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MASTER

REPORT TO CONGRESS PURSUANT TO SECTION 8(f)(1) OF THE EMERGENCY PETROLEUM ALLOCATION ACT

Federal Energy Administration
February 23, 1977

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IV. EFFECTS OF PRICE REGULATIONS ON PRODUCTION INDICATORS (CONTINUED)

CHAPTER I

EXECUTIVE SUMMARY: CONCLUSIONS

This report responds to the reporting requirement of Section 8(f)(1) of the Emergency Petroleum Allocation Act (EPAA) as amended by the Energy Policy and Conservation Act (EPCA) and Energy Conservation and Production Act (ECPA). Chapter II of this report describes in detail the requirements of the various laws and the actions that the Federal Energy Administration (FEA) has taken or will take to implement these laws through regulation. Chapter III provides details of FEA's rationale followed in implementing these provisions of the law and quantifies, where possible, the impacts believed to have resulted from the legislation in 1976 on price, production, supply and the economy. Since the eleven month period starting with February 1976 and ending in December of that year is short compared to the time required for the effects of price on production to be realized, forecasts of impacts are provided for 1980 and 1985 to offer a further dimension in understanding the effects of these provisions. Four appendices to Chapter III supply the details of the analytical methodology used. Finally, Chapter IV assesses the possible impacts of these provisions on future domestic crude oil production through an analysis of the response of the leading indicators of domestic crude oil production to changes in price.

The conclusions reached by this report are summarized below. They are based in part on analyses through FEA's PIES model, FEA's Short-Term Petroleum Forecasting Model and the DRI model of the economy. All computer models contain debatable assumptions and are thus vulnerable to debate over their conclusions. The conclusions should be read in this light.

1. During the period 1974 through 1975 the average rate of decline in domestic crude oil production was approximately 400,000 barrels per day. During 1976, the average rate of decline in domestic crude oil production was reduced to approximately 230,000 barrels of oil per day. Too many variable events have occurred during 1976 to state that the changes in EPAA, EPCA and ECPA have had either a positive or negative effect on the production of domestic crude oil. A major impact on prices has been realized from the requirement to keep ceiling prices frozen since June 1, 1976, in order to recoup excess receipts generated after initial estimates of prices and rates of inflation used in the Stage I and Stage II rulemakings proved to be too high. These estimates resulted in a higher than targeted initial composite price. Accordingly, there has been no experience with escalation at a 10 percent annual rate during the period covered by this report.
2. Continuation of price controls on domestically produced crude oil specified in the EPCA and the ECPA beyond May 1979

(including an annual escalation of approximately 10 percent in the composite price) will have a dampening effect of at least 200 MB/D in 1980 on domestic crude oil production compared to projections of what production would have been if EPCA controls terminated in May of 1979, if the real world oil price is held constant at $13.00. The increment is relatively small because the escalators allow the upper tier price to approach the world price by 1980. Extension of EPCA/ECPA controls through 1985 instead of removing them in May 1979 is estimated to reduce domestic production by about 600 MMB/D in 1980 and 700 MB/D by 1985, if the real price of imported crude oil increases by 2 percent per year.

3. Since the EPCA/ECPA controls, even with escalators, constrain the upper tier price below the world market price that upper tier oil would have been allowed if the EPAA had been extended unamended through May 1979, we can derive that domestic crude oil production in 1980 and 1985 would have been even higher if the EPAA had been extended without the limitations imposed by the EPCA.

4. The provisions for escalation of the composite price are extremely important to future domestic crude oil production. FEA's analysis indicates that domestic crude oil production will be at least 1.7 MMB/D higher in 1980 and 2.6 MMB/D higher in 1985 with the escalator provisions than it would have been if the original composite price had not been allowed to increase.

5. The biggest and most significant macroeconomic effect of EPCA/ECPA price controls on domestic crude oil is not on gross national product, where the differences are barely discernable, but on the balance of payments, where the differences are large.

6. Examination of actual impacts in 1976 of EPCA/ECPA controls indicates that compared to an extension of the EPAA, current regulations have had the effect of:

   a. Showing measurable savings through reductions in the price of domestic crude oil;

   b. Showing a small offset against these savings by creating higher levels of demand, thus requiring increased imports;

   c. Creating minor favorable impacts on most economic indicators;

   d. Creating a significant adverse impact on the balance of trade.

7. Domestic crude oil production does not immediately respond to changes in the price of crude oil of the degree generated by imposing EPCA/ECPA price controls. Examination of leading indicators of production, however, appear to show an initial adverse response to controls from the imposition of EPCA/ECPA. Activity that precedes production changes (seismic activity, active rigs, wells drilled) shows a sharp decline during the first quarter of 1976 followed by sustained recovery to near record levels by

the end of 1976. Limited surveys of industry indicate that one reason for the first quarter decline was the uncertainty as to future prices during the deliberations leading to enactment of the EPCA. The recovery in activity of leading indicators during the last three quarters of 1976 has been attributed to the expectations of price increases under the Stage II EPCA rulemakings as supplemented by the ECPA escalator provisions.

CHAPTER II

INTRODUCTION

General

The Emergency Petroleum Allocation Act (EPAA), as amended by the Energy Policy and Conservation Act (EPCA) and Energy Conservation and Production Act (ECPA), in Section 8(f)(1) specifies that the President shall submit to the Congress on February 15, 1977, a report containing:

A. an analysis of the impact of any Section 8 amendment
   1. on the economy, and
   2. on the supply of crude oil and products; and

B. an analysis of the effects resulting from ECPA §§121 and 122 amendments on
   1. price, and
   2. production of domestic crude oil.

The applicable EPAA amendments are:

1. Stage I [Section 8(a)]--imposition of ceiling prices on previously uncontrolled domestic crude oil (upper-tier)
2. Stage II [Section 8(d)]--provision for gradual increases in lower-tier and upper-tier prices.

The applicable ECPA amendments are:

1. Section 121 = stripper well exemption
2. Section 122 = elimination of 3% limitation to
   a. eliminate gravity differentials, and
   b. promote tertiary recovery methods.

The Conference Report on ECPA states that the ECPA "requires that specific information be contained in the [February 15, 1977] report concerning the use of greater flexibility which attends removal of the 3% limitation as well as the effects (on both production and price) resulting from the removal of price controls on stripper well production."

Chapter III discusses successively the five major topics on which reporting is required and for each examines impacts on production, price, supply and the economy, insofar as available data allows. Since domestic crude oil production is not measurably responsive to price changes in the short run, the report examines long-term effects on production and on the economy, as well as examining short term (i.e., 1976) effects of the amendments on price and on the economy.

Chapter IV discusses in some detail the effects of the EPCA and ECPA amendments collectively on leading indicators of domestic crude oil production in order to document expectations for the long-term effects of these amendments on domestic production and to provide a basis of information for future examination of the appropriateness of current provisions for incentives for increased domestic crude oil production.

Legislative Overview

The EPAA, enacted during the Arab Oil Embargo, required price controls along with mandatory allocation authority so as to prevent price discrimination which would result from shortages. It required that the President, in exercising this authority, strike an equitable balance between the sometimes conflicting needs to provide adequate inducement for the production of domestic crude oil and to hold down spiraling consumer costs.

The EPAA contemplated that the Phase IV price controls established by The Cost of Living Council under authority of the Economic Stabilization Act would continue in effect until modified. Provision was made for a dollar-for-dollar pass-through of increases in the cost of crude oil and refined petroleum products to all marketers or distributors through to the retail level. An important element in the initial Cost of Living Council price regulations was a two-tier pricing system for crude oil. A description of the crude oil price regulations promulgated by the Cost of Living Council and by FEO/FEA under the EPAA will be presented in the next section of this chapter.

The EPCA, enacted on December 22, 1975, amended the EPAA to require establishment of a domestic crude oil "composite" price of $7.66 per barrel in February 1976 and to establish a forty-month program of continued controls on crude oil price with gradual escalation allowance. The President was also authorized to increase the composite price to:

1. account for inflation, and thereby maintain the composite price in real dollar terms, and;
2. provide an incentive to increase production.

Limitations were imposed on this authority. They included:

1. a three-percent limitation on the production incentive, and;

2. a ten-percent total limitation on the combined inflation adjustment and production incentive increases.

The EPCA also established a procedure whereby the President was authorized to propose to the Congress that adjustments to the composite price in excess of three percent and/or ten percent limits be permitted. If neither House of Congress disapproved such a proposal within a 15-day Congressional review period, the President could implement the proposal. In connection with later amendments to the EPCA, it was understood that FEA would defer any request for an adjustment to these limitations until March 15, 1977.

The Energy Conservation and Production Act (ECPA), enacted August 14, 1976, again exempted stripper well production from price controls and specified the method of including stripper well production in the calculation of the composite price. The President was authorized to implement special price regulations that would provide a fair treatment for heavy gravity crude oil produced on the West Coast and to stimulate domestic crude oil production in enhanced oil recovery operations. Accordingly, the three-percent limitation on production incentive adjustments of the EPCA was removed, and provisions were made for the correction of gravity differential problems in the current price mechanism. The ECPA provided

FEA with the authority to escalate the composite price at a full ten percent per year, regardless of the actual value of the GNP deflator.

Description of Relevant Price Regulations

(A) CLC Regulations. On August 17, 1973 the Phase IV price regulations applicable to the petroleum industry were issued by the Cost of Living Council (CLC). Declining domestic production since 1971 and sharp increases in prices and volumes of imported oil on which the U.S. had become increasingly dependent contributed to the decision by CLC to control petroleum industry prices on the basis of specific regulations covering the entire petroleum industry rather than on the basis of the general price regulations then applicable only to a segment of the industry.

Two-tier Price System

The central element in the initial CLC crude oil price regulations was a two-tier pricing scheme which was an attempt to achieve two objectives: (1) hold domestic petroleum prices below rapidly rising world price levels, (2) provide sufficient price incentives for increased domestic crude oil production. The net effect, however, was to encourage additional shallow drilling into established reserves, which yielded a minimum amount of oil per unit of drilling and did not add to proven reserves.

The CLC two-tier system initially provided a ceiling price for "old" oil frozen at May 15, 1973 posted price levels plus 35 cents. The ceiling price for "new" and "released" crude oil was the market price. "Stripper well lease" crude oil was later (November 16, 1973) exempted from CLC regulations. "Old" crude oil was the volume of crude oil produced and sold from the property concerned in the same month of 1972 (the base production control level, or "BPCL"). "New" crude oil was that volume produced and sold each month in excess of the property's BPCL. Also, for every barrel of "new" crude oil produced and sold, the producer was permitted, as a further production incentive, to "release" one barrel of "old" crude oil for sale at the market price ("released" oil).

The May 15, 1973, posted price was chosen as the base price for "old" crude oil because that date represented a time of relative stability in the crude oil market. The additional 35 cents per barrel was based on estimated average increases in posted prices between May 15, 1973, and August 19, 1973, the effective date of the CLC Phase IV petroleum regulations. An additional $1.00 per barrel was added to the "old" crude oil ceiling price in December, 1973 in order to narrow the gap between the lower ("old" crude oil) and upper ("new" and "released" crude oil) tier prices which had widened considerably during the Embargo due to dramatic increases in world prices.

Property definition. The amount of crude oil eligible for the "upper tier" or market price and the amount required to be sold at the "lower tier" ceiling price were calculated with respect to each "property". The CLC defined a "property" as the right which arises from a lease or from fee interest to produce crude petroleum. This definition of property, which was subsequently adjusted by FEO and FEA, was recently amended by FEA as discussed below.

"Base Production Control Level" (BPCL) is basically the historic volume of crude oil produced and sold from a given property above which a producer must increase production levels in order to qualify current production as "new" or "upper tier" crude oil.

As defined by CLC, the BPCL for each property was the number of barrels produced and sold from the property in the corresponding month of 1972, or the number of barrels produced and sold in the year 1972 divided by 12, if crude oil was not produced and sold from that property in every month of 1972. This definition was adopted by FEO and FEA but was later redefined by FEA to permit 1975 to be used as an optional base year. (See Section C below).

Pursuant to the requirements of the EPAA, CLC exempted production from stripper well leases under regulations which defined a stripper well lease as a property whose daily average production did not exceed 10 barrels per day per well during the preceeding calendar year. As indicated below, this definition was later amended by FEA in 1975 and again in 1976 pursuant to the ECPA.

(B) EPAA and FEO/FEA Regulations. The Federal Energy Office (FEO) was established on December 4, 1973 pursuant to the EPAA and issued its initial Mandatory Petroleum Allocation and Price Regulations effective January 14, 1974.

The EPAA directed the President to promulgate regulations to specify (or prescribe a manner for determining) prices of crude oil, residual fuel oil and refined petroleum products, and to provide for their equitable distribution at equitable prices. The EPAA provided for a dollar-for-dollar passthrough of net increases in the cost of crude oil, residual fuel oil and refined petroleum products. FEO promulgated regulations designed to achieve these objectives. The CLC two-tier pricing system applicable to producers of crude oil was adopted by FEO with "old" crude oil subject to a ceiling price. "New" and "released" crude oil could be sold at market prices, and stripper well lease crude oil was exempt from controls. Crude oil supplier-purchaser relationships were frozen to provide equitable distribution of domestic crude oil.

Generally, refiners, resellers and retailers of petroleum products could charge a price which reflected the weighted average price at which the product was priced in transactions with the class of purchaser concerned on May 15, 1973, plus increased costs incurred since that time.

Crude Oil Entitlements

By the end of the Arab Oil Embargo of 1973-1974, there was a five to six dollar price spread between "old" domestic crude oil and "new and released" domestic and imported crude oils. The average crude oil cost for refiners ranged from less than $5 a barrel to more than $11 a barrel, depending primarily on each refiner's mix of foreign, "old", "new", "released" and "stripper" oil. This wide spread in crude oil costs resulted in product prices differing by as much as fifteen cents a gallon. Consumers were able to price shop, and high cost suppliers had to lower prices in order to sell their output. The competitive viability of the large independent and the many small refiners who were dependent on foreign or upper tier crudes was seriously threatened. Since regulations under the EPAA had to provide for "preservation of an economically sound and competitive petroleum industry .... and to preserve the competitive viability of independent refiners (and) small refiners", FEA determined that its regulatory program had to be modified.

The FEA narrowed its options to two general approaches: creation of a single domestic price tier and the proportionate allocation of "old" oil to all refiners. However, a single tier approach could be applied only to domestic oil, and it would still leave a large crude cost disparity between refiners of domestic crude and refiners of foreign crude. The independent refiners and the small Northern tier and other small refiners dependent on foreign crude would still be unable to recover their increased crude costs. Therefore, proportionate allocation of old oil to all refiners was selected as the best mechanism to assure competitive viability of these refiners and the marketers they supply, while accomplishing the other requirements of mandatory allocation. The Old Oil Allocation Program was made effective in November 1974, and was later modified to account for the ceiling prices, effective February 1, 1976, on upper tier domestic crude oil provided for by the Energy Policy and Conservation Act, and the September 1, 1976 exemption of stripper well crude oil. This program is generally referred to as the Entitlements Program, and is the key to maintaining competitive viability of refiners and marketers and providing for equitable prices to consumers under a multi-tier crude price structure. Though it was developed to offset certain undesirable effects of a multi-tier crude pricing system, it has become the support structure for this crude pricing system. The present multi-tiered price system, established by FEA to conform to the crude pricing requirements of the Energy Policy and Conservation Act, continues to rely on the Entitlements Program to assure competitive viability among petroleum refiners and marketers, while equitably distributing the benefits of price controlled domestic crude oil among all petroleum product users.

(C) EPCA Regulations.

Certain modifications to the crude oil pricing structure adopted by the CLC and FEO/FEA (described above under Sections (A) and (B)) were mandated by Section 401 of the EPCA. The rationale for the required changes as noted in the Conference Report was to provide for domestic crude oil prices that would encourage domestic production but at the same time not inhibit economic recovery with new inflationary pressure.

The required modifications, which were implemented by FEA regulations, involved the implementation of a system of price controls applicable to all first sales of domestic crude oil designed to result in a statutorily-mandated weighted average first sale price ("composite price") of $7.66 per barrel in February 1976. The EPCA permitted upward adjustments in the composite price to reflect inflation plus not more than a 3 percent annual increase as a production incentive provided the sum of the two adjustments did not exceed 10 percent annually. Further, the EPCA provided a mechanism for further adjustments in excess of the 3 percent and 10 percent limitations, if justified as a further production incentive, subject to the disapproval of Congress. Finally, the EPCA repealed the EPAA stripper well exemption. The expiration of the crude oil pricing mandate under the EPCA is May 31, 1979.

Stage I Implementation. Effective February 1, 1976, FEA implemented some of these provisions by retaining the pre-existing two-tier crude oil pricing system with the following modifications: (1) The provisions which permitted upper tier crude oil to be sold at the market price were eliminated; (2) Upper tier crude oil (formerly new, released and stripper crude oil), assumed to comprise 40 percent of total domestic production, was controlled at an estimated average first sale price of $11.28 per barrel in February 1976, by means of a $1.32 per barrel roll-back in price; (3) Lower tier crude oil (formerly old crude oil) was assumed to comprise the balance (60 percent) of domestic production controlled at an estimated average first sale price of $5.25 per barrel in February 1976. Lower tier ceiling prices were determined to be the highest posted price in the same or nearest field on May 15, 1973, plus $1.35 per barrel. Upper tier ceiling prices were determined to be the highest posted price in the same or nearest field on September 30, 1975, less $1.32 per barrel.

There were several reasons for retaining the two-tier pricing system. First, the two-tier mechanism provided producers and refiners alike with the smoothest transition from prior regulations into the EPCA-mandated 40-month program of controls on crude oil prices. Second, it would serve generally to maintain the proportion of upper and lower tier crude oil, which previously existed, until FEA had an opportunity to measure price and volume data more accurately through a new data system that was adopted concurrently with the roll-back. Third, a two-tier system allowed for a price of approximately $11.28 per barrel at the upper tier. It was believed that this would provide sufficient price incentive to maintain existing levels of production and to encourage additional exploration and development of domestic reserves.

To help assure continued production incentives for fields experiencing natural declines in general rates of production since 1972, a property's BPCL was redefined as either, at the election of the producer, the property's average monthly production and sale of old crude oil in 1975, or the average monthly production and sale of all crude oil in 1972. All existing cumulative deficiencies in production, which previously had to be made up before oil could be qualified as "new" oil were eliminated, as was the released oil concept.

Stage II Implementation. Effective March 1, 1976 FEA issued "Stage II" of the EPCA implementation by adopting the first adjustments to the composite price. Section 401 of the EPCA (until later amended by the ECPA, as discussed below) permitted upward adjustments for production incentives and to reflect inflation, subject to the restrictions that the adjustment to provide a production incentive may not exceed 3 percent annually and the adjustment to reflect the impact of inflation must be based on the first revision of the most recent implicit price deflator for the gross national product. The combined effect of both adjustments could not exceed a maximum of 10 percent annually.

FEA initially implemented these provisions by adopting the full adjustment of 3 percent for production incentive and 6.8 percent for inflation, applicable to crude oil produced and sold in March-May, 1976, and by applying the adjustments in equal percentages to the upper and lower tier prices.

FEA's analysis indicated that the 3 percent adjustment to the composite price available to provide a production incentive will have to be used over the course of the 39-month program almost entirely to take account of the impact of changes in the relative proportions of upper and lower tier crude oil on the composite price. The natural decline in production of "old" crude oil due to reservoir depletion results in a decline in the proportion of lower tier crude oil to total domestic production. This decline in the percentage of lower tier crude oil results in an automatic increase in the actual composite price.

Stage III Proposed Rulemaking. The purpose of the Stage III proposal was to consider whether additional incentives, beyond the adjustments adopted in the Stage II proceeding, were needed to maintain or increase production. If additional incentives were found to be necessary, such proposed amendment would then be forwarded to Congress for review. The need for additional incentives was considered in three areas: (1) incentives for discovery and development of high cost and high risk properties; (2) the application of enhanced recovery techniques; (3) sustaining production from marginal wells. Specific proposals for increased production incentives which were considered were the following:

- Upper tier or market level prices for all production from new reservoirs.
- Market level prices for production from new wildcat properties.
- Market level prices for production from new properties located on the Outer Continental Shelf.
- Market level prices for production from new deep wells or deep horizons in onshore properties.
- Market level prices for production from properties operated by independent producers.
- Upper tier or market level prices for incremental production derived through application of certain high cost enhanced recovery techniques.
- Qualification for stripper well prices based on the preceding 12 months of production rather than the preceding calendar year.

- Qualification for stripper well prices according to well depth and according to onshore or offshore location.
- Qualification for stripper well prices according to the ratio of non-crude oil fluids produced.
- Qualification of marginal gas wells for stripper well prices.
- Market level prices for stripper well production. Adjustments to historical gravity price differentials for heavy crude oil.

The Stage III proposal was deferred, in part, because of the increased pricing flexibility afforded by the elimination of the 3 percent production incentive limitation by the Energy Conservation and Production Act (ECPA) enacted August 14, 1976. (See Section D, below.)

Price Freeze. Because the estimated impact of the Stage I and Stage II crude oil price amendments on the composite price was based on estimates of upper and lower tier volumes and prices, Stage II regulations provided that the crude pricing schedule would be adjusted when actual price and volume data became available. When the actual February and March 1976 data became available to FEA, they revealed that the Stage II adjustments were resulting in composite price overages and that the crude pricing schedule would have to be adjusted.

Based on actual production volumes and prices for the months of February and March, 1976, FEA estimated that revenues received by crude oil producers were approximately $60 million in excess of those which would have been received if the actual composite price for that period had coincided exactly with the statutory composite price in February and March, 1976.

It was determined that, rather than a roll-back, the best method would be to freeze prices effective July 1, 1976, initially for two months (July and August). This would give FEA an opportunity to receive and evaluate two additional months of actual volume and composite price data, before further adjusting the crude pricing schedule.

(D) ECPA Regulations. On August 14, 1976 the ECPA was enacted. It contained several significant provisions regarding crude oil prices.

Removal of the 3-percent limitation. The ECPA removed the EPCA 3-percent limitation on the production incentive. The overall 10 percent annual limitation on price adjustments to reflect inflation and as a production incentive remained. (Under the EPCA, the annual escalator would be reduced below 10 percent by the same number of percentage points that the GNP deflator for the preceding calendar quarter was less than 7 percent.) This greater flexibility was intended to provide FEA with a further means to encourage domestic production, with a high priority on development and application of high-cost enhanced recovery techniques, and compensation for certain large gravity price differentials associated with heavy crude oils.

