.0
Industrial	-0.9	0.0	0.0
Transportation	-0.4	0.7	0.5
Raw materials	-3.2	9.7	3.0
Gasoline production	-1.0	0.4	-0.2
Miscellaneous	4.3	3.7	1.5
Total	-0.5	3.1	1.2

Growth in the residential, commercial, and industrial markets may be understated by a modest amount. On the other hand, growth in the raw materials and miscellaneous sectors may well be overstated. If U.S. demand does not expand to the extent indicated, usage in Japan and Western Europe will probably make up the difference.

With respect to the interfuel competitive markets--residential, commercial, industrial, and power plant--LPG has never been a significant factor nor will it become one. LPG is used in the above applications in areas outside of the natural gas distribution systems, as a standby fuel, and for other uses where the price premium can be justified. LPG's share of the competitive markets is tabulated below for selected years (LPG consumption as a percent of total end-use energy use):

	1960	1970	1980	1990
Residential	4%	5%	5%	4%
Commercial	3	3	3	3
Industrial	<1	<1	<1	<1
Power plants	--	--	--	--

The LPG supply/consumption balance for the free world is given in Table 34.

Table 33

SUPPLY/DISPOSITION BALANCE OF LPG IN THE UNITED STATES
(MBD)
1975-2000

	Historical				Projected				
	1975	1976	1977	Prel. 1978	1980	1982	1985	1990	2000
Supply									
Gas processing plants	879	830	817	781	685	664	629	577	441
Refineries	300	325	334	340	330	330	330	330	330
Subtotal	1,179	1,155	1,151	1,121	1,015	994	959	907	771
Imports	112	130	161	112	220	356	570	713	919
From stocks	--	42	--	6	--	--	--	--	--
Total supply	1,291	1,327	1,312	1,239	1,235	1,350	1,529	1,620	1,690
Disposition									
Consumption									
Residential	343	358	351	350	352	352	352	352	352
Commercial	115	119	117	116	120	120	120	120	120
Industrial	70	69	68	68	68	68	68	68	68
Transportation	76	76	75	75	77	78	79	81	85
Raw materials	298	296	270	270	255	341	515	596	664
Gasoline production	246	261	233	239	243	246	245	243	231
Miscellaneous	89	123	129	101	100	125	130	140	150
Subtotal	1,237	1,302	1,243	1,219	1,215	1,330	1,509	1,600	1,670
Exports	26	25	18	20	20	20	20	20	20
To stocks	28	--	51	--	--	--	--	--	--
Total	1,291	1,327	1,312	1,239	1,235	1,350	1,529	1,620	1,690

Source: SHCA.

Table 34

LPG* PRODUCTION AND CONSUMPTION BY REGION
(MBD)
1979-2000

	1979	1980	1982	1985	1990	2000
United States						
Production	1,051	1,015	994	959	907	771
Consumption	1,191	1,215	1,330	1,509	1,600	1,670
Net exports (imports)	(140)	(200)	(336)	(550)	(693)	(899)
Canada						
Production	183	180	186	201	230	231
Consumption	83	88	95	106	130	176
Net exports (imports)	100	92	91	95	100	55
Western Europe						
Production	505	520	552	600	600	600
Consumption	563	600	640	700	750	750
Net exports (imports)	(58)	(80)	(88)	(100)	(150)	(150)
Japan						
Production	140	140	140	140	140	140
Consumption	492	514	570	652	775	905
Net exports (imports)	(352)	(374)	(430)	(512)	(635)	(765)
Other free world						
Production	1,114	1,235	1,571	2,161	2,509	2,881
Consumption	670	700	801	1,094	1,131	1,122
Net exports (imports)	444	535	970	1,067	1,378	1,759
Total free world						
Production	2,993	3,090	3,443	4,061	4,386	4,623
Consumption	2,999	3,117	3,436	4,061	4,386	4,623
Stock increase (decrease)	(6)	(27)	(7)	0	0	0

* Propane, butane, and propane-butane mixes. Excludes ethane, which is included in some U.S. tables.

Source: SHCA.

7. U.S. OIL SUPPLY*

The U.S. supply of petroleum over the 1979-2000 period includes 6 to 8 MMBD of foreign crude oil that will be required, total U.S. production of crude oil, NGL, and synthetic oil totalling roughly 10 MMBD, and net product imports of 1.6 MMBD in 1979 but steadily declining to 0.9 MMBD in 2000 (Table 35). U.S. total oil production includes 1.6 MMBD of synthetic oil within 20 years, which can hardly be low by very much but may prove to be much too high (e.g., twice as high as the amount that can be realized because of the many constraints†). Conventional production could conceivably be higher than projected if some unexplored areas contain large reserves, but the downside probability is considered to be higher than the upside because of disappointing exploration results in so many locations.

Reliance on foreign crude oil increases by 1.2 MMBD by 1985 but imports from the Middle East should not increase appreciably. Direct and indirect (via imported products made from OPEC crude) reliance on OPEC should not increase; on the other hand, it will be exceedingly difficult to reduce the U.S. reliance on OPEC unless economic growth is drastically curtailed.

The downward trend in product imports reaches a level in 1985-2000 that is the lowest likely to be experienced, with imports of residual fuel oil virtually disappearing by 2000. Very little expansion in U.S. refining capacity over and above that already scheduled would be needed to reduce product imports to the degree shown, and the present emphasis on reliance on U.S. sources is the basis for our projections, but the degree of reduction in residual fuel oil imports may well be too extreme. Thus, reliance on the Caribbean refineries may well continue at a higher level than would be inferred from our residual fuel oil balance, particularly after the mid-1980s.

Total imports of crude and products are (in MMBD):

1979	8.0	1985	8.9
1980	8.1	1990	9.0
1982	8.6	2000	8.3

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* See also discussion of the oil resource base and production estimates given in Section 3.

† As noted earlier these include environmental, legal, regulatory, and financing constraints as well as the long lead times needed to make an orderly transition from design to full scale commercial operation.

Table 35

U.S. OIL SUPPLY
(MMBD)
1978-2000

	1978	1979	1980	1985	1990	2000
Crude oil						
Foreign						
Middle East	2.25	2.14	2.11	2.42	2.18	1.89
Africa and Western Europe	2.50	2.70	3.00	3.00	3.00	3.00
Venezuela	0.18	0.20	0.20	0.20	0.20	0.20
Mexico	0.32	0.50	0.60	0.80	1.00	1.00
Canada	0.25	0.30	0.30	0.30	0.30	0.30
Indonesia	0.50	0.50	0.50	0.50	0.50	0.50
All other	0.23	0.40	0.40	0.50	0.50	0.50
Total foreign crude	6.23	6.46	7.11	7.72	7.68	7.39
United States						
Lower 48	7.28	7.19	6.92	6.53	6.44	4.94
Alaska	1.20	1.40	1.40	2.10	2.50	3.00
Total U.S. crude	8.48	8.59	8.32	8.63	8.94	7.94
Total crude runs	14.71	15.05	15.43	16.35	16.62	15.33
NGL	1.57	1.52	1.48	1.37	1.26	0.96
Synthetic fuel production	--	--	--	0.10	0.30	1.60
Product imports						
LPG	0.10	0.14	0.22	0.57	0.71	0.92
Gasoline	0.20	0.18	0.18	0.06	0.06	0.05
Jet fuel	0.08	0.05	0.04	0.02	0.02	0.02
Distillate fuel oil	0.18	0.18	0.09	0.03	0.03	0.03
Residual fuel oil	1.33	1.24	1.12	0.80	0.71	(0.05)
Other	(0.14)	(0.15)	(0.15)	(0.35)	(0.23)	(0.04)
Total product imports	1.75	1.64	1.50	1.13	1.30	0.93
Total petroleum imports	7.98	8.10	8.61	8.85	8.98	8.32
Total U.S. production	10.05	10.11	9.80	10.10	10.50	10.50
Stock change	0.17					
Total U.S. supply*	19.04	19.03	19.29	19.79	20.19	19.51

* Includes 0.50 MMBD processing gain and 0.20 MMBD of products available for export.

Source: SHCA.

From 1982-90 the imports slightly exceed the recently agreed upon limit of 8.5 MMBD, but if the limit is in terms of net imports, product exports of 200 MBD to 300 MBD will result in exceeding the limit only in 1985-90 and then only by 200 MBD to 300 MBD. If the nation is willing to accept slow economic growth, quite rapid increases in oil prices, and supplementary gas and oil projects, net oil imports and total petroleum demand can be held to about the level of the past two years.

U.S. refinery operations are tabulated in Table 36, along with those for PAD Districts I and II. Refinery capacity is almost certain to reach the 1980 to 1982 level, or 18 to 18.5 MMBD, because the expansion is already underway. Small expansion in existing refineries can easily account for the additional capacity needed to reach the 1990-2000 level of 19.2 MMBD. U.S. operating rates range from 85% to 88%. Operating rates in Districts I and II are a little higher, as they have been in the past, and are achievable. The modest expansion in refining capacity in these districts is also quite possible.

The U.S. and District refining operations include production of synthetic fuel, which may or may not pass through conventional refineries. When the output from these synthetic fuel plants is taken into account, the overall balance between domestic production and imports is much more realistic; production from these plants will displace imported fuel oil and other products.

U.S. product supply/disposition balances are furnished in Table 37. The major products are discussed below.

LPG

Demand for LPG is expected to outstrip the projected increase in refinery output. Thus, imports of this product are likely to increase significantly, particularly after the mid-1980s.

Gasoline

Refinery output need increase only about 200 MBD over the next three years, with imports of 175 MBD which is 20 MBD below the 1978 level. However, we may have underestimated the demand by several hundred MBD if use of the automobile is not discouraged. We have held the demand down because we believe that policy, publicity, and disruptions will prevent the 1973-78 trend from continuing. A second qualification is in actually achieving the level of production even though the increase is very modest. The unleaded/leaded mix is rapidly shifting in favor of the former, which requires much more feedstock and processing, and price controls may be deliberately designed to limit supply as in recent years. Thus, limited supply may force a lesser usage than estimated of several hundred MBD while return to "normalcy" may raise the usage by several hundred MBD. In the longer term, there is little question that demand will level off and may decline as projected. The realistic range of usage in 1985-2000 is from 6.5 MMBD to 7.5 MMBD.

Jet Fuel

If the demand really increases as expected, substantial additional production will be required. Since distillate fuel oil use is also expected to increase along with naphtha and total feedstock requirements for gasoline, while the average gravity of crude runs declines, significant additional upgrading capacity will be required. If price controls are eliminated (or not re-imposed, as pertinent), this can readily be accomplished, but it is not at all certain that this will be the case. If not, then imports will probably make up some of the difference because in our balance we have reduced imports by 50 MBD by 1982 and 60 MBD by 1985. Imports could account for 50 MBD to 100 MBD more than estimated, reducing the increase in needed refinery output to about 10% or 100 MBD by 1985.

Distillate Fuel Oil

Imports of distillate fuel oil are only about 180 MBD or 5% to 6% of total requirements. Consistent with the other products, we have reduced imports to 25 MBD by 1985, but if they remain at the present level, U.S. refinery production need increase only about 100 MBD through 1985.

Residual Fuel Oil

Imports of residual fuel oil meet 40% of total requirements. We have projected that with a static demand to 1990, imports will decline as U.S. production increases. The tendency toward heavier gravity crude runs would support these trends but declining imports for this product are less likely than for light products. However, as coal liquids plants commence operating, a decline in imports is likely. Virtually all imports are assumed to be low sulfur, 0.5% sulfur or less.

District Balances

Product supply/disposition balances for Districts I and II are given in Table 38. In these balances, receipts from and shipments to other districts are included. For both districts, receipts increase over the projection period, and the source is District III (the Gulf Coast). District II relies on almost no imports and is not expected to in the future, but District I accounts for almost all the nation's imports. The split between imports and domestic supply for this district will be almost solely a function of government policy. Our balance should not be construed as a recommendation.

Table 36

REFINERY RECEIPTS, INPUT, AND OUTPUT IN THE UNITED STATES AND PAD DISTRICTS I AND II
(MBD)
1978-2000

	United States							PAD District I							PAD District II						
	1978	1979	1980	1982	1985	1990	2000	1978	1979	1980	1982	1985	1990	2000	1978	1979	1980	1982	1985	1990	2000
Refinery input																					
Crude oil receipts																					
Domestic, conventional	8,477	8,585	8,321	8,057	8,633	8,944	7,941	204	207	201	195	209	217	193	2,387	2,417	2,343	2,269	2,431	2,519	2,237
Domestic, synthetic	--	--	--	--	100	300	1,600	--	--	--	--	--	7	38	--	--	--	--	28	84	448
Foreign	6,231	6,459	7,108	7,829	7,717	7,682	7,390	1,517	1,540	1,591	1,636	1,658	1,730	1,789	1,411	1,439	1,600	1,742	1,639	1,580	1,480
Total receipts	14,708	15,044	15,429	15,886	16,450	16,926	16,931	1,721	1,747	1,792	1,831	1,867	1,954	2,020	3,798	3,856	3,943	4,011	4,098	4,183	4,165
Stock change	-20	+20	--	--	--	--	--	+4	--	--	--	--	--	--	-7	--	--	--	--	--	--
Refinery fuel use and losses	4	3	3	3	3	3	3	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Crude runs to stills	14,724	15,021	15,426	15,883	16,447	16,923	16,928	1,717	1,747	1,792	1,831	1,867	1,954	2,020	3,805	3,856	3,943	4,011	4,098	4,183	4,165
Unfinished oils rerun (net)	36	35	35	35	35	35	35	28	25	25	25	25	25	25	3	3	3	3	3	3	3
Natural gas liquids (net)	401	397	390	383	359	301	201	1	1	1	--	--	--	--	77	76	75	74	69	58	41
Other hydrocarbons	53	50	50	50	50	50	50	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total input	15,214	15,503	15,901	16,351	16,891	17,309	17,214	1,749	1,776	1,821	1,859	1,895	1,982	2,048	3,888	3,938	4,024	4,091	4,173	4,247	4,212
Processing gain	495	500	500	500	500	500	500	70	70	70	70	70	70	70	141	140	140	140	140	140	140
Total refinery supply	15,709	16,003	16,401	16,851	17,391	17,809	17,714	1,819	1,846	1,891	1,929	1,965	2,052	2,118	4,029	4,078	4,164	4,231	4,313	4,387	4,352
Refinery output																					
Gasoline*	7,202	7,200	7,320	7,410	7,395	7,331	6,951	777	778	793	803	798	792	752	2,140	2,138	2,178	2,203	2,198	2,177	2,067
Jet fuel†	973	1,025	1,060	1,120	1,205	1,352	1,682	65	68	70	73	76	82	94	177	185	190	197	205	220	250
Distillate fuel oil‡	3,302	3,420	3,540	3,635	3,775	3,890	4,195	456	470	485	495	507	555	632	928	960	985	1,000	1,040	1,080	1,175
Residual fuel oil	1,675	1,800	1,900	2,050	2,300	2,400	2,000	210	220	230	240	255	280	280	243	255	265	275	290	305	250
Other light products§	1,373	1,379	1,392	1,427	1,477	1,552	1,602	133	135	136	138	140	145	155	180	180	182	185	190	195	200
Other heavy products	1,184	1,179	1,189	1,209	1,239	1,284	1,284	178	175	177	180	189	198	205	361	360	364	371	390	410	410
Total refinery output	15,709	16,003	16,401	16,851	17,391	17,809	17,714	1,819	1,846	1,891	1,929	1,965	2,052	2,118	4,029	4,078	4,164	4,231	4,313	4,387	4,352
Refinery capacity (crude oil)	17,315	17,654	18,066	18,656	19,000	19,230	19,230	1,926	1,945	1,963	2,011	2,030	2,125	2,195	4,235	4,280	4,348	4,460	4,555	4,650	4,650
Crude runs	14,724	15,021	15,426	15,883	16,447	16,923	16,928	1,717	1,747	1,792	1,831	1,867	1,954	2,020	3,805	3,856	3,943	4,011	4,098	4,183	4,165
Crude operating rate (percent)	85%	85%	85%	85%	87%	88%	88%	89%	90%	91%	91%	92%	92%	92%	90%	90%	91%	90%	90%	90%	90%

* Includes natural gas liquids blended at the refinery plus other hydrocarbons blended; also motor and aviation gasoline.
† Naphtha and kerosene types.
‡ Includes kerosene.
§ Includes ethane, LPG, petrochemical feedstocks, special naphthas, and still gas.

Source: SHCA.

