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Crude Oil Prices, Drilling Incentives and the Supply of New Discoveries

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CRUDE OIL PRICES, DRILLING INCENTIVES AND THE SUPPLY OF NEW DISCOVERIES*

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The economics of the U.S. petroleum industry have been the subject of much discussion and little estimation. Oil accounts for about 40 percent of the total energy consumed in the United States. Oil, gas and natural gas liquids together account for more than 65 percent.[1] Special tax provisions apply to petroleum exploration and production while petroleum imports are subject to mandatory restrictions. In many states, the production of crude oil is controlled by regulatory agencies. The wellhead price of natural gas is controlled by the Federal Power Commission. In an industry as large and diverse as the domestic petroleum industry which is subject to as much regulation as it is, it is not surprising that policy disputes are a continuing problem. It is surprising that attempts to estimate empirically important economic relationships are so scarce. The costs and effectiveness of alternative policies depend upon the price elasticities of supply and demand for oil and gas, the economic relationship between oil and gas discoveries, and the effects of economic incentives other than their own prices upon oil and gas production, discoveries and consumption. Much of the previous work on supply is concerned with the special legal and technical conditions under which petroleum exploration and production occur. The investigation of the economic characteristics of oil in the total demand for energy is still in an early stage.

I
SIGNIFICANT TRENDS

Despite its size and diversity, a panoramic view of the post-war domestic oil industry can be obtained by highlighting some significant trends. The dimensions of domestic industry performance are reflected in its current operating record, its investment activity and the relationship between its investment activity and its current operations. Statistical categories which most directly relate to these performance dimensions are: the price and output of crude oil, exploration activity and additions to reserves, the cost schedules of current output and additions to reserves, and the relation between

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1. S. Schurr & B. Netschert, Energy in the American Economy, 1850-1975 (1960).

production and reserves. Some data in these categories are readily available while trends but not absolute levels can be approximated for others, and some are not part of the public record.

Between 1946 and 1967, the production of crude oil in the U.S. increased from under two to over three billion barrels per year. Proved reserves of crude oil in the U.S. increased from 21 billion barrels in 1946 to 31 billion barrels in 1967. However, the ratio of proved reserves to production fell from about 12:1 to slightly over 10:1. The decline in the reserves to production ratio is accounted for by the fact that U.S. proved reserves reached 30 to 31 billion barrels in the late 1950's and have shown no tendency to increase since then. In fact, total proved reserves in 1968 were lower than total proved reserves in 1959, the year that mandatory import quotas took effect.

The decline in domestic reserves occurred despite protection of the U.S. industry through import quotas and vigorous regulatory action to stabilize prices in the major producing states. Pursuit of these policies has not been without cost, but their net contribution to national security and a healthy domestic industry have been questionable.

The performance of the domestic industry has been seriously affected by these policies. Examination of this effect can best be accomplished through a review of the statistical record of the industry.

II
THE PRICE OF CRUDE OIL

Crude oil is produced in the U.S. in five major geographic areas. These areas have been designated as Petroleum Administration for Defense (PAD) Districts. These Districts roughly correspond to the major petroleum provinces. District I is the East Coast. District II is the Midcontinent. District III is the Southwest and Gulf Coast. District IV is the Rocky Mountain area. District V is the West Coast including Alaska.[2]

2. The composition by states of Petroleum Administration for Defense Districts is as follows:

District I: Maine, New Hampshire, Vermont, Massachusetts, Virginia, West Virginia, North Carolina, South Carolina, Georgia, Florida, District of Columbia, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland.

District II: Ohio Kentucky, Tennessee, Indiana, Michigan, Illinois, Wisconsin, Minnesota, Iowa, Missouri, Oklahoma, Kansas, Nebraska, South Dakota, North Dakota.

District III: Alabama, Mississippi, Louisiana, Arkansas, Texas, New Mexico.

District IV: Montana, Wyoming, Colorado, Utah, Idaho.

District V: Arizona, California, Nevada, Oregon, Washington, Alaska, Hawaii.

The price of crude oil at the wellhead by PAD Districts for the years 1946-67 is presented in Table 1. These prices are in constant

TABLE 1

DEFLATED WEIGHTED AVERAGE WELLHEAD PRICE PER BARREL OF CRUDE OIL BY PAD DISTRICTS, 1946-1967[a]

	PAD District					
Year	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	3.29	1.30	1.22	1.07	1.08	1.23
1947	2.97	1.42	1.38	1.26	1.23	1.38
1948	3.25	1.75	1.71	1.59	1.60	1.71
1949	2.42	1.82	1.80	1.66	1.57	1.76
1950	2.50	1.75	1.72	1.53	1.44	1.67
1951	2.50	1.57	1.55	1.37	1.35	1.51
1952	2.57	1.61	1.58	1.41	1.37	1.56
1953	2.63	1.71	1.71	1.53	1.56	1.67
1954	2.08	1.77	1.77	1.57	1.59	1.73
1955	2.15	1.75	1.77	1.55	1.55	1.72
1956	2.57	1.70	1.69	1.54	1.58	1.68
1957	2.72	1.78	1.84	1.62	1.78	1.81
1958	2.30	1.72	1.78	1.55	1.73	1.74
1959	2.35	1.68	1.73	1.52	1.47	1.67
1960	2.56	1.67	1.72	1.48	1.41	1.66
1961	2.63	1.68	1.73	1.50	1.41	1.67
1962	2.52	1.68	1.74	1.49	1.45	1.67
1963	2.53	1.68	1.73	1.49	1.44	1.67
1964	2.41	1.65	1.72	1.49	1.41	1.66
1965	2.36	1.62	1.68	1.45	1.36	1.62
1966	2.35	1.59	1.64	1.42	1.30	1.57
1967	2.36	1.60	1.65	1.43	1.29	1.59

SOURCES: *Petroleum Facts and Figures,* 1959 and 1963; *Economic Report of the President,* 1962 and 1968; *Oil and Gas Journal,* 1968.

[a] The yearly wellhead prices are reported by states. These prices are weighted by the yearly crude production of the individual states in the aggregation to PAD Districts. The deflator is the BLS wholesale index for all commodities, 1947-1949 base, with 1945 set equal to 100.

dollars and are weighted averages of the prices in each of the states that make up a PAD District. The weights are the relative importance of each state's production per year in the District to which it belongs. As can be seen from examination of Table 1, there are consistent price differentials between Districts. These differentials represent differences in the quality of the crude, costs of production, and proximity to markets. There is also a tendency for the real price to rise early in the period, stabilize in the late 1950's and then decline slightly in recent years. The stabilization of prices corresponds to the implementation of severe production restrictions in the states which practice market demand prorationing and the imposition of import controls. These are complementary policies, and their effects go beyond price stabilization. We shall return to them

later for a more detailed discussion. The slight decline in prices corresponds to a relaxation of production restrictions.

III
CRUDE OIL PRODUCTION

Domestic production of crude oil nearly doubled between 1946 and 1967. Inspection of Tables 2 and 3 indicates consistent rankings in the importance of each District in total U.S. output. District

TABLE 2
PERCENT OF U.S. CRUDE OIL PRODUCTION BY PAD DISTRICTS FOR SELECTED YEARS

	PAD District					
Year	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	1.2	19.9	57.3	3.4	18.2	100.0
1951	0.8	18.0	60.6	4.7	15.8	100.0
1956	0.5	19.0	60.0	7.2	13.4	100.0
1961	0.4	18.5	59.8	9.6	11.7	100.0
1966	0.4	16.0	64.2	7.5	11.9	100.0

SOURCE: *Petroleum Facts and Figures*, 1967.

