Marginal Wells

A Report of the National Petroleum Council • July 1994

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Victor G. Beghini, Chairman, Committee on Marginal Wells

NATIONAL PETROLEUM COUNCIL

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U.S. DEPARTMENT OF ENERGY

Hazel R. O'Leary, *Secretary*

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to oil and natural gas or to the oil and gas industries.

Library of Congress Catalog Card Number: 94-69458

Printed in the United States of America

Table of Contents

Introduction

On December 20, 1993, Hazel R. O'Leary, Secretary of Energy, requested the National Petroleum Council (NPC) to examine and study the role of marginal wells in the nation's energy and economic future. The Secretary's letter specifically requested that the NPC's study "should consider the cost and benefits of tax incentives for maintaining production for marginal and stripper wells." The Secretary also requested that "the Council undertake an analysis of economic and other challenges that domestic producers face in maintaining marginal production." As requested by the Secretary, the study also includes an assessment of informational resources and specific policy recommendations for preserving access to oil and natural gas reserves from marginal wells. It was requested that this study be performed within a six-month period to be finalized by June 1994. (See Appendix A for a copy of the Secretary's letter.)

The Council established the Committee on Marginal Wells and appointed Victor G. Beghini, President, Marathon Oil Company, to chair the Committee. Reginald W. Spiller, Deputy Assistant Secretary, Fossil Energy, U.S. Department of Energy, served as Cochair. The Committee was assisted by a Subcommittee chaired by David C. Gerard, Marathon Oil Company, and cochaired by Leonard L. Coburn and Sandra L. Waisley of the Department of Energy (see Appendix B for rosters of the Committee and Subcommittee).

This report provides an historical overview of the domestic oil and gas industry with highlights that focus on conditions that have caused a proliferation of marginal wells during recent history. The report examines both physical and economic characteristics of producing wells in the domestic petroleum industry.

Understanding the historical background of the industry and the important role of marginal wells in the United States are key to the primary focus of this report. The report provides an evaluation of marginal well contributions to the national, state, and local economies, and to the domestic oil and gas industry. While the central theme of this report is maintaining marginal well production and the resource access these wells provide, it is important that the industry strive to continually replace reserves in order to remain a viable industry. In that regard, this report does not address important aspects of the industry such as infill and development drilling, exploration, offshore, and Alaska operations. Due to the scope of the study request and short time frame for conducting an analysis, the report focuses only on lower-48 onshore wells.

Further, the report provides an evaluation of various solutions to preserve marginal well production and proposed legislative/policy actions consistent with the evaluation. These proposed solutions are integral to the Secretary's request to "ensure that no potential contributor to our energy security and economic prosperity is overlooked."

This report relies heavily on the Energy Information Administration's (EIA) report entitled *Economic Analysis of Domestic Oil Production*. In addition to utilization of the findings in the EIA's report, the analysis model created by the EIA was used in conjunction with an ICF Resources model to simulate the cost and benefit impact of various incentives on marginal well production.

All of the production, well count, reserve values, etc., published in this report were taken from public or commercially available sources, e.g., API Statistics Book, DOE/EIA reports, Interstate Oil and Gas Compact Commission reports, Dwight's Energydata, Inc., and Petroleum Information Corp. Data quality and availability, summarized in Appendix C, are addressed throughout the report.

Executive Summary

WHY ARE MARGINAL WELLS IMPORTANT?

The nation has more than 500,000 marginal oil wells, which produce approximately 700 million barrels of oil equivalent per year, one-third of lower-48 onshore domestic production, representing $10 billion of avoided imports each year. These wells contribute nearly 80,000 jobs and generate close to $14 billion per year in economic activity.

Marginal wells are important contributors to the nation's energy supply and economic well-being. These wells help provide access to a known resource base of 350 billion barrels of oil, which is a target for recovery under an improved economic environment and enhanced oil recovery technology.

Many domestic oil and gas businesses, both large and small, rely on these marginal wells as the backbone of their operations. These operations, comprised of many producing leases, should be viewed as a small business struggling to survive in a global marketplace. However, as global market factors cause commodity prices to fluctuate, the economic viability of these wells is precarious. As a result, the backbone of these many businesses can collapse as decreasing oil prices destroy the contribution of marginal oil wells.

There is a growing recognition of the importance of marginal wells. Some producing states have enacted measures to preserve marginal well contributions to their economies. In December 1993, the Secretary of Energy requested that the National Petroleum Council conduct this study on marginal wells. In February 1994, a broad industry and bipartisan congressional coalition developed proposals aimed at preserving marginal wells. President Clinton, in a letter to Senator Boren on July 5, 1994, recognized the need "...to identify policies that can extend the margin of economic production..." which could include "provisions to extend the economic life of stripper wells onshore."

WHAT IS AT RISK?

Low prices endanger marginal wells. Their profitability is extremely sensitive to prices, operating expenses, and regulatory compliance costs. Almost two-thirds of the marginal wells, representing over 200 million barrels of annual production, could be lost during a period of sustained low oil prices.

Marginal wells are by definition endangered. As domestic oil production declines, oil and gas industry jobs are lost, and the trade deficit increases as more crude oil is imported. There are hundreds of thousands of marginal wells, each of which is a tiny economic engine, providing jobs, energy security, and state and federal tax and royalty revenues. It is important to recognize that marginal wells almost always run out of money before they run out of oil and gas. The danger in losing these wells is embodied in their collective loss. This would cause the country to lose the opportunity to take advantage of new technology and improved prices which are crucial in recovering a portion of the 350 billion barrels of resource.