Table 37

PRODUCT SUPPLY/DISPOSITION BALANCE IN THE UNITED STATES
(MBD)
1978-2000

	1978	1979	1980	1982	1985	1990	2000
Gasoline							
Supply							
Refinery output	7,148	7,150	7,280	7,370	7,355	7,296	6,921
Gas processing plants	2	2	2	2	2	1	1
Other hydrocarbons	54	50	40	40	40	35	30
Imports	195	175	175	175	60	60	50
From stocks	55	--	35	--	--	--	--
Total supply	7,454	7,377	7,532	7,587	7,457	7,392	7,002
Disposition							
Consumption	7,453	7,340	7,530	7,585	7,455	7,390	7,000
Exports	1	2	2	2	2	2	2
To stocks	--	35	--	--	--	--	--
Total disposition	7,454	7,377	7,532	7,587	7,457	7,392	7,002
Jet fuel							
Supply							
Refinery output	973	1,025	1,060	1,120	1,205	1,352	1,682
Imports	86	52	42	32	22	20	20
From stocks	3	--	--	--	--	--	--
Total supply	1,062	1,077	1,102	1,152	1,227	1,372	1,702
Disposition							
Consumption	1,060	1,075	1,100	1,150	1,225	1,370	1,700
Exports	2	2	2	2	2	2	2
To stocks	--	--	--	--	--	--	--
Total disposition	1,062	1,077	1,102	1,152	1,227	1,372	1,702
Distillate fuel oil							
Supply							
Refinery output	3,302	3,420	3,540	3,635	3,775	3,890	4,195
Gas processing plants	--	1	1	1	1	--	--
Other hydrocarbons	1	2	2	2	2	1	1
Imports	183	178	93	53	25	25	25
From stocks	109	--	--	--	--	--	--
Total supply	3,595	3,601	3,636	3,691	3,803	3,916	4,221
Disposition							
Consumption	3,592	3,600	3,635	3,690	3,775	3,915	4,220
Exports	3	1	1	1	1	1	1
To stocks	--	--	--	--	27	--	--
Total disposition	3,595	3,601	3,636	3,691	3,803	3,916	4,221
Residual fuel oil							
Supply							
Refinery output	1,675	1,800	1,900	2,050	2,300	2,400	2,000
Other hydrocarbons	13	13	13	12	10	5	5
Imports	1,346	1,247	1,127	938	805	720	--
From stocks	--	--	--	--	--	--	--
Total supply	3,034	3,060	3,040	3,000	3,115	3,125	2,005
Disposition							
Consumption	3,021	3,050	3,030	2,990	3,105	3,115	1,875
Exports	13	10	10	10	10	10	55
To stocks	--	--	--	--	--	--	75
Total disposition	3,034	3,060	3,040	3,000	3,115	3,125	2,005

Table 37 (concluded)

	1978	1979	1980	1982	1985	1990	2000
All other light products							
Supply							
Refinery output	1,373	1,379	1,392	1,427	1,477	1,552	1,602
Gas processing plants	1,183	1,169	1,148	1,127	1,057	888	620
Other hydrocarbons	--	--	--	--	--	--	--
Imports	136	177	237	283	393	632	1,045
From stocks	10	--	--	--	--	--	--
Total supply	2,702	2,725	2,777	2,837	2,927	3,072	3,267
Disposition							
Consumption	2,656	2,680	2,735	2,795	2,885	3,030	3,225
Exports	46	45	42	42	42	42	42
To stocks	--	--	--	--	--	--	--
Total disposition	2,702	2,725	2,777	2,837	2,927	3,072	3,267
All other heavy products							
Supply							
Refinery output	1,184	1,179	1,189	1,209	1,239	1,284	1,284
Gas processing plants	1	1	1	1	1	1	1
Imports	12	10	15	15	20	30	30
From stocks	--	--	--	--	--	--	--
Total supply	1,197	1,190	1,205	1,225	1,260	1,315	1,315
Disposition							
Consumption	1,045	1,055	1,070	1,090	1,125	1,180	1,180
Exports	140	135	135	135	135	135	135
To stocks	12	--	--	--	--	--	--
Total disposition	1,197	1,190	1,205	1,225	1,260	1,315	1,315
Total all products							
Supply							
Refinery output	15,655	15,953	16,361	16,811	17,351	17,774	17,684
Gas processing plants	1,186	1,173	1,152	1,131	1,061	890	622
Other hydrocarbons	68	65	55	54	52	41	36
Imports	1,958	1,839	1,689	1,496	1,325	1,487	1,170
From stocks	177	--	35	--	--	--	--
Total supply	19,044	19,030	19,292	19,492	19,789	20,192	19,512
Disposition							
Consumption	18,827	18,800	19,100	19,300	19,570	20,000	19,200
Exports	205	195	192	192	192	192	237
To stocks	12	35	--	--	27	--	75
Total disposition	19,044	19,030	19,292	19,492	19,789	20,192	19,512

Source: Historical--U.S. Department of Energy, Energy Information Administration, Energy Data Reports, PAD Districts Supply/Demand, Quarterly.
Projected--SHCA.

Table 38

PRODUCT SUPPLY/DISPOSITION BALANCE IN PAD DISTRICTS I AND II
(MBD)
1978-2000

	PAD District I							PAD District II						
	1978	1979	1980	1982	1985	1990	2000	1978	1979	1980	1982	1985	1990	2000
Gasoline														
Supply														
Refinery output	774	775	790	800	795	790	750	2,137	2,135	2,175	2,000	2,195	2,175	2,065
Gas processing plants	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Other hydrocarbons	3	3	3	3	3	2	2	3	3	3	3	3	2	2
Receipts from other districts	1,738	1,704	1,725	1,747	1,812	1,783	1,683	464	474	468	475	426	413	373
Imports	160	150	150	150	35	35	25	7	5	2	2	1	--	--
From stocks	7	--	17	--	--	--	--	29	--	17	--	--	--	--
Total supply	2,682	2,632	2,685	2,700	2,645	2,610	2,460	2,640	2,617	2,665	2,680	2,625	2,590	2,440
Disposition														
Consumption	2,521	2,485	2,550	2,565	2,520	2,495	2,360	2,516	2,480	2,540	2,555	2,510	2,485	2,350
Shipments to other districts	161	135	135	135	125	115	100	124	125	125	125	115	105	90
Exports	--	--	--	--	--	--	--	--	--	--	--	--	--	--
To stocks	--	12	--	--	--	--	--	--	12	--	--	--	--	--
Total disposition	2,682	2,632	2,685	2,700	2,645	2,610	2,460	2,640	2,617	2,665	2,680	2,625	2,590	2,440
Jet fuel														
Supply														
Refinery output	65	68	70	73	76	82	94	177	185	190	197	205	220	250
Receipts from other districts	290	308	320	339	367	415	503	47	45	45	48	55	70	105
Imports	36	21	17	13	9	8	8	--	--	--	--	--	--	--
From stocks	2	--	--	--	--	--	--	3	--	--	--	--	--	--
Total supply	393	397	407	425	452	505	605	227	230	235	245	260	290	355
Disposition														
Consumption	387	392	402	420	447	500	600	212	215	220	230	245	275	340
Shipments to other districts	6	5	5	5	5	5	5	15	15	15	15	15	15	15
Exports	--	--	--	--	--	--	--	--	--	--	--	--	--	--
To stocks	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Total disposition	393	397	407	425	452	505	605	227	230	235	245	260	290	355
Distillate fuel oil														
Supply														
Refinery output	456	470	485	495	507	555	632	928	960	985	1,000	1,040	1,080	1,175
Gas processing plants	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Other hydrocarbons	--	--	--	--	--	--	--	1	1	1	1	1	--	--
Receipts from other districts	852	880	954	996	1,045	1,022	1,025	193	204	184	184	184	180	180
Imports	171	165	86	49	23	23	23	1	--	--	--	--	--	--
From stocks	33	--	--	--	--	--	--	43	--	--	--	--	--	--
Total supply	1,512	1,515	1,525	1,540	1,575	1,600	1,680	1,166	1,165	1,170	1,185	1,225	1,260	1,355

Table 38 (continued)

	PAD District I							PAD District II						
	1978	1979	1980	1982	1985	1990	2000	1978	1979	1980	1982	1985	1990	2000
Distillate fuel oil (cont.)														
Disposition														
Consumption	1,460	1,465	1,475	1,490	1,515	1,550	1,630	1,136	1,135	1,140	1,155	1,185	1,230	1,325
Shipments	52	50	50	50	50	50	50	30	30	30	30	30	30	30
Exports	--	--	--	--	--	--	--	--	--	--	--	--	--	--
To stocks	--	--	--	--	10	--	--	--	--	--	--	10	--	--
Total disposition	1,512	1,515	1,525	1,540	1,575	1,600	1,680	1,166	1,165	1,170	1,185	1,225	1,260	1,355
Residual fuel oil														
Supply														
Refinery output	210	220	230	240	255	280	280	243	255	265	275	290	305	250
Other hydrocarbons	--	--	--	--	--	--	--	1	1	1	1	--	--	--
Receipts from other districts	101	195	300	470	580	920	760	32	34	25	21	20	20	--
Imports	1,278	1,185	1,070	890	765	400	--	46	35	34	28	15	--	--
From stocks	--	--	--	--	--	--	--	2	--	--	--	--	--	--
Total supply	1,589	1,600	1,600	1,600	1,600	1,600	1,040	324	325	325	325	325	325	250
Disposition														
Consumption	1,587	1,600	1,600	1,600	1,600	1,600	1,000	323	325	325	325	325	325	200
Shipments to other districts	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Exports	--	--	--	--	--	--	--	1	--	--	--	--	--	--
To stocks	2	--	--	--	--	--	40	--	--	--	--	--	--	50
Total disposition	1,589	1,600	1,600	1,600	1,600	1,600	1,040	324	325	325	325	325	325	250
All other light products														
Supply														
Refinery output	133	135	136	138	140	145	155	180	180	182	185	190	195	200
Gas processing plants	39	38	37	36	34	29	20	208	206	202	198	186	156	109
Receipts from other districts	114	115	115	114	115	115	115	293	295	295	295	295	295	295
Imports	19	20	20	20	20	25	69	75	76	86	91	104	140	235
From stocks	1	--	--	--	--	--	--	--	--	--	--	--	--	--
Total supply	306	308	308	308	309	314	359	756	757	765	769	775	786	839
Disposition														
Consumption	304	306	306	306	307	312	357	662	665	673	677	683	694	747
Shipments to other districts	--	--	--	--	--	--	--	90	90	90	90	90	90	90
Exports	2	2	2	2	2	2	2	2	2	2	2	2	2	2
To stocks	--	--	--	--	--	--	--	2	--	--	--	--	--	--
Total disposition	306	308	308	308	309	314	359	756	757	765	769	775	786	839

Table 38 (concluded)

	PAD District I							PAD District II						
	1978	1979	1980	1982	1985	1990	2000	1978	1979	1980	1982	1985	1990	2000
All other heavy products														
Supply														
Refinery output	178	175	177	180	189	198	205	361	360	364	371	390	410	410
Gas processing plants	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Receipts from other districts	71	68	69	71	69	70	63	24	24	23	24	17	13	13
Imports	9	10	10	10	10	10	10	--	--	--	--	--	--	--
From stocks	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Total supply	258	253	256	261	268	278	278	385	384	387	395	407	423	423
Disposition														
Consumption	241	243	246	251	258	268	268	370	374	377	385	397	413	413
Shipments to other districts	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Exports	11	10	10	10	10	10	10	12	10	10	10	10	10	10
To stocks	6	--	--	--	--	--	--	3	--	--	--	--	--	--
Total disposition	258	253	256	261	268	278	278	385	384	387	395	407	423	423
All products														
Supply														
Refinery output	1,816	1,843	1,888	1,926	1,962	2,050	2,116	4,026	4,075	4,161	4,228	4,310	4,385	4,350
Gas processing plants	39	38	37	36	34	29	20	208	206	202	198	186	156	109
Other hydrocarbons	3	3	3	3	3	2	2	5	5	5	5	4	2	2
Receipts from other districts	3,166	3,270	3,483	3,737	3,988	4,325	4,149	1,053	1,076	1,040	1,047	997	991	966
Imports	1,673	1,551	1,353	1,132	862	501	135	129	116	122	121	120	140	235
From stocks	43	--	17	--	--	--	--	77	--	17	--	--	--	--
Total supply	6,740	6,705	6,781	6,834	6,849	6,907	6,422	5,498	5,478	5,547	5,599	5,617	5,674	5,662
Disposition														
Consumption	6,500	6,491	6,579	6,632	6,647	6,725	6,215	5,219	5,194	5,275	5,327	5,345	5,422	5,375
Shipments to other districts	219	190	190	190	180	170	155	259	260	260	260	250	240	225
Exports	13	12	12	12	12	12	12	15	12	12	12	12	12	12
To stocks	8	12	--	--	10	--	40	5	12	--	--	10	--	50
Total disposition	6,740	6,705	6,781	6,834	6,849	6,907	6,422	5,498	5,478	5,547	5,599	5,617	5,674	5,662

Source: SHCA.

8. U.S. GAS OUTLOOK

Total U.S. gas supply is estimated to decline from its current level of about 20 Tcf to about 19 Tcf in the mid-1980s and to around 18 Tcf in the 1990s.

Supply from all sources is shown in Table 39. Net production in the lower 48 states is expected to remain in the range of 19 to 20 Tcf per year for 1979 and 1980, as it has for the past two years. Gross additions to reserves are estimated at 11 to 12 Tcf per year for the next five years before commencing the ultimate decline. The only way in which production can remain above 19 Tcf through 1980 is for the RLI to drop to 8 years by 1980 (from 9.2 years in 1977). This is at or close to the minimum RLI that can be expected to be maintained indefinitely. The production must then swiftly drop toward the annual level of gross reserves additions. By 1985, production will have dropped roughly 20%, to 15.8 Tcf, and by 2000 the present production rate will be halved, to 9.6 Tcf. But without the price increases permitted by the NGPA, production would decline much more steeply.

The most probable net production in the lower 48 states is as set forth in Table 39, and compared below with a high and low set of estimates (in Tcf):

	Most Probable	High Supply*	Low Supply†
1979	19.5	19.5	18.8
1980	19.3	19.3	18.0
1982	17.5	18.9	16.9
1985	15.8	17.8	15.4
1990	13.1	14.9	13.1
2000	9.6	10.3	9.6

---

* In the high supply case, the RLI drops to eight years by the early 1980s with gross additions reaching 15 Tcf in 1979 and remaining at that level into the early 1980s before declining.

† In the low supply case, the RLI holds at nine years with gross additions reaching 13.5 Tcf in 1979 and remaining at that level into the early 1980s before declining.

Table 39

U.S. INTERSTATE AND INTRASTATE GAS SUPPLY
(Bcf)
1978-2000

	1978	1979	1980	1982	1985	1990	2000
Lower 48 production							
Net	19,580	19,500	19,300	17,500	15,800	13,100	9,600
Marketed	19,473	19,390	19,190	18,400	15,700	13,000	9,500
Extraction loss	840	830	815	800	750	630	440
Marketed less extraction	18,633	18,560	18,375	16,800	14,950	12,370	9,060
Intrastate	8,200	8,100	8,000	7,600	7,000	6,500	6,000
Interstate	10,433	10,460	10,375	9,200	7,950	5,870	3,060
Presently certificated							
Canada	871	950	1,000	1,000	901	727	0
SNG	360	365	375	402	300	300	300
LNG	65	310	408	565	565	565	565
Subtotal	1,296	1,625	1,783	1,967	1,766	1,592	865
Total supply--certificated	19,929	20,185	20,158	18,767	16,716	13,962	9,925
Supplemental non-certificated supply							
LNG	0	0	0	0	1,000	1,500	1,900
SNG	0	0	0	100	100	100	100
Coal gas	0	0	0	0	500	1,000	2,000
Canada	0	0	0	200	200	200	1,000
Mexico	0	0	0	700	700	700	1,000
Other, including North Slope	0	0	0	0	0	700	2,000
Total	0	0	0	1,000	2,500	4,200	8,000
Total gas supply and use	19,929	20,185	20,158	19,767	19,216	18,162	17,925

Source: SHCA.

As can be noted, the probable supply approximates the high supply estimates through 1980, is roughly midway between the high and low in 1982, and becomes the same as the low supply estimates by the mid-1980s.

These observations can be made:

- The gross additions are very probably overstated in the high supply case and may even be overstated in the other case as well. Reserve additions are more likely to be in the range of 11 Tcf to 12 Tcf per year rather than in excess of 13 Tcf. There is no evidence of any surge or planned surge in drilling activity.

- The RLI is almost certain to drop further. The "great gas bubble" identified by DOE is surplus producibility only and reliance on it will further reduce the RLI. There is literally no choice but to rely on surplus producibility to avoid deeper curtailments and to remove the bans on new attachments. Unfortunately for the nation, the bubble of producibility has also been used as an argument against supplementary projects, although it is conceivable that supplementary projects will permit the RLI to rise back to 9 or even 10 years.

- The above two points suggest that through 1980, the net production in the high case is more likely but with lower reserves additions (e.g., 12 Tcf per year), the RLI reaches 7 years very quickly--in 1980--and then production drops rapidly. Thus, the most probable trend in net production is as tabulated above.

In addition to lower-48 production, the only other sources of supply that can be counted on with any great deal of certainty are:

- Existing liquid hydrocarbon gasification plants--these plants are identified in Table 40, which also provides our estimates of maximum annual average output (about 400 Bcf). Once considered a promising supplemental source, significantly greater supplies of gas beyond the 400 Bcf level are not likely. In 1973, for example, some 50 plants had been announced, with a total design capacity of about 3.5 Tcf per year. This number of plants has dwindled to roughly 15, for the following reasons:

  -- The earlier FEA's opposition on the grounds that conversion from liquid hydrocarbon to gas was an inefficient use of energy.

  -- A low priority in the raw material allocation policy with respect to feedstock for the SNG plants.

  -- The dependence on foreign sources as the main source of feedstocks.