TABLE 3
PRODUCTION[a] OF CRUDE IN THE U.S. BY PAD DISTRICT, 1946-1967

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	20,868	344,949	993,751	59,658	314,713	1,733,939
1947	20,389	347,717	1,086,533	69,216	333,132	1,856,987
1948	20,303	366,682	1,210,834	82,292	340,074	2,020,185
1949	19,122	356,925	1,051,719	81,232	332,942	1,841,940
1950	19,318	376,093	1,156,285	94,271	327,607	1,973,574
1951	18,964	404,044	1,363,127	107,015	354,561	2,247,711
1952	18,678	410,132	1,391,778	109,798	359,450	2,289,836
1953	18,038	427,980	1,413,232	132,447	365,085	2,357,082
1954	15,821	426,823	1,360,607	155,839	355,898	2,314,988
1955	14,254	470,495	1,473,375	167,790	354,876	2,484,428
1956	13,640	496,883	1,568,370	187,572	350,818	2,617,283
1957	13,537	493,667	1,573,897	196,105	339,690	2,616,896
1958	10,982	482,575	1,424,237	216,558	314,469	2,448,821
1959	10,744	490,540	1,521,809	242,306	309,191	2,574,590
1960	10,853	484,405	1,524,810	249,213	306,012	2,574,933
1961	10,437	484,867	1,567,571	252,720	306,163	2,621,758
1962	10,780	490,288	1,617,866	250,239	307,012	2,676,185
1963	10,579	485,282	1,698,033	246,995	311,834	2,752,723
1964	10,983	486,625	1,745,098	232,729	311,387	2,786,822
1965	11,552	474,254	1,804,945	229,901	327,862	2,848,514
1966	11,553	485,405	1,943,259	227,454	360,092	3,027,763
1967	9,920	476,983	2,106,239	229,224	388,345	3,210,711

SOURCE: *Petroleum Facts and Figures*, 1967.

[a] Thousands of U.S. barrels.

IV, the Rocky Mountain area, becomes relatively more important, but the absolute change in output in District IV is relatively small compared to the change in total U.S. output. The most important feature of Tables 2 and 3 is the emphasis they give to the role of PAD District III, the Southwest and Gulf Coast. Roughly two-thirds of domestic crude oil production comes from this area.

IV
CRUDE OIL RESERVES

Proved reserves of crude oil increased by 50 percent between 1946 and 1956. Since 1956, there has been very little change in the level of domestic reserves. Proved reserve data are subject to certain limitations, but they provide a consistent statistical record of the domestic industry's activity.[3] Tables 4 and 5 show again the importance of PAD District III, the Southwest and Gulf Coast, in the location of U.S. crude oil producing capacity. The recent discoveries in Alaska will affect the relative importance of the various PAD Districts. Alaska is included in District V. The other principal state in District V is California. Since Alaska and the rest of District V are neither contiguous nor otherwise homogeneous, Alaska should be accorded treatment as a separate PAD District for purposes of reporting clarity and consistent interpretation.

V
TOTAL DRILLING ACTIVITY

Between 1946 and 1956, drilling activity, measured by total wells

TABLE 4
PERCENT OF U.S. CRUDE PROVED RESERVES BY PAD DISTRICTS FOR SELECTED YEARS

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	1.0	9.6	68.9	4.8	15.8	100.1[a]
1951	0.7	11.4	69.0	5.2	13.7	100.0
1956	0.7	14.1	65.8	7.0	12.4	100.0
1961	0.6	12.6	68.0	7.1	11.4	99.7[a]
1966	0.4	10.5	67.2	6.1	15.7	99.9[a]

SOURCE: American Petroleum Institute, *Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas,* 1946-68.

[a] Detail does not add to 100.0 because of rounding and miscellaneous entries.

3. *See* Musket, *The Proved Oil Reserves of the U.S.,* 15 J. Petroleum Technology 915-21 (1963).

TABLE 5

PROVED RESERVES OF CRUDE OIL IN THE U.S. BY PAD DISTRICT, 1946-1968

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	209,445	1,997,296	14,890,889	993,474	3,293,491	20,873,560
1949	204,248	2,738,646	16,715,593	1,164,638	3,822,751	24,649,489
1950	204,210	2,922,242	17,091,571	1,313,446	3,733,562	25,268,398
1951	190,825	3,130,421	18,941,090	1,436,719	3,760,870	27,468,031
1952	211,790	3,388,010	18,933,761	1,568,993	3,854,171	27,960,554
1953	196,778	3,680,594	19,298,669	1,845,286	3,919,379	28,944,828
1954	184,992	4,013,504	19,528,801	1,941,036	3,888,588	29,560,746
1955	183,287	4,232,304	19,746,292	2,043,693	3,801,408	30,012,170
1956	226,117	4,295,761	20,017,463	2,119,763	3,771,357	30,434,649
1957	216,568	4,187,449	19,943,371	2,189,682	3,759,754	30,300,405
1958	207,739	4,125,075	19,995,469	2,337,215	3,866,430	30,535,917
1959	199,030	4,178,873	21,282,047	2,287,697	3,762,507	31,719,347
1960	191,448	4,094,627	21,369,930	2,266,385	3,658,542	31,613,211
1961	180,060	4,015,270	21,588,764	2,269,176	3,614,729	31,758,505
1962	176,026	3,870,082	21,472,216	2,131,935	3,648,434	31,389,223
1963	167,472	3,679,085	21,327,728	2,113,510	3,674,655	30,969,990
1964	158,892	3,558,650	21,030,750	2,021,998	4,208,347	30,990,510
1965	143,880	3,424,933	21,071,279	1,967,069	4,727,281	31,352,391
1966	139,184	3,306,362	21,150,967	1,911,001	4,929,360	31,452,127
1967	134,084	3,091,253	21,487,799	1,892,389	4,750,203	31,376,670
1968	125,802	2,959,225	20,840,408	2,046,917	4,713,934	30,707,117

SOURCE: American Petroleum Institute, *Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas,* 1946-1968.

drilled of all classes and types, more than doubled. Between 1956 and 1967, such drilling activity fell by over 40 percent. Tables 6 and 7 show the allocation of total drilling activity among PAD Districts and the numbers of wells drilled. PAD District III again dominates U.S. activity, although PAD District II, the Midcontinent area, is quite important. The rank of PAD District I, the East Coast, has steadily dwindled from third to last in importance. Along with the changes in the level of total drilling activity, there

TABLE 6

PERCENT OF TOTAL WELLS OF ALL TYPES DRILLED IN THE U.S. BY PAD DISTRICTS FOR SELECTED YEARS

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	18.5	35.0	37.2	2.4	6.6	99.7[a]
1951	6.8	36.9	47.5	3.0	5.5	99.7[a]
1956	4.5	35.6	50.4	4.6	4.0	99.1[a]
1961	4.8	39.7	46.1	4.9	4.5	100.0
1966	5.1	35.8	46.7	5.8	6.5	100.0

SOURCE: *Petroleum Facts and Figures,* 1967 and 1959.

[a] Detail does not add to 100.0 percent because of rounding.