WHAT MUST BE DONE TO PRESERVE MARGINAL WELL CONTRIBUTION?

The National Petroleum Council recommends the following:

- Marginal well credit
- Improved EOR credit
- Inactive well incentive
- Expensing of marginal well capital expenditures
- Regulatory, royalty, and cost relief.

Preserving marginal wells is central to our energy security. Neither government nor the industry can set the global market price of crude oil. Therefore, the nation's internal cost structure must be relied upon for preserving marginal well contributions.

This report recommends four federal income tax incentives to help preserve the contribution of marginal wells to the domestic economy. In order for these incentives to be fully effective, all of the recommended tax credits and deductions should be applicable to both regular and alternative minimum tax liability. Additionally, the marginal well credit should be transferable.

- A marginal well credit to allow a tax credit for a specified amount of daily production from marginal wells. This credit is intended to be a safety net. It would be phased in as the average domestic wellhead crude oil price falls below a specific level.

- An improved enhanced oil recovery credit to expand the current 15 percent tax credit for certain projects on marginal properties.

- An inactive well incentive to provide a 15 percent tax credit for qualifying expenditures incurred in reactivating wells that have been inactive for two or more years.

The following is an example of the range of costs and benefits over the next ten years of the above tax incentives.

Additional Production (MMBOE)	300–500
Jobs Added (Labor Years)	47,400--110,700
Additional State/Local Revenues ($MM)	300–900
Reduction in Trade Deficit ($MM)	3,700–7,500
GDP Added ($MM)	5,700–13,400
Credit Cost ($MM)	2,700--2,400

Other actions recommended include:

- Immediate expensing of all capital expenditures to encourage investment in needed equipment on marginal properties.

- Regulatory, royalty, and cost relief to help preserve the contribution of marginal wells by reducing the impact of increasing costs.

Implementation of the above recommendations is an investment in the domestic oil and gas industry, yielding specific economic and social benefits. The various recommendations, when taken in aggregate, provide these benefits in a cost-effective manner. Since the economic benefit of these proposals will accrue to the nation, the costs should be borne by society at large.

Findings, Conclusions, and Recommendations

FINDINGS

As domestic oil prices fall, nearly 175,000 marginal oil wells and associated production could be lost through abandonments from 1995 through 2004. Providing some of these wells with a safety net through federal tax credit mechanisms could result in 50,000 fewer abandonments, preservation of between 47,000 and 110,000 labor years, and a reduction in the trade deficit by $3.7 to $7.5 billion through avoided imports.

Each of the 479,000 oil wells producing less than 15 barrels of oil equivalent per day and all heavy oil wells are at risk when oil prices decline. These wells provide access to part of a nationwide known resource base of 350 billion barrels of oil. As wells are abandoned, access to a piece of this national resource is lost.

Each producing lease can be viewed as a small business, an economic engine, daily creating jobs, economic prosperity, and state and federal tax and royalty revenues. Ownership of these marginal well businesses is as diverse as society itself. Nearly 45,000 individuals are represented through the National Association of Royalty Owners and an additional 23,000 corporations including the small family run business to the large integrated company are integral to the domestic oil and gas producing industry.

Crude oil and natural gas prices, which are subject to large, unpredictable changes, both upward and downward, are a primary determinant of the economic life of all wells. In order to preserve access to the resource base, encourage continued production, and maintain industry jobs associated with domestic marginal properties, regardless of sudden price declines, incentives need to be provided to owners of marginal properties. This conclusion is based on the following findings:

- The U.S. domestic oil and gas industry is part of a global marketplace that must compete for capital investment to remain viable.
- An important national resource, which contributes to national energy security and benefits the nation's economic well-being, is at risk when prices decline.
- Marginal wells in the United States are at risk when price fluctuations result in negative cash flow at the wellhead.
- All operators own marginal wells.
- In 1992, there were approximately 500,000 marginal oil wells (defined below), which contributed about one-third of lower-48 onshore domestic production.
- Premature abandonment of marginal wells permanently eliminates access to reserves and resource potential available under higher prices and enhanced recovery technology.

- Marginal economics impact natural gas operations; however, data are not readily available to perform a quantitative analysis of the production costs of marginal gas wells.

- Marginal well policy deliberations should consider both oil and gas operations.

- Producing state governments have recognized the value of the industry to their states and have enacted legislation to preserve both marginal oil and gas well operations. These states have recognized that the benefits of such incentives on state revenue and economic health extend beyond the annual budget planning cycle.

- Environmental statutory and regulatory reform addressed jointly by industry and policymakers is needed to minimize the costs and optimize the results.

It is important that all marginal wells capable of contributing to the nation's oil and gas needs receive the benefit of incentives, regardless of the type of entity owning the property. The incentive concepts proposed in this report are intended to preserve production from marginal properties, encourage further development of these properties, accelerate enhanced oil recovery, bring inactive wells back into production, and limit premature well abandonment.

The national economy and the American people will be the primary beneficiaries of the incentive proposals set out in this report. The proposed solutions provide a safety net for marginal properties in periods of low prices and encourage capital investment in such properties. An underlying principle of this report is that the beneficiaries of the proposed solutions should bear the cost of the incentives when they are triggered by low price. No individual segment of society, industrial or commercial, should be singled out in order to offset the costs of these proposals.