Stripper Exemption. The ECPA permitted stripper well crude oil once again to be sold at market price levels by removing the price limitations imposed on stripper well production by the EPCA. However, stripper well production and sales were not excluded from the calculation of the composite price. Rather, stripper oil was to be given an initial "imputed" price of $11.63 per barrel for purposes of the composite price calculation. It was later established that this price exceeded the actual EPCA stripper price approximately by 30 cents.

FEA implemented the ECPA provisions with respect to stripper well properties by exempting crude oil produced from such properties from price controls effective September 1, 1976.

Enhanced Oil Recovery Mandate

The ECPA identified two priorities with respect to optimizing domestic production: enhanced recovery techniques and the correction of gravity differential problems. The FEA has issued a notice of proposed rulemaking to consider how high-cost enhanced recovery techniques can be identified and how price incentives can be applied to stimulate such domestic production. This rulemaking will not be completed by the date this report will be submitted.

<u>Gravity Differential Price Adjustment</u>

Effective October 1, 1976, the FEA acted to adjust gravity price differentials with respect to heavy California and Alaskan crude oil. Lower tier heavy California crude oil historically was priced substantially below the national average for the lower tier due to larger than average gravity price differentials existing on May 15, 1973. Nationally, on May 15, 1973, gravity price differentials for crude oil averaged between 2 and 2.5 cents per degree per barrel, while in California the gravity price differentials averaged 6.2 cents per degree per barrel. Since most crude oil produced in California is classified as "old" crude, it was still subject to the May 15, 1973 average 6.2 cents per degree differential; and while the current average price for old crude oil nationwide was $5.15 per barrel, in California the average price was $4.28 per barrel.

Accordingly, the FEA amended the price rules to permit the ceiling price for lower tier California and Alaskan crude oil to be increased by 2 cents per barrel for each degree API gravity between 34° API and 40° API that it falls below 40° API, and by 3 cents per barrel for each degree API that it falls below 34° API. While this amendment increased the ceiling price, it appears that actual sale prices were not affected significantly due to market forces.

Redefinition of Property

FEA issued clarifications necessary to resolve ambiguity in the meaning of a "right to produce" which had prevented the completion of many audits. As part of these clarifications, FEA concluded that the original property concept (see Section (A) above) which followed a "premises described by a single oil and gas lease" concept without regard to the separate reservoirs which might underlie the premises did not provide appropriate incentives under the longer term system of price controls mandated by EPCA. This was because increased production from one reservoir might fail to qualify as upper tier crude oil because of the requirement that total production from the property must exceed the BPCL and cumulative deficiency determined from all reservoirs which underlie the property.

Accordingly, the definition of property was amended, effective September 1, 1976, to permit a producer to treat as a separate property each separate producing reservoir subject to the same right to produce crude oil provided the reservoir is recognized as separate and distinct by the appropriate governmental regulatory authority. Although this change was not required in order to implement the EPCA or ECPA, it had been under consideration by FEA for some time and is noted here because it has some effect on volumes of lower tier and upper tier oil. This effect increases the difficulty of relating upper tier production changes to the composite price limitation.

CHAPTER III

IMPACT OF EPCA, ECPA AMENDMENTS

IMPLEMENTATION OF THE EPCA STAGE I COMPOSITE PRICE

Background

The Energy Policy and Conservation Act (EPCA) established a mandatory weighted average first sale ("composite") price of $7.66 per barrel in February 1976 for domestic crude oil.

In order to achieve the required composite price in February 1976, FEA adopted a "two-tier" system of price controls applicable to all first sales of domestic crude oil. Crude oil sold at the lower tier was composed of what was formerly "old" crude oil. FEA assumed that lower tier crude oil was 60 percent of total production and that the February 1976 price of lower tier crude oil was $5.25 per barrel. Postings for crude oil at the upper tier, comprised of what was formerly "new", "released" and "stripper well" oil, were estimated to have been at a weighted average of $12.60 per barrel on September 30, 1975.

To arrive at the composite price FEA proposed to allow lower tier crude oil to remain at the ceiling price that then existed and to reduce the upper tier price so that it would average $11.28 per barrel, nationally, by establishing a ceiling price for previously uncontrolled crude oil at the highest posted price for that crude on September 30, 1975, less \$1.32 per barrel. Based on the assumptions previously stated this was believed to yield a composite price of \$7.66 per barrel in February 1976:

$$(.6)(\$5.25) + (.4)(\$12.60 - \$1.32) = \$7.66$$

The new two tier mechanism provided refiners and producers alike with the smoothest transition from prior regulation; it served generally to maintain the proportion of controlled versus uncontrolled domestic crude oil which previously existed, until FEA had an opportunity to determine more accurately both the quantities and prices of the tiers; and it most closely complied with the objectives contained in the EPCA concerning administrative feasibility and obtaining optimum production of crude oil.

At the time the composite price regulation was implemented, FEA also undertook to establish a comprehensive crude oil price reporting system. Because of preliminary work done between enactment of EPCA in December, 1975, and implementation of the composite price on February 1, 1976, FEA was able immediately to begin collecting data from purchasers of crude oil. The first data were requested by telegram on the date the regulation was issued. Not until March, 1976, however, was FEA able to gather sufficient data to gain a preliminary indication of the effect of the composite price regulations.

Impacts In 1976

Stage I of the EPCA was only in effect for the month of February before Stage II, providing a three percent per year price increase as a production incentive and an increase in price of up to seven percent per year as an offset to inflation, was added.

During February 1976, the first month of composite price regulations, upper tier production, including new, released oil and stripper well oil totalled 104.4 million barrels. The upper tier price reduction in that month was about $1.52 per barrel,[1/] and represented a loss to the producers and a potential saving to the consumer of $158.7 million for February on the 104.4 million barrels produced. Further analysis of actual figures is complicated by the implementation of Stage II as mentioned above.

In order to attempt to isolate the impact of Stage I, FEA analyzed this stage through its Short Term Petroleum Forecasting Model by assuming that Stage I would have continued, unchanged, throughout 1976, and compared the effects with the alternative of continuing the EPAA unamended through 1976. If Stage I had remained unchanged, the composite legal price of crude oil would appear to have remained at $7.66, although under the regulations issued, based on the assumptions described in the background section,

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the actual composite price was $7.87 in February. This, of course, would have required an additional downward adjustment in ceiling prices. The actual February composite price of $7.87 was used in FEA's Short Term Forecasting Model to attempt to estimate the 1976 impacts on total demand that would have resulted from continuation of the composite price limitation without escalators.

It is estimated that continuation of EPCA Stage I could have increased total demand in 1976 by 25,000 barrels per day over what the total demand would have been under unamended EPAA regulations. This figure is well within the range of error in the model. No quantitative conclusions can therefore be derived as to the effect of the Stage I composite price limitation on demand. The results of the analysis are shown in Appendix A.

Consumer savings would have been realized from the lower composite price under the EPCA Stage I controls. Assuming a constant $8.65 per barrel price for domestic production under the EPAA continued,[1/] the 2.7 billion barrels of domestic production for the eleven months from February through December 1976,[2/] cost the consumer $2.1 billion less under EPCA Stage I controls than it would have cost under EPAA

1/ (.56)(5.02) + (.44)(13.27) = 8.65

2/ Table IV-2

controls unamended.[3/] These savings were offset by the demand increases resulting from lower prices and by the higher level of imports resulting from higher demand. This offset would be comparatively very small.

The effect on the U.S. economy in 1976 of maintaining EPCA Stage I controls without change throughout 1976 has also been calculated by using the demand change derived from the short-term forecasting model. The economic impacts are also very small and do not lend themselves to material conclusions. A discussion is contained in Appendix C.

Long-Term Impacts

Projections can be made as to prices through 1980 (assuming 1975 constant dollars) if the composite price were held constant through continuation of Stage I of the EPCA. Due to the shifts in the weights of the upper and lower tiers, the lower tier price would be \$4.46 in 1980 while the upper tier price would be \$10.05 (Table III-B-1).

Long-term impacts of maintaining the EPCA Stage I controls without change have been calculated by comparing the continuation of EPCA Stage I controls through 1980 (Case C) with two alternative scenarios:

3/ 2.7 (8.65 - 7.87) = 2.1

A. Continuation of EPCA/ECPA controls through May 1979, after which no controls are in effect;

B. Continuation of EPCA/ECPA controls beyond May 1979.

These comparisons were made by using FEA's PIES Forecasting System. Tables comparing these cases are in Appendix B.

Assuming a $13.00 world oil price for all years, (in constant 1975 dollars), 1980 total domestic crude oil production realized through long-term continuation of EPCA Stage I controls would be 1.9 MMB/D lower than for Case A and 1.7 MMB/D lower than for Case B. All of the difference would have been in production from traditional sources (lower tier, upper tier and stripper well oil) and almost all of the difference would have been in upper tier oil (although the model does not allow a breakout of lower tier, upper tier, and stripper well oil).

By 1985, long-term continuation of EPCA Stage I control (Case C) would result in 2.6 MMB/D less domestic crude oil production than Case A (EPCA Stages I and II through May 1979) or Case B (continued EPCA control).

The differences would be larger assuming a 2% annual increase over a $13.00 real import price, as shown in Table III-B-4 of Appendix B.

The economic impacts of these changes are presented in Appendix D. The economic impacts are measurable but not particularly significant except for the balance of payments.

PIES Model will not accommodate a comparison of future domestic production under EPCA/ECPA controls with the alternative, which was available to the Congress in 1975, of extending EPAA controls. However, by comparing the effect of the EPCA escalators (Case B) with the composite price limitation above (Case C) and noting the significant additional production yielded from the effect of the escalators, we can derive the reasonable assumption that the continuation of EPAA controls, with upper tier oil selling at world market prices, would yield even higher levels of domestic crude oil production in 1980 and 1985.

IMPLEMENTATION OF THE EPCA STAGE II ESCALATORS

Background

Stage II of implementation of the EPCA consisted primarily of devising appropriate means for permitting lower and upper tier price ceilings to be increased on a monthly basis to reflect the maximum 10% adjustment in the statutory composite price to reflect the impact of inflation (limited to 7%) and to provide a production incentive (limited to 3%) beginning March 1, 1976.

FEA regulations effective March 1, 1976, applied the full percentage amount available to reflect the impact of inflation and to provide a production incentive equally (on a percentage basis) to both upper and lower tier crude oil production. However, FEA noted that the natural decline in the percentage of lower tier crude oil would cause the actual weighted average or composite price to increase automatically, such that the 3 percent adjustment to the statutory composite price available to provide a production incentive would be needed over the course of the 39-month program just to accommodate the effect of the natural decline in the lower tier proportion.

The following estimates and assumptions were used in developing the initial schedule of price ceilings:

- The inflation rate would continue at 6.8% per year.
- The division of crude oil, by tiers, for February, 1976 was 40% upper tier, 60% lower tier.
- Lower tier crude oil would decline, volumetrically, at the rate of 8% per year.
- The estimated average first sale prices of $11.28 per barrel for upper tier crude oil and $5.25 for lower tier crude oil would prove to be correct for February 1976. This would match the $7.66 per barrel average price in the first month of the 40-month crude oil pricing program as provided for by EPCA.

The crude oil price reporting program was developed immediately prior to Stage I implementation and was made effective concurrently with it. The first reliable data and first reliable conclusions from these data were available in May 1976. They indicated that:

- The first sale average price of lower tier crude oil in February 1976 was $5.07 rather than the estimated $5.25 per barrel.
- The first sale average price of upper tier crude oil in February 1976 was $11.48 rather than the estimated $11.28 per barrel.

- The division of upper tier and lower tier crude oil in February 1976 was 43.87% and 56.13%, respectively, rather than 40% and 60% originally estimated.
- The price deflator that would be used as an index of the rate of inflation and which would govern the adjustment allowed for inflation was reported as 3.5% in May for the first quarter, rather than the estimated 6.8%, for a simple average of 5.2% for the two quarters.

As a result of these four differences FEA determined by June 1976, that the actual average price had been $7.87 rather than the target $7.66 per barrel in February 1976. Further, a continued increase, above projections, in the upper tier crude oil portion of production, combined with the too-high projection of the inflation rate, was resulting in a continued overage in sales receipts by domestic crude oil producers. By June 1976 the actual composite crude oil price was $7.99 per barrel. This was 8 cents per barrel above the legal composite for that month.

To correct for cumulative excess receipts to producers, the FEA halted further increases in upper and lower tier crude oil at the prices in effect in June 1976. The cumulative excess receipts continued to increase, however, due to a variety of factors including statutory amendments under the ECPA on September 1. Effective January 1, 1977, the price ceiling freeze was continued for three months and in addition the ceiling price on upper tier crude oil was rolled back by $0.20 per barrel.

Impact in 1976

The short-term impact of EPCA Stage II provisions is so intermingled with Stage I that a separate analysis is difficult. By applying the FEA Short Term Petroleum Forecasting Model to attempt to isolate the impact of Stage II provisions, it is estimated that Stage II implementation alone would result in an insignificant impact on petroleum demand during the last eleven months of 1976 (Appendix A).

Implementation of Stage II escalators yield the following economic impacts in comparison with the alternative of continuing the EPAA unamended (Appendix C):

- o Real GNP was $1.5 billion higher - a 0.1 percent increase;
- o The Consumer Price Index was 0.1 percent lower;
- o The Wholesale Price Index was 0.3 percent lower;
- o The Wholesale Price Index for all Energy was 1.6 percent lower;
- o Net exports of goods and services was $200 million lower.

Long-Term Impacts

An analysis of the long-term impact of continuation of EPCA Stage II controls beyond May 1979 can be made by comparing this case (Case B) with the alternative Case C, implementing EPCA Stage I only (Appendix B). The Stage II will yield at least 1.7 MMB/D more domestic crude oil production in 1980 than would the continuation of the Stage I composite price limitation alone. In 1985 the increment from the escalator provisions would be at least 2.6 MMB/D.

Under the conditions listed above the price projections (in constant 1975 dollars) are for Case B lower tier prices of $5.56 per barrel and upper tier prices of $11.95 in 1980.

Table III-B-4 in Appendix B illustrates that the provision for escalators yields substantially higher domestic crude oil production in 1980 than does the continuation of EPCA Stage I controls alone. Domestic crude oil production, in all categories, is projected to be 1.7 MMB/D barrels greater than production in 1980 from continuing from Stage I only into the 1980's, assuming a constant $13.00 per barrel world oil price. In 1985 the effect would be even more pronounced. The difference would widen to 2.6 MMB/D.

If the real world oil price is assumed to increase by 2% annually, the differences in domestic crude oil production in 1985 would be slightly higher. The escalators would yield increased domestic crude oil production of 2.8 MMB/D.

The long-term economic effect of these changes in long-term prices and production are discussed in Appendix D. Although the effects on most economic indicators are small, the impact on the balance of trade is significant.

IMPLEMENTATION OF EPCA/ECPA STRIPPER WELL PROVISIONS

Background

Stripper well production is currently defined as crude oil produced from properties whose average daily production is 10 barrels per well or less for any preceding consecutive 12-month period beginning after December 31, 1972. In December, 1976, stripper wells produced 1.08 million barrels of oil per day (MMB/D), or 13.6 percent of domestic oil production. Stripper wells numbered 367,872 in January, 1976, or 86 percent of the total well population. The average number of stripper wells in 1975 was 366,095. The average production from stripper wells was 3.08 barrels of oil per day in January, 1975, and 2.93 barrels of oil per well per day in January, 1976.

Prior to the enactment of the EPCA, stripper well crude oil first sale prices were exempt from regulation. Stripper well production was about 0.94 MMB/D (Table III-2) and prices in January, 1976 averaged $12.89 per barrel (Table III-1). Production during 1975 had tended to increase, from 0.89 MMB/D in January to 0.94 MMB/D in December, or by 5.6 percent. Monthly figures, however, are erratic (Table III-2).

The enactment of EPCA, implemented by regulations effective February 1, 1976, resulted in stripper well production being placed under price controls at upper tier prices. Stripper crude oil prices were rolled back about $1.55 per barrel from $12.89 to $11.34 per barrel. (Table III-1). Stripper crude prices were escalated (as upper tier) in accordance with the EPCA (as implemented in Stage II pricing regulations) from March through June, 1976, but on July 1, 1976, all domestic crude oil prices were frozen, as discussed in Chapter II. The freeze continued through July and August. During this period, February through August 1976, stripper crude volumes varied from 1.00 to 0.94 MMB/D (Table III-2).

Impacts in 1976

The ECPA became effective in September, 1976. This Act again released stripper well crude oil to market level prices and in addition, changed the qualification period to any preceding twelve consecutive months. Formerly, the qualification period had been any preceding calendar year. Stripper crude prices increased to $13.21 per barrel (in September) from $11.52 per barrel in August (Table III-1). Prices tended to increase during the remainder of the year. Stripper crude volumes increased from 0.95 MMB/D in August, 1976, to 1.04 MMB/D in September to 1.08 MMB/D in December, or by 0.13 MMB/D (14 percent) in four months.

The increase in production figures in September and following months was probably due more to the change in qualification period than to price incentives. Since operators were given until December 31, 1976 to complete certification of stripper well properties that became eligible in September, the change in qualification continued to be a major factor, in addition to the obvious price incentives, in production increases toward the end of 1976. In other words, the recent increase in reported stripper well crude oil production is predominantly the result of a change in category rather than an actual production increase. The period February-August, 1976, when stripper crude oil was controlled at the upper tier price, may have had a depressing effect on production, but the magnitude cannot be determined since production figures are masked by the movement of other oil to the stripper well category. The price reduction in February, 1976 of $1.55 per barrel probably had some effect on the rate of abandonment of stripper wells, since many are only marginally economic. Hence, upon price reductions, equipment from the poorer wells is sometimes salvaged to keep better wells in operation. A consequence is that some potential reserves that may have been available by continued operation or future enhanced oil recovery techniques are lost.

While the ECPA released stripper crude oil to market level prices, it mandated that the share of stripper crude oil be included in calculation of the composite price at an imputed price of $11.63 per barrel in September, 1976. The price is required by statute to be escalated in subsequent months to reflect escalations in the upper and lower tier prices.

Future Impacts

FEA's long-term forecasting model will not isolate forecasts of stripper well production or allow a determination of future production rates based upon alternate price scenarios. There are no data on stripper well abandonments that will allow even tentative projections. We can say with reasonable certainty that stripper well production will become an increasingly large portion of domestic production as long as total domestic production continues to decline, because of the movement of upper and lower tier production to the stripper well category, and that any significant rollback in stripper well prices would be likely to have an adverse impact on the number of stripper wells and total stripper well production. The failure of stripper well production to decrease in March to August of 1976 is masked in part by transfers of oil among categories and may be due also to the belief by operators that the stripper well exemption would be reinstated shortly. It is similarly difficult to draw long-term conclusions from the noticeable increase in stripper well production after the ECPA exemption became effective in September.

TABLE III-I

Stripper Well Crude Oil Prices

Month	1975 (Nominal Dollars)	1976 (Nominal Dollars)	1976 (1975 Dollars)
January	11.18	12.89	12.26
February	11.32	11.34	10.79
March	11.52	11.32	10.77
April	11.49	11.43	10.88
May	11.62	11.50	10.94
June	11.71	11.51	10.95
July	12.25	11.52	10.96
August	12.36	11.52	10.96
September	12.46	13.21	12.57
October	12.68	13.35	12.70
November	12.83	13.31	12.66
December	12.89	13.30	12.65

Source: FEA

TABLE III-2

STRIPPER WELL PRODUCTION
(MMB/D)

Month	1975	1976
January	0.89	0.94
February	0.88	0.94
March	0.82	0.99
April	0.91	0.98
May	0.88	0.96
June	0.92	1.00
July	0.94	0.96
August	0.93	0.95
September	0.93	1.04
October	0.94	1.02
November	0.88	1.08
December	0.94	1.08

Source: FEA

ECPA INCENTIVES FOR DOMESTIC TERTIARY PRODUCTION

Background

The EPCA had provided, as an incentive for development of high cost/high risk properties, the application of enhanced recovery techniques, and sustaining production from marginal wells, a three percent annual escalator to the composite price limitation over and above the allowance for inflation. No price incentive applicable specifically to production through tertiary recovery techniques was provided. Consequently, crude oil produced through tertiary recovery methods was limited to the allowable price for the tier(s) in which it fell (primarily upper tier).

The ECPA requires the promulgation of amendments to "provide additional price incentives for bona fide tertiary enhanced recovery techniques" as soon as practicable after its enactment. It defined such techniques to mean "extraordinary and high cost enhancement technologies of a type associated with tertiary applications including, to the extent that such techniques would be uneconomical without additional price incentives, miscible fluid or gas injection, chemical flooding, steam flooding, microemulsion flooding, in situ combustion, cyclic steam injection, polymer flooding, and caustic flooding and variations of the same."

Pursuant to the mandate of the ECPA, FEA issued a Notice of Proposed Rulemaking and Public Hearing on January 6, 1977. Hearings were scheduled in Washington, D.C. and Dallas, Texas for the period beginning February 24 and ending March 4, 1977. In these proceedings FEA requested comment on a number of issues pursuant to implementing the mandate of the ECPA. These include:

(a) Determination of what constitutes a "tertiary enhanced recovery project" qualifying for the incentive;

(b) Determination of quantities of crude oil produced from a qualifying project which would qualify as tertiary crude oil - incremental vs "current" (pre-tertiary) or "total" production from the project;

(c) The price to which tertiary crude oil would be entitled (upper tier or market); and,

(d) The applicability of the incentive to existing projects.

Impacts in 1976

Inasmuch as FEA's rulemaking proceedings on this aspect of ECPA implementation have not been completed, no impact can be felt with respect to price incentives for tertiary production until 1977 at the earliest. Current information on the cost of tertiary recovery and the amount of production from these recovery techniques is too sketchy to allow a definitive assessment as to the extent to which the effect under the EPCA of limiting prices for this production to lower and upper tier levels has limited production or reserve additions.

FEA recognizes that there are substantial lead times involved in applying tertiary recovery techniques and that the majority of the production increment resulting from any currently provided incentives will therefore be realized in the time frame beginning near the expiration date of the 40-month control period provided by the EPCA. However, FEA is preliminarily of the view that adoption of regulations providing special price incentives for tertiary recovery may:

(1) Provide earlier stimulus to those projects which would result in some incremental production before the end of the control period;

(2) Assure continuity of production from secondary to tertiary modes of recovery on those properties whose economic limit would otherwise be reached before the end of the control period, thus preventing premature abandonments and consequent irretrievable loss of future production;

(3) Provide as much certainty in the investment environment for producers as is possible within the current structures of the EPAA as amended; and

(4) Provide for larger volumes of tertiary reserve additions in the long run as well as earlier production of these reserves.