TABLE 7

TOTAL WELLS OF ALL TYPES DRILLED IN THE U.S.
BY PAD DISTRICTS FOR SELECTED YEARS

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	5003	9,444	10,054	648	1790	26,991
1947	4956	10,640	12,020	785	2053	30,842
1948	4711	12,809	15,846	1136	2876	37,503
1949	3231	13,663	17,160	948	2512	37,656
1950	2994	15,838	20,316	684	1828	42,030
1951	2931	15,931	20,478	1296	2355	43,136
1952	3166	15,806	21,089	1513	2423	44,339
1953	2929	17,730	22,252	2102	2566	48,017
1954	2978	19,412	24,749	2922	2335	52,919
1955	2642	20,608	26,939	2835	2455	55,922
1956	2584	20,308	28,770	2646	2304	57,111
1957	2622	16,347	28,732	2131	2225	52,777
1958	1966	18,509	24,808	2320	1507	49,111
1959	1741	18,939	25,966	2465	1582	50,893
1960	2061	18,034	22,493	2377	1786	46,751
1961	2239	18,647	21,629	2318	2123	46,962
1962	2341	16,597	21,760	2283	2648	46,179
1963	2280	15,132	21,316	2079	2496	43,653
1964	2597	16,782	21,196	2239	2422	45,236
1965	2803	13,967	20,136	2208	2309	41,423
1966	1928	13,565	17,704	2207	2477	37,881

SOURCES: *Petroleum Facts and Figures*, 1967 and 1959; *Oil and Gas Journal*, February 5, 1968.

have been changes in its composition and results. Drilling for new fields and for new pools in old fields fell relative to total drilling. There was also a significant change in average discovery size between the 1946-1956 and 1957-1967 periods. These effects are intimately connected with the related policies of market demand prorationing and import quotas.

VI
EXPLORATORY DRILLING

Exploratory drilling measured by wells intended to tap new fields or new pools in old fields, has followed a time path of roughly the same profile as total drilling. Exploratory drilling expanded much more rapidly than total drilling over the 1946-1956 period and contracted more sharply over the 1957-1967 period, but the peak of activity for both was 1956. District III is again the most important area of activity in the U.S. Of the five PAD Districts, Districts III and IV have grown in relative importance in the post-war era and Districts I, II and V have incurred a decline in relative status. With the inconsequential exception of

PAD District I, exploratory drilling is down sharply in all of the Districts. The allocation of exploratory drilling among districts and the numbers of wells drilled are shown in Tables 8 and 9.

TABLE 8

PERCENT OF NEW FIELD PLUS NEW POOL WILDCATS DRILLED IN THE U.S. BY PAD DISTRICTS FOR SELECTED YEARS

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	2.6	42.2	46.4	2.1	6.7	100.0
1951	0.9	39.9	49.6	4.3	5.3	100.0
1956	0.6	33.7	51.8	10.2	3.6	100.0
1961	1.4	36.7	46.7	10.3	4.8	100.0
1966	1.2	33.6	50.6	10.8	3.8	100.0

SOURCE: *Bulletin of American Association of Petroleum Geologists.*

TABLE 9

NEW FIELD PLUS NEW WILDCATS DRILLED IN THE U.S. BY PAD DISTRICTS, 1946-1967

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	102	1,653	1,818	82	264	3,919
1947	147	1,972	2,182	112	283	4,696
1948	142	2,195	2,897	164	367	5,765
1949	108	2,404	3,109	246	450	6,317
1950	79	3,243	3,384	239	372	7,317
1951	77	3,446	4,286	370	459	8,638
1952	90	3,349	4,899	599	426	9,363
1953	119	3,283	5,251	679	485	9,817
1954	112	3,254	4,985	989	493	9,833
1955	94	3,716	5,463	1,273	489	11,035
1956	69	4,028	6,182	1,221	435	11,935
1957	69	3,626	5,784	1,036	445	10,960
1958	73	3,378	5,020	807	373	9,651
1959	74	3,449	4,812	896	395	9,626
1960	105	3,166	4,130	881	380	8,662
1961	117	3,040	3,869	854	399	8,279
1962	99	2,923	3,712	932	403	8,069
1963	92	3,015	4,093	808	366	8,374
1964	65	3,330	3,842	815	486	8,538
1965	84	2,859	3,893	690	363	7,889
1966	95	2,680	4,033	859	306	7,973
1967	75	2,294	3,362	784	312	6,827

SOURCE: *Bulletin of the American Association of Petroleum Geologists,* 1947-1968.

VII

DISCOVERIES

The relative importance of the various Districts in total U.S. discoveries is shown in Tables 10 and 11. As with production, drill-

TABLE 10

PERCENT OF TOTAL CRUDE OIL DISCOVERIES BY PAD DISTRICTS FOR SELECTED YEARS

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	0	27.5	65.0	1.9	5.7	100.0
1951	0.1	22.3	66.4	8.1	1.8	98.7[a]
1956	0.7	18.8	66.5	10.0	4.0	100.0
1961	0.2	7.7	80.4	6.0	5.8	100.0
1966	0	7.7	62.0	4.2	26.0	100.0

SOURCE: *Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas,* 1946-67.

[a] Detail does not add to 100.0 percent because of miscellaneous.

TABLE 11

PROVED CRUDE OIL RESERVES[a] DISCOVERED IN NEW FIELDS AND IN NEW POOLS IN OLD FIELDS IN THE UNITED STATES, 1946-1967

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	0	67,102	158,876	4,580	13,876	244,434
1947	0	123,398	295,057	13,620	13,355	445,430
1948	100	81,872	231,929	23,680	58,075	395,656
1949	1,125	88,889	621,471	12,737	166,195	890,417
1950	350	91,637	437,729	24,455	10,745	564,916
1951	420	86,663	258,524	31,490	7,159	389,256
1952	0	99,132	300,712	53,042	43,542	496,428
1953	0	115,410	408,784	45,809	20,802	591,680
1954	900	81,283	424,079	52,779	26,345	585,806
1955	0	65,078	350,159	31,782	29,668	476,957
1956	3,138	87,675	310,703	46,803	18,903	467,222
1957	0	108,157	257,518	35,412	15,060	416,197
1958	0	52,033	227,290	19,577	15,659	314,729
1959	0	59,220	291,096	10,816	8,080	369,362
1960	0	38,495	168,479	15,951	10,916	253,856
1961	550	27,658	290,721	21,575	20,860	361,374
1962	50	23,267	332,047	21,045	4,052	380,586
1963	0	26,266	293,413	17,350	11,705	349,891
1964	0	30,343	249,087	25,150	39,275	346,293
1965	120	27,741	284,471	23,650	135,835	471,947
1966	0	23,899	192,613	13,145	80,760	310,422
1967	80	16,346	210,351	69,631	38,277	344,595

SOURCE: American Petroleum Institute, *Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas,* 1946-1967, Vols. 1-22.

[a] Thousands of U.S. barrels.

ing, and reserves, the most significant things to be learned from these tables are the dominant importance of District III and the trend of discoveries since the mid-1950's. It is not an exaggeration to say that as District III has gone, so has the U.S. industry.