Because of the low level of production from marginal properties, price declines can cause negative cash flow from the operation of such properties. Further, low prices preclude the creation of sufficient cash flow for production and environmental enhancement of the properties. Incentives are also needed to encourage continued investment in marginal properties to maintain and improve production, and to mitigate increased reliance on crude oil imports.

In order to ensure continued production from domestic marginal properties and provide a more competitive capital investment environment, regardless of the level of prices, meaningful regulatory, royalty, and cost relief measures, combined with federal and state income tax and investment incentives, are needed. Investment incentives could also encourage improved operation, and increased development, of marginal properties. Since the categorization of a property as a marginal property does not depend in any way on the type of entity owning the property, the incentives should be available to the marginal property itself without regard to the nature of the entity owning the property. In addition, the incentives must be designed in such a manner as to allow the *owner* of the marginal property to realize economic benefit from the incentive without having to enter into disruptive and costly transactions.

DEFINITIONS

Based on the analysis and review of marginal well characteristics during the preparation of this report, a well could be classified as marginal whenever estimated future revenues from the well are equal to or less than future anticipated operating costs, environmental costs, litigation costs, federal and state tax liabilities, lease maintenance, recovery of capital expenditures, and plugging and abandonment liability. Using this concept, a number of wells not normally considered marginal would be characterized as such. This subjective definition is difficult to utilize in practice, particularly for federal and state income tax purposes, but does provide a sound basis for understanding the true nature of a marginal well. Further, most legislative and administrative pronouncements regarding marginal production are based on "marginal properties," rather than "marginal wells," since most data are accumulated on a property basis (i.e., all wells operating on a lease or other property unit) rather than on a well basis, and management is generally at the property, rather than the well, level. Further, current federal income tax incentives are applied at the property, rather than the well, level. Many of the investment analyses conducted during preparation of this report address marginal wells, but are equally applicable to marginal properties. Accordingly, the incentives recommended in this report apply to both marginal properties and marginal wells, unless otherwise specified.

Based on the findings in this report, the most convenient definition of a marginal property for purposes of applying legislative and administrative incentives is an oil or gas property with wells that average 15 barrel equivalents of production per day or less, or which produces heavy oil. While, as recognized above and discussed further in Chapter Five, wells with larger amounts of production may be categorized as marginal because of their particular economic and physical characteristics, it is not practical to provide a legislative and administrative definition broad enough to cover every possible marginal property situation.

The definition of "marginal property" in this report is the same as the definition in the Internal Revenue Code of 1986 (see Appendix D), modified to include high water cut properties and to include injector wells for purposes of computing average daily production. The following properties are marginal properties under the expanded definition:

- Properties that have an average daily production of 15 barrel equivalents or less per well (injector wells being counted as wells on the property in calculating average daily production).

- Properties that have an average daily production of 25 barrel equivalents or less per well with produced water accounting for 95 percent or more of total production (injector wells being counted as wells on the property in calculating average daily production).

- Properties that produce heavy oil with an API gravity less than 20 degrees.

FEDERAL AND STATE INCOME TAX INCENTIVES

In addition to regulatory, royalty, and cost relief to aid in creating, or improving, cash flow from marginal properties, federal and state income tax incentives should be made available to the working interest owners of marginal properties in order to provide funds for continued operation, additional development, and improved operational and environmental efficiency of the properties.

When reviewing the entire spectrum of marginal property owners, the diverse nature of this population becomes apparent. Marginal properties are owned by the very largest integrated petroleum companies to the very smallest independent oil and gas producers. In addition, unique operating problems and costs exist in each distinct geographic area of the United States where oil and gas are produced from marginal properties, as discussed in Chapter Four. Accordingly, designing incentives that will be uniformly available to all marginal property owners is difficult, particularly since some producers may not be able to utilize tax incentives since they may not have taxable income during periods of low prices. The incentives recommended in this report are intended to be equally applicable to *all* owners of marginal properties, without regard to size of the owner and/or the geographic location of the property, and provide true economic assistance which encourages continued production from marginal properties across the industry.

During the preparation of this report, the NPC noted a number of instances in which the tax credits made available to the oil and gas industry over the past several years, have not always been as effective as intended because such credits are not allowed to offset Alternative Minimum Tax (AMT) liability, as well as regular federal income tax liability.

In 1990 and 1992, Congress provided AMT relief to oil and gas companies, which appears to have encouraged some increased domestic drilling activity. Even with these positive changes in the AMT, a number of oil and gas companies remain subject to it.

The federal income tax incentives recommended for marginal properties in this report have two purposes. The first, in the form of a credit (which phases out based on price level), is to encourage continued production when prices are low. The second, in the form of credits and/or deductions, are to encourage investment and enhance production from marginal properties. In order for the credits to create the intended economic benefit, the credits must be allowable against both regular income tax and AMT liability. If the credits recommended in this report are not creditable against 100 percent of AMT liability, the incentives will not provide the full benefit to all owners of marginal properties.

Since the recommended credits are available only during periods when prices are low and phase out as prices increase, allowing the credits to offset both federal income tax and AMT liability should allow many oil and gas producers to reduce the tax burden at a time when it is really needed. As prices increase toward the phase-out level, the credit has a diminishing impact on both federal income tax and AMT liability until the maximum phase-out price is achieved, at which point there is no impact on either federal income tax or AMT liability.