Table 40

LIQUID HYDROCARBON GASIFICATION PLANTS IN THE LOWER-48 STATES
(Bcf)

Company	Type of Plant	States of Probable Consumption	Full Year Output	1976 Output	1977 Output	1982 Estimated Annual Output
Public Service Electric and Gas	Seasonal	New Jersey	7.3	3.1	3.3	3.7
Public Service Electric and Gas	Seasonal	New Jersey	45.6			22.8
Consumers Power	Base load	Michigan	73.0	59.9	17.1	73.0
Algonquin SNG	Seasonal	New England	43.8	18.9	18.0	21.9
Ashland Oil	Base load	New York and Pennsylvania	21.9	18.1	18.2	17.5
Boston Gas	Seasonal	Massachusetts	14.6	3.2	1.6	7.3
Brooklyn Union Gas	Seasonal	New York	21.9	5.9	4.9	11.0
Columbia LNG	Base load	Columbia System states	91.3	58.8	75.5	91.3
Commonwealth Natural Gas	Seasonal	Virginia	11.0	2.1	1.1	5.5
Northern Illinois Gas	Base load	Illinois	67.5	61.4	65.4	67.5
Peoples Gas Light and Coke	Base load	Illinois	58.4	40.7	36.7	58.4
Baltimore Gas and Electric	Seasonal	Maryland	21.9	--	0.8	11.0
Philadelphia Gas Works	Seasonal	Pennsylvania	6.2	--	--	11.0
Total			484.4	272.1	242.6	401.9

Note: In addition to the above plants, Gasco, Inc. has a 16.6 Mcf per day plant operational in Oahu, Hawaii; 1976 production was 3.2 Bcf and 1977 production was 3.3 Bcf.

Sources: Basic details from American Gas Association, Gas Supply Review, Vol. 5, No. 12, September 1977 and Vol. 7, No. 7, April 1979. Estimated annual output--SHCA.

-- Much higher costs of construction and feedstock.

-- Effective opposition by the petrochemical industry.

- Canada's presently certificated supplies which total about 1 Tcf per year--these contracts begin to expire in the mid-1980s and if not renewed, expire completely by 1995. The maximum imports under long term contracts authorized by Canadian and U.S. governmental agencies are set forth below by importing company and by estimated destination for the year 1980 (in Bcf):

Company	Bcf	Destination	Bcf
Northwest Pipeline	332	Washington	181
Pacific Gas and Electric	373	Oregon	100
Montana Power	22	Idaho	51
Midwestern Gas	129	Northern California	373
Great Lakes Gas	121	Montana	22
St. Lawrence Gas	6	North Dakota	6
Vermont Gas	7	Minnesota	28
Inter-City Gas	8	Wisconsin	143
Michigan-Wisconsin	18	Illinois	58
Total	1,016	Michigan	41
		New York	6
		Vermont	7
		Total	1,016

The maximum authorized imports by selected year are tabulated below (in Bcf):

1980	1,016	1988	650
1981	966	1990	212
1982	891	1992	53
1983	891	1995	7
1984	891	2000	0
1985	879		

In Table 39,* we show our estimates of the total deliveries that will be made on the basis of the above mentioned long term contracts, and as can be inferred from the foregoing tabulation, have assumed that some contract extensions will be allowed.

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* In this table our preliminary estimate of imports from Canada in 1978 was 871 Bcf. In DOE's United States Imports and Exports of Natural Gas 1978, the final number is stated as 881 Bcf.

- LNG--the presently certificated projects and the quantities of gas involved are identified below:

  -- Distrigas (from Algeria)--maximum quantity of 43 Bcf. Estimated destination is the New England area.

  -- El Paso I (from Algeria)--maximum quantity of 365 Bcf. Estimated destinations are the Middle Atlantic (84 Bcf), East North Central (110 Bcf), South Atlantic (125 Bcf), and East South Central (46 Bcf) regions.

  -- Trunkline (from Algeria)--maximum quantity of 157 Bcf. Estimated destination is the East North Central region.

  In Table 39, our preliminary estimate of LNG for 1978 is 65 Bcf. The final number is now reported at 85 Bcf (Distrigas, 15 Bcf and El Paso I, 70 Bcf).

Supplemental Noncertificated Supply

Although several supplemental gas supply projects have been proposed, none to date (other than those cited above) have been certificated. The outlook for certification is highly uncertain, based on the past record. Two projects have been denied (TAPCO and El Paso II--both Algerian sources) even though the feasibility and need were clearly demonstrated during the hearings before the FERC and despite approval by the presiding law judge. The LNG projects to California (Indonesia and Alaska) will be greatly delayed (post-1988) from the original schedule, if not ultimately defeated by terminal siting problems in California. The Alaska North Slope project will also be delayed (to 1988 or later) by its enormous problems, not the least of which is the high delivered cost to the lower-48 states. Gas from Mexico was initially turned down by the government, coal gasification projects beset by their numerous problems are still years away from commercial operations, and the outlook for new SNG plants is not bright because of problems in obtaining feedstocks and in overcoming various environmental considerations. About the only new and currently noncertificated supplies that can be flowing by 1982 are in Canada and Mexico, and the outside limit from these two sources combined is 1 Tcf per year. Obtaining 2 Tcf by 1985 will not be easy, not because the resources are not already known but because of the ease with which such projects can be defeated by administrative fiat, totally independent of the hearing record.

In Table 39, we have estimated additional supply in 1982 at 1 Tcf, including a modest increase in SNG supply as well as gas from Canada and Mexico. These amounts can well materialize. In 1985, however, we assume additional supplies of 2.5 Tcf, including a highly unlikely amount of 500 Bcf from coal gas and 1 Tcf of additional LNG. Tabulated below are various LNG

projects* that at one time seems capable of delivering gas by 1985 (in Bcf):

Algeria (El Paso II)	365
Algeria (Tenneco)	365
Indonesia	182
Nigeria	183†
Trinidad	173
South Alaska	146
Colombia	50
Chile	100
Total	1,564
Total excluding El Paso II and Tenneco	834

The odds now favor that none of the above projects will be flowing by 1985, and perhaps never for some of the projects. This is because of the adverse stance assumed by various regulatory agencies and special interest groups. Frustrated producing countries may well turn (as has already happened) to Western Europe and Japan instead of continuing negotiation with the United States. Thus, we could easily have a shortfall of 1.5 Tcf (0.5 Tcf coal gas, 1.0 Tcf LNG) of gas in 1985 as compared with the Table 39 estimates.

Although our LNG and coal gas estimates for 1990 and 2000 must also be considered to be uncertain, we assume that the nations' need for these supplemental sources will not only be recognized, but more importantly, will actually be implemented. It should be noted, however, that in order to meet our estimate of 1 Tcf from coal gas in 1990, eleven 250 MMcf per day full-scale commercial plants will be required. This presents a formidable undertaking in view of such problems as:

- Coal supply: Although U.S. coal reserves are more than adequate to support a large scale and growing coal gasification industry, exploitation of these reserves may be another matter. A 250 MMcf per day coal-gasification unit, using an average grade of coal will have an annual coal requirement of roughly 8.5 million tons. While production of this magnitude does not necessarily present a problem, it should be noted that in 1978 only three mines produced more than this amount.‡

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* In addition to three projects presently authorized.

† Start-up quantity.

‡ 1978 production from the four largest mines in the United States was as follows (in millions of tons):

AMAX Coal (Belle Ayr, Wyoming)	18.1
Western Energy (Rosebud, Montana)	10.6
Decker Coal (Decker, Montana)	9.1
Utah International (Navajo, New Mexico)	8.0

Since many of the coal-gasification plants are scheduled to be located in the west, western coal production would increase by orders of magnitude over the amount produced now (assuming the gasification plants materialize). The infrastructure needed to support such significant increases is formidable and implementation will result in all the problems that are inherent in the change-over from a nondeveloped area to a rapidly growing regional economy. Increasing opposition to such a development can be expected from the local populace. Strong and effective opposition can also be expected on all environmental aspects from the mining phase of operations through the gasification and transmission elements.

Numerous permits and leases are required from federal, state, and local authorities, as well as from tribal councils when coal is located on Indian reservations. As experience has shown to date, acquisition of these permits has been fraught with difficulties.

- Water availability: Coal gasification projects require very large amounts of water for process and cooling purposes, and except for coal, water is the most important element in gasifying coal. Particularly in the west, water availability is of critical concern and will be a limiting factor in development of the gasification industry.

- Technological problems: Although production of high Btu gas from coal has been proven to be technologically feasible, the process has not yet been attempted in a commercial size project. First generation commercial plants can be expected to uncover various technological problems that will need to be solved before design capacity pipeline quality gas is forthcoming.

- Capital financing: Capital requirements for each coal-gasifications facility amount to hundreds of millions of dollars. Raising such vast sums from traditional sources of capital for these high risk ventures has already proven to be a problem of major proportions. It appears likely that federal government financial support in one form or another will be a necessary prerequisite for implementation of at least the initial first generation plants or until such time as the full-scale commercial plants prove economically feasible.

In view of the above factors, prospects for realization of the coal-gasification potential are highly uncertain, despite the fact that an important plus feature of coal gasification is a supplemental supply based entirely on domestic resources. Actual output could indeed range from virtually zero to several Tcf per year. With a lead time of from six to eight years from the planning stage to pipeline flow, coupled with technical problems that are likely to arise and that will take time to solve, the one thing that appears reasonably certain at this time is that none of the plants built will go on-stream until the late 1980s.

In summary, therefore, most other sources of gas supply listed in Table 30 carry even a greater uncertainty than lower-48 production. The presently noncertificated supplemental supply that is listed in the above referenced table is in every single instance subject to a greater probability of less (or delayed or even no) supply than that they will be available and certificated, or be higher than projected. U.S. policy has effectively destroyed supplemental gas supplies and it will not be easy to reverse this negative momentum even if policy could change. There is as yet absolutely no indication of any change in policy. Therefore, we are forced to conclude that total gas supply is more probably high than low. Lower supplies than projected will either be made up by imported oil or more probably will result in lower economic growth than projected.

Field and City Gate Prices

Field prices are dictated by the Natural Gas Policy Act of 1978 (NGPA) through 1985 or 1987. Our evaluation of NGPA prices and our estimates of related production volumes are given in Table 41. The field prices permitted by NGPA are not much different from our earlier estimates based on the Opinion 770 formula. The one notable exception is that there is no vintaging after 1976, which makes a substantial difference in the average field price by 1990. In our present analysis, we have assumed that complete decontrol of gas field prices will occur before 1990 (except for some vintage categories), but it is quite possible that controls will be extended beyond 1987 and the field prices will continue to be well below the price of crude oil.

The prices by type of production are given in Table 31, with the vintages retained through 1976 and with 20 or more other categories for post-1976 production combined into three groupings:

- "Old" gas from structures or wells near existing structures or wells.
- "New" gas which qualifies for the distance definitions.
- "Incentive" gas which includes stripper wells and structures at great depth, etc.

The first two groupings start with the same price in 1977, but the price of "old" gas increases with inflation, while that of "new" gas increases 4 percentage points more rapidly than inflation. The "incentive" gas price is higher than that of "new" gas by more than 10%.

The results are summarized below (in actual cents per Mcf):

1980	130¢
1982	170
1985	250
1990	670

Table 41

VOLUMES AND FIELD PRICES OF INTERSTATE GAS SUPPLY
(Volume in Tcf and Price in Cents per MMBtu)

	Pre-1973		1973-74		1975-76		1977 and On								Total Interstate		
							Old		New		Incentive		Total				
	Volume (1)	Price (2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	(1)	(2)	Volume	Price	Rounded Price
Actual cents																	
1976	9.50	42¢	0.60	97¢	0.60	102¢	0	--¢	0	--¢	0	--¢	0	--¢	10.70	48.4¢	
1977	7.70	45	0.50	98	1.10	149	0.60	149	0.10	149	0.20	225	0.90	166	10.20	69.5	
1978	7.00	49	0.40	99	0.90	155	1.60	188	0.30	196	0.20	225	2.10	193	10.40	89.1	89¢
1979	6.40	53	0.36	106	0.80	165	1.80	208	0.84	226	0.30	250	2.94	217	10.50	109.3	110
1980	5.80	56	0.33	113	0.70	177	2.00	229	1.20	260	0.37	300	3.57	247	10.40	131.5	130
1982	4.70	60	0.27	126	0.57	199	2.00	274	1.26	335	0.40	375	3.66	306	9.20	168.4	170
1985	3.40	66	0.21	150	0.42	265	2.03	344	1.54	470	0.40	550	3.97	414	8.00	251.2	250
1990	1.70	72	0.10	200	0.25	349	1.91	520	1.54	1,400	0.40	1,400	3.85	963	5.90	667.6	670
2000	0	--	0	--	0	--	1.40	1,100	1.34	5,000	0.36	5,000	3.10	3,239	3.10	3,238.7	3,240
1978 cents																	
1979	6.40	48	0.36	96	0.80	150	1.80	189	0.84	205	0.30	227	2.94	197	10.50	99.1	99
1980	5.80	46	0.33	93	0.70	146	2.00	189	1.20	214	0.37	247	3.57	204	10.40	108.4	110
1982	4.70	42	0.27	87	0.57	138	2.00	190	1.26	232	0.40	260	3.66	212	9.20	116.9	115
1985	3.40	36	0.21	83	0.42	146	2.03	189	1.54	259	0.40	303	3.97	228	8.00	138.3	140
1990	1.70	27	0.10	75	0.25	131	1.91	195	1.54	525	0.40	525	3.85	361	5.90	250.4	250
2000	0	--	0	--	0	--	1.40	191	1.34	868	0.36	868	3.10	562	3.10	562.3	560

Source: SHCA.

These averages may be understated by several percent because severance taxes can be added on the maximum allowed prices and it appears that the pipeline industry is bidding up to the maximum with taxes as an add-on. However, most of the interstate supply is from federal offshore waters and we doubt that the legal attempt to apply a 7% severance tax to this source will succeed. On average, a 1% or 2% increase in the above average prices to allow for taxes might be appropriate (this is within the margin of error of the estimates).

The city gate prices for the U.S. average and several eastern regions are developed in Table 42. The average field price is taken from Table 41 and is of course the same for all regions. The variation in transmission margins is attributable to differences in pipeline mileage. We have assumed that the overall average delivered price of Canadian and Mexican gas will approximate each other and that the overall weighted average cost of all other supplementary sources will not only approximate each other but that by 1990 will also approximate the cost of Canadian and Mexican supplies. These assumptions are somewhat over-simplified, but, nevertheless, are reasonable and any variations are likely to fall within the margin of error of the estimates. Using the New England-Middle Atlantic prices to compare the prices of low sulfur fuel oil ex-refinery on the East Coast, gas prices compare very favorably as shown below (in 1978 dollars per MMBtu):

	1979	1985	1990
Gas	$1.88	$2.93	$4.30
Oil	3.28	4.70	5.66

Consumption

For purposes of convenience, our estimates of U.S. end-use gas consumption given earlier in Table 6, are repeated below (in Bcf):

	1980	1982	1985	1990	2000
Residential	4,995	5,055	5,140	5,235	5,425
Commercial	2,810	2,935	3,070	3,215	3,410
Industrial	6,350	6,245	6,385	6,370	6,120
Power plants	2,450	2,050	1,100	500	500
Other*	3,553	3,482	3,221	2,842	2,470
Total	20,158	19,767	19,216	18,162	17,925

* Field use, pipeline fuel and transmission losses, and net injection to storage.

Table 42

VOLUMES AND PRICES OF GAS IN THE UNITED STATES
AND IN SELECTED REGIONS
(Volume in Bcf and Price in Actual Cents per MMBtu*)
1979-1990

	1979		1980		1985		1990	
	Volume	Price	Volume	Price	Volume	Price	Volume	Price
United States								
Conventional lower-48 supply								
Field price		110¢		130¢		250¢		670¢
Transmission margin		50		55		82		121
City gate	18,560	160	18,375	185	14,950	332	12,370	791
Canada and Mexico, city gate	950	236	1,000	286	1,801	800	1,627	1,500
Other supplementary, city gate	675	450	783	500	2,465	1,000	4,165	1,500
Total volume and weighted average city gate price	20,185	173	20,158	202	19,216	462	18,162	1,017
City gate price in 1978 cents		157¢		167¢		254¢		381¢
New England and Middle Atlantic								
Conventional lower-48 supply								
Field price		110		130		250		670
Transmission margin		70		77		115		169
City gate	1,770	180	1,775	207	1,522	365	1,160	839
Canada and Mexico, city gate	11	236	11	286	136	800	136	1,500
Other supplementary, city gate	194	450	229	500	462	1,000	884	1,500
Total volume and weighted average city gate price	1,975	207	2,015	241	2,120	531	2,180	1,148
City gate price in 1978 cents		188¢		198¢		293¢		430¢
East North Central								
Conventional lower-48 supply								
Field price		110		130		250		670
Transmission margin		40		44		66		97
City gate	3,740	150	3,700	174	3,000	316	2,250	767
Canada and Mexico, city gate	250	236	250	286	296	800	286	1,500
Other supplementary, city gate	280	450	317	500	964	1,000	1,724	1,500
Total volume and weighted average city gate price	4,270	175	4,267	205	4,260	504	4,260	1,113
City gate price in 1978 cents		158¢		169¢		278¢		417¢

* Except where noted.

Source: SHCA.

