

*Journal of the*

# GRADUATE RESEARCH CENTER

INCORPORATING  
FIELD & LABORATORY

**FEBRUARY • 1963**

**COST ANALYSIS IN THE  
PETROLEUM INDUSTRY**

by

**Wallace F. Lovejoy**

**Paul T. Homan**

with

**Charles O. Galvin**



SOUTHERN METHODIST  
UNIVERSITY PRESS

*Journal of the*  
**GRADUATE RESEARCH CENTER**

Incorporating FIELD & LABORATORY

Claude Albritton, *Editor*

Published by Southern Methodist University Press,  
Dallas 22, Texas

Price \$3.00 per copy.

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**A Study of the Problems  
of  
COST ANALYSIS IN  
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WALLACE F. LOVEJOY

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PAUL T. HOMAN

with

CHARLES O. GALVIN

Southern Methodist University



## Preface

In the spring of 1961, Resources for the Future, Inc. made a grant to the Department of Economics and the School of Law at Southern Methodist University to hold a seminar on economic and legal aspects of the petroleum industry. A central purpose of the project was to bring face to face around the conference table, for discussion of some fundamental topic, people from within the industry, academic personnel engaged in research upon the industry, and other persons who in a consulting or regulatory capacity were concerned with the problems of the industry. The initial project was conceived of as possibly the opening step in a series of studies in petroleum economics and law; and it was felt that the establishment of direct lines of communication between the various types of personnel concerned with the problems of the industry would be valuable.

It was decided, for purposes of this experiment, to choose a topic of limited scope and technical character. This limitation excluded consideration of, and argument about, controversial questions of policy. Following this principle, the subject chosen was "Oil and Gas Finding, Development, and Producing Costs." Within this limited scope, the orientation was not toward the specific costing problems of individual companies, but rather toward questions of whether meaningful cost studies could be made, whether existing cost concepts and methods of analysis are correct and useful, and whether cost data are essential information in evaluating the future availability of petroleum supplies.

In preparation for the seminar a planning committee was appointed and charged with the responsibility of preparing a "background paper" to be distributed in advance and to serve as the point of departure for discussion. The bulk of the present volume consists of the paper that was prepared, the authors being also the members of the planning committee. Circumstances did not permit original empirical research into actual cost figures. The paper was therefore primarily centered around (1) the conceptual basis of cost analysis, (2) a review of earlier cost and availability studies, and (3) the bearing of costs upon regulatory activities and policy-making.

The seminar met at Southern Methodist University in five sessions over a period of two and a half days, March 22 to 24, 1962. The members of the planning committee put together a summary report of the discussion and this report makes up the remainder of the present volume. A draft summary was circulated to participants and revised in the light of their comments. The final form, while

generally approved by most participants, is not approved in detail by all of them. It is therefore issued upon the sole responsibility of the drafting committee.

A list of the participants is presented on a separate page.

Resources for the Future, Inc., the sponsoring agency, is a non-profit, tax-exempt corporation whose purpose is to advance the development, conservation, and use of natural resources through programs of research and education.

We are grateful to Mrs. Mary Adair Johnson for assistance in preparing the manuscript through its various stages.

Dallas  
August, 1962

W.F.L.  
P.T.H.

*Journal of the*  
**GRADUATE RESEARCH CENTER**

Volume XXXI

February, 1963

Numbers 1 and 2

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# A Study of the Problems of Cost Analysis in the Petroleum Industry

## I. THE POSTWAR PETROLEUM SUPPLY SITUATION

The significance of the subject of the present study—the cost of finding, developing and producing petroleum—can be better understood by placing it against a summary view of the supply situation in the postwar world. The most striking fact is the appearance of vast new reserves of oil in various parts of the world. Earlier concern over “conservation” was aroused by the fear of depletion of the available supply. Taking a long view, this possibility is not to be dismissed. But in recent years the practical problems of the industry, and of public policy toward it, are of a different sort. The capacity of the industry to produce in the countries of the “free world” greatly exceeds the current rates of consumption. From the sellers’ point of view, at least, it seems self-evident that “too much” oil exists today.

The rise of this situation can be seen in Table I-A which shows free-world crude oil reserves and production by major world regions for the years 1947-1959.<sup>1</sup> While U. S. proved reserves grew from 21.5 billion barrels to 31.7 billion barrels during the period, or about 50%, the U.S. share of free world reserves dropped from almost 34% to about 12%. Total reserves for the free world grew from 63.4 to 264.2 billion barrels. U. S. production in 1947 was 1.9 out of a total 2.8 billion barrels, or 66.4%. In 1959, it was 2.6 out of 6.1 billion barrels, or 43%. The critical figures here are the rise in world production from 2.8 to 6.1 billion barrels. (It need hardly be said, to those acquainted with the industry, that “proved reserves” do not represent total petroleum expected to be recovered from known reservoirs, to say nothing of undiscovered ones, but are the well-authenticated underground inventories immediately available for production. New reserves are constantly being “proved.”)

The great increase in potential supply has occurred in the Middle East. Its estimated reserves in 1959 were 70% of the free world total, but its production was only 21%. The United States, by contrast, held only 12% of the reserves but accounted for over 42% of the production. Part of the slow rise in U. S. net reserves has been caused by the severe drain of annual production. (It has been severe only in relation to other nations and not in relation to MER.) During

TABLE I-A  
 PRODUCTION AND RESERVES OF WORLD CRUDE OIL:  
 1947-1959<sup>1</sup>

Year	United States		Canada		Latin America	
	Reserve <sup>5</sup> (Mil.)	Production <sup>6</sup> (Tbous.)	Reserve <sup>5</sup> (Mil.)	Production <sup>6</sup> (Tbous.)	Reserve <sup>5</sup> (Mil.)	Production <sup>6</sup> (Tbous.)
1959	31,719	2,574,590	3,497	184,768	25,062	1,300,937
1958	30,536	2,449,016	3,166	165,496	19,343	1,214,520
1957	30,300	2,616,901	2,874	181,846	18,254	1,258,415
1956	30,435	2,617,283	2,849	171,981	14,974	1,127,875
1955	30,012	2,484,428	2,510	129,440	15,515	1,000,431
1954	29,561	2,314,988	2,208	96,080	14,356	893,403
1953	28,945	2,357,082	1,845	80,899	13,182	828,792
1952	27,961	2,289,836	1,680	61,237	11,883	843,522
1951	27,468	2,247,711	1,600	47,615	12,711	804,154
1950	25,268	1,973,574	1,500	29,044	11,525	716,655
1949	24,649	1,841,940	1,200	21,305	11,401	634,560
1948	23,280	2,020,185	500	12,287	10,883	633,568
1947	21,488	1,856,987	500	7,692	10,712	574,170

  

Year	Europe <sup>2</sup>		Middle East <sup>3</sup>		Africa	
	Reserve <sup>5</sup> (Mil.)	Production <sup>6</sup> (Tbous.)	Reserve <sup>5</sup> (Mil.)	Production <sup>6</sup> (Tbous.)	Reserve <sup>5</sup> (Mil.)	Production <sup>6</sup> (Tbous.)
1959	1,722	94,341	183,160	1,684,636	8,100	41,943
1958	1,437	87,275	173,951	1,558,351	4,119	31,713
1957	1,304	73,282	169,501	1,292,705	814	19,089
1956	1,305	63,456	144,405	1,260,464	285	12,968
1955	1,261	58,401	126,271	1,185,519	169	13,837
1954	1,049	51,485	97,459	998,932	112	15,225
1953	642	45,367	78,160	884,736	158	17,900
1952	473	38,156	64,825	760,599	163	17,561
1951	502	31,660	51,520	700,643	175	16,947
1950	445	24,401	41,567	640,862	188	16,702
1949	289	17,240	33,013	511,507	203	16,135
1948	183	14,745	32,621	416,780	122	13,499
1947	194	12,517	29,005	306,320	142	8,649

  

Year	Asia and Pacific <sup>4</sup>		Total Free World	
	Reserve <sup>5</sup> (Mil.)	Production <sup>6</sup> (Tbous.)	Reserve <sup>5</sup> (Mil.)	Production <sup>6</sup> (Tbous.)
1959	10,907	193,312	264,167	6,074,527
1958	9,647	171,703	242,199	5,678,074
1957	8,643	169,339	231,690	5,611,577
1956	6,205	148,170	200,458	5,402,197
1955	3,000	138,682	178,738	5,010,738
1954	2,708	127,627	147,453	4,497,750
1953	2,583	121,380	125,515	4,336,156
1952	2,062	108,981	109,047	4,119,892
1951	1,981	108,218	95,757	3,956,948
1950	1,780	93,883	82,273	3,495,121
1949	1,552	81,508	72,307	3,124,195
1948	1,297	63,944	68,886	3,175,008
1947	1,348	32,316	63,389	2,798,651

<sup>1</sup> Includes only crude oil; excludes natural gas liquids.

<sup>2</sup> Includes only Non-Communist Bloc nations.

<sup>3</sup> Includes Bahrain, Iran, Iraq, Israel, Kuwait, Neutral Zone, Qatar, Saudi Arabia, Southern Arabia, Syria and Turkey.

<sup>4</sup> Excludes Middle East and Communist Bloc nations.

<sup>5</sup> Reserves in millions of barrels.

<sup>6</sup> Production in thousands of barrels.

Sources: *Oil & Gas Journal*, DeGolyer and MacNaughton, *20th Century Petroleum Statistics*.

these 13 years the U. S. produced about 29,645 million barrels of crude oil, an amount considerably larger than the 21,488 million barrels of proved reserves in 1947.

Though world demand for oil has increased greatly, the situation continues to be as described by the London *Economist* in 1957: "It now looks as if the world oil industry is entering another phase where its ability to produce crude oil is rising faster than demand." This development has made the world price situation inherently weak and has led to various measures of production and price control designed to offset this weakness. The increasing entry of oil into Western Europe from the Soviet Union, together with competition among other producing areas, nevertheless limits the extent and effectiveness of such controls.<sup>2</sup>

The burgeoning supply of crude oil outside the United States has resulted in rising imports into this country since the end of World War II. While the U. S. total supply of liquid hydrocarbons has risen about 67%, imports have increased their portion of the total from 7.42% to 18.57% between 1947 and 1960, and were only prevented from being larger by import restrictions. In addition to the market impacts from rising imports, domestic crude oil has also been faced with the rapidly rising production of natural gas liquids, which contributed 6.18% in 1947 and 9.62% in 1960. Together, imports and NGL accounted for over 28% of total liquid hydrocarbons in 1960.<sup>3</sup>

Since the world picture at least for the near future seems to be one of continued abundance of liquid hydrocarbons, the domestic producing industry has little basis for expecting higher field prices for crude oil.<sup>4</sup> This pattern has already developed. While the crude oil wholesale price index rose quite rapidly immediately after the war, it has moved downward since 1957. This is true also for gasoline. Field prices for natural gas present a very different picture. They have had a steady rise throughout the postwar period, but gas sales are still a relatively small fraction of the total revenues of the industry.

The postwar changes in the world oil supply and demand picture were bound to have widespread repercussions in this nation. The price ceiling created by the world supply situation was one factor in reducing incentives in exploration, drilling and production in the U. S. The figures in Table I-B make this point quite apparent. Total new wells drilled, as well as footage drilled, hit a peak in 1956 and have been declining since that time. Most of the decline has come in oil wells and dry holes drilled. Gas, condensate and service wells have remained at about their peaks and thus have become *relatively*

TABLE I-B  
 NUMBER OF WELLS DRILLED, FOOTAGE DRILLED, AND AVERAGE WELL DEPTH BY TYPE OF WELL,  
 TOTAL DRILLING—1950-1960\*  
 (Footage Drilled in 000's)

	1960	1959	1958	1957	1956	1955	1954	1953	1952	1951	1950
Total New Wells Drilled	46,778	48,328	48,331	53,350	58,206	55,819	51,902	49,039	45,885	44,826	43,204
Total Footage Drilled	194,583	202,528	195,830	219,404	235,221	227,480	209,502	196,466	186,400	174,262	159,384
Average Well Depth	4,160	4,191	4,052	4,113	4,041	4,075	4,036	4,006	4,062	3,888	3,689
Oil Wells Drilled	22,233	24,043	23,774	27,364	30,528	30,432	28,141	25,323	23,290	23,179	23,812
Oil Footage Drilled	86,538	94,611	93,105	110,043	120,351	121,149	113,362	102,135	98,147	95,106	92,695
Average Oil Well Depth	3,892	3,935	3,916	4,021	3,942	3,981	4,028	4,033	4,214	4,013	3,893
Condensate Wells Drilled	750	800	710	748	551	706	672	374	348	344	466
Condensate Footage Drilled	7,442	7,891	6,736	7,077	4,918	6,350	5,853	3,224	3,142	3,116	4,060
Ave. Condensate Well Depth	9,923	9,864	9,487	9,462	8,926	8,995	8,710	8,621	9,029	9,058	8,713
Gas Wells Drilled	4,379	4,131	4,295	3,727	3,980	3,560	3,366	3,594	3,166	3,094	2,973
Gas Footage Drilled	20,757	18,715	18,820	16,758	17,820	13,580	13,004	15,024	12,115	10,830	9,625
Average Gas Well Depth	4,740	4,530	4,382	4,496	4,477	3,815	3,863	4,180	3,827	3,500	3,237
Service Wells Drilled	1,231	765	1,390	1,355	1,036	669	793	1,299	1,322	1,183	1,154
Service Footage Drilled	2,505	2,835	2,526	2,359	1,941	1,297	1,493	2,221	2,267	2,116	2,026
Ave. Service Well Depth	2,035	3,706	1,817	1,741	1,874	1,939	1,883	1,710	1,715	1,789	1,756
Dry Holes Drilled	18,185	18,589	18,162	20,156	22,111	20,452	18,930	18,449	17,759	17,026	14,799
Dry Hole Footage Drilled	77,341	79,476	74,643	83,167	90,191	85,102	75,790	73,861	70,729	63,093	50,978
Ave. Dry Hole Depth	4,253	4,275	4,110	4,126	4,080	4,161	4,004	4,004	3,983	3,706	3,445

\* Excludes old wells drilled deeper.

Source: *World Oil*, annual numbers.

more important in the total drilling picture. In the light of what was said about the profitableness of gas and gas-condensate wells, this pattern is not surprising. The fairly high levels of service wells drilled may reflect growing investment to obtain secondary reserves, as an alternative to risking capital on the less certain primary reserves which result from new drilling.

Exploratory drilling statistics, shown in Table I-C, reflect the same general pattern. Of 16,173 exploratory tests made in 1956, the peak year, 8,709 (53.85%) were "new-field wildcats." By 1960, total exploratory tests had dropped to 11,704 with 7,320 of them classified as new-field wildcats. It is interesting to note that new field wildcats accounted for 62.54% of exploratory drilling, considerably larger than the usual 51 to 54%. The "success-ratio" in terms of the percent of total exploratory wells which are producers has remained surprisingly constant. From 1947 through 1960 the percentage which proved to be producers ranged from 20.78 (in 1955) to 18.25 (in 1948). The simple average for the period 1947-1960 is 19.56%.

Drilling-success ratios tell only a partial story and at times can be quite misleading. They do not get to the very critical question of success in terms of barrels of reserves uncovered. A successful wildcat may uncover a million barrels of oil or 50 million barrels. One of the critical and as yet unanswered questions in determining finding and development costs is how to relate effort to results, *e.g.*, drilling to reserves.

Part of the difficulty of evaluating results lies in the manner in which reserves are reported.<sup>5</sup> Table I-D shows the official proved reserves figures for liquid and gaseous hydrocarbons which are reported

TABLE I-C  
U. S. EXPLORATORY DRILLING BY WELL CLASSES, 1947-1960

	1960			1956			1947		
	Number	Well %	Class %	Number	Well %	Class %	Number	Well %	Class %
<b>Outposts:</b>									
Producers	828	34.06		1,207	33.31		489	31.71	
Dry holes	1,603	65.94		2,416	66.69		1,053	68.29	
Total	2,431	100.00	20.77	3,623	100.00	22.40	1,542	100.00	22.76
<b>New-pool wildcats:</b>									
Producers	342	25.48		708	21.95		324	26.64	
Dry holes	1,000	74.52		2,518	78.05		892	73.36	
Total	1,342	100.00	11.47	3,226	100.00	19.95	1,216	100.00	17.95
<b>Deeper-pool tests:</b>									
Producers	186	37.58		204	43.97		145	29.06	
Dry holes	309	62.42		260	56.03		354	70.94	
Total	495	100.00	4.23	464	100.00	2.87	499	100.00	7.37
<b>Shallower-pool tests:</b>									
Producers	88	75.86		109	72.19		26	68.42	
Dry holes	28	24.14		42	27.81		12	31.58	
Total	116	100.00	0.99	151	100.00	.93	38	100.00	.56
<b>New-field wildcats:</b>									
Producers	745	10.18		868	9.97		394	11.32	
Dry holes	6,575	89.82		7,841	90.03		3,086	88.68	
Total	7,320	100.00	62.54	8,709	100.00	53.85	3,480	100.00	51.36
Total producers	2,189	18.70		3,096	19.14		1,378	20.34	
Total dry holes	9,515	81.30		13,077	80.86		5,397	79.66	
Grand Total	11,704	100.00	100.00	16,173	100.00	100.00	6,775	100.00	100.00

Source: American Petroleum Institute, *Petroleum Facts and Figures*, 1959 and 1961; authority American Association of Petroleum Geologists.

TABLE I-D  
SUMMARY OF PROVED RESERVES AS REPORTED FOR 1946 AND THEREAFTER  
(Barrels of 42 U. S. Gallons)

	NEW OIL ADDED DURING YEAR					
	Through Revisions of Previous Estimates and Extensions to Known Fields (1)	Through Discoveries of New Fields and of New Pools in Old Fields (2)	Total Through New Discoveries, Extensions, and Revisions (Columns 1 + 2) (3)	Production During Year (4)	Estimated Proved Reserves as of End of Year (Column 3-4) (5)	Increase Over Previous Year (6)
<b>CRUDE OIL ONLY</b>						
1946	2,413,628,000	244,434,000	2,658,062,000	1,726,348,000	20,873,560,000	931,714,000
1947	2,019,140,000	445,430,000	2,464,570,000	1,850,445,000	21,487,685,000	614,125,000
1948	3,398,726,000	396,481,000	3,795,207,000	2,002,448,000	23,280,444,000	1,792,759,000
1949	2,297,428,000	890,417,000	3,187,845,000	1,818,800,000	24,649,489,000	1,369,045,000
1950	1,997,769,000	564,916,000	2,562,685,000	1,943,776,000	25,268,398,000	618,909,000
1951	4,024,698,000	389,256,000	4,413,954,000	2,214,321,000	27,468,031,000	2,199,633,000
1952	2,252,860,000	496,428,000	2,749,288,000	2,256,765,000	27,960,554,000	492,523,000
1953	2,704,450,000	591,680,000	3,296,130,000	2,311,856,000	28,944,828,000	984,274,000
1954	2,287,231,000	585,806,000	2,873,037,000	2,257,119,000	29,560,746,000	1,918,000
1955	2,393,767,000	476,957,000	2,870,724,000	2,419,300,000	30,012,170,000	451,424,000
1956	2,507,114,000	467,222,000	2,974,336,000	2,551,857,000	30,434,649,000	422,479,000
1957	2,008,603,000	416,197,000	2,424,800,000	2,559,044,000	30,300,405,000	(-134,244,000)
1958	2,293,513,000	314,729,000	2,608,242,000	2,372,730,000	30,535,917,000	235,512,000
1959	3,297,383,000	369,362,000	3,666,745,000	2,483,315,000	31,719,347,000	1,183,430,000
1960	2,111,472,000	253,856,000	2,365,328,000	2,471,464,000	31,613,211,000	(-106,136,000)
<b>NATURAL GAS LIQUIDS ONLY</b>						
1946	(.....) This detail not available for 1946 (.....)				3,163,219,000	
1947	192,237,000	59,301,000	251,538,000	160,782,000	3,253,975,000	90,756,000
1948	405,874,000	64,683,000	470,557,000	183,749,000	3,540,783,000	286,808,000
1949	294,211,000	92,565,000	386,776,000	198,547,000	3,729,012,000	188,229,000
1950	707,879,000	58,183,000	766,062,000	227,411,000	4,267,663,000	538,651,000
1951	648,497,000	75,494,000	723,991,000	267,052,000	4,724,602,000	465,939,000
1952	475,170,000	81,668,000	556,838,000	284,789,000	4,996,651,000	272,049,000
1953	648,047,000	95,922,000	743,969,000	302,698,000	5,437,922,000	441,271,000
1954	20,830,000	86,520,000	107,350,000	300,815,000	5,438,457,000	(-193,465,000)
1955	447,160,000	67,348,000	514,508,000	320,400,000	5,438,565,000	194,108,000
1956	715,764,000	94,056,000	809,820,000	346,053,000	5,902,332,000	463,767,000
1957	8,884,000	128,508,000	137,392,000	352,364,000	5,687,360,000	(-124,972,000)
1958	749,956,000	108,250,000	858,206,000	341,548,000	6,204,018,000	516,658,000
1959	593,905,000	109,539,000	703,444,000	385,154,000	6,522,308,000	318,290,000
1960	603,621,000	121,509,000	725,130,000	431,379,000	6,816,059,000	293,751,000
<b>TOTAL LIQUID HYDROCARBONS</b>						
1946	(.....) This detail not available for 1946 (.....)				24,036,779,000	
1947	2,211,377,000	594,731,000	2,716,108,000	2,011,227,000	24,741,660,000	704,881,000
1948	3,804,600,000	461,164,000	4,265,764,000	2,186,197,000	26,821,227,000	2,079,567,000
1949	2,591,639,000	982,982,000	3,574,621,000	2,017,347,000	28,378,501,000	1,557,274,000
1950	2,705,648,000	623,099,000	3,328,747,000	2,171,187,000	29,536,061,000	1,157,560,000
1951	4,673,195,000	464,750,000	5,137,945,000	2,481,373,000	32,192,633,000	2,656,572,000
1952	2,728,030,000	578,096,000	3,306,126,000	2,541,554,000	32,957,205,000	764,572,000
1953	3,352,497,000	687,602,000	4,040,099,000	2,614,554,000	34,382,750,000	1,425,545,000
1954	2,308,061,000	672,326,000	2,980,387,000	2,557,934,000	34,805,203,000	422,453,000
1955	2,840,927,000	544,305,000	3,385,232,000	2,739,700,000	34,450,735,000	645,532,000
1956	3,222,878,000	561,278,000	3,784,156,000	2,897,910,000	36,336,981,000	886,246,000
1957	2,017,487,000	544,705,000	2,562,192,000	2,911,408,000	35,987,765,000	(-349,216,000)
1958	3,043,469,000	422,979,000	3,466,448,000	2,714,278,000	36,739,935,000	752,170,000
1959	3,891,288,000	478,901,000	4,370,189,000	2,868,469,000	38,241,655,000	1,501,720,000
1960	2,715,093,000	375,365,000	3,090,458,000	2,902,843,000	38,429,270,000	187,615,000

Source: American Petroleum Institute and American Gas Association, *Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas*, Vol. 16, December 31, 1961.

annually by the American Petroleum Institute and the American Gas Association. From this table it is possible to trace the growth of proved reserves, their relation to production, and their breakdown between (1) new discoveries and (2) extensions and revision figures for existing pools. The figures do not, however, throw any light on the total amount of oil in newly discovered fields, year by year.

In the annual review of exploratory drilling, published by the American Association of Petroleum Geologists, one authority has undertaken the difficult task of assigning reserves to specific exploratory wells to get a more detailed picture of what quantities of reserves are found from this drilling effort.<sup>6</sup> The one million barrel oil field (or the equivalent in gas), which is considered by the industry as the minimum size to be profitable, is a rare occurrence. While some of the smaller fields may break into the one million barrel category with the application of new secondary recovery techniques, the picture remains substantially unchanged.<sup>7</sup>

Extensive drilling programs carried on in the United States during the past thirty or forty years have resulted in an enormous number of producing oil and gas wells. Since 1947 the nation has added a net of more than 170,000 producing oil wells and almost 21,000 producing gas wells. The slowdown in drilling in recent years is evidenced by the fact that there were 67,257 flowing oil wells in 1957 and only 67,267 flowing wells in 1960, while the number of older wells with artificial lift has increased. As might be expected, the growth of producing gas wells has been more rapid than that of oil wells in recent years. Between 1955 and 1960, producing gas wells increased by more than 18%, while producing oil wells rose by only 11.5%.

This relationship of gas to oil is also borne out in production figures. The gas-oil production ratio has risen from a low of 2,749 cubic feet per barrel in 1948 to 4,574 cubic feet per barrel in 1960, an increase of about 66%. This, no doubt, reflects a number of factors, including: (1) a restriction of liquid production, (2) an expansion of gas production, (3) intensive drilling in gas-rich geographical and geological areas, (4) burgeoning market for gas at prices charged in these years, and (5) the supply and demand factors for oil discussed earlier.

The analysis presented here is designed to paint with a broad brush a picture of the postwar oil and gas industry *vis-a-vis* supply. This is a picture of: (1) rapidly rising world oil supplies, (2) tremendous increases in domestic drilling particularly in early postwar years, (3) increasing imports of oil and increasing production



of natural gas and gas liquids, (4) general price softness for crude oil in domestic and world markets, (5) the development of substantial overcapacity for oil production, and (6) a general slowing down of activity in recent years in the domestic oil industry.

Clearly the key to this entire situation is economic incentive. The slow-down today reflects worsening cost-revenue relationships. Overcapacity, on the other hand, may reflect greater than necessary domestic incentives in the past and/or improving cost-revenue relationships in foreign production. The whole picture of changing supply and demand for fuels, and of competition among fuels, is extremely complex and has been imperfectly understood.

## II. CONCEPTS AND DEFINITIONS

Against the background of the supply conditions outlined in Part I, the costs of finding and developing new sources of petroleum and producing from them are critical factors in the future of the industry. The cost factors are the subject of extreme concern and considerable confusion within the industry, and of equal though different concern for those responsible for formulating public policy with respect to energy sources at both state and federal levels. The present study attempts to draw together the scattered information. It does not purport to present new data or new methods of analysis. Rather it is designed to catalogue and appraise other peoples' efforts, to raise questions and problems that appear to require solution, and to point out data gaps and methodological weaknesses in the work that has already been done. The definition of a problem is a major step towards its solution.

Here we discuss a few concepts which must enter into any petroleum cost study. One of the greatest barriers to successful analysis of costs is the lack of uniformity in the content of certain concepts, like "finding costs" and "development costs." Much of the difficulty of reading any petroleum cost study is in discovering the conceptual apparatus of the investigator and in mastering the devious statistical devices by which he attempts to utilize deficient data. When different studies are compared, the non-uniform data and procedures make comparison almost impossible.

### *Reserves*

The concept of "reserves" is central to any cost study, since finding and development costs are conventionally measured in terms of reserves discovered. "Reserves" is a term applied to crude oil or other liquid hydrocarbons as barrels, and to natural gas as thousands of

cubic feet. Finding costs, for example, are related to the estimated number of barrels of oil in place attributed to certain expenditures.

The measurement of "proved reserves" is carried out on an accepted conventional base. The American Petroleum Institute and the American Gas Association make annual reports on the "Proved Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States." Each organization has a reserve committee which gathers information by fields and carefully analyses this information from all the data available. The definition given for crude oil reserves is as follows:

The reserves listed in this Report, as in all previous Annual Reports, refer solely to "proved" reserves. These are the volumes of crude oil which geological and engineering information indicate, beyond reasonable doubt, to be recoverable in the future from an oil reservoir under existing economic and operating conditions. They represent strictly technical judgments, and are not knowingly influenced by policies of conservation or optimism. They are limited only by the definition of the term "proved." They do not include what are commonly referred to as "probable" or "possible" reserves.

The proved reserves may be considered as the known and established underground working inventory available for recovery under prevailing conditions. These estimates are subject to future revisions, either downward or upward, even though the *presently established* "proved" reserves may be accurate, in the light of current information.

Both drilled and undrilled acreage are considered in the estimates of the proved reserves. However, the undrilled proved reserves are limited to those drilling units immediately adjacent to the developed areas which are virtually certain of productive development, except where the geological information on the producing horizons insures continuity across the undrilled acreage.

The proved crude oil reserves estimates do not include:

- (1) Oil whose recovery is subject to reasonable doubt because of uncertainty as to geological conditions, reservoir characteristics or economic factors.
- (2) Oil in untested prospects.
- (3) Oil that may become available by fluid injection or other methods from fields in which such operations have not yet been applied.
- (4) Liquid hydrocarbons that may become available through the processing of natural gas.
- (5) Oil that may be recovered from oil shales, coal or other substitute sources.<sup>8</sup>

The reserve concept described here is relatively narrow in scope and technical in content. The reserves included are "proved"—an "established underground working inventory available for recovery under prevailing conditions." Obviously the definition excludes huge

quantities of potential reserves suspected in a whole range of probabilities.

The concept of natural gas reserves is similar. There is included an interesting additional sentence. "Proved recoverable reserves of natural gas are those reserves estimated to be producible under present operating practices, with no consideration being given to their ultimate use." Gas available in small quantities with oil may have no use (other than assisting in bringing the oil to the surface); but it would be included in reserves.

Annual additions to reserves are divided into:

*Discoveries.*—Reserves in newly discovered fields or pools. Reported reserves are apt to be small because of the lack of information concerning the extent and geological characteristics of the reservoir.

*Extensions.*—Reserves proved by development drilling after the initial discovery. This may take several years, and will continue until the field limits are determined.