Consideration should also be given to how producers without taxable income can benefit from a credit based on marginal production in periods of low prices, since the purpose of the incentive is to allow the owner of a marginal property to generate cash flow that will allow continued production. A mechanism has been included to allow benefit from the credit without undue administrative and legal complexity.

Based on the findings of this report, both tax incentives that apply only during periods of low prices and tax incentives that apply regardless of price levels should be available to owners of marginal properties.

Recommended Federal Income Tax Incentives

Set forth below are four federal income tax incentives for marginal properties. The examples provided for each of the incentives are intended to illustrate the application of the concept generally. The actual impact of an incentive on a particular taxpayer can vary significantly depending on that taxpayer's particular circumstances.

Marginal Well Credit

Description

In order to encourage continued production from marginal properties in periods of low prices, a specific dollar per barrel Marginal Well Credit (MWC) for a specified number of barrel equivalents of production per day attributable to the working interest in each well in the property should be allowed for federal income tax purposes. The MWC would be phased out over a range of prices (based on annual average unregulated wellhead price per barrel and adjusted for inflation). The MWC would be fully allowable as a credit against both regular federal income tax liability and AMT liability. Unused MWC could be carried back three years (at the election of the taxpayer) and carried forward 15 years.

Production qualifying for the Section 29 credit for nonconventional fuel would not also qualify for the MWC. A taxpayer could elect to utilize either, but not both, of the credits on marginal properties qualifying for both credits.

In order to ensure that the MWC will create cash flow for an owner of a marginal property having no taxable income for the taxable year in which the MWC is earned, the owner could monetize the MWC earned in that taxable year by selling it to an unrelated taxpayer by the end of the taxable year following the taxable year in which the MWC is earned. The purchaser could utilize the full amount of the MWC acquired against its federal income tax or AMT liability for the taxable year in which the MWC is acquired, and could carry unused MWC forward for 15 years. The seller would realize taxable income in the taxable year the MWC is sold to the extent of the value of the consideration received. The transaction would be evidenced by simple documentation as prescribed by the Internal Revenue Service.

Examples

(1) Assuming an MWC of $3 per barrel for the first three barrels of production in 1995, a producer owning a marginal property with five wells, each averag-

ing 10 barrel equivalents of production per day would be entitled to MWC of $16,425 (3 x 365 x $3 x 5 wells) from that property in 1995, which could be used to offset the producer's federal income tax or AMT liability. Unused MWC could be carried back to calendar year 1992 or forward to calendar year 2010.

(2) If production from the marginal well averages only 2 barrel equivalents of production per day in 1995, the MWC would be $10,950 (2 x 365 x $3 x 5 wells).

(3) If the producer had total MWC for calendar year 1995 of $50,000 and had no taxable income for that year, the producer could sell the $50,000 of MWC. If the producer sold its 1995 MWC for $40,000 in cash on December 31, 1996, the producer would have taxable income of $40,000 in calendar year 1996 and the buyer would be allowed to offset the full $50,000 of MWC against its federal income tax, or AMT, liability in 1996 (or carry the unused portion of the MWC forward for use in future years).

Economic Analysis

A specific recommendation on an effective credit is not provided, although two economics scenarios for the $3 per barrel credit are illustrated in Table 1. Additional examples and alternative credit scenarios are provided in Chapter Five of this report. The range of costs and benefits considers cash flow at both the well/ lease level and the corporate level (full cost). This analysis recognizes that not all of an operator's costs are always "pushed down" to the well/lease level.

TABLE 1

10-YEAR SUMMARY OF INCREMENTAL COSTS AND BENEFITS OF A MARGINAL WELL TAX INCENTIVE

CYCLICAL PRICE ($8 TO $20 PER BARREL) TRACK CASE

Costs and Benefits	Case 1	Case 2	Case 3	Case 4
Average Wells Saved (# Wells)	32,066	33,571	19,339	20,752
Wells Receiving Credit (# Wells)	263,535	166,446	192,998	117,934
Additional Oil Produced (MMBOE)	205	285	137	167
Jobs Added (Labor Years)	121,239	98,531	49,917	41,044
State and Local Revenues ($MM)	482	615	256	325
Imports Avoided ($MM)	2,574	3,481	1,688	1,990
GDP Added ($MM)	4,214	6,398	2,727	3,653
Credit Cost ($MM)	5,172	3,530	1,945	1,281

Notes: Case 1: $3/BOE MWC, Lease/Well Level Cost Basis, $14-$20/BOE Phase-Out
Case 2: $3/BOE MWC, Full Cost Basis, $14-$20/BOE Phase-Out
Case 3: $3/BOE MWC, Lease/Well Level Cost Basis, $8-$16/BOE Phase-Out
Case 4: $3/BOE MWC, Full Cost Basis, $8-$16/BOE Phase-Out

More detail describing each of these and other cases is provided in Chapter Five and Appendix F, Section IV. These example cases are intended to provide a range of costs and benefits that could be realized from an MWC.

However, many operators make economic decisions based on full costs, not just the well/lease level costs.

Improved EOR Credit

Description

The enhanced oil recovery (EOR) credit, which is currently equal to 15 percent of qualified domestic EOR costs paid or incurred during the taxable period, provides some incentive for undertaking EOR projects. The current EOR credit begins to phase out when the annual average unregulated wellhead price per barrel exceeds $28 (adjusted for inflation).