Residential and commercial use is considered by regulatory authorities and gas utilities to have priority over other uses and thus supplies are allocated first to these markets. In our analysis, we estimated gas use within the framework of a particular market's total energy requirements, taking into account the various interfuel competition elements* as well as the effect of the various energy conservation measures on consumption patterns. In the residential and commercial sectors, past and probable future trends in gas use per customer compared with probable increases in the number of gas customers were a main element in our estimates. Estimates were made in the "other" category on the basis of past trends in field use related to lower-48 state marketed production and with pipeline fuel related to total gas supply. Use of gas in power plants was projected to decline steadily as West South Central utilities turn more and more to coal (and/or nuclear if allowed) and away from their traditional energy source, gas. Industrial consumption of gas was then considered to equate to the amount of gas remaining after all the other markets had been met. In view of the generally favorable price advantage gas is likely to have over oil in the industrial sector, more gas could be marketed if available, particularly in view of the oil price increases that we now foresee. However, another important feature of the NGPA is the mandatory imposition of incremental pricing. This theoretically forces all increases in the cost of gas onto the industrial user until the gas price reaches parity with the price of competitive fuel and then further increases are borne by high priority customers. It is not certain which competitive fuel will be used and it may well vary by region; however, heavy fuel oil is a likely prospect, although the sulfur content may vary. This should pose no problem to gas' competitiveness if carried through by state commissions, but it is understood that the industrial prices may be forced above the competitive price by purchased gas adjustment clauses which generally flow through equally to all applications. There will be great pressure to permit this because of strong consumer and public interest group resistance to higher gas rates. Incremental pricing carries no benefits but it potentially places another constraint upon the gas industry in retaining its market, let alone expanding.

Further, the Federal Power Plant and Industrial Fuel Use Act of 1978 (FUA) establishes specific rules regarding the fuel that can be used in existing and new power plants and industrial installations. In brief form, these rules are as follows:

- Existing power plants
  - -- Natural gas shall not be used as a primary energy source on or after January 1, 1990.

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* Relative price and price elasticity, availability and dependability of supply, historical trends and general customer preference characteristics.

-- Natural gas shall not be used as a primary energy source before 1990, unless it was used as a primary source in 1977.

-- Natural gas used before 1990 cannot exceed the quantity used in such power plants as a primary energy source during calendar years 1974 through 1976.

- Existing major fuel burning installations

  The DOE Secretary may prohibit the use of petroleum or natural gas as a primary energy source if:

  -- The installation has or previously had the technical capability to use alternative fuels.

  -- The installation could obtain alternative fuel capability without substantial physical modification or substantial reduction in capacity.

  -- It is financially feasible to use alternative fuels as a primary energy source in such installation.

- New power plants

  -- Natural gas or petroleum shall not be used as primary energy source in any new electric power plant.

  -- No new electric power plant may be constructed without the capability to use coal or another type of alternative fuel as a primary energy source.

- New major fuel burning installations

  -- Natural gas or petroleum shall not be used as a primary energy source in a boiler.

  -- The DOE Secretary may prescribe categories of new major fuel burning installations other than boilers in which natural gas or petroleum or both shall be prohibited from being used as a primary energy source.

The act defines an "existing" facility as any facility on which contruction was initiated or which was acquired after April 20, 1977.

Exemptions from the rules are possible; temporary exemptions may be granted for five years and permanent exemptions may be granted if "certain physical, economic, environmental, legal, or other factors preclude compliance."* An exemption based on economic factors can be obtained only if it can be proved that the cost of generating electricity in a coal or alternate fuel fired power plant or the cost of raising steam in a large industrial boiler exceeds the cost of oil or gas use for the same purposes by

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* Federal Register, Volume 43, No. 223, November 17, 1978.

30% to 80% (the specific ratio is to be selected later). In calculating the present value alternatives of electric power generation or steam raising, the specific rules to be followed all tend to bias the comparison in favor of coal:

- The discount rate to be used is 3.5 percentage points for power plants and 7 percentage points for industrial facilities over and above the annual rate of inflation. This requirement will result in a total discount rate most likely below a rate that would normally be used for economic comparisons of that kind and thus favoring the coal burning facility that requires a larger capital investment.

- Investment tax credits cannot be taken into consideration in estimating the costs associated with oil or gas fired facilities, but the maximum investment tax credit must be taken into consideration in estimating the costs associated with a coal fired facility.

- Accelerated depreciation for oil and gas fired units cannot be used, whereas the maximum accelerated depreciation rate allowed by law must be used for coal fired units.

- When comparing oil and coal fuels, the oil must be imported oil, with the price calculated as the price of the fuel oil under consideration but multiplied by a factor which is the ratio of recent imported crude oil receipts to the average price of recent total receipts of domestic and imported crude oil. Thus, although the differential between international and domestic oil prices may narrow in the future, for the purpose of this comparison it will remain frozen (as a ratio) for the entire period of the economic comparison.

- All other costs (labor, replacement materials, and taxes) must be expressed in uninflated terms, thereby favoring the unit with the higher operating (excluding fuel) costs; coal fired facilities customarily incur greater operating costs (fuel handling and ash removal) than do oil or gas fired facilities. As the cost of coal fuel is nowhere mentioned separately, it may be presumed to be included with "other" costs; therefore, the cost of oil or gas must be escalated, whereas the cost of coal cannot be escalated under the proposed rule.

It is evident that the new legislation will make it difficult to avoid using coal or another fuel other than oil and gas in any new power plant or large industrial facility. But the Act does not make it impossible, because there is the exemption provision. There may also be a legal challenge to the method of comparing costs, which is so obviously rigged that the cost in use of coal may be two to three times higher than costs of relying on oil or gas, making the use of coal totally uneconomic without subsidies. Even an 80% premium in using coal, which the Act considers as possibly acceptable, could render a new energy intensive industrial

plant uneconomic in world competition. The bill faces problems in achieving its objectives in that there are no incentives* and in fact, there are negative financial impacts. The major exemption to FUA is likely to be air pollution rules, but attempts will undoubtedly be made on all grounds. As noted earlier, the FUA appears to have had little or no effect on industrial conversion to coal so far, and our evaluation of the act is that it will continue to have little effect.

In sharp contrast to the above possible restrictions on industrial and power plant use of gas is the sudden reversal in DOE's policy, which now encourages boiler fuel sales, at least over the short term.

Taking all factors into account, we consider our projections of industrial use of gas as reasonable, assuming of course adequate availability. On the other hand, should uncertainty in gas supply once again lead to shortages--moratorium on attachment of new customers and deep curtailment of industrial customers--no further growth in gas demand in any sector can be expected and the industrial gas market will shrink even more than it has in the past few years.

Gas market shares as they have developed over time and as they are projected to occur (on the basis of supply given in Table 39) are as follows (gas share as a percent of total end-use energy requirements):

	1960	1973	1980	1990
Residential	45%	49%	47%	45%
Commercial	36	46	47	47
Industrial	37	50	40	35
Power plants	22	19	10	1
Total primary energy	30	31	25	19

* The Energy Tax Act does alter tax credits for conversion or new investment in coal facilities.

Appendix A

U.S. ENERGY BALANCE

Table 43

CONSUMPTION OF ENERGY IN THE UNITED STATES*
(Trillions of Btu)
1960-1990

	1960	1965	1970	1973	1974	1975	1976	1977	Prel. 1978	1979	1980	1982	1985	1990
Residential														
Light oil	2,177.6	2,319.2	2,462.6	2,422.2	2,265.2	2,249.8	2,492.9	2,452.0	2,490.0	2,475.0	2,450.0	2,425.0	2,400.0	2,300.0
LPG	302.6	383.2	544.5	562.2	518.0	502.4	524.2	513.9	512.0	513.0	515.0	515.0	515.0	515.0
Coal	353.1	247.5	149.2	93.0	81.0	62.9	56.7	49.4	50.0	48.0	45.0	43.0	40.0	35.0
Gas	3,217.3	4,040.8	5,011.0	5,061.0	4,955.4	5,099.8	5,229.6	4,990.7	5,128.0	5,156.0	5,172.0	5,230.0	5,319.0	5,417.0
Biofuels	410.5	334.2	262.9	229.6	218.9	212.4	216.6	219.9	224.0	228.0	232.0	239.0	247.0	258.0
Electricity	691.9	958.8	1,528.2	1,891.2	1,894.2	2,000.5	2,092.3	2,226.6	2,324.0	2,415.0	2,525.0	2,700.0	2,950.0	3,335.0
Solar	--	--	--	--	--	--	--	--	--	--	6.0	13.0	29.0	75.0
Total	7,153.0	8,283.7	9,958.4	10,259.2	9,932.7	10,127.8	10,612.3	10,452.5	10,728.0	10,835.0	10,945.0	11,165.0	11,500.0	11,935.0
Commercial														
Light oil	820.5	900.0	989.9	1,053.1	901.9	861.9	956.9	954.0	970.0	950.0	900.0	825.0	750.0	650.0
Heavy oil	176.5	221.0	261.2	250.4	209.6	177.7	172.2	142.9	150.0	150.0	140.0	135.0	125.0	100.0
LPG	101.1	127.3	180.4	187.4	172.8	167.7	174.8	170.8	170.0	172.0	175.0	175.0	175.0	175.0
Coal	343.6	246.0	147.7	90.5	78.3	61.4	54.7	47.1	50.0	50.0	50.0	50.0	50.0	50.0
Gas	1,056.7	1,498.3	2,484.8	2,672.3	2,639.1	2,591.9	2,755.0	2,583.7	2,655.0	2,800.0	2,910.0	3,035.0	3,178.0	3,328.0
Electricity	460.9	793.7	1,234.4	1,542.8	1,525.0	1,623.2	1,708.0	1,808.1	1,857.0	1,950.0	2,025.0	2,170.0	2,400.0	2,780.0
Solar	--	--	--	--	--	--	--	--	--	--	--	--	2.0	17.0
Total	2,959.3	3,786.3	5,298.4	5,796.5	5,526.7	5,483.8	5,821.6	5,706.6	5,852.0	6,072.0	6,200.0	6,390.0	6,680.0	7,100.0
Industrial														
Light oil	255.8	317.4	330.7	480.6	455.2	454.2	552.8	727.0	750.0	717.0	752.0	759.0	735.0	728.0
Heavy oil	1,861.9	1,848.6	2,009.5	2,230.6	2,094.5	1,840.5	2,278.5	2,362.4	2,369.0	2,248.0	2,381.0	2,281.0	2,496.0	2,569.0
Still gas	745.4	839.5	993.7	1,072.7	1,043.2	1,050.5	1,141.8	1,193.9	1,258.0	1,265.0	1,276.0	1,322.0	1,393.0	1,427.0
Petroleum coke	320.2	327.2	313.7	400.1	374.0	390.1	395.2	400.2	384.0	391.0	400.0	417.0	437.0	461.0
LPG	56.8	65.1	84.9	104.3	102.2	103.2	100.4	99.7	99.0	100.0	100.0	100.0	100.0	100.0
Coal	2,593.0	2,618.3	2,155.2	1,606.7	1,586.3	1,327.8	1,324.3	1,460.4	1,238.0	1,597.0	1,512.0	1,782.0	1,396.0	1,219.0
Gas	4,300.2	5,661.8	7,465.0	8,366.8	7,937.5	6,620.3	6,816.4	6,745.7	6,490.0	6,672.0	6,571.0	6,462.0	6,607.0	6,595.0
Biofuels	274.5	256.4	237.9	227.1	222.4	220.2	226.5	228.7	231.0	235.0	238.0	242.0	246.0	250.0
Electricity	1,160.2	1,479.0	1,953.9	2,345.6	2,352.9	2,257.9	2,475.0	2,584.2	2,675.0	2,860.0	3,050.0	3,475.0	4,210.0	5,467.0
Solar	--	--	--	--	--	--	--	--	--	--	--	--	6.0	29.0
Total	11,568.0	13,413.3	15,544.5	16,834.5	16,168.2	14,264.7	15,310.9	15,802.2	15,494.0	16,085.0	16,280.0	16,840.0	17,626.0	18,845.0
Power plants														
Light oil	29.2	23.0	154.0	433.1	453.7	350.6	361.1	427.0	415.0	425.0	435.0	455.0	500.0	600.0
Heavy oil	539.9	723.5	1,962.1	3,128.6	2,896.3	2,811.1	3,113.4	3,469.3	3,551.0	3,700.0	3,480.0	3,475.0	3,500.0	3,475.0
Coal	4,214.2	5,834.7	7,524.8	8,934.8	9,018.1	9,257.1	10,172.6	10,753.9	10,854.0	11,582.0	12,175.0	13,788.0	16,325.0	20,956.0
Gas	1,806.0	2,423.8	4,091.1	3,785.4	3,562.6	3,275.9	3,207.7	3,323.4	3,320.0	2,588.0	2,536.0	2,122.0	1,450.0	518.0
Hydroelectric	1,455.1	1,938.4	2,474.6	2,716.3	3,009.1	3,000.5	2,836.8	2,204.1	2,806.0	2,952.0	3,037.0	3,181.0	3,264.0	3,329.0
Nuclear	5.2	36.6	218.0	833.3	1,135.8	1,725.1	1,911.1	2,508.5	2,764.0	2,870.0	3,656.0	4,906.0	6,932.0	9,848.0
Geothermal and other	2.0	2.5	5.7	21.6	26.1	34.4	38.9	40.7	33.0	48.0	56.0	73.0	104.0	124.0
Total	8,051.6	10,982.5	16,430.3	19,853.1	20,101.7	20,454.7	21,641.6	22,726.9	23,743.0	24,165.0	25,375.0	28,000.0	32,075.0	38,850.0
Transportation														
LPG	85.7	114.0	127.6	134.4	124.9	110.6	111.5	109.2	109.0	112.5	113.0	114.0	116.0	119.0
Gasoline	7,848.5	9,217.3	11,511.6	13,202.5	12,627.1	12,992.8	13,743.0	14,133.7	14,602.0	14,381.0	14,753.0	14,861.0	14,606.0	14,479.0
Jet fuel	188.0	613.1	1,366.1	1,447.9	1,336.0	1,357.5	1,386.7	1,440.9	1,473.0	1,496.0	1,538.0	1,622.0	1,748.0	1,995.0
Light oil	828.7	1,028.2	1,502.2	2,030.4	2,041.3	1,972.9	2,156.9	2,323.7	2,450.0	2,525.0	2,630.0	2,820.0	3,080.0	3,485.0
Heavy oil	617.9	481.3	576.1	586.9	583.2	612.5	742.6	814.4	616.0	650.0	700.0	720.0	750.0	750.0
Gas	648.0	859.1	1,065.6	1,000.0	993.9	852.7	842.2	848.2	832.0	825.0	825.0	810.0	785.0	740.0
Electricity	16.2	15.8	15.8	14.0	14.5	14.6	14.7	14.4	15.0	15.5	16.0	17.0	19.0	22.0
Total	10,233.0	12,328.8	16,165.0	18,416.1	17,720.9	17,913.6	18,997.6	19,684.5	20,097.0	20,005.0	20,575.0	20,964.0	21,104.0	21,590.0

Table 43 (concluded)