Cumulative domestic discoveries fell considerably between the

periods 1946-56 and 1957-67. If Alaska is credited with all the reserves that many people claim, the balance tips the other way. It is always difficult to measure discoveries and make comparisons over time. This is because the terms reserves and discoveries frequently mean different things to different people.[4] Using API's yardstick of additions to proved reserves through discoveries of new fields and new pools in old fields, the record shows that discoveries (excluding Alaska) in the second half of the post-war era are barely equal to 70 percent of those in the first half. But this figure masks an important additional piece of information. Because of the low base of activity in the years 1946-1949, more exploratory wells were actually drilled in the 1957-1967 period than in the years 1946-1956. This means that average discovery size per successful new field and new pool wildcat decreased drastically in the later period. This phenomenon cannot be adequately understood without examining the practice and effects of market demand prorationing.

VIII

MARKET DEMAND PRORATIONING

Market demand prorationing is significant in five states.[5] Together these five states account for about two-thirds of the activity in the domestic crude oil industry. Market demand prorationing is part of what is generally referred to as "conservation" regulation. The proper aim of conservation regulation is the avoidance of economic waste and the promotion of economic efficiency. State-directed conservation regulation, however, has generally sacrificed efficiency for a kind of equity within the market demand proration scheme.[6]

> The determination of equitable rights in a restricted marketable output may collide with economic efficiency not only through its encouragement of excess costs of capacity but also through its shortrun division of quotas among high-and-low-cost producers . . . [T]his system creates a kind of leverage effect against the flush reservoirs subject to proration, which becomes greater the more production is restricted below the total rated productive capacity of the state . . . It is readily apparent that the effect of restricting production to "market demand"—the quantity demanded at the going price—is to lend support to the going price . . . [C]onservation practices have

4. *See* Musket, *supra* note 3.
5. Texas, Louisiana and New Mexico in PAD District III and Kansas and Oklahoma in District II.
6. McKie & McDonald, *Petroleum Conservation in Theory and Practice,* 76 Q.J. Econ. 118-21 (1962).

> not done much to keep the costs of domestic oil down to competitive levels on world markets. It seems clear that the present policies fail to meet . . . rudimentary tests of conservation in that they encourage the waste of "other" resources—labor and capital—in the name of oil conservation.

Conservation regulation, as it has been primarily practiced in the major oil states in PAD Districts II and III, has prevented waste and encouraged efficiency only to the extent that it has been less wasteful than previous practices under the unbridled rule of capture. The principal difficulty with market demand prorationing is that it regards the well, rather than the reservoir, as the unit of production.[7]

> 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 . . . (these) cost features (are) 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. . . . [T]he nature of the general impact on costs is clear. . . . [P]rorationing 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.

Lovejoy, Homan and Galvin conclude:

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

7. W. Lovejoy & P. Homan with C. Galvin, Cost Analysis in the Petroleum Industry 71 (1964).

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 prorationing rules.

Market demand prorationing causes inefficiencies in development and production. It also reduces the incentives to explore in the U.S. The increasing severity of market demand prorationing has had serious effects upon the performance of the U.S. crude oil industry. The degree of restrictiveness of Texas regulations is shown in Table 12. Texas is representative of the five market demand states.

TABLE 12

TEXAS PRODUCTION RESTRICTIONS, 1946-68

YEAR	*NUMBER OF SHUTDOWN DAYS*	*PERCENT OF DAYS PRODUCING*
1946	69	81
1947	41	89
1948	0	100
1949	127	65
1950	135	63
1951	87	76
1952	107	71
1953	129	65
1954	171	53
1955	171	53
1956	176	52
1957	194	47
1958	243	33
1959	242	34
1960	262	28
1961	264	28
1962	268	27
1963	264	28
1964	262	28
1965	259	29
1966	242	34
1967	215	41
1968	201	45

SOURCE: Texas Railroad Commission

Note that 1956 marks the dividing line between over 50 and under 50 percent of days producing.

Market demand prorationing has both short-run and long-run effects upon exploration. The short-run effects result because the regulations determine which drilling prospects out of a set of known options are most attractive. The features of the regulatory scheme which most affect this decision are depth bracket allowables and

restrictions on multiple completions. Drilling costs increase exponentially with depth, while allowables do not. Therefore, allowables discourage the exploration of deep horizons. Another way to offset the expense of probing deep formations is to complete several known shallower formations out of the same well that goes on to test a deep formation. To the extent that regulatory agencies have discouraged multiple completions, they have inhibited exploration and caused operators to choose less desirable prospects than they would have in the absence of regulatory restraint.[8] Conservation authorities have controlled multiple completions.

The effects of depth bracket allowables, control of multiple completions, and curtailing the output of the most efficient reservoirs also carry over into the long run. It is obvious that if one cannot produce oil once it is found, that the incentives to find oil are reduced. This is true even if the production restrictions maintain the going price. This effect shows up in the amount and character of exploratory drilling which is the long-run investment process of the oil industry. Long-run investment behavior of the domestic oil industry has been markedly distorted by market demand prorationing. Market demand prorationing could not have survived without the crutch of mandatory import controls.

A part of the exploration process is the use of geophysical and geologic analyses. As shown in Table 13, the use of geophysical crews[9] in the U.S. has fallen drastically. Seismograph crew time has declined relatively further in the U.S. at large than in PAD District III. But because crew time peaked later in District III, the rate of decline has been steeper than in other areas. In the long run, it is the use of geophysical and geological analysis, combined with the information achieved from drilling wells, which generates new prospects. Thus, because incentives to find and develop new oil fields have been reduced by market demand prorationing, the process which generates new prospects has been drastically curtailed.

The types of wells drilled by operators are also affected. Geophysical and geologic analyses aid in finding large reservoirs and help limit the proportion of wells which are unsuccessful. Market demand prorationing affects the characteristics of prospects that

8. For a full discussion of the effects of the conservation system upon exploration incentives, see E. Erickson, Economic Incentives, Industrial Structure and the Supply of Crude Oil Discoveries in the U.S., 1946-58/59, at 51-89, (unpublished Ph.D. dissertation, Vand. Univ.)

9. There are several kinds of geophysical work. The most common are seismic, gravity and magnetic. Data on gravity meter and magnemeter crews are incomplete, but the overwhelming bulk of geophysical crew work is seismic. Therefore, the data on seismic crew weeks capture the trends.

TABLE 13

SEISMOGRAPH CREW TIME IN THE U.S., 1951-67

	CREW TIME IN CREW WEEKS	
YEAR	*TEXAS AND LOUISIANA*	*U.S.*
1951	3,615	6,537
1952	3,753	7,948
1953	3,727	7,666
1954	3,410	6,863
1955	4,006	7,090
1956	3,866	6,858
1957	3,282	6,283
1958	2,737	5,064
1959	2,640	5,097
1960	N.A.	N.A.
1961	2,457	4,557
1962	2,187	3,915
1963	2,165	3,966
1964	2,261	4,102
1965	N.A.	N.A.
1966	2,113	3,672
1967	1,882	3,337

SOURCE: Society of Exploration Geophysicists.

firms can afford to accept.[10] In 1951, roughly three-quarters of a week of seismograph crew time was used for each new field and new pool wildcat drilled. The amount of seismograph crew time used per new field and new pool wildcat fell below one-half crew week per well in 1961 and has not risen above that level since.[11] The result, as shown in Tables 14 and 15, is a severe decline in average discoveries per successful new pool and new field wildcat and a slight decline in the success ratio.