In order to make the EOR credit available to a larger number of projects using current technology and encourage investment in marginal properties with reserve potential, the EOR credit should be expanded. The types of tertiary projects qualifying for the EOR credit would be modified to include all forms of current tertiary technology, and the credit would be allowed on all tertiary costs incurred on all new or existing projects on marginal properties.

Consideration should also be given to including new or substantially expanded secondary recovery projects on marginal properties as costs qualifying for the EOR credit. The process for qualifying a project for the EOR credit should also be simplified. For example, state certification of a project as a qualified EOR project should be an acceptable alternative means of qualifying a project for the federal EOR credit.

The EOR credit would be allowable against both regular federal income tax liability and AMT liability in the same manner as the MWC. Excess EOR credit could be carried back three years and carried forward 15 years. The EOR credit would not be transferable.

In any year, the producer may elect to claim either the EOR credit or the MWC for the qualifying property, but not both.

Example

If a producer owning a marginal property elects to undertake a new tertiary project (or continue an existing tertiary project) on a marginal property in calendar year 1995 and incurs $100,000 of qualifying EOR costs during the year, the taxpayer would be allowed an EOR credit of $15,000 ($100,000 x 15 percent). The tax basis or deductions resulting from the $100,000 of EOR expenditures would be reduced by the $15,000 EOR credit claimed. The $15,000 EOR credit would be allowable against the taxpayer's federal income tax or AMT liability. Excess EOR credit could be carried back to calendar year 1992 or forward to calendar year 2010.

Economic Analysis

The estimated benefits of the EOR credit proposal are shown in Table 2.

TABLE 2

10-YEAR SUMMARY OF INCREMENTAL COSTS AND BENEFITS OF AN EOR AND INFILL CREDIT

	$10 per Barrel	$18 per Barrel
Reserves Developed (MMBOE)	305	456
Additional Oil Produced (MMBOE)	90	127
Jobs Added (Labor Years)	14,461	34,700
State and Local Revenues ($MM)	44	169
Imports Avoided ($MM)	1,017	2,440
GDP Added ($MM)	1,606	3,856
Credit Cost ($MM)	392	903

Assumption—Operators with Taxable Income in AMT: 50 percent.

Inactive Well Incentive

Description

If a well is returned to production after being inactive for at least two years (i.e., the well has not produced oil or gas, or used as an injector, in more than one month in the two previous taxable years) or orphaned (i.e., abandoned by an operator and taken over by a state regulatory agency), certain costs incurred to reactivate those wells would also be eligible for a 15 percent credit similar to the EOR credit. Intangible drilling cost workovers, recompletions, horizontal extensions, and other capital costs on such properties would be subject to a 15 percent credit. The deductions or tax basis resulting from the expenditures qualifying for the credit would be reduced by the amount of the credit allowable with respect to the expenditures. This credit would phase out in the same manner as the EOR credit.

Costs qualifying for the inactive or orphaned well credit could not also be qualifying EOR expenditures. If a property qualifies for the MWC after returning to production, both the MWC and the inactive or orphaned well credit could be claimed for such property.

The inactive or orphaned well credit would be allowable against both regular federal income tax and AMT liability in the same manner as the MWC. Any excess credit could be carried back three years and carried forward 15 years. The credit would not be transferable.

This incentive, which is similar to the incentive allowed for inactive wells by several states, could be made available for a limited period, such as for wells returned to production in calendar years 1995 through 1997, to test its effectiveness.

Example

If a producer returned a well to production which had not produced in the previous two taxable years, and incurred $20,000 of intangible drilling cost workover expense in reactivating the well, a credit of $3,000 (15 percent x $20,000) would be allowable against the taxpayer's federal income tax or AMT liability. Any excess credit could be carried back to calendar year 1992 or carried forward to calendar year 2010.

Economic Analysis

Table 3 illustrates the benefits of the inactive well incentive. This table reflects benefits assuming two different rates for the wells returned to production. The high rate case assumes wells produce similar to wells reactivated in the Texas incentive program. The low rate case assumes typical reactivated wells will initially produce one quarter of the rate of Texas' reactivated wells.

TABLE 3

10-YEAR SUMMARY OF INCREMENTAL COSTS AND BENEFITS OF AN INACTIVE WELL INCENTIVE

	$10 per Barrel	$18 per Barrel
Additional Oil Produced (MMBOE)	53	107
Jobs Added (Labor Years)	7,467	20,746
State and Local Revenues ($MM)	33	178
Imports Avoided ($MM)	598	2,050
Credit Cost ($MM)	120	35

Assumptions—Operators with Taxable Income in AMT: 50 percent.
Incremental initial production of 4 BOE/D per well.

Immediate Expensing of Capital Expenditures on Marginal Properties

Description

The full cost of all capital expenditures on marginal properties would be deductible in the taxable year in which paid or incurred for both federal income tax and AMT purposes. As an alternative, the capital expenditures should be subject to recovery through accelerated depreciation (not subject to add back for AMT purposes) over three years or less. This provision should encourage the addition of appropriate equipment, including environmental equipment, to existing marginal properties.

Expenditures that also qualify for the EOR credit would not be subject to immediate expensing, unless the taxpayer elected to forego the EOR credit on those expenditures.