<u>Future Impacts</u>

While estimates of tertiary crude oil production in the future cannot be made with certainty, the FEA PIES model projects that as much as 400,000 additional daily barrels of production can be obtained by 1980 (Appendix B), and up to 1,000,000 barrels per day by 1985 resulting from oil in tertiary recovery were allowed the world price. These projections are confirmed by several independent studies, including the most recent National Petroleum Council effort published in December 1976. Hearings to be held in the near future are expected to produce additional information on which to base an appropriate structure of price incentives and to estimate the amount of incremental production that may be realized.

Given the high cost of the tertiary recovery techniques which may have a unique applicability to a specific oil field, it is uncertain at this time what prices will be necessary to elicit the application of this technology to specific projects. Many, if not all, of the techniques are believed to be price sensitive. Therefore, in the long run added domestic crude oil production will be secured through price incentives, but how much production may be associated with specific price incentives cannot yet be carefully estimated.

WEST COAST GRAVITY DIFFERENTIAL PRICE ADJUSTMENTS

Effective October 1, 1976, in accordance with the Congressional policy set forth in ECPA, the FEA acted to adjust gravity price differentials with respect to California and Alaskan crude oil. Lower tier heavy (low gravity) California crude oil historically was priced substantially below the national average for lower tier crude oil partially because of greater than average gravity price differentials existing on May 15, 1973. Nationally, on May 15, 1973, gravity price differentials for crude oil averaged between 2 and 2.5 cents per barrel per degree below 40 degrees API, while in California the gravity price differentials averaged 6.2 cents per degree per barrel. Moreover, the September 1976 average price for lower tier crude oil nationwide was $5.15 per barrel, while in California the average price was $4.32 per barrel.

Accordingly, the FEA amended the price rules to permit the ceiling price for lower tier California and Alaskan crude oil to be increased by 2 cents per barrel for each degree API gravity between 34° API and 40° API that it falls below 40° API, and by 3 cents per barrel for each degree API that it falls below 34° API.

California and Alaska production does not match the national average distribution by price tiers. For September 1976, California crude oil, excluding Naval Petroleum Reserve No. 1 production, was 69% lower tier. Alaska production for the same month was 83% lower tier.

With average California crude oil gravity of 20 degrees API and 560 MB/D of lower tier crude oil production, and with average Southern Alaska crude oil gravity of 35 degrees API and 160 MB/D of lower tier crude oil production, the following increases in lower tier crude oil payments became permissible.

California	Alaska
$0.54 per barrel	$0.10 per barrel
$271,000 per day	$16,000 per day
$ 98.9 million per year	$5.8 million per year

The combined increase of $104.7 million per year would have added 3.5 cents per barrel to the composite price of domestic crude oil if passed through. On a percentage basis the composite price would have been increased by 0.43%.

However, although increases in lower tier prices were permitted by the amendment, significant price increases did not occur with respect to California crude oil. The majority of purchasers had not adjusted lower tier prices as of February, 1977 to add any part of the permissible ceiling price increase.

The action of California crude oil purchasers was not entirely unexpected by the FEA. In public hearings, FEA representatives had questioned the ability of the California crude oil market to match the proposed increases in lower tier crude oil price ceilings. In internal analyses the FEA had projected that only part of the permissible price increases would materialize -- largely because of sharply increasing sulphur penalties for both imported and domestic crude oil. This condition was assumed to continue as long as Saudi Arabia crude oil pricing policies were unchanged.

The state of California and the City of Long Beach maintain that they should be paid for crude oil produced to their account (whether royalty or working interest crude oil) at full market "value." It is claimed that "value" is represented by the price permitted under FEA regulations and not by a lesser price which purchasers are willing to pay. Responding to demands by the governments involved, crude oil purchasers began placing the incremental funds in escrow in December 1976. The volume of crude oil involved is approximately 140,000 barrels per day and the funds involved are approximately $2.2 million per month. However, until such time as the dispute is resolved, data collected by FEA will not show the disputed volumes or funds.

The basic problem in the pricing of lower tier California crude oil is demonstrated in the application of the entitlements program to the California crude oil market.

Crude oil imported into California is of higher API gravity and lower sulfur content than national average foreign crude oil imports. Conversely, crude oil produced in California is of lower API gravity and higher sulfur content than that produced nationally. The entitlement calculations, based on national average prices paid for imported crude oil and for each tier for domestic crude oil, introduces another element into the calculation of crude oil values to a California crude oil user (refiner). This effect is more pronounced in California than elsewhere because of the high volume of lower-tier low-gravity high-sulfur crude oil.

Consider the following tables:

	California Lower Tier Crude Oil	Crude Oil Imported into California
	(Dollars per barrel)	
October, 1976 Ceiling Price	$ 4.89	
October, 1976 Actual Price	4.32	$ 13.45
Entitlement Cost (Credit)	5.54	(2.30)
*Cost to Refiner	$ 9.86	$ 11.15
Approximate value of Quality Differential		$ 1.30

	Ex-California Lower Tier Crude Oil	Crude Oil Imports Other than California
October 1976 Price	$ 5.25	$ 13.15
Entitlement Cost (Credit)	5.54	(2.30)
*Cost to Refiner	$ 10.79	$ 10.85
Approximate value of Quality Differential	$ .80	

*Not including domestic transportation costs, etc.

In contrast to the rest of the country, the crude oil imported into California is of considerably higher quality than domestic production in the area. This means that even before recent lower tier price ceiling adjustment is considered, lower tier California crude oil was fully priced (after considering entitlements) compared to imported crude oil.

To date, the effect of the West Coast lower tier gravity differential adjustment on production has been slight because of the lack of market response to the ceiling price increases. FEA is amending its regulations to provide an appropriate solution.

Appendix A

ANALYSIS OF SHORT-TERM IMPACTS

In order to estimate the impacts of various EPCA/ECPA provisions in 1976, FEA analyzed three alternative cases through its Short Term Petroleum Forecasting Model. The cases are:

> Case A: (Base Case) - Continued EPAA Controls Through 1976. This case assumes that the Congress had simply extended the EPAA unamended rather than enacting the EPCA or ECPA, and that EPAA regulations had continued unchanged in 1976.
>
> Case B: EPCA Stage I Only. This case assumes that only the Stage I composite price limitation had been implemented in 1976. This case is designed to isolate the impacts of the composite price limitation without escalators.
>
> Case C: EPCA Stage I and II. This case assumes that the composite price limitation and escalators, but not ECPA provisions, had been implemented in 1976. It is designed to allow isolation, by derivation, of the impacts of escalator provisions.

Price assumptions for the various cases are given in Table III-A-I.

TABLE III-A-1

Price Assumptions 1/

Case	Lower Tier	Upper Tier	Composite	Imports
A 2/	$ 5.02	$ 13.27	$ 8.65	$ 13.27
B	NA	NA	7.87 3/	13.27
C	NA	NA		13.27
March			7.79	
April			7.86	
May			7.89	
June			7.99	
July			8.04	
August			8.03	
September			8.03	
October			8.03	
November			8.03	
December			8.03	

1/ All prices are in nominal dollars.

2/ January 1976 price of old oil is used for lower tier. January actual cost of imports booked into refineries are used for upper tier and imports (MER).

3/ February 1976 actual composite.

Table III-A-2 gives the results of this analysis in terms of total domestic demand and imports. No measurable effect on domestic production was realized in this short time span; therefore, domestic production is assumed to be similar in all cases.

TABLE III-A-2

1976 Imports
(MB/D)

	Total Demand	Imports
Case A	17,210	6,964
B	17,235	6,989
C	17,231	6,985

All import differences are crude oil, since domestic refining capacity is adequate to hold product imports constant in the alternative cases. The changes in total demand and imports resulting from this analysis are well within the range of error in the model. Although these changes are discussed in terms of consumer impact in Chapter III, only the direction of the impact is valid. The absolute numbers are not reliable estimates.

Appendix B

COMPARATIVE ANALYSIS OF SUPPLY RESPONSE TO PRICE CHANGES

This analysis examines possible long term effects that various pricing alternatives would have on domestic oil production. This section presents and compares petroleum supply, demand and import forecasts under domestic price alternatives for the period 1976 through 1980 for these cases:

Case A: Implement EPCA Stage I, II and ECPA Through May 1979 Only. This case assumes that all provisions of the EPCA and ECPA would be in effect through May 1979, after which controls would expire and all domestic crude oil would be priced at world market levels. It assumes exemption of North Slope, Tertiary, and Elk Hills crude oil.

Case B: Current Price Controls Beyond May 1979. This case assumes that the EPCA and ECPA restraint on the composite national average price with appropriate escalators were to stay in effect beyond May 1979. All other assumptions are the same as for Case A.

Case C: Implement EPCA Stage I Only Beyond May 1979. This case assumes that EPCA Stage II and ECPA provisions had not been put in effect. It assumes that all domestic oil, including stripper well oil but not North Slope crude is constrained at a composite price of $7.66 (in 1975 dollars) beyond May 1979. This allows us to compare the effect of not using additional escalators with other cases which assume the existence of such escalators.

Methodology and Basic Assumptions Common to All Cases:

Price

The price of world oil is a principal factor in any forecast of future oil production. In an effort to capture possible supply changes resulting from world oil price fluctuations, two alternative options are provided for each of the cases described above:

(1) The price of imported crude oil is assumed to remain constant at $13.00 per barrel in 1975 dollars (cost, including freight, U.S. east coast). Under this assumption, future prices of imports would increase only with inflation, in an amount sufficient to maintain this $13.00 price in constant dollars.

(2) The real price of world oil is assumed to increase at 2% per annum in constant dollars. Table III-B-1 shows the price levels that are assumed for the various cases and categories of domestic oil. Prices throughout the analysis are given in 1975 constant dollars.

TABLE III-B-1

Price Assumptions
(1975 Constant Dollars)

1980
($13.00* World Oil Price)

Case	Lower Tier	Upper Tier	Tertiary	Elk Hills	North Slope
Case A-Decontrol May 1979	13.00	13.00	13.00	13.00	13.00
Case B-Continued EPCA Control	5.56	11.95	13.00	13.00	13.00
Case C-EPCA Stage I Only	4.46	10.05	13.00	13.00	13.00
1985 ($13.00 World Oil Price)					
Case A-Decontrol May 1979	13.00	13.00	13.00	13.00	13.00
Case B-Continued EPCA Control	8.49	13.00+	13.00	13.00	13.00
Case C-EPCA Stage I Only	4.10	9.23	13.00	13.00	13.00
1980 ($14.35** World Oil Price)					
Case A-Decontrol May 1979	14.35	14.35	14.35	14.35	14.35
Case B-Continued EPCA Control	5.56	11.95	14.35	14.35	14.35
Case C-EPCA Stage I Only	4.46	10.05	14.35	14.35	14.35
1985 ($15.85** World Oil Price)					
Case A-Decontrol May 1979	15.85	15.85	15.85	15.85	15.85
Case B-Continued EPCA Control	6.37	13.69	15.85	15.85	15.85
Case C-EPCA Stage I Only	4.10	9.23	15.85	15.85	15.85

* The price of imported crude oil is assumed to be $13.00 per barrel in 1975 dollars (cost, including freight), U.S. east coast.

** Price of world oil is assumed to increase at 2 percent per annum in constant dollars.

+ Upper tier price reaches world price levels prior to 1985.

Supply Forecasts

Supply forecasts presented in this report are generated by the FEA Oil and Gas Supply Model and the PIES Modeling System.

The FEA Oil and Gas Model consists of an analytical framework which attempts to represent real-world activities associated with domestic oil exploration, development and production. In particular, it includes the important economic and engineering factors which affect future production as well as the way these factors interact in oil supply decisionmaking by private firms. For example, many processes involved in the search for and development of oil production are discussed in Chapter IV. The FEA Oil and Gas Supply Model views these operations and considers the time requirements associated with them in its forecast of future oil production.

Outer Continental Shelf

Leasing of lands on the U.S. outer continental shelf (OCS) represents a major governmental lever on domestic oil supply. Five lease sales per year, each offering an average of 1 million acres, are assumed in all cases. This rate is lower than the Department of the Interior's leasing schedule, which has six sales annually through 1978. Likely legal and environmental delays are assumed to make the six-sale rate unobtainable.

Transportation

New transportation facilities are required to adapt to this shift away from traditional sources to frontiers over the next 15 years. Also, new facilities are required to accommodate increasing imports. In all cases, major transportation adjustments are assumed to be made to accommodate frontier development and increased imports. The Trans-Alaskan Pipeline System (TAPS) is assumed to be capable of moving 1.6 MMB/D from the North Slope to Valdez by 1980, and adequate domestic pipeline capacity to transport this crude oil in the lower-48 is assumed.

Reserves and Resources

Estimates of the oil reserves and resources are a main factor in determining future production. The resource estimates used in these forecasts are from the USGS. Uncertainty in the resource base is large and has a very significant impact on the oil production forecast. For this analysis, the USGS 50% confidence estimates are used. More pessimistic assessments of oil resources will have a downward effect on production forecasts and vice-versa.

At the beginning of 1976, U.S. measured (proved) reserves of crude oil were 32.7 billion barrels. Approximately two-thirds of these measured reserves were in the lower-48 onshore areas; 9.6 billion barrels were in the Prudhoe Bay field on the Alaskan North Slope. Over the next 15 years, production from these reserves is well assured. In order to support the forecasts presented in these cases, an additional 39 billion barrels must be added to the measured category between 1975 and 1990. This amount represents approximately 38 percent of the total remaining resource potential expected by the USGS to be available. Of this remaining potential (excluding measured reserves), 28 billion barrels are "indicated" and "inferred" (24 percent of the total). These two categories consist of reserves expected to be converted to the measured category in known fields. Although much less certain than measured reserves, indicated and inferred reserves are likely to prove out in practice.

The balance of domestic oil resources, 89 billion barrels, currently is undiscovered. In contrast to known fields, the USGS expects undiscovered resources to reside in approximately equal amounts in (1) the lower-48 onshore areas, and (2) frontier areas, the lower-48 offshore, and in Alaska. In these frontier areas, where little exploratory exploratory drilling has occurred, the extent and characteristics of the resources base are extremely uncertain.

Supply Projections

Table III-B-2 summarizes the impact of the scenarios on domestic production for all cases. For the year 1980 ($13.00 cases) the decontrol case (Case A) has the highest production rates, at 9.9 MMB/D. Those cases (Cases B&C)

where various provisions of the EPCA are assumed to continue have the lowest production rates. The difference between the decontrol case and the continued EPCA Phase I and II case for 1980 is 0.2 MMB/D. This small difference can be attributed to the fact that decontrolled oil prices would have been in effect for only 7 months and the upper tier price ($11.95) is close to the assumed world oil price of $13.00. Relative to the EPCA Stage I case, however (Case C), a significant difference of 1.9 MMB/D is shown.

If the +2 percent annual increase in the price of world oil is assumed, the variance of the production forecast widens but the trend is consistent. Decontrol in May 1979 provides the most optimistic production forecast of 10.3 MMB/D. The difference in the highest and lowest forecast for the +2 percent case is 2.3 MMB/D, evidencing a widening gap between domestic production potential when domestic prices are assumed to be regulated at a low level and world prices are assumed to increase at higher levels.

Thus, decontrol after May 1979 could mean anywhere from .2 MMB/D to .6 MMB/D in increased crude production, depending on the price of oil imports.

The production forecasts for the year 1985 highlight the long-term effects that various government policies would have on domestic production. Decontrol assumptions again provide the most optimistic projection of domestic

TABLE III-B-2

Total Production
(MMB/D)

	Option A ($13.00)	Option B (+2 Percent)
1976	8.1	8.1
1980 Case		
Case A-Decontrol May 1979	9.9	10.3
Case B-Continued EPCA Control	9.7 (-.2)*	9.7 (-.6)
Case C-EPCA Stage I Only	8.0 (-1.9)	8.0 (-2.3)
1985 Case		
Case A-Decontrol May 1979	10.2	12.1
Case B-Continued EPCA Control	10.2 (0)	11.4 (-.7)
Case C-EPCA Stage I Only	7.6 (-2.6)	8.4 (-3.7)

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* Numbers in parenthesis show difference from base case (Case A).

production while the EPCA Stage I case shows the most pessimistic results. Under the $13.00 case, 1985 production is forecasted to be the same for continued EPCA controls and for decontrol in May 1979. This results because the price of upper tier[1/] oil meets the assumed $13.00 world oil price, thereby resulting in defacto decontrol for upper tier oil. Had EPCA Stage I controls remained, however, domestic crude production would be decreased by 2.6 MMB/D compared to EPCA escalators.

The 1985 forecast for the +2 percent world price assumptions show the most significant variance in domestic production. Under the decontrol case (Case A) crude oil production levels of 12.1 MMB/D are forecast for 1985. Continued EPCA controls are shown to restrict production levels by 0.7 MMB/D while continued Stage I controls result in a production level of 8.4 MMB/D.

Imports

Government controls on domestic oil prices significantly impact import levels. Case A levels of 7.2 MMB/D are 0.6 MMB/D less than those forecasted under the assumption of continued EPCA Phase I and II controls and 2.5 MMB/D less than those forecasted under the assumption of continued EPCA Stage I controls only for 1980 (Table III-B-3). The +2 percent cases

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1/ EPCA regulations allow the composite price to increase a maximum of 10 percent per annum.

TABLE III-B-3

Imports*
(MMB/D)

		$13.00 World Oil Price	+2 Percent World Oil Price
1980	Case A-Decontrol May 1979	7.2	6.4
	Case B-Continued EPCA Control	7.8 (+.4)***	7.7 (+1.3)
	Case C**-EPCA Stage I Only	9.7 (+2.5)	9.6 (+3.2)
1985	Case A-Decontrol May 1979	7.6	4.8
	Case B-Continued EPCA Control	8.0 (+.4)	6.2 (+1.4)
	Case C-EPCA Stage I Only	10.8 (3.2)	9.5 (+4.7)

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* Imports are from PIES forecasts.

** PIES demand case is not available for Case C. As a result, imports for Case C were calculated on the assumption of Case B's demand forecast.

*** Numbers in parenthesis show variance from base Case A.

increase these differentials. Reference case imports are shown to be 1.3 MMB/D less than Case B and 3.2 MMB/D less than Case C.

Imports are forecasted to increase by 0.4 MMB/D over the $13.00 reference case if the EPCA controls are maintained and 3.2 MMB/D if the EPCA Stage I controls are maintained. The +2 percent case forecasts Case B imports to be 1.4 MMB/D and Case C imports to be 4.7 MMB/D in excess of the reference case.

Production Summary 1/

Maintaining EPCA price controls on domestic crude oil production through 1980 compared with eliminating them in May 1979 would:

a. result in reducing domestic crude oil production by 0.6 MMB/D in 1980.

b. increase imports by 1.3 MMB/D in 1980.

The effects of EPCA Stage II escalators (Case B) are significant compared with forecasts derived from assuming continuation of the Stage I limitation only (Case C). The escalators yield an increment of 1.9 MMB/D in domestic crude oil production with a corresponding reduction in imports.

1/ This discussion is based on the +2 percent cases.

Results for all cases are summarized in Table III-B-4. Analysis of Table III-B-4 indicates that production levels are significantly affected by:

a. The price of oil (world and domestic)

b. The extent of controls

c. The point in time when controls are imposed.

Price is a principal determinant of future production. The variance in domestic production between the case with the lowest price assumptions (Case C) and the highest price assumptions (Case A) is 2.1 MMB/D for the 1980 period at $13.00 world price. The variance for the same cases and year but with a +2 percent world price increase is 2.4 MMB/D.

The extent of controls also is important to these forecasts. Production levels of decontrolled oil (North Slope, Elk Hills and Tertiary Oil) represent a significant source of supply. The supply/price relationships presented in this study argue that controlling this oil would severely restrict production potential and increase dependence on imports. Although Table III-B-4 does not show an impact on tertiary production, runs of the PIES model for 1985 do reveal an additional impact in that year in the next digit.

Extensive lead times associated with future crude oil production condition the conclusions of this study. Even under the most attractive pricing, tax and environmental policies, finding and developing oil takes time. Production

TABLE III-B-4

Domestic Production
(MMB/D)

$13 (Constant 1975) World Oil Price

Year	Case	Traditional Sources	Tertiary 1/	Elk Hills 2/	North Slope	Total	Other 3/	Import 4/	Total Supply 5/
1976		8.1	-	-	-	8.1	1.6	7.3	17.0
1980	Case A - Decontrol May 1979	7.7	.4	.2	1.6	9.9	1.3	7.2	18.3
	Case B - Continued EPCA Control	7.5	.4	.2	1.6	9.7	1.3	7.8	18.8
	Case C - EPCA Stage I Only	5.8	.4	.2	1.6	8.0	1.1	9.7	18.8-6/
1985	Case A - Decontrol May 1979	7.0 8/	1.0	.18	2.0	10.2	1.2	7.6	19.0
	Case B - Continued EPCA Control	7.0	1.0	.18	2.0	10.2	1.2	8.0	19.3
	Case C - EPCA Stage I Only	4.4	1.0	.18	2.0	7.6	.9	10.8	19.3

+2 Percent World Oil Price 7/

Year	Case	Traditional Sources	Tertiary	Elk Hills	North Slope	Total	Other	Import	Total Supply
1980	Case A - Decontrol May 1979	8.1	.4	.2	1.6	10.3	1.3	6.4	18.0
	Case B - Continued EPCA Control	7.5	.4	.2	1.6	9.7	1.3	7.7	18.7
	Case C - EPCA Stage I Only	5.8	.4	.2	1.6	8.0	1.1	9.6	18.7
1985	Case A - Decontrol May 1979	8.1	1.0	.18	2.8	12.1	1.3	4.8	18.1
	Case B - Continued EPCA Control	7.4	1.0	.18	2.8	11.4	1.3	6.2	18.9
	Case C - EPCA Stage I Only	4.4	1.0	.18	2.8	8.4	1.0	9.5	18.9

1/ Tertiary production increases under the +2 percent world oil price assumption. These increases do not show on the table because of rounding. Assumes tertiary production sells at market price levels.
2/ The Naval Petroleum Reserve Production Act of 1976 mandates production at the maximum efficient rate (MER) regardless of price.
3/ Includes gas liquids, butane, syncrude and shale oil.
4/ Includes product imports.
5/ Total supply does not include refinery gains nor does it account for fuel used directly in the refinery.
6/ Total supply requirements are assumed to equal supply requirements for Case B (controlled case) for purposes of this analysis. PIES demand case is not available for Case C assumptions. As a result, "Total Supply" and "Imports" are understated for Case C.
7/ Price of world oil is assumed to increase at 2 percent per annum in constant dollars.
8/ The difference between the composite price and the world oil price ($13) is small. As a result differences in production forecasts between Case A and B are negligible.

levels which are forecasted for 1985 reflect efforts begun in 1980. Similar production efforts which are forecasted for 1980 are contingent on the price, tax, and environmental policies that are now being establisned and on the duration of controls prior to forecast year.