Using the periods 1946-1956 and 1957-1967 as the bases for comparison, average discovery size in the U.S. fell 38 percent. Average discovery size in PAD District III fell 32 percent. For the same base periods, the average U.S. success ratio fell 1.1 percent

10. Part of this is the overdrilling that Lovejoy, *et al.*, discuss, but it would be possible to have overdrilling as a result of inept administration of a well-based conservation system without market demand restrictions. The market demand system, combined with exemptions and well-based allowables, causes a distortion in the kind of new capacity that is developed. Lovejoy & Homan with Galvin, *supra* note 7. *See also* Adelman, *Efficiency of Resource Use in Crude Petroleum* 31 S. Econ. J. 101-22 (1964).

11. In part, the decline in the use of seismic crews can be attributed to natural causes. Seismic work is least effective in the location and analysis of stratigraphic traps. However, the coincidence of the decline with the advent of severe prorationing is too marked to result solely from chance. The decline in seismic crew activity is also a result of the relative shift in exploration activity to offshore areas in District III. A given crew can produce more seismic work in offshore work.

and the average PAD District III success ratio fell 0.5 percent. The fall in average discovery sizes and success ratios in PAD District III was mitigated by the opening of the offshore oil lands in the Gulf Coast.

The combined effect of reduced drilling, lower success ratios and lower average discovery sizes has been to reduce total U.S. discoveries. The decline has been more severe in PAD District III than in the U.S. generally. This is despite the effects of offshore drilling to limit the fall in District III. Because the prorationing system protects inefficient wells whose costs are very high, it depends upon a high domestic price to survive. Without the protection of import quotas, market demand prorationing would require sweeping reform.

IX
THE SUPPLY OF NEW CRUDE OIL DISCOVERIES

The number of new discoveries in an area for any period is the

TABLE 14
AVERAGE SIZE[a] OF CRUDE OIL DISCOVERIES PER SUCCESSFUL NEW FIELD PLUS NEW POOL WILDCAT, 1946-67

	PAD DISTRICT					
YEAR	*I*	*II*	*III*	*IV*	*V*	*U.S.*
1946	0	295.6	662.0	381.7	447.6	623.7
1947	0	415.5	855.2	801.2	430.8	948.5
1948	4.3	285.3	514.3	877.0	1,528.3	686.3
1949	33.1	273.5	1,111.8	374.6	7,225.9	1,409.6
1950	16.7	251.1	761.3	679.3	826.5	772.1
1951	30.0	210.3	368.8	699.8	238.6	450.6
1952	0	260.9	378.3	855.5	1,209.5	530.2
1953	0	257.0	489.6	602.8	424.5	602.7
1954	37.5	179.4	488.0	493.3	612.7	595.8
1955	0	128.1	381.4	260.5	549.4	432.2
1956	261.5	174.3	337.7	544.2	343.7	391.5
1957	0	263.2	282.4	368.9	358.6	379.7
1958	0	117.5	273.8	275.7	505.1	326.1
1959	0	139.3	349.9	121.5	218.4	383.7
1960	0	126.2	268.7	212.7	242.6	293.1
1961	13.4	81.6	495.3	312.7	521.5	436.4
1962	1.9	75.5	518.0	244.7	122.8	471.7
1963	0	55.8	430.9	289.2	433.5	417.8
1964	0	72.1	425.8	335.3	935.1	405.6
1965	8.6	93.1	493.9	463.7	4,244.8	598.2
1966	0	81.3	355.4	173.0	4,038.0	389.3
1967	5.3	57.8	447.6	1,123.1	1,275.9	504.8

SOURCES: *Bulletin of the American Association of Petroleum Geologists*, June issues, 1947-68. *Proved Reserves of Crude Oil, Natural Gas Liquids and Natural Gas*, 1947-67.

[a] Thousands of U.S. barrels.

TABLE 15
THE SUCCESS RATIO[a] BY PAD DISTRICTS, 1946-67

	PAD DISTRICT					
YEAR	I	II	III	IV	V	U.S.
1946	35.29	13.76	13.20	14.63	11.74	13.93
1947	19.05	15.06	15.81	15.18	10.95	15.29
1948	16.20	13.08	15.57	16.46	10.35	14.33
1949	31.48	13.52	17.98	13.82	5.11	15.43
1950	26.58	11.26	16.99	15.06	3.49	13.80
1951	18.18	11.96	16.36	12.16	6.54	13.92
1952	20.00	11.35	16.23	10.35	8.45	13.79
1953	13.45	13.68	15.90	11.19	10.10	14.52
1954	21.43	14.92	17.43	10.82	8.72	15.21
1955	29.79	13.67	16.80	9.58	11.04	14.77
1956	17.39	12.49	14.88	7.04	12.64	13.20
1957	30.43	11.33	15.77	9.27	9.44	13.52
1958	30.14	13.11	16.53	8.80	8.31	14.48
1959	10.81	12.32	17.29	9.93	9.93	14.45
1960	33.33	9.63	15.18	8.51	11.84	12.55
1961	35.04	11.15	15.17	8.08	10.03	13.00
1962	26.26	10.54	17.27	9.23	8.19	13.56
1963	25.00	15.62	16.64	7.43	7.38	15.07
1964	24.62	12.64	15.23	9.20	8.64	13.34
1965	16.67	10.42	14.80	7.39	8.82	12.31
1966	17.89	10.97	13.44	8.85	6.54	11.90
1967	20.00	12.34	13.98	7.91	9.62	12.60

[a] The success ratio is defined as follows:

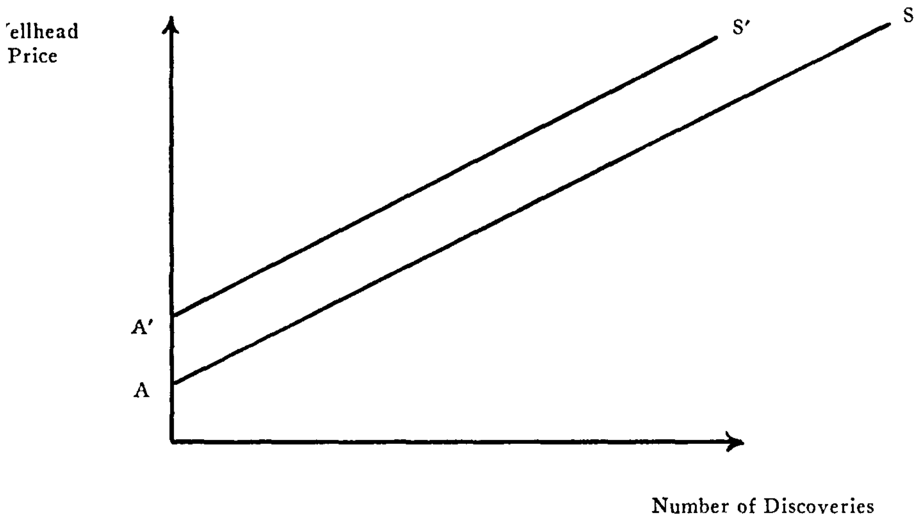
$$\left[\frac{\text{Successful New Field Plus New Pool Wildcats}}{\text{Total New Field Plus New Pool Wildcats}}\right] \times 100$$

product of three components. These are: (1) the number of wildcat wells drilled, (2) the fraction of wildcat wells that are successful, and (3) the average discovery size per successful wildcat. All of these components are affected by the wellhead price of crude oil. When the net effect of price changes upon each of these components is separately estimated and then combined, the result is an estimate of the price responsiveness of new crude oil discoveries.[12] This result is a supply curve of crude oil discoveries. A measure of the responsiveness of total discoveries to price is the elasticity of supply—the percentage change in discoveries for a one percent change in price. An illustrative supply curve, AS, is shown in Figure 1. The best estimate of the elasticity of supply is +0.9—a one percent increase in price yields, a nine-tenths of one percent increase in quantity supplied.[13]

The effect of increasingly severe market demand prorationing has been to shift the supply of new discoveries in the U.S. so that

12. *See* F. Fisher, Supply and Costs in the U.S. Petroleum Industry (1964); Erickson, *supra* note 8.
13. Erickson, *supra* note 8, at 28-50.