	1960	1965	1970	1973	1974	1975	1976	1977	Prel. 1978	1979	1980	1982	1985	1990
Military														
Jet fuel	548.8	611.1	593.5	524.8	533.4	521.5	493.6	507.5	515.0	520.0	525.0	535.0	550.0	575.0
Light oil	63.1	87.2	72.7	114.8	103.7	105.2	102.9	106.7	105.0	105.0	105.0	106.0	107.0	108.0
Heavy oil	196.6	251.8	177.7	143.9	128.7	119.7	116.8	114.7	110.0	113.0	115.0	115.0	115.0	115.0
Total	808.5	950.1	843.9	783.5	765.8	746.4	713.3	728.9	730.0	738.0	745.0	756.0	772.0	798.0
Raw materials														
LPG (including ethane)	354.6	531.7	834.0	1,081.1	1,051.3	936.4	964.9	999.1	983.0	998.5	1,049.0	1,077.0	1,126.0	1,225.0
Petrochemical feedstocks and special naphthas	153.0	476.7	760.3	936.5	959.4	824.9	1,058.0	1,246.8	1,423.0	1,427.0	1,437.0	1,458.0	1,487.0	1,590.0
Lubes and greases	259.6	306.6	335.1	413.0	384.4	355.5	369.8	377.6	403.0	412.0	417.0	429.0	443.0	459.0
Petroleum coke	127.9	142.1	177.1	195.6	186.5	178.1	172.2	204.9	196.0	198.0	200.0	200.0	200.0	200.0
Asphalt and road oil	783.0	964.5	1,160.8	1,317.8	1,190.0	1,050.0	1,034.4	1,164.1	1,263.0	1,266.0	1,287.0	1,314.0	1,359.0	1,439.0
Miscellaneous oil	257.0	140.6	128.0	166.1	194.1	229.0	315.5	361.7	340.0	342.0	342.0	342.0	342.0	342.0
Gas	445.3	537.7	733.3	721.5	706.0	690.8	692.6	699.0	695.0	700.0	700.0	700.0	700.0	700.0
Coking coal	2,073.6	2,432.8	2,428.7	2,301.9	2,213.2	2,174.7	2,169.0	2,008.9	2,086.0	2,100.0	2,125.0	2,150.0	2,150.0	2,150.0
Total	4,454.0	5,532.7	6,557.3	7,133.5	6,884.9	6,439.4	6,776.4	7,062.1	7,389.0	7,443.5	7,557.0	7,670.0	7,807.0	8,105.0
Miscellaneous uses														
LPG†	5.6	7.5	24.5	50.6	88.4	129.9	186.1	191.7	195.0	200.0	210.0	225.0	240.0	255.0
Light oil	380.5	477.0	463.1	498.0	425.3	426.7	468.7	551.0	500.0	500.0	500.0	500.0	500.0	500.0
Heavy oil	39.0	62.1	45.1	50.7	53.6	38.2	36.0	30.0	25.0	25.0	25.0	25.0	25.0	25.0
Gas	2,020.3	1,353.3	1,875.0	2,022.6	1,752.0	1,833.4	1,848.4	2,249.1	2,176.0	2,150.0	2,150.0	2,100.0	1,850.0	1,500.0
Electricity	2.1	6.2	16.0	18.5	18.0	18.6	21.3	24.3	25.0	25.5	26.0	28.0	31.0	36.0
Total	2,447.5	1,906.1	2,423.7	2,640.4	2,337.3	2,446.8	2,560.5	3,046.1	2,921.0	2,900.5	2,911.0	2,878.0	2,646.0	2,316.0
Total energy														
Still gas	745.4	839.5	933.7	1,072.7	1,043.2	1,050.5	1,141.8	1,193.9	1,258.0	1,265.0	1,276.0	1,322.0	1,393.0	1,427.0
LPG	906.4	1,228.8	1,795.9	2,120.0	2,057.6	1,950.2	2,061.9	2,084.4	2,068.0	2,096.0	2,162.0	2,206.0	2,272.0	2,389.0
Gasoline	7,848.5	9,217.3	11,511.6	13,202.5	12,627.1	12,992.8	13,743.0	14,133.7	14,602.0	14,381.0	14,753.0	14,861.0	14,606.0	14,479.0
Jet fuel	736.8	1,224.2	1,959.6	1,972.7	1,869.4	1,879.0	1,880.3	1,948.4	1,988.0	2,016.0	2,063.0	2,157.0	2,298.0	2,570.0
Light oil	4,555.4	5,152.0	5,975.2	7,032.2	6,646.3	6,421.3	7,092.2	7,541.4	7,680.0	7,697.0	7,772.0	7,890.0	8,072.0	8,371.0
Heavy oil	3,431.8	3,588.3	5,031.7	6,391.1	5,965.9	5,599.7	6,459.5	6,933.7	6,821.0	6,886.0	6,841.0	6,751.0	7,011.0	7,034.0
Petrochemical feedstocks and special naphthas	153.0	476.7	760.3	936.5	959.4	824.9	1,058.0	1,246.8	1,423.0	1,427.0	1,437.0	1,458.0	1,487.0	1,590.0
Petroleum coke	448.1	469.3	490.8	595.7	560.5	568.2	567.4	605.1	580.0	589.0	600.0	617.0	637.0	661.0
Lubes and greases	259.6	306.6	335.1	413.0	384.4	355.5	369.8	377.6	403.0	412.0	417.0	429.0	443.0	459.0
Asphalt and road oil	783.0	964.5	1,160.8	1,317.8	1,190.0	1,050.0	1,034.4	1,164.1	1,263.0	1,266.0	1,287.0	1,314.0	1,359.0	1,439.0
Miscellaneous	257.0	140.6	128.0	166.1	194.1	229.0	315.5	361.7	340.0	342.0	342.0	342.0	342.0	342.0
Total oil	20,125.0	23,607.8	30,142.7	35,220.3	33,497.9	32,921.1	35,723.8	37,590.8	38,426.0	38,377.0	38,950.0	39,347.0	39,920.0	40,761.0
Coal	9,577.5	11,379.3	12,405.6	13,026.9	12,976.9	12,883.9	13,777.3	14,319.7	14,278.0	15,377.0	15,907.0	17,813.0	19,961.0	24,410.0
Gas	13,493.8	16,374.8	22,725.8	23,629.6	22,546.5	20,964.8	21,391.9	21,439.8	21,296.0	20,891.0	20,864.0	20,459.0	19,889.0	18,798.0
Biofuels	685.0	590.6	500.8	456.7	441.3	432.6	443.1	448.6	455.0	463.0	470.0	481.0	493.0	509.0
Hydroelectric	1,455.1	1,938.4	2,474.6	2,716.3	3,009.1	3,000.5	2,836.8	2,204.1	2,806.0	2,952.0	3,037.0	3,181.0	3,264.0	3,329.0
Nuclear	5.2	36.6	218.0	833.3	1,135.8	1,725.1	1,911.1	2,508.5	2,764.0	2,870.0	3,656.0	4,906.0	6,932.0	9,848.0
Geothermal and other	2.0	2.5	5.7	21.6	26.1	34.4	38.9	40.7	33.0	48.0	56.0	73.0	104.0	124.0
Solar	--	--	--	--	--	--	--	--	--	--	6.0	13.0	37.0	121.0
Total primary energy	45,343.6	53,930.0	68,473.2	75,904.7	73,633.6	71,962.4	76,122.9	78,552.2	80,058.0	80,978.0	82,946.0	86,273.0	90,600.0	97,900.0
Electricity	2,331.3	3,253.5	4,748.3	5,812.1	5,804.6	5,914.8	6,311.3	6,657.6	6,896.0	7,266.0	7,642.0	8,390.0	9,610.0	11,640.0
Total energy	47,674.9	57,183.5	73,221.5	81,716.8	79,438.2	77,877.2	82,434.2	85,209.8	86,954.0	88,244.0	90,588.0	94,663.0	100,210.0	109,540.0

* Including Alaska and Hawaii.
† Does not include LPG used in gasoline production.

Source: SHCA.

ADDENDUM NUMBER 1

DRI'S UNITED STATES ENERGY REVIEW, SUMMER 1979

ADDENDUM 1

DRI's UNITED STATES ENERGY REVIEW, SUMMER 1979

Attached is a summary of DRI's Summer 1979 Review of long-term United States energy demand and supply. This forecast, which is linked to DRI's model of the United States economy, takes fully into account the recent OPEC price increases and the revised expectations about the future price trend of internationally traded petroleum. The full report will be available to subscribers of the DRI Energy Service towards the end of August.

In the absence of the full analysis, only a cursory comparison between the DRI and the Sherman C. Clark forecasts can be made at this time. A comparison of the major conclusions is shown in the attached table. These forecasts are in fairly close accord to 1990 but divergent significantly for the 1990-2000 period, the divergence apparently being due to Clark's lower assessment of United States and foreign availability of petroleum after 1990. This assessment involves the size of the as yet undiscovered petroleum resources, their rate of discovery over time, and the production limits imposed by petroleum exporting countries.

Although the DRI forecast does not explicitly review United States energy demand and supply in an international context, the assumption of a globally higher availability of petroleum is evidenced by DRI's forecast of United States petroleum production and imports. By year 2000, DRI's United States petroleum production is 14% higher than the Clark forecast; imports are 25% higher. As a consequence, petroleum prices will also depart significantly after 1990. Whereas the Clark forecast of imported crude oil prices is only about 10% higher in 1990 than the DRI forecast - not a significant difference, in our opinion, given the uncertainties about the variables that have to be included in the quantification of future prices - by year 2000, imported crude oil prices are about 35% above the DRI forecast.

Energy notes #257 is included at the end of this report

COMPARISON OF DRI AND S. C. CLARK FORECASTS

	1985		1990		2000	
	DRI	Clark	DRI	Clark	DRI	Clark
TOTAL ENERGY CONSUMPTION (Quads)	87.7	90.6	97.9	97.9	116.7	NA
PETROLEUM						
Consumption (10^6 Bbl/Day)	19.0	19.6	20.1	20.0	22.0	19.2
Domestic Production (10^6 Bbl/Day)*	9.5	10.0	10.3	10.2	10.8	9.5
Imports (10^6 Bbl/Day)	8.9	8.9	9.1	9.0	10.4	8.3
Refiner Acquisition Cost (1978 $/BBl)	22.54	25.00	27.13	31.00	38.72	53.00
Price of Imported Crude (1978 $/Bbl)	22.95	25.00	27.58	31.00	39.30	53.00
NATURAL GAS						
Consumption (10^{12} cf/Year)	20.0	19.2	19.9	18.2	19.0	17.9
Avg. Interstate Price (1978 $/Mcf)	2.49	1.38	3.62	2.50	6.84	5.62
COAL CONSUMPTION (Quads)	20.4	20.0	26.4	24.4	37.2	NA

* Crude oil and natural gas liquids only

NA - Not available

ENERGY FORECAST RELEASE

Total energy demand rises from 78.4 quadrillion Btu (quads) in 1979 to 97.9 quads in 1990 and 122.6 quads in 2003. Fuel demand growth in the household and commercial, industrial and transportation sectors averages slightly more than 1% over the forecast period while demand in the electric utility sector advances 3.3%. The fuel growth in the electric utility sector parallels the growth in electricity demand which rises from 7.1 quads in 1979, to 11.3 quads in 1990, and to 15.6 quads in 2003. Petroleum consumption continues to increase. By 1990, U. S. demand is 19.0 million barrels per day (mmbd), up from 17.5 mmbd in 1979. Consumption in 2003 is projected to be 21.4 mmbd. The domestic supply of crude oil and natural gas liquids remains relatively constant over the forecast interval at approximately 11 mmbd. Consequently, total petroleum imports rise from 8.0 mmbd in 1979 to 9.1 in 1990 and 10.8 in 2003.

The delivered price of imported oil is projected to be $19.50 per barrel in 1979, $22.50 in 1980, and to rise 3.6% in real terms over the remainder of the forecast interval. Expenditures on imported oil, in 1979 dollars, increase from $56 billion in 1979, to $99 billion in 1990, and $186 billion in 2003.

Natural gas consumption declines only slightly over the forecast period as Alaskan production, LNG imports, imports from Canada and Mexico and synthetic natural gas help to offset the decline in lower-48 states' production. Consumption is projected to decline from 19.5 quads in 1979 to 19.0 quads in 1990 and 18.0 quads in 2003.

Coal production is forecast to rise from .74 billion tons in 1979 to 1.3 billion tons in 1990 and to 2.0 billion tons in 2003. Electric utilities consume 70% to 75% of the production while the industrial sector absorbs 15% to 25% over the forecast period.

Nuclear generation supplies 3.1 quads in 1979, increasing to 8.7 quads in 1990 and to 15.1 quads in 2003. Hydropower contributes approximately 3.3 quads in each year of the forecast period. Solar energy and energy from exotic sources is projected to add 1.5 quads and .7 quads by 2003.

APPENDIX
MACROECONOMIC FORECAST SUMMARY

DEMOGRAPHIC UNDERPINNINGS

Demographic considerations are of paramount importance in a 25-year projection. The rate of growth of the population, and changes in its composition, have considerable impact on the likely rate of growth of the labor force, the full-employment unemployment rate, the demand for housing and several other spending categories, notably consumption of motor vehicles and state and local government spending.

ENERGY FORECAST RELEASE

The trend outlook is consistent with the Bureau of the Census Series II population projection. In this projection, the fertility rate is assumed to return gradually to 2.1. Some small improvement in mortality is assumed. Combined with net immigration of 400,000 per year, these assumptions lead to a total population of 244 million in 1990 and 265 million in 2000. Series II projections by age bracket for the years 2001-2003 have been produced by DRI.

THE OUTLOOK

The forecast period can conceptually be divided into two parts. From 1979 to 1985, the economy's path is dominated by cyclical considerations. The present high rate of inflation, tightening monetary policy, and the maturation of the recovery combine to lead to a mild recession in 1979. Thus GNP growth of 2.8% is foreseen for 1979. The weakness at the end of 1979 means that growth for 1980 is also weak at 2.3%, even though output is recovering over the course of that year. Growth in 1981 is a relatively strong 3.8%. The persistence of inflation, however, leads to further difficulties in mid-1981, and 1982 is another weak year, with only 2.6% growth in GNP.

The subsequent recovery in 1983-1985 is more durable, primarily because it is accompanied by relatively favorable inflation developments. The weakness of the economy in 1982 contributes to this improvement in inflation, but also of importance are the absence of large Social Security hikes and the relatively low rate of increase of energy prices once the move to decontrol has been completed.

From 1985 onward, the economy grows at close to its potential path, with the unemployment rate in the 4.8-5.0% range and the inflation rate relatively stable. Some interruption to this smooth growth is provided by a muted housing cycle in the nineties, caused by shifts in the age-structure of the population.

THE LABOR FORCE AND POTENTIAL OUTPUT GROWTH

Projections of labor-force growth have been derived from DRI's separate model of labor force participation by age-sex group. A significant slowing in labor force growth is envisaged, reflecting slower growth in both the prime-age population (aged 18 to 64) and in participation rates. The population aged 18 to 64 has averaged 1.6% annual growth in the decade to 1978. 1.1% average annual growth is expected from 1978 to 1990, with the slowing due mainly to the pattern of post-war births. A further slowing to 0.8% is projected for the period 1990 to 2003.

ENERGY FORECAST RELEASE

The civilian labor force participation rate, defined here as the ratio between the civilian labor force and the civilian population aged 18 to 64, rose from 58.4% in 1968 to 62.2% in 1978, with increasing female participation being the most important factor. Further rises to 63.5% by 1981, 66.7% by 1990, and 68.3% by 2003 are projected. This rise in the participation rate, combined with the above picture for population growth, implies that labor force growth slows from 2.5% in the last decade to 1.6% from 1978 to 1990 and then to only 1.0% a year from 1990 to 2003.

Such dramatic slowing in the rate of growth of the labor force leads to a commensurate slowing in the rate of growth of potential output, from an annual average of 3.0% from 1978 to 1981 to 2.8% by 1990 and to an average of 2.5% from 1990 to 2003.

FISCAL POLICY

The forecast incorporates an explicit tax cut in 1981, totalling $10 billion ($7 billion personal, $3 billion corporate). In addition, it is assumed that the increase in Social Security taxes due in 1981 is $5 billion less than that which would result from current law. From 1982 onward, the assumption is made that Federal personal tax rates are continually adjusted to prevent the average effective rate from rising too rapidly owing to the progressivity of the income tax schedule. The effective tax rate is thus projected to rise from 13.2% to 14.4% in 1981, and to settle down at 14.2% thereafter.

In addition to the shading of the 1981 Social Security tax hike discussed above, it is assumed that the increase projected for 1985 will not take place. Some rearrangement of Social Security financing which obviates the need for this increase is implicitly assumed.

On the expenditure side, pressures to hold down the proportion of GNP which passes through the Federal budget are assumed to be at least partially successful. This proportion is projected to fall from 21.9% in 1978 to 20.8% in 1985, and to 20.1% by 2003. Real expenditures on final goods and services are projected to average about 1.5% annual growth throughout the forecast period.

Transfers to persons are assumed to average 4.6% real annual growth from 1978 to 1990, with their share of the budget thus increasing from 39% to 48% over that period. Further increases of this order are not sustainable given the assumption of a slowly-declining share of Federal spending in GNP. Thus a slowing to 3.5% real annual growth is projected for the period 1990 to 2003. One consideration which makes this slowing possible is a marked change in the age structure of the population in the 1990s. The proportion of the population over the age of 65 has risen steadily in the past, from 8.1% in 1950 to 11.0% in

ENERGY FORECAST RELEASE

1978. Further increases to 12.2% in 1990, and 12.4% by 1995 are projected. Subsequent to 1995, however, the low birth rates of the Depression years lead to a diminution in the proportion of the aged, to 12.1% by 2003. Even with this assumed slackening of growth, transfers to persons as a share of the budget continue to climb to 55% by 2003.

PERSONAL COMSUMPTION EXPENDITURES

Real personal consumption expenditures are projected to average 3.9% from 1978 to 1985, 3.4% from 1985 to 1990, and 2.7% from 1990 to 2003. The share of consumption in gross national product is projected to average 63.4% from 1979 to 1985, and from 1986 to 1990, and 63.9% after 1990. An important determinant of the increased consumption share is the reduced share of residential construction, discussed below.

Conservation efforts are assumed to be moderately successful, holding the energy share of consumption to an average of 9.3%, compared with the 8.1% recorded in 1978.

RESIDENTIAL CONSTRUCTION

The fundamental determinants of the long-run outlook for housing are demographic factors and real income growth. Total potential housing demand is derived from analysis of trends in age-specific headship rates. In the near term, cyclical variations in housing are relatively large, stemming mainly from variations in financial conditions. Thus starts are projected at 1.61 million units this year, the weakest result since 1976. Starts are projected to recover to 1.84 million units in 1980, and then to average 2.17 million from 1981 to 1985.

From 1986 onward, demographic considerations lead to a long, slow decline in housing activity, with starts bottoming out at 1.73 million units in 1997. The most important demographic determinant of this decline is the exit of the post-war baby boom from the prime house-buying age groups. Thus, for example, the population aged 21 through 28 is projected to peak at 33.1 million in 1984 and then to fall to as low as 26.0 million by 2000.

The share of residential construction in GNP falls to an average of only 4.1% from 1991 to 2003, compared with its average from 1956 to 1977 of about 4.5%.

ENERGY FORECAST RELEASE

BUSINESS FIXED INVESTMENT

Real business fixed investment is projected to average 3.8% annual growth from 1978 to 1985, 4.0% from 1985 to 1990, and 2.6% from 1990 to 2003. The share of business fixed investment in gross national product averages 10.6% from 1978 to 1985, 11.3% from 1986 to 1990, and 11.7% thereafter. These figures are consistent with annual growth in the business fixed capital stock of 3.3% from 1978 to 1985, 3.7% from 1985 to 1990, and 3.9% thereafter.

Inventory investment in 1972 dollars is projected to average $12.2 billion from 1979 to 1985, $13.6 billion from 1986 to 1990 and $15.7 billion thereafter.

One implication of the investment picture, taken together with the detailed projection of income components, and the assumption of equilibrium in the government and external sectors, is that the personal saving rate may well be low by historical standards in the 1990s. This is essentially a reflection of the low projected rate of housing investment by the personal sector. Should this decline in the saving rate not occur, it may be possible to finance a somewhat higher rate of business fixed investment.

STATE AND LOCAL GOVERNMENTS

Real state and local government spending on final goods and services is forecast to grow at an average 2.7% from 1978 to 1985, at 2.9% from 1985 to 1990, and 2.4% thereafter. The ratio of the school-age population to the total, which has been in decline since the late 1960s, is expected to stabilize in the 1990s, thus cushioning the decline in the rate of growth of spending to some extent.