*Revisions.*—Reserves added (1) because fuller information makes possible more accurate estimates, or (2) because newly introduced production techniques are used, *e.g.*, secondary recovery or pressure maintenance projects.

The reserves in a given field usually enter the "annual additions" figures over a period of years. A small amount is put in at the time of discovery; as the field develops, reserves continue to be added; finally, if secondary recovery is introduced, there will be another increment added to total recoverable reserves.

The thorny aspect of this definition lies in the assumption concerning (1) existing operating conditions, *i.e.*, technology, and (2) existing economic conditions. These two things are closely related. If there are changes in technology, then presumably there would be changes in the proved recoverable reserves. This might work directly as in the case of a new efficient method of secondary recovery which would increase reserves that can be recovered economically, given a price for oil. Technology might work to the detriment of reserves through economics in a situation, for example, in which substitute sources of energy are developed. Needless to say, the estimators of reserves usually do not attempt to predict future technology, yet the concept of reserves is in part a function of future technology.

Changes in economic conditions are equally important. For example, consider what U.S. crude oil reserves would be, if market forces generated crude oil prices of \$4.00, \$5.00, or \$10.00 per barrel; or conversely, what happens to reserves if prices drop from

\$3.00 to \$2.00 per barrel. In the first instance, proved recoverable reserves would be much higher, not because more oil had been discovered, but rather that it would be economical for these reserves to be produced. Oil now excluded would enter the category of "proved reserves." In the case of the lowered price, presumably proved recoverable reserves shrink. Since reserve figures include a recovery factor of about a third of estimated oil in place, the oil reserve potential ranks much greater than the conventional estimates, depending on economic and technological factors.

At least one cost study has urged that "the best-informed estimate of probable ultimate recovery from the entire reservoir discovered by the exploratory well" be given to assist in obtaining more representative cost data.<sup>10</sup> Although revisions of these early estimates would have to be made, the errors and consequent problems might be smaller than under the present technical and limited estimates of reserves at discovery.

The recent increase in unitization of oil producing properties and in secondary recovery projects has generated problems of distinguishing between primary and secondary reserves and production. In general, primary reserves have been considered to be those recoverable through utilization of the natural energies in the reservoir—gas, water, gravity or some other pressure. Pumping may be applied to assist the natural energies, but such pumping does not replace natural drive forces in the reservoir.

Secondary reserves are those reserves which can be recovered through the application of some artificial stimulus to the reservoir. This usually takes the form of gas or water injection, but many other techniques are currently being tried. If secondary recovery is applied before the natural energies in the reservoir are dissipated, then the operation is referred to as pressure maintenance. Secondary recovery is used only if it is profitable, or in other words, only if the revenues realized from the increased reserves more than offset the cost of installing and operating the secondary recovery project. Thus there are many fields in which such production methods will never be used. Whether or not a project is launched boils down to a price-cost comparison; either an increase in price or a decrease in costs will bring about additional secondary recovery.

The industry appears to take for granted the status quo in economics and technology when discussing primary and secondary reserves. The possible impact of economics and technology on reserves must nevertheless be kept in mind in developing cost concepts for a dynamic industry.

### *Basic Cost Categories*

The basic cost categories most widely used in studies of the petroleum industry are (1) finding or exploration costs, (2) development costs, and (3) production or lifting costs. Different analysts give a different content to these categories. We can usefully start from well-thought-out definitions given by Hodges and Steele, summarized as follows:<sup>11</sup>

#### *Finding (or exploration) costs*

- a. Lease acquisitions.
- b. Geological and geophysical expenditures.
- c. Drilling costs of all exploratory wells, whether dry or successful.
- d. Completion cost of successful exploratory wells through installation of the Christmas tree.

#### *Development costs*

- a. Equipment cost of successful exploratory wells (flow lines, storage tanks, etc.) beyond the Christmas tree.
- b. Drilling costs for all subsequent development wells, whether productive or dry, including drilling to define the limits of the pool.
- c. Field development outlays.
- d. Capital expenditures for pressure maintenance and secondary recovery projects.

#### *Production costs*

Current operating outlays made to secure production from existing wells, including

- a. Pumping or other lifting costs.
- b. Field maintenance and upkeep costs, not including capital expenditures on secondary recovery and the like, which are included in development costs.
- c. Certain leasing and other land-use outlays.

To each of these categories, an overhead cost must usually be allocated.

Production cost is a straightforward accounting concept, relating direct outlays and depreciation to current output. The other two categories present some complications which we must explore.

For accounting purposes, an arbitrary line has to be drawn between some items, in particular the line between exploratory drilling and development drilling. A noteworthy point in the Hodges and

Steele classification is that, under both the finding and development categories, wells may be either productive or dry. By way of contrast, most cost studies assign the drilling costs of all dry holes to finding costs, and of all productive wells to development costs, even though some of the latter are the result of wildcat drilling.

In this matter, the advantage appears to be on the side of Hodges and Steele's definitions. Granted that the line between exploratory and development drilling is blurred, the nature of development drilling is different from wildcat drilling, and such things as costs and risks are substantially at variance. It seems more logical to put dry holes drilled in defining the limits of a pool in the development category and to put productive wells from wild-cattling operations in the finding category.<sup>12</sup> In any case, a uniform plan of reporting is needed.

A special problem area centers around capital expenditures for secondary recovery. Logically these might be called development costs and amortized over the life of the secondary reserves. Current operating expenses would thus be charged to production. Even this procedure, however, leaves out some pertinent information. Since secondary recovery investment is in considerable degree an alternative to investment for exploration, or even for development, it would be useful to have separate figures on secondary recovery. Some thought should be given to the way in which secondary recovery costs are handled, and to the impact of these costs on exploratory and conventional development costs (both of which would be lowered, on a per barrel basis).

Natural gas can no longer be ignored in crude oil cost studies. Much exploration and drilling is directed towards gas, which is increasingly valuable to the industry. Many of the cost studies discussed below have not mentioned gas, and thus implicitly allocate all gas costs to oil; or they have recognized and commented upon the problems of joint cost allocation, and then have proceeded to assign all joint costs to oil.

With reference to anticipated production both finding and development costs are capital items. Using these items to calculate the "cost of oil" leads to some anomalous results, as demonstrated in the following section.

#### *The "Replacement Cost" of a Barrel of Oil*

Most petroleum cost studies—or at least those primarily concerned with crude oil—are directed to calculating for the present and estimating for the future a relation between the cost of oil and

the supply of oil. This means cost per barrel—an amount of supply made available divided by the cost outlay required to possess it. This apparently simple relationship is actually most difficult to assess.

As we shall see a little later, there is no existing way to calculate the *economic cost* properly chargeable to current production of hydrocarbons collectively, or of the constituent elements—crude oil, natural gas, and natural gas liquids—separately. Consequently, conventional statistical analysis is mostly concerned with a different sort of cost analysis, expressed in the phrase *replacement cost*. In spite of its familiarity, this is a complex concept from which misleading conclusions may follow.

The conventional idea of replacement cost per barrel of crude oil can be summarized in the following way:

1. Current production costs divided by the number of barrels produced; plus
2. Current development costs divided by the number of barrels added to proved reserves by development activity (“extensions” and “revisions”); plus
3. Current finding costs divided by the number of barrels added to proved reserves by exploratory activity (“discoveries”); are
4. Adjusted for costs allocated to natural gas and natural gas liquids.

Cost and quantity figures are for the same time period, *e.g.*, one year. The sum of items 1, 2, and 3, as adjusted for 4, if this is done, is called the replacement cost of a barrel of oil. The costs incurred in any year, under the three categories, are not in sum the costs assignable to the oil produced this year. Only *production costs* meet this test.

*Finding costs* incurred today are assignable as economic costs to some future volumes of production, spaced over many years. Current *development costs* likewise refer to some future quantity of oil made recoverable over time by the outlays. When, for a particular year, a calculation is made of finding costs per barrel and development cost per barrel, the reference is to different barrels of oil—that is, to additions to reserves assigned separately to the two cost categories.

The result of these calculations depends on (1) what amount of reserves is assigned to what cost category, (Here the conventional procedure is to assign the American Petroleum Institute estimate of “discoveries” to finding costs, and “extensions and revisions” to development costs.) and (2) how the cost categories are constructed.

(Here, as we have seen, non-uniformity of categories permits diverse estimates of the cost of "finding" and "developing" oil.)

What significance can be attached to the process of adding together three sets of costs relating to different amounts of oil, accruing as product at different points of time? The logic of the matter is stated by Megill in this way: "Three different barrels of oil are involved; however, each operator to replace a barrel of oil must find another barrel, develop it, and lift it to the surface, all at *today's costs*. This necessitates the use of the three different costs."

Commenting upon the replacement cost concept, Hodges and Steele say that replacement costs "are not a measure of current costs, but rather constitute a cost standard which can be compared with the current crude oil price."<sup>13</sup> In this emphasis, the importance of the figures lies in the statistical trends which they reveal over a period of years. They represent a crucial kind of evidence as to the prospects of the oil industry within the total universe of fuels. Writing in another place, Hodges has said that, given complete and accurate information, "the national averages of such cost figures would be distinctly meaningful . . . as a figure for trend comparisons over periods of time." And again, "generally speaking, the statistics on finding cost should be the most critically important indicator of future cost prospects for exploration programs. Any pronounced trend increase in this figure should, if properly defined, be recognized as tantamount to 'handwriting on the wall' and must be given sober acknowledgment in planning drilling programs at the level of the individual oil company, and in making recommendations for the appropriate scheduling of over-all fuel-use patterns at the national level."<sup>14</sup>

As against the great *potential* usefulness of such figures, the operational facts are that the statistics actually used in replacement cost estimates are spotty and unreliable, and are utilized in defective or non-uniform concepts of the three basic cost categories. Far-reaching conclusions are often drawn from replacement cost figures, conclusions which go beyond the scope and limitations of the concept even assuming accurate data. The statistical defects are not beyond substantial improvement, if the industry would arrange and report the necessary figures on an acceptable basis. It will always be difficult, if not impossible, to allocate money cost outlays accurately to the reserves and production to which they give rise, but clearly defined concepts and procedures can reduce the existing analytical confusion.



### *Economic Cost*

The replacement cost concept, examined above, has nothing in common with the concept either of *economic cost*, which underlies the concept of *economic profit*, or of conventional accounting costs and profit. To calculate economic cost requires the isolation of all costs, past and current, capital and operating, which are properly attributable to current production. In the case of petroleum, this would involve an isolation of the portion of past discovery and development costs properly chargeable to present production. It appears impracticable for any company to fragment its past costs in such a way that the various bits and pieces of past capital outlay and opportunity cost could be allocated to the production of a particular year. It seems necessary, therefore, to abandon the rigorous economic cost concept and turn to some method of analysis that will give a rough approximation of economic costs.

A modified and improved replacement cost concept may offer the best alternative, given the current state of industry statistics and analytical techniques. If these costs could be more precisely calculated and could be broken down accurately into the three categories discussed above—finding, developing, and producing—some approach to economic cost might be made by lagging the finding and development costs, according to some estimated average interval between outlay and product. Since the regulatory, technological, and economic milieu in which the industry operates is subjecting both the quantities and rates of inputs and outputs to constant change, proper consideration must be given to the lagging techniques used and the specific lag periods used for historical time intervals, geographic regions, and certain types of wells (oil, gas, or condensate). Also of critical importance is the discounting of costs over time, a step often overlooked in cost analysis.

### *Joint Supply and Joint Cost*

Joint supply and joint cost occur where increasing cost outlays result in increasing outputs of two or more products. The output may increase in either fixed or variable proportions. The phenomenon is found in many areas of production; and economic and accounting literature is full of discussions on how to “cost” and “price” joint products. There is, in economic theory, no reasonable or “correct” way to allocate joint costs to joint products. By definition any such allocation must be arbitrary, in the sense that judgment rather than fact dictates the result. Nevertheless, in cost studies it is necessary to make such allocations, and the problem is to find the procedure

most reasonably applicable to particular situations and for particular purposes. Regulatory agencies, such as the I.C.C. and the F.P.C., are constantly faced with the problem.

As the problem appears in the petroleum industry, Hodges has written in his discussion of C. C. Anderson's paper cited below:

Actually, a very large number of wells discover both crude oil and natural gas, which are jointly produced from the well. In such a case, all the costs of finding these resources must be recognized to be joint costs. . . . A certain exploratory outlay is expended to find a certain composite resource consisting of so much oil, so much natural gas, and so much of various related liquid hydrocarbons. . . . one must be satisfied with the least arbitrary compromise method that can be arrived at.<sup>15</sup>

In most crude oil cost studies, the practice has been the highly arbitrary one of assigning all the joint costs to crude oil, thus exaggerating the apparent cost of oil. What appears to be called for is an agreed standard method of allocating costs. Given this basic standard of comparison, analysts could use as much ingenuity as they liked in applying other methods, the results of which would all be comparable with one another in terms of the standard calculation.

One of the difficulties in agreeing on such a standard method is that the various segments of the petroleum industry have an *ex parte* interest in cost calculations, as an element in their arguments with respect to one public policy or another. The point is well illustrated by the rapidly growing literature on cost allocation generated in connection with the Federal Power Commission's regulation of natural gas field prices.<sup>16</sup> There is an ironical element in the distortion created by loading most gas and gas liquids costs onto oil in crude oil cost studies, at the same time that gas producing companies (many of them major oil companies) are attempting to load as many costs as possible onto gas.

It is not suggested that the heavy loading of costs onto crude oil in the studies reviewed below is in any way dictated by *ex parte* interests. To a large degree it arises simply from a conventional way of dealing with a difficult problem, and from the extremely low commodity value placed on gas in the past. But the existence of *ex parte* interests makes it all the more important that objective analysts have some conventional method of procedure.

Allowing for many formulas, one or the other of two principles—or some compromise between them—dominates most discussion of the subject: (1) the value-of-product approach, and (2) an approach which uses some common physical component, of which Btu's of energy content appears to be the most manageable.

*The Value Approach.*—The discovery and development activities of any particular year, or series of years, give rise to certain estimated additions to reserves of oil and gas, respectively. To these can be applied the current wellhead price, or some estimate of future prices (perhaps discounted) to establish a ratio between the prospective revenues from the two products. This ratio can then be applied to the relevant joint costs as a formula for allocating the costs applicable to each product.

As a device for allocating costs, there is an inherent lack of logic in this formula. As Hodges and Steele say, "Why should the cost of finding gas fall because the market price of crude oil has risen?" At the same time, as Kahn says, "Sales realizations at least objectively reflect the actual respective contributions of the joint products to the joint expenses that produced them in the recent past."<sup>17</sup>

*The Energy-Content Approach.*—The other basic approach is to avoid all price relations, and to link costs to a common physical characteristic—the estimated number of British thermal units (Btu's) contained in new reserves and production of oil, gas, and natural gas liquids, respectively, assigned as well as possible to the categories of discovery, development, and production costs. All liquid and gaseous hydrocarbons can be reduced to this common energy unit; or, conversely, they can all be translated into barrels of crude oil equivalent on the basis of energy content.

While it is an objective measure in a purely physical energy sense, this allocation is weak in the economic sense. Energy in the form of gas at the wellhead is something very different from energy in the form of oil. They are close substitutes only over a limited range, and they have very different economic values at the wellhead, as measured in energy content.

Needless to say, there is bound to be statistical confusion as long as every analyst working with company or industry statistics uses his own conversion factor. If there were a standard industry procedure, followed by all analysts, the statistical picture could be made more orderly. This standard practice would not need to stop analytical ingenuity. But if each cost study were first made in the standard form, other analytic procedures could be presented as deviations from it, and thus be more easily understood and assessed.

One suggestion which has been advanced is to start from a standard Btu cost allocation, and to modify this by some standard value factor in order to increase the economic significance of the cost calculations. There is no easy solution to the cost allocation

dilemma, but some agreement must be sought on useful approaches to the problem.

### *Some Problems of Cost Measurement*

Whatever the cost categories used in analytical studies, costs must be made measurable. Since most petroleum cost studies are designed to show trends over periods of time, the technical problem is to provide units of measurement which permit valid comparisons between different time periods. To do this, it is necessary to have in mind three basic concepts: (1) costs measured in current dollars, (2) costs measured in dollars of constant purchasing power, and (3) costs measured in non-monetary cost units.

*Current Money Costs.*—Raw cost data are recorded in accounting records in terms of dollars. If the prices of cost goods remained the same, the dollar series would provide an adequate measure of cost trends over time—for such items as cost per foot of drilling, cost per well, cost per barrel of added reserves, etc. Since, however, the prices of cost goods do not remain stable, it is necessary to make an adjustment for the changing purchasing power of the dollar.

*Adjusted Money Costs.*—In times of changing price levels, it is necessary to apply some index number of prices in order to convert current prices into “dollars of constant purchasing power.” The conventional index for this purpose is the wholesale price index. But this may be very inaccurate in application to the cost goods of the petroleum industry. (An index of drilling and completion costs has been made by the Cost Committee of the I. P. A. A.) A special purpose index for the prices of petroleum cost goods is needed. Even such an index would have deficiencies due to the changing technical characteristics of the cost goods, such as drilling rigs; but this raises the general problem of price indexes, into which we need not enter.

*Non-monetary Cost Units.*—If there existed a comprehensive series of money prices for all relevant cost factors and an appropriate index for “deflating” prices, we would possess all the information required for any cost study. For example, if the money cost of a foot of drilling were rising, but the “deflated” money cost were falling, we would know that the “real” input of resources into drilling per foot was falling. From this we could deduce improving technology. Or again, if the number of feet of drilling per barrel of new reserves were rising, we could calculate by how much the resource input per barrel of reserves was rising or falling.

However, in the absence of good adjusted money cost series, for some purposes it is expedient to use non-monetary units of measure-

ment. (This is done, for example, by Hodges and Steele in a study which will be reviewed later.) Take a unit of one foot of drilling. From statistical sources, it is possible to relate footage drilled to reserves added. A rise in this ratio is a significant fact, quite apart from the money measure per foot or per barrel. However, the money measure is also needed to disclose other significant facts. In the example just given, the economic significance of rising drilling-foot-cost per barrel of new reserves cannot be judged without knowledge of the adjusted dollar cost per foot.

With an eye on the measurement problems just mentioned, it is possible to identify some serious barriers to accurate and objective cost analysis in the petroleum industry. First, even the cost series in current money terms are defective, being neither comprehensive nor known to be based upon sound sampling techniques. Second, no satisfactory method of translating them into adjusted dollar terms exists. On this account, all money cost data, and the analysis based on them, are suspect. It is a condition of fully acceptable cost studies that these deficiencies be removed.

### III. POSTWAR COST AND AVAILABILITY STUDIES

Cost studies of various sorts are made by individual companies; but, being made strictly for internal use, they are not available for analysis and comparison. Other studies are of a primarily statistical character, based upon publicly available data and referring to the industry at large or to some segment of it rather than to individual companies. It is to studies of this sort that our attention is necessarily limited.

In this chapter, we shall review the principal "cost" studies and "availability" studies that have been made in recent years. A cost study is taken to mean one which is either primarily concerned with cost information and costing techniques, or makes cost a central consideration in determining or discussing some other factor. Costs can be either "money" costs or "real" costs.<sup>18</sup> An availability study is any one of a number of types of studies designed primarily to provide information about supply conditions for oil, gas or both. Included in this group are studies and data which go only part way in answering the broader availability questions, *e.g.*, drilling, reserve, productive capacity, and production information. Also included are studies which extend trend analysis into predictions of supply and demand. To a considerable degree cost and availability studies overlap, as for example when cost trends are used to forecast future supplies.

Any attempt to review the studies made on finding and development costs since the War of necessity requires considerable selectivity. The criteria used in choosing these studies were: (1) their general applicability to domestic finding, developing and producing costs; (2) their completeness as to rationale and techniques of analysis; (3) the degree to which they are relied upon by the industry and others; and (4) their apparent insight into one or more of the problems of cost analysis in the industry. Several studies not reviewed in detail will be mentioned on specific points.

Cost studies can be classified under three headings: (1) those providing primary data, with or without analysis of these data; (2) those utilizing primary data from other sources and placing most of their emphasis on techniques of handling the data and on the conclusions derived therefrom; and (3) those specifically designed for natural gas regulatory problems and in which the emphasis is placed on gas costs alone rather than on the costs of oil and gas or of oil alone. These latter studies are included because they contain some of the newest innovations in cost analysis and can, perhaps, give clues to solving the more general problems.

Availability studies also fall into three groups: (1) those providing primary historical data about energy supply and demand, or some facet thereof; (2) those providing forecasts of energy supply and demand, utilizing historical data or other techniques but not primarily oriented toward economic factors; and (3) those studies which provide techniques for estimating future energy supply and demand and which put major emphasis on economic factors. This last classification overlaps with the number 2 category of cost studies.

#### *Historical Primary Data*

The vast mountain of statistical information reporting what has happened in the oil and gas industry need not be treated here in any detail. The best general references are as follows: (1) American Petroleum Institute, *Petroleum Facts and Figures*, issued about every two years; (2) American Gas Association, *Gas Facts*, issued annually; (3) the *Oil and Gas Journal*; (4) *World Oil* magazine; and (5) *Minerals Yearbook, Vol. II: Fuels*, issued annually. Both primary and secondary data are found in each of these.

In order to organize the statistical information in a way that would make it useful for a study of finding, development, and producing costs, the following discussion will outline the pertinent data and comment briefly on their use.

*Drilling.*—Since both finding and development costs hinge in

part on the amount of drilling done during a given time period (and usually related to the reserves added by such drilling), various aspects of drilling activity are important. Historical series are available on the total number of wells drilled; the total broken down by end result, *i.e.*, oil, gas, dry, etc.; total footage and average depth by end result; and the above breakdowns by states and by areas within states in some cases. In addition, the American Association of Petroleum Geologists annually reports information on exploratory drilling which includes classification of exploratory wells by *ex ante* plans (new field wildcat, outpost, etc.), by end result, by total and average footage, ranges of quantities of reserves uncovered, and by state or district. From private sources it is also possible to obtain data on the number of drilling rigs operating and the number "stacked."

From such information it is possible to compute various ratios and relationships, such as success ratios for total and exploratory drilling over time, the number of feet required to be drilled to obtain a successful well, and the number of gas wells or amount of gas well footage relative to oil wells and footage.

In addition there is information available on rotary versus cable tool drilling, contract versus company drilling, offshore drilling and some other minor categories. In some instances these might be useful in computing costs.

*Reserves.*—Reserve information is available for proved, recoverable reserves from the American Petroleum Institute and American Gas Association and is broken down by type of reservoir for gas (*i.e.*, associated, non-associated, dissolved), by stage of discovery (new discoveries, extensions and revisions), by state annually, and by major fields annually (from the *Oil and Gas Journal*). Crude oil, natural gas liquids, and natural gas reserves are reported separately. Because of the masking of details by aggregation, and because of some rather restricted definitions, reserve data are extremely difficult to interpret and manipulate.

From time to time estimates are made of total primary versus total secondary reserves, and the Interstate Oil Compact Commission annually reports primary and secondary reserves underlying stripper wells in the U. S.

With drilling and reserve data it is possible to calculate assorted types of ratios such as: reserves (either barrels, Mcf's., or Btu's) discovered per well or foot drilled; discoveries and extensions and revisions per well or foot; reserves per dry hole, per exploratory well, per producer; moving averages of any of these ratios; and many others. Such analysis is severely limited by the shortcomings of

reserve data. Those studies aimed at discovering costs in "real" terms rely heavily on reserve and drilling information.

*Production.*—Since producing costs are in large part variable costs, data on physical output of oil and gas are important information. Production figures are available from the Bureau of Mines, state agencies and trade journals by type of commodity (*i.e.*, oil, gas, NGL); by state and region within some states; by days, and annually. *Potential* production information is available irregularly. The most important recent source is a report by the National Petroleum Council on "Proved Petroleum and Natural Gas Reserves and Availability 1960." Information is also available on oil production from flowing and from pumping wells, and on the number of wells in these categories. In addition, some information is available from the I. O. C. C. on secondary recovery projects and on stripper well production.

Production information when combined with drilling and reserve data gives some measure of per well efficiency, payout periods, production "availability," reserve life indices, gas-oil ratios, and the like.

*Supply, Demand, and Prices.*—Information on consumption of crude oil and refined products is available by product, monthly, by state. Data on movements of crude and products, intrastate, interstate, and in foreign trade are regularly released by the Bureau of Mines. Similar information on gas consumption by end use can be obtained. Wellhead values for oil and gas are computed periodically and oil field posted prices can be found in trade journal and reporting services. Short-term consumption (called "market demand") forecasts are made by the Bureau of Mines to assist states in conservation regulation. Finally, crude oil and product supply data are available by source of supply, including domestic production, domestic stocks, and imports.<sup>19</sup>

These types of information are particularly helpful in determining secondary cost effects which work through governmental controls of production, well spacing, and other conservation practices, as well as through governmental activity in the areas of import quotas, tariffs, and taxation. Supply and demand information also relates to costs through prices.

*Financial Information.*—Somewhat removed from the immediate problems of cost determination and energy availability is the information available on industry profits and on capital expenditures in finding, developing and producing oil and gas. Industry-wide figures on these aspects are reported regularly by the Chase-Manhattan Bank, by McGraw-Hill in its plant and equipment expenditure data,



by the U. S. Department of Commerce in its expected plant and equipment spending and in its construction data, and by the Census Bureau in its Census of Mineral Industries.<sup>20</sup>

To the extent that profits and capital outlay figures reflect cost-price relationships and determine areas of effort within the industry and within a company, such data find an important use. Decision-making in American business is still an area of unknowns, but it is known at least that the stuff from which decisions come is the whole array of cost and revenue series.

*Miscellaneous Information.*—The greatest dearth of information in the broad category included here under historical primary data lies in the exploration phase of the business other than exploratory drilling. Very little reliable information is available on geological and geophysical work, lease acquisition, scouting, and the like. The only component of exploratory costs reported with any accuracy is exploratory drilling. The I. O. C. C. until recently published the number of geophysical crews working, by states and by type of crew. The Independent Petroleum Association of America annually reports estimates of acreage under lease for oil and gas, by states. There is no breakdown between productive and unproductive acreage, nor information on surrendered or acquired leases. Membership lists in professional groups are the only clues to geological, scouting, or other costs related to the acquisition of land.

#### *Forecasts of Availability—Non-Economic Emphasis*

Forecasts of energy needs and supplies, already plentiful, are increasing in number. The seriousness with which some of these studies have been made points up a growing concern for future supplies of fuel. At best, such forecasts are intelligent estimates of what will happen in the future, *given certain assumptions about technology and economic conditions*. Since assumptions about developments in technology are among the most precarious, forecasts using these assumptions are vulnerable. Nevertheless it is worthwhile to review briefly some of the major efforts along these lines, since in every instance certain cost assumptions must be made, explicitly or implicitly.

At the top of the list is the recent survey by Schurr and Netschert, for Resources For The Future, which reviews the historical patterns of supply and demand of all types of energy and projects supply and demand to 1975.<sup>21</sup> This is a vital, basic statistical study designed to provide the foundation upon which other studies may be built.

The assumptions used in estimating future energy consumption

include the following: "(a) that the average price of all energy resources together does not change significantly relative to the general price level, and (b) that the price relationships among different energy sources remain essentially unchanged." It is further assumed that past energy consumption is not related in any overall sense to general economic growth indicators, nor has the growth rate been regular.<sup>22</sup> The last assumption requires that individual fuels and uses be examined singly, but in the presence of all other factors.

The basis for estimating future supplies is an interest in those energy resources "that can be exploited at approximately current costs with foreseeable technological advancement by 1975."<sup>23</sup> After reviewing virtually every study of future oil and gas supplies, this study concludes ". . . that the indicated total domestic availability of crude oil in the United States in 1975, at no appreciable increase in constant dollar costs, is on the order of 6 billion barrels."<sup>24</sup> This compares to an estimate by the National Petroleum Council of crude oil productive capacity of about 3.8 billion barrels annually as of the beginning of 1960.<sup>25</sup> Schurr and Netschert add another 1 billion barrels of available natural gas liquids by 1975<sup>26</sup> which compares to a current annual availability of about 725 million barrels.<sup>27</sup>

This study is stressed because it is unique in several ways. First, the estimates of future availability are quite high relative to other estimates both in and out of industry. Second, it is assumed that real costs in the future will not rise significantly, if at all. This is contrary to industrial predictions of rising real costs. Third, Schurr and Netschert provide a rather complete review of all the literature on the subject of energy supply and demand up to 1958 and are particularly thorough in oil and gas. Their reviews are more than summaries. They provide a critical appraisal of each and very useful comparisons with other similar studies. Fourth, this is the first time that a thorough and systematic job of data collection has been done on historical information and on studies which make estimates of the future. And last, this is the first time that detailed analysis has been performed on the relationship of the many, many variables in and out of the industry which influence long-term supply and demand. The footnotes and table references in this volume provide the most complete bibliography on oil and gas availability that exists. Part of this bibliography is included in the appendix of this study.

One of the most recent availability studies made is *Fossil Fuels in the Future*, by Milton F. Searl for the U. S. Atomic Energy Commission.<sup>28</sup> This study is concerned with U.S. and other free world energy requirements and availability for the years 1980 and 2000. It takes

a rather broad view of the energy picture and makes some interesting comments on costs and prices.<sup>29</sup>

Domestic fossil-fuel resources are also large in comparison to energy requirements. An estimated 28.57 Q remain to be produced of which 5.57 Q are in the low-cost category (not over 25 percent increase in real prices). Requirements during the remainder of the century are 3.81 Q; however, the distribution of fuel resources with respect to fuel consumption patterns is poor.