Example

If a producer pays $50,000 for new equipment on a marginal property in calendar year 1995, the producer could elect to expense the entire $50,000 in calendar year 1995 for federal income tax purposes, rather than depreciate the asset over its useful life. If the equipment cost was also a qualifying EOR expenditure, the taxpayer could not immediately expense the equipment cost, unless the taxpayer elected to forego the EOR credit with respect to such cost.

Economic Analysis

No economic analysis has been done of this incentive because of a lack of readily available empirical data. Nevertheless, the incentive could create an increased investment in marginal properties at a rather small cost per barrel.

Geological and Geophysical Costs

The legislation currently being considered that would allow the immediate expensing of domestic geological and geophysical costs (G&G) on all properties has some beneficial impact on marginal properties and should be enacted. Immediate expensing of all G&G would eliminate substantial complexity (including identifying G&G by properties) and reduce compliance cost for both taxpayers and the government. This incentive would also create capital for domestic exploration generally, as well as provide some encouragement for further development of marginal properties. However, G&G is a rather small incentive for marginal properties, and should be enacted as a marginal property incentive only if it is part of a larger group of incentives specifically focused on marginal properties.

Percentage Depletion

During the preparation of this report, the NPC gave serious consideration to including modifications in the existing percentage depletion rules to encourage continued production for marginal properties. Percentage depletion is an important federal income tax provision for a number of independent oil and gas producers. On the other hand, major oil and gas companies do not receive the benefit of percentage depletion. Since percentage depletion is not available to all owners of marginal properties, modifications of percentage depletion were not included in the incentives recommended in this report.

STATE TAX INCENTIVES

State severance taxes are direct reductions of revenue from marginal properties. A number of states have already provided significant severance tax relief for marginal properties. All producing states should review existing severance tax arrangements on marginal properties and provide tax relief as appropriate. In addition, severance tax reductions or exemptions should be provided for returning inactive or orphaned wells to beneficial production in a way similar to that being done by the Texas Railroad Commission.

Producing states imposing an income tax on oil and gas companies should carefully review the federal income tax incentives being recommended in this report and adopt similar incentives as appropriate. For example, a state having a corporate tax rate of 10 percent could adopt an MWC equal to 30 percent of the amount allowed for federal income tax purposes. Such a state MWC would have approximately the same mathematical relationship to the federal MWC as a state tax rate has to the federal tax rate. State income tax incentives can be as important as federal income tax incentives in encouraging continued production from, and further development of, marginal properties.

REGULATORY, ROYALTY, AND COST RELIEF

In addition to the tax incentives recommended above, various other methods of maintaining marginal well profitability were considered. This section summarizes the recommendations relating to regulatory, royalty, and cost relief for marginal properties.

Although several studies have analyzed the cost impact of current and future regulations on the industry, these analyses were region specific and did not provide adequate cost data for use in this report. Chapter Seven reviews several of these regulatory impact studies. The short time frame of this study precluded an evaluation of regulatory impacts which could be translated into dollars and lost barrels resulting from higher marginal well economic limits. Existing and future regulations have real cost impacts which affect marginal well profitability. Regulatory reform through joint industry and agency efforts can minimize these impacts. Following are specific recommendations regarding environmental and regulatory issues that will benefit marginal properties, the government, and the domestic oil and gas industry as a whole.

Regulatory and Administrative Relief

Streamline Regulatory Processes

More intensive cooperation between industry and federal and state regulatory agencies is needed to assess the effectiveness and cost/benefit of existing and future regulations and compliance efforts. To facilitate this "partnership," a federal agency should be given responsibility for initiating the discussion and bringing participants together. The partnership must incorporate the following processes:

- The scope, purpose, and objective of the partnerships must be identified.
- Procedural and organizational ground rules must be developed and agreed to by all participants, and working groups must be established.
- Issues under discussion must be defined specifically enough to arrive at a consensus.
- Resources necessary for solving any specific issue must be identified and mobilized.
- A federal agency should facilitate the establishment of principles of "sound science" requirements, cost benefit analysis, and reasonable risk assessment for use in guiding and determining acceptable input from the participants.

Reduce Interagency Rule and Jurisdiction Conflicts

State and federal regulatory decision making should be enhanced by minimizing interagency rule and jurisdiction conflicts, and incorporating balance between regulatory impacts. Sound technical information regarding environmental risk associated with oil and gas operations, as well as the costs and benefits of alternative approaches, should be more readily available from government agencies. To initiate effective interagency cooperation to minimize regulatory overlap and duplication, we suggest the federal government implement immediate relief by establishing a moratorium on new federal regulations that raise costs on marginal wells. Under the National Performance Review initiative, the Department of Interior is examining the efficiency of Interior's regulations and procedures that are currently in effect. Similar studies should be done on all existing and currently proposed regulations and programs that affect oil and gas.

Increase Environmental Dialogue

Dialogue and joint venture activities between industry, federal and state agencies, and other interested parties to address regional environmental compliance issues constraining oil and gas producers should be promoted. The Department of Energy should implement, make use of, and publicize government activities to improve existing and developing technologies and work to develop general consensus on scientific "facts." They should also work to develop environmental and regulatory impact analysis based on scientific data that is acceptable to both industry and regulatory agencies.

Quantify Current Regulatory Cost Burdens

In order to quantify current regulatory impacts on oil and gas exploration, development, and production, a complete evaluation and analyses of current costs associated with regulation on a regional, and local, basis would be helpful. The results of this analysis should quantify the effect of regulatory overlap and inefficiency. The analyses should also examine the feasibility of developing a methodology for identifying and tracking specific regulatory compliance costs in the industry. In addition, models to predict the impact of existing and future regulations should be developed.