The share of property taxes in total state and local taxes has declined from 37.9% in 1958 to 25.3% in 1978, and is projected to continue to decline to 18.5% by 2003.

FOREIGN TRADE

Estimates of likely growth of the production indexes of our trading partners are provided by DRI's Canadian, European and Japanese services. Industrial production in Canada is projected to average 5.1% from 1979 to 1985, 4.5% from 1985 to 1990, and 4.4% thereafter. In Europe, the projected growth rate is 4.1% from 1979 to 1985 and 4% thereafter, while in Japan, 6.0% growth is expected from 1979 to 1990, followed by 5.7% thereafter.

ENERGY FORECAST RELEASE

It is assumed that approximate balance in the external account will be achievable through the 1980s and 1990s with the exchange rate held constant.

PRICES AND WAGES

As discussed above, some improvement in the rate of inflation is projected in the first half of the 1980s. But the implicit deflator for GNP, which is projected to increase by 8.4% this year, will still register annual rises of more than 7% through to 1984. Thereafter, further improvement is assumed to be possible in the context of the steady balanced- growth scenario depicted here. Thus the average annual rate of increase of the implicit GNP deflator slows to 5.8% from 1985 to 1990 and to 5.4% thereafter. Adjusted hourly earnings are expected to average annual increases of 8.6% from 1978 to 1985, 7.6% from 1985 to 1990, 7.2% thereafter. The wholesale price index displays somewhat greater volatility, averaging increases of 7.8% from 1979 to 1985, 5.9% from 1985 to 1990, and 5.5% thereafter.

The consumer price index is expected to increase at an average annual rate of 7.4% from 1979 to 1985, 6.0% from 1985 to 1990, and 5.7% thereafter. Particularly in the later years of the projection, the index significantly overstates the rate of increase of consumer prices, due to the fact that it is a fixed- weight index and no rebasing is assumed.

Nonfarm business productivity is projected to grow by only 0.6% in 1979 following the dismal 0.4% recorded in 1978. Some improvement is projected subsequent to 1979, so that for the 25-year period as a whole, expected annual productivity growth averages 1.9%. Contributing factors to this improvement include the maturation of the workforce, capital deepening, and the use of efficient labor management techniques made possible by the smooth growth in output. This productivity growth is of course still markedly below the annual average recorded prior to 1967.

PRODUCTION

The generated outputs implied by projections of final demand were monitored for individual industries, and where necessary production indexes were add- factored to preserve long-run relationships between the growth rates of production and the generated output series. The overall industrial production index is projected to average 4.4% growth from 1978 to 1985, 3.6% from 1985 to 1990, and 3.4% thereafter. This pattern is, of course, consistent with the slowing in the rate of growth of potential. No radical changes in production technologies are assumed in the forecast.

ENERGY FORECAST RELEASE

INCOMES AND PROFITS

The ratio of personal income to gross national product rises from 81% in 1978 to 82.5% in 1982, but then averages a steady 81.7% from 1984 onwards. The share of before-tax profits in GNP is projected to fall from the 9.6% recorded in 1978 to 9.2% in 1979. For the period 1979 to 2003 as a whole, the share averages 9.0%. Real aftertax profits are projected to grow at an average annual rate of 4.1% from 1978 to 1985, 2.3% from 1985 to 1990, and 2.6% thereafter. This uneven growth pattern reflects, among other things, the 1979 and 1981 tax cuts, and the cyclical recovery projected in the mid-1980s.

FINANCIAL CONDITIONS

Monetary policy in the trend scenario is assumed to be aimed at promoting stable credit conditions. The present episode of monetary tightness is followed by a further contraction in 1981, with the prime rate again above 11%. From early 1982, rates are allowed to decline steadily. The Federal funds rate falls from 10.1% in 1981 to 8.3% in 1984. The yield on high-grade corporate bonds falls more slowly, from a 1981 peak of 9.7% to 9.55% by 1984. From 1985 onward, the real corporate bond rate is approximately constant at about 2.8%, with the nominal rate dropping slowly from 9.4% in 1985 to 7.9% by 2003 as inflationary expectations slowly improve.

The main exogenous monetary policy lever in the DRI model, nonborrowed reserves, grows by 9.9% in 1979, and by 5.6% in both 1980 and 1981. Thereafter, the rate of increase expands to 8.3% by 1986, to accommodate the cyclical recovery, and then slows to an average of 6.0% from 1990 to 2003. The required reserve ratios for demand deposits and time deposits are held constant at 0.112 and 0.046 respectively, with the proportions of deposits subject to reserve requirements declining by 1.0% annually.

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MOTOR GASOLINE DEMAND
FUELS AND FACTORS

	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
MOTOR FUELS (BILLIONS OF GALLONS)										
Motor Gasoline	113.5	114.2	103.4	97.3	99.5	102.5	104.2	0.6	-1.6	0.5
Regular	65.8	58.1	25.6	10.0	9.4	8.8	8.4	-11.6	-16.1	-1.3
Nonleaded	47.7	56.0	77.9	87.3	90.1	93.7	95.7	17.5	4.5	0.7
Diesel	12.2	14.2	25.0	36.2	43.3	48.2	50.6	16.1	9.9	2.6
Total Motor Fuels	125.7	128.3	128.4	133.6	142.8	150.8	154.7	2.1	0.4	1.1
Percent Nonleaded	42.0	49.1	75.3	89.7	90.6	91.4	91.9	16.8	6.2	0.2
AVERAGE EFFICIENCIES (MILES PER GALLON)										
New Cars - Nonleaded	16.2	17.0	23.3	25.5	26.3	27.0	27.5	4.9	4.1	0.6
Stocks										
Regular	13.5	13.5	15.1	23.3	24.8	25.8	26.2	0.1	5.6	0.9
Nonleaded	15.2	15.5	18.6	22.3	24.7	25.8	26.2	1.9	3.7	1.2
Trucks	8.9	8.9	9.3	9.5	9.8	10.2	10.5	0.6	0.6	0.8
Light Trucks	10.6	10.6	11.0	11.2	11.6	12.2	12.6	0.3	0.5	0.9
VEHICLE MILES (BILLIONS OF MILES)										
Car	1,146.4	1,163.4	1,239.8	1,377.6	1,491.9	1,571.5	1,622.1	1.5	1.7	1.3
Truck	345.4	373.1	483.7	607.3	730.0	838.1	897.5	8.0	5.0	3.1
Total	1,491.8	1,536.5	1,723.5	1,984.9	2,221.9	2,409.6	2,519.6	3.0	2.6	1.9

	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
VEHICLE STOCKS (MILLIONS OF VEHICLES)										
Passenger Cars										
Regular	50.2	41.7	9.4	1.3	1.3	1.4	1.4	-16.8	-29.4	0.7
Nonleaded	49.1	58.5	94.2	108.4	116.4	123.1	126.5	19.0	6.4	1.2
Diesel	0.5	0.9	4.2	8.7	11.3	12.3	12.6	72.0	25.7	2.9
Total	99.8	101.1	107.8	118.4	129.0	136.8	140.5	1.3	1.6	1.3
Trucks										
Light	25.1	26.9	34.5	42.9	52.5	61.8	67.4	7.4	4.8	3.5
Med & Hvy	4.6	4.6	4.7	4.9	5.4	5.9	6.2	0.9	0.6	1.8
Total	29.6	31.5	39.1	47.8	57.9	67.7	73.5	6.4	4.2	3.4
VEHICLE SALES (MILLIONS OF VEHICLES)										
Cars	11.0	10.9	12.1	13.2	14.0	14.6	14.9	-1.1	1.9	1.0
Trucks	3.9	4.0	4.7	5.8	6.8	7.7	8.4	3.2	3.8	2.8
USAGE RATES (THOUSAND MILES PER VEHICLE)										
Miles per Car	9.8	9.8	9.8	9.9	9.8	9.8	9.8	0.2	0.1	-0.1
Miles per Truck	9.0	9.2	9.6	9.9	9.8	9.6	9.5	1.5	0.7	-0.3
MOTOR FUEL PRICES										
Nominal Gasoline Price										
Cents per Gallon	86.8	101.1	178.8	270.8	406.1	604.2	768.1	16.4	10.4	8.3
Real Gasoline Price										
Cents per Gallon *	79.0	85.1	106.1	119.9	135.5	153.4	165.6	7.7	3.5	2.5
Real Operating Costs										
Cents per Mile *	11.3	11.6	11.8	11.4	11.6	12.1	12.4	2.8	-0.2	0.7

* 1978 Dollars

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	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
SECTORAL ENERGY CONSUMPTION (QUADRILLION BTU)										
Total Consumption	78.4	79.3	87.7	97.9	107.3	116.7	122.6	1.1	2.1	1.7
Household & Commercial	15.0	15.0	15.6	16.7	17.6	18.6	19.1	0.0	1.1	1.1
Industrial	19.4	19.3	20.6	20.7	21.4	23.4	25.2	-0.6	0.7	1.5
Transportation	20.0	20.6	21.3	22.6	24.2	25.6	26.4	3.0	0.9	1.2
Electric Utility	24.0	24.4	30.3	37.9	44.1	49.1	52.0	1.6	4.5	2.5
AGGREGATE CONSUMPTION BY SOURCE (QUADRILLION BTU)										
Petroleum Consumption	37.1	37.2	37.9	40.1	42.0	44.0	45.4	0.2	0.8	1.0
Natural Gas Consumption	19.5	19.0	18.9	19.0	18.9	18.3	18.0	-2.6	0.0	-0.4
Coal Consumption	14.9	15.9	20.3	25.8	30.6	35.5	38.6	6.3	5.0	3.2
Nuclear Consumption	3.1	3.4	6.7	8.7	11.3	13.7	15.1	11.2	9.8	4.3
Hydropower Consumption	3.3	3.3	3.4	3.3	3.3	3.3	3.3	0.0	0.0	0.0
Electricity Consumption	7.1	7.3	9.1	11.3	13.2	14.7	15.6	1.7	4.6	2.5
Solar Consumption	0.0	0.0	0.0	0.2	0.6	1.1	1.5	83.2	43.4	15.3
Exotic Consumption	0.4	0.4	0.6	0.6	0.6	0.7	0.7	5.3	4.5	1.1
PRICES-ANNUAL RATES OF CHANGE										
Crude Oil (Refiner Acquisition)	27.4	21.6	10.2	9.5	9.2	9.0	9.1	21.6	11.9	9.2
Crude Oil (Average Domestic)	22.8	28.8	10.1	9.5	9.2	9.0	9.1	28.8	13.5	9.2
Crude Oil (Wellhead)	24.7	24.7	9.4	13.2	9.5	9.2	9.3	24.7	14.9	9.4
Residual Fuel-Industrial	40.2	21.2	20.8	9.1	8.9	8.7	8.7	21.2	12.6	8.8
Gasoline	31.8	16.4	9.2	8.6	8.4	8.2	8.4	16.4	10.4	8.3
Coal-Contract	12.4	11.8	10.0	8.6	8.2	7.9	7.8	11.8	10.1	8.1
Coal-New Contract	13.0	10.5	6.9	7.1	8.3	8.1	7.5	10.5	8.5	8.0
Natural Gas-Residential	15.5	9.7	34.5	9.9	8.6	8.4	8.6	9.7	14.3	9.4
Natural Gas-Industrial	17.6	22.8	34.5	10.2	9.3	8.7	8.7	22.8	15.4	9.5
Electricity-Marginal Residential	12.0	12.1	11.1	4.2	6.1	6.7	7.1	12.1	6.8	6.5
Electricity-Average Industrial	16.4	16.2	12.6	4.5	6.6	7.1	7.5	16.2	7.9	7.0

	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
FUEL CONSUMPTION BY SECTOR (QUADRILLION BTU)										
Household and Commercial										
Petroleum	7.1	6.9	6.7	6.9	6.9	6.7	6.7	-2.4	0.0	-0.2
Natural Gas	7.7	7.8	8.6	9.4	10.1	10.8	11.2	2.1	1.9	1.3
Coal	0.2	0.2	0.3	0.3	0.3	0.4	0.4	2.3	2.4	2.5
Electricity	4.3	4.5	5.4	6.6	7.3	8.0	8.4	2.8	3.9	1.9
Solar	0.0	0.0	0.0	0.1	0.3	0.6	0.8	63.8	35.8	17.3
Industrial										
Petroleum	7.0	7.0	7.2	7.5	8.4	9.6	10.5	0.4	0.7	2.6
Natural Gas	8.9	8.3	7.9	7.7	7.3	6.3	5.8	-6.3	-0.8	-2.1
Coal	3.6	4.0	5.4	5.3	5.5	6.9	8.2	11.6	3.0	3.3
Electricity	2.7	2.7	3.6	4.7	5.8	6.6	7.1	0.0	5.6	3.2
Solar	0.0	0.0	0.0	0.1	0.3	0.5	0.6	200.0	52.2	14.4
Exotic	0.0	0.0	0.0	0.1	0.1	0.1	0.1	32.7	19.3	8.4
Transportation										
Petroleum	20.0	20.6	21.3	22.6	24.2	25.6	26.4	3.0	0.9	1.2
Gasoline	14.2	14.3	12.9	12.2	12.4	12.8	13.0	0.6	-1.6	0.5
Electricity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	1.9	1.8
Electric Utility										
Petroleum	3.0	2.7	2.8	3.2	2.5	2.0	1.9	-12.4	1.8	-4.0
Natural Gas	3.0	2.9	2.4	1.9	1.5	1.2	1.0	-4.0	-4.1	-4.8
Coal	11.1	11.6	14.6	20.1	24.8	28.2	30.0	4.7	5.6	3.1
Nuclear	3.1	3.4	6.7	8.7	11.3	13.7	15.1	11.2	9.8	4.3
Hydropower	3.3	3.3	3.4	3.3	3.3	3.3	3.3	0.0	0.0	0.0
Solar	0.0	0.0	0.0	0.0	0.1	0.1	0.1	NC	NC	8.6
Exotic	0.4	0.4	0.5	0.6	0.6	0.6	0.6	4.8	3.9	0.0
OTHER KEY MEASURES-ANNUAL RATES OF CHANGE										
Real GNP	2.8	2.3	3.9	2.8	2.4	2.5	2.5	2.3	3.3	2.5
GNP Deflator	8.4	7.9	6.5	5.7	5.4	5.2	5.3	7.9	6.5	5.4
Real Disposable Income	3.8	2.6	3.9	2.9	2.5	2.5	2.6	2.6	3.5	2.6
FRB Production Index	3.2	1.6	5.2	3.4	3.1	3.5	3.6	1.6	4.3	3.4
Consumer Price Index	9.9	8.1	6.8	6.0	5.7	5.6	5.6	8.1	6.6	5.7
Wholesale Price Index	11.7	8.9	6.9	5.8	5.3	5.5	5.6	8.9	6.7	5.5
Fuel and Power Index	22.1	20.0	23.0	9.3	9.1	8.7	8.6	20.0	13.0	9.2
Adjusted Avg. Hourly Earnings	8.5	8.9	7.9	7.5	7.4	7.1	7.1	8.9	8.0	7.2

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WELLHEAD PRICE AND QUANTITY OF NATURAL GAS

	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
Prices - Cents per MCF										
Average Contract Price	141.1	170.3	531.8	942.8	1,673.3	2,577.1	3,312.8	20.7	18.7	10.1
Average Interstate Price	101.7	120.7	407.6	797.1	1,650.1	2,543.6	3,269.9	18.7	20.8	11.5
Average Intrastate Price	169.1	193.9	624.3	1,016.6	1,649.6	2,542.9	3,268.9	14.6	18.0	9.4
Alaskan Border Price	0.0	0.0	0.0	1,060.4	1,650.1	2,543.6	3,269.9	NC	NC	9.0
Canadian Border Price	277.3	370.2	668.1	1,060.4	1,650.1	2,543.6	3,269.9	33.5	11.1	9.0
Mexican Border Price	0.0	0.0	668.1	1,060.4	1,650.1	2,543.6	3,269.9	NC	NC	9.0
Citygate Cost of LNG	367.0	436.3	810.1	1,305.7	2,035.0	3,101.4	3,982.5	18.9	11.6	9.0
Citygate Cost of SNG	514.1	589.0	993.9	1,471.8	1,919.9	2,806.8	3,571.5	14.6	9.6	7.1
Interstate Price Ceiling	213.0	237.7	668.1	1,060.4	1,650.1	2,543.6	3,269.9	11.6	16.1	9.0
Old Interstate Price	81.4	87.9	124.5	164.9	1,650.1	2,543.6	3,269.9	7.9	6.5	25.8
Quantities - BCF per Year										
Lower 48 States Production	18,912.0	18,392.6	17,116.6	15,928.2	15,054.9	14,390.6	13,998.9	-2.7	-1.4	-1.0
Interstate Production	11,878.0	11,392.0	10,078.7	8,917.9	8,144.1	7,595.7	7,272.3	-4.1	-2.4	-1.6
Intrastate Production	7,034.0	7,000.6	7,037.8	7,010.3	6,910.8	6,794.9	6,726.6	-0.5	0.0	-0.3
Alaskan Production	0.0	0.0	0.0	900.0	1,200.0	1,200.0	1,200.0	NC	NC	2.2
Canadian Imports	1,050.0	1,100.0	1,200.0	1,200.0	1,200.0	1,000.0	1,000.0	4.8	0.9	-1.4
Mexican Imports	0.0	0.0	600.0	800.0	800.0	800.0	800.0	NC	NC	0.0
Liquified Natural Gas	90.0	200.0	770.0	770.0	770.0	770.0	770.0	122.2	14.4	0.0
Synthetic Natural Gas	290.3	303.3	303.3	303.3	600.0	800.0	850.0	4.5	0.0	8.2
Total Natural Gas Supply	20,342.3	19,995.9	19,989.9	19,901.5	19,624.9	18,960.6	18,618.9	-1.7	0.0	-0.5
Old Interstate Production	9,389.0	8,309.2	4,511.0	2,449.0	0.0	0.0	0.0	-11.5	-11.5	-100.0

Notes:

1. (NA) - Old gas in this table refers to domestic volume committed to the interstate market as of 1978. Values for 1976 and and 1977 are not applicable.
2. (NC) - The compound annual growth rate from 1976 to 1980 is not computable.