This study does not place great emphasis on energy requirements by fuel type since technological developments may well have radically altered consumption patterns before the end of the century. If, however, the possibility of such technological changes is ignored, the present world trend toward an increased use of fluid fuels can still be met. More specifically, it is estimated that over 63 percent of the world's fossil-fuel requirements can be produced from petroleum and shale oil in the year 2000. This compares with less than 44 percent of the world fossil-fuel requirements produced from these sources in 1958.

The real cost per unit of producing fluid fuels in the year 2000 should be less than 50 percent above 1958 costs. Such an increase should not prove particularly burdensome. The cost of fossil fuels, at mine and wellhead, is only a small part of national income, and thus even a large increase in these costs over a long period of time will not seriously impair economic growth. In the United States, fossil-fuel costs, at the mine and wellhead, are less than 2 percent of national income. Prices to consumers should increase by considerably less than costs at the point of production since a large part of the cost to the consumer is in processing, transporting, and marketing costs, which should not rise significantly in terms of real dollars.

The liquid hydrocarbon situation is less favorable. Without imports, amounts of reserves almost equal to the total of the low- and medium-cost increments would be consumed by 1980. Amounts in the high-cost category would supply less than an additional ten years requirements. Actually, it is doubtful if the remaining reserves could be found and produced as fast as this, since oil discovery is a function of both effort and time, and since there are maximum rates at which oil reserves can be produced without reducing ultimate recovery.

In all likelihood, large-scale production of medium-cost oil shale would be started long before medium-cost oil reserves were exhausted. In fact, even if oil imports are not cut off, it is quite likely that shale oil will be produced commercially before 1980. Oil shale reserves in the medium-cost increment category are 2.32 Q. Combined with the low and medium-cost increment oil reserves this gives a total of 2.98 Q available to meet the demand of 1.70 Q to the end of the century. Demands could be met without imports, but large-scale capital investment in oil shale facilities would be necessary.

Low and medium incremental-cost reserves of natural gas would suffice until the early 1980's, and high-cost natural-gas reserves would be exhausted shortly before the turn of the century, subject, as with oil, to some qualification regarding discovery rates.<sup>30</sup>

Searl thus comes to approximately the same conclusions about cost as a factor in future supply as Schurr and Netschert—namely, that technology will play a decisive role here. Searl reviews some additional studies, and these references are carried in the bibliography also.

Statements by various experts on specific energy resources are found in *Hearings on Energy Resources and Technology* held before the Joint Economic Committee of Congress. Of particular interest again are the assumptions about costs, technology, and economic conditions in the specific forecasts which were made for oil and gas.<sup>31</sup>

In late 1960, the Joint Committee on Atomic Energy of Congress published a five-volume report on *Background Material for the Review of the International Atomic Policies and Programs of the United States*.<sup>32</sup> This is referred to as the Second McKinney Report and includes the latest estimates made on energy availability. A study by W. C. Schroeder reinforces the optimism about total energy availability in the U. S. He feels that during this century domestic supplies are ample, although he feels the cost differential which exists between U. S. and foreign crude and which will get even wider, may dictate greater use of foreign supplies. He makes an interesting observation on the concept of reserves that has been indicated in other parts of this study.

Since petroleum is such a vital energy commodity there has always been a strong desire to know the total resources of a country or area in order that due warning could be raised when there was imminent danger of exhaustion. This conception is incorrect, and exhaustion of petroleum from a very large country is virtually impossible. New places can always be found to explore and very likely some oil will be found. Furthermore, fields which no longer flow prolifically can be worked by secondary recovery methods and more oil can be obtained. *While the exhaustion of oil is not a threat, the question of the cost of finding and producing oil is of real concern.* Therefore, any attempt to evaluate the potential reserve of a country must be concerned with reserves that can be found and produced at reasonable costs. (Emphasis supplied.)<sup>33</sup>

In this same Joint Committee Report, the Department of the Interior has estimated future availability of oil and gas. The discussion of the impact of technology and economics is particularly pertinent to the discussion here.<sup>34</sup>

The relationship between price and production of petroleum is shown in Table 7. The responses shown have been computed by estimating new oil wells needed to achieve the production noted, estimating the associated total footage drilled, and estimating the total wellhead revenue from oil and gas associated with this footage drilled.

Historically the United States and Canada have had about a third more wells than are necessary to achieve the desired producing capacity

and to prove reserves in the most economic manner. In Table 7 this excess of wells is presumed to have been eliminated by 1975. If the historical pattern of excess wells persists, production in 1975 and 2000 will be lower than the figures shown by about 10 per cent at the low end of the price range and by about 20 per cent at the high end. The 1975 and 2000 figures presume also that the 40 per cent excess industry capacity described in the next section will be reduced to 10 per cent.

TABLE 7. — UNITED STATES CRUDE PETROLEUM PRODUCTION AT ALTERNATIVE PRICE LEVELS AND STAGES OF TECHNOLOGY

Well Price in 1959 Dollars	Millions of barrels of petroleum		
	1959 Actual	1975 Expected	2000 Likely
3.00 a barrel	2,570	3,800	3,400
¼ less (2.25)	2,400	3,300	3,000
¼ more (3.75)	3,200	4,500	3,950
½ more (4.50)	3,400	5,300	4,500

Finally, there are some new estimates of availability from a study by the Stanford Research Institute, prepared for the F. P. C. Permian Basin Area Rate Hearings.<sup>35</sup> In this study the following assumptions were made:

1. There will be a generally high level of economic activity.
2. The international cold war climate will continue but without a major war.
3. There will be no radical advances in technology to change the basic fuel consumption trends.
4. Individual fuel supplies will be available to meet the projected requirements.
5. There will be no change in governmental policy which would further restrict the consumers' freedom of choice as to type of fuel desired, or would change the relative economic attractiveness of each fuel.
6. Normal weather and water conditions will prevail.<sup>36</sup>

The all pervasive nature of the assumptions indicates that different circumstance would greatly alter the outcome. Assumptions 4 and 5 are of interest to us, since number 4 has implicit in it certain cost-price relationships among fuels, and number 5 is not clearly stated since government policy can be one of inaction as well as action, thus causing changes in attractiveness of a fuel or in consumers' freedom of choice.

Since the completion of this study, two important papers have appeared, one by Mr. A. D. Zapp of the Geological Survey, *Future Petroleum Producing Capacity in the United States*, and one by Mr. C. L. Moore of the Department of the Interior, *Method for*

*Evaluating U. S. Crude Oil Resources and Projecting Domestic Crude Oil Availability.*<sup>37</sup> Mr. Zapp proposes data on the trend of producing capacity as the guide to future availability of oil, in preference to proved reserves data. Mr. Moore, using historical data on additions to reserves and percentage recovery, makes elaborate mathematical projections of these data into the future. Both rely heavily on the National Petroleum Council report of 1960.<sup>38</sup>

The studies referred to here, combined with those which were the predecessors of these, bring together an impressive amount of expert knowledge regarding the question of oil and gas availability. Most of these studies make some predictions about cost conditions, since this is a major determinant of availability. If these studies are read more or less chronologically, there appears to be a definite change of attitude with regard to oil and gas finding and development costs. The earlier studies are rather pessimistic about cost and make estimates based on assumptions of rapidly rising real costs. The more recent studies are more optimistic, for while they do not actually forecast decreasing unit costs, they look to technology to hold costs in check. Two major aspects of technology appear to account for the increased optimism. One is the relatively stable contract drilling rates which must reflect, in part at least, relatively constant costs per foot, even in the face of increasing depths. The other is the hope now held out for some of the new techniques for secondary recovery, and their success in increasing proved reserves by raising the percent of oil in place that is recovered. A look at the cost studies made most recently seems to support this guarded optimism.

#### *Availability Studies—Economic Emphasis*

While all the studies reviewed above make comments on, and assumptions about, economic variables influencing the availability of oil and gas, none of them put as much emphasis on these aspects as is felt necessary by some experts in this field. Because of this, we have somewhat arbitrarily separated two major availability studies from the rest to designate them as having economic emphasis. These are the studies by W. B. Davis, "Future Petroleum Producing Capacity of the United States," and P. S. McGann "A Method of Projecting U. S. Petroleum Supply."<sup>39</sup>

These papers are quite similar in objectives and techniques, and, in fact, McGann builds on what Davis has done. Both of the studies place major emphasis on cost, price and other economic factors. Both, however, use cost data developed by others and do not attempt to arrive independently at this information. Both are primarily con-

cerned with methodology, and both minimize the complications introduced by gas and gas liquids.

McGann has built a model which, with given assumptions, information, and targets, will tell what has to be done to achieve these targets. Starting with a target of crude oil production needed or desired at some date in the future, it is possible to determine a price that will bring forth that much production at the target date. This procedure is also reversible. A target price for the future can be chosen, and the model will compute the amount of productive capacity available in the target year.

McGann's system of determining the inputs needed to get a given output of oil at some target date in the future has as its key the number of new oil wells needed. Critical to this computation are the assumptions of (1) "the computed gross annual decline rate of capacity at 10.4 percent of production," and (2) "the average addition to capacity per new well whether projected at a constant 34.2 barrels/day or at a decreasing value."<sup>40</sup> The rate of decline of capacity is seen to be the major factor necessitating new wells being drilled. McGann notes that the existence of substantial excess producing capacity that can be drawn on is of major importance in keeping down the oil price needed in 1965 or 1975 to generate adequate capacity.

Another set of critical assumptions centers on the forecasts for demand and for imports. Relatively small changes in assumptions for demand can cause substantial changes in new wells needed. Equally important are the assumptions governing regulations for the spacing of wells. McGann notes the considerably lower price that would be needed to bring forth some given target of production, if well density were only half as great (which is probably a reasonable spacing pattern in terms of engineering efficiency). More study on spacing is urged.

The concept of "oil price needed" that McGann uses is merely another way of describing the field revenue or income necessary to furnish adequate incentives to producers to drill the required number of wells. The price needed is quite close to the "replacement cost" projected for the target dates, given the same assumptions. McGann, using reserve and well data from published sources as the basis for "barrels found" determines the reserves that must be discovered. To the derived price, well, and reserve information he adds cost information obtained from Anderson, Megill, and the Joint Association studies.<sup>41</sup> This gives a series of relationships such as replacement cost per barrel and replacement cost divided by the oil price needed.

The rise in costs per barrel, it is noted, is due primarily to the rising number of wells required to discover and develop a given quantity of oil. To summarize, this methodology, given a number of assumptions including an amount of production at some target date, can be used to compute the price needed (because of cost considerations), the wells needed, and the reserves needed to provide the production. As McGann himself points out, the critical questions to be raised are more likely to be with the assumptions than with the methodology.

The Davis paper, which preceded McGann's by about two years, also used a mathematical model "to predict the future crude oil producing rates of the U. S. under several possible conditions." Davis is particularly concerned with the point in time which will mark the peak of U. S. productive capacity and the beginning of the decline. This date he marks as about 1967, given certain assumptions. "The two principal factors affecting ultimate volume of crude to be found in the U. S.," he notes, "are drilling returns (barrels of reserves developed per foot drilled) and crude oil price."<sup>42</sup> Particularly lacking in earlier studies, Davis observes, is the inclusion of economic factors.

Davis' most important assumption is that of a declining return (in terms of barrels found) compared to drilling effort as more reserves are developed. McGann makes the same assumption. With a given set of economic conditions, Davis notes that such a decline will eventually make drilling unprofitable. The important cost variable used in Davis' calculations is derived from a graph based on the 1953 Joint Association Survey data which relates average drilling and completion costs to average well depths. The upshot of the calculations is that, even with the most optimistic assumptions, U. S. productive capacity of availability will reach a peak between 1963 and 1973 and will drop rapidly from that peak. The height of the peak itself may vary, depending on certain conditions, but availability will turn down.<sup>43</sup>

The studies of McGann and Davis represent interesting first efforts to include important economic variables in availability calculations—variables which were largely ignored or minimized in earlier studies. The importance of these variables is dramatically illustrated in both studies, and new studies seem to be putting more emphasis on cost and price.

#### *Cost Studies with Primary Cost Data*

Many articles have been written on the cost of finding and de-



veloping petroleum resources. A careful collating of a number of these articles indicates an almost complete reliance on three or four basic sources. This section will review only the fundamental studies, although a number of other studies using the same basic data are included in the bibliography.

The *1958 Census of Mineral Industries* reports on activities for establishments primarily engaged in operating oil and gas field properties.<sup>44</sup> Included are items related to exploration for oil and gas, to the drilling, completing and equipment of wells, and to other activities incident to making oil and gas marketable at the producing property. The infrequent editions of the *Census* uniformly exclude a number of expenditure items. Among the important items omitted are: data on depreciation or obsolescence amounts or rates; data on leasing costs, including rentals, bonuses, royalties, etc.; and data on some overhead items and several minor expenses which are significant in the aggregate. There is little attempt to distinguish clearly among costs incurred for exploration, development, primary production, and secondary production, although some segregation is made. Also there is no attempt to report costs on a per-barrel basis, either for production or for reserves. Table III-A indicates the types of cost information available. Particularly useful are the data on costs by type of well, for 1939, 1954, and 1958. No attempt has been made to deflate the costs to some common base. The techniques and methods of analysis are described in some detail so that the reader can satisfy himself on that score. Information is also given on the degree of completeness. There is, however, no analysis in the sense of evaluations or conclusions.

By far the most widely quoted source of cost data in the petroleum industry is the *Joint Association Survey*, a study undertaken cooperatively by the American Petroleum Institute, the Independent Petroleum Association of America, and the Mid-Continent Oil & Gas Association. The survey has been undertaken three times—1953, 1955-56, and 1959—although only the data for 1956 and 1959 are considered comparable. Reported in the 1959 *Survey* are the number, footage, per well costs, and per foot costs for oil wells, gas wells and dry holes by depth, by state and by region. The survey was done using sampling techniques which are not explained in any detail. Generalizations about the characteristics of the total universe are made by comparing the cost and depth information received on questionnaires with information found in the *Oil and Gas Journal* on the depth distribution by state and by type of well.

TABLE III-A  
CENSUS DATA ON DRILLING AND EQUIPPING COSTS

		1958 <sup>1</sup>	1954 <sup>1</sup>	1939
Number of wells drilled, total <sup>2</sup>		46,954	52,327	22,560
Oil wells <sup>3</sup> .....		23,754	28,879	17,263
Gas wells <sup>3</sup> .....		4,526	3,885	1,594
Dry holes <sup>4</sup> .....		16,351	16,422	3,703
Service wells <sup>4</sup> .....		2,323	3,141	(NA)
Footage drilled, total	1,000 <sup>5</sup>	193,626	210,801	72,191
Oil wells .....	do	92,663	117,897	55,837
Gas wells .....	do	24,584	18,510	4,439
Service wells .....	do	3,542	4,181	(NA)
Av. footage drilled per well, all wells	feet	4,124	4,029	3,200
Oil wells .....	do	3,901	4,082	3,234
Gas wells .....	do	5,431	4,764	2,785
Dry holes .....	do	4,455	4,276	3,218
Service wells .....	do	1,524	1,331	(NA)
Cost of drilling & equipping wells, total <sup>5</sup>	\$1,000	2,424,798	2,306,947	404,904
Per well .....	do	51.6	44.1	17.9
Per foot .....	\$1	12.52	10.94	5.61
Oil wells .....	\$1,000	1,310,523	1,449,654	330,547
Per well .....	do	55.2	50.2	19.1
Per foot .....	\$1	14.14	12.30	5.92
Gas wells .....	\$1,000	440,833	263,619	20,926
Per well .....	do	97.4	67.9	13.1
Per foot .....	\$1	17.93	14.24	4.71
Dry holes .....	\$1,000	649,342	565,745	53,431
Per well .....	do	39.7	34.5	14.4
Per foot .....	\$1	8.91	8.06	4.48
Service wells .....	\$1,000	24,100	27,929	(NA)
Per well .....	do	10.4	8.9	(NA)
Per foot .....	\$1	6.81	6.68	(NA)
Cost, excluding amount paid or due contractors, total	\$1,000	1,419,729	1,307,142	256,923
Oil wells .....	do	837,837	882,471	213,807
Gas wells .....	do	271,357	158,102	12,366
Dry holes .....	do	297,376	251,697	30,750
Service wells .....	do	13,159	14,872	(NA)
Cost of drilling, total <sup>6</sup>	\$1,000	733,444	702,346	131,718
Oil wells .....	do	342,629	387,299	98,228
Gas wells .....	do	139,973	90,510	6,344
Dry holes .....	do	245,331	217,793	27,146
Service wells .....	do	5,511	6,744	(NA)
Cost of casing, total <sup>7</sup>	\$1,000	384,487	344,683	75,317
Oil wells .....	do	244,930	263,011	67,730
Gas wells .....	do	86,436	46,485	4,347
Dry holes .....	do	48,276	30,419	3,240
Service wells .....	do	4,845	4,768	(NA)
Cost of equipment for flowing & pump- ing & production derrick, total <sup>8</sup>	\$1,000	301,798	260,113	49,888
Oil wells .....	do	250,278	232,161	47,849
Gas wells .....	do	44,948	21,107	1,675
Dry holes .....	do	3,769	3,485	364
Service wells .....	do	2,803	3,360	(NA)

		1958 <sup>1</sup>	1954 <sup>1</sup>	1939
Amount paid or due contractors for				
drilling & equipping wells, total ....	do	1,005,069	999,805	147,981
Oil wells .....	do	472,686	567,183	116,740
Gas wells .....	do	169,476	105,517	8,560
Dry holes .....	do	351,966	314,048	22,681
Service wells .....	do	10,941	13,057	(NA)

N. A. — Not available.

<sup>1</sup> Includes the number, footage, and costs for offshore wells for which statistics are shown separately in other census data.

<sup>2</sup> Represents wells drilled which were completed during the year, wells completed during the year although begun in the previous year, and wells drilled and abandoned before completion during the year.

<sup>3</sup> For wells that produced both oil and gas, respondents were requested to classify the wells according to the more valuable total product. They were requested to classify "distillate" wells as oil wells if the value of all liquids produced was greater than the value of gas produced; but otherwise to classify them as gas wells.

<sup>4</sup> Dry holes represent wells drilled and abandoned without commercial production during the year. Service wells include gas-injection, water injection, and brine-disposal wells. The distinction between dry holes and service wells was not made uniformly by all respondents; hence the combined figures for dry holes and service wells in a State are somewhat more significant than the separate figures for each class.

<sup>5</sup> Represents only the tangible costs specified; respondents were asked to exclude taxes, interest on investment, overhead costs, etc.

<sup>6</sup> Represents the cost of labor, supplies, water, fuel, and power used in such operations as: moving on to location all equipment and supplies incidental to operations; excavating for and building derrick foundation; digging slush pits; erecting and wiring derricks; building loading and pipe racks; laying fuel and water lines; rigging up; drilling hole; making straight-hole tests or surveys; coring; well logging and core analysis; testing formations; mud conditioning; reaming; running casing, screen, and liner; cleaning out, bailing, and swabbing; fishing; repairing and maintaining rig and derrick; tearing down rig; dismantling derrick and racks; and moving equipment off location. It includes tool charges and rentals, but excludes the value of materials salvaged after use and the cost of the drilling derrick if it was left over well for production after completion.

<sup>7</sup> Includes the cost of delivering and installing equipment. Excludes the value of equipment that was salvaged and used again but includes the cost of salvaging.

<sup>8</sup> See footnote 7. Includes tubing, wellhead fittings, gas traps, flow tanks, etc., drilling derricks retained over well after completion, and special-production derricks.

Source: U. S. Bureau of the Census, 1958 *Census of Mineral Industries* (Washington: Government Printing Office, 1960), pp. 13B-22 and 13B-50.

Whether "scientific" sampling can be carried out successfully is open to question, particularly in light of the highly fluid character of the universe itself. The joint associations maintain that their survey is representative but certainly not beyond improvement.<sup>45</sup> While it may be granted that scientific sampling in this type of situation is difficult, it would still be helpful to those attempting to evaluate the *Survey* if more information on data collection were available.<sup>46</sup>

Tables III-B and III-C give the pertinent summary data presented in the survey. In table III-C no attempt is made to adjust the 1959 figures for changes in the value of money. Expenditures in the survey include charges for drilling and equipping wells up to and including the "Christmas tree," but exclude exploration (except explora-

tory drilling), leasing, and some production costs. Thus, except for the inclusion of some production costs in the Census data the two are fairly comparable as to the types of costs covered. Costs are also broken down between tangible and intangible (although there is no description of what items are included in each category.) Inconsistency within the industrial accounting procedures places some doubt on the usefulness of this breakdown.

The figures in Table III-B were estimated from the information obtained in a survey embracing 240 producers both large and small, who accounted for 27 percent of all wells and 37 percent of footage drilled in 1959.

TABLE III-B

## SUMMARY OF 1959 DRILLING OPERATIONS AND EXPENDITURES

	<i>Oil</i>	<i>Gas</i>	<i>Dry</i>	<i>Total</i>
Wells Drilled	25,413	5,049	19,101	49,563
Footage Drilled (000)	96,931	27,585	80,996	205,512
Expenditures (000)	\$1,321,426	\$508,895	\$820,775	\$2,651,096
Average Depth per Well	3,814	5,464	4,240	4,146
Average Cost per Well	\$52,000	\$100,700	\$43,000	\$53,500
Average Cost per Foot	\$13.63	\$18.45	\$10.13	\$12.90

Source: A. P. I., I. P. A. A., M. C. O. G. A., *Joint Association Survey*, 1959.

TABLE III-C

## COMBINED FIGURES FOR ALL PRODUCING WELLS (OIL AND GAS) AND DRY HOLES FOR 1956 AND 1959

	<i>Productive Wells</i>		<i>Dry Holes</i>		<i>Total Wells</i>	
	<i>1956</i>	<i>1959</i>	<i>1956</i>	<i>1959</i>	<i>1956</i>	<i>1959</i>
Wells Drilled	35,280	30,462	21,845	19,101	57,125	49,563
Footage						
Drilled (000)	143,611	124,516	88,563	80,996	232,174	205,572
Expenditures						
(mills.)	\$1,959	\$1,830	\$909	\$821	\$2,868	\$2,651
Av. Depth	4,071	4,088	4,054	4,240	4,064	4,146
Av. Cost per						
Well	\$55,600	\$60,100	\$41,600	\$43,000	\$50,200	\$53,500
Av. Cost per						
Foot	\$13.64	\$14.70	\$10.26	\$10.13	\$12.35	\$12.90

Source: A. P. I., I. P. A. A., M. C. O. G. A., *Joint Association Survey*, 1959.

In addition to the summary tables, the *Survey* breaks drilling down by state (or areas within a state), by depth range, and for oil wells, gas wells, dry holes, and total wells. The number of wells and footage are reported for each of these categories, and for productive wells costs are divided between tangibles and intangibles.

TABLE III-D  
U.S. OIL AND GAS PRODUCING INDUSTRY  
ESTIMATED EXPENDITURES AND RECEIPTS  
(Millions of Dollars)

EXPENDITURES	1955	1956	1959
Exploration:			
Dry Hole Costs	\$ 774	\$ 909	\$ 821
Lease Acquisition	651	561	554
Geological & Geophysical	306	360	320
Lease Rentals			193
Other	263	287	124
Total	<u>\$ 1,994</u>	<u>\$ 2,117</u>	<u>\$ 2,012</u>
Development:			
Producing Wells	\$ 1,826	\$ 1,959	\$ 1,830
Equipping Leases	426	477	483
Total	<u>\$ 2,252</u>	<u>\$ 2,436</u>	<u>\$ 2,313</u>
Production:			
Producing Costs	\$ 1,183	\$ 1,331	\$ 1,450
Production Taxes	258	278	316
Ad Valorem Taxes	166	169	192
Total	<u>\$ 1,607</u>	<u>\$ 1,778</u>	<u>\$ 1,958</u>
Overhead:			
Exploration	\$ 189	\$ 208	\$ 183
Development	197	212	181
Production	232	252	261
Total	<u>\$ 618</u>	<u>\$ 672</u>	<u>\$ 625</u>
<u>Total Expenditures:</u> *	<u>\$ 6,471</u>	<u>\$ 7,003</u>	<u>\$ 6,908</u>
RECEIPTS:			
Oil and Gas Production**	\$ 6,671	\$ 7,095	\$ 7,676
Other Lease Revenue	23	24	26
Royalty Payments Received	178	201	228
Total Receipts	<u>\$ 6,872</u>	<u>\$ 7,320</u>	<u>\$ 7,930</u>

\* Exclusive of federal, state and local income taxes, payments of interest or principal on debts, or payments to owners as return on their investment in the business.

\*\* Represents total oil and gas production income, less 15% royalty payments.

Source: American Petroleum Institute, Independent Petroleum Association of America, and Mid-Continent Oil and Gas Association, *Joint Association Survey (Section 2); Estimated Expenditures and Receipts of U. S. Oil and Gas Producing Industry, 1959 (1961)*, mimeo.

Section 1 of the Joint Association Survey for 1959 was limited to the costs of drilling and equipping wells. In a recently issued Section 2, the data are expanded to include all phases of exploration cost and development as well as production costs. The summary figures are presented in Table III-D. The precise character of the statistical sample from which the figures were blown up to national scale is not stated. But it is said that the sample includes producers receiving 62.2 percent of total oil and gas revenues, and that the results are a summation of calculations made for each of 13 size groups.

As to the scheme of classification, it is to be noted that all dry hole costs are assigned to "exploration" and all producing well drilling costs to "development."

A third series of reports on costs comes annually (or nearly so) from the American Association of Oilwell Drilling Contractors.<sup>47</sup> Drilling and completion costs are aggregated to get figures on (1) average contract cost per foot, and (2) average total cost per foot. No other detail is given except for index numbers showing changes in labor costs, equipment costs, miscellaneous costs, total rotary drilling costs, drilling prices (footage basis), average drilling time (days), and rate of penetration. The A. A. O. D. C. sends questionnaires to drilling contractors and to producing companies to get drilling and completion costs, respectively. The figures reported are perhaps better characterized as "representative" than as "average." Table III-E shows the type of information given in the last report, which reports drilling contractor footage rates, by region. Cost coverage is being expanded to include other items in the 1961 survey. The average *total* cost per foot reported by the A. A. O. D. C. for 1955 was \$13.50, compared to \$12.35 reported by the Joint Association Survey for 1956. Unfortunately, no detailed explanation is given of the statistical techniques used.

TABLE III-E  
ANNUAL SURVEY OF ROTARY DRILLING FOOTAGE PRICES  
RECEIVED BY CONTRACTORS  
(Exclusive of Day Work Charges)

Area	1957	1958	1959	1960*
	Average Price Dollars Per Foot	Average Price Dollars Per Foot	Average Price Dollars Per Foot	Average Price Dollars Per Foot
Alabama	4.92	-----	-----	-----
Arkansas	2.41	2.74	3.02	2.02
California	3.90	4.18	4.58	4.30
Colorado, except 4 Corners	3.23	3.32	2.79	2.55
Four Corners	4.57	5.30	5.08	4.76
Illinois-Indiana-Kentucky	3.36	3.24	3.29	3.26
Iowa and Missouri	-----	4.50	4.50	4.44
Kansas	3.36	3.30	3.17	3.26
North Louisiana	4.55	4.08	4.45	3.66
South Louisiana—Land	4.40	3.88	3.82	4.06
South Louisiana—Inland Waters	4.25	3.80	3.75	3.53
South Louisiana—Offshore	12.00	11.95	9.94	9.11
Michigan	-----	-----	5.10	5.03
Mississippi	5.11	4.68	4.67	4.42
Nebraska	2.59	2.35	2.21	2.61
North Dakota and Montana	5.49	4.98	4.71	4.12
Oklahoma, except Panhandle	4.74	4.18	4.75	4.41
Pennsylvania and Ohio	6.32	6.56	6.28	5.38
Texas Upper Gulf Coast	3.18	3.39	3.57	3.24
Texas Middle Gulf Coast	2.67	2.50	2.65	2.88
Texas Lower Gulf Coast & Southwest Texas	3.04	3.02	2.91	2.87
West Texas & Southeast New Mexico	6.00	5.35	5.49	5.67
West Central Texas	3.54	3.43	3.51	3.12
South Central Texas	3.93	3.86	3.62	2.89
East Texas	3.78	3.83	4.67	4.70
North Texas	3.23	2.89	2.71	2.78
North Central Texas	2.64	2.74	4.83	6.19
Texas and Oklahoma Panhandles	5.15	4.80	4.44	4.21
Utah, except 4 Corners	6.32	6.50	5.58	4.68
West Virginia and Maryland	6.61	8.97	9.68	6.81
Wyoming	6.69	5.88	5.88	4.88
Rocky Mountains	4.00	3.50	3.00	2.50
UNITED STATES	4.51	4.27	4.33	4.11

\* 1960 data do not cover full year; some reports are for 10 months and others for 11 months. All other years cover full 12-month period.

Source: *The Drilling Contractor*, February-March, 1961, p. 44.

While the preceding three cost studies are in the nature of surveys, the other three recent ones discussed in this section were done by individuals relying upon their own experience, company records, and other sources reporting on particular aspects of finding and development cost. These three individuals are R. E. Megill, C. C. Anderson, and H. J. Struth.<sup>48</sup>

R. E. Megill has written three papers on costs, each dealing with a particular geographic region of the United States.<sup>49</sup> Megill's primary objective is to determine the current replacement cost of crude oil, which when compared to prices, gives some indication of whether or not incentives are great enough to bring forth the necessary reserves. There are variations in emphasis and analysis in the three studies, but they all revolve around the central theme of replacement costs. Contrary to what most industry experts say, Mr. Megill feels there is ". . . sufficient information . . . available to estimate almost any desired industry cost."