FIGURE 1



smaller amounts of discoveries occur at any price.[14] The most pronounced effect is upon average discovery size. In Figure 1, this effect is depicted as a shift in the whole supply curve from AS to A′S′. A simple present value example illustrates what lies behind the observed effect of the shift from AS to A′S′. The present value of an oil reservoir is equal to the wellhead price of the oil times the quantity produced less operating costs, properly discounted, and summed over the life of the reservoir. The net present value is this sum less exploration and development costs necessary to initiate production. A simplified illustration is as follows:

$$(1)\ V = \frac{(P_1 Q_1) - C_1}{1+i} + \frac{(P_2 Q_2) - C_2}{(1+i)^2} + \ldots + \frac{(P_n O_n) - C_n}{(1+i)^n}$$

$$(2)\ NPV = V - D - E$$

The wellhead price is P, Q is annual production, C is annual operating costs, i is the discount rate, the subscripts 1, 2, . . . n denote years with n equal to the life in years of the reservoir. D and E are the accumulated present value costs of development and exploration expenditures until production begins.

The effect of market demand prorationing has been to maintain P and reduce allowable Q. This in itself reduces V and, other things being equal, decreases the amount of exploration activity which is profitable at the expected time profile of prices. But other things

14. *Id.* at 51-88.

are not equal. The administrative procedures through which market demand prorationing has operated have also increased D and C above what would otherwise have been necessary to achieve the stream of output, Q_1 Q_2 . . . Q_n.[15] In addition, the restrictive effect of prorationing has not been equally borne by all reservoirs. Larger reservoirs have been more severely limited than smaller ones. The total effect of the resulting changes in the structure of net exploratory incentives and inducements has contributed to the marked decrease in average discovery size reported in Table 14. The shift in supply from AS to A'S' in Figure 1 is picked up by the econometric analysis.[16]

In the absence of market demand prorationing, however, the time profile of expected prices would be lower. For those engaged in the search for large reservoirs, the effect of lower prices could be partially, or completely offset (in a present value sense) by changes in the other variables. Elimination of market demand prorationing would result in increases in output for new discoveries (Q), decreases in development and operating costs (D and C) and a decrease in the period of time (*n*) for recovering investments. The ensuing fall in price would itself induce a decrease in some exploration costs (E). The element in exploration costs most susceptible to decrease would be bonus payments. Bonus payments are lump sum amounts paid to landowners to acquire drilling rights. They are important, for example, in offshore exploration in the Gulf of Mexico.[17] The extent to which the elements in equations (1) and (2) can be rearranged to maintain or increase the attractiveness of petroleum exploration in the U.S. will determine the long-run supply position of U.S. oil production relative to U.S. energy needs. Even in the absence of policy changes, this is a current question because fundamental relationships in the prorationing system are being altered.

X

EXEMPT PRODUCTION, EXCESS CAPACITY AND OUTPUT RESPONSE

Incidental to creating a niche in the market for high cost oil production, the policies of state regulatory agencies have encouraged

15. Adelman, *supra* note 10. For new discoveries, at least, the effect has also been to make *n* larger and delay returns.

16. Part of these observed effects may also be a result of the exhaustion of geologically promising prospects in the U.S. Resources for the Future is supporting my current research in which I am attempting to estimate the net contribution of each of these effects.

17. *See* McKie, *Market Structure and Uncertainty in Oil and Gas Exploration,* 74 Q. J. Econ. 543-71 (1960).

the creation of considerable excess capacity in the U.S. crude oil industry.[18] Excess capacity has been a persistent and substantial feature of the U.S. industry for over a decade (see Table 12). But excess capacity has been decreasing in recent years.[19] This is because of the combined effects of regulatory policies to shift the supply of new discoveries to the left, the growth of demand, the natural consequence of operators' adjustments over time within the regulatory framework, and marginal adjustments to the framework itself.[20] The market demand prorationing system was not originally intended to provide excess capacity for national defense purposes. Rather it has been a mechanism to allocate[21] permissible output among different classes of producing units. Thus the current erosion of excess capacity should not be regarded as a "failure" of the system.[22] Rather than a calamity, it is a welcome event. Figure 2 is a schematic interpretation of the recent trends in exempt production and excess capacity.

Production in barrels per day is measured on the left-hand vertical axis; the market demand factor is measured on the horizontal axis, and projected productive capacity in barrels per day is measured on the right-hand vertical axis. The downward trend of exempt production is shown by the fact that the left-hand intercept of KC at J (Year 2) is below the left-hand intercept of AB at E (Year 1). Because exempt production is not restricted according to market demand factors, it is a constant (at a point in time) for all market demand factors and (reading horizontally across Figure 2) exempt capacity equals exempt production. Production in excess of amount E in Year 1 and amount J in Year 2 is subject to market demand restrictions. If a total output (exempt plus prorated) of A is observed at a market demand factor of 30 in Year 1, a naive projection of total productive capacity at a market demand factor of 100 would be to divide the difference between A and E (in

18. *See* McKie & McDonald, *supra* note 6; Lovejoy & Homan, with Galvin, *supra* note 7; Adelman, *supra* note 10; and S. McDonald, Conservation Policies and National Security, paper presented at the Rocky Mountain Petroleum Economics Institute, Colorado Springs, Colorado, June 22-25, 1969.