Appendix C

EFFECTS OF CRUDE OIL PRICE REGULATIONS ON THE U.S. NATIONAL ECONOMY DURING 1976

The effects of five alternative sets of domestic crude oil price regulations on the U.S. national economy during 1976 have been evaluated. The price regulation scenarios are:

1. The Unamended EPAA
2. EPCA Stage I
3. EPCA Stage II
4. ECPA Stripper Well Exemption
5. ECPA Elimination of the 3 Percent Production Limitation

Crude oil price regulations affect the U.S. economy in many and complex ways, which are described in detail in Appendix D. Essentially, lower prices for domestic crude oil reduce the long-run rate of domestic crude oil production, induce additional crude oil and product imports, and may reduce real GNP by constraining investment in domestic energy industries. The short-term effect is to reduce average annual energy prices in the U.S. economy as well as the average price level for all goods and services. The lower general price level affects aggregate demand and leads to an increase in real GNP in the short run. The increase is obtained at a cost of increased dependence on imported oil, since to sustain the higher level of economic activity requires additional energy, which would not likely be forthcoming from domestic sources given the lower domestic crude oil prices.

The effects of the first three scenarios listed above are estimated with use of the Data Resources, Inc. (DRI) Quarterly Econometric Model of the U.S. Economy. The effects of the other two scenarios are estimated without the use of models.

Only the price of old oil is subject to control under the first scenario. The actual market price for such oil in January 1976 is assumed to remain in effect throughout that year. All other oil is priced at approximately the world price during 1976. This set of prices would have prevailed during 1976 if the EPAA had continued in effect unamended by the EPCA and the ECPA.

Stage I of the EPCA provides for legal limits on the price of all domestically produced crude oil for the month of February 1976. As a result, the average actual transactions price for that month was less than that for January. The EPCA Stage I scenario assumes that the average actual transactions price for January is the same as the unamended EPAA price for that month and that the average price from March through December is equal to the Stage I February price. These Stage I prices are those that would in fact have been realized in the market during 1976 if the only amendment to the EPAA during that year had been the EPCA Stage I amendment. The average 1976 price for domestically produced crude oil under the EPCA Stage I scenario is about 8 percent less than under the EPAA scenario.

The EPCA Stage II scenario provides for monthly increases to the Stage I February 1976 crude oil prices. The prices assumed for this scenario for the January-August period are those that were actually realized in the market during those months, since the Stage II regulations were in effect through August. If the Stage II crude oil price regulations had remained in effect after that time rather than being superseded by ECPA regulations the prices for the rest of 1976 would have been approximately equal to the August price because of a price freeze that had been in effect since June and which would have continued in effect for the rest of the year. As a result, the average price for domestically produced crude oil for 1976 under the Stage II scenario is about 7 percent less than under the EPAA scenario and 1 percent greater than under the Stage I scenario.

The Stripper Well Exemption scenario is identical to the Stage II scenario through August 1976. After that time it differs from the Stage II scenario in that stripper well oil is free from control. The effect of this exemption is to increase prices above the Stage II prices for the September-December period. The average 1976 price for the Stripper Well Exemption scenario is less than for the EPAA scenario.

The fifth scenario (ECPA Elimination of the 3 Percent Production Incentive Limitation) roughly approximates the actual experience incurred during 1976. That is, it assumes full implementation of ECPA beginning in September rather than only the exemption of stripper oil as in the preceding scenario. The additional element introduced in this scenario relative to the stripper scenario is to allow the price of controlled oil to increase at a compound annual rate of 10 percent beginning in September rather than at the lower annual rate of 3 percent as a production incentive plus the rate of inflation. This higher rate had no effect during those months, however, since the prices of controlled oils were frozen. As a result, the average price of domestically produced crude in the fourth and fifth scenarios are estimated to be equal.

A summary of price differences for domestically produced crude oil relative to the EPAA base case are in the following table.

The EPAA crude oil price regulation scenario is adopted as a base case against which the other price scenarios are compared to determine differential effects on the economy. The effects of all price scenarios on the economy are negligible for 1976.

TABLE III-C-1

Estimated Percent Differences in the Average Prices of Domestically Produced Crude Oil in 1976 Relative to the EPAA Scenario

Scenario	Percent Difference
EPAA Unamended	N.A.
EPCA Stage I	-7.6
EPCA Stage II	-6.7
ECPA Stripper Well Exemption	-4.8
ECPA Elimination of 3% Limitation	-4.8

N.A. - Not applicable

The implementation of the EPCA Stage I price scenario reduces the average price of domestically produced crude oil in 1976 by an estimated 7 to 8 percent below the EPAA price. As a result, the average wholesale price of energy is 2 percent lower. The wholesale and consumer price indices are also lower than in the base case but only by about one-fourth of one percent, as shown in Table III-C-2. The small reductions in general price levels lead to an increase in real GNP of about one-tenth of one percent. Crude oil and product imports increase by about 25 thousand barrels a day, which has little effect on the balance of trade in goods and services.

The EPCA Stage II scenario produces effects in 1976 which are nearly the same as those for the Stage I scenario,

TABLE III-C-2

Effects on U.S. Economy in 1976 of Maintaining Selected Crude Oil Price Controls Relative to Maintaining Unamended EPAA Controls

	EPCA Stage I Controls	EPCA Stage II Controls
Differences in Real GNP (Billions of 1972 Dollars.) (Percent Difference in Parentheses)	1.6 (0.1)	1.5 (0.1)
Percent Difference in Consumer Price Index	-0.2	-0.1
Percent Difference in Wholesale Price Index	-0.3	-0.3
Percent Difference in Wholesale Price Index for All Energy	-1.9	-1.6
Percentage Point Difference in Unemployment Rate	0	0
Difference in Net Exports of Goods and Services (Billions of Current Dollars)	-0.3	-0.2

as shown in Table III-C-2. Domestic crude oil prices in the Stage II scenario are only about 1 percent greater than for Stage I.

The estimated effects of the ECPA stripper well exemption are based on the assumption that the EPCA Stage II controls for other than stripper oil are retained. The effects of this combined scenario relative to the EPAA base case are about two-thirds as great as those shown for the EPCA Stage II scenario in Table III-C-2, since the average price for domestic crude oil is higher when stripper oil is exempt from control than when control is retained.

The scenario which provides for the elimination of the 3 percent price increase production incentive limitation is otherwise identical in all respects to the stripper exemption scenario. The effects for both scenarios are the same since the price freeze for controlled oils that was in effect at the time the 3 percent limitation was removed continued in effect throughout the remainder of 1976.

Table III-C-3 presents the estimated effects on real GNP for all scenarios.

TABLE III-C-3

Effects on Real Gross National Product In 1976 of Maintaining Selected Crude Oil Price Controls Relative to Maintaining Unamended EPAA Controls

(Billions of 1972 Dollars.)
(Percent Difference in Parentheses)

EPAA	EPCA Stage I	EPCA Stage II	ECPA Stripper Well Exemption	ECPA Elimination of 3 Percent Limitation
N.A.	1.6	1.5	1.1	1.1
N.A.	(0.1)	(0.1)	(0.1)	(0.1)

N.A. - Not Applicable

Appendix D

LONG-TERM EFFECTS OF CRUDE OIL PRICE REGULATIONS ON THE U.S. NATIONAL ECONOMY

Introduction

Four major factors link the energy sector to the rest of the economy: the price of imported oil, domestic energy prices, domestic energy supply, and domestic energy demand. The changes in these four factors implied by a given crude oil price regulation scenario may not have the same directional impact on the economy. For any particular scenario, changes in some of these factors may cause an increase in GNP, for example, while changes in other factors may cause a decrease. As a result of this ambiguity, questions concerning the macroeconomic impacts of alternative price scenarios are inherently empirical and, as such, can be answered only on the basis of quantitative assessment. This appendix is intended to serve two purposes: first, to provide a perspective on the macroeconomic issues surrounding three crude oil price scenarios and second, to present quantitative and qualitative assessment of the relative magnitudes of effects on the national economy under the different price scenarios.

General Issues

In the short run, higher imported oil prices will cause an increase in domestic energy prices and lead to an increase in the overall domestic price level. Such an increase in domestic prices reduces demand for energy in particular and aggregate demand in general. Higher energy prices squeeze profit margins in energy consuming industries and depress real investment. The associated increase in the general level of domestic prices reduces real consumer incomes. In the short run, in the absence of an expansionary monetary/fiscal policy, such an increase in the general price level would thereby reduce aggregate demand by dampening both real investment and consumption expenditures. A decline in real gross national product and in employment must result unless policies to offset the reduction in aggregate demand are adopted. Such offsetting policies increase the rate of inflation.

In the long run, following adjustments in international markets, the negative impact on aggregate demand may be offset by increases in U.S. exports. It may futher be offset by increases in domestic energy production and associated investment as a result of higher domestic energy prices in the absence of price controls. As a result of the increases in domestic energy production and investment and in export demand, real GNP may approach the long run levels it would have reached without the increase in imported oil prices. However, a larger share of domestic output must eventually be exported to pay for oil imports, thereby reducing domestic living standards. The necessary decline in real consumption is likely to be affected through a higher inflation rate, as opposed to reductions in nominal wages (owing to downward wage rigidities) and higher unemployment.

If domestic oil and other energy prices are determined by market forces, they depend on world oil prices and domestic energy supply and demand. In such a context, they are not an independent force. They serve as a channel through which energy sector developments are transmitted to the rest of the economy, but they will not exert any independent influence on economic activity. However, if manipulated by government policies, domestic energy prices do play a separate and important role.

The imposition of controls on prices of domestically produced crude oil is one way in which the government can manipulate domestic energy prices. By constraining the increase in the average domestic price of energy, controls on prices of domestically produced crude oil cushion the reductions in output and investment in energy consuming industries that are associated with higher world energy prices. At the same time, controls inhibit both crude oil production and advances in energy conservation technologies designed to reduce consumption. Since neither domestic energy production nor energy conservation technologies can instantaneously adjust to changes in energy prices, the benefits of controls outweigh their costs in the short run. However, controls block feasible long run expansions in domestic energy production and reductions in consumption which would otherwise occur in response to higher world oil prices. Thus, in the long run, controls intensify dependence on foreign oil supplies and exacerbate the effects of higher world oil prices.

Price Scenarios

The effects of three crude oil price scenarios on the national economy have been evaluated. These scenarios are the same as those described in detail in Appendix B.

A. Continuation of current price controls through May 1979 and then decontrol.

B. Continuation of current price controls beyond May 1979.

C. Continuation of EPCA Stage I price controls only beyond May 1979.

The scenarios differ with respect to the prices assigned to domestically produced crude oil. The first scenario assumes that all price controls on such oil are eliminated early in 1979. The second scenario assumes that all current price controls continue in effect beyond that date. The third scenario assumes that the composite price of domestically produced crude oil is kept at its February 1976 level of $7.66 per barrel except for increases to compensate for general inflation.

Each scenario was evaluated under two alternative assumptions on the price of imported crude oil. First, the cost of such oil was assumed to be $13.00 per barrel (cost, including freight, U.S. East Coast) in constant 1975 dollars from 1975 onward. Second, this real cost was assumed to increase in constant 1975 dollars at a compound annual rate of 2 percent.

Methodology

The effects of two of the three crude oil price regulation scenarios were simulated with the use of the Data Resources, Inc. (DRI) Quarterly Econometric Model of the U.S. Economy. These two scenarios compare the continuation of current price controls beyond May 1979 with the continuation of current price controls through May 1979 followed by decontrol. Estimates of the effects of these scenarios were made under each of the two alternative assumptions concerning the price of imported crude oil. No models were used to simulate the macroeconomic effects of the other scenario. The results presented for this scenario are based on the general points discussed above, ceiling and legal limit price data associated with the scenario, and the relative effects derived for the two scenarios for which the DRI model was used.

The energy inputs incorporated into the DRI model for the two scenarios analyzed were generated by a system of energy models known as the Project Independence Evaluation System (PIES). PIES was used to generate annual energy data for 1980 and 1985 for each of the two scenarios. These data were then converted into a form adaptable to the DRI model for 1980 and 1985 in accordance with variable definitions used in the DRI model. Then, quarterly data for the DRI variables for the entire 1976-1985 interval were obtained by interpolating between 1976 historical data and the 1980 annual values for these variables and between the 1980 and 1985 annual values for these variables. The DRI model was then solved for each of the two price regulation scenarios under each of the two alternative price levels for the imported crude. The net result was to replace DRI's energy assumptions with data consistent with PIES as generated by interpolation. Differences between solution values show the macroeconomic effects of one price regulation scenario compared to another.

Effects on the Economy

The EPAA as amended by the EPCA and the ECPA stipulates that the current crude oil price controls will be in effect until the end of May 1979. The state of the economy under Case A above consistent with this situation was adopted as a base case. States of the economy consistent under the other scenarios were then compared with this base case to determine differential impacts on the economy. Results of these comparisons for Cases A and B above are summarized in Tables III-D-1 and III-D-2.

Table III-D-1 summarizes the effects of retaining current controls beyond May 1979 rather than eliminating them during 1979, based on an imported crude oil price of $13.00 per barrel in real 1975 dollars. The retention of controls has minor impact on the economy. Domestic price levels are lower, and the economy is more robust in 1980. Current dollar energy prices are projected to be 8.1 percent lower than in the base case and, as a result, the consumer price index is 1.0 percent lower. The lower prices lead to a higher level of aggregate demand, and real GNP is higher by three-tenths (0.3) of one percent. The unemployment rate is lower by one-tenth (0.1) of one percentage point. The balance of trade in goods and services is worse by about $7 billion, reflecting both the greater reliance on imported oil with price controls and higher imports of all goods and services due to the slightly higher level of economic activity with controls. The higher level of U.S. exports which results from the lower U.S. price level is not sufficient to prevent the adverse effect on the balance of trade. Most impacts are smaller in 1985 than in 1980 owing to a gradual reduction in the differences in energy prices introduced between the two scenarios at the end of May 1979.

Table III-D-2 summarizes the differential effects on the U.S. economy for continued controls relative to decontrol after May 1979 that result from assuming that the real (1975 dollar) price of imported crude oil increases in both scenarios at a compound annual rate of 2 percent. The impacts on the real economy as measured by real GNP and the unemployment rate are similar to those previously described. Price differences between the two scenarios are greater than those previously presented, however, as is the impact on the balances of trade in goods and and services. The trade balance impact is now twice as great in 1980 because the price of imported oil is higher and the change in the volume of imported oil is greater. The volume of imports in the continued controls scenario exceeds the volume in the decontrol scenario by a greater amount when the real price of imported crude is allowed to increase by

2 percent a year than when the price of imported oil is held constant. This impact offsets the greater reductions in domestic price levels shown in Table III-D-2 than in Table III-D-1 to keep the impacts on real GNP about the same.

TABLE III-D-1

Effects of Maintaining Current Crude Oil Price Controls Beyond 1979 Compared to Eliminating Them in May 1979

(Assumes $13.00 Per Barrel Imported Oil in Constant 1975 Dollars)

1980	1985
Differences in Real GNP (Billions of 1972 Dollars. Percent Difference in Parentheses)	
3.8 (0.3)	0.6 (0.0)
Percent Difference in Consumer Price Index	
-1.0	-0.5
Percent Difference in Wholesale Price Index	
-2.0	-0.8
Percent Difference in Wholesale Price Index for All Energy	
-8.1	-2.8
Percentage Point Difference in Unemployment Rate	
-0.1	0
Difference in Net Exports of Goods and Services (Billions of Current Dollars)	
-6.7	-6.9

TABLE III-D-2

Effects of Maintaining Current Crude Oil Price Controls Beyond 1979 Compared to Eliminating Them in May 1979

(Assumes a 2 Percent Compound Annual Rate of Increase in the Real $13.00 Price of Imported Crude Oil)

	1980	1985
Difference in Real GNP (Billions of 1972 Dollars. Percent Difference in Parentheses)		
	4.0 (0.3)	3.0 (0.2)
Percent Difference in Consumer Price Index		
	-1.5	-1.5
Percent Difference in Wholesale Price Index		
	-3.1	-2.6
Percent Difference in Wholesale Price Index of All Energy		
	-11.5	-8.1
Percentage Point Difference in Umemployment Rate		
	-0.1	(-0.1)
Difference in Net Exports of Goods and Services (Billions of Current Dollars)		
	-13.0	-24.1

The real GNP and unemployment rate effects presented in Tables III-D-1 and III-D-2 should be considered as maximum possible effects. They have overstated the effects that would probably result if current price controls were in fact extended beyond 1979 for several reasons. First, no compensating monetary or fiscal policy to mitigate the effects reported is incorporated into the analysis. The introduction of a compensating monetary policy, defined as retention of base case interest rate levels in both scenarios, could substantially reduce the magnitude of the effects presented in the tables. A compensating fiscal policy could further reduce the magnitude of the effects. Also, the imposition or retention of price controls introduces inefficiencies into the economic system by distorting the efficient allocation of resources. The quantitative analysis presented here probably does not adequately reflect the disincentives to investment and future production in the petroleum sector that result from the suppression of petroleum prices below their free market equilibrium levels. The costs of such misallocation become increasingly important in the long run, and by 1980 could offset the favorable short-term effects of controls.

The scenario (Case C) which assumes that the EPCA Stage I composite price limitation without escalators would remain in effect into the future would result in lower average prices for domestic crude oil during that period than any other scenario. These lower prices imply levels of real GNP that are greater than for the other scenarios. However, these higher GNP levels also imply higher volumes of imported crude oil to compensate for lower domestic production and as a result of greater aggregate demand. Although the net effect on real GNP is expected to be positive and is estimated to be greater than for any other scenario, a larger transfer of purchasing power abroad is required to pay for these imports. As a result, the degree of U.S. oil dependency would be significantly greater than for the other scenarios.

CHAPTER IV

EFFECTS OF PRICE REGULATION ON PRODUCTION INDICATORS

Introduction

In Chapter III the various provisions of the EPCA and ECPA were discussed individually and the short-term and long-term impacts of these provisions were quantified to the extent possible. However, the impacts of price regulation and production incentives tend to be reflected first in leading indicators of production and only later, as will be discussed in detail, in actual production figures.

This chapter identifies and discusses major factors which bear on domestic crude oil production. Conventional indicators of production are analyzed to identify trends and possible responses to past and current price controls and production incentives. General information on price and production trends is also supplied in order to serve as a foundation for subsequent FEA proposals to the Congress regarding production incentives.

Summary Findings. Some crude oil production activities and other indicators of exploration and/or development can be shown to correlate in a broad time frame with the price received by the producer. However, numerous non-price factors such as weather, taxes, technology and cost inflation also exert strong influences on production. Over a long period of time - prior to the 1970's - when prices were roughly stagnant (at least in the context of today's price movements), domestic petroleum activity diminished, which led to the decline in production rates we are now experiencing. Seismic exploration, well abandonments, and drilling statistics heralded this turnabout well in advance. Conversely, the 1970's are exhibiting increasing prices and, for the most part, indicators of future production are increasing also; however, the momentum of production decline has not yet been completely overcome.

In February of 1976, the implementation of the EPCA brought about a rollback of more than $1 per barrel in the price of upper tier oil. The upper tier price is the relevant marginal price for new exploration and development activities. Drilling indicators, which had been increasing sharply for several years, leveled off in apparent response to the reduced incentives, but at least remained at relatively high levels.

Production declined during 1976, but the amount of decline was only about 200,000 barrels per day compared to about 400,000 barrels per day for the previous two years. This improvement was the result of the increased exploration and development activity earlier in the decade, independent of any positive or negative effect of the EPCA. It is too early to determine exactly what the total effect of the resurgence of activity in the 1970's will be on future production, or to determine empirically what the effects of the EPCA, the ECPA, and the various implementing regulations in 1976 will be. Inasmuch as the domestic supply of petroleum in the future is dependent on exploration and development activities today, particular concern must attend changes in indicators of future production--especially the leveling-off of past increases in these indicators which was experienced in 1976.

During the 1970's, the price of domestic crude oil increased dramatically, while the continued decline in production reflected the deceleration of developmental activity which had occurred in the 1960's. When North Slope oil begins to flow in the latter part of 1977, there will be an abrupt increase in production; but in itself, the North Slope present reserves will only interrupt, not arrest the <u>trend</u> of declining production.

Proved reserves have declined every year since 1967 except in 1970 (booking of Prudhoe Bay field) and by an average of over one billion barrels per year since then. Additions have become more dependent upon revisions than upon extensions or new discoveries; already, of the nearly 10 billion barrels of crude oil reserves added by the discovery of the Prudhoe Bay, more than half has been eroded away in net reserve losses in the remainder of the country.

There have been, however, several hopeful signs since 1970. Seismic exploration in general increased since 1970.

Since this is the first major technical step in domestic exploration and development programs it can serve as the earliest of the leading indicators of new oil development. The number of active rotary drilling rigs has also been increasing since 1971, and annual exploratory and developmental well completions have continuously increased since 1971. This increase can be interpreted as a direct response to the more favorable price climate resulting from the response of domestic crude oil prices to the increases in foreign prices in the early 1970's. As noted later, gas well completions responded to higher intrastate prices by 1971 while oil well completions only began to increase after 1973.

While production has continued to decline since 1970, 1976 data indicate that the rate of production decline may be slowing. Production declined by more than 400,000 barrels per day between 1973 and 1974 and between 1974 and 1975, but has only declined by a little more than 200,000 barrels per day during 1976. This trend would appear to be the first indication of results from the increasing exploration and development activity cited above. Given favorable conditions for oil industry investment, the 1976 reduction in the decline rate may signal an arrest of the decline in the near future. However, some of the recent reduction in the decline rate is almost certainly attributable to workovers and in-field drilling, which do not reliably contribute to future reduction figures.

Analysis of Interrelationships Between Price, Production and Leading Indicators

While some correlations between price, exploration, development and production can be observed over an extended period of time, there are several qualifications that must be set forth before attempting to form conclusions for these effects.