He breaks costs down into three categories: (1) finding costs—geological, geophysical, leasing costs, lease rentals, dry hole losses, and the value of surrendered leases; (2) development costs—costs of drilling all oil wells, pumping and lease equipment; (3) producing costs—lease and well expense incurred in operating the property, plus overhead. He points out that in speaking of replacement costs at any given point in time we are speaking about the costs incurred on three different barrels of oil, since oil cannot be found, developed, and produced simultaneously. The factor of time thus introduces complications caused by changing technological and economic conditions.

To determine finding costs, Megill looks at the following things: (1) geological and scouting costs based on the number of geologists and scouts in the region; (2) geophysical costs based on crew months effort; (3) leasing costs from acreage holdings; and (4) dry hole costs from average well costs and number of dry holes drilled. In each of these categories it is necessary to apply a judgement factor to get a dollar amount, *e.g.*, an assumed cost per geologist and per scout, per geophysical crew month, per acre under lease, and per dry hole. Megill uses the dry hole costs reported in the *Joint Association Surveys*. Except for dry holes, there are few if any published figures on the cost categories.

One perplexing problem which Megill avoids by his classification of wells is the treatment of dry holes and producing wells. It seems to be illogical not to include productive exploratory wells in finding



TABLE III-F  
REPLACEMENT COST PER BARREL-KANSAS AND OKLAHOMA

	Cost Per Net Barrel-Dollars <sup>1</sup>					
	Finding (Primary)	Developing	Operating <sup>2</sup>	Replacement		Av. Crude Price Per Bbl.
				Primary	Primary + Secondary	
1942	0.45	0.39	0.47	1.31	1.21	1.19
1943	0.23	0.44	0.51	1.18	1.13	1.19
1944	0.12	0.50	0.53	1.15	1.12	1.23
1945	0.68	0.53	0.54	1.75	1.59	1.26
1946	0.18	0.50	0.59	1.27	1.22	1.43
1947	0.32	0.56	0.66	1.54	1.46	1.96
1948	1.82	0.64	0.70	3.16	2.77	2.58
1949	0.85	0.59	0.73	2.17	1.98	2.57
1950	1.24	0.64	0.74	2.62	2.34	2.57
1951	1.38	0.60	0.79	2.77	2.49	2.57
1952	0.97	0.61	0.82	2.40	2.17	2.57
1953	1.04	0.69	0.84	2.57	2.34	2.68
1954	1.21	0.58	0.89	2.68	2.41	2.77
1955	1.40	0.54	0.88	2.82	2.49	2.78
1956	1.58	0.60	0.92	3.10	2.72	2.77
1957	1.75	0.61	0.94	3.30	2.86	3.02
Average	0.74	0.59	0.72	2.05	1.88	2.28

<sup>1</sup> Cost per barrel of reserves found for finding and developing costs and per barrel produced for operating costs.

<sup>2</sup> Producing costs.

Source: Robert E. Megill, "The Cost of Finding Oil in Oklahoma and Kansas," For presentation before the Tulsa Geological Society, April 25, 1958.

costs. It also seems illogical to put development dry holes in the finding cost category.<sup>50</sup>

Megill allocates reserves back to the discovery year so as to get the proper distribution of per barrel costs over time. As more and more reserves are proved, be they primary or secondary, the lower become the per barrel exploration costs. In his study of Kansas and Oklahoma the author separates primary from secondary reserves by assigning reserves to particular geological formations. Certain of these formations yield more readily than others to the present technology of secondary recovery.

Because of the inclusion of the large item for the cost of dry holes, finding costs make up a large part of Megill's replacement cost per barrel.

Development costs are not dealt with in comparable detail. Megill evidently uses the *Joint Association Survey* for drilling and com-

TABLE III-G

## REPLACEMENT COST PER BARREL-PRIMARY AND SECONDARY\*

	<i>Rocky Mountains</i>		<i>Kansas and Oklahoma</i>		<i>Ill. and Mich. Basins</i>	
	<i>Repl. Cost Per Bbl.</i>	<i>Av. Crude Price</i>	<i>Repl. Cost Per Bbl.</i>	<i>Av. Crude Price</i>	<i>Repl. Cost Per Bbl.</i>	<i>Av. Crude Price</i>
1942	\$0.43	\$0.93	\$1.21	\$1.19	\$0.73	\$1.36
1943	0.52	1.03	1.13	1.19	0.82	1.38
1944	0.56	1.06	1.12	1.23	0.86	1.40
1945	1.13	1.07	1.59	1.26	1.75	1.42
1946	0.69	1.22	1.22	1.43	1.63	1.60
1947	1.12	1.76	1.46	1.96	1.81	2.15
1948	0.91	2.41	2.77	2.58	1.62	2.77
1949	0.97	2.39	1.98	2.57	1.97	2.77
1950	1.20	2.28	2.34	2.57	2.22	2.77
1951	1.02	2.28	2.49	2.57	2.70	2.77
1952	1.46	2.28	2.17	2.57	2.55	2.77
1953	1.97	2.43	2.34	2.68	2.95	2.90
1954	2.44	2.51	2.41	2.77	2.53	2.97
1955	2.40	2.53	2.49	2.78	2.64	2.91
1956	1.69	2.59	2.72	2.77	3.16	2.92
1957	1.73	2.83	2.86	3.02	3.76	3.14

\* Cost per barrel of reserves found for finding and developing costs and per barrel produced for operating costs.

Source: *Oil and Gas Journal*, March 30, 1959, Vol. 57, No. 14, p. 254.

pletion costs. No sources are given for costs of pumping and lease equipment or for secondary recovery capital expenditures. Apparently the operating costs are estimates, although they are almost as large a part of the total replacement cost as are the finding costs. Table III-F is an example of the breakdown Megill presents. It shows the breakdown between finding, developing, and producing costs for the Kansas-Oklahoma region by year, compared with crude oil prices. Table III-G shows the total replacement costs of this region, as well as for the Rocky Mountain and Michigan-Illinois regions.

Megill recognizes the growing importance of gas and its influence on oil costs. He notes that the per barrel costs for oil should be lowered somewhat, since some of the cost should properly be allocated to gas. However, he goes no further. He does not attempt any of the joint cost allocation formulas now in vogue. In his Rocky Mountain study he does present a table showing the industry's cost position in which the importance of gas is indicated.

Megill's studies make many useful suggestions as to what should be included in a thorough cost study. His actual cost figures are, on the other hand, impossible to verify, since they appear to repre-

sent his own best estimates except in the case of drilling costs, for which he relies on the *Joint Association Surveys*. This is not to say that Megill's estimates are not good. On the contrary, his long experience with a major oil company which has well-kept books would in itself give credence to his cost estimates. It would, however, be useful if more details of how these estimates are determined could be made available, and if a broader sample of companies could be used.

C. C. Anderson, Chief Petroleum Engineer for the Bureau of Mines, gave a paper before the Canadian Sectional Meeting of the World Power Conference in 1958, entitled "Petroleum and Natural Gas in the United States—Relation of Economic and Technologic Trends." The paper discusses "various important economic and technologic factors that affected petroleum and natural-gas operations in the United States during the post-World War II period." It covers the interval 1948 through 1955. Anderson takes much the same approach used by Megill in his cost analysis, although he carries it through the refining stage as well as through production. He defines finding costs as those incurred for dry holes and for "other" items, *i.e.*, bonus and rental payments for leases, costs of professional service (presumably geological, scouting, geophysical work, etc.), and some overhead costs. Anderson specifically analyzes each of these items and applies average figures to such things as the number of acres leased, the number of geologists, scouts, and landmen working, and the number of geophysical crews working. He comes up with the cost estimates shown in Table III-H, for the years 1948, 1951, 1953, and 1955. In addition to the "other" costs, Anderson shows dry hole cost estimates based on the *Joint Association Surveys*. The cost estimates of the *Surveys* are combined with exploratory footage figures from published journal sources.

TABLE III-H  
EXPLORATION COSTS  
(Thousand dollars)

	1948	1951	1953	1955
Geological, geophysical and related professional services	164,590	186,000	243,590	245,440
Lease purchases and rentals	409,370	637,910	744,630	876,520
Dry holes	406,150	650,290	795,890	940,210
Overhead	74,490	126,780	171,270	206,220
Total	1,054,600	1,600,980	1,955,380	2,268,390
Study of API, IPAA, and MCO&G <sup>1</sup>				
Dry holes	462,000		797,000	
Other <sup>2</sup>	570,000		987,000	
Overhead	79,000		172,000	
Total	1,111,000		1,956,000	

<sup>1</sup> API, *Petroleum Facts and Figures*, 1956, p. 133.

<sup>2</sup> Lease purchases, lease rentals, geological and geophysical work.

Source: C. C. Anderson, "Petroleum and Natural Gas in the United States—Relation of Economic and Technologic Trends," World Power Conference, Montreal, September 7-11, 1958, p. 6.

Anderson's analysis is different from Megill's in that he actually states cost ranges for such things as lease rentals, lease bonuses, and various types of geophysical crews. However, no averages or representative figures as such are given.

Table III-I shows Anderson's breakdown for development costs. Drilling costs are based on average cost per foot times footage of productive wells. Equipment costs are based on the *Joint Association Surveys* and trended for the missing years.

TABLE III-I  
DEVELOPMENT COSTS  
(Thousand dollars)

	1948	1951	1953	1955
Producing wells	1,067,704	1,390,050	1,689,607	2,097,225
Equipment	362,000	420,360	483,000	556,210
Overhead	98,650	135,780	168,378	205,640
Total	1,528,354	1,946,190	2,340,985	2,859,075

Source: C. C. Anderson, "Petroleum and Natural Gas in the United States—Relation of Economic and Technologic Trends," World Power Conference, Montreal, September 7-11, 1958, p. 9.

Producing costs are based primarily on Megill's study of Oklahoma and Kansas, although they are checked against the *Joint Association Surveys* and the *Census of Mineral Industries*. Anderson feels that Oklahoma and Kansas are typical or average for the nation. Gas producing cost data are obtained from F. P. C. statistics on gas pipeline companies. The summary of information reported by Anderson is shown in Table III-J. Included in this table are estimates of the value of the industry's output. A "net balance" or position is then computed for the industry indicating that in 1948 and 1951 revenues exceeded costs but in 1953 and 1955 the reverse was true.

TABLE III-J  
EXPENDITURES AND NET VALUE OF OIL AND GAS OPERATIONS  
(Thousand Dollars)

	1948	1951	1953	1955
<b>INPUT</b>				
Finding expenditures	1,054,600	1,600,980	1,955,380	2,268,390
Developing expenditures	1,528,354	1,946,190	2,340,985	2,859,075
Subtotal	2,582,954	3,547,170	4,296,365	5,127,465
Operating costs:				
Oil	1,214,262	1,516,295	1,698,902	1,877,850
Gas	99,257	96,978	145,595	143,484
Subtotal	1,313,519	1,613,273	1,844,497	2,021,334
Total expenditures	3,896,473	5,160,443	6,140,862	7,148,799
<b>OUTPUT</b>				
Net value to industry:				
Oil	4,490,871	4,862,136	5,401,018	5,884,215
Gas	286,101	465,451	660,501	836,324
Total	4,776,972	5,327,587	6,061,519	6,720,539
Net annual balance:				
Positive	880,499	167,144		
Negative			79,343	428,260

Source: C. C. Anderson, "Petroleum and Natural Gas in the United States—Relation of Economic and Technologic Trends," World Power Conference, Montreal, September 7-11, 1958, p. 14.

Although Anderson discusses discovery rates and reserves, he makes no attempt to put this information on a per-barrel basis.

Anderson does not really take us much further than Megill in the cost area, and does not carry us as far as Megill in applying costs to reserves or production.

H. J. Struth's study is one of a long series begun in 1943.<sup>51 52</sup> The treatment of cost, reserve and drilling date is quite elaborate and

has been developed and extended over the years. In his 1960 article, the author states that "For each net barrel of crude oil produced in 1959, the U. S. oil industry spent \$3.19, compared with an average wellhead value of \$2.92 per barrel. Related to production, an approximate breakdown of this cost included exploration, \$1.07; development \$1.21; and lifting and overhead cost, \$.91"<sup>53</sup> Unfortunately there is virtually no detail as to what is included in each category, nor is there any discussion of how these figures are determined. There is a worthwhile discussion of the relationship of drilling to reserves, but it is impossible to determine the sources of the cost data. In the light of this deficiency, it is impossible to comment or to analyze critically the information presented, even though it serves as the foundation for a superstructure of very elaborate analysis. For this reason or for others, the industry spokesmen who discuss costs rarely rely on the Struth series for their data.<sup>54</sup>

Three other dollar cost studies should be briefly mentioned. One is entitled "Cost of Exploration and Production in the United States," by R. Granier de Lilliac and Gilbert Lugol.<sup>55</sup> This study first appeared in French in 1952 and was translated to the English with some updating in 1955.<sup>56</sup> The basic cost data in this study are taken from World War II studies done by or for the Office of Price Administration<sup>57</sup> and from the studies of H. J. Struth, discussed above. Thus, although the English version of this study appeared in 1955, most of the cost information reflects conditions and technology of the wartime or immediate postwar periods.

While the basic information is out of date, the paper does contain some novel techniques of handling costing problems. For example, there is a discussion of the relationship of production to reserves and the problems encountered in maintaining a given ratio if production rises rapidly. The authors also delve into the interest factor so often overlooked in computing costs, and relate interest rates to the life of a field and the flow of receipts from a field. In computing total costs, these opportunity costs must be considered and judgments made on what the appropriate interest rates are. This study assumes production at M. E. R. (maximum efficient rate of production) and does not contemplate the additional difficulties created by a supply situation which leads to limited domestic allowables.

The last two studies which attempt to arrive at a dollar cost figure are those by Siskind, who worked on a study jointly sponsored by the Bureau of Labor Statistics and the A. A. O. D. C.; and by the Rice University Petroleum Research Project which was part of

the early (1950) Interindustry Study sponsored by the Air Force.<sup>58</sup> Both studies appeared in 1952, and both utilized 1947 data in part. The Siskind study excludes exploration expenses other than drilling and completion costs, and also excludes pumping and other lifting costs and other costs incurred in maintaining production. The Rice study excludes exploration costs other than those for drilling and completion, but does include equipping wells for production.<sup>59</sup>

Both of these studies attack the cost problem by building up, piece by piece, the tangible and intangible inputs into the industry. These cost inputs are reported by Standard Industrial Classification on a percentage, a total cost, or a per-well basis so that the detail is considerable. Adjustments are made for rotary or cable-tool drilling, for depth and geographic distribution, and for the type of result (oil, gas, dry, etc.) to arrive at "representative" or weighted "average" costs. In the Rice study there is a substantial amount of detail describing how each cost category was built up. In neither study is there any attempt to relate costs to reserves, or to relate drilling effort in terms of wells or footage to reserves. Since technology has changed substantially, and depth and geographic weight factors are different, the actual figures have little meaning today. Certain of the techniques of data accumulation and sampling, however, are unique and are probably more elaborately described in these studies than elsewhere in all the literature on costs.

At least some mention should be made of several cost studies that date back to the period of World War II or earlier. Working back chronologically we find the "Report on the Cost of Finding, Developing, and Producing Crude Petroleum," submitted to the Office of Price Administration by the National Crude Oil Industry Advisory Committee, dated February 11, 1946.<sup>60</sup> The industry committee making this report was urging that crude oil price either be freed from price control or allowed to rise under controls. The conclusions of the study were that rapidly rising replacement costs had outrun price so that there was little or no incentive for capital to be attracted to this industry at a time when demand had outrun domestic supply.

The study was based on a survey of companies accounting for about half the nation's crude oil production and covers two periods, 1936-39 and 1941-44. Operating, developing and finding costs are each treated separately and analyzed in some detail by size of company, but not by geographic regions. There is some attempt to relate costs to reserves. The survey techniques used in this study may be of assistance in the design of a new survey. Some of the discussion

about the concept of replacement cost is interesting and warrants study in connection with definitions of cost.<sup>61</sup>

The second study in this group was done by the U. S. Tariff Commission for the Office of Price Administration to be used as the basis for fixing crude oil prices.<sup>62</sup> It covers the period 1939-1942. This report was also done on a survey basis with companies reporting *current* expenses: operating; general and administrative; depletion; depreciation; and amortization of intangible drilling costs. Per-barrel costs were computed by dividing total production into current expenses. There was no attempt to relate expenses to reserves. Since a number of assumptions about the relationship of production to reserves must be made to make such cost figures meaningful, this study affords only an opportunity to gain some ideas about definitions of cost categories.

Data covering the 1920's are found in two other Tariff Commission studies. The methodology is similar to that used in the 1942 and 1943 reports, and the data have the same basic shortcomings.<sup>63</sup>

Two final bits of cost information should at least be mentioned. Beginning in May, 1959, the Independent Petroleum Association of America (I. P. A. A.) released "Indexes of Rotary Drilling and Completion Cost Per Foot and Per Well."<sup>64</sup> These indexes have been computed for the years 1947-49 to the present and are given on a per well and per foot basis. Included in the indexes are prices (or price indexes) for labor, casing, special contract services, rock bits, oil field machinery and tools, drilling mud, and drilling contractor services. These items are weighted according to the information found in the 1947 Siskind study plus some adjustment by the Committee. Using 1947-49 as 100, the cost index per well in 1960 stood at 177.2 and per foot at 151.00.

While the usual caveats about the pitfalls and limitations of index numbers are necessary, this series could be useful in correcting cost information for price and depth changes and for giving some perspective on the relationship of costs to revenues.

The Chase Manhattan Bank makes annual estimates of expenditures for fixed assets in the production phase of the industry.<sup>65</sup> This estimate is broken down between gasoline and cycling plants, and crude oil and natural gas. The latter includes only natural gas facilities of oil companies, and for all companies it includes the cost of drilling dry holes and lease acquisitions, but excludes the exploration expenses and lease rentals charged to income. It is conceivable that expenditure data of these sorts might be related in some way



to reserves. It is the only annual estimate made regularly of total industry expenditures.

This review shows that virtually every recently published study of finding, development, and producing costs relies on the *Joint Association Survey* for costs of exploration and development. The same holds for expenditures for capital and expendable items in oil and gas production. *The Joint Association Survey* thus appears to be the major source of information. The Struth studies are an exception to this rule, but here it is impossible to determine basic data sources, and in any case the industry uses this series only on rare occasions.<sup>66</sup>

While there is near complete reliance on the *Joint Association Survey*, the *Survey* fails to provide information on its methods of data collecting, sampling and analysis. If it would itself provide a benchmark of sophisticated statistical analysis, the results would not only be more valuable, but an example would be set for improved quality in the analysis and reporting done by companies within the industry. The *Survey* should become the model for industry reporting.

It is surprising to note how little the 1954 and 1958 *Censuses of Mineral Industries* are used. This source, in many ways, is the most complete and most accurate, and can be handled statistically with more ease and certainty than other sources of information.

Cost information on geological, geophysical, scouting, landmen, and leasing (new and renewal) activities is virtually non-existent. The attempts made by Megill and Anderson to fill this gap are commendable in pointing the way toward a solution.

None of the studies has coped adequately with the problem of assigning costs to barrels of new reserves.

#### *Cost Studies Using "Real Cost" Concepts*

There are two major studies that fall into the "real cost" category.<sup>67</sup> One is by P. R. Schultz, entitled "Oil-Discovery Trends," which appeared in 1953.<sup>68</sup> The other is by John E. Hodges and Henry B. Steele, *An Investigation of the Problems of Cost Determination for the Discovery, Development, and Production of Liquid Hydrocarbon and Natural Gas Resources*.<sup>69</sup> Both studies point out that better cost information is urgently needed.<sup>70</sup>

Schultz's major concern is whether or not the current (1953) rates of exploratory drilling are sufficiently high to maintain the necessary productive capacity of the nation. He devotes most of his analysis to relationships between drilling and reserves. He points out that more reserves are being discovered per well than at any time in

the industry's history. Schultz never tries to bridge the gap between wells and money costs per barrel or per Mcf. And, as in the case of Hodges and Steele, real costs of human and non-human resources utilized are never estimated except in terms of wells or footage.

The most detailed and comprehensive "real cost" study is that by Hodges and Steele. The chapter headings in this important volume explain the approach taken — "I. A Survey of Recent Cost Studies." Reviewed here are the studies by Struth, Schultz, Davis, Megill (first two studies), the Joint Association (the 1955-56 study), and Anderson; "II. Recommendations for Conduct of a Study of Crude Oil and Natural Gas Costs," and "III. A Survey of Certain Apparent Trends in the Cost of Finding Oil and Gas Reserves in the United States." The analysis of the six earlier studies is an effort to evaluate techniques and point out gaps and errors. The second chapter discusses the nature and form of information that would be needed to make an adequate cost study. Hypothetical examples are used to show the methodology involved. The rationale to be followed is developed in great detail with comments on the inadequacy of the data currently being collected.

The final chapter leaves the methodology and proceeds to examine the information available. The basic problems as seen by Hodges and Steele are as follows:

- (1) Where do you get reliable data on total dollar outlays on finding programs?
  - (2) Have the various elements of cost been properly defined?
  - (3) What is the physical volume of reserves discovered by the outlays of a given period?
  - (4) How should we allocate the joint costs of finding crude oil, natural gas liquid, and natural gas to the individual products?
  - (5) How should we eliminate the effect of price changes on the dollar costs of various years in order to make them comparable?
- The resolution of all of these problems would be essential to a comprehensive study of finding costs. For present purposes, however, we can do a little more than to suggest an approach to the solution of each of these problems.<sup>71</sup>

Because the problems of dealing in dollar terms seem insuperable, given the present state of industry data, Hodges and Steele couch their study in terms of wells and footage needed—the output necessary to generate the required reserves. These wells are "costs" in the sense that certain inputs of resources are required to bring forth the wells. They summarize the problems in the following way.

- (1) Virtually all of the exploration outlay data considered herein consists of real-cost data. Specifically, the volume of reserves found in different discovery categories is measured in terms of barrels of discoveries per exploratory well, per dry hole, per foot drilled, and the like. No

continuous year-by-year series of acceptable quality on total money outlays is available; hence real cost data constitute the bulk of the statistical evidence for establishing trends.

(2) The outlays have been defined, by and large, in real terms. The published data on wells drilled and footage drilled are investigated in terms of as complete a breakdown by drilling categories as can be obtained from the available data. When recourse is occasionally had to money outlay statistics, we are working with data the nature of which is neither well defined nor well described by its compilers. Consequently, less confidence can be placed in the meaning of the results which are obtained from the use of these data.

(3) On the basis of the data currently available, it does not seem to be of any value to try to estimate the ultimate reserves discovered in a given year by crediting subsequent extensions and revisions back to the year of initial discovery. It is to be hoped that adequate data will someday be developed so as to permit this procedure, but that day has not yet arrived. Instead, this study concentrates on the composition of current additions to total discoveries, using new discoveries alone for some purposes, new discoveries plus extensions and revision for still other purposes. In general, it is considered preferable to measure current discoveries in terms of the statistics for current additions to total cumulative discoveries, rather than to attempt to allocate extensions and revisions backwards, and thereby to introduce at best some distortion between the amounts allocated to earlier and later years.

(4) By and large, the joint cost problem is dealt with by means of the first alternative discussed above: that of allocating all relevant costs to the crude oil component of discoveries, and ignoring other liquid hydrocarbons and natural gas. However, information is given on the recent ratios of discovery of crude oil to total liquid hydrocarbons and natural gas, and in a few instances real costs are computed both on the basis of crude oil alone, and of the crude oil equivalent of all liquid hydrocarbons and natural gas combined.

(5) Since most of the cost indexes employed are real cost indexes, the problem of obtaining comparability between dollar figures seldom arises. This is not to say that real cost indexes are always comparable. A good example is the case of the exploratory well. The average exploratory well seems to become increasingly deeper over time, so that it is necessary to supplement data on discoveries per exploratory well with those on discoveries per exploratory foot. Even the exploratory foot is not a homogeneous unit over time, since the real cost of drilling, at the same depth level, tends to decrease as technological progress cuts unit drilling costs. On the other hand, a foot drilled at five thousand feet is not the same as a foot drilled at fifteen thousand feet; given the same level of technology, costs per foot increase sharply with increasing depth of drilling. Here, dollar costs would have been an invaluable supplement to real cost figures, had they been available. In those few instances where money cost figures have been employed, a simple and approximate price level adjustment has been made by means of the index of wholesale prices.<sup>72</sup>

After extended discussion of available data for drilling and reserves, the authors conclude that these “. . . seem to support the hypothesis that the phenomenon of diminishing returns to exploratory drilling is being experienced with increasing severity from year to year. . . .”<sup>73</sup> This conclusion stems from the greater drilling effort required to find the same or smaller reserves. Hodges and Steele are pessimistic about the chances that any major technological breakthrough may reverse this situation, although they do not rule out this possibility. They are optimistic about the increasingly important role gas will play in the future. An impressive plea to the industry to find out where it stands with respect to costs, their study offers many ideas to assist in such an undertaking.

*Cost Data in Federal Power Commission Proceedings*

The Federal Power Commission, since the *Phillips* case in 1954, has had the task of regulating field prices for gas which is transported or marketed for resale in interstate commerce. Early attempts at producer regulation utilized the traditional public utility cost-of-service concept. The result has been confusion—and a mountain of relatively untouched cost data. While these data were designed for purposes of gas regulation they also provide information on oil production in many instances. The following discussions will provide some examples of the types of information which are available. The companies involved are not mentioned.

In addition to cost information and the relationship of drilling to reserves the materials submitted to the F. P. C. contain discussions and criticisms of every conceivable method of joint cost allocation. Since cost allocation is a part of the general problem of the determination of oil and gas finding and development costs, this information should prove useful.

The data available in the F. P. C. proceedings have both advantages and disadvantages. They are on a company-by-company basis, except for the Arthur Young and Co. study which is discussed below. Not all major oil producing companies have made detailed cost studies, nor have they all been studied by the F. P. C. Staff. In some cases, there is probably a great deal of corporate information on costs which has not been made public. Thus, at best, the available information would have to be treated as a sample, with its limitations duly noted. Probably there are now enough companies on record to provide an adequate sample of industrial experience.

The company data that are supplied do not represent uniform concepts and definitions, so that differences in definitions, account-

ing practices and concepts, and methods of handling data would have to be reconciled. In most instances there is much detailed information on exploratory, leasing, developing, producing, and overhead expense and investment (where applicable) for gas properties, joint oil and gas properties, oil properties, and gas-condensate properties. In most instances a "test year" is used so that historical records are not always available. In all of the studies there is much detail on current production of oil, gas and condensate. In several studies there is information on developed and undeveloped acreage, on exploratory drilling (often in footage and dollar terms) and on reserves of oil, gas and NGL added during a given time period. Companies which report reserves are likely to give figures for several years to avoid the possibly atypical nature of figures for a single year. There is no assignment of costs to reserves, nor is there any attempt to divide reserves into the categories of new discoveries, extensions, and revisions. The paucity of reserve data is perhaps the greatest liability of these studies generally, along with the short time span most of them cover.

Several companies on two occasions (1958 and 1961) have attempted to get a more comprehensive picture of industrial costs by pooling information in the hands of Arthur Young and Company, which combined the data into "representative" industry figures.<sup>74</sup> In the 1958 study a vast amount of information was collected which deals with costs, physical factors such as wells, footage, reserves, production, etc., and with the relationship between costs and the physical factors. While some of this information was on a given "test year" basis, much of it spans four or five years, thus giving some perspective on trends. The questionnaires used to collect the data from participating companies were constructed with much thought and give much greater detail than in the case of the *Joint Association Survey* questionnaire.<sup>75</sup> Again, the reporting of reserves seems to be the greatest weakness in the study. If a cost per barrel of reserve figure is the aim, this study can not help a great deal. It covers too short a time period; it makes no attempt to relate reserves to expenditure, nor does it relate drilling and other physical factors to reserves. It does, however, give more reliable information on costs per well and per foot drilled. At least, this is a step forward.

#### IV. LEGAL AND REGULATORY ASPECTS OF COSTS

In the preceding section we have reviewed a number of cost studies which utilize the statistical data of the industry. Some of these showed historical trends in replacement cost within the limits imposed

by defective data. Some extrapolate the trends to relate hypothetical future costs to hypothetical future availability of petroleum under various economic, geological and technological assumptions. For statistical purposes, such studies must take the cost data as given, and do not inquire into the surrounding circumstances which make costs what they are.

These procedures leave out some important institutional facts. In particular, they fail to reveal the way in which property rights, legal rules, and regulatory procedures may affect costs. These institutional aspects require explicit attention in order to bring the cost picture in perspective.

#### *Property Interests in Relation to Costs*

*Legal Rights and Limitations.*—The laws governing subsurface mineral rights in the United States closely follow the laws governing real property on the surface. The owner of a piece of land is said to own the minerals beneath his land. With minerals which are liquid or gaseous, and hence mobile, it is impossible to determine precisely how much of these minerals underlie a given surface area, and, because of the recovery methods used, it is impossible to know if the oil and gas originally beneath an area is what is recovered. The major difficulty arises from the fact that such liquids and gases can migrate through many types of permeable geological formations.