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COAL DEMANDS, PRODUCTION AND PRICES

	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
DEMANDS AND PRODUCTION (Thousand Short Tons)										
Household and Commercial	7,775.5	8,008.7	9,470.4	11,203.4	12,987.8	15,056.4	16,452.5	3.0	3.4	3.0
Industrial	149,899.5	167,986.4	233,596.8	231,272.8	235,975.4	300,705.4	357,150.6	12.1	3.2	3.4
Coking	80,522.6	79,325.4	88,908.2	96,127.6	106,507.5	116,278.3	122,678.1	-1.5	1.9	1.9
Steam	69,376.9	88,661.0	144,688.6	135,145.2	129,467.9	184,427.1	234,472.5	27.8	4.3	4.3
Electric Utilities	523,194.4	547,629.6	689,497.4	950,905.0	1,172,140.2	1,333,163.2	1,420,446.3	4.7	5.7	3.1
Synthetic Fuel Production	0.0	0.0	7,000.0	36,000.0	65,000.0	88,125.0	102,000.0	NC	NC	8.3
U.S. Domestic Consumption	680,869.4	723,624.8	939,564.6	1,229,381.2	1,486,103.4	1,737,050.0	1,896,049.4	6.3	5.4	3.4
Exports	50,128.6	55,291.8	70,301.3	80,966.9	88,608.0	96,970.2	102,361.8	10.3	3.9	1.8
Imports	2,800.0	2,912.0	3,010.1	3,268.5	3,200.6	3,306.1	3,306.1	4.0	1.2	0.1
Change in Inventories	9,123.0	11,245.0	3,819.0	1,031.0	0.0	0.0	0.0	23.3	-21.3	-100.0
Implied Coal Production	737,321.0	787,249.6	1,010,674.8	1,308,110.6	1,571,510.8	1,830,714.1	1,995,105.0	6.8	5.2	3.3
DEMANDS AND PRODUCTION (Trillion BTU)										
Household and Commercial	178.1	183.4	212.6	246.5	285.7	331.2	362.0	3.0	3.0	3.0
Industrial	3,521.3	3,934.1	5,382.1	5,280.3	5,404.5	6,848.1	8,102.7	11.7	3.0	3.3
Coking	1,932.5	1,903.8	2,133.8	2,307.1	2,556.2	2,790.7	2,944.3	-1.5	1.9	1.9
Steam	1,588.7	2,030.3	3,248.3	2,973.2	2,848.3	4,057.4	5,158.4	27.8	3.9	4.3
Electric Utilities	11,128.3	11,648.1	14,617.3	20,140.2	24,790.8	28,196.4	30,042.4	4.7	5.6	3.1
Synthetic Fuel Production (1)	0.0	0.0	148.4	762.5	1,374.8	1,863.8	2,157.3	NC	NC	8.3
U.S. Domestic Consumption	14,827.7	15,765.6	20,360.4	26,429.4	31,855.7	37,239.6	40,664.4	6.3	5.3	3.4
Exports (2)	1,203.1	1,327.0	1,687.2	1,943.2	2,126.6	2,327.3	2,456.7	10.3	3.9	1.8
Imports (1)	59.6	61.9	63.8	69.2	67.7	69.9	69.9	4.0	1.1	0.1
Change in Inventories (1)	194.0	239.2	81.0	21.8	0.0	0.0	0.0	23.3	-21.3	-100.0
Implied Coal Production	16,165.3	17,269.9	22,064.8	28,325.2	33,914.6	39,496.9	43,051.1	6.8	5.1	3.3

	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
PRICES										
Without Scrubbing Costs										
New Contract ($/ton)	30.4	33.6	51.8	75.9	113.1	165.2	205.9	10.5	8.5	8.0
New Contract ($/mmbtu) (1)	1.4	1.6	2.4	3.6	5.3	7.8	9.7	10.5	8.5	8.0
Average Contract ($/ton)	24.2	27.1	46.2	70.8	105.8	155.5	195.0	11.8	10.1	8.1
Average Contract ($/mmbtu)	1.1	1.3	2.2	3.3	5.0	7.4	9.2	11.8	10.1	8.1
Including Scrubbing Costs										
New Contract ($/ton)	30.4	33.6	56.4	86.5	129.5	188.7	235.0	10.5	9.9	8.0
New Contract ($/mmbtu) (1)	1.4	1.6	2.7	4.1	6.1	8.9	11.1	10.5	10.0	8.0
Average Contract ($/ton)	24.2	27.1	47.1	76.6	118.1	176.0	221.4	11.8	11.0	8.5
Average Contract ($/mmbtu)	1.1	1.3	2.2	3.6	5.6	8.3	10.5	11.8	11.0	8.5

Notes
(1) Converted to btu units using BTUBITEU from energy model
(2) Converted to btu units using BTUBITCK from energy model

In 1976, implied coal production (domestic coal consumption + exports + inventory changes - imports) does not agree with actual coal production. Both sets of data are reported in the Department of Energy publication, Energy Data Reports.

Coal demand includes bituminous and lignite only.

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CRUDE OIL PRICES AND QUANTITIES

	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
PRICES - DOLLARS PER BARREL (Including Taxes and Transportation Costs)										
Average Acquisition Price	15.88	19.31	37.71	59.68	93.26	144.05	186.91	21.6	11.9	9.2
Average Domestic	13.03	16.78	37.64	59.58	93.07	143.69	186.41	28.8	13.5	9.2
New World Tier	19.50	22.50	38.40	60.68	94.73	146.17	189.52	15.4	10.4	9.2
Upper Tier	13.77	16.64	38.40	60.68	94.73	146.17	189.52	20.9	13.8	9.2
Lower Tier	6.47	7.01	10.00	13.28	17.42	22.39	26.36	8.4	6.6	5.4
Stripper	19.50	22.50	38.40	60.68	94.73	146.17	189.52	15.4	10.4	9.2
Ennanced	19.50	22.50	38.40	60.68	94.73	146.17	189.52	15.4	10.4	9.2
Alaskan	17.55	20.25	34.56	54.61	85.26	131.55	170.57	15.4	10.4	9.2
Natural Gas Liquids	15.21	17.55	29.96	47.33	73.89	114.01	147.83	15.4	10.4	9.2
Avg. U.S. Transp. Cost	0.57	0.64	0.98	1.34	1.80	2.39	2.83	13.2	7.6	5.9
Alaskan Transp. Cost	7.80	8.26	10.65	12.82	15.24	17.90	19.70	5.9	4.5	3.4
Average Imported	19.50	22.50	38.40	60.68	94.73	146.17	189.52	15.4	10.4	9.2
PRICES - DOLLARS PER BARREL (Excluding Taxes and Transportation Costs)										
Average Domestic Wellhead Price	11.19	13.96	28.56	56.16	88.91	138.68	180.82	24.7	14.9	9.4
New World Tier	17.47	19.56	30.94	59.34	92.93	143.77	186.70	12.0	11.7	9.2
Upper Tier	13.18	14.99	28.77	59.34	92.93	143.77	186.70	13.7	14.7	9.2
Lower Tier	5.90	6.37	9.02	11.94	15.62	20.19	23.53	7.9	6.5	5.4
Stripper	17.47	19.56	30.94	59.34	92.93	143.77	186.70	12.0	11.7	9.2
Enhanced	17.47	19.56	30.94	59.34	92.93	143.77	186.70	12.0	11.7	9.2
Alaskan	9.75	11.99	23.91	41.79	70.02	113.65	150.88	23.0	13.3	10.4
Natural Gas Liquids	14.64	16.91	28.97	45.99	72.09	111.62	145.00	15.5	10.5	9.2
QUANTITIES - MILLIONS OF BARRELS PER DAY										
Total Crude Oil Supply	14.52	14.52	14.72	15.74	16.51	17.35	17.94	0.0	0.8	1.0
Domestic Supply	8.58	8.43	7.99	8.84	9.13	9.46	9.75	-1.6	0.5	0.8
New world Tier	0.00	0.16	0.98	1.55	1.64	1.74	1.80	NC	25.7	1.2
Upper Tier	3.67	4.25	3.60	3.22	2.99	2.57	2.27	15.9	-2.7	-2.7
Lower Tier	2.46	1.31	0.00	0.00	0.00	0.00	0.00	-46.9	-100.0	NC
Stripper	1.20	1.27	1.35	1.29	1.22	1.14	1.09	6.0	0.1	-1.3
Enhanced	0.00	0.05	0.47	1.18	1.69	2.42	3.00	NC	37.4	7.4
Alaskan	1.25	1.40	1.60	1.60	1.60	1.60	1.60	12.0	1.3	0.0
Imported	5.94	6.08	6.72	6.91	7.38	7.89	8.19	2.4	1.3	1.3
Natural Gas Liquids	1.59	1.57	1.49	1.42	1.35	1.29	1.25	-1.0	-1.0	-1.0
Total Petroleum Imports	7.96	8.24	8.89	9.14	9.76	10.44	10.83	3.6	1.0	1.3
Crude Oil	5.94	6.08	6.72	6.91	7.38	7.89	8.19	2.4	1.3	1.3
Products	1.92	1.96	2.17	2.23	2.38	2.55	2.64	2.4	1.3	1.3
Strategic Storage	0.10	0.20	0.00	0.00	0.00	0.00	0.00	100.0	-100.0	NC
Total Natural Gas Imports	0.55	0.63	1.24	1.34	1.34	1.24	1.24	14.0	7.9	-0.6

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QUANTITIES - PERCENT OF TOTAL CRUDE OIL AND NATURAL GAS LIQUIDS SUPPLY

	YEARS							%CH 79 TO 80	%CH 80 TO 90	%CH 90 TO 03
	1979	1980	1985	1990	1995	2000	2003			
Domestic Supply	60.27	59.35	55.62	56.66	55.54	54.41	54.01	-1.5	-0.5	-0.4
Natural Gas Liquids	9.42	9.32	8.76	7.85	7.16	6.51	6.13	-1.0	-1.7	-1.9
New World Tier	0.00	0.98	6.05	9.01	9.18	9.31	9.36	NC	24.9	0.3
Upper Tier	21.74	25.19	21.08	17.80	15.83	13.00	11.15	15.9	-3.4	-3.5
Lower Tier	14.58	7.75	0.00	0.00	0.00	0.00	0.00	-46.9	-100.0	NC
Stripper	7.13	7.56	7.89	7.11	6.45	5.77	5.33	6.0	-0.6	-2.2
Enhanced	0.00	0.29	2.76	6.51	8.94	12.23	14.71	NC	36.4	6.5
Alaskan	7.41	8.30	9.38	8.84	8.48	8.10	7.86	12.0	0.6	-0.9
Imported - U.S.	35.22	36.06	39.41	38.17	39.08	39.98	40.24	2.4	0.6	0.4
Imported - V.I. & P.R.	4.51	4.58	4.96	5.17	5.38	5.61	5.75	1.7	1.2	0.8

Notes:
1) Natural gas liquids are included in the average acquisition cost computations and in domestic supply but are excluded from the total crude oil supply
2) The Alaskan category includes only the North Slope production. This distinction is made due to the special pricing and transportation provisions regarding North Slope oil.
3) Natural gas imports are included for comparison purposes only using a conversion factor of (1.024/(5.8*365)) to convert trillion BTUs to million barrels per day.
4) Crude oil imports to the Virgin Islands and Puerto Rico are included in the U.S. entitlements program.

ADDENDUM NUMBER 2

WORLD AVAILABILITY OF COAL LIQUEFACTION FEEDSTOCK

ADDENDUM 2

CONTENTS

1. GENERAL

This analysis determines the worldwide location and reserves of coal that appear to be suitable feedstocks for the SRC-II process. Outside the U.S., countries that appear to have substantial suitable reserves include England, West Germany, Poland, France, Australia and China.

SRC-II is a hydrogenation process of low severity which does not use specific catalysts. Virtually any coal except anthracite can be hydrogenated under appropriate conditions, as was amply demonstrated by Germany in World War II and by current work on Australian lignite.

The owner of a specific coal resource normally searches for a process that is optimally suited for the coal, including processes other than direct hydrogenation (e.g. synthesis from gas or pyrolysis). The suitability of a given coal for a process can be evaluated best by direct testing of that coal. Only then can the appropriate processing criteria be established. This includes maximizing liquid production and the combined output of liquids and gases, minimization of hydrogen consumption, and minimization of process severity. Such process characterization is lacking for many coals. Of the systematic (screening) tests that have been performed on foreign coals, much of the resulting information has been kept proprietary.

2. COAL CHARACTERISTICS

The lack of published data leaves no option other than to attempt judgments of coal suitability based on data that are commonly determined and discussed in the literature. These parameters include rank, petrographic analysis and pyrite content. Of the three, only the rank (or equivalent information) is generally reported. Sulfur content is typically discussed only when it is so high that it presents a problem. Petrographic data are seldom available, expensive to determine, and always an approximation only.

2.1 RANK

Concerning rank, experience to date seems to indicate that hvb (high-volatile bituminous) coal is the optimum feedstock. If rank is determined by carbon content, 78 - 83% C (maf) seems to be the ideal range. If rank is measured by volatile matter content, 35 to 30% is the best range.

2.2 PETROGRAPHIC ANALYSIS

Petrographic analysis refers to the balance between vitrinite and exinite on one side, and durite and invertinite (fusinite, semi-fusinite), on the other. Vitrinite and exinite are highly reactive; durite is intermediate and fusinite is almost totally unreactive. Generally, good coking quality is an indication of high vitrinite content.

2.3 PYRITE CONTENT

The pyrite content is coal acts as a natural catalyst upon transformation into pyrrhotite. This transformation occurs naturally during the SRC-II process. Generally, a high sulfur content in coal is an indication of a high pyrite content. The activity of the pyrite/pyrrhotite also depends upon its degree of dissemination throughout the coal.

3. COAL RESOURCES OUTSIDE THE U.S.

Due to time limitations, this analysis is confined to resource estimates for the most important coal countries (see Table 1), with the following exceptions:

TABLE 1
COAL RESOURCE ESTIMATES FOR MAJOR COAL COUNTRIES

COUNTRY	DATA SOURCE		
	USBM	WEC	Matveev
USSR	6298	4860	6800
US	3968	2570	2911
China	1102	1438	1500
W. Germany	316	247	287
Australia	219	262	172
UK	180	164	170
Canada	120	115	1234
India	92	57	125
Poland	67	124	124
South Africa	49	58	N.A.

USBM: data is in billion st, including bituminous coal and lignite; excludes anthracite. (Ref. 1)

WEC: data is stated in billion TCE - metric tons coal equivalent. (One TCE = 27.78 million Btu) Includes bituminous coal, anthracite, and lignite (Ref. 2).

Matveev: data is in billion metric tons, probably includes anthracite, bituminous and lignite (Ref. 3).

USSR: Not likely to become a coal exporter to a western country and not likely to purchase U.S. coal liquefaction technology. Its major coalfields are all in the interior with long shipping distances to potential markets outside the country.

U.S. Covered in detail elsewhere.

India: India is a net importer of coal, despite a sizeable coal resource base. It is a coal-poor country relative to its population, which needs all the coal it can produce for traditional uses.

3.1 EUROPE

The coal reserves of England, W. Germany, Poland, and France can be considered simultaneously for the purpose of this study because they are geologically and petrographically similar. The bituminous coals in these countries are of Pennsylvanian age (Carboniferous age, in the European nomenclature) and have substantial vitrinite contents (the most reactive material). All of these countries have, with respect to rank, a full range of bituminous coals, from low-volatile bituminous to even subbituminous coal. Most European bituminous coals are low in sulfur and thus in pyrite - generally under 1% for Silesian (Polish) and Ruhr coal, and slightly higher in England. In the past, coal liquefaction in these countries has always required the addition of iron and sulfur compounds.

All the countries mentioned above have ample reserves of coal in the high-volatile range that is best suited for SRC-II. In Poland and England, high volatile bituminous coal accounts for most of the production. Even in Germany, where medium and low volatile coal production is predominant, the resource of high-volatile coal is very large.

Much of it occurs at great depth in the northern extension of the Ruhr coalfield.

3.4 CHINA

The WED (ref. 1) stated Chinese coal resources as 1.424 billion TCE, which includes only 13 billion TCE lignite and/or subbituminous coal. This agrees well with Matveev's 1.50 trillion metric tons (ref. 3) and USBM's 1.102 trillion st, (ref. 2) considering that the USBM figure excludes anthracite. Matveev commented that he considers the 1.50 trillion figure as "greatly underestimated."