19. Oil & Gas J., Apr. 28, 1969.

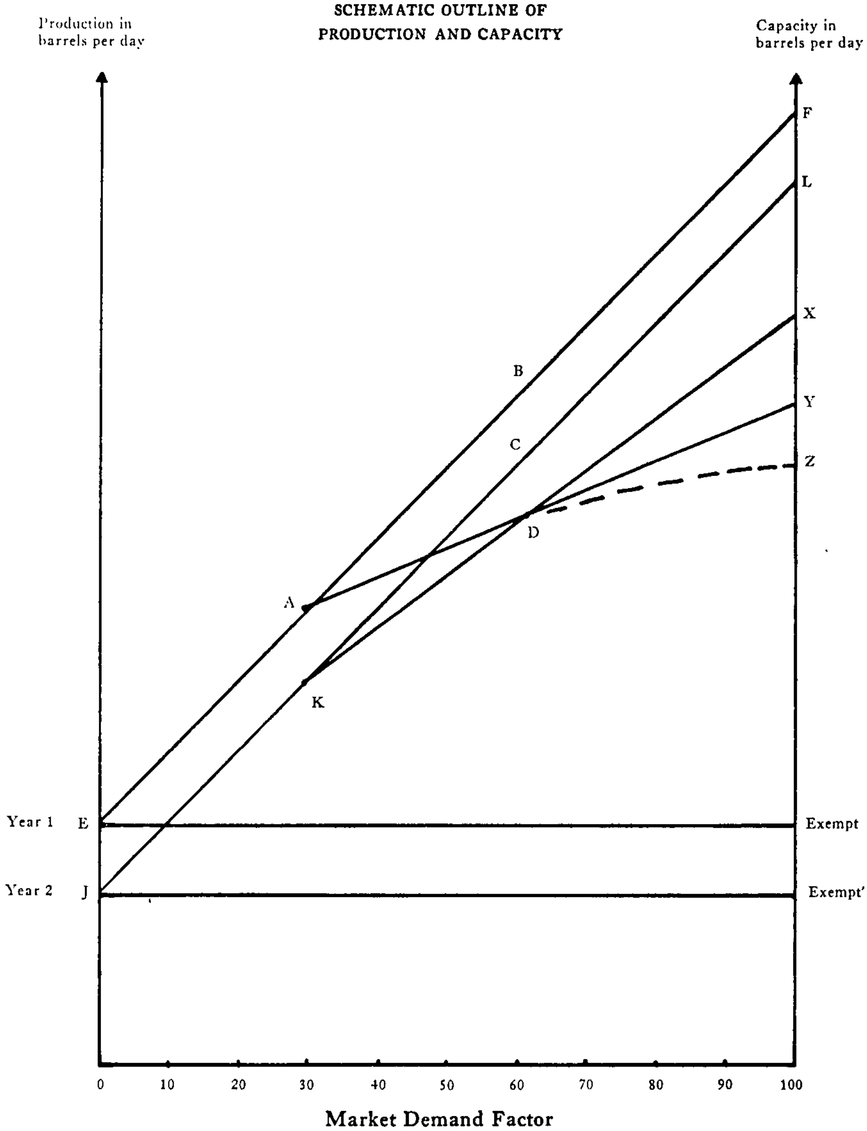
20. McKie & McDonald, *supra* note 6, at 11-18.

21. The term "prorationing" is a serious misnomer. Every producing unit does not receive a *pro rata* share of permissible output based upon its MER, capacity or reserves. Rather the base and the extent to which the market demand factor is applied is determined in a quasi-political fashion and varies among producing units. If regulatory authorities had in fact maintained the domestic price by *pro rata* reduction of the output of all producing units, the attendant misallocation of resources would have been substantially lessened.

22. Oil & Gas J., *supra* note 19.

FIGURE 2

SCHEMATIC OUTLINE OF
PRODUCTION AND CAPACITY



barrels per day of production) by 0.3 and add it to the output at E. The result is a schedule of projected outputs at all market demand factors such as EABF in Figure 2.[23] Even in the absence of

23. The slope of EABF depends upon the relative scales of the horizontal and vertical axes. EABF is drawn with slope of 45 degrees in Figure 2 solely for ease of presentation.

calendar day testing, such an estimate of effective productive capacity would probably be in error because the surface facilities would not be available to allow it to be sustained.

If exempt production is in a downward trend over time,[24] the same market demand factor will generate less output in Year 2 than in Year 1. This is shown by the vertical difference between points A and K. The same kind of estimation of total productive capacity as that described above would yield a naive projection of L barrels per day and a Year 2 prorationing response schedule of JKCL. If the market demand factor increases to, say 60 between Year 1 and Year 2 (a logical consequence of shrinking exempt production), and if actual output follows the projected response schedule, output in Year 2 will be at point C. Connecting points A and C would yield an observed response schedule different from either EABF or JKCL and a projected total productive capacity of less than L. This result is caused simply by the time trend of exempt production.

The provisions of calendar day testing guarantee results similar to those described above, but for a different reason.[25] Calendar day testing causes the increase in output of wells, reservoirs and fields to fall below the simple projected response as the market demand factor increases. This happens for two major reasons. First, if permissible output is expected to be considerably less than capacity as a result of a generally low ruling market demand factor, surface facilities adequate to handle capacity (or substantially increased) output will not be installed or maintained. Second, the presence of a continuum of wells on "limited" status whose regulated capacities are distributed over a range of output beginning at ten barrels per day and extending to the maximum allowable means that the col-

24. For purposes of simplicity, assume no other cause for a decline rate in productive capacity and no new additions to productive capacity. Such is not the case, of course, but complicating the presentation does not change the point.

25. Calendar day testing is a Texas provision that works as follows: If the depth/acreage allowable for a well is 1,000 b/d at market demand factor (MDF) equal to 100, then the permissible output of the well is 300 b/d at MDF equal to 30. If the MDF goes to 50 and the well can only make 400 b/d, it goes on "limited" status. A limited status well such as the one just described is free to make 400 b/d at all MDF in excess of 40. At MDF of 40 and below, its permissible output is restricted according to the ruling MDF and its depth/acreage allowable at an MDF of 100. Formerly the "base" allowable of a well against which the ruling MDF was applied was equal to either the depth/acreage yardstick allowable applicable to it, or the maximum production it could make wide open, whichever was less. In the example above and in the absence of calendar day testing, if all the well could make was 400 b/d, the permissible output at an MDF of 30 would have been 120 b/d rather than the 300 b/d in the case of calendar day testing.

lective total capacity for prorated wells is not derivable by simply dividing output at some market demand by that factor. This means that the schedule of prorated response is not a nicely defined linear function (Such as EABF or JKCL) which can be derived analytically, but an empirical function which can only be determined by direct observation or built up field by field.

In terms of Figure 2, calendar day testing leads to a prorationing response curve which appears as KDX. We will call KDX the unbiased extrapolation. The observed projection of productive capacity and output response to increases in market demand factor, ADY, is biased downward.[26] The bias results because exempt capacity trends downward over time. Recently the market demand factor has trended upward from its nadir in 1962. Points A and D are actually on different response curves. Of course, there is no reason for the response curve to be uniformly linear like KDX; it might taper off in the manner in KDZ.[27]

However, points Z, Y, and X are not true estimates of actual productive capacity in the U.S. at current prices. This result occurs for two reasons. First, even if the unbiased linear extrapolation (KDX) were the relevant response curve, the slope and position of the curve are in part determined by operators' expectations about what market demand factors will be. Certain capital expenditures in subsurface and surface improvements which would enhance and accommodate increased daily production rates would be attractive in the range DX, but are not attractive in the range KD. If operators expected market demand factors at prolonged high rates, these expenditures would be made. The result would be an upward shift in the whole response curve. The second, more important, reason why a response curve such as KDX underestimates actual productive capacity is that some Texas fields have productive capacity substantially in excess of their 100 percent market demand factors.[28]

The economic implications are clear. There are still substantial benefits to be achieved by the elimination of market demand prorationing which restricts low cost output to protect high cost output. In the short run, the U.S. could produce much more oil than it cur-

26. *See* Oil & Gas J., *supra* note 19.

27. Informed opinion regards the total response for Texas to be linear in the fashion of KDX and Louisiana incremental response to decrease in the manner of KDZ. *Presentation on Petroleum Industry Exploration and Production Costs and Volumes,* by M. Wright of Humble Oil and Refining Company for the Cabinet Task Force on Oil Import Control, August, 1969.