In an attempt to adjust the law to fit the peculiar nature of the resource, the courts evolved the now famous "rule of capture" when dealing with oil and gas. This rule, in its simplest form, stated that ownership of oil and gas commences only after the oil or gas has been reduced to a person's possession, or in other words, not until it has been "captured." The rule of capture, in this form, contained the difficulty that one person could drain what was "rightfully" another's. Self-protection necessitated the drilling of wells to prevent drainage, and this in turn led to drilling patterns which did not permit fullest recovery, and which imposed unnecessary drilling costs. The legal rules which developed reinforced the right of self-protection and the consequent wasteful development. This is evidenced by the "implied covenants" put into early oil and gas leases by the courts. Such implied covenants covered things such as time requirements to drill discovery (first) wells, additional developmental wells, offset (protection) wells, as well as requirements to produce and market the product once it had been discovered. Failure to fulfill such express or implied covenants could result in lease forfeiture by the lessor or in damages, or in both. The rule of capture became

counterbalanced by the doctrine of correlative rights, which required that owners whose lands overlie a common reservoir so conduct their operations that each will have an opportunity for a fair share of the minerals.

As the oil industry developed and the waste and chaos became readily apparent to all who looked, statutory law began to replace the well established common law doctrines, particularly after 1930. Usually, the statutes were modeled as closely as possible after the common law. Since laws to prevent waste were contrary to past practices, these laws were attacked on the grounds that they interfered with individual property rights. Eventually these early conservation laws were upheld. The most important early case decided by the U. S. Supreme Court set forth the right of a state to exercise its police power, first, to prevent the waste of natural resources in which there was a general public interest, and second to protect the rights of owners in a common source of supply.<sup>76</sup> Thus the common law doctrines of "prevention of waste" and "protection of correlative rights" were written into state statutes. These principles have since become fundamental to virtually all oil and gas conservation regulation, and every statute and regulation is relevant to one or the other of them.

*Cost Aspects of Property Rights.*—Statutory law, which brought about a kind of order out of chaos after 1930, did not remove some fundamental difficulties arising out of the fact that mineral rights go hand-in-hand with surface ownership. In a nation such as the United States where the ownership of land is extremely diversified, it means that mineral ownership is also diversified. When inheritance is added, the picture gets more complex. Getting assurance of clear title before leasing is often a costly process. As time passes these problems get worse.

Multi-ownership creates additional expense in several ways. Most oil-producing companies do not purchase and hold land in fee. Rather they purchase an oil and gas lease and in so doing acquire rights to specified minerals (if any are present) and rights to search for and produce these minerals. A valid oil and gas lease must be signed by all the ownership interests affected. Thus, leasing frequently is difficult and expensive. A lease also contains provisions for payment of lease rentals, payment of lease bonuses, division of revenues (if any) among royalty interests when production commences, and many other stipulations. If a state requires that no more than one well be drilled for every 40 acres in a field, consider the leasing problems in

putting 40 acres together if the field lies under a 100 year old city having town lots of about  $\frac{1}{4}$ th acre each.

Multi-ownership also may cause difficulties if the operators of the field wish to "unitize" the field for production purposes. This unit operation is sound from an engineering standpoint but involves shutting in some wells, using some for gas or water input and using others for production. How are the revenues from such a project to be divided among the royalty owners?

Private ownership of minerals also has tended to stimulate the drilling of unnecessary wells. Many oil and gas leases contain provisions which require the lessee to drill an "offset" well within a given time in the event a producing well is brought in on adjacent land. Whether the geological or engineering considerations dictate that such a well be drilled is often immaterial. Failure to drill means forfeiture by the lessee.

Closely related to the offset drilling problem is the problem of drainage. Since, under the rule of capture, it is generally (although not always) lawful to produce oil and gas from a well on a given piece of land, regardless of where the oil and gas was located originally underground, there is a great incentive for lessees and lessors of property adjoining producing property to get a well into the producing formation as rapidly as possible. Ratable take laws usually become effective if wells are drilled. They cannot, however, protect the lease holder who could drill an offset well but does not do so.

Finally, there is the expense to the industry of paying the royalty to the land owner or owners, and to other ownership interests, if any. In the United States the royalty interests retained by the land-owners usually range from  $\frac{1}{8}$ th to  $\frac{1}{4}$ th of the *gross* revenues produced from the sale of minerals extracted from the land. Computed as an expense to the operator of the lease, the  $12\frac{1}{2}$  to 25 percent of gross revenue may become as high as 50 percent of *net* revenue. The operator must bear almost all the exploration, development, production and marketing costs.<sup>77</sup> Royalty is a good example of pure economic rent.

With the brief analysis given above, it is possible to summarize several aspects of the private ownership of oil and gas interests that appear to raise costs above what they would be if fields were developed as units.

*Finding Costs.*—Several components of finding costs are affected by the private property arrangements in the United States. Leasing costs may be higher because of the added effort necessary to contact all parties owning any part of the mineral rights in ques-



tion. In some instances leasing costs may be higher—*i.e.*, royalties, lease rentals, lease bonuses—because of competitive bidding for small land parcels. Such trading can be quite profitable, and the result is a rapid turnover of leases in situations in which the economic rent can be capitalized by the lease holder.

Geological and geophysical efforts aimed at detecting subsurface structures which are *possible* producing formations are less effective with diverse property ownership than with single ownership, because of limited access by individual operators. The knowledge that one of several lessees has is, therefore, incomplete. Consequently the choice of exploratory well drilling sites may be something less than the best possible. If, under an atomistic surface ownership situation, a given geological and geophysical cost plus a given exploratory drilling cost are less productive in terms of reserves discovered than would be the case with complete flexibility of operations, then the *per-barrel* costs in these categories are higher.

*Development Costs.*—Drilling costs in known fields may be higher because surface ownership boundaries do not correspond to the boundaries of the reservoir being drilled. This may result in too many wells being drilled, wells drilled in other than the optimum locations or patterns, or in too few wells being drilled. This depends in part upon well spacing regulations, if any are in effect. Drilling costs are no doubt also higher because of time and offset requirements found in leases. Such requirements frequently apply irrespective of engineering considerations or long range plans of an operator in exploring and developing several possible areas.

Other development costs may be higher because lease provisions require that the operator perform in such a way so as to maximize gross revenues from a given property. This may involve drilling and production schedules which are more costly than might be possible. This is closely tied to proration and well-spacing regulations which are discussed later.

*Producing Costs.*—The costs of producing tend to be higher also, given the property system that exists in the U. S. economy. Since too many wells may have been drilled, then maintenance and production outlays are sure to be higher than otherwise. Additionally, many fields cannot be unitized under existing regulations and thus must be operated in pieces rather than as a whole. This is likely to result in lower ultimate recovery and higher *per-barrel* production cost. This is an implicit expense which arises from not being able to produce as cheaply as might be possible. Unitization, as applied under the property system, itself may be costly from the standpoint

of the time and expense of meeting the demands of property owners in the planned unit. In addition, there is often substantial administrative expense in keeping track of multi-ownership in large fields and making payments to the interests involved.

The discussion above indicates areas where private property rights may affect costs. In some instances very little can be done to rectify high costs without a major overhaul of the laws governing mineral property. In other instances measures could be taken which would not alter basic ownership relationships but which would lower costs significantly. Some such measures are already operating in some states. Whether or not feasible solutions are readily apparent, it is important to isolate these causes of high or rising costs.

*Property Relationships in Other Oil-Producing Countries.*—A clearer idea of the costs implicit in property rights can be gained, negatively, from looking at situations where the American type of subsurface rights does not exist. Rather dramatic cost comparisons have been drawn between the United States and other major oil producing nations of the world. In general, the U. S. comes off second best to most other nations. There are certainly important exceptions if specific fields or wells are considered, but for the industry as a whole, U. S. costs are far above the average costs in other nations, if profit and price indicators give a rough approximation of conditions.

While some part of the cost differential can be explained by special geological or other circumstances, another part must be attributed to the very different systems of mineral ownership and regulation which exist in other nations. For most nations in Latin America, Africa, the Middle East and elsewhere, subsurface minerals belong to the national (or in some instances the state or provincial) governments. The right to explore for minerals rests with the government and can be transferred by the government to an individual or company. The owner of the surface has no voice in determining the lessee and in many nations receives no compensation. Since the government owns the minerals, the income equivalent to the royalty going to the U. S. landowner accrues to the government. In Canada, the system is slightly different with the provincial governments owning the minerals on all lands except those portions granted in patents to such organizations as railroads, trading companies, and the like. Each province regulates the distribution of leases and exercises control over royalties, drilling and production practices, and other related things. Alberta does not lease large solid blocks of land but rather retains

part of each block leased to be disposed of later through sealed bid sales.

The upshot of these rather different laws in other countries is that they make for entirely different methods of "lease" acquisition, exploration, development, and production. The *right* to explore is secured through "concessions" granted to one company, or a combine operating as one company, by the government on large areas of land. There are often stipulations about the commencement of drilling activities and the continuation of drilling, but these do not relate to drilling on other concessions or to a specific pattern within the concession. Exploration activity itself can be done on a very large scale using aerial surveying techniques. Ground survey work has free rein over a wide area. Exploratory drilling locations are determined by geological, geophysical and engineering considerations. Development drilling is done in a pattern deemed most economical from the standpoint of reservoir engineering. It is not bothered by surface property lines, well spacing laws and regulations, or lease provisions. Production can be adjusted to the economic optimum also, although some nations do prohibit production rates and practices that reduce the ultimate recovery from the reservoir. Gas-oil ratios are rarely a deterrent to production, and gas, if it cannot be sold or used in pumping and drilling, is recycled or vented. The overall result is low cost in some aspects of exploration (allowing of course for remoteness of some areas), optimum well spacing, production at M. E. R. or some other economic rate. With respect to lease acquisition, the costs to operating companies are not necessarily lower, since nations may require that large portions of the operating revenues be turned over to them.<sup>78</sup>

#### *Conservation Regulation in Relation to Costs*

One of the major forces shaping the structure, practices, and policies of the domestic oil and gas producing industry is a complex set of state conservation statutes and administrative rules and regulations. These laws and regulations have undergone a long evolutionary process which continues to change as technologic, political, and economic conditions change. It is inevitable that conservation regulations influence finding and development costs—sometimes apparently raising costs, and other times apparently lowering costs. It has been pointed out earlier that two major areas where cost savings can be realized are (1) in improved technology at all stages of finding and development and (2) in improved planning, organization, communication, and rationalization within firms and within the industry as

a whole. A third major area which is beginning to receive attention as a possible source of cost saving is state conservation regulation. This section will review only the major conservation tools and point out situations where the regulation itself, or in conjunction with other regulations, appears to influence costs.

The goals of oil and gas conservation are twofold. The Kansas Corporation Commission has stated these ideas succinctly.

The modern day concept of conservation is that it is the state's duty on behalf of the general public to prevent wasteful exploitation of its irreplaceable natural resources. Conservation is the antithesis of waste in any form. The law does not recognize the indisputable right to produce gas [or oil] as an exclusive right but predicates the right on the ability to do so without waste. . . . The statute is definitely specific that this Commission shall take steps for the conservation of gas [and oil] from common sources of supply and to see that inequities do not arise so as to be violative of correlative rights in the field.<sup>79</sup>

Thus, prevention of waste and protection of correlative rights in the field provide the foundation upon which specific conservation regulations are built. The regulations which are discussed below include well-spacing, M. E. R. and market demand proration, pooling of drilling units and unitization of production units, and secondary recovery. Primary emphasis will be placed on regulations dealing with oil; however, some instances where gas regulations are significantly different will be noted. The discussion will be in terms of the most common form of each type of regulation. It must, however, be remembered that each state has jurisdiction over drilling and production within its boundaries (with the exception of federally owned land, in some respects), and there are, therefore, wide variations in the details from state to state. Finally, court interpretation of state laws can alter or restrict statutory provisions substantially.

Numerous other conservation measures affect finding and development costs. Included are such items as: gas-oil ratio requirements; permission to drill and to produce; specified drilling, well completion, production, work-over, and abandonment procedures and equipment; filing of drilling and production reports; permission to introduce secondary recovery methods; and prohibition, except under special circumstances, of wasting of natural gas, of polluting fresh ground or surface water supplies, and of storing crude oil above ground in a wasteful fashion.

*Well Spacing.*—Prior to conservation regulation, well drilling was controlled by common law doctrines dealing with land and mineral ownership. The result, in most cases, was that a property owner or

lease holder could drill a well on land of any size and could drill as many wells as he wished on land he owned or leased. The major considerations under the rule of capture were those of private economic interest—how much could a person get for his oil, what method provided the fastest means of extracting as much oil as possible, and how much would it cost to do the necessary drilling and production. Since competitive drilling and production would drain oil and gas from beneath a person's property, he had no other choice than to get as much oil as fast as possible. The doctrine of correlative rights provided the only barrier, and this was often ineffective in preventing waste. The unnecessary drilling in such situations is obvious. In addition, production would probably proceed under conditions which made ultimate recovery less than the maximum amount.

In 1951, the Research and Coordinating Committee of the Interstate Oil Compact Commission reviewed a series of papers on well spacing and discussed the subject in the light of more modern techniques and information. The conclusions of this committee are important enough to be quoted at length.

If the full aims of conservation are to be accomplished, individual property or lease boundary lines will be disregarded in choosing well locations.

Individual wells will become channels through which oil is expelled from whole reservoirs or producing segments rather than from separate properties. Some form of unitization of fields will be necessary, with pooling of all petroleum ownership, all driving energy, and all expenses of development and production.

It is probable that in many fields wide well spacing would result in slower recovery of all ultimately recoverable oil than closer spacing. Even though close spacing involves much higher costs some close well spacing pattern might result, through a saving in time and operating costs, in greater ultimate profit than wide spacing. All of the elements of comparative costs and revenues would be involved, and selection of well density programs would be a subject of joint study by engineers, geologists, and economists.

The importance of joint study and the application of sound principles of geology, engineering and economics to well spacing problems may be emphasized by two observations:

1. Fields with characteristics suggesting the need for close spacing for adequate and efficient drainage are the ones least likely from an economic viewpoint to justify high drilling and production costs.
2. Fields with characteristics indicating low well density would adequately and efficiently drain the reservoirs have frequently been burdened with costs of unnecessary closely spaced wells.

As a matter of economics or of public interest, or both, it may be desirable to plan to either increase [sic.] or restrict daily production from a single pool or in many pools, to conform with market demand.

If, during the development stage of a field, market demands do not require a high level of production the wells may be widely spaced according to strictly geological and engineering dictates. If markets call for high field production it may be that low production from many wells will accomplish the ends of physical conservation more efficiently than high production from a few wells.

Finally, dictates of economics, influenced at times by those of expediency are, and properly should be, the most important influences in fixing well spacing or density in any field. Public conservation authorities are always in a position to safeguard public interests by refusing to permit strictly economic control of development and production practices regardless of whether or not such control would or would not lead to reasonably complete production of all practicably recoverable oil.

The ends of conservation and the demands of economics would be fully served if fields or pools could be originally developed on wide spacing patterns to determine the field limits and the reservoir and fluid characteristics. Following the studies thus made possible infill wells could be located and drilled to provide adequate reservoir drainage and to meet the requirements of conservation, economics, or expediency.

While this has been primarily a study of the well spacing problem it has necessarily included discussion of orderly oil production, involving control of production rates where necessary to conserve reservoir energy. Production control has frequently been considered to involve two possible stages of oil recovery, referred to as primary and secondary. Because the two so-called stages require the application of the same primary types of driving energy, modern thought is that there is no real necessity for dividing operations into stages and delaying the initiation of one phase of operation until another is nearly completed.

A field with an active water drive, showing relatively stable reservoir pressures, normally will not require fluid injection to maintain reservoir energy at efficient producing levels.

Limited water-drive fields or combination water-drive and gas drive fields may require reinjection of produced brines and excess produced gas early in field life if reservoir energy is to remain at efficient producing levels. Such reinjection would tend to sustain producing rates and prolong flowing life of the wells.

If the producing mechanism is solution gas, gas-cap, or gravity and it is determined early in the life of a field that artificial means of supplementing energy are desirable, pressure maintenance, rather than repressuring, is in order. Either gas or water injected into a reservoir during the early producing life as a pressure maintenance project is much more effective than injection at a later time when reservoir pressure has declined. If early pressure maintenance is practiced the overall field control should be considered as primary, and so-called secondary recovery would lose its identity.

In conclusion, it is the opinion of this committee that, disregarding the element of time, there is not necessarily a relationship between well density and ultimate recovery from a reservoir. Rather, the ultimate recovery of oil is dependent upon the early application of good conservation practices.<sup>80</sup>

Several very critical points should be noted. First, wide spacing might result in *slower* but not necessarily *less* recovery. Second, economics should be the most important determinant in fixing well density in any field. This amounts to a comparison of the costs incurred in dense spacing and rapid recovery with those incurred in wide spacing and slower recovery. Third, where feasible, primary and secondary recovery should lose their separate identities, and fields should be planned for total recovery from the start. Last, ultimate recovery depends upon early application of good conservation practices rather than on well density.<sup>81</sup>

If geology, engineering, and economics dictate much wider well spacing than has been practiced in most states, what are the reasons for relatively close spacing? With the exception of Kansas, every state has some regulations or laws dealing with well spacing. The answer seems to lie in the legal area and is closely tied to those problems discussed earlier in connection with private ownership of subsurface minerals. In some states, well-spacing laws actually stimulate unnecessary drilling.

The well spacing regulation in Texas was originally promulgated by the Texas Railroad Commission in 1919 as "Rule 37." This rule has undergone several changes, but has remained substantially the same. Section (A) of Rule 37 states that:

No well for oil or gas shall hereafter be drilled nearer than nine hundred thirty-three (933) feet to any well completed in or drilling to the same horizon on the same tract or farm, and no well shall be drilled nearer than three hundred thirty (330) feet to any property line, lease line or subdivision line; provided that the Commission in order to prevent waste or to prevent the confiscation of property may grant exceptions to permit drilling within shorter distances than above prescribed when the Commission shall determine that such exceptions are necessary either to prevent waste or to prevent the confiscation of property.

. . . the Commission reserves the right in particular oil and gas fields to enter special orders increasing or decreasing the minimum distances provided by this rule.<sup>82</sup>

The effect of this rule is to provide about 20 acre well spacing, subject to discretionary exceptions to prevent "waste" or "confiscation" of property. Whether the 20-acre rule provides an efficient standard is a matter for technical judgment. The Texas Railroad Commission is, in fact, in a position to give weight to engineering, geological and economic considerations in determining the spacing rules for different fields. A similar rule for gas establishes 320-acre spacing in Texas.

Troublesome problems of a legal or political nature are generated by prescriptions for well spacing. In areas where small ownership parcels of land are numerous, the lease holder or land owner must not have his property confiscated by others, merely because his tract of land is small. On the other hand, a well drilled on a small tract of land may be too costly unless some drainage is allowed from neighboring land to allow enough production to pay for the well. In this instance, there is confiscation by the small tract owner, and ratable take laws are violated. This then becomes a situation in which well spacing and proration are both involved.

Some evidence on exceptions in favor of small units is found in Table IV-A, reporting Rule 37 applications in relation to regular drilling applications. It is impossible to generalize about exceptions to the spacing rule, but no doubt a large proportion of them were in favor of small tracts. The present Texas law requires that an exception be granted to anyone requesting it for land subdivided before Rule 37 was promulgated.

TABLE IV-A  
REPORT COVERING REGULAR DRILLING APPLICATIONS AND  
RULE 37 APPLICATIONS 1947-1961

Year	Regular Drilling Applications	Rule 37 Applications			Exceptions Granted As % of Total Applications
		Filed	Granted	Denied	
1947	9,748	1,579	1,357	41	13.92
1948	12,996	1,794	1,537	33	11.83
1949	13,635	2,028	1,706	22	12.51
1950	16,921	2,218	1,942	50	11.48
1951	20,690	1,997	1,731	40	8.37
1952	18,366	1,459	1,273	24	6.93
1953	20,285	1,596	1,308	32	6.45
1954	20,962	1,673	1,343	57	6.41
1955	24,225	2,480	2,315	57	9.56
1956	24,436	1,538	1,444	19	5.91
1957	22,163	1,475	1,447	28	6.53
1958	19,553	1,290	1,256	43	6.42
1959	19,042	1,399	1,256	64	6.60
1960	15,601	1,376	1,295	55	8.30
1961	15,369	1,561	1,509	39	9.82

Source: Annual Reports of the Texas Railroad Commission, 1947-61, Table 12.



The permit to drill on a small tract will, of course, not be used unless the operator thinks that the production from such a well will cover the costs of drilling and producing and return some profit. In Texas, many small tract wells are granted allowables which result in drainage from surrounding acreage. The recent *Normanna* case has cast doubts on the legality of such allowables. In this case, the Texas Supreme Court declared such drainage to be unlawful confiscation of property and ordered the Railroad Commission to find an equitable formula.<sup>83</sup>

The basic Texas law and Railroad Commission Rules appear flexible enough to permit most spacing on the basis of technical considerations. Probably it would be necessary to have compulsory unitization of drilling and production units to assure low-cost efficiency and equitable treatment of all property interests. The two major stumbling blocks for successful implementation would be (1) political pressure put on the Railroad Commission and State Legislature by those who feel they would be hurt by such changes, and (2) the courts' emphasis on individual property rights taking precedence over the more nebulous social or public rights.

Texas well spacing should be studied to determine the basis upon which spacing patterns are set, the degree to which the actual spacing conforms to accepted criteria, and whether any changes might be suggested that would keep the beneficial aspects of the spacing, but would also permit a reduction in the number of wells drilled. Before any recommendations can be made, a thorough engineering and economic study needs to be made. This would have to be done in conjunction with a study of proration.

The Oklahoma well spacing law is similar to that of Texas but lacks the mandatory "exception" for small tracts. The pertinent provisions read as follows:

(2) All wells drilled for oil or gas to a common source of supply in excess of 2,500 feet in depth shall be located not less than 330 feet from any property line, or lease line, and shall be located not less than 600 feet from any other producible or drilling oil or gas well when drilling to the same common source of supply unless otherwise specifically permitted by order of the Commission upon hearing; provided and except that in drilling to a known common source of supply that is less than 165 feet from a property line, or lease line, and not less than 300 feet from any other producible oil or gas well, or drilling well, in said source of supply, unless otherwise specifically permitted by order of the Commission; provided, however, that the completed depth of the discovery well shall be recognized as the depth of the pool for spacing purposes.

(b) When such an exception is granted the Commission may adjust the allowable or take such other action as it deems necessary for the prevention of waste and protection of correlative rights.

(c) The Corporation Commission may establish well spacing and drilling units provided by law and such special orders creating drilling and spacing units shall supercede the provisions of this rule as set forth in Paragraph (a) hereof, and, it shall be the responsibility of any operator who proposes to drill to ascertain the existence and provision of special spacing orders.<sup>84</sup>

The distance requirements in the Oklahoma rule are somewhat different from those of Texas, but are about as flexible. Section (c) gives the Corporation Commission the power to set the size of the drilling unit.

Professor Zimmermann, using a memorandum on conservation prepared by the Production Research Organization of the Humble Oil Company, makes a comparison of spacing, production, and reserves of fields developed before conservation regulations with fields developed thereafter. The conclusion is that regulation has brought about considerably wider spacing, which has contributed to larger recoveries of oil in place and more orderly development and production. Pressure and production declines were much more rapid in the unregulated fields than in the regulated ones.<sup>85</sup>

A study by the Standard Oil Company of New Jersey published in 1947 states that: "Before 1929, only seven percent of Texas fields were drilled on a spacing as large as one well to each 20 to 30 acres. Since 1935, more than a quarter of its fields have been drilled on that basis, and 14 percent are on 40-acre spacing."<sup>86</sup> If, as engineers now claim, oil well spacing can usually be about 40 acres or more, and gas well spacing about 640 acres, there is still a long way to go.

An A. P. I. Committee in 1941 concluded that:

In most cases, a spacing within the range of one well to between ten and eighty acres will meet these conditions of providing information and securing an efficient rate of production.

Actual well spacing patterns are seldom determined by the physical factors alone, but more often by many practical factors which enter in the problem, such as land subdivisions or exceptions to accepted spacing patterns. In most reservoirs, well spacing does not become an essential part of the conservation problem until the important economic factor is introduced.<sup>87</sup>

Work needs to be done on what well spacing patterns actually exist. Since most states keep records of this sort, it seems feasible to get representative figures from each state. Existing rules and regu-

lations give most states a great deal of flexibility to do what is best to prevent waste and confiscation. A broad picture of what is being done should prove helpful.

If, as seems clear, many more wells are drilled in the U. S. than are necessary to discover, develop and produce a given amount of oil, then clearly this is a factor raising costs per barrel of proved reserves. Exploration costs are not affected substantially by excessively close spacing, since much the same geophysical, geological, leasing and exploratory drilling expenses would be incurred regardless of the spacing pattern selected once a field is discovered. The spacing of initial development wells is extremely important, since a pattern can more easily be reduced than enlarged. Development costs, therefore, bear the brunt of the unnecessary incremental drilling. Production costs are also higher, since more wells must be maintained to produce the reservoir. If production costs per barrel are relatively high, then abandonment will occur earlier than if the costs are lower. This means that the proved reserves (given their economic definition by the A. P. I.) are less for closely spaced fields.

The exploration costs are indirectly affected if abandonment is earlier than it might otherwise be. These costs are sunk and are fixed in amount. The more reserves proved up, the lower the exploration costs *per barrel*. Close spacing also may reduce ultimate recovery by causing too rapid a decline in reservoir pressure and thus irregular migration, water bypassing oil, and, in the case of some gas fields, retrograde condensation. The smaller recoverable reserves boost both exploration and development costs on a per-barrel (or per Mcf) basis. The *Oil and Gas Journal* reported that there were about 44,000 wells drilled in the U. S. during 1960 (excluding service wells). If the average cost of wells is about \$50,000, and if 10 percent of the wells drilled were "unnecessary," this would mean that almost a quarter of a billion dollars was "wasted."

*Proration.*—A second important regulatory tool at the disposal of state agencies is the power to regulate production from each well in the state, to allocate a state allowable among pools in the state, and to allocate pool allowables among wells in a field. This process, called proration, is in part separate from well spacing, insofar as it relates to regulating the flow from wells already in existence. But it also overlaps well spacing, since the allowables of new wells permitted to be drilled also have to be regulated. This particular aspect of conservation has generated a great deal of controversy. The courts have held that a state may use its police power to prevent the waste of a natural resource, and that reasonable proration comes within

this power. Under the form for a model oil and gas statute proposed by the Interstate Oil Compact Commission, the definition of "waste" includes:

- (1) physical waste, as that term is generally understood in the oil and gas industry;
- (2) the inefficient, excessive, or improper use, or the unnecessary dissipation of reservoir energy;
- (3) the inefficient storing of Oil or Gas;
- (4) the locating, drilling, equipping, operating, or producing of an Oil or Gas well in a manner that causes, or tends to cause, reduction in the quantity of Oil or Gas ultimately recoverable from a Pool under prudent and proper operations . . . ;
- (5) the production of Oil or Gas in excess of (a) transportation or marketing facilities; (b) Reasonable Market Demand. . . .<sup>88</sup>

Proration falls into two primary types: (1) M. E. R. proration; and (2) "market demand" proration. The first type permits oil (or gas) to be produced at the "maximum efficient rate," *i.e.*, the most rapid rate possible which does not reduce the ultimate recovery from a reservoir.<sup>89</sup> The second type limits production to what the regulatory agency feels is needed for consumption and maintenance of proper inventories. All of the major producing states, with the exception of California and Wyoming, have these two ideas embodied in their proration laws and regulations. For practical purposes, it is the second type which has come to assume major importance.

The allowable set for any particular well or field depends upon a number of factors, and the relative importance of one factor to others in the proration formula varies from state to state and field to field. There is usually the general requirement that the regulatory agency must allocate production on a reasonable basis and without discrimination. Among the factors considered by states in allocating production among wells within a pool, or among pools within a state are: (1) the number of wells on a tract; (2) the number of acres in a tract; (3) producing potential of wells; (4) the gas-oil ratios; (5) the bottom hole pressures; (6) thickness of the formation; (7) the depth of the formation; (8) the effective drainage area for a well; and (9) the type of water encroachment or production (if any). Rarely are all of these factors used in any given situation.

There are three steps in establishing an allowable for a well: (a) a state quota must be determined; (b) the state quota must be allocated among fields; (c) the field allowable must be allocated among the individual wells within the field.

*The first step*, determining the state quota, is done monthly in most states and is based on: (1) the physical capacity of the state

based on the MER; (2) the refiner or buyer "nominations" for purchases of crude oil; (3) the monthly "demand" or consumption forecasts made by the Bureau of Mines for each state and for the nation; (4) the quantity of crude and finished products in above ground storage; (5) crude oil transportation facilities that are available; (6) estimates of crude and refined product imports and of production in other states; and (7) the general expertise of the regulatory agency.

When state regulatory agencies make short-run consumption forecasts for crude oil in their jurisdictions and restrict supply to near that level, each state is to some extent competing for advantage against other states. This is particularly true in times when there are "surpluses" of crude oil, extant or potential. Each state must then consider importing supplies from other areas. One guiding factor in establishing state quotas is nominations by major buyers. Also, a state cannot force a buyer to purchase the full allowable of each well to which the buyer is connected. These factors place a limitation on the power of regulations to penalize other states. Compulsory purchasing was attempted in Oklahoma in an effort by that state to maintain production and crude sales; this effort failed.<sup>90</sup> A purchaser, if he is a common carrier, must, however, purchase ratably from all sellers. Also, a common carrier pipe line must tie in to any unconnected well in a field, if the well is a reasonable distance from the line.