- Lead Times. As is brought out in more detail later, there is a set sequence of events leading to production. Each facet of exploration and development has a different lead time associated with it, and the same is probably true of the same activities on different properties. The EPCA has activities on different properties. The EPCA has been in effect for only a year, but leases, seismic crews and rigs must be arranged in advance of any drilling stimulated by price expectations. Consequently, nearly all of the lead indicator statistics for 1976 reflect responses to earlier stimuli, such as the ability to price new oil at the world price which was allowed by regulations pursuant to the EPAA in 1975, rather than to regulations issued pursuant to the EPCA in 1976.
- Overlap. Since 1973, there have been a relatively large number of legislative/regulatory actions resulting in impacts on producers. One leading

indicator may be increasing in response to one event of lack thereof, while another may be responding to different stimuli. For example, in 1975, while the number of oil wells drilled increased substantially because of the favorable incentives for new oil recovery provided in Federal regulations since 1973, most of these newly drilled wells were performed in known areas where drilling and production had not been profitable at old price levels.

- Ambivalent Indicators. In the period 1974-1976, average well depth decreased from levels in previous years. This, if examined by itself, could lead to the conclusion either that shallower reserves were being produced, or that exploratory drilling had detected shallower reserves than in previous years. By including in the analysis the dramatic increase in the number of wells drilled during 1974-1976, the logical conclusion is that known reserves with relatively shallow depth were being developed through the drilling of extensions in response to the incentive provided by the new and released oil regulatory provisions.
- Seasonality. Many oil field operations, including production, are influenced by the weather, which varies by year and location, as well as by the

cycle of seasons. For example, seismic exploration requires the transport and support of people and delicate instruments into sometimes undeveloped areas, and therefore seismic activity generally tends to be maximized in season of easiest transportation. However, this is not necessarily a stable trend in <u>every</u> year. This seasonal effect must be compensated for by reviewing data for several years before reliable conclusions can be drawn.

- <u>Other Factors</u>. Final decisions whether and when to invest are made by individuals or corporations confronted by a shortage of hard facts and an uncertain future. It is never certain whether or not oil will be found, even in the middle of an already developed field. Similarly, development and production costs are uncertain as they depend on labor costs, material costs and inflationary factors, as well as on the nature and volume of oil discovered. Since 1973, the price to be received has not been highly predictable. Of necessity, the decision maker must rely partly upon informed guesses as to expected prices and costs in the future. Thus, it is not surprising to see investment decisions or delays in such decisions based on events which seemingly are not directly related to production expectations in the oil industry. For example, the lessening of activity in 1975 might have reflected the protracted energy policy debate leading to the EPCA. This debate served not only to increase lead time by creation of a "wait and see" attitude by investors, but may also have generated indicator data that appear to contradict the expectations of any particular action.

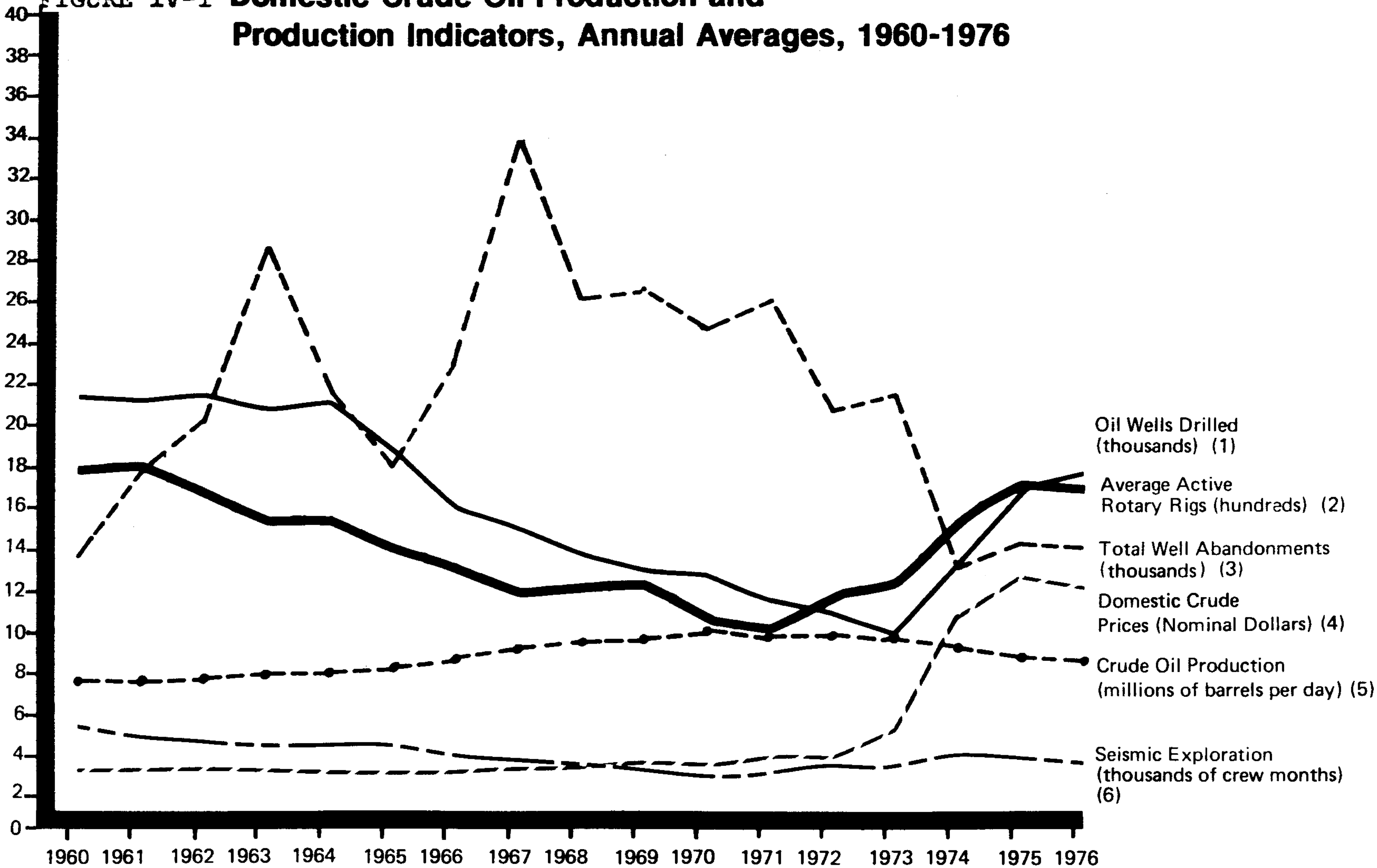
Furthermore, the influence of tax policy on exploration, development and production is strong, as is the influence of stable regulatory agencies on production rates.

In the following figures various indicators are plotted to highlight possible cause-effect relationships.

Figure IV-1 presents domestic crude oil production and production indicators. The top line (oil wells drilled) indicates total oil wells drilled during the period from 1960 to 1976. This line shows a substantial decrease in wells drilled from 1964 to 1973, the period in which the world oil price encouraged increasing U.S. dependence on imported oil. Since 1973, the number of oil wells drilled has increased sharply in response to the upward swing in the world oil price which began in 1972.

The second line indicates average rotary rig activity. The trend for this activity is similar to seismic exploration; the decline from 1961 to 1971 is substantial, with a few brief interruptions. From 1972 to 1975 activity increases, reflecting the price incentives for domestic

FIGURE IV-1 **Domestic Crude Oil Production and Production Indicators, Annual Averages, 1960-1976**



Sources: (1) Monthly Energy Review; (2) Hughes Tool Co.; (3) 1960-1975 API; 1976 FEA estimate; (4) 1960-1972, Platt's Oil Price Handbook; 1973-1976, MER and P-124-MO (new and upper tier prices only); (5) 1960-1972, Bureau of Mines; 1973-1975, MER; 1976, FEA P-124-MO; (6) 1960-1974 API; 1974-1976, MER.

production during that period. In 1976, there is a very slight reduction from the 1975 level of 1,660 to 1,653. The stabilization of this trend may reflect a reaction to the containment of upper-tier prices pursuant to the EPCA.

The third line indicates total well abandonments. While this indicator has fluctuated more than others, with the exception of oil wells completed, a new precipitous decline in abandonments began in 1974, which may reflect the higher prices commanded in 1972 and 1973 stripper well oil. The slight increase in abandonments in 1975 and 1976 is probably accounted for by the rising cost of production operations relative to the leveling off of upper tier prices and may also reflect added stripper well abandonments due to the EPCA repeal of the stripper well exemption.

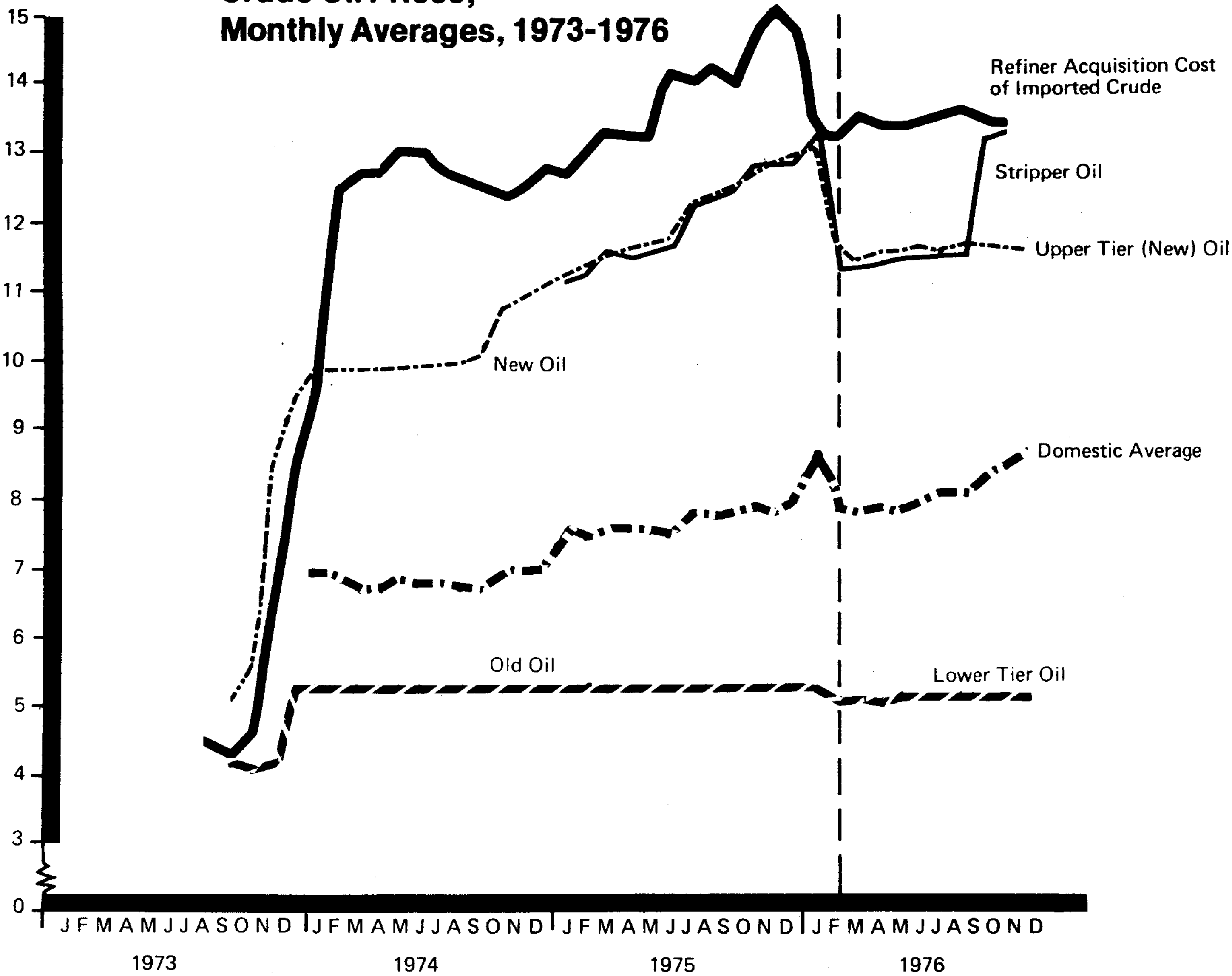
The fourth line indicates the relatively stable level of domestic crude oil prices until 1972. From 1974 to 1976, the domestic average price increased in response to the ability to price new, released and stripper well oil at upper tier prices required by the EPCA is paralleled by a decline in rotary rig activity.

The fifth line represents total crude oil production between 1960 and 1976. It clearly indicates that total domestic production peaked in 1970 and steadily decreased thereafter. Even with the accelerated production effort of the industry after 1972 the decline in total production continued. This may also indicate that the unused production capacity in existing oil fields has been essentially depleted. The step-up of the production effort has been able to slow down the rate of decline but cannot reverse it.

The bottom line represents seismic exploration activity, which is utilized in determining potential drilling sites. Seismic activity peaked in 1960 at 4,625 crew months and declined after that until 1972. This trend reflected the period of increasing cheap foreign oil imports which discouraged domestic exploration and production. By 1971, the trend was slightly reversed as foreign oil prices increased, and a new resurgence of seismic activity was brought about by OPEC price increases and subsequent regulatory incentives provided by allowing new, released and stripper well oil to be priced at world levels. However, seismic activity has not retruned to the 1960 level and it is unlikely that it will, since a substantial part of onshore reserves have already been located; but significant seismic activity can be expected to continue in search of offshore reserves.

Figure IV-2 shows crude oil price movements by month for 1973-1976. The top line presents average refiner acquisition cost of imported crude oil. The second line shows the movement in prices for new oil from September 1973 through January 1976, and for upper tier oil from February through November 1976. Average prices for stripper oil closely followed the pattern established by new/upper tier

FIGURE IV-2 **Crude Oil Prices, Monthly Averages, 1973-1976**



Source: MER, FEA P-124-MO.

oil from January 1975 until August 1976, when controls over this production were instituted.

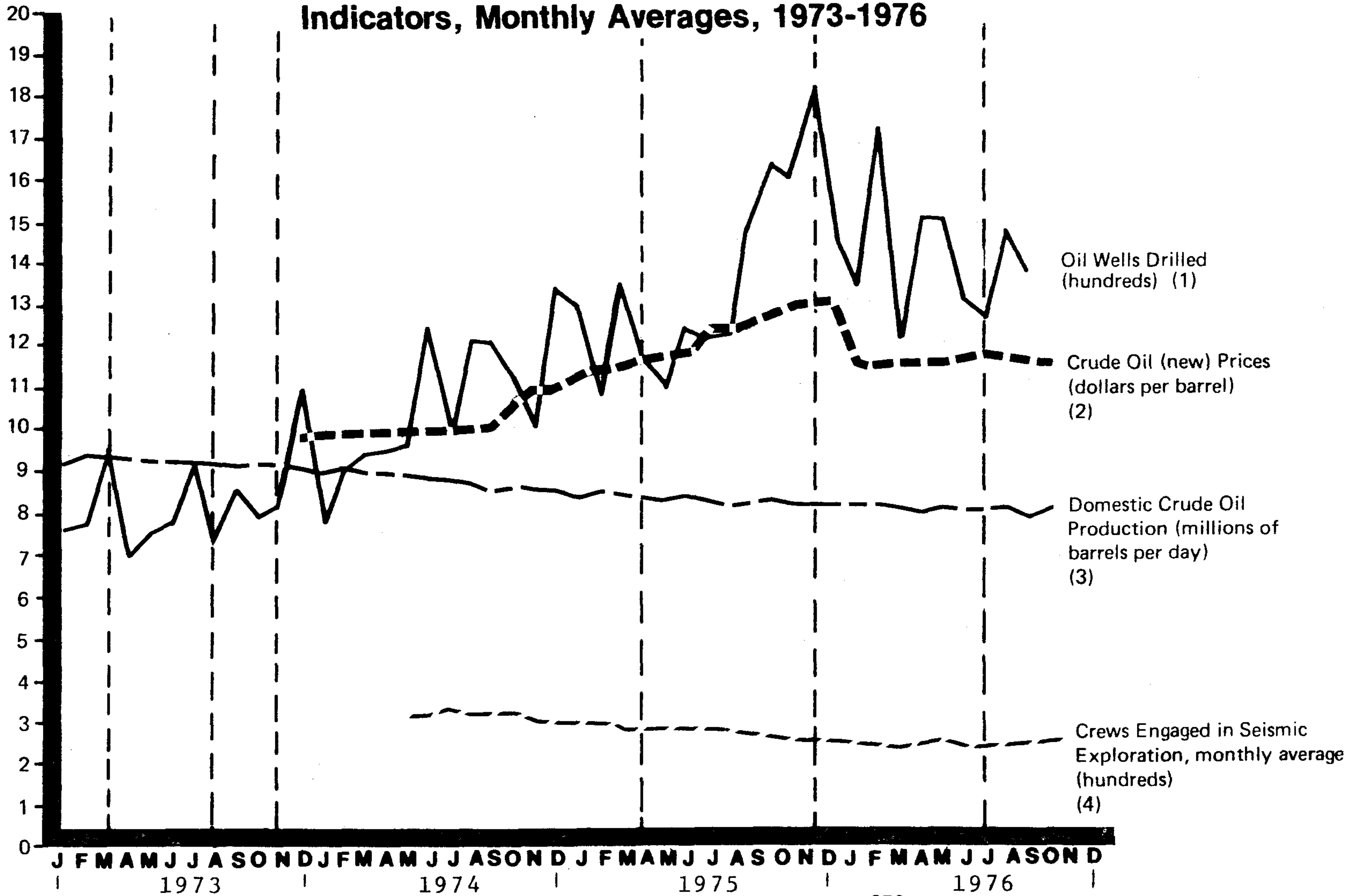
The next line illustrates the average of prices for all domestic crude oil during this period.

The lowest line on the graph demonstrates price trends displayed by old oil until January 1976, and continues with lower tier prices for subsequent months. The abrupt increase in the old oil price late in 1973 was the effect of a rule change adding a dollar per barrel to the allowable price. The average price dropped slightly at the beginning of 1976 in response to the regulation issued pursuant to the EPCA and required a short period to find a steady level.

Figure IV-3 depicts detailed exploration, production and price data for the period 1973 to 1976. It shows that drilling has declined somewhat since implementation of the ECPA in February 1976, but seismic activity does not show a similar response. The sharp decline in the upper tier prices resulting from the crude oil price rollback in February 1976 clearly correlates with the falling-off in drilling activity, but the time period analyzed is too short to allow a cause-effect inference to be drawn.

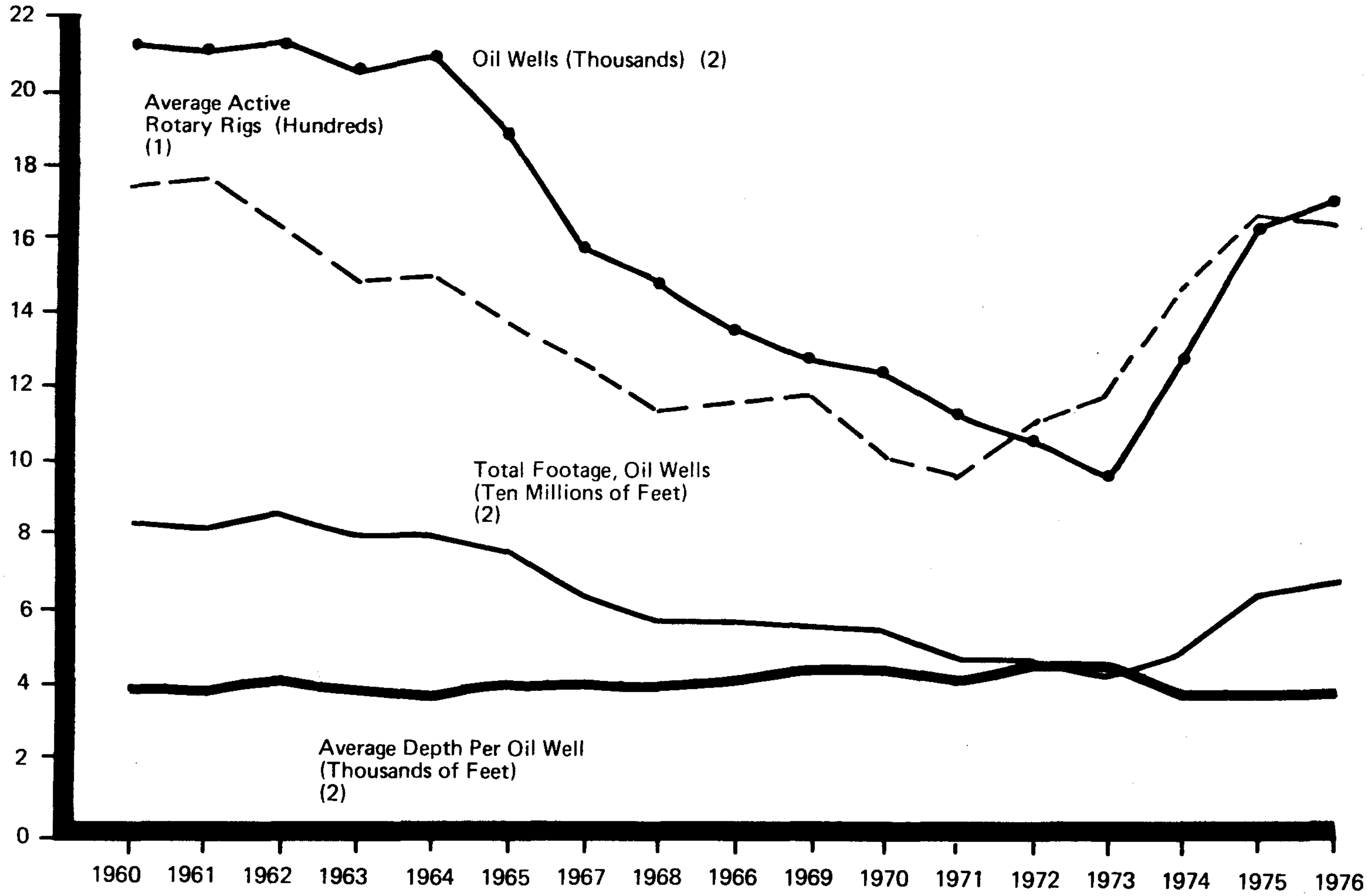
Figure IV-4 (drilling indicators) indicates a sharp increase in oil wells drilled and rotary rig activity following the OPEC crude oil price increase of the early 1970's which caused domestic crude oil prices to increase in response. It also shows a slight decline in rotary

FIGURE IV-3 **Domestic Crude Oil Production and Production Indicators, Monthly Averages, 1973-1976**



Sources: (1) Monthly Energy Review; (2) January 1974—January 1976, MER; February 1976—November 1976, P-124-MO; (3) 1973—January 1976, MER, February—November 1976, FEA P-124-MO; (4) MER.