Royalty Relief

Royalty relief has a significant and beneficial impact on marginal properties because royalty payments are a direct reduction from gross revenues. Reductions in royalty rate provide a direct cash flow improvement to owners of marginal properties.

The existing federal lands (Bureau of Land Management [BLM]) royalty reduction program has proved beneficial to marginal well operators and should be encouraged for use on state and other government lands. Under this program, royalty on wells producing less than 15 barrel equivalents per day are granted a reduction in the normal 12.5 percent royalty rate. A sliding scale is used to determine the actual royalty rate as shown in Table 4. To date, the BLM has received 4,900 applications for royalty reduction and has granted 4,500 approvals. There are approximately 5,500 BLM leases or agreements that could ultimately request

TABLE 4

SLIDING SCALE ROYALTY RATES BASED ON PRODUCTION RATES

Average Production (Barrel of Oil Equivalents per Day)	Royalty Rate (Percentage)
0	0.5
2	2.1
4	3.7
6	5.3
8	6.9
10	8.5
12	10.1
14	11.7

royalty reductions. The BLM is in the process of evaluating the benefits of this program. Additionally, the BLM has formulated a program for royalty relief on federal lands for wells producing 30°API or lower crude oil. This program involves a sliding scale royalty rate reduction as shown in Table 5. This program is expected to be approved before the end of 1994.

The above programs will have a significant positive impact where they can be applied; unfortunately there are not large numbers of wells on federal lands. However, producing states should review royalty arrangements on state-owned marginal properties and follow the federal royalty procedure.

TABLE 5

SLIDING SCALE ROYALTY RATES BASED ON GRAVITY

Gravity (Degrees API)	Royalty Rate (Percentage)
0	0.5
5	2.5
10	4.5
15	6.5
20	8.5
25	10.5
30	12.5

OTHER MARGINAL PROPERTY INVESTMENT INCENTIVES

Government-Industry Cost Sharing Programs

While the Department of Energy and certain state agencies currently offer cost sharing opportunities in the areas of marginal production and EOR to oil and gas producers, such as the DOE's Research, Development, and Demonstration Program, the process and procedures of entering into such transactions with a government agency is currently time consuming, administratively complex, burdensome, and costly. As demonstrated recently with the Small Business Administration and with certain of the state regulatory agencies, paperwork and burdensome procedures can be minimized thereby substantially increasing interest from prospective joint venture partners.

Encouraging Marginal Property Transactions

The life of many marginal properties can be extended if the properties can be transferred or sold. If impediments to these transfers exist, many properties will be prematurely abandoned.

In order to facilitate financing for marginal property transactions, incentives should be made available which encourage loans for such transactions. Perhaps a simplified loan process through the Small Business Administration could be developed to meet this need. Also, a price-risk management program should be made available for financings of such transactions.

Since companies may have a reluctance to sell properties considering the inability to transfer environmental liabilities, operators may plug and abandon wells as opposed to selling them. Even though a buyer and seller contractually agree that the seller will have no liability for future environmental costs, applicable law appears to require that the seller remain liable in many cases. Also, a financial institution providing financing for a property transaction may be treated as an owner of a property for future environmental liabilities. Appropriate and effective federal and state legislation is needed to correct these impediments to marginal property transactions.

Removal of Artificial Market Constraints

Artificial constraints on free market conditions that negatively affect crude oil prices should be eliminated. For example, the federal ban on exporting Alaskan North Slope (ANS) crude oil causes an oversupply of ANS oil on the California crude oil market, which tends to decrease all crude oil prices in California. This ban is further discussed in Chapter Four, and consideration should be given to its repeal.

Other Considerations

The NPC recognizes that the analysis and proposals set forth in this report do not cover the full spectrum of incentives/actions that could benefit marginal properties. Some of the areas not included are technology transfer, better access to petroleum futures markets for the small producers, and reductions in cost structure. Steps that could reduce the cost structure include electricity/utility reform, insurance reduction on marginal properties, and incentive to reduce water handling costs.

Chapter One

Historical Overview of Domestic Production

OVERVIEW

To understand the current state of the domestic oil and gas industry and the role of marginal wells in this industry, it is important to recognize the multitude of factors that have impacted the industry over the years and that continue to impact it today. Some of these factors stem from being part of a global marketplace and are beyond the control of domestic producers. Other factors are unique to domestic producers and include certain physical, economic, and regulatory constraints that affect the competitiveness of domestic producers. For example, production rates and product prices fall while operating costs continue to increase with inflation. Understanding these many factors provides insight into forces that have influenced the evolution of marginal wells and enhances our knowledge of their current and future role in the nation.