*The Second step*, allocating a state quota among fields, involves breaking out marginal wells, discovery wells, and flowing wells. Marginal wells are frequently defined in terms of what they can produce in a given day, from various depths. In Texas, a well which produces no more than 10 barrels a day, without artificial lifting power, from a depth of 2,000 feet or less is considered marginal. As the depth increases, the production for marginal wells rises. At 8,000 feet or more a well can produce 35 barrels and still be classed as marginal. Many wells which are on some type of artificial lift or part of a secondary recovery project (whether flowing or pumping) are classed as marginal. Marginal wells are exempt from proration, and the aggregate production of all such wells in the state is subtracted from the state quota to obtain a quota allowable among flowing wells and exploratory wells.<sup>91</sup>

Exploratory wells in Texas are allowed a bonus of production based on depth and well spacing considerations. A well is classed as exploratory for 18 months after a field is discovered or until six wells have been drilled in the field, whichever occurs first. After

this period, exploratory wells are reclassified and put into the flowing wells category. The production from exploratory wells is deducted from the state quota to arrive at a figure which can be divided among the flowing wells in the state.

The allocation of the remainder of the state quota is among pools having *flowing wells*; thus, cutbacks or increases in the state quota fall primarily on this category. Proration in this category is a reservoir engineering problem and is based primarily on the relative producing potentials of all these pools. The potential production is calculated for each pool; if the quota to be allocated is, for example, one-half the sum of these potentials, then each pool is allowed to produce one-half of its potential for a particular month. In Texas this is stated in days production at potentials set by the Commission for any month; in this example it would be 15 days production.

Depth is often of primary concern in establishing field or pool allowables and is written into the statutes or rules and regulations of some states. In New Mexico, for example, one of the rules of the Conservation Commission reads as follows:

Rule 505. OIL PRORATION

(a) In allocated pools, the allocation between pools is in accordance with the top of the producing depth of the pool and the corresponding proportional factor set out below. The depth to the casing shoe or the top perforation in the casing, whichever is the higher, in the first well completed in a pool determines the depth classification for the pool. Top unit allowable shall be calculated for each of the several ranges of depth in the following proportions.

(b)

POOL DEPTH RANGES	40-acre Proportional Factor	80-acre Proportional Factor
0 to 5,000 feet	1.00	
5,000 to 6,000 feet	1.33	2.33
6,000 to 7,000 feet	1.77	
7,000 to 8,000 feet	2.33	3.33
8,000 to 9,000 feet	3.00	4.00
9,000 to 10,000 feet	3.77	4.77
10,000 to 11,000 feet	4.67	5.67
11,000 to 12,000 feet	5.67	6.67
12,000 to 13,000 feet	6.75	7.75
13,000 to 14,000 feet	8.00	9.00

(c) The 4-acre proportional factor shall be applied to pools developed on the normal statewide 40-acre spacing pattern.

(d) The above 80-acre proportional factor shall hereafter be applied to all pools developed on an 80-acre spacing pattern, which the Com-

mission hereafter authorizes as an exception to the normal state wide 40-acre spacing pattern.

(e) Normal unit allowable shall be set by the Commission.

(f) Top unit allowables for each range of depth shall then be determined by multiplying the normal unit allowable by the proportional factor for each depth range as set out in the table hereinabove; and fraction of a barrel shall be regarded as a full barrel for both normal and top unit allowables.

(g) The top unit allowables hereinabove determined shall be assigned to the respective pools in accordance with each pool's depth range.<sup>92</sup>

Such provisions in proration rules give recognition to the more expensive wells drilled to and producing from greater depths, and give incentives to search for production at deep levels.

The rules recently promulgated in Oklahoma carry a similar provision. In Texas there is no such formula; adjustments are made at the discretion of the Railroad Commission.

*The third and final step* is the allocation of a pool allowable among wells within a pool. It is here where many of the nagging problems enter. Ideally, the owner (or lessor) of a tract should be allowed to recover the oil which lies beneath his land. As a practical matter, this ideal can rarely be achieved. Some of the most common proration formulas base the allowable for a particular tract or lease on the areal size of the tract, and/or the number of wells on the tract. Some fields, for example, are prorated by a formula giving a  $\frac{2}{3}$ rds weight to acreage and a  $\frac{1}{3}$ rd weight to wells. Neither the size of a tract nor the number of wells on it *necessarily* has anything to do with the amount of producible oil or gas beneath that tract. In a field where the producing formation varies in thickness, porosity, permeability, or in other important ways, two tracts, each 40 acres in area, may have vastly different recoverable reserves and MER's. Thus spacing based on area may be inequitable.

Proration based on the number of wells may be much more unsound. Engineering studies have established that for all but a few types of reservoirs, well density does not affect the recoverable reserves, assuming that production is no greater than the engineering optimum. If well spacing follows a regular pattern, then proration on a per-well basis achieves the same results as proration on a basis of acreage. The shortcomings of area spacing would then apply.

If a per-well formula for allocating production is used, *and* if at the same time irregular spacing is permitted by issuing "exceptions" to the spacing rules, then there is apt to be (1) unnecessary drilling with the resultant increased costs for the life of the field, (2) a danger of a more rapid pressure decline than under other

drilling and production rules, (3) reduced ultimate recovery from the reservoir, and thus higher costs per barrel of reserves, and (4) inequities or losses accruing to some operators in the field, who, in many cases, may be practicing the most efficient drilling and production practices.

Thus we find a legal institution, in the form of spacing and proration regulations, which may increase drilling and producing costs substantially. Why are such regulations continued? As a practical matter it is difficult to establish what is equitable, since it is hard to estimate precisely how much oil or gas underlies a given piece of land. Also, if wells have been properly spaced in a field which is fairly uniform in terms of underlying reserves, then the per-well formula described earlier really becomes an acreage formula. For those fields in which pay thickness is fairly uniform and in which the flow characteristics are relatively uniform, an acreage formula comes close to achieving the ideal. And given proper well spacing (from a reservoir engineering standpoint), the same might be said for a formula based solely on the number of wells, since each would be draining comparable areas and would be producing comparable amounts of oil or gas.

A summary of the formulas used for the allocations of oil among wells in a given field or of gas among wells in a given field was reported for Texas in 1949. This information is found in Table IV-B. For oil the most widely used formula is one allocating production strictly on the basis of the number of wells in a field. The importance of these fields, in terms of reserves, is not given. Next in importance is the 50 percent acreage and 50 percent per-well basis, followed by 75 percent acreage and 25 percent per-well basis. In a few fields, well potential, bottom hole pressure or some other basis is used. Well potential has the defect that it leads to dense drilling in the most permeable portions of the field where well spacing should be quite wide. This also causes producers to use completion practices which will stimulate initial production and provide high allowables, but which ultimately may cause excessive production of gas and water.<sup>93</sup>



TABLE IV-B  
 BASIC FORMULA USED FOR ALLOCATION TO WELLS  
 OF OIL ALLOWABLE ASSIGNED FIELD

	<i>Number of Fields in Which Used</i>
Per Well	1,065
100% Acreage	40
50% Acreage and 50% Per Well	232
75% Acreage and 25% Per Well	163
25% Acreage and 75% Per Well	5
2/3 Acreage and 1/3 Per Well	3
50% Acreage and 50% Potential	27
60% Acreage and 40% Per Well	5
50% Acreage and 25% Potential and 25% Per Well	1
75% Acreage and 25% B.H.P.	1
50% Acreage and 50% B.H.P.	2
75% Acreage and 25% Potential	3
1/3 Acreage and 2/3 Per Well	2
1/3 Acreage and 1/3 B.H.P. and 1/3 per well	4
Acreage Times Effective Pay Thickness Times B.H.P.	1
Acreage Times B.H.P.	1
Per Well Plus % of Potential	12
% of Hourly Potential with Minimum Well Allowable	1
25% Acreage and 75% Average Unit Potential with Minimum Unit Allowable	1
40% Per Well and 60% Average Unit Potential	1
100% Average Unit Potential with Minimum Unit Allowable	1
*A = $\frac{T B X}{FVF + (2 PR - SR - IR) f}$	1

\* In this formula the symbols used stand for the following: "A" is daily well allowable in barrels of stock tank oil; "B" is productive acres assigned the individual well; "X" is the acreage thickness factor obtained by dividing the assigned oil allowable for the reservoir by the summation of the products obtained by multiplying the acreage assigned each oil well by the effective thickness of the oil sand of each such well; (FVF) is formation volume factor of the oil; "T" is effective thickness of the oil sand in the individual well; "PR" is the producing gas-oil ratio of the individual well; "SR" is the solution gas-oil ratio of the reservoir; "IR" is the injected gas-oil ratio for the reservoir; and "f" is the gas factor.

Source: Interstate Oil Compact Commission, Research and Coordinating Committee, "Report on the Study of Allocation Formulae, by State," *Interstate Oil Compact Quarterly Bulletin*, Vol. 8, Nos. 3 and 4, December 1949, p. 86.

Given the proration procedures outlined above, what can be said in summary about their impact on finding and development costs? Proration formulas which put primary emphasis on wells tend to

cause unnecessary drilling, unless well spacing is tightly controlled and unitization of drilling and producing is made compulsory on some equitable basis. Allowables granted on an acreage basis reduce the incentive to drill unnecessary wells.

Most proration rules today carry provisions for maximum allowed gas-oil ratios. In some instances the gas must be returned to the reservoir; in other instances the flow of oil and gas is restricted. Recycling raises the investment necessary to produce the oil, but it may substantially increase recoverable reserves significantly reducing exploration and development costs per barrel.

To the extent that a well's production is restricted below its MER, the cost per barrel of oil recovered increases. Longer-lived wells require greater outlay for maintenance and production. Also, some discounting factor must be applied to the "investment" in underground oil and gas "inventories," if this inventory cannot be disposed of as rapidly as it might be. In this connection, imports affect costs, insofar as they lead to restricted domestic production.

To see the consequences of restricted production for costs, we need to examine some cost features connected with the "excess" productive capacity in the domestic crude producing industry, about which much has been written. The presence of excess capacity has a direct relationship with proration as it is practiced in the "market demand" states. A recent National Petroleum Council Report indicates that productive capacities in the industry as of January 1, 1960, were as follows:

1) Crude Oil	10,585,000 barrels daily
2) Natural Gas Liquids	1,799,600 barrels daily
3) Natural Gas	71,504,000 Mcf. daily

Production during 1960 averages the following:

1) Crude Oil	7,035,000 barrels daily
2) Natural Gas Liquids	941,342 barrels daily
3) Natural Gas	41,224,000 Mcf. daily (Gross Production)
	[36,431,000 Mcf. daily (Gross Production Less Repressuring)] <sup>94</sup>

One simple way to look at the effect of idle capacity on costs is to consider (1) the effect on finding and development costs per barrel of drilling more wells than are necessary to meet current demands for domestic oil, and (2) the operating and maintenance costs of these wells.

Once the wells are in existence, however, the cost of restricting their output must be calculated in a more elaborate way. Let us

take a simplified and somewhat unrealistic example to illustrate the opportunity costs of restricted output.

Assume the following things:

- (1) A field is discovered which has one million barrels of recoverable reserves.
- (2) The field can be produced at its optimum rate so that it will be depleted at the end of ten years and will produce 100,000 barrels per year.
- (3) The price of oil at the wellhead will be \$3.00 per barrel for the next ten years.
- (4) The average rate of profit, after taxes, in this business is 8 percent.
- (5) Ignore finding, development and producing costs for the time being.

If, at the outset, this field is restricted to one-half its capacity to produce, *i.e.*, to 50,000 barrels per year, what opportunity costs are incurred by the operator by the fact that production is restricted and the life of the field is pushed to 20 years? The opportunity cost would be 8 percent of \$150,000 compounded annually for ten years, or \$173,835 per year. Since the producer must postpone producing 50,000 barrels each year for ten years, the total opportunity cost over the life of the field would be \$1,738,350. An alternative way of stating the same problem, leading to the same result, is to ask how much profit a producer could make producing at one half capacity each year for 20 years compared to producing at full capacity each year for 10 years.

Since capital resources in an economy are relatively scarce, a cost of the type described above is a real social cost and not just an individual's profits foregone for some finite period. If we add to this example: (1) the increased cost of production per barrel because of the lengthened period; (2) the increased maintenance cost; and (3) the increased cost of spreading certain fixed costs over a longer period, the implications for average per barrel costs are obvious. They rise substantially.

The simple example ignores possible price changes; it assumes an unrealistic production curve for an oil field, and abstracts from the interaction of the possible additional oil on industry-wide prices. Despite these assumptions, the nature of the general impact on costs is clear. It is interesting to note that proration in market demand states hits those wells whose opportunity costs are greatest when output is cut back. In other words, efficient wells are penalized and inefficient wells are rewarded, in a relative sense.

*Pooling of Drilling and Unitization of Production Units.*—The ideal way to develop a field after its discovery is to use relatively wide (several hundred acre) well spacing to define the limits of the field and to obtain as much information as possible about drilling and producing conditions over a wide area. With the field fairly well defined and with considerable information on such things as reservoir and fluid characteristics, recoverable reserves, optimum producing rates, gas-oil ratios, pressures in the reservoir, and the like, reservoir engineers can estimate fairly accurately the number of wells that need to be drilled and where they should be located to get the maximum ultimate recovery at the lowest cost. This planning can be done for both the primary and secondary stages of production so as to facilitate pressure maintenance or secondary recovery projects in the future. Given large concession areas in Latin America, Africa, or the Middle East, a company will proceed along these general lines. And as was noted earlier, the result is frequently the drilling of, and producing from, relatively few wells.

We have seen from the discussion of mineral property rights and conservation regulation in the various states that domestic producers usually cannot develop a field in the manner described above. There are, however, ways of approximating the ideal situation. These are lumped under the terms "pooling" and "unitization." Pooling is a term applied to the combining or pooling of tracts so as to comply with a state well spacing order for drilling purposes. Unitization is the combining of producing tracts overlying a given pool so that the pool can be produced in the most efficient and economical manner possible, regardless of surface ownership boundaries.

A well spacing regulation which does not allow "exceptions" to be made, and thus permit small tract drilling, can effectively enforce the *pooling* of drilling units, if the parties concerned are interested in having the property drilled. There remains the problem, in such cases, of mutually agreeing to a division of costs and possible revenues. In some states, if the parties involved cannot reach an agreement, the regulatory agency is authorized to hold hearings and establish the fair shares. This is compulsory pooling. The establishment of a realistic well spacing law, accompanied by commission powers to require that drilling units be defined, provides a useful tool for keeping drilling costs down and at the same time protects the interests of individuals concerned. Much of what has been said earlier about well spacing applies here. It should be noted, however, that well spacing regulation does not assure the optimum number

of wells being drilled, particularly when the spacing pattern is determined before the characteristics of the field are fully known.

*Unitization* of production is something quite different and is an aspect of conservation regulation that needs more attention. It usually has application when a pool has a pressure maintenance or a secondary recovery project in operation, or when such projects are being contemplated. Problems of unitization are usually discussed in relation to fields already developed, where the problem is that of recovering a large portion of the underlying oil, and we will first examine that situation.

From an engineering and economic standpoint it may be best (*i.e.*, result in lowest cost) to treat a pool in its entirety, shutting in some wells, using others for gas or water injection, and using others to produce the oil. It may also be wise to move the oil within the producing formation in one direction or another to optimize production. If a pool has multiple developers, each owning a piece of the field, the problems of obtaining mutual agreement of all interests (including royalty owners) are difficult. It is necessary to agree upon sharing costs and revenues from the pool as a whole, regardless of where the costs are physically incurred or where the oil (revenue) is physically produced.

There is no question that many pressure maintenance and secondary recovery projects are sound from an economic standpoint in that new reserves are "found" at relatively low costs. To the extent such projects are thwarted by the inability of owners of a pool to agree on sharing costs and revenues, there is an increase in the cost of finding and developing domestic oil. In some states, unitization is compulsory (Louisiana and Oklahoma among the major producing states) at the option of the regulating body, provided certain statutory requirements are met. In other states, unitization is "voluntary," (Texas, New Mexico, Kansas, California and Wyoming, for example) which means that the conservation laws and state antitrust laws do not prohibit agreements for such projects. In those states where unitization is voluntary, a regulatory agency can put a great deal of pressure on the owners of the pool to agree. Under their powers to prevent waste, these commissions can, for example, shut in an entire pool if existing production practices are "wasting" oil and/or gas. The field can be kept shut in until provisions are made to eliminate the "waste."

Table IV-C gives some idea of the growth of unit operations in the U. S. Between 1951 and 1958 the number of projects in operation rose from 173 to 779. By 1958 about 15 percent of the nation's

production came from unitized projects. As pressure maintenance and secondary recovery techniques are improved, it is expected that an increasing part of U. S. output will come from these projects.

TABLE IV-C  
UNITIZATION PROJECTS IN THE U. S.—1951 AND 1958

State	No. of Unitized Projects		Unitized Oil Production During	Total Oil Production During	Unitized Production As % of Total Pro- duction '58
	Jan. 1, 1951	Jan. 1, 1958	1958	1958	
Arkansas	4	17	11,285	28,700	39.32
California	5	23	50,197	313,672	16.00
Colorado	5	32	32,529	48,736	66.75
Illinois	5	135	19,174	80,275	23.89
Indiana	0	29	2,691	11,864	22.68
Kansas	22	55	5,542	119,942	4.62
Kentucky	0	4	482	17,509	2.81
Louisiana	33	104	29,785	313,891	9.49
Michigan	0	5	917	9,308	9.85
Mississippi	4	4	7,131	39,512	18.05
Montana	1	3	13,668	27,957	48.89
New Mexico	2	3	864	98,515	.88
North Dakota	0	3	5,988	14,259	41.99
Oklahoma	16	197	40,981	200,699	20.42
Texas	25	137	135,760	940,166	14.40
Utah	3	0	0	—	—
Wyoming	48	28	N.A.	—	—
Totals	173	779	357,005	2,448,987	14.60

N.A. — Not Available.

Sources: Interstate Oil Compact Commission, *Unitized and Cooperative Projects in the United States*, September 1, 1952; and *Ibid.*, *Unitized Oilfield Conservation Projects in the United States*, 1 January, 1959.

Virtually everyone is agreed on the desirability of unitizing production and is aware of the cost savings possible both from decreased operating expenses and increased recoverable reserves. Yet there is opposition in some states to "compulsory" unitization. This opposition stems largely from a fear on the part of small operators that they will lose what is rightfully theirs to those who have more bargaining strength. To meet such opposition it appears necessary, not only to devise compulsory unit operations which safeguard the rights of individuals, but also to demonstrate the advantages to

various interested parties, in terms of increased reserves and ultimate revenues. Studies to determine the additions to reserves and the costs and revenues of such projects might well provide evidence which would help to overcome the objections to unitization.

Secondary recovery operations and unitization of production units are closely related. Most unitization is done to put a pressure maintenance or secondary recovery project into operation. However, many secondary recovery projects do not require unitization agreements. Conservation regulations usually cover the physical aspects of establishing and operating secondary recovery projects in addition to covering the legal aspects of unitization.

It is difficult to obtain accurate information on secondary recovery operations for the nation as a whole. However, the Interstate Oil Compact Commission estimates that there were 16.3 million barrels of oil reserves recoverable by conventional fluid injection methods under economic conditions as of February 1, 1962.<sup>95</sup> It is not unlikely that secondary recovery methods will ultimately contribute largely to the reserves of the future. But to achieve this result a much greater degree of unitization will be required.

Out of the contents of this Part IV, which has gone somewhat far afield to show the way in which property rights and regulatory rules may affect costs, may be distilled the following conclusions:

1. The laws of property relating to mineral rights permit or induce the drilling of wells which are unnecessary from the point of view of efficient development of fields, and generate practices inimical to maximum recovery.

2. The regulatory process includes the power to exercise some restraint on inefficient development and to impose more efficient methods which would both reduce development costs and increase ultimate recovery.

3. Prorating procedures, in some jurisdictions and in some respects, are favorable to excessive drilling and other cost-raising practices.

4. While conservation regulation has in some degree mitigated wasteful and cost-increasing practices, there are still unexploited possibilities for improvement through well-spacing, pooled drilling, secondary recovery, unitization, and modified prorating rules.

#### V. PROSPECTIVE SUPPLY AND COSTS IN RELATION TO POLICY

The burden of this study has been that certain improvements in the informational sources of the petroleum industry, and certain

tasks of analysis which depend on these improvements, ought to be accomplished. While it is assumed that these tasks are related to questions of public policy, we take no position on matters of policy. We do, however, believe that command and analysis of the facts should precede future formulations of policy. Since policy is mainly concerned with supply, we need to place in perspective some quantitative estimates of future requirements, as a basis for identifying the nature of the central policy issues.

*Consumption and Availability Estimates to 1975*

In order to establish some orders of magnitude, a few figures may be cited from two standard sources—the Paley Commission Report and the Resources for the Future study.<sup>96</sup>

The relevant table from the Paley Commission Report is reproduced as Table V-A, where the United States figures are shown in the context of the world situation. In this projection, translated to annual terms, the hypothetical domestic production figure for crude oil and natural gas liquids in 1975 is placed at 4.09 billion barrels, against 2.16 billions in 1950 (and 2.9 billions in 1960), an increase of 85 percent from 1950 (and of 41 percent from 1960).

Consumption in 1975 is estimated at 5.0 billion barrels as against 2.35 in 1950, an increase of 109 percent. The balance of production is made up by a 363 percent increase in imports. Imports would then make up 18 percent of total consumption.

In Tables V-B and V-C, we reproduce the Schurr and Netschert projections of consumption in 1975, in the context of total U. S.



TABLE V-A  
 HYPOTHETICAL PATTERN OF FREE WORLD OIL SUPPLIES AND  
 DEMAND IN 1975 COMPARED WITH 1950  
 (Thousands of barrels per day)

Region	Production		Apparent Consumption		Net Imports— Net Exports+	
	1950	1975	1950	1975	1950	1975
United States	5,910	11,200	6,450	13,700	-540	-2,500
Other Western Hemisphere	2,040	5,900	1,190	4,600	+850	+1,300
Total Western Hemisphere	<u>7,950</u>	<u>17,100</u>	<u>7,640</u>	<u>18,300</u>	<u>+310</u>	<u>-1,200</u>
Europe	60	300	1,200	4,000	-1,140	-3,700
Middle East and other						
Eastern Hemisphere	2,040	9,400	1,100	4,500	+940	+4,900
Total Eastern Hemisphere	<u>2,100</u>	<u>9,700</u>	<u>2,300</u>	<u>8,500</u>	<u>-200</u>	<u>+1,200</u>
Total free world excluding						
United States	<u>4,140</u>	<u>15,600</u>	<u>3,940</u>	<u>13,100</u>	<u>+650</u>	<u>+2,500</u>
Total free world	10,050	26,800	9,940	26,800	+110	.....

<sup>1</sup> Crude oil, natural gas liquids, shale oil and other synthetics.

Source: U. S. Bureau of Mines, *Minerals Yearbook, 1950*; 1975—President's Materials Policy Commission, *Resources for Freedom, Vol. III: The Outlook for Energy Sources* (Washington: Government Printing Office, 1952), p. 9.

TABLE V-B

PHYSICAL UNITS OF ENERGY CONSUMPTION, BY SOURCE,  
1955 AND ESTIMATED 1975

Energy Source	Consumption		Absolute Change (3)	Percentage Change (4)
	1955 (1)	1975 (2)		
Coal (million tons)	451	768	+ 317	+ 70.3
Bituminous	431	754	+ 323	+ 74.9
Anthracite	20	14	— 6	— 30.0
Crude oil (million bbl.)	2,774	5,154	+ 2,380	+ 85.8
Natural gas (billion cu. ft.)	9,614	19,881	+ 10,267	+ 106.8
Natural gas liquids (mil. bbl.)	260	769	+ 509	+ 195.8
Hydropower (billion kwh)	120	265	+ 145	+ 120.8
Consumed as electricity (bil. kwh)	633	1,966	+ 1,333	+ 210.6

Source: Schurr and Netschert, *Energy in the American Economy 1850-1975 Its History and Prospects* (Baltimore: The Johns Hopkins Press for Resources for the Future, Inc., 1960), p. 238. (footnotes omitted)

TABLE V-C

BTU'S OF ENERGY CONSUMPTION, BY SOURCE,  
1955 AND ESTIMATED 1975

Energy Source	Consumption (trillion Btu)		Percentage Share of Each Fuel in Total Change (3)	Percentage Change in Btu Consumption (4)	Percentage Share of Each Energy Source in Total Btu Consumption	
	1955 (1)	1975 (2)			1955 (5)	1975 (6)
Total	39,723	74,541	100.0%	+ 87.7%	100.0%	100.0%
Coal	11,422	19,043	+ 21.9	+ 66.7	28.8	25.5
Bituminous	10,910	18,688	+ 22.3	+ 71.3	27.5	25.1
Anthracite	512	355	— 0.4	— 30.7	1.3	0.5
Oil	16,090	29,896	+ 39.7	+ 85.8	40.5	40.1
Natural gas	9,552	19,726	+ 29.2	+ 106.5	24.0	26.5
Natural gas liquids	1,235	3,495	+ 6.5	+ 183.0	3.1	4.7
Hydropower	1,424	2,381	+ 2.7	+ 67.2	3.6	3.2
Consumed as electricity	7,680	18,053	+ 29.8	+ 135.1	19.3	24.2

Source: Sam H. Schurr and Bruce C. Netschert, *Energy in the American Economy 1850-1975 Its History and Prospects* (Baltimore: The Johns Hopkins Press for Resources for the Future, Inc., 1960), p. 239. (footnotes omitted)

energy consumption. The principal difference from the Paley Commission Report is that total consumption in 1975 is projected at 5.9 billion barrels (crude oil and NGL) as against 5.0 billions. On the supply side this would mean an increase of .9 billion barrels in domestic production and imports above the Paley Commission Report projection.

Though not venturing a domestic production estimate, Schurr and Netschert conclude that domestic availability of crude oil in 1975 *could* be as high as 4 billion barrels by primary-recovery methods and 2 billion barrels by secondary-recovery methods, or 6 billion barrels in all, *at no appreciable increase in constant dollar costs*. In addition, potential availability of natural gas liquids is estimated at 1 billion barrels, bringing all liquid hydrocarbons to a total of 7 billion barrels. These estimates admittedly reflect an optimistic view of the amount of "ultimate reserves," the prospects for discovery, and the technology of recovery. They run counter to a widely held view that substantial increases in proved reserves will entail a marked increase in real costs.

The differences of view on future costs have a bearing on alternative sources of future energy. If, because of higher costs, a higher price would be required to induce any substantial increase in oil discovery and development, the price increase might itself destroy the market for expanded oil production. It appears that oil-shale and tar sands are fairly close to the point, cost-wise, of competitive production, and a higher crude oil price could carry them across the margin. The prospect of a higher price for oil might also lead to an interest in expanded imports which would hold the price down, negating the need for crude oil expansion. Or again, a higher price for oil could change the competitive relations with coal.

Under the Schurr-Netschert conclusion, a rise in the price of oil (in constant dollars) would be unnecessary to provide incentives for a substantial increase of oil production. This situation would postpone the competitive impact of alternative sources of energy, even to some extent in the face of improved technology and lower costs for substitutes.

#### *The Impact of Excess Capacity*

When speculating upon the consequences of future oil prices, it is necessary to distinguish between the short-run and long-run influences bearing on prices. At the present time, the most striking fact is a world-wide over-capacity of the industry. Domestic prices are kept as high as they are primarily as the result of two lines of policy:

(1) the limitation of imports, and (2) the shutting in of potential production by prorating. It would appear that this situation will continue for the calculable future. In an expanding market, the longer-run consequences depend upon an economic fact (a cost fact governing the response of domestic supply to alternative prices) and a policy fact (the price which will be supported by the two methods cited above and the degree of reliance on each method).

Holding imports down would decrease the immediate reliance on prorating. If new domestic supplies became available only with increasing real cost, a stable real price would have the effect of removing domestic excess capacity; and in the end, increased domestic supply would call for a higher price. If, however, one follows the Schurr-Netschert projection, the present real price might perpetuate a perennial over-capacity, and call for continued prorating even if imports were sharply checked. National security considerations might, in fact, dictate such policies. The effects on domestic supply of any particular import policy and conservation policy would have to be observed from experience; but accurate observation of these effects would be the primary basis for charting the course of policy.

These abstract considerations appear in a new light when checked against present domestic capacity estimates. In the Report of the National Petroleum Council, referred to earlier, it is estimated that crude oil and natural gas liquids productive capacity at the end of 1960 totalled 12,385 thousand barrels per day, or 4.5 billion barrels per year.<sup>97</sup> Actual production in 1960 was 2.9 billion barrels, or only 64 percent of the estimated capacity.

This estimated present capacity is 1,185 thousand barrels per day, or 10.6 percent, larger than the Paley Commission Report production figure for 1975. It is also equal to 90 percent of the estimated total consumption for 1975 in the Paley Commission Report, and to 77 percent of the Schurr-Netschert estimate of total consumption in 1975. Depending upon whose figures you prefer, and allowing for substantial imports, capacity might be somewhat less in 1975 than in 1960, or somewhat more, and still provide adequately for the demands from domestic consumption.

But no one should on this account underestimate the high level of exploration and development activity required, even if we use the lower Paley Commission estimate of 4.09 billion barrels of domestic production required in 1975. This amounts to an average annual increase of about 80 million barrels from 1960 to 1975—which is above the average of the last 10 years. If production rose at that rate from the 1960 base, the total production 1961-75 would be of

the order of 53 billion barrels. Merely to maintain proved reserves at the present level would therefore imply average gross annual additions to reserves of 3.5 billion barrels, which is well above the rate of the past decade, and still further above the past 5 years. If reserves were to maintain the present ratio to annual production, the average annual addition to reserves would have to be larger by nearly 1 billion barrels.