FIGURE IV-4 **Drilling Indicators, Annual Averages, 1960-1976**



Source: (1) Hughes Tool Company; (2) A.P.I.

rig activity and an apparent leveling off of increased drilling since implementation of the EPCA. Again, it may be premature to draw conclusions from such a short period of data.

Close-Up View of Indicators

The previous section summarized the general analysis and findings of this chapter. In order to place these findings in perspective, production data and indicators are examined over time in detail to support the summary analysis.

Supply Trends: 1960-1976

Domestic crude oil production showed relatively healthy increases in every year from 1960 to 1970, but thereafter production began to decline. By 1976 domestic production had returned to a level slightly below that of 1966. The rate of decline in 1976, however, was somewhat less than the rate of decline in the two previous years. (Table IV-1 and Figure IV-5). It is clear from comparing Figure IV-5 with Figure IV-7 that there is no immediate relationship between price alone and production alone.

TABLE IV-1

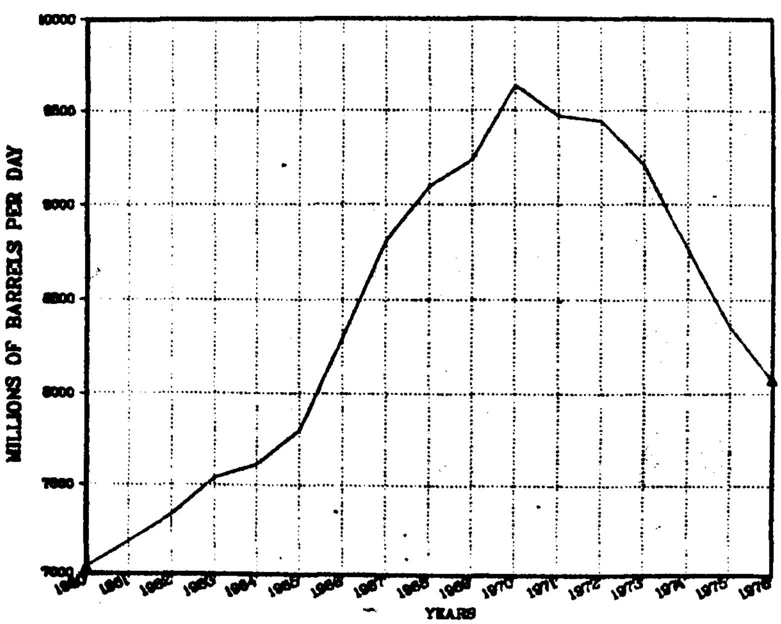
Domestic Crude Oil Production: 1960-1976

Year	MB/D	% Change From Pervious Year
1960	7,035	---
1961	7,183	2.1
1962	7,332	2.1
1963	7,542	2.9
1964	7,614	1.0
1965	7,804	2.5
1966	8,295	6.3
1967	8,810	6.2
1968	9,096	3.2
1969	9,238	1.6
1970	9,637	4.3
1971	9,463	(1.8)
1972	9,441	(0.2)
1973	9,208	(2.5)
1974	8,774	(4.7)
1975	8,362	(4.7)
1976	8,078	(3.4)

Source: FEA

FIGURE IV-5

DOMESTIC CRUDE OIL PRODUCTION: 1960-1976



Source: FEA

Monthly production figures for the period of controls indicate similar characteristics (Table IV-2), but the rate of production decline in 1976 is clearly less than the 1974 rate of decline (Figure IV-6). 1975 and 1976 monthly production curves tend to be more irregular than 1974, but these irregularities do not correllate directly with revisions to the law of regulations.

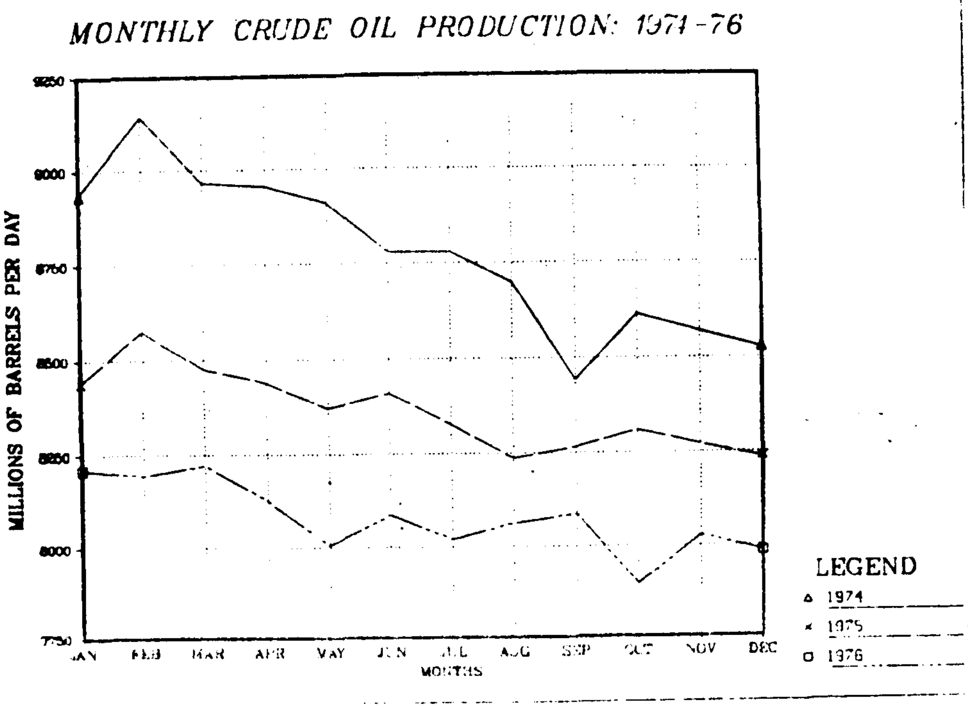
TABLE IV-2

Monthly Crude Oil Production: 1974-76
(MB/D)

Month	1974	1975	1976
January	8,934	8,439	8,211
February	9,142	8,575	8,196
March	8,965	8,476	8,223
April	8,954	8,440	8,129
May	8,911	8,371	8,005
June	8,780	8,409	8,089
July	8,730	8,327	8,022
August	8,699	8,237	8,065
September	8,443	8,266	8,090
October	8,611	8,310	7,894
November	8,569	8,271	8,029
December	8,527	8,239	7,986 (Est.)
Average	8,774	8,362	8,078 (Est.)

Source: Monthly Energy Review (1974, 1975, Jan., 1976)
FEA Form P 124-M-O (Feb., Dec. - 1976)

FIGURE IV-6



Source: Monthly Energy Review (1974, 1975, January 1976)
FEA Form P 124-M-O (Feb. - Dec., 1976)

Domestic oil production was curtailed by governmental authority until about 1972. Therefore, excess producing capacity was available as shown in Table IV-3. From 1960 to 1966 excess capacity was over 20 percent. After 1960 excess capacity started to decline, was essentially eliminated by mid-1972 and since then the domestic oil production industry has been operating at capacity commensurate with conservation and engineering constraints (Figure IV-7).

TABLE IV-3

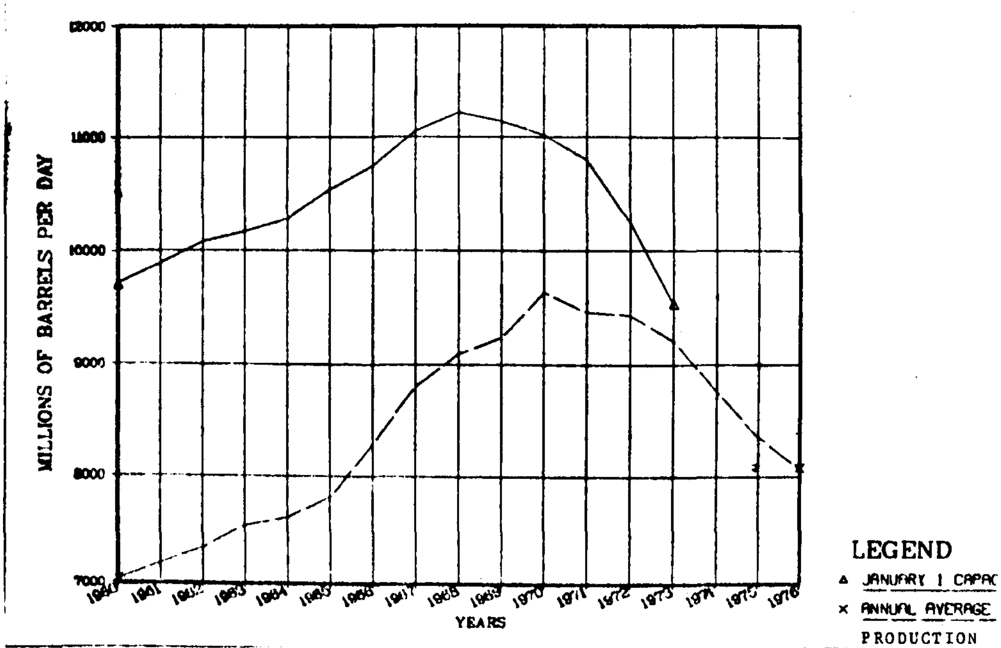
Crude Oil Productivity Capacity: 1960-1976

Year (Jan. 1)	Productive Capacity (MB/D)	Annual Average Production (MB/D)
1960	9,708	7,035
1961	8,982	7,183
1962	10,081	7,332
1963	10,169	7,542
1964	10,286	7,614
1965	10,534	7,804
1966	10,743	8,295
1967	11,050	8,810
1968	11,218	9,096
1969	11,137	9,238
1970	11,013	9,637
1971	10,794	9,463
1972	10,246	9,441
1973	9,535	9,208
1974	N.A.	8,774
1975	N.A.	8,362
1976	N.A.	8,078

Source: IPAA, FEA

FIGURE IV-7

CRUDE OIL PRODUCTIVITY CAPACITY: 1960-1976



Source: IPAA, FEA

Price Trends: 1960-1976

The average price of crude oil at the wellhead remained virtually constant (in nominal dollars) from 1960 to 1968, thereafter showing slow but steady growth through 1973, followed by the abrupt increases in 1974 and 1975 (Table IV-4) occasioned by similar increases in world market prices. In constant 1975 dollars, however, the wellhead price of crude oil decreased steadily (with slight interruption in 1971) from 1960 to 1972. The nominal price gains from 1968 to 1973 were offset by inflation during those years. It was not until the abrupt price increases during and after the embargo of 1973 and 1974 that the crude oil price in constant 1975 dollars showed a real gain over its 1960 level.

TABLE IV-4

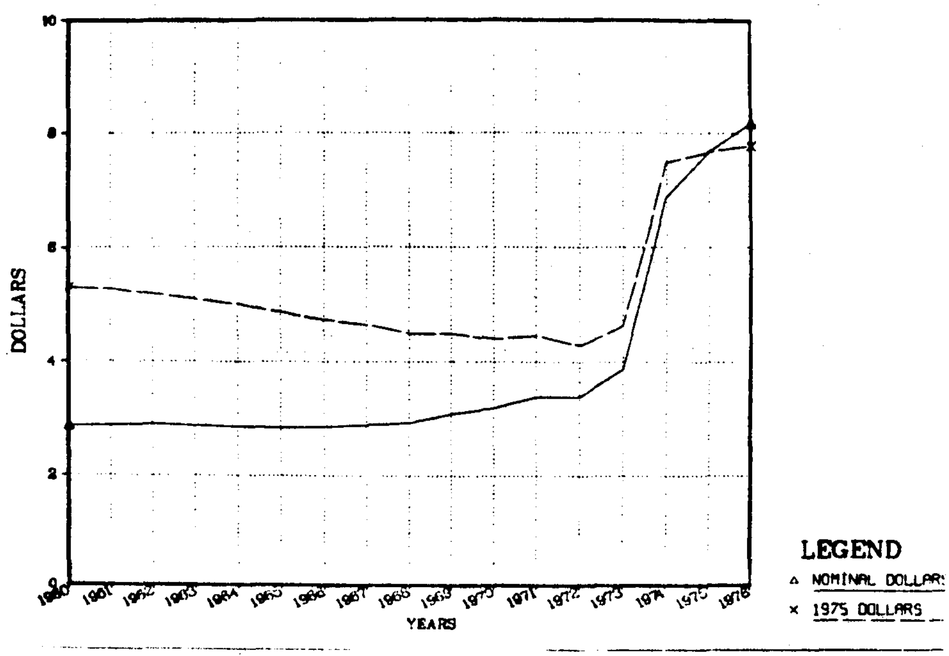
Domestic Average Crude Oil Prices: 1960-1976

Year	Nominal Dollars	1975 Dollars
1960	2.88	5.30
1961	2.89	5.27
1962	2.90	5.19
1963	2.89	5.10
1964	2.88	5.01
1965	2.86	4.86
1966	2.88	4.74
1967	2.91	4.65
1968	2.94	4.50
1969	3.09	4.50
1970	3.18	4.40
1971	3.39	4.46
1972	3.39	4.28
1973	3.89	4.64
1974	6.87	7.47
1975	7.67	7.67
1976	8.18	7.78

Source: IPAA (1960-1973)
FEA (1974-1976)

FIGURE IV-8

DOMESTIC AVERAGE CRUDE OIL PRICES: 1960-1976



Source: IPAA (1960-1973)
FEA (1974-1976)

Price Controls and Production

Prior to the onset of government regulations, the only differences in domestic crude oil prices had been a function of quality and location. The requirements of regulations, however, divided domestic oil into categories based on consideration of cost of production and provisions for incentives for increased production. The amount of domestic production priced in the various categories is shown in Table IV-5.

TABLE IV-5

Domestic Crude Oil Production by Control Category: 1974-1976

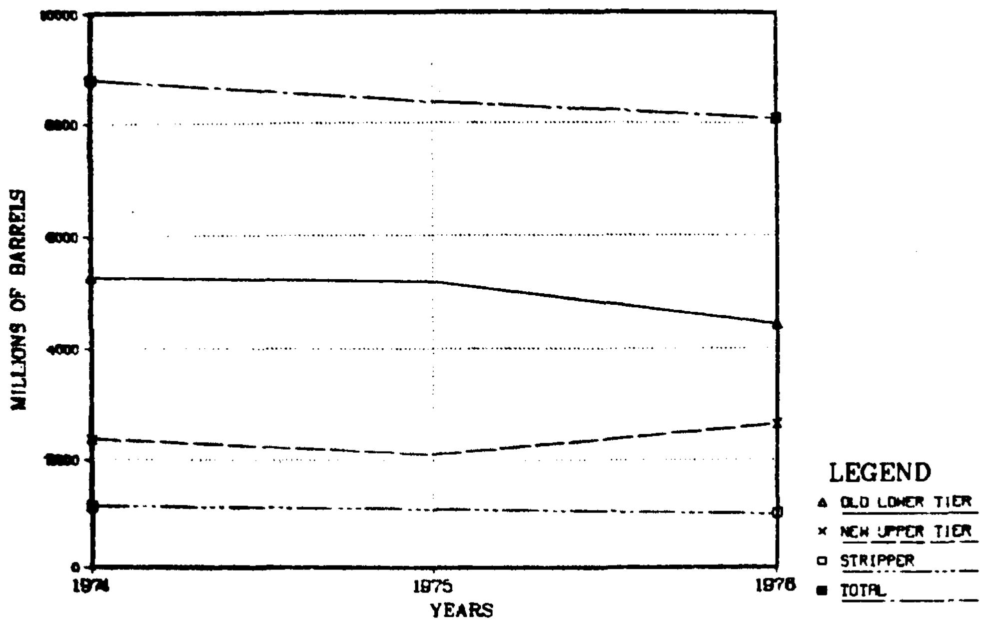
Year	Controlled (MB/D)				Uncontrolled (MB/D)		
	Lower Tier (Old)	Upper Tier (New)	Stripper	Total	New and Released	Stripper	Total
1974	5,264	-----	-----	5,264	2,381	1,129	3,510
1975	5,184	-----	-----	5,184	2,098	1,080	3,178
1976 (Est.)	4,442	2,646*	990**	8,078	-----	-----	-----

* Not controlled during January 1976.
** Controlled at upper tier price from February to September 1976. Thereafter not controlled.

Source: FEA

FIGURE IV-9

DOMESTIC CRUDE OIL PRODUCTION BY CATEGORY



Source: FEA

Montnly production figures during the period of controls (Table IV-6) do not reveal any strong response to the controls. The production of old (lower tier) oil declined under the pricing limitations, but the production of new and stripper well oil, which were not controlled in 1974 and 1975 also declined. The rate of decline of production of upper tier oil does not seem to have changed in response to price controls placed in it pursuant to the EPCA from the rate of decline shown by uncontrolled new oil in 1974 and 1975 (Figure IV-10). Although it would be interesting to examine monthly stripper well abandonment throughout the period of controls to explore in detail the effects of the EPCA on stripper well production, a source of data does not exist.

TABLE IV-6

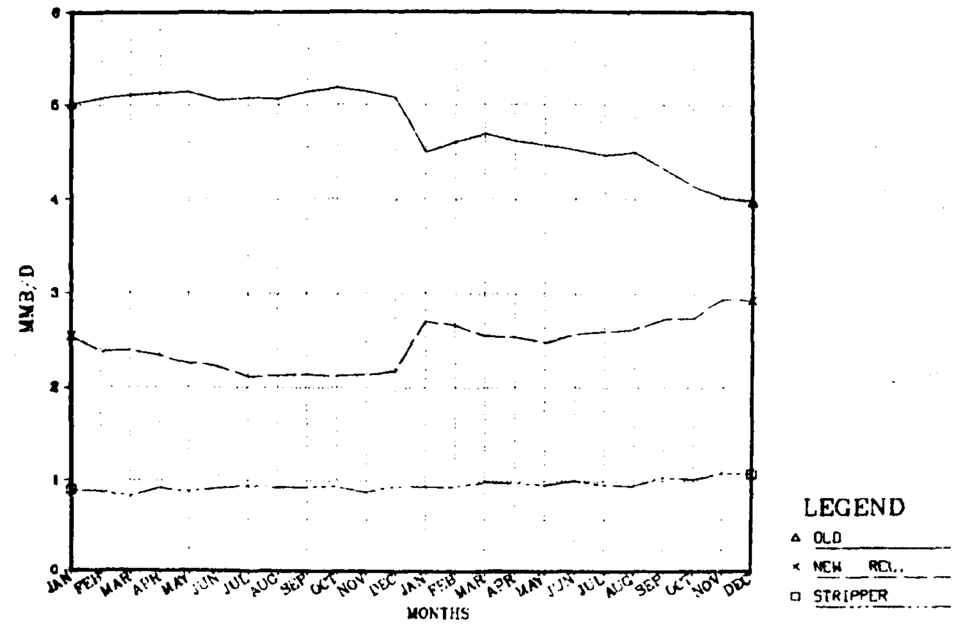
Monthly Production by Control Category*: 1975-1976
(MMB/D)

Month	1975			1976		
	Old	New & Released	Stripper	(Lower)	(Upper)	Stripper
January	(5.01)	2.54	0.89	(4.50)	2.71**	0.94
February	(5.07)	2.38	0.88	(4.60)	(2.66)	(0.94)
March	(5.10)	2.39	0.82	(4.68)	(2.55)	(0.99)
April	(5.12)	2.34	0.91	(4.61)	(2.54)	(0.98)
May	(5.13)	2.25	0.88	(4.57)	(2.48)	(0.96)
June	(5.05)	2.23	0.92	(4.52)	(2.57)	(1.00)
July	(5.07)	2.12	0.94	(4.46)	(2.60)	(0.96)
August	(5.06)	2.13	0.93	(4.49)	(2.62)	(0.95)
September	(5.13)	2.14	0.93	(4.32)	(2.73)	(1.04)
October	(5.18)	2.13	0.94	(4.14)	(2.74)	1.02
November	(5.13)	2.14	0.88	(4.01)	(2.94)	1.08
December	(5.07)	2.18	0.94	(3.98)	(2.93)	1.08

* Price-controlled categories in parenthesis.
** New and released oil volumes uncontrolled
Source: FEA Form P124

FIGURE IV-10

MONTHLY PRODUCTION BY CONTROL CATEGORY 1975-1976



Seismic Exploration

Inherent in the production of crude oil are very long lead times between the initial decision to explore or expand operations on a particular tract and the realization (if successful) of commercial production. Lead times of two to five years and longer, depending upon the exact circumstances, are common.

A typical sequence of events is as follows:

- select area
- conduct seismic tests
- drill exploratory wells
- field survey and plan
- drill developmental wells
- realize commercial production

- further develop fields (i.e., enhanced recovery)
- abandon property

Seismic activity is the best available indicator of basic exploration. The use of gravity, magnetic and other methods are not as definitive as modern seismology and are less used. Seismic exploration is normally measured in crew-months during a year. Crew months of geophysical exploration activity for 1960-76 are presented in Table IV-7 and Figure IV-11. There was a pattern of general decline in activity from 1960 through 1970 after which there was a general increase followed by a decline after 1974.

TABLE IV-7

U.S. Petroleum Seismic Exploration: 1960-1976

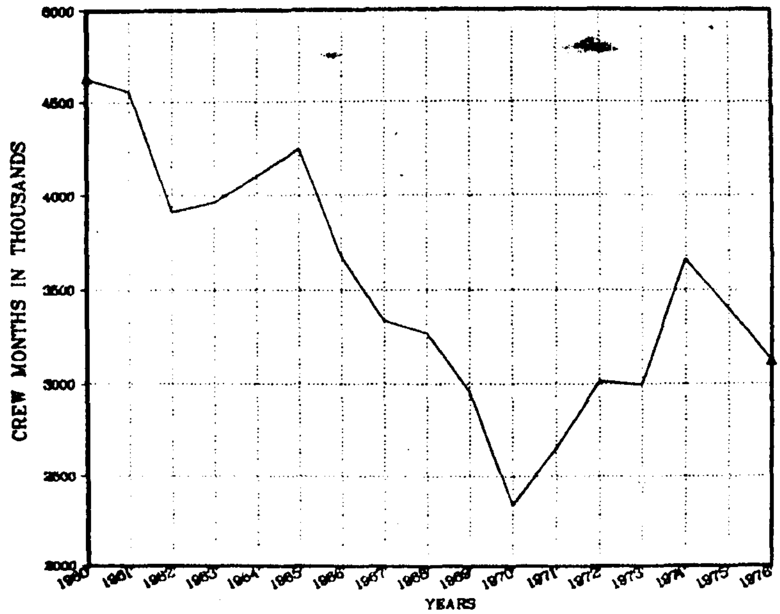
Year	Crew Months	% Change from Previous Year
1960	4,625	1/
1961	4,557	(1.5)
1962	3,915	(14.1)
1963	3,966	1.3
1964	4,102	3.4
1965	4,247	3.5
1966	3,672	(13.5)
1967	3,337	(9.1)
1968	3,268	(2.1)
1969	2,958	(9.5)
1970	2,340	(20.9)
1971	2,655	13.5
1972	3,016	13.6
1973	2,999	(0.6)
1974	3,662	22.1
1975	3,403	(7.1)
1976 (Est.)	3,125	(8.2)

Source: Society of Exploration Geophysicists, Annual Reports

1/ Numbers in parenthesis note negative growth rate.