The Chinese recently told a visiting delegation from the USGS that their resources have increased to 6 trillion tons, and another very recent source (ref. 4) gives the total resource as 9.6 trillion tons (presumably metric tons). A member of the USGS delegation who visited China hinted at the possibility that a large share of the recent additions might be high-ash coal in the interior provinces. Whereas the WEC credits China with 99 billion tons of proven reserves, the Chinese recently (ref. 4) claimed 200 billion tons, which is plausible in light of the resource increases and would reflect a low reserve to resource ratio. This is indicative of very incomplete exploration. Over two-thirds of the 200 billion tons are said to be bituminous, and most of the rest is anthracite.

Other indications, however, suggest that Chinese coal reserves encompass the full range from anthracite to high-volatile C, the most reactive coal. Chinese coals were deposited during Carboniferous, Permian, Jurassic and Tertiary ages. The very rich deposits (seam thickness up to 650 feet) of tertiary coal in the Liaoning province in the NE are reported to have 30 to 40% volatiles which would be very reactive for SRC if the petrography is favorable. The sulfur content, however is low. Reserves of this coal are reported to be 20 billion tons.

Another clue to the rank can be gained from the type of underground mining machinery the Chinese are buying from Europe and are trying to build themselves. Cutting machines (drum and disk shearers) predominate over ploughs, which indicates a coal hardness normally found in coals with over 35% volatiles.

Ten percent of Chinese coal is produced in open pits; 90% comes from underground mines. Chinese coal seams are thicker than those of many other countries (6.5 feet average in China compared with 5 feet for the U.S. and 4.5 feet for the U.S.S.R.) and occur generally at moderate depths, compared with European and Russian deep coal mines, but deeper than the U.S. mines.

Traditionally, Chinese reserves and production were concentrated in the northeast of the country. Transportation to the other parts of the country represented a serious bottleneck. This led to an intensive exploration effort in the southeastern and interior provinces which, the Chinese claim, was highly successful. Last year, almost one-third of China's coal production came from provinces south of the Yangtze River. It is not known, of course, how the Chinese determine their resources with respect to maximum depth, minimum seam thickness and ash content.

China increased its coal production form 310 million tons in 1970 to 427 million tons in 1975 and 600 million tons in 1978. The production target for 1985 is 725 million tons, and the Chinese are eager to export coal in order to pay for imports of western technology. Japan is the ideal market for Chinese coal, especially since the traditional mining centers and large reserves, including the Liaoning coal fields, are in the northeast, near the coast.

Analyses of several coals offered for export by the Chinese government (ref. 5) indicate volatile contents mostly in the 25 to30% range, and in one case 33 to37%. Sulfur content is low, 0.6 to 1.0%, and in one case, under 0.5%.

Some of these coals are offered as coking coals, which indicates that they cannot be deficient in vitrinite. To judge by rank and sulfur content, these coals would be poorly reactive in a SRC-II plant and would require addition of iron and sulfur compounds.

3.3 CANADA

Canada is unlikely to have significant coal resources suitable as SRC-II feedstock. All of the western Canadian coals are very low in sulfur (usually below 0.5%), high in ash, and deficient in vitrinite. They are marginally suitable as coking coal only because the micrinite content behaves atypically, developing a limited fluidity during carbonization, but it is doubtful whether it would be highly reactive in SRC processing.

Canada provides a particularly striking example of vast discrepancies between estimates by different authors. Resources estimates range from 120 billion st in the latest (1975) edition of "Mineral Facts and Problems" (ref. 1) (including bituminous, subbituminous and lignite) to 1234 billion mt (1357 billion st) by Matveev (ref. 3). The WEC estimated 115 billion TCE (mt, and lignite converted to the equivalent of bituminous coal). The WEC estimate attributes only 19 billion TCE to lignite and subbituminous coal, which is obviously far too low (ref. 2).

The Canadian Government estimated its coal resources in seams at least 30 inches thick and under less than 2500 ft. of overburden to be 518 billion tons (presumably st and without adjustment for heating value, ref. 6).

It is speculated that by extending the depth limit to 4500 ft., the resource estimate could be at lease doubled, resulting in a figure close to Matveev's.

TABLE 2

CANADIAN RESOURCE ESTIMATE BREAKDOWN

REGION	BILLION T	PRINCIPLE COAL TYPE
Maritime Provinces	1.7	hvb
Saskatchewan	38.8	lignite
Alberta - Plains	360.0	subbituminous
- Foothills	10.0	lvb, mvb, hvb
- Mountains	30.0	lvb, mvb, hvb
British Columbia	77.8	mvb, lvb, subbitum.
Total	518.3	

The coal in the Maritime Provinces (mostly Nova Scotia) is of Carboniferous age (Pennsylvanian), has 80.6 to 90.9% C and is described generally similar to Appalachian coal. The C - range is not entirely consistent with the hvb classification; it would rather suggest mostly hvb. Based on limited testing, the coal is apparently suitable for liquefaction but is of limited interest due to the very small resource.

Among the western coals, the bituminous coal from Alberta and British Columbia could be of interest. All of these coals are Cretaceous and (perhaps) Jurassic age. However, only 9.3 billion tons of the 117.8 billion tons bituminous coal is hvb; almost all of it is in the foothills of Alberta (ref. 7). The remainder is mvb and lvb.

For all of the western Canadian bituminous coals, the mining conditions are very difficult. The only reason this coal is being mined at all is that it is an acceptable blending ingredient for coking coal and Japan is a ready market. The difficult mining conditions are due to intensive folding (steeply pitching seams), faulting, discontinuous seams, weak roof and floor and high CH_4 content.

Very limited liquefaction tests of western Canadian hvb coal, with tetralin as H-donor, showed that output of pyridine solubles and benzone solubles is quite low in comparison with Nova Scotia coal.

3.4 SOUTH AFRICA

South Africa has attracted a disproportionate share of attention as a coal resource country because it operates the only commercial synfuels plant in the world (SASOL - coal gasification followed by Fisher-Tropsch synthesis).

South Africa's coal resources rank lowest on Table 1, with 49 billion t according to USBM and 57.6 billion TCE according to WEC. Although South Africa reportedly has the lowest mining cost among all major coal producing countries, it is, as a whole, very poorly endowed with coal reserves.

Matveev (ref. 3) stated that the entire continent of Africa has only 1% of the world's coal reserves, although WEC credits it with 1.7%. The WEC statistics list 100 billion TCE for Botswana, immediately north of South Africa and once under its control. It must be assumed that these resources are the result of very recent exploration and still are highly speculative.

These resources are in the category of bituminous and anthracite, and a relatively large portion of the resources are considered as presently mineable reserves (26.9 billion TCE). South Africa's resources are not estimated to be 81.3 billion t (ref. 8). The biggest probelm of South Africa's coals is their exceedingly high ash content.

All of the south African coals occur in the Ecca series of the Karroo formation of Permian age, in contrast with the Carboniferous (Pennsylvanian) age of most bituminous coals of the northern hemisphere. They are classified as Gondwana coals, in reference to a postulated Gondwana - a continent that subsequently broke up into South America,

Africa, India, Antarctica, and Australia. The coals of these continents have many characteristics in common.

The South African coals were deposited immediately following an extensive glaciation, during a temperate climate, contrasting with the subtropical and humid climate during which the coals of Carboniferous age were formed. The flora was different, and the swamp conditions generally drier, resulting in more oxidation of the peat formed. This resulted in coals generally low in vitrinite, high in invertinite, and high in ash as well.

Most South African coals are unreactive during carbonization and yield poor coke, although their rank falls mostly into the mvb - hvb range which normally indicates good coking coals. The sulfur content varies considerably, but is mostly medium to high, up to 6.5% in some unwashed coals, and up to 3.0% in washed coals.

Another characteristic of Gondwana coals is that they were deposited mostly in many small and separate basins, and the conditions of peat formation varied considerably. Therefore, there are some coals for which the above-discussed characteristics apply less than for others.

Reference 8 describes liquefaction tests with anthracene oil as solvent on coal samples from 7 different South African mines, ranging from 78.8% to 84.0% C, 28.0 to 42.5% volatile matter (daf) and H/C ratios from 0.63 to 0.83. Those coals with the highest volatile contents and the highest H/C ratios yielded conversion rates (to liquid and gaseous products) up to 92% under laboratory conditions* and might be considered as acceptable feedstocks for SRC-II.

Since the vitrinite content of these favorable samples was high, it must be assumed that they are representative of relatively good coking coals, the reserves of which are extremely limited in South Africa.

* 430°C, 25 M Pa final hydrogen pressure, residence time not stated, no catalyst added.

TABLE 3

SUMMARY OF SOUTH AFRICAN COAL RESERVES (MILLION T)

ASH%	5-10	10-15	15-20	20-25	25-30	30-35	Total
Proven	18	794	3,720	6,197	7,912	13,582	32,223
Indicated	0	645	2,866	5,507	5,224	11,785	26,027
Inferred	2	60	2,034	3,516	5,429	11,983	23,024
TOTAL	20	1,499	8,620	15,220	18,565	37,350	81,274

3.5 AUSTRALIA

This country is of particular interest because it has in recent years become one of the foremost coal experters. The various resource estimates are relatively consistent, ranging from 172 billion mt (Matveev) to 262 billion TCE (WEC). About 18% of the total resources are lignite, located in the state of Victoria. Lignite is not considered suitable for SRC but can be liquefied by other processes. An intensive research effort into the liquefaction of lignite is in progress.

The bulk of the Australian bituminous coal occurs in the Bowen basin in Queensland, and in the Sidney basin in New South Wales. Both are of Permian age and exhibit most of the attributes of Gondwana coals: low vitrinite and high invertinite content, few and very thick seams, high variability over short distances, and generally high ash content, although not as high as South African coals. In contrast with South Africa, the sulfur content is low, generally less than 1.0% and frequently below 0.5%.

The rank varies from subbituminous to anthracite, but high-volatile bituminous coal seems to make up the largest share. A quantitative breakdown is not available.

Despite suitable rank, Australian Permian coals are marginal coking coals due to their low vitrinite content and are usually blended with high-vitrinite coals. For the same reasons and because of their low sulfur content, they must not be expected to be good SRC feedstocks. However, these coals are highly variable not only with respect to rank, but also in their petrography. Limited liquefaction tests on a number of these coals identified some that approach the results obtained with Pittsburgh seam coal in their H/C ratio as well as in conversion rate in comparison tests. The extent of the reserves for which these favorable samples might be representative is not stated (ref. 10).

In addition to the Permian coals, Australia also has some Triassic and Jurassic coals in the Walloon or Clarence-Morton basin which straddles the border between Queensland and NSW. This basin include the Millmerran coal field, which is still incompletely explored, but appears to contain very substantial reserves.

These Mosozoic coals are subbituminous and very low in sulfur, generally below 0.5%. This would suggest poor reactivity if used without the addition of iron and sulfur compounds. In addition, the ash content is generally high. These coals have attracted considerable interest as SRC feedstocks because of their high content of reactive macerals - vitrinite plus exinite amount to 90%. At least some of the coal has 78% C (daf), which puts it at the border between subbituminous and hvb coal. The Japanese are presently testing this coal in a SRC pilot plant, with the objective of obtaining SRC material suitable as a blending ingredient for upgrading marginal coking coals.

4. UNITS OF MEASUREMENT FOR COAL RESERVES

International statistics about coal reserves and production must be interpreted with utmost care. Frequently, the units of measurement are not clearly indicated, or their exact meaning is ambiguous. In the measurement of reserves, a distinction is made between resources (geologic reserves) and reserves (economic reserves believed to be recoverable at an adequate return on investment with current technology and under current prices). Resources and reserves must further be subdivided according to the degree of certainty with which they are known, proven, indicated, or potential reserves.

Reserves, regardless of economics and certainty, can be stated on an "in place" basis, i.e. what is physically there, or a "recoverable" basis, which makes allowance for the losses during extraction, sometimes including beneficiation. Recovery factors range from under 50% in room-and-pillar mining to over 90% in longwall mining under good geologic conditions.

Due to the use of different reserve bases, gross discrepancies between different statistics are quite frequent and are difficult to reconcile.

International statistics typically combine anthracite and bituminous coal because they commonly occur together in one coal field and differ very little in heating value. However, the same statistics treat lignite as a separate item, while frequently, as in the World Energy Conference data (ref. 1), treating subbituminous coal, lignite, and brown coal together because they often grade into one another. Unfortunately, the heating value of coals in this group varies over a wide range (from 2,000 k/cal/kg to 6,000 k/cal/kg) so that comparisons based on true tonnage can be quite misleading.

4.1 TONS

Tons can mean metric tons or short tons. (Long ton units are almost never used for coal.) One metric tons equals 1.1025 short tons.

4.2 SKE/TCE

For German mines, production is generally stated in SKE's (Steinkohleneinheit = hard coal unit, the equivalent in metric tons of bituminous coal with a standardized heating value.) This unit has become internationalized as TCE (metric ton coal equivalent) and represents 7×10^9 cal, 27.776 million BTU, or approximately 1.1 short tons of coal with a heating value of 12,600 BTU/lb.

4.3 RAW COAL/SALEABLE TONNAGE

For countries where most coal is beneficiated, production can be stated as raw coal (ROM or run-of-mine coal) or as saleable tonnage. Beneficiation losses can be as high as 30% of the raw coal. For beneficiation plants that produce a middlings product in addition to clean coal, the middlings can be included in saleable tonnage according to their actual weight, or they can be included at the BTU-equivalent of clean coal.

Appendix A includes a more comprehensive listing of data from which the WEC set of figures was taken, including recoverable reserves and a breakdown into "hard coal" and lignite.

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APPENDIX A

World Coal Resources and Reserves

(10^6 t.c.e.)

Country and Continent	Resources 1/ Hard Coal 3/	Resources 1/ Brown Coal 4/	Resources 1/ Total	Reserves 2/ Hard Coal 3/	Reserves 2/ Brown Coal 4/	Reserves 2/ Total
America						
Argentina	-	384	384	-	100	100
Brazil	4,040	6,042	10,082	2,510	5,588	8,098
Canada	96,225	19,127	115,352	8,708	673	9,381
Chile	2,438	2,147	4,585	36	126	162
Columbia	7,633	685	8,318	397	46	443
Mexico	5,448	-	5,448	875	-	875
Peru	3,862	-	3,862	105	-	105
United States	1,190,000	1,380,398	2,570,398	113,230	64,358	177,588
Venezuela	1,630	-	1,630	978	-	978
Other Countries	55	5	60	-	-	-
Total America	1,311,331	1,408,788	2,720,119	126,839	70,891	197,730
Europe						
Belgium	253	-	253	127	-	127
Bulgaria	34	2,599	2,633	24	2,179	2,203
Czechoslovakia	11,573	5,914	17,487	2,493	2,322	4,815
Fed. Rep. of Germany	230,300	16,500	246,800	23,919	10,500	34,419
France	2,325	42	2,367	427	11	438
Germany Democ. Rep.	200	9,200	9,400	100	7,560	7,660
Greece	-	895	895	-	400	400
Hungaria	714	2,839	3,553	225	725	950
Netherlands	2,900	-	2,900	1,430	-	1,430
Poland	121,000	3,000	124,000	20,800	990	21,790
Romania	590	1,287	1,877	50	363	413
Spain	1,786	512	2,298	322	215	537
United Kingdom	163,576	-	163,576	45,000	-	45,000
Yugoslavia	104	10,823	10,927	35	8,430	8,465
Other Countries	309	130	439	58	57	115
Total Europe	535,664	53,741	589,405	95,010	33,752	128,762
Africa						
Mozambique	400	-	400	80	-	80
Nigeria	-	180	180	-	90	90
Rep. of Botswana	100,000	-	100,000	3,500	-	3,500
Rep. of S. Africa	57,566	-	57,566	26,903	-	26,903
Rhodesia	7,130	-	7,130	755	-	755
Swaziland	5,000	-	5,000	1,820	-	1,820
Zambia	228	-	228	5	-	5
Other Countries	2,390	10	2,400	970	-	970
Total Africa	172,714	190	172,904	34,033	90	34,123
Australia & the Pacific S. Sea						
Australia	213,760	48,374	262,134	18,128	9,225	27,353
New Zealand	130	660	790	36	108	144
Other Countries	-	-	-	-	-	-
Total Australia & the Pacific S. Sea	213,890	49,034	262,924	18,164	9,333	27,497
Asia						
Bangdladesh	1,649	-	1,649	517	2	519
China (PR)	1,424,680	13,365	1,438,045	98,883	n.a.	98,883
India	55,575	1,224	56,799	33,345	355	33,700
Indonesia	573	3,150	3,723	80	1,350	1,430
Iran	385	-	385	193	-	193
Japan	8,583	58	8,641	1,000	6	1,006
N. Korea	2,000	-	2,000	300	180	480
S. Korea	921	-	921	386	-	386
Turkey	1,291	1,977	3,263	134	624	758
U.S.S.R.	3,993,000	867,000	4,860,000	82,900	27,000	109,900
Other Countries	5,368	353	5,721	1,488	74	1,562
Total Asia	5,494,025	887,127	6,381,152	219,226	29,591	248,817
Total World	7,727,624	2,398,880	10,126,504	493,272	143,657	636,929

1/ Total amount available in the earth that can be successfully exploited and used by man within the foreseeable future.
2/ Amount of reserves in place that can be recovered under present local economic conditions using available technology.
3/ Bituminous and anthracite.
4/ Subbituminous and lignite.

Note: Estimates of U.S. coal reserves in this survey do not agree with other domestic data; among other reasons, criteria used for thickness of seam and depth of overburden are not those employed by the U.S. Bureau of Mines, or U.S. Geological Survey. Metric tons coal equivalent (t.c.e.) = 7 gigacalories = 27.78 MMBTU.

Source: World Energy Conference Survey of Energy Resources, 1977.