Obviously, discovery and development activity could decline, or even lapse, for several years before productive capacity was cut back close to the production level. But this is impracticable because of the desirability of maintaining continuity in physical operations and technical improvement. For this purpose, a substantially high level of exploratory and development activity would be necessary. The direction and scope of this activity would depend upon various contingencies, such as the progress of secondary recovery methods and the degree of unitization accomplished. If substantial progress were made in these two directions, it would reduce the pressure for new discoveries, and possibly have the effect of reducing the cost per barrel of additions to reserves.

#### *Some Policy Considerations*

Much of the active pressure of retaining or modifying existing policies arises from vested interests within the industry and from consumers of the industry's products. Into the intricacies of these positions we cannot enter.

Federal policies center upon the objective of stimulating the discovery and development of oil reserves through regulation of taxes and limitation of imports. State policies center upon improving recovery and sustaining the values of oil by limitation of production.<sup>98</sup> These two pairs of objectives apparently contain contradictory elements, which stimulate production and at the same time restrict output. At the level of primary production petroleum policy issues may fall in two groups: (a) determining the size and role of the domestic industry in relation to domestic requirements and (b) compromising the conflicts of interest which arise in connection with (a).

*Short-Run Oversupply and Long-Run Adjustment.*—In the short-run, the potential oil production overhangs the market, and is only prevented from weakening it seriously by import restrictions and proration procedures. The immediate concern of producers is a restriction of supply which will permit profitable operation and pro-

tect the capital values of their assets, including their underground inventories of oil.

On this side of the problem there is little that can be said about costs. The relevant costs are mainly those which have heretofore been sunk in finding and development. Barring deliberate restriction of supply, prices could sink to any point which covered the variable costs of those who remained in production.

The concern of producers in current prices is not, however, limited to current profitability and capital values. The current prices maintained by restriction of supply, and the price anticipations created thereby, provide the incentives for some level of investment. The price validates costs. And costs, relative to price, regulate the processes of discovery and development. The essential problem of policy in this connection is to achieve some desired rate of addition to domestic reserves to be produced for domestic markets. While easy to state in principle, this is a prescription which is difficult to follow with any precision, because of the uncertainties surrounding the discovery of oil.

Nevertheless, there is a history in these matters. The wide spread between present capacity and production may, in a certain sense, be regarded as the result of a premature development of reserves. Looking backward, it may be said that past incentives were more than adequate to provide for present requirements. Looking forward, though there is no sure knowledge of the costs of adding to future supply and of the amount of reserves which would be forthcoming as the result of any particular price; more adequate cost studies and supply projections would nevertheless permit the "old game" to be played with more intelligence.

The above discussion is couched in terms of the presumed necessity for controls in the future. This is the point in such a discussion at which some economist asks why the control of production should not be abandoned, except perhaps for regulations designed to enforce equity and efficient drilling and recovery. This is a fair question, but not really relevant to the point we are making. An industry which has had its structure and operations built upon a body of law and of incentives maintained by production, import controls and tax benefits could not conceivably have the rug pulled out from under it with one motion. Even if a long-run policy of return to the free market were in view, the pathway would still require the use of existing types of control adapted to that end, or some as yet unformulated and untried alternative controls. This would entail de-

cisions based as soundly as possible on projections of costs and added reserves in relation to possible alternative prices.

Since, practically speaking, it seems improbable that controls will be abandoned in the foreseeable future, the case is so much the stronger that a clear and unambiguous analysis of the cost factors is an essential condition of policies intelligently geared to any desired level of capacity and rate of additions to reserves at minimum cost.

*Conservation.*—Conservation in the oil industry has two facets of meaning: limitation of present use to provide more fully for future generations; and efficient physical recovery of oil discovered, with due regard to economic considerations. The first meaning has all but disappeared from view, reflecting an optimistic view of forthcoming alternative sources of energy. With respect to the second meaning, it has been noted earlier in this paper what sorts of methods are available and to some extent employed. But the more striking showing is the extent to which these methods are not employed, due to property rights and the pressures from conflicting interests. The failure to impose strict conservation measures, it has been shown, has the effect of raising the cost of oil, by leading to the drilling of unnecessary wells and by reducing the recovery from known reserves. No attempt, so far as we know, has ever been made to measure the cost effects.

*Price Supports and Special Incentives.*—Under present policies, prices are supported in two ways: by limitation of imports and by aggregate proration of production in all states. The cost impacts of import control are impossible to measure, though presumably if imports were larger, the finding cost of future oil would be less per barrel, due to limiting the finding effort to the more likely areas. The impact of proration on costs was examined at an earlier point, in terms of opportunity cost of extending the time period of recovery of investment. With fuller data, this factor would be capable of measurement.

The cost effects of tax incentives to discovery and development cannot be measured, and there is therefore nothing to say about them in the present context. The incentives affect the amount of new effort, and the result of the effort leads into the various cost-increasing categories of policy.

*National Defense.*—The implications of the cost-increasing policies we have reviewed would be much clearer, though none the less controversial, if the industry were operating in a chronically peaceable world. The issues would be largely analogous to those in the perennial tariff controversy, with special facets added because of the

“wasting-asset” character of the industry and the uncertainties of new supply in response to investment.

However, in the face of perennial cold war and the danger of hotter wars, the subject of national defense inevitably enters the discussion. The central point, to which all others are subordinate, is that the United States and its Western allies must never be caught short of oil, while mounting a large defense effort or in the actual emergency of war. This means, in effect, envisaging the possible unavailability of Middle Eastern sources and the necessity of primary, if not sole, reliance upon the reserves and productive capacity of the Western Hemisphere.

The necessary safeguards are ordinarily thought of as requiring three practical applications of policy: possessing some excess capacity to permit expanded production in an emergency, maintaining an apparatus for expanding the potential future supply of oil by additions to reserves, and supporting a set of incentives which will insure the desired size of the industry.

With these points in view, it is necessary to ask what sort of emergency is envisaged. For global nuclear war, all the points would probably become irrelevant. For an extended conventional war, for a limited war which cut off Middle Eastern sources, or for a long cold war which might lead into the other two, they might be important. It may, therefore, be properly held that there is a reason for national defense policy on petroleum and petroleum substitutes, separate from the general problem of “economical allocation of resources.”

From one point of view it can be argued that existing policy has placed the country in a posture of sound national defense. The country has substantial excess capacity (though not matched by equivalent transport and processing facilities); and it has the apparatus and system of incentives to support more intense development. But is this enough?

The practical question is how best to assure the nation, and our allies, the supplies of oil which might be required in an emergency. Here, two possible principles come into conflict. One is to seek the least costly way (in a broad social sense) to achieve the desired degree of self-sufficiency. The other is to achieve the desired self-sufficiency with the least disturbance to the institutional structure of the industry.

If we settle for the second principle—minimum disturbances of existing procedures—it would appear that national defense does not necessarily introduce any new question. Independent of national



defense, the current questions of policy relate to the volume of imports, conservation measures, the incentive structure, the desired amounts of capacity and proved reserves, and restrictions upon recovery from developed sources. The problems of national defense raise precisely the same questions. Discussions based upon considerations of national defense may yield different *quantitative* answers to the questions. But these considerations do not affect the analysis of what is involved in achieving a desired result, be it larger or smaller. Insofar as costs are involved, the earlier analysis in this paper is wholly applicable.

The consideration of national defense may, however, raise other questions of a less conventional sort. The desired degree of protection during an emergency might, for example, be sought partly through storage of imported oil or government-owned shut-in pools. Or added emphasis might be put on low-cost development and fuller recovery. For defense purposes, cost is not a prime consideration. But, under pressure of defense needs, the whole cost structure of the industry might be surveyed and modified.

Moreover, discussion of national defense requires some sort of time perspective. An immediate threat of separation from Middle Eastern sources would necessitate bringing sources of domestic supply into a state of readiness. The prospect of an emergency 10 or 20 years hence might favor reliance on imports, in order not to dissipate domestic resources.

*Policy and "Rational Allocation of Resources".*—It is possible to argue pragmatically that past policies have been highly successful in causing the industry to meet the needs of the community. Defense considerations aside, the industry has successfully met the energy requirements of an expanding civilian economy, and can continue to do so. What then is wrong about the policies that have accomplished this result?

Looking at this question solely from the side of public interest, the primary answer is likely to be that the results of policy offend acceptable economic principles of allocation of resources. With regard to import restrictions, our policy effectively substitutes high-cost for low-cost energy, and at the same time depletes domestic sources of energy at an unnecessarily rapid rate. As for domestic supply, existing laws and regulatory policies stimulate a much larger investment than is required for the productive result, and induce operating practices which fail to recover much of the available reserves. Costs are higher than necessary, and prices are indirectly regulated through supply to validate the excessive costs.

Such criticisms impinge upon an industry whose structure has developed upon a foundation of law and policy. Any substantial changes in this structure would also involve "costs." Policy-making necessarily involves some weighing of a general economic advantage against the established interests dependent upon the industry, in addition to weighing the conflicting interests within the industry.

The existing apparatus of policy-making never comes to grips with the fundamental problem of determining the levels of capacity and production desired of the industry or the means by which these levels could be achieved at minimum cost. Lacking such an economic yardstick, there is no way to compute the "social cost" levied by present policies and by the present structure of the industry. Even in the absence of such a yardstick, there are nevertheless certain measures of policy—some of them reviewed in this study—which could reduce costs without major violence to the historical structure of the industry.

#### VI. RECOMMENDATIONS

One of the most difficult problems the nation and the oil industry face is the determination and implementation of appropriate public policies for energy. Information on costs is a prerequisite for proper policy making. Although accurate forecasts of costs are impossible it should be possible to refine our measurements of past and present costs, and to determine how they have interacted with economic, political, technological, and other institutional forces. With this knowledge the industry and the nation would be in a better position to appraise the alternative policies that are being proposed. In view of the need for general policy goals, let us look more closely at the details of adequate cost analysis.

##### *Definitions and Concepts*

The starting point for any cost study is the establishment of definitions. The word "cost" itself has a variety of meanings. Finding costs, development costs, replacement costs, economic costs, accounting costs, real costs, money costs—all need precise definition.<sup>99</sup> In addition there needs to be clarification of what is to be included in "exploration," "development," "primary production," and "secondary production."

Another broad area in which clarity and precision are important is that of reserves. The definitions of proved reserves given by the A. P. I. and A. G. A., whatever the uses of the data so defined, do not give a full picture of the oil and gas made potentially available

by exploratory and developmental activities. Since calculating "the cost of oil" is mainly a matter of relating cost outlays to estimated amounts of recoverable oil, the methods of estimation appear to require critical review. How to relate types of current cost outlays to uncertain amounts of future product is a slippery analytical problem which will breed confusion until the conceptual elements in the problem have been clarified.

### *Information*

The informational needs for preparation of a comprehensive study of finding, developing, and producing costs are large and only partially filled. For satisfactory results, cost information itself which exists in the hands of individual drilling and producing companies would have to be collected, systematized, and analyzed. The *Joint Association Surveys* are certainly moving in the direction of reliable, representative cost data. Expansion and refinement of these periodic surveys hold out the best short-run promise to the information question. Greater detail showing cost breakdowns by stages of exploration, development, and production and by type of well are needed.

The greatest void in cost information remains in the exploratory phase for expenses other than drilling. These costs are important insofar as they must be made in order to find likely drilling locations. In any attempt to evaluate the necessary effort and expenditure to attain or maintain productive capacity, these costs are especially critical in the long run.

Reserve information could be improved by expanding the techniques and tools of estimation. The A. P. I. and A. G. A. estimates are valuable for what they purport to do. But they lack detail on allocations of reserves to specific fields and to specific periods of time. The trend of discovery of new oil resources in response to exploratory effort is perhaps the most important kind of information that could be had on reserves, but no organized method of supplying this information is in operation. The agencies now reporting reserve data could probably supply the additional information by some moderate revision of reporting practice. The possibilities are at least suggested by the recent study by the National Petroleum Council. Such trend analysis would bring into focus the changing geological outlook and changing technological and economic conditions.

Much information is needed on the application and operation of conservation regulations. A state-by-state reporting of well spacing, unitization, proration, and secondary recovery is a necessary first step toward evaluating the cost implications of conservation as it is prac-

ticed today. The data are available in the files of state regulatory bodies, and access should present no problems.

The information that is becoming available in Federal Power Commission proceedings in the natural gas industry is as yet relatively untapped as a source of finding and development costs for the oil industry. This presents an important device by which surveys and other samples of data can be cross-checked. Some attempt to organize this information seems called for.

Finally, the entire area of reserves, production and costs in other producing areas of the world needs investigation. Current information is scanty, yet the comparison of domestic with foreign costs may be one of the most critical of public policy questions relating to imports and supply generally. Since the number of firms operating in any given foreign nation is small, data collection, assuming a willingness on the part of the cooperating companies, should be relatively simple.

### *Methodology*

The needs in the area of methodology are partly a function of the information available, the problems posed, and the end-results sought. If we assume the goals to include finding, developing, and producing costs per barrel or Mcf. of oil or gas found (and produced), then one of the most difficult methodological barriers is putting costs and reserves (or production) together. The lag techniques suggested by some recent studies to handle exploration costs are examples of the types of problems which must be solved. The construction of target "availability" studies such as those of Davis, McGann and Moore attack a related but different aspect of methodology, given a time dimension. The introduction of this ever important time dimension complicates the methodological problems.

A methodological problem which has had a great deal of attention in recent years, but which remains unsolved, is that of allocating joint costs between gas and liquid hydrocarbons. Most of the work done in this area thus far has been oriented toward natural gas producer regulation. Conceptually, the same problems exist in conducting a study of oil finding and development costs. Apparently the problems can be minimized by proper accounting practices. The Phillips Petroleum Company has reported the successful separation of many costs, thus reducing that portion of total cost included in the "joint cost" category. Joint costs will always be present to some extent, and there is no theoretically "correct" way of dealing with them. Nevertheless, a method of treating them needs to be establish-

ed in the industry to achieve the necessary comparability. If alternative methods are used, they should be capable of cross comparisons.

Some of the more conventional problems of cost analysis are also in need of solution. Sampling procedures are being developed to give a better picture of the statistical universes tested. This has not been perfected, nor is it possible to cross check the accuracy of the sampling currently being done. Again, the time dimension complicates the problem, since substantial changes occur rapidly in this industry. The problem of developing proper "deflators" to arrive at constant dollar costs has only been partially solved.

Finally, the introduction into predictive models or methodologies of different combinations of assumptions concerning such vital matters as technological change, changing world and domestic economic forces, and shifting political winds presents the analyst with some of his most difficult problems. Yet, some set of assumptions must be made. What are these to be, and how are they to be handled? Different methods should be capable of cross comparison.

#### *Analysis*

Given precise definitions and concepts, adequate information, and the necessary tools to handle the information, the most difficult tasks remain to be done. These are the making of a series of specialized studies, and thereafter the subjective, interpretive analysis of the results of such studies, the fitting of pieces together, the viewing of each part in proper perspective and relationship to the other parts.

Such analysis must be piece-meal at first, in an attempt to fill the gaps that currently exist or to improve those areas where information and analysis are weakest. We can do no more than indicate some of the areas where analysis is badly needed. These are not necessarily in their order of importance.

High on the list is the need for a study of the relationships of incentives to effort in the petroleum industry. This effort could be in the direction of more exploration, more development, more secondary recovery, greater effort on gas or on oil, or greater effort abroad or at home. Such analysis relates to costs in that changes or shifts in emphasis of effort are both caused by cost change and the cause of cost change.

An area which has had little study is the implications of adopting different technological, economic, and political assumptions in cost and availability studies. The problems of handling different assumptions from a methodological standpoint were mentioned in the preceding section. If, for example, we can assume a domestic price

of \$5.00 per barrel, what are the implications for "proved reserves" and, thus, for the costs of these reserves? Or what are the implications of improving technology that offsets increasing drilling costs resulting from greater drilling depths?

Virtually untouched is analysis of the impact on costs of existing or hypothetical conservation regulations and property concepts. New interest has been aroused recently in this area, but thus far no studies in depth have been forthcoming. Related to this are studies of the "opportunity costs" of various public policies such as proration, import restrictions and the like. These are but a few of the needed analytical studies that should be carried out to obtain insight into the problems of finding and development costs.

To expect that all the suggestions made in this paper can be fulfilled quickly or completely is Utopian. On the other hand, it is essential for the industry and the government to take concrete steps toward understanding the problems that are faced in the energy supply field and to grasp the implications of the various alternative public policy paths that are open. Rational private and public decisions in the energy field await a clarification of the issues raised in this study.

## NOTES

## Part I

<sup>1</sup> It is generally conceded that U.S. reserves are more conservatively estimated than those of other nations.

<sup>2</sup> For a discussion of the growing importance of Soviet oil, see D. J. Frenzel, *The Soviet Seven-Year Plan (1955-65) for Oil*, U.S. Bureau of Mines Information Circular 8023 (Washington: 1961).

<sup>3</sup> Production and import data from U.S. Bureau of Mines.

<sup>4</sup> This assumes no drastic change in national or international regulatory policies in such areas as imports, production, tariffs, taxation, etc.

<sup>5</sup> A discussion of this problem is found in the following section.

<sup>6</sup> J. Ben Carsey, "Exploratory Drilling in 1960," *Bulletin of the American Association of Petroleum Geologists*, Vol. 54, June 1961. This work was organized by Dr. F. H. Lahee in earlier studies.

<sup>7</sup> See also Tables I, II, and III of the National Petroleum Council's *Proved Discoveries and Productive Capacity* (1961) for summaries of estimated discoveries of oil, gas, and NGL assigned to the year in which each field was discovered.

## Part II

<sup>8</sup> American Petroleum Institute and American Gas Association, *Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas*, Vol. 15, December 31, 1960, p. 6.

<sup>9</sup> *Ibid.*, p. 18.

<sup>10</sup> Hodges and Steele, *loc. cit.*, pp. 85-86.

<sup>11</sup> Hodges and Steele, *loc. cit.*, pp. 1-2.

<sup>12</sup> See the discussion by Hodges and Steele, *loc. cit.*, pp. 47-51.

<sup>13</sup> *Ibid.*, p. 30.

<sup>14</sup> John E. Hodges, A Discussion of C. C. Anderson's paper "Petroleum and Natural Gas in the United States—Relation of Economic and Technologic Trends," before the Canadian Sectional Meeting of the World Power Conference, Montreal, 1958.

<sup>15</sup> *Ibid.*

<sup>16</sup> A special study by Foster Associates describes all the allocation methods presented in F. P. C. cases through mid-1958. Stephen F. Sherwin, *Catalogue of Cost Allocation Methods Presented in Independent Producer Proceedings before the F. P. C.* Washington, 1958.

<sup>17</sup> Alfred E. Kahn, "Economic Issues in Regulating the Field Price of Natural Gas," *Proceedings of the American Economic Association*, May, 1960, p. 513.

## Part III

<sup>18</sup> See previous section for a discussion of real costs.

<sup>19</sup> The Bureau of Mines has, over a period of years, made several broad studies of energy supply and demand for the United States. There is some excellent information on oil and gas included in these. See Harold J. Barnett, *Energy Uses and Supplies, 1939, 1947, 1965*, U.S. Bureau of Mines Information Circular 7582 (1950); W. H. Lyon and D. C. Colby, *Production, Consumption, and Uses of Fuels, and Electric Energy in the United States in 1929, 1939, and 1947*, U. S. Bureau of Mines Report of Investigation 4805 (1951), and Perry D. Teitelbaum, *Energy Production and Consumption in the United States: An Analytical Study Based on 1954 Data*, U. S. Bureau of Mines Report of Investigation 5821 (1961), done under a cooperative agreement with Resources for the Future, Inc.

<sup>20</sup> This last source contains a variety of information, some of which will be discussed below.

<sup>21</sup> Schurr, Netschert, Eliasberg, Lerner, and Landsberg, *Energy in the American Economy, 1850-1975* (Baltimore: Johns Hopkins Press for Resources for the Future, Inc., 1960.)

<sup>22</sup> *Ibid.*, pp. 193-194.

<sup>23</sup> *Ibid.*, pp. 297-298.

<sup>24</sup> *Ibid.*, p. 386.

<sup>25</sup> National Petroleum Council, *Report on Proved Petroleum and Natural Gas Reserves and Availability*, 1961, p. 4.

<sup>26</sup> Schurr and Netschert, *op. cit.*, p. 435.

<sup>27</sup> N. P. C., *op. cit.*, p. 4.

<sup>28</sup> United States Atomic Energy Commission, TID-8209 (1960).

<sup>29</sup> The discussion in this study is couched in terms of a common unit of heat, Q, which is equal to one quintillion ( $10^{18}$ ) Btu's. Cumulative consumption of *all* fossil fuels in the U. S. up through 1960 was about 1.474 Q.

<sup>30</sup> *Ibid.*, pp. 1, 14-15.

<sup>31</sup> 86th Congress, 1st Session (Washington: Government Printing Office, 1959).

<sup>32</sup> 86th Congress, 2d Session (Washington: Government Printing Office, 1960).

<sup>33</sup> W. C. Schroeder, "Fuels—Consumption and Availability for 1975 and 2000," Joint Committee on Atomic Energy, *International Atomic Policies of the United States*, (Washington: Government Printing Office: 1960), p. 1459.

<sup>34</sup> United States Department of the Interior, March 1960, "Resources of Coal, Petroleum, Natural Gas, Oil Shale, and Tar Sands in the United States and Allied and Neutral Countries," Prepared for the Joint Committee on Atomic Energy, United States Congress, p. 1533.

<sup>35</sup> S. H. Clark, *U. S. Demand for Natural Gas and Competitive Fuels by Census Regions and End Use, 1965 and 1970*, Stanford Research Institute, prepared for the F. P. C. Permian Basin Area Rate Hearings, Dockets AR61-1, *et al.*, 1961.

<sup>36</sup> *Ibid.*, pp. 10-11 of prepared testimony.

<sup>37</sup> A. D. Zapp, *Future Petroleum Producing Capacity of the United States*, U. S. Geological Survey Bulletin 1142-H (Washington: G.P.O., 1962); and C. L. Moore, "Method for Evaluating U. S. Crude Oil Resources and Projecting Domestic Crude Oil Availability," Office of Oil and Gas, Department of the Interior (Washington: 1962).

<sup>38</sup> Additional material can be found in the recently released Staff report to the Senate Committee on Interior and Insular Affairs, *Report of the National Fuels and Energy Study Group*, 87th Cong., 2d Session., (Washington: Government Printing Office, 1962).

<sup>39</sup> Warren B. Davis, "The Long-Range Crude Oil Productive Capacity of the United States," preprint of a paper delivered at the 1958 A.I.M.E. Annual Meeting, New York; and Paul S. McGann, "A Method of Projecting U. S. Petroleum Supply," preprint of a paper delivered at the 1960 A.I.M.E. Annual Meeting, New York.

<sup>40</sup> McGann, *op. cit.*, p. 3.

<sup>41</sup> See below for a description of these.

<sup>42</sup> Davis, *op. cit.*, p. 1.

<sup>43</sup> Davis, Figures 7 and 8.

<sup>44</sup> There have also been mineral censuses in 1860, 1870, 1880, 1889, 1902, 1909, 1919, 1939, and 1954.

<sup>45</sup> Letter of Mr. Fred Van Covern, former director of the Statistical Department of the A.P.I. to Mr. D. S. Colby, Chief, Branch of Petroleum Economics, U. S. Bureau of Mines, June 9, 1960.

<sup>46</sup> Recent testimony of Mr. R. M. Brackbill representing gas producers in the Permian Basin Hearings before the Federal Power Commission, Docket No. 61-1, gives the fullest explanation yet made public by the Joint Associations on the data and techniques used in their survey. See the transcript pp. 374-446.

<sup>47</sup> *Oil and Gas Journal*, Feb. 6, 1961, pp. 90-91.

<sup>48</sup> There are two earlier studies which were made and which at least warrant mentioning because of the rather different approach taken in determining costs. David Siskind, "Drilling Costs," *The Petroleum Engineer*, January 1952, p. B-14; and J. E. Hodges, L. Cookenboo, and W. F. Lovejoy, "Capital Coefficients Arising from the Drilling of Wells for Oil, Gas, and Condensate," Rice University, Petroleum Research Project, Houston, 1952, mimeo.

<sup>49</sup> "The Cost of Finding Oil in Oklahoma and Kansas," paper presented before the Tulsa Geological Society, Tulsa, April 25, 1958; "Crude Oil Replacement Costs in the Illinois-Michigan Basin Area," paper presented before the spring meeting of the Eastern District A. P. I. Division of Production, Columbus, Ohio, May 7-9, 1958; and "The Cost of Finding Oil," *Oil and Gas Journal*, March 30, 1959, pp. 250-256. (Covers primarily the Rocky Mountain Area).

<sup>50</sup> See Hodges and Steele for a discussion of this point.

<sup>51</sup> "What It Costs to Find U. S. Oil," *The Petroleum Engineer*, November, 1960, p. B-19.

<sup>52</sup> See *The Petroleum Engineer*, January, 1943, p. 31, for the first of these articles.

<sup>53</sup> *The Petroleum Engineer*, *op. cit.*, November 1960, p. B-21.

<sup>54</sup> See the criticism made by Hodges and Steele, pp. 4-7.

<sup>55</sup> *Petroleum Engineer*, July, 1955, p. B-40; translated from the French by E. C. Leonardon.



<sup>56</sup> The French version first appeared in the *Revue de l'Institut Francais du Petrole et Annales des Combustibles Liquides*, Vol. II, 1952.

<sup>57</sup> See below for a comment of these studies.

<sup>58</sup> See full citations given above, footnote 48.

<sup>59</sup> A study of the drilling contractor industry by itself appeared in monograph form. See J. E. Hodges and L. Cookenboo, Jr., *The Oil Well Drilling Contractor Industry*, Rice Institute Pamphlet, July, 1953, Vol. XL, No. 2.

<sup>60</sup> This complete report is found in *The Independent Petroleum Company*, Hearings before a Special Senate Committee Investigating Petroleum Resources, 79th Cong., 2d Sess., 1946, pp. 229-311.

<sup>61</sup> See also the testimony of L. H. Noble of the O.P.A. in this volume, p. 341, on the replacement cost concept.

<sup>62</sup> U. S. Tariff Commission, *Crude Petroleum: Report on the Cost of Producing Crude Petroleum in the United States (1942) and Supplement (1943)*.

<sup>63</sup> U. S. Tariff Commission, *Production Costs of Crude Petroleum and of Refined Petroleum Products*, 72d Cong., 1st Sess., House Doc. 195 (1932); *Ibid.*, *Report to the Congress on the Cost of Crude Petroleum*, 71st Cong., 3rd Sess., Senate Doc. No. 267 (1931).

<sup>64</sup> See, for example, the Report of the Cost Study Committee of the IPAA, presented at the Midyear Meeting, New Orleans, April 30-May 2, 1961.

<sup>65</sup> Frederick G. Coqueron, *Annual Analysis of the Petroleum Industry, 1960* (New York: Chase Manhattan Bank, 1961).

<sup>66</sup> Siskind and Lilliac and Lugol do use some of the Struth information. The Joint Association Surveys had not been started at the time the Siskind study was made.

<sup>67</sup> See comment on real costs in Section II.

<sup>68</sup> *Bulletin of the American Association of Petroleum Geologists*, Vol. 37., No. 7, July, 1953, pp. 1562-1585.

<sup>69</sup> *Rice Institute Pamphlet*, Vol. XLVI, No. 3, October, 1959.

<sup>70</sup> Professor Hodges makes another forceful plea for more and better information in an address before the A.P.I. See John E. Hodges, "Determining the Cost of Finding and Developing Oil and Gas Reserves, *Proceedings of the American Petroleum Institute*, Section VI. (New York: 1960), p. 13.

<sup>71</sup> Hodges and Steele, *op. cit.*, p. 84.

<sup>72</sup> *Ibid.*, pp. 86-87.

<sup>73</sup> *Ibid.*, p. 164.

<sup>74</sup> Arthur Young and Company, "Study of Industry Costs of Finding, Developing and Producing Liquids and Gas," Reports I-III Tulsa (1958).

<sup>75</sup> The Young studies, however, do not give regional breakdowns.

#### Part IV

<sup>76</sup> *Ohio Oil Company v. Indiana*, 177 U. S. 190 (1900).

<sup>77</sup> Certain taxes, hauling charges, etc., are often shared by the royalty owner.

<sup>78</sup> For an interesting and relatively simple discussion of laws relating to petroleum in foreign countries, see Northcutt Ely, *Summary of Mining and Petroleum Laws of the World*, U. S. Bureau of Mines Information Circular 8017 (Washington: 1961).

<sup>79</sup> Corporation Commission of the State of Kansas, Conservation Division, Docket No. 35, 154-C (C-1868), Memorandum Opinion, February 23, 1949, pp. 7-8.

<sup>80</sup> *Well Spacing*, published and distributed by Interstate Oil Compact Commission for the Commission's meeting at Fort Worth, Texas, September 10, 1951; pp. 56-57.

<sup>81</sup> The references in the above cited work on *Well Spacing* will provide the geological and engineering background and arguments which the I.O.C.C. committee considered, as well as much discussion on the topic.

<sup>82</sup> *Texas Gas Conservation Laws and Oil and Gas Regulations*, published by Texas Mid-Continent Oil and Gas Association, May 1946, p. 179.

<sup>83</sup> *Atlantic Refining Co., et al. v. Railroad Commission, et al.*, 346 S.W. 2d 801 (1961).

<sup>84</sup> Corporation Commission of Oklahoma, C.D. No. 11126, Order No. 44297, General Rules and Regulations Governing the Drilling of Oil and Gas Wells and the Production Therefrom in the State of Oklahoma, effective April 1, 1961.