FIGURE IV-11

U.S. PETROLEUM SEISMIC EXPLORATION: 1960-1976



Source: Society of Exploration Geophysicists, Annual Reports

Seismic activity is somewhat seasonal in nature, making it difficult to assess the recent trends in monthly seismic activity (Table IV-8 and Figure IV-12). However, the slope of the 1976 curve strongly suggests some recovery from the continuous trend of decline which set in after 1974. The mid-year increase in activity appears higher than would have been expected from a purely seasonal trend, and the autumn and winter rate of change appears to overcome normal seasonal factors. If the 1976 trend continues it could be interpreted as a response to the ability of the industry to forecast future price levels with certainty based on the composite domestic price regulated in accordance with the EPCA.

TABLE IV-8

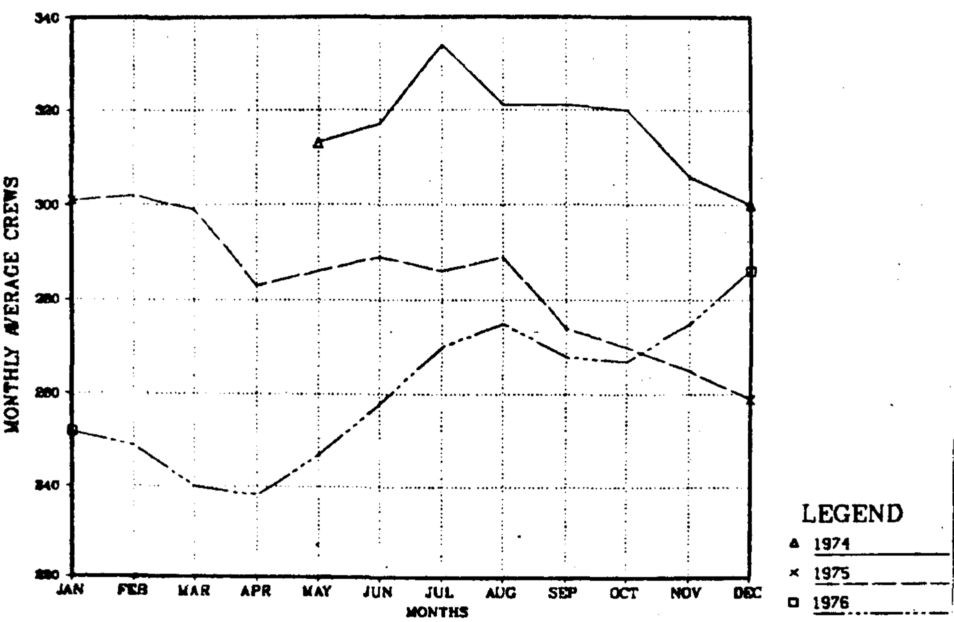
Crews Engaged in Seismic Exploration: 1974-1976

Month	1974	1975	1976
January	NA	301	252
February	NA	302	249
March	NA	299	240
April	NA	283	238
May	313	286	247
June	317	289	258
July	334	286	270
August	321	289	275
September	321	274	268
October	320	270	267
November	306	265	275
December	300	259	286
Average	305	284	260

Source: Monthly Energy Review

FIGURE IV-12

SEISMIC EXPLORATION ACTIVITY: 1974–1976



Source: Monthly Energy Review

Drilling Activities

Exploratory well drilling activity is another significant indicator of the response to production incentives and of production activity. Table IV-8 and Figure IV-13 show the exploratory wells drilled in the U.S. from 1960 to 1976. The absolute number declined relatively steadily from 1960 to 1971, rallied slightly in 1972 and 1973 and then began to increase significantly in 1974. The improvements after 1971 tend to correspond to the pattern of price increases during that period.

TABLE IV-9

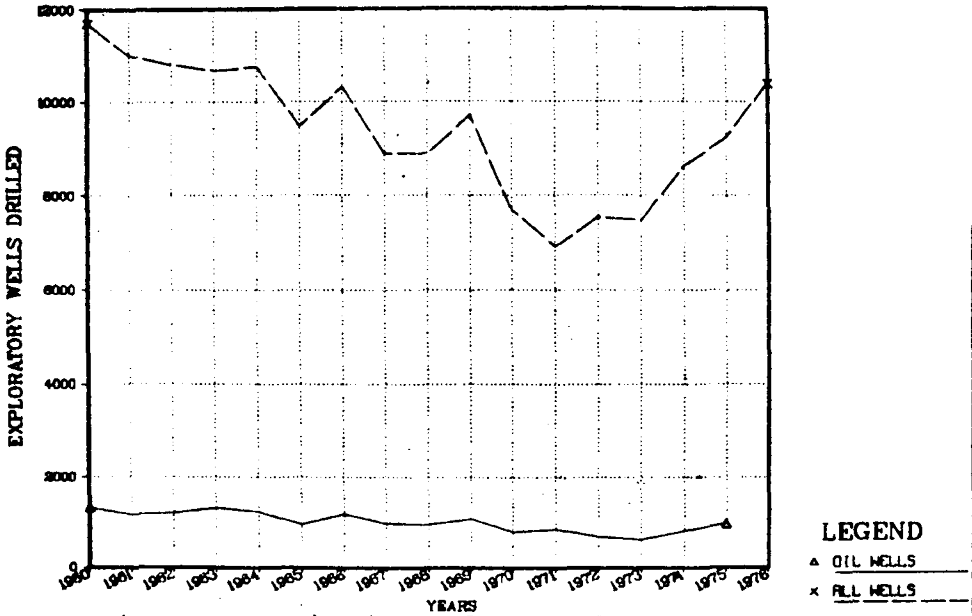
Exploratory Wells Drilled: 1960-1976

Year	Oil	Gas	Dry	Total	% Change From Previous Year
1960	1,321	868	9,515	11,704	---
1961	1,157	813	9,022	10,992	(6.1)
1962	1,211	771	8,815	10,797	(1.8)
1963	1,314	664	8,688	10,664	(1.2)
1964	1,219	577	8,951	10,747	0.8
1965	946	515	8,005	9,466	(11.9)
1966	1,196	698	8,419	10,313	8.9
1967	986	532	7,360	8,878	(13.9)
1968	954	486	7,439	8,879	---
1969	1,084	616	8,001	9,701	9.3
1970	790	481	6,422	7,693	(20.7)
1971	851	437	5,834	6,922	(10.0)
1972	684	601	6,254	7,539	8.9
1973	619	900	5,947	7,466	(0.7)
1974	814	1,195	6,610	8,619	15.4
1975	972	1,171	7,071	9,214	6.9
1976	NA	NA	NA	10,385(Est.)	12.7

Source: American Association of Petroleum Geophysicists and American Petroleum Institute

FIGURE IV-13

EXPLORATORY WELLS DRILLED: 1960–1976



Source: American Association of Petroleum Geophysicists and American Petroleum Institute

Drilling of development wells is a more accurate indicator of short-term future production than drilling of exploratory wells, although both activities are influenced by many external factors, such as the availability of drilling rigs, availability of capital, Federal income tax policy, and similar forces. Development wells showed approximately the same pattern as exploratory wells, with some general stability from 1960 to 1965, a general decline from 1965 to 1971 and slight growth thereafter, sharpening in 1974 (Table IV-10 and Figure IV-14). The marked increase in drilling of development wells is not so much directly related to prior finds from exploratory drilling as it is to the incentive provided by the "released" oil concept in 1974 and 1975, which encouraged development drilling in existing fields.

TABLE IV-10

Development Wells Drilled: 1960-1976

Year	Oil	Gas	Dry	Total	% Change From Previous Year
1960	19,865	4,390	8,059	32,314	---
1961	19,944	4,851	8,084	32,879	1.7
1962	20,038	5,077	7,867	32,982	0.3
1963	18,974	4,087	7,661	30,722	(6.9)
1964	19,401	4,278	8,537	32,216	4.9
1965	17,815	4,209	8,020	30,044	(6.7)
1966	15,584	3,679	6,808	26,071	(13.2)
1967	14,343	3,127	5,886	23,356	(10.4)
1968	13,377	2,970	5,373	21,720	(7.0)
1969	13,284	3,467	5,735	22,486	3.5
1970	12,230	3,359	4,838	20,427	(9.2)
1971	11,207	3,393	4,329	18,929	(7.3)
1972	10,622	4,237	4,803	19,752	4.3
1973	9,283	5,485	4,358	19,126	(3.2)
1974	11,970	6,045	5,064	23,079	20.7
1975	15,436	6,429	6,176	28,021	21.4
1976	NA	NA	NA	29,541 (Est.)	5.4

Source: American Association of Petroleum Geologists and American Petroleum Institute

FIGURE IV-14

DEVELOPMENT WELLS DRILLED: 1960–1976

Source: American Association of Petroleum Geologists and American Petroleum Institute

Examining both exploratory wells and development wells as a group it can be observed that the pattern of decline in activity in total wells remained virtually uninterrupted until 1971, but that the gas well decline showed some recovery beginning in 1972, increasing significantly in 1973 and after, while oil well activity took a further abrupt dip in 1973, recovering in 1974 and thereafter . (Table IV-10). It should be noted that the price of intrastate gas increased sharply beginning in 1972 while the price of crude oil increased much more slowly during 1972 and 1973. Thus, the recent variations in gas and oil well drilling activities (Table IV-11 and Figure IV-15) are directly related to price changes during 1968 to 1976, but production is not.

TABLE IV-11

Total Wells Drilled: 1960-1976

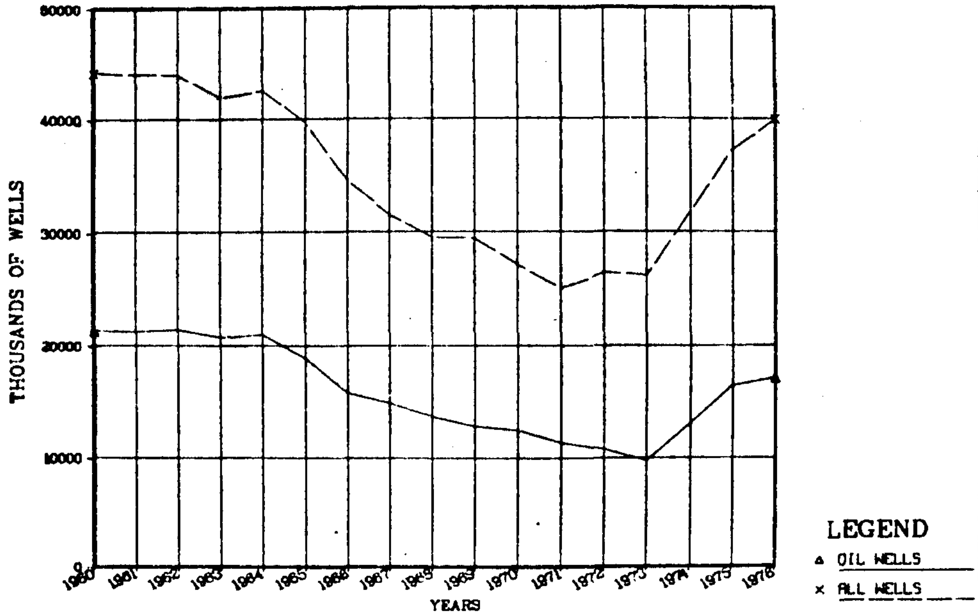
Year	Oil	Gas	Dry	Total	% Change from previous year
1960	21,294	5,262	17,577	44,133	1/
1961	21,204	5,674	17,110	43,988	(0.3)
1962	21,402	5,858	16,684	43,944	(0.1)
1963	20,678	4,779	16,386	41,853	(4.8)
1964	21,012	4,874	17,600	42,486	1.5
1965	18,857	4,772	15,967	39,596	(6.8)
1966	15,856	4,060	14,605	34,521	(12.8)
1967	14,985	3,558	13,045	31,538	(8.6)
1968	13,767	3,324	12,485	29,576	(6.2)
1969	12,915	3,927	12,639	29,481	0.3
1970	12,547	3,844	10,786	27,177	(7.8)
1971	11,405	3,679	9,956	25,040	(7.9)
1972	10,753	5,086	10,604	26,443	5.6
1973	9,705	6,427	10,112	26,244	(0.8)
1974	13,073	7,240	11,674	31,698	20.8
1975	16,408	7,580	13,247	37,235	17.5
1976 (Est)	17,108	9,032	13,786	39,926	7.2

Source: "Joint Association Survey of the U.S. Oil and Gas Producing Industry" Annual; American Petroleum Institute, Independent Petroleum Association of America, Mid-Continent Oil and Gas Association, (JAS)

1/ Numbers in parenthesis note negative growth rate.

FIGURE IV-15

TOTAL WELLS DRILLED: 1960–1976



Source: JAS, supra.

A closer examination of oil wells drilled during the period of price controls (1974-76) indicates a general and substantial increase in all wells drilled during that period, continuing the trends begun in 1973 which reversed a decade of declining activity (Table IV-12). The response is obviously a response to general price increases. The curve in 1976 shows a trend of leveling off of drilling activity (Figure IV-16), but it is impossible to predict from these data the effect that EPCA price regulations will have on future drilling activity. The fact is, nevertheless, that drilling increases stabilized at the same time that upper tier prices were brought under controls.

TABLE IV-12

Monthly Oil Wells Drilled: 1974-1976

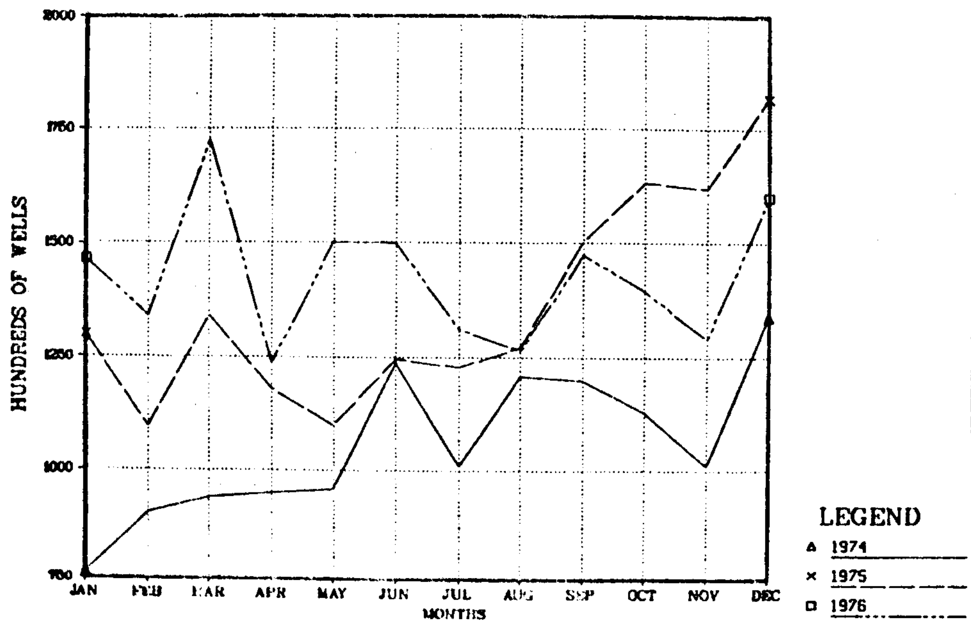
Month	1974	1975	1976	
January	763	1,299	1,465	
February	901	1,097	1,341	
March	936	1,341	1,726	
April	947	1,181	1,237	
May	957	1,100	1,501	
June	1,238	1,246	1,500	
July	1,008	1,229	1,312	
August	1,210	1,272	1,265	
September	1,200	1,504	1,474	
October	1,131	1,633	1,396	
November	1,008	1,619	1,291	
December	1,339	1,817	1,600	(Est.)
Total*	12,784	16,408	17,108	(Est.)

Source: Monthly Energy Review, FEA estimates.

* Totals reflect subsequent data revisions and therefore may not agree with cumulative monthly data.

FIGURE IV-16

MONTHLY OIL WELLS DRILLED: 1974–1976



Source: Monthly Energy Review, FEA estimates.

The annual number of oil well completions declined steadily during the decade from 1963-1973, as shown in Tables IV-11 and IV-13. After 1973 the number of oil well completions started to increase and continued to do so at a rate of about 33 percent per year through 1975. The volume of oil reserves found by drilling in the 1963-1973 decade averaged over 65,000 barrels per well. However, since 1973 the volume of reserves attributable to each new well completion has been declining by about 12 percent per year. The decline in reserves per well is unlikely to continue much longer since the minimum reserves required for a profitable well will be approached.

It appears, however, that the existence of crude oil price controls, and perhaps the form of the controls (i.e., the exemption of new and released oil in the 1973-1975 period) contributed to the development of smaller, usually shallower reserves at the expense of the development of the larger, normally deeper and more risky, reserves. The likelihood is that the restraint on the price of old (or lower tier) oil may be encouraging the diversion of drilling activity to areas that can reasonably be expected to produce new (or upper tier) oil at a relatively low cost, albeit in relatively small volumes, and discouraging drilling activity in areas in which realization of production may entail greater costs and a longer time lag, even though they might result in larger reserve additions and greater production. Table IV-13 and Figure IV-17 illustrate this point by comparing reserve additions due to drilling with oil well completions.

TABLE IV-13

Reserve Additions Due to Drilling: 1960-1976

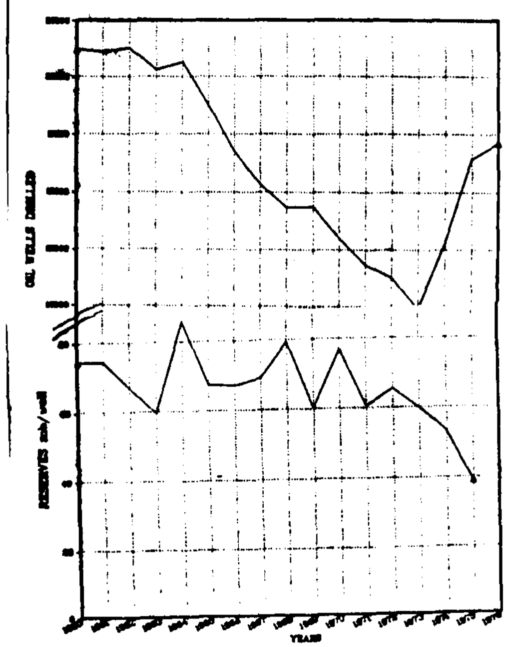
Year	Oil Well Completions	Reserves added* Billion barrels	Reserves per Well (Thousand barrels)
1960	21,186	1.577	74.4
1961	21,101	1.571	74.4
1962	21,249	1.422	66.9
1963	20,288	1.208	59.5
1964	20,620	1.766	85.7
1965	18,761	1.265	67.4
1966	16,780	1.125	67.0
1967	15,329	1.061	69.2
1968	14,331	1.135	79.2
1969	14,368	0.862	60.2
1970	13,020	1.002	77.0
1971	11,858	0.718	60.6
1972	11,306	0.738	65.3
1973	9,902	0.594	60.0
1974	12,784	0.683	53.4
1975	16,408	0.641	39.1
1976	17,108	NA	NA

* Includes discoveries and extensions to existing fields. North Slope reserve additions omitted.

Source: IPAA and API.

FIGURE IV-17

RESERVE ADDITIONS DUE TO DRILLING: 1960-1976



Source: IPAA and API

There is a general correlation between active rotary drilling rigs and drilling statistics. Table IV-14 and Figure IV-18 show the monthly average active rotary rigs in the U.S. for the period 1960 to 1976. Rotary rig activity is somewhat seasonal, but it is difficult to generalize about the pattern from an examination of monthly figures for the period. Active rigs, like drilling, declined gradually after 1960, reaching a low point in 1971, after which substantial recovery occurred which increased even more sharply in 1974. Because rotary rig activity returned to 1960 levels in 1975, land based rigs were being used at full capacity, but rig availability appears adequate now. Offshore drilling rigs are currently at a low level of utilization, possibly because of the lack of good drilling prospects.

TABLE IV-14

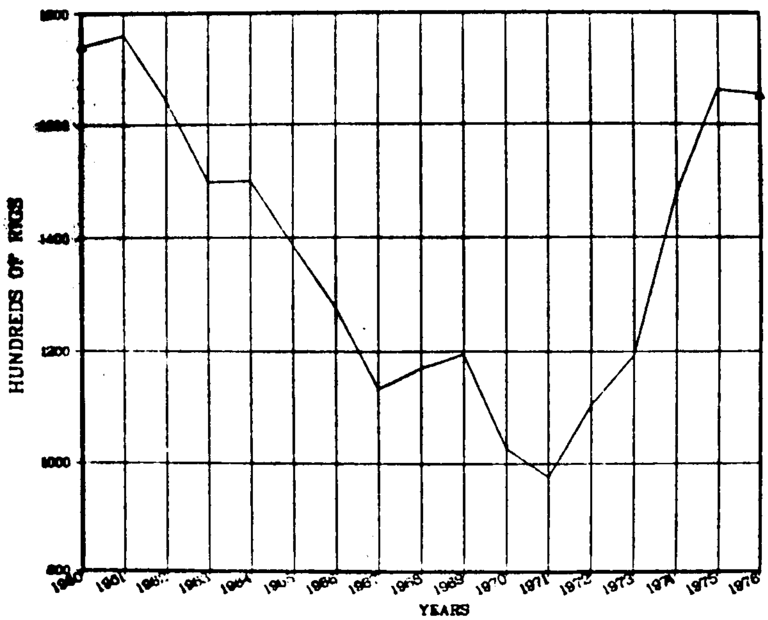
Monthly Average Active Rotary Rigs: 1960-1976

Year	Number	% Change from previous year
1960	1,748	
1961	1,761	0.7
1962	1,641	(6.8)
1963	1,499	(8.7)
1964	1,501	0.1
1965	1,387	(7.6)
1966	1,277	(7.9)
1967	1,135	(11.1)
1968	1,171	3.2
1969	1,195	2.0
1970	1,028	(14.0)
1971	976	(5.1)
1972	1,107	13.4
1973	1,194	7.9
1974	1,475	23.5
1975	1,660	12.5
1976	1,653	(0.4)

Source: Hughes Tool Co.