28. Oil & Gas J., Jun. 23, 1969. Some sources place the amount of capacity that exists beyond that output permitted at an MDF of 100 in the neighborhood of 600,000 to 700,000 barrels a day. Wright, *supra* note 27.

rently produces at substantially lower real unit costs.[29] The more interesting implications, however, are those for the long run. As exempt capacity disappears and market demand factors are permitted to increase while still maintaining wellhead prices, excess capacity is absorbed into the system. This process is going on now.[30] In addition, the Texas Railroad Commission is considering holding "MER" hearings for the large Texas fields whose permissible output at 100 percent market demand factors is less than their actual capacity.[31] The purpose of such hearings would be to increase permissible output for these fields. The effects of these changes, combined with the possibility of compulsory unitization in Texas, will go a long way to remove amount and character distortions of domestic drilling activity that prorationing has imposed. The resulting constellation of costs, prices, incentives and regulatory policies will be "normal," however, in only a very special sense. The relaxation of market demand restrictions is a cobweb phenomenon. If high U.S. prices and a relaxed regulatory atmosphere lead to a successful drilling and exploration campaign in District III, it can be expected that if the existing regulatory framework still exists these discoveries will not be permitted to displace high cost oil in the U.S. market. New restrictions and a new class of exempt production will emerge. The old costs of resource misallocation will reemerge. If oil prospects in the contiguous 48 states are entering a state of exhaustion, and exploration and production are in a stage of decline and liquidation,[32] then maintenance of other policies at levels which protect the state regulatory system will not even yield accidental excess U.S. capacity.

XI
OFFSHORE EXPLORATION

Offshore production from the Gulf of Mexico has been a significant element in new domestic supplies of crude oil. Over the last fifteen years, Louisiana offshore output increased from a fraction

29. Neither KDZ nor KDX in Figure 2 illustrate output responses at lower prices. Price is held constant in the construction of the graph. At lower, say world market, prices some wells now producing would shut down and the amount of effective excess capacity in wells now restricted would be less. Nevertheless, a substantial increase in output would occur. *See* H. Steele, *Hearings on the Petroleum Industry Before the Senate Subcomm. on Antitrust and Monopoly,* 91st Cong., 1st Sess. pt. 1. *See also* Wright, *supra* note 27. The Humble estimate is that output would increase about 2,000,000 barrels a day.

30. McKie & McDonald, *supra* note 6.

31. Interviews at the Tex. R.R. Comm'n.

32. *Supra* note 16. Such seems to be the implication of the presentation of Wright, *supra* note 27.

of one percent to nearly ten percent of U.S. oil output. If offshore production rates were not restrained by state-administered market demand prorationing, offshore production would be an even larger fraction of total U.S. output. In 1968, areas off Louisiana and Texas probably contributed a larger portion of the additions to proved reserves than any other area in the contiguous U.S. This was accomplished through new reserves discovered in new fields and in new pools discovered in old fields. Since a large proportion of U.S. production in 1985 will come from oil that is not now in the proved reserve status, the price and cost conditions under which companies would still find it attractive to explore and develop offshore Gulf of Mexico reserves are of special interest. For example, a common observation is typified by the following:[33]

> [Offshore] is a source of intrinsically high cost crude oil, but "offshore" is where the oil is and that is where much of the exploratory effort has been concentrated. There is no evidence that profitability offshore is substantially high; in fact, profitability on offshore operations ranges from good to less than adequate. Overall profitability of the industry in exploration and production is also not so high that a significant reduction (in price) would not have serious adverse impacts on new exploration.

The most prominent evidence that profitability of offshore operations ranges from good to less than adequate is developed in a study by Humble Oil and Refining Company.[34] As a guide to public policy, the Humble study is defective for at least one reason. It does not distinguish between real resource costs and avoidable costs imposed by the structure of institutions subject to change.[35]

One of the major costs of offshore production is bonus payments to governmental agencies. These costs are price-determined and compressible. If wellhead prices of crude oil were lower, bonus payments would be reduced. Another cost of offshore production has been the higher per barrel operating costs that state prorationing imposes upon operators. This is done by restricting output below

33. Sherman H. Clark, Overall Significance of the Oil Import Control Program 7 (Stanford Research Institute, Menlo Park, California). This document was submitted to the Cabinet Task Force on Oil Import Control by Louisiana Land and Exploration Company.

34. D. Barrow, *Economics of Offshore Development*, presented as a paper before the Institute on Exploration and Economics of the Petroleum Industry of the Southwestern Legal Foundation, Dallas, Texas, March 9, 1967. The same document was submitted to the Cabinet Task Force on Oil Import Control by Standard Oil Company of New Jersey as Supplementary Report No. 5.

35. What the Barrow study shows, rather than that offshore operations are intrinsically high cost, is that federal lease sales may have been quite effective at extracting available rents.

what it would otherwise be. Neither bonus payments nor artificially high production costs are real resource costs necessitated by the niggardliness of nature. The relevant question is whether, in the absence of such artificial costs and at a much lower price, the historical rate of offshore exploration and development of oil reserves in the Gulf of Mexico and other offshore areas would continue to be financially attractive.

There are about 300 drilling rigs operating in offshore areas around the world, with the majority of these located in U.S. waters. However, exploration activities are being conducted on the continental shelves of about 70 countries. Exploration wells have been drilled in 1,300 feet of water and production wells have been completed from platforms in 340 feet. Deep water exploratory drilling is generally conducted from mobile rigs, while development is usually from fixed platforms. Offshore drilling is expensive. The 1,600 offshore wells drilled during 1968 in the U.S. cost about $350 million or over $220,000 per well. This corresponds to operating rates for offshore rigs of from $6,000 to $25,000 per day.[36] The combination of exploration, production and rental fees cause costs per offshore well to be high. But costs per unit of output are low relative to onshore production and technical problems can usually be overcome. This explains the attractiveness of offshore operations. Only a small portion of the ten million square miles covered by 1,000 feet or less of water has been explored. Recent history may not be a guide to future realizations, but the oil industry is pursuing an exploration campaign that is conditioned upon the expectation that these areas will yield large reserves.

The real question is whether offshore operations in the Gulf of Mexico and on the U.S. continental shelf (*ex* bonus payments geared to an artificially high U.S. price and prorationing) can compete with worldwide offshore exploration. There is no reason to suppose that the answer to this question is no. A corollary to this question involves how we should view past, present and future exploration and development on the northern slopes of Canada and Alaska. Many of those involved would like to have policy makers believe that what has been done or may be done, can only be justified on a netback price based on a U.S. wellhead price sufficiently high to keep the least efficient stripper in Texas in operation. An alternative is to suppose that Arctic exploration is just part of the industry portfolio of activity and would have been undertaken on the basis of world prices. Current exploration off Nova Scotia, Newfoundland and in the Yellow Sea, for example, is now done on such a basis.

36. Weaver, *Offshore Drilling Completions*, 10 Int'l Oil Scouts Ass'n (Feb., 1969).

CONCLUSION

The U.S. petroleum industry is not in a state of equilibrium. The long-run position of the domestic industry has not been noticeably protected by insulating it from the competitive pressures of world markets. If the industry is dying, decay will progress regardless of public policy changes. If the domestic industry is not moribund, the symptoms of the cure have been worse than the disease. The old axiom is true, there is no sure proof of oil other than the drillbit. In the last decade, public policies have not encouraged the operation of that axiom.