<sup>85</sup> Erich W. Zimmermann, *Conservation in the Production of Petroleum*, Petroleum Monograph Series, Volume 2, (New Haven: Yale University Press, 1957), pp. 281-290.

<sup>86</sup> Standard Oil Company of New Jersey, *Conservation: Making the Most of Our Oil*, (New York: 1947).

<sup>87</sup> American Petroleum Institute, "Progress Report on Standards of Allocation of Oil Production Within Pools and Among Pools," preliminary draft, October 3, 1941, p. 23.

<sup>88</sup> I.O.C.C., *A Form for an Oil and Gas Conservation Statute, 1959* (Oklahoma City: 1959), Section 1.1.1.

<sup>89</sup> There is a great deal of confusion about what MER means. There are those experts who look on it as an engineering or physical concept. See for example, P. J. Jones, *Petroleum Production*, Vol. II (New York: Reinhold Publishing Corp., 1946), Chapter I, in which formulae are set forth to compute the MER's of types of reservoirs. On the other hand, there are other experts who maintain that MER is an economic concept balancing costs and revenues. See the discussions in Stuart E. Buckley (ed.) *Petroleum Conservation* (New York: American Institute of Mining and Metallurgical Engineers, 1951), pp. 151 ff.; and Zapp, *op. cit.*, pp. 4-6 ff.

<sup>90</sup> *Gulf Oil Corporation v. State of Oklahoma, et al.*, 369 P. 2d 933 (1961).

<sup>91</sup> This is an oversimplification. The rules and regulations governing which wells are exempt from proration are extremely complex.

<sup>92</sup> New Mexico Oil Conservation Commission, *Rules and Regulations*, Revised December 1, 1959, pp. 31, 32, 33.

<sup>93</sup> Interstate Oil Compact Commission, Research and Coordinating Committee, "Report on the Study of Allocation Formulae, by State," *Interstate Oil Compact Quarterly Bulletin*, Vol. VIII, Nos. 3 and 4, December 1949, pp. 65-89.

<sup>94</sup> National Petroleum Council, "Report on Proved Petroleum and Natural Gas Reserve and Availability," May 15, 1961.

<sup>95</sup> Paul D. Torrey, "Evaluation of United States Oil Reserves as of February 1, 1962," Report to the I.O.C.C. Midyear Meeting, Omaha, June 18, 1962.

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<sup>96</sup> *Resources for Freedom*. Report of the President's Materials Policy Commission (The Paley Commission Report). House of Representatives Document 527, 82nd Congress, 2nd Session. U. S. Government Printing Office 1952; and Sam H. Schurr and Bruce C. Netschert, *Energy in the American Economy 1850-1975*. Baltimore: Johns Hopkins Press, 1960.)

<sup>97</sup> *Report of the National Petroleum Council Committee on Proved Petroleum and Natural Gas Reserves and Availability*, National Petroleum Council, Washington, 1961.

<sup>98</sup> There is, of course, the further legal objective of state policy of assuring equity among ownership interests in the field.

<sup>99</sup> The definitional problems encountered in joint cost allocation are discussed under methodology below.

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## APPENDIX

SUMMARY OF THE DISCUSSIONS  
of the  
SEMINAR ON THE COST OF FINDING, DEVELOPING  
AND PRODUCING PETROLEUM  
held at  
Southern Methodist University  
March 22-24, 1962

The Seminar on the Cost of Finding, Developing and Producing Petroleum consisted of five three-hour sessions devoted to problems raised in the background paper which makes up the main content of the present monograph. The participants at the seminar were selected by the Planning Committee in consultation with industry and academic people interested in this field. The selection of participants was intended to bring into the discussion the knowledge and varied viewpoints of industrial, academic, consulting and regulatory personnel. Each individual was invited in his individual capacity and not as a member of a firm, agency, or institution.

The general area of discussion was that defined in the background paper, the major purpose of which was to raise questions concerning the costs of finding, developing, and producing petroleum. These questions deal with concepts and analytical methods appropriate to cost studies.

This report does not represent a chronological resumé of the discussion, but is arranged topically. Although no hard and fast agenda were imposed upon the various sessions, certain subject areas were brought into focus at each session.

It was agreed in advance that in any report of the proceedings, individuals would not be identified with their comments, questions, or proposals. This anonymity assured openness of discussion. Since the matters under discussion were highly technical, there was little division of opinion because of the different backgrounds of the participants, but instead a pooling of expert thought and knowledge. Although no effort was made to achieve a consensus, substantial agreement did develop on some points. The informed and penetrating quality of the detailed discussion cannot be adequately reflected in a summary.

A draft of this summary was sent to each participant and some changes were made as a result of comments received. While almost all participants approved the general tone and content, in matters of technical detail and emphasis, the summary in its present form is not entirely satisfactory to all of them.

*The Replacement Cost Concept*

The initial discussion concerned the concept of "replacement cost" described in Part II of the study, and moved into such varied problems as (1) meaningful definitions of costs, (2) the purposes for which cost studies should be designed, (3) the practicability of measurement, and (4) the improvement of basic data.

As it is used in some published studies the conventional meaning of replacement cost per barrel was summarized as follows:

- (1) Current production costs divided by the number of barrels produced, *plus*,
- (2) Current development costs divided by the number of barrels added to estimated reserves by development activity, *plus*
- (3) Annual finding costs divided by the number of barrels added to estimated reserves by exploratory activity, *with*
- (4) Adjustments for costs allocated to natural gas and natural gas liquids.

These cost and quantity data are for a given time period, *e.g.*, one year. The question was raised as to what purpose is served by adding cost types 1, 2 and 3 together, as is done in several published studies, to get a total replacement cost per barrel. The questions raised were of four general sorts: Is the aggregate which arises out of the sum of these calculations meaningful, informative and useful? Are the cost calculations of the three separate components meaningful, informative and useful? If some usefulness or validity is found in either the aggregated or component calculations in principle, are the data which now go into these calculations acceptable? To the extent that the data are defective, are they susceptible to improvement?

The central conceptual difficulty with respect to replacement cost per barrel was felt to be with the fractions of which the calculation is composed. In each case, the numerator is a current cash outlay for finding, development and production, respectively. The denominators are estimates of new reserves attributable to discovery, development and production in the current year. The outlays in the finding and development numerators are not in any economic sense the costs of the current additions to reserves stated in the denominators. The outlays are related as costs to barrels of oil in a time stream starting with those being currently produced and continuing into those producible at varying stages of remoteness of time in the future.

The question was raised whether current outlays, in relation to conventionally estimated current additions to reserves, are part of a calculation which has any significance. This question brought out some differences of view. As the discussion proceeded, something like a consensus developed that replacement cost calculations, as presented in various studies, have relatively little significance. This tentative conclusion stemmed in part from the inadequacies of the data on both costs and reserves, but also from the conceptual difficulties stated above.

The principal affirmative argument in favor of the replacement cost calculation was that, although it is useless for any single year, it does provide a rough gauge of the cost trend of adding to supplies of petroleum over time. There was no doubt in anyone's mind that a good measure of this trend was important; the only question was whether it should be sought through an improvement of the data underlying replacement cost calculations, or whether some superior measure of trend might be devised. In the course of this discussion, it was suggested that some light on trend might be obtained by relating current additions to reserves, not to current

outlays, but to outlays a few years previously, or by some moving averages of cost outlays and additions to reserves with a time lag between the two. Against this, there arose some skepticism concerning the results because they would contain biases of unknown sign and duration.

Granted the desirability of a good measure of trend, there was discussion of what use replacement cost calculations might serve, both in the processes of private decision-making and in the discussion of public policies.

As to the significance replacement cost might have for the decision-making processes of private companies, it was suggested that the replacement cost of individual companies could be compared with the industry average and used as *one* measure of the relative success or failure of individual companies over time. The suggestion, however, was not seriously defended as of any importance to companies.

Apart from the point of industry-firm comparison, the discussion suggested that replacement cost has very little significance for corporate decision-making. Companies certainly do make cost comparisons in evaluating possible investment opportunities. However, there are *ex ante* costs, looking to the future, and these costs include a time or discount factor which often can be substantial. A company must, of necessity, compare *expected* costs with *expected* prices and revenue. This type of comparison is a substantially different one than that of the replacement cost concept. Replacement costs are, of necessity, experienced or historical costs which may or may not correspond to anticipated future cost trends.

Although it was never specifically stated, it appeared that oil companies do make the best possible *economic* cost estimates in their capital budgeting. The economic cost concept is concerned with the same barrel of oil over time, *i.e.*, over the stages of finding, developing, and producing. The replacement cost concept, in contrast, is concerned with different barrels of oil at a given instant of time.

Company cost estimates are, of course, spread out over time, but they are based on the principles of orthodox economic analysis. Finding costs are the most difficult to estimate, *ex ante*, but even in this case there are probability ranges which can be used. As the finding, developing, and producing operations proceed step by step, continued analysis, *ex ante*, is the basis for further expenditure. Sunk costs are of little concern; thus marginal (expected) cost analysis with its ever-present and important time factor constitutes the basis for investment decisions. Current costs, in relation to currently added "proved" reserves, developed from past outlays, are irrelevant to current investment decisions. It was, of course, recognized that the results of past outlays in terms of reserves found and developed was a crucial test of relative success in operations. But this is not what replacement cost shows. It was suggested that, by introducing a time lag formula between outlays and results, some light might be thrown on trend relations between outlays and reserves. It was further suggested that if additions to reserves were regularly attributed back to year of discovery of the fields in which they lay, certain information on trend relations between outlays and results might appear.

Turning from the apparently slight relation between replacement cost estimates and management decision-making processes, there was some discussion of whether replacement cost calculations have any significance for

public policy-makers. The point was made that in so far as such calculations are conceptually defective, they have the same weakness for policy purposes as for any other purpose. Cost trends in petroleum supply have a bearing upon all policy questions concerned with total energy supply and inter-fuel competition and with national security issues. As in other connections, the question arose as to whether improved trend analysis should come from improvements in the data underlying replacement cost, or from some alternative analytical approach.

Still in the policy field, it appeared that replacement cost figures have little if any interest for state regulatory agencies which prorate production. Their interest is in productive capacity and in the rate of flow of supply to the market. Good trend figures on the relation between outlays and reserves added might, nevertheless, be very important to state governments in thinking ahead about their economic potential and tax structure.

In the course of the discussion, the extreme position taken concerning the aggregated statement of "replacement cost per barrel" was that it is conceptually meaningless and lacking in validity, since the current costs stated in the numerators of the fractions had no assignable relationship to the estimated currently "proved" reserves in the denominators. While the general opinion seemed to lean in this direction, some reluctance to part company with the concept of replacement cost developed. Some light on the trend of relations between outlays and additions to reserves might result, it was suggested, if the data underlying both the outlay numerators and the reserves denominators were improved, and if some technique of applying a time lag between outlays and results were introduced.

A basic difficulty in the replacement cost concept was pointed out; namely, that the opportunity cost of funds sunk in underground "inventories" of oil was omitted. When current outlays are associated with future product, a true economic cost calculation would have to allow for time discount of future revenues. While difficult to compute with approximate accuracy, this cost factor is conceptually inescapable. Upon this point there was general assent.

There was general agreement that the published comparisons between the current replacement cost per barrel and the current price per barrel of oil were invalid and misleading. Such comparisons suggest that, if replacement cost is above price, the industry is operating at a loss and the incentive to search for new reserves should disappear. This proposition may be criticized on three counts: (1) The costs relevant to oil being currently produced and sold are costs incurred at various degrees of remoteness in the past. (2) The resources being currently shown as "proved" in no way represent the ultimate recovery from the fields in which these reserves are located. And (3) the reserves which will eventually accrue from current outlays are in substantial degree unknown. This is not to say that comparisons might not have some use if a proper trend factor could be derived from the time series. A persistent failure of revenues to cover outlays would herald the decline of the industry. Some published comparisons have tended to suggest this without presenting the data to support it.

The discussion of replacement cost on an aggregated basis (without isolating the component finding, development and producing costs) ended

on a note of general skepticism about the meaning and usefulness of present replacement cost figures. Some difference of opinion remained as to whether the whole concept should be abandoned. The substantive, unanswered question remaining was how to measure trends in the relation between outlays and resulting additions to reserves, a question of great importance both in its public and private aspects.

Collateral to the foregoing discussion was the problem of measuring the different components—finding, development and producing costs—which enter into total replacement cost per barrel. Some participants, regarding the whole replacement cost concept as invalid, considered the component costs, out of which the aggregate is compounded, as being invalid for the same reasons; namely, the doubtful character of the outlay data in the numerator, the lack of direct connection between such data and the reserve data in the denominator, the imperfect character of the reserve data, and the lack of any useful purpose served by the calculations. Others, however, stated that knowledge of the trend behaviour of finding, development, and producing costs was in principle useful and should be undertaken, if these cost categories could be uniformly defined and filled with improved data. This naturally suggested the observation that the most pressing analytical need is not better data, but a better conceptual apparatus within which to utilize improved data.

The course of the discussion indicated that component costs per barrel are no better than the denominator of the fractions, and serious doubts were expressed as to the accuracy and validity of reserve data breakdowns between “extensions and revisions” and “discoveries.” In this connection, the question was raised whether or not it is useful or feasible to separate finding and development costs, and whether or not it is possible to separate reserves by these same functions.

There were no conclusions respecting what elements should be included in the component cost categories. It was agreed that production costs could be computed most easily. However, as between the finding and development categories, there is a relatively large portion of costs which can be separated only arbitrarily. If there were consistency among companies or reporting agencies in making such separations, the data would be more useful. It was generally agreed that this was one area in which industry-wide consistency would be helpful and would make the data more meaningful. At the same time some skepticism was expressed about the possibility of getting oil companies to keep their records on a comparable basis.

With difference of emphasis and possible dissent by individuals, the following points appear to get as near as is possible to an expression of the common mind of the group:

- (1) Replacement cost calculations in their present form are conceptually unacceptable as a way of measuring the cost per barrel of finding, developing and producing oil.
- (2) Some method of measuring trends in the relation between outlay and the accruing availability of oil is of great importance for the policy discussions of the energy problem, and it is equally important to the industry for others to have a correct picture.
- (3) Existing types of replacement cost calculation have little value for

this purpose from the point of view either of management decision-making or of public policy decisions.

(4) Some validity might be achieved for replacement cost analysis on the basis of improved conceptualization and improved data and the introduction of lag techniques. The essential problem, however, is not the improvement of replacement cost analysis as such, but the constructive invention of methods of trend analysis. Whether this can come from analytical and data improvements in the replacement cost context, or should be approached by a different analytical route, is moot.

(5) There are serious problems of misinterpretation of replacement cost information as evidenced by the use of these data in published statements and studies.

(6) The components of replacement cost—*i.e.*, finding, development, and producing costs—are probably more useful in trend analysis than when aggregated in total replacement cost. But much of their usefulness is dependent upon improved analytical procedure and data.

(7) A major shortcoming of the replacement cost concept, as usually used, is the neglect of the time dimension or discount factor.

(8) The categories of cost which enter into replacement cost calculations are basic to a company's evaluation of its own income-earning situation and prospects. If improved in content and used with recognition of its inherent limitations, the replacement cost concept might be of some use to management, as one of several tools available for evaluation. The industry's primary concern is, however, with profits over time—costs and revenues; and replacement cost helps very little in specific capital-budgeting decisions.

(9) Economic cost—the accumulated cost over time of a single barrel of current or anticipated product—is conceptually more acceptable than replacement cost, current outlays in relation to current additions to reserves representing different future barrels of product. Little analysis has been devoted to economic cost, and the problems may be insuperable.

#### *Estimation of Reserves in Relation to Cost Studies*

As the preceding part of this report has shown, the discussion of replacement costs necessarily included some discussion of petroleum reserve data—how these data are collected, aggregated, reported, and transmuted into a cost context. The significance of reserves is evident when it is recalled that finding costs per barrel and development costs per barrel are computed by dividing annual expenditures on finding and development by the barrels of additional reserves "proved up" during that year. Even if economic cost concepts (or some variation of these) are used, it is necessary to have a denominator for the fraction to obtain a cost *per barrel* of reserves. The discussion with respect to reserves was interspersed in the general discussion on costs; it is dealt with separately at this point in order to emphasize some of the unique aspects of reserve estimation. Three principal questions were as follows. How are reserve data collected? Are the data reliable and adequate for the uses to which they are put? Can reserve data be broken down by functional stages—*e.g.*, discoveries, extensions, revisions—in a meaningful way?

The discussion brought out the procedures used by the American Petroleum Institute, the American Gas Association and the National Petroleum Council to collect and report reserve data. Most participants indicated that

the annual breakdown between additions to reserves from discoveries on the one hand and from extensions and revisions on the other hand was not reliable enough for purposes of cost analysis. Dividing total development costs by extensions and revisions to get a development cost per barrel was not justified, as there is no established relationship between the two. The same general comment applies to finding costs and new reserves from discoveries. It applies also if combined finding and development costs are related to total additions to reserves.

The question was raised as to what extent there is a bias in the official A.P.I. and A.G.A. reserve data. It was recognized that they are, by their very definition, conservative, representing a working inventory concept and not a prediction of probable or possible recovery from known reservoirs. Companies customarily make further estimates of probable reserves, although these figures contain a large judgment factor and are apt to diverge widely even within a company among different people. Some in the group advocated that companies pool the estimates on the probable reserves or that the A.P.I. and A.G.A. report both "proved" and "probable" reserves by whatever methods are available to them. The group seemed to agree that the A.P.I.-A.G.A. estimates of reserves added by discoveries for single years do not present a time series of much use for charting the time trend of discovery.

Some members of the group emphasized a need for greater detail in the reporting of reserves, especially in differentiating revisions and extensions. This led to the further suggestion that it would be valuable if specific additions to reserves could be attributed to specific factors, such as changes in information, further drilling or recompleting, introduction of secondary recovery operations, technological innovations or applications, and changes in underlying economic conditions. Such information would record reserve changes over a time path, pin-pointed to show certain events or factors responsible for the changes. Conceptually, it was agreed, such a breakdown would be helpful in cost analysis, since cause and effect could be more clearly discussed in the relations between outlay and results. Some in the group felt that such detailed reporting would not only be excessively costly, but also difficult to make internally consistent, given the large degree of judgment which would have to be exercised by the reporting sources. The discussion ended on the note of practicability—to what extent such reporting may be feasible. This, it was agreed, was a matter for further investigation.

In the course of the discussion, some members of the group voiced the need for reporting reserves by reservoir as well as by geographic region. This additional detail, they felt, could be fairly easily obtained and would assist in the more detailed forms of cost analysis. It was assumed that the API reporting procedures were built up from a base of reservoir information. An objection was raised that reporting on this basis would not only be difficult and costly, but that companies would refuse to cooperate in compiling such information, since it would prejudice their position in negotiating with landowners.

The matter of "dating back" reserves to the year of discovery of their fields was a thorny question. Some participants felt strongly that such

action was required for determining (1) trends in additions to the physical availability of oil and (2) trends in discovery outlay associated with this physical availability. They felt that cost analysis required additions to a known reserve to be credited back to the earlier costs of finding and developing reserves in order to get a meaningful unit cost having trend significance.

Others in the group emphasized the extreme difficulty of attempting to date back existing reserves in the absence of a suitable technique, beyond what has already been attempted by the National Petroleum Council. Although they conceded the difficulty of such reporting retrospectively, some participants insisted on the desirability of initiating this type of reporting from now forward, with respect to newly discovered fields, crediting later revisions and extensions back to the year of discovery. The consensus was that the feasibility of such reporting should be investigated.

In this matter, as in others, there sometimes appeared a difference of outlook or emphasis as between industry participants and those with an academic status. Two different kinds of tests could be applied to various proposals for improvements in data and extensions of analysis. One was whether they were significant for management in decision-making with respect to profitability. The other was whether they would serve some useful purpose in relation to questions of public policy. And in either case, are the changes worth the toil, trouble and expense involved? Everyone recognized that these questions were appropriate, so that the differences were only in the weighting of judgment.

#### *Profitability Studies as an Alternative to Cost Studies*

There were extensive comments on the idea of profitability studies, as distinct from cost studies. Some participants emphasized the fact that profits rather than costs are the guide to decision-making in the industry. One major consideration that recommends the "profits approach" is that cash flows can be observed and used as an indicator of what cost studies strive to reveal. The problems of tracing costs over time or of adding costs of different barrels in different stages of production are eliminated. Such a procedure, it was suggested, provided a shortcut which bypassed many of the troublesome problems of definition and assignment that are encountered in unit cost analysis. Current cash flows do not necessarily reveal future cash flows, but the latter can be estimated. The *future* profitability, taking the time (discount) factor into consideration, determines the choice among investment alternatives. Costs are one part of estimating future profits, but the concept is that of economic cost rather than of replacement cost. Profit studies on an aggregate basis for individual companies, while subject to reservations, were more to their purpose than attempts at computing replacement costs per barrel. For industry-wide studies the profits approach is difficult to apply, although it has been attempted in terms of aggregate cash receipts and expenditures.

No consensus was reached on what theoretical framework should be developed for either cost or profitability studies, nor was there agreement on what information was needed and how certain types of data could be used. Several members of the group noted that the cost of gathering and processing data was a consideration. The conclusion of the cost and profit discussion



seemed to be that more thought needed to be given to (1) what problems need to be solved, (2) what data are necessary, (3) in what theoretical framework the data are to be used, and (4) what the costs of these alternatives would be, as compared to what is done today.

*Joint Costs as a Problem in Cost Analysis*

It was generally agreed that when, in studies of the cost of oil, all finding and development costs for both oil and gas are allocated to oil alone—as is commonly the case—the effect is to distort the cost and supply picture and to make the data less useful. Beyond this rather obvious point, there was little agreement either as to the importance of attempting to separate gas from oil costs or as to the methods to be applied in such an attempt.

One view, noted earlier, was that companies are interested only in profitability analysis. In this context, they are interested in the total revenues obtainable from *joint products*, not in any allocation of the joint costs.

Other participants were unwilling to accept such an aggregative approach, even from the viewpoint of company planning. They pointed out that the output mix of the industry is changing, so that gas is becoming increasingly important. To the extent that oil and gas are not competitive in their uses and to the extent that they have differing values or earning capacity for a producer, then the output mix is important. Joint cost analysis helps to tell the limits of discretion a producer has in maximizing dollar returns from a given dollar input. From a management viewpoint, joint cost analysis provides a sharpening of the decision-making tools. From a public, or aggregative, point of view, continuing recognition of joint costs is necessary to avoid the misleading implications of studies which load all costs onto crude oil reserves and production.

It was generally agreed that the allocation of true joint costs is by definition impossible except in some arbitrary manner. Since oil and gas are in considerable degree used non-competitively as fuels and have dissimilar money values at the wellhead per unit of energy, the summation of oil and gas is difficult if not impossible. Allocations of costs according to value energy content are inadequate. Continued work in allocation methodology was urged, not with the idea that a "correct" way could be determined, but with the idea that some consistency would evolve in basic industrial statistics, and thus provide a point of departure for more detailed studies of special situations.

Some participants stated that the problem of joint cost allocation is diminishing in difficulty and importance because the portion of cost which must be regarded as jointly shared has been shrinking as more work is done on cost analysis. The Phillips testimony in the Permian Basin Area Rate Hearing was cited in this connection. There is of course an irreducible element of joint costs, but it is much smaller than was previously supposed. Insofar as the separable costs are isolated and made available for statistical analysis, the problem should diminish in importance.

Those who took the "profitability" viewpoint seemed least concerned with problems of methodology in the field of joint costs.

The discussion did not deal in detail with the problems presented in the preparation of gas cost figures for Federal Power Commission hearings, as related to regulation of the price of gas.

In the discussion of joint costs, several participants expressed concern over the inadequacy of data on gas reserves and production. Some wished that gas production data might be broken down between associated and non-associated gas. It was also noted that much gas production was reported on a "wet" basis which made it difficult to compare with reserves which are reported on a "dry" basis. One participant noted that gas which is flared is not included in gas reserve data, but that economic use of that gas would bring it into the revised reserve data. The discussion demonstrated that there are several intricate problems associated with gas reserves and production data. The group felt that clarification of these data would be useful and would provide the basis for sounder analysis.

With differences of emphasis, there appeared to be a general feeling that some more satisfactory way must be found to allow for costs attributable to gas in studies primarily concerned with the cost of oil.

#### *The Impact of Conservation Regulation on Costs*

A relatively short time was devoted to this topic. At the outset it was noted that precise measurement of costs arising out of regulation was probably impossible, and that perhaps the best that could be done would be to indicate areas which held out hope for cost reduction. Among the most important factors increasing costs were waiting, *i.e.*, foregoing income because of production restrictions, and drilling unnecessary wells. The latter is a particularly troublesome factor that is currently receiving attention both from the industry and from regulatory bodies. In general, it appeared to be accepted that more emphasis should be placed on acreage and less on number of wells in setting proration formulas. In the longer run, wider spacing and less drilling of small tracts could substantially reduce costs. Participants with an intimate knowledge of the regulatory process commented on the technical and legal difficulties of imposing "strictly economic" rules of development.

The discussion led into some consideration of the causes of the chronic "over-capacity" of the industry which is one of the factors involved in prorationing. One participant likened the situation to a cartel with free entry and price maintenance; in such a theoretical situation over-capacity is inevitable. Another participant suggested that economic considerations have to be set aside; maintenance of excess capacity is costly but is essential to provide a necessary measure of national security. To the extent that this is true, the cost of over-capacity may be cheap. However, this is something different from drilling more wells than are needed to drain a given field efficiently. Moreover the incentives to exploration, and the results of it, are in no way closely geared to a desired national security standard of over-capacity.

In this context, it was noted that industrial continuity is important, and that a regulatory agency cannot disrupt existing institutions solely on economic principles, and expect to maintain continuity. Both the time lag between economic incentive and development of the resource, and the uncertainty of the outcome in available resources, are parts of the problem. Though institutional structure and uncertainties place obstacles in the way of the most economical development of petroleum resources, however,

there appear to be ways for regulatory and legislative bodies to effect substantial improvements in this respect.

Another area in which cost savings could be realized, it was noted, is in secondary recovery, especially by undertaking pressure maintenance operations early in the life of the fields and installing secondary recovery projects before fields reach the "salvage" category. Present regulation puts a premium on delaying the installation of secondary recovery measures. Money saved by a wider spacing of wells could reap handsome rewards if put into pressure maintenance and secondary recovery.

There was a somewhat desultory discussion of the market demand and M.E.R. principles in prorationing, the extent to which M.E.R. is an economic rather than solely physical principle, and of the economic aspect of the idea of "waste" of physical resources. The discussion was inconclusive, except to indicate the problems of regulatory agencies in attempting to direct the industry toward economical practices despite institutional and legal obstacles.

There was no suggestion regarding whether or not the effects of regulatory practices on costs is measurable. The possibility of measuring the time-cost of shut-in capacity and the over-riding cost of unnecessary wells was suggested, and further research in this area was proposed.

#### *Miscellaneous Comments and Recommendations.*

In the two and one-half days of discussion, there were numerous comments, questions and suggestions which do not fall into the categories already covered in this summary. A few of these seem worth reporting.

Considerable dissatisfaction was expressed concerning the defects of industrial data and the limitations these impose on analytical studies. The group went on record without dissent as endorsing a broad program of research on the matters considered by the seminar and related topics in the economics of the petroleum industry. A suggested sequence of procedure was formulated as follows:

- (1) To determine what information is needed for what purpose.
- (2) To determine what information is available.
- (3) To explore the feasibility of getting information which is lacking.
- (4) To proceed in an orderly fashion to obtain the needed information which is potentially available.
- (5) To design, or re-design, analytical studies for the use of this information.

Despite the common assent to this procedure, there were substantial differences as to what needed to be done, or what could be done. One view was expressed that the seminar had failed to develop a framework for gathering data, displaying a lack of precision regarding what problems should be attacked, how they should be attacked, and what data were needed for attacking them. It was pointed out that the industry already spends a great deal of money collecting and processing data, and is apt to be reluctant to collect more unless persuasive reasons are presented. It was further urged that companies were disinclined to go to the trouble and expense of collecting and processing data unless the results were likely to be of some internal use. These obstacles are the more serious because companies are reluctant to disclose confidential data even if the source is con-

cealed, and because companies do not keep records in a uniform manner which would permit industrial data to be aggregated.

It was recognized that little progress on informative industry studies could be made without substantial cooperation from individual companies. This fact suggests the necessity of supporting proposals for particular studies with arguments for the useful purposes they might serve. From a starting point of agreement in principle on such proposals, the availability of data and the filling of data gaps could be considered in detail with those who would have to provide them. Considerable cooperation, it was suggested, might be expected from companies because they would benefit from careful analyses based on more extensive and more accurate data. Against this the point was made that companies might be reluctant to provide for studies which might be used against them by public agencies or by competitors.

Although the group recognized the obstacles and limitations, it was agreed that useful studies could be carried out relevant to the subject-matter of the seminar, and went on record as endorsing a program of inquiry along the lines outlined at the beginning of this section. The group supported a recommendation that Resources For The Future, Inc. pursue some of the avenues of research revealed by the discussion and support investigation in these areas. Professor Homan was designated as the person to retain contact between the seminar group and Resources For The Future, Inc. The individuals in the group indicated a willingness to meet for further discussion and to assist further research in any way they could.

Subsequent to the writing of this Summary, Resources For The Future has made two further grants to Southern Methodist University: one for a technical study of methods of estimating petroleum reserves, the other for a seminar-conference to be held in the spring of 1964 on economic aspects of petroleum conservation regulation.