FIGURE IV-18

MONTHLY AVERAGE ACTIVE ROTARY RIGS IN U.S.



Source: Hughes Tool Co.

A close-up of rotary rig activity during the period of crude oil price controls is provided in Table IV-15 and Figure IV-19. Examination of monthly rig activity indicates that the slight decline in 1976 rotary rig activity identified in Table IV-14 and Figure IV-18 is probably not indicative of a general downward trend but is a resumption, in the first three months of 1976, of the normal seasonal drop-off of activity which had not been occurring in 1974 and 1975. Activity increased rapidly after April of 1976 and was at a three-year high in November of 1976.

The drop-off in rotary rig activity in the first three months of 1976 may also be related to enactment of the EPCA. The industry generally believed that the EPCA would not be enacted and, following enactment believed that the President would veto any measure that entailed a rollback in domestic crude prices. Following the signing of the bill into law, industry uncertainty existed as to the form of regulatory implementation of the composite price provisions of the EPCA. Once the escalator provisions were put into effect, however, and the industry was able to identify a reasonably long-term trend in crude oil price controls, rotary rig activity resumed the pattern of increase which had been established in previous years and, by August of 1976, reestablished itself at higher monthly levels than in the prior two years.

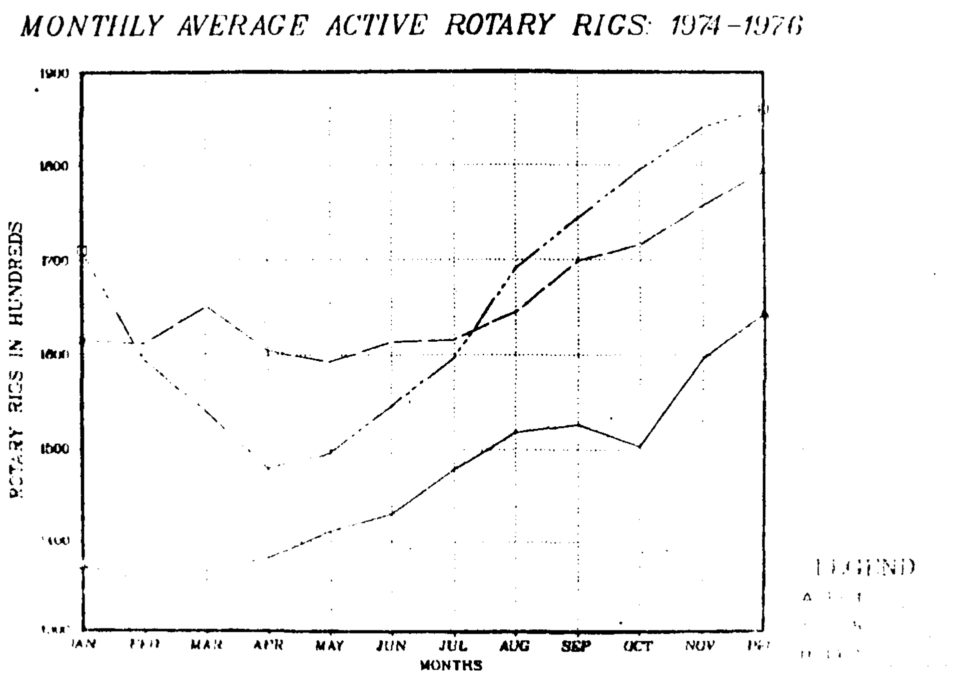
TABLE IV-15

Average Active Rotary Rigs: 1974-1976

Month	1974	1975	1976
January	1,372	1,615	1,710
February	1,355	1,611	1,594
March	1,367	1,651	1,540
April	1,381	1,604	1,480
May	1,412	1,592	1,496
June	1,432	1,613	1,546
July	1,480	1,616	1,597
August	1,518	1,645	1,691
September	1,527	1,699	1,744
October	1,504	1,716	1,794
November	1,596	1,757	1,840
December	1,643	1,793	1,860
Annual Average	1,475	1,660	1,653

Source: Hughes Tool Co.

FIGURE IV-19



Source: Hughes Tool Co.

Drilling Costs

Although the value of domestic crude petroleum had been declining in real dollars between 1960 and 1973, the cost of drilling had been increasing in terms of real dollars. Drilling costs per foot had increased with inflation, and footage per well had also increased, so that the cost to bring in an average well had increased much faster than inflation alone would have caused. Table IV-16 displays these factors for oil wells.

TABLE IV-16

Drilling Costs of Oil Wells: 1960-1976

Year	Oil Wells	Footage (000)	Costs ($ 000)	Average Cost($) Per Well	Per Foot
1960	21,294	84,034	1,110,701	52,160	13.22
1961	21,204	82,924	1,086,761	51,253	13.11
1962	21,402	86,494	1,160,472	54,223	13.42
1963	20,678	81,100	1,071,138	51,801	13.21
1964	21,012	80,989	1,062,995	50,590	13.13
1965	18,857	76,548	1,066,795	56,573	13.94
1966	15,856	65,554	985,754	62,169	15.04
1967	14,935	59,934	995,368	66,647	16.61
1968	13,767	58,488	1,089,328	79,126	18.63
1969	12,915	57,934	1,117,128	86,499	19.28
1970	12,547	56,417	1,088,057	86,718	19.29
1971	11,405	48,535	894,505	78,431	18.41
1972	10,753	48,400	1,005,471	93,506	20.77
1973	9,705	44,867	1,006,975	103,758	22.54
1974	13,073	51,765	1,440,326	110,176	27.82
1975	16,408	64,509	NA	NA	NA
1976 (Est.)	17,108	68,132	NA	NA	NA

Source: "Joint Association Survey of the U.S. Oil and Gas Producing Industry". American Petroleum Institute, Independent Petroleum Association of America, Mid-Continent Oil and Gas Associates.

FIGURE IV-20

OIL WELLS DRILLED--NUMBER AND FOOTAGE: 1960-1976

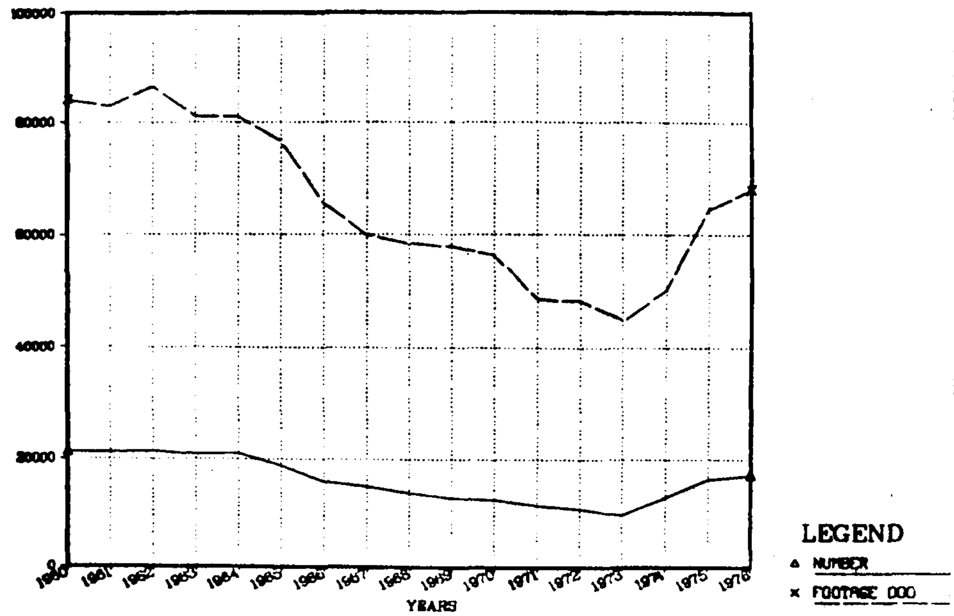
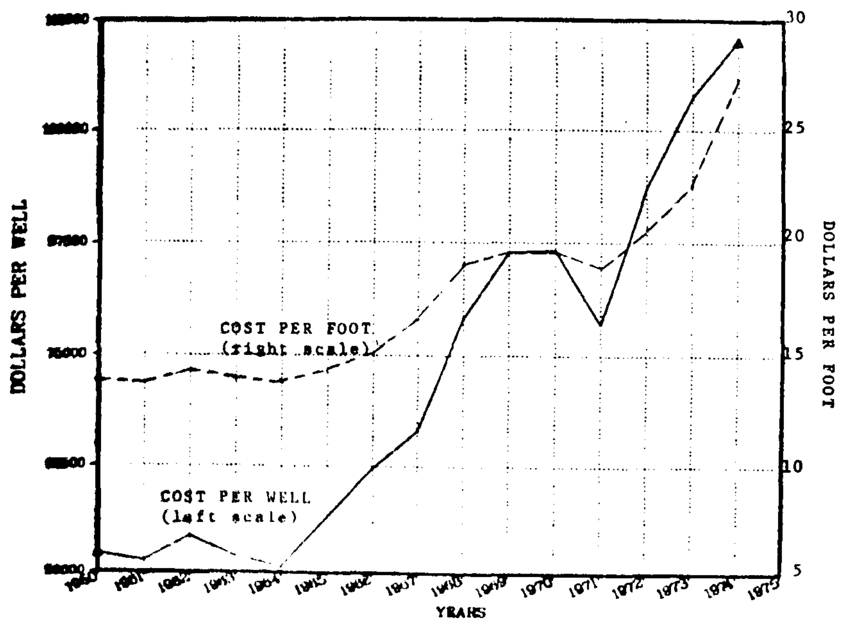


FIGURE IV-21

OIL WELLS DRILLING COSTS: 1960-1975



Further examination of Table IV-16 shows that capital devoted to oil well drilling remained relatively constant in nominal dollars from 1960 to 1973 and hence declined in real dollars, as had the price of domestic crude oil. This restraint on total capital, taken in conjunction with the fact that average depth per well increased from 3,946 feet in 1960 to 4,602 feet in 1973 (not in table) and that average nominal dollar drilling costs per foot increased by more than 70% in the same period, clearly accounted for the decrease in footage drilled and total wells drilled. In 1974 and thereafter, footage per well decreased to 3,398 feet per well in 1976, reinforcing the point that the structure of price controls and incentives has resulted in shallower in-field drilling.

A reasonable conclusion is that the price of crude oil must increase to accommodate not only inflation but increased drilling costs due to the higher cost per foot of deeper wells if capital is to be available to be devoted to exploration and development of more significant reserves.

Although capital invested in oil wells changed very little between 1960 and 1973 in nominal dollars, capital invested in dry holes in the same period increased from $773,539,000 in 1960 to $1,069,625,000 in 1973, an increase of more than 38%.[1/] Thus, crude oil prices must further

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1/ "Joint Association Survey..." supra.

reflect declines in the success rate in order to generate sufficient capital to maintain domestic crude oil production levels.

Reserves

Table IV-17 shows the trend in proved reserves and in reserve additions, from 1960 to 1976. Reserve additions include revisions, extensions, new field discoveries and new reservoir discoveries in old fields. In each year since 1968, production exceeded reserve additions except in 1970 when North Slope reserves were added. The result is that even with the addition of the massive North Slope reserves in 1970, proved reserves at the beginning of 1976 had fallen again to slightly above 1960 levels. Figure IV-22 plots the relationship between proved reserves, reserves added and production.

TABLE IV-17

Reserves and Discoveries: 1960-1976

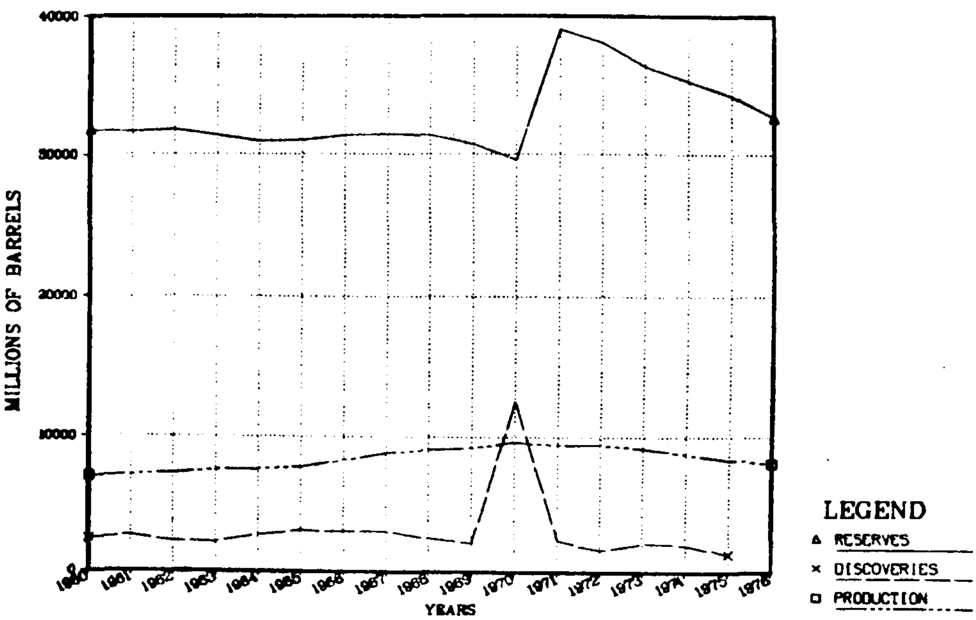
Year	Proved Reserves Beginning of Year (MMB)	Discoveries, Revisions and Extensions (MMB)
1960	31,719	2,365
1961	31,613	2,658
1962	31,759	2,181
1963	31,389	2,174
1964	30,970	2,665
1965	30,991	3,048
1966	31,352	2,964
1967	31,452	2,962
1968	31,377	2,455
1969	30,707	2,120
1970	29,632	12,689*
1971	39,001*	2,318
1972	38,063	1,558
1973	36,339	2,146
1974	35,300	1,994
1975	34,250	1,318
1976	32,682	NA

* Alaska North Slope Added

Source: IPAA

FIGURE IV-22

RESERVES, DISCOVERIES AND PRODUCTION: 1960-1976



Source: IPAA

Of the remaining domestic crude oil reserves, 72.3 percent are in the 100 largest fields. These reserves are primarily in "giant" oil fields -- those initially containing over 100 million barrels of recoverable oil. The annual discovery rate of giant oil fields is shown in Table IV-18 and Figure IV-23. The finding rate for these fields has decreased since the decade of the 1930's, when 63 giant fields were discovered onshore, to 11 in the decade of the 1960's, all but one of which was offshore.

TABLE IV-18

Giant Oil Fields Discovered 1900-1972
(100 Million Barrels of Recoverable Oil or More)

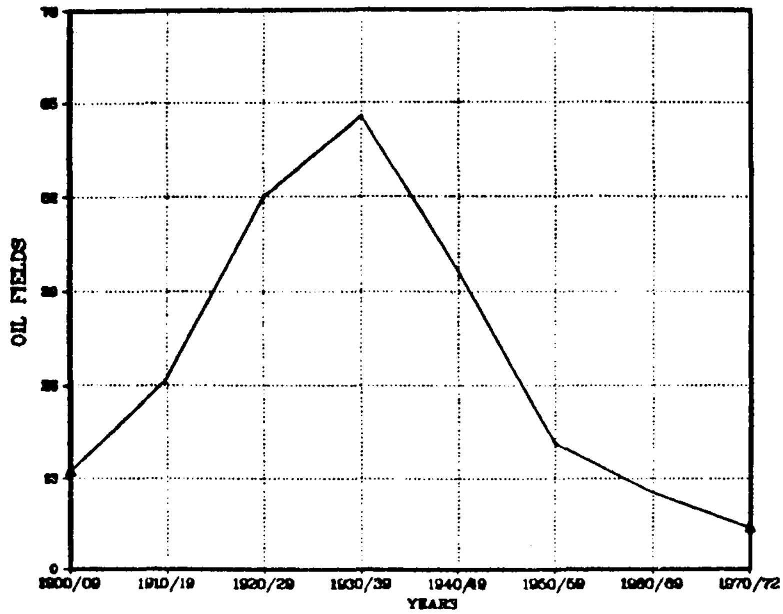
Year	Fields	Year	Fields	Year	Fields	Year	Fields
1900	1	1920	4	1940	7	1960	0
1	2	1921	3	1941	3	1961	0
2	1	1922	4	1942	3	1962	2*
3	1	1923	3	1943	1	1963	2*
4	2	1924	3	1944	8	1964	1*
5	3	1925	3	1945	5	1965	1+2*
6	2	1926	8	1946	1	1966	0
7	0	1927	5	1947	3	1967	1*
8	1	1928	12	1948	5	1968	2*
9	1	1929	7	1949	6	1969	0
10	3	1930	7	1950	3	1970	1+3*
11	2	1931	8	1951	6	1971	1*
12	3	1932	2	1952	2	1972	1
13	1	1933	4	1953	2		
14	2	1934	9	1954	0		
15	2	1935	6	1955	1		
16	3	1936	6	1956	2		
17	2	1937	7	1957	1		
18	4	1938	3	1958	0		
19	5	1939	11	1959	1*		

*Offshore

Source: Oil and Gas Journal; American Petroleum Institute; American Association of Petroleum Geologists; International Association of Petroleum Landmen.

FIGURE IV-23

GIANT OIL FIELDS DISCOVERED SINCE 1900
(100 MMB RECOVERABLE OIL OR MORE)



Source: Oil and Gas Journal; American Petroleum Institute; American Association of Petroleum Geologists; International Association of Petroleum Landmen.

Other Factors

Any analysis of crude oil supply and indicators of exploration and production activity must take into account the many other factors causing changes in the industry. Over the period discussed in this report, there are three other major factors operating which affect oil industry operations.

Probably the major consideration affecting exploration and production since 1960 has been the declining number and quality of geological prospects[1/] in the historical petroleum provinces. Domestic production and exploration activity in producing areas will be even more constrained in the future by this decline of prospects. This has been a factor in the production rate decline which started in 1970. Future oil discoveries in these extensively explored provinces are expected to be smaller and/or at greater depths where deeper geological prospects exist. Oil produced under these constraints will be progressively more expensive.

Relatively unexplored areas exist in Alaska, both onshore and offshore, on the continental shelf areas of the lower 48 states, and in the Gulf of Mexico, where relatively virgin areas are beyond the shelf on the continental slope. These unexplored areas represent much higher cost operations than in the historical, continental lower 48 states, and lease availability depends on federal and state policy.

Federal income tax policy has been an important factor in petroleum operations. Historically, the industry operated under a percentage depletion allowance of 27.5 percent limited, on a lease basis, to 50 percent of net income. Public Law 91-172, on October 9, 1969, reduced the percentage depletion from 27.5 percent to 22 percent. It has been estimated that

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1/ Undrilled geological structures or other geological features in which hydrocarbons might logically be entrapped.

the reduction in retained earnings by the oil industry was about $700 million dollars annually out of exploration and production expenses of $5.6 billion, or 13 percent (IPAA). The law also denied percentage depletion to certain types of production payments and required them to be treated as loans.

Domestic crude oil production was increasing at about 4.4 percent per year during the decade prior to enactment of PL 91-172. Subsequently, production declined at about 2.3 percent per year. While the reduction in percentage depletion undoubtedly had an effect on oil production it is unlikely to have been sufficient to reverse the trend in oil production.

Public Law 94-12, effective January 1975, essentially repealed percentage depletion as historically applied to the oil industry. The 22 percent depletion was retained only for independent producers and royalty owners and applicable up to a maximum of 2000 barrels per day for properties owned continuously, prior and subsequent to January 1, 1975. Both the percentage depletion and the maximum production to which it may apply are reduced by stages in future years by the Act. It is estimated this law will reduce retained earnings by the oil industry by $3 billion annually (API).

The Tax Reform Act of 1976 contained provisions concerning the treatment of intangible drilling costs and certain types of loans for tax purposes. Effects of this change could mask the EPCA/ECPA influences considered in this report. However, it is estimated that EPCA/ECPA price controls reduced oil industry revenue by about $2 billion and retarded after-tax earnings by $1 billion in 1976.

Summary of Effects of Price Controls on Production

As can be seen in Figures IV-5 and IV-8, there is no identifiable immediate response of total crude oil production to price controls. The implementation of price controls in general has not exerted an observable effect upon production in the short run; neither did the freedom of new and released oil and stripper well oil from controls under the EPAA or the imposition of controls under the EPCA on new and stripper well oil have any observable effect on oil in that category.

The significant decrease in production of "old" (lower tier) oil in 1976 can be in part accounted for by a shift of "old" oil to "new" (upper tier) oil in the same year, allowed by definitional changes while implementing the composite domestic average price provisions of the EPCA. Stripper well oil, which had declined by 4.3% between 1974 and 1975, when it was allowed the world price pursuant to the EPAA, declined by 7.9% in 1976 when, for eight months, it was controlled at the upper tier price pursuant to the provisions of the EPCA before being exempt again by the

ECPA. (Table IV-5 and Figure IV-8.) The 1976 decline in stripper well production might reflect removal of the stripper well exemption, which may have had the effect of stopping some workovers, entry into waterflood projects and similar activities. However, the incentive to reclassify "old" oil as stripper well production is so pervasive that it masks any possible direct relationship of regulatory changes to production.

Since 1960, both the quantity and quality of geological prospects in existing petroleum provinces of lower 48 has been declining. Reserve additions each year since 1970 have decreased continuously, from 1.002 billion barrels per year in 1970 down to 0.641 billion barrels per year in 1975. Reserve additions per well have decreased even faster, dropping from 77 million barrels per well in 1970 to 39 million barrels per well in 1975. Though these phenomena may be attributed to the lack of new major petroleum provinces in lower 48, the existence of price controls as well as the enactment of Public Law 94-12 in January 1975, which essentially repealed the percentage depletion allowance for the oil industry, may have also contributed to the lack of activity to develop new reserves in high-cost and high-risk areas.

Drilling statistics give strong indications that, in recent years, most of the crude oil reserve additions developed were from smaller and/or shallower areas adjacent to existing major provinces instead of the larger, normally deeper, more risky and higher cost frontier areas. This can almost certainly be attributed to the influences of the EPAA price controls. Whether EPCA/ECPA amendments will reverse this trend has yet to be seen, but seismic exploration data and rotary rig activity figures show some promise of renewed attention to deeper reserves.

With the anticipated special treatment for tertiary recovery oil and Alaskan North Slope Oil and the continuous escalation of average oil price permitted by EPCA and ECPA, the continued decline of reserve additions may be reversed or, at least, slowed down subsequently. Although price incentives are a major factor in the consideration of investment by oil industry, both tax policy and engineering considerations have also heavily influenced decision-making for new reserves development.