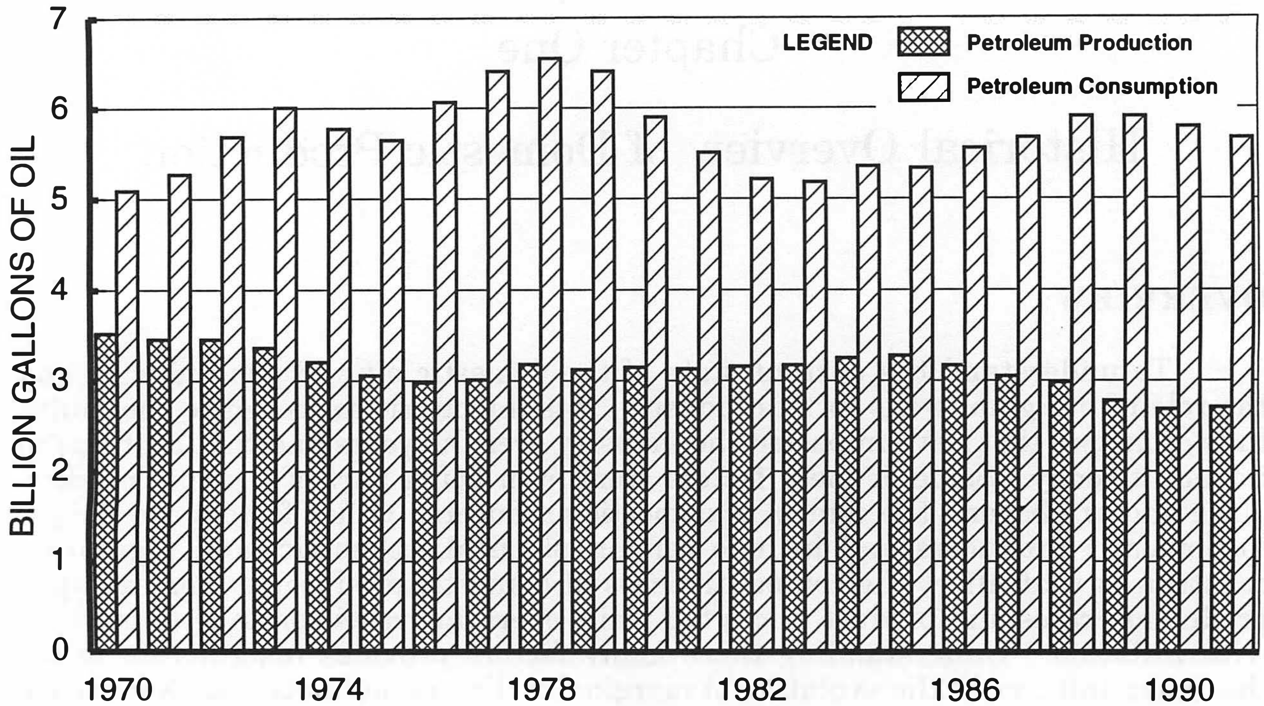
While the remainder of this chapter and a majority of the report focuses on the oil segment of the domestic industry, many similar factors affect natural gas producers. A discussion of the natural gas segment and its importance to the nation and industry can be found in Chapter Two. Although a majority of this report addresses marginal oil wells, natural gas operations are vital to the nation's energy security and must be given an equal consideration in energy policy decisions.

Domestic Oil Production in the Global Marketplace

The price received for domestic and imported crude oil is primarily influenced by the global marketplace. A variety of national and international events have a day-to-day impact on the price of crude oil. Over the longer term, it is the world supply and demand and related events that contribute to the volatile commodity pricing and the "ripple" effects these price swings have on domestic petroleum industry activities. Several examples of how price influences certain activities are provided later in this chapter.

The U.S. domestic oil and gas industry has reached a state of maturity much sooner than the industry throughout most of the remainder of the world. This is in part due to the relatively early industrialization, based on crude oil, that has continued to today. As can be seen in Figure 1-1, this crude oil demand continues to outpace the internal supply (production) which continues to decline. This results in ever increasing levels of crude oil imports and a greater reliance on world markets for supplying the country's crude oil demand. Although numerous wells provide access to a significant resource base, reserve depletion continues and a decline in significant U.S. oil discoveries contribute to the growing reliance on foreign oil.

As domestic crude oil production falls further below the U.S. crude oil demand, there will be a continued and increasing reliance on foreign oil. As oil



Note: Excludes natural gas.
Source: U.S Energy Information Administration, *Monthly Energy Review.*

Figure 1-1. U.S. Production of Petroleum Energy versus U.S. Consumption of Petroleum Energy.

imports increase, the U.S. trade deficit grows and petroleum industry activity outside the United States increases to meet the additional demand. This activity may be replacing growth which could occur if the U.S. domestic oil and gas industry is provided with an adequately competitive investment environment. Factors that reduce the U.S. oil and gas industry competitiveness in the world market include the relatively fixed royalty and taxation schemes, regulatory and environmental requirements, and the great number of low rate and marginal producing oil wells. The growing differential between crude oil supply and demand, petroleum industry growth abroad, and the trade deficit effects related to oil imports will continue as long as factors affecting the trends remain unchanged.

Energy Security

The National Petroleum Council has determined that the Secretary's request to consider the nation's energy security relates to these supply and demand trends. Energy security can be defined as the ability to internally supply sufficient energy to meet internal demands with minimal energy imports. These trends indicate that the nation can currently supply less than 50 percent of crude oil demands. Figure 1-2 shows EIA data comparing U.S. crude oil production and consumption in 1980 and 1990 with projections into the future for the years 2000 and 2010. Also shown on this graph are actual and projected growth of consumption in East Asia. This graph indicates that U.S. consumption will continue to grow and imports will increase. There is also likely to be increased competition for world oil in the future, as energy needs increase for developing countries.

Marginal production is important for the U.S. economy. For instance, replacing marginal oil production with imported crude oil would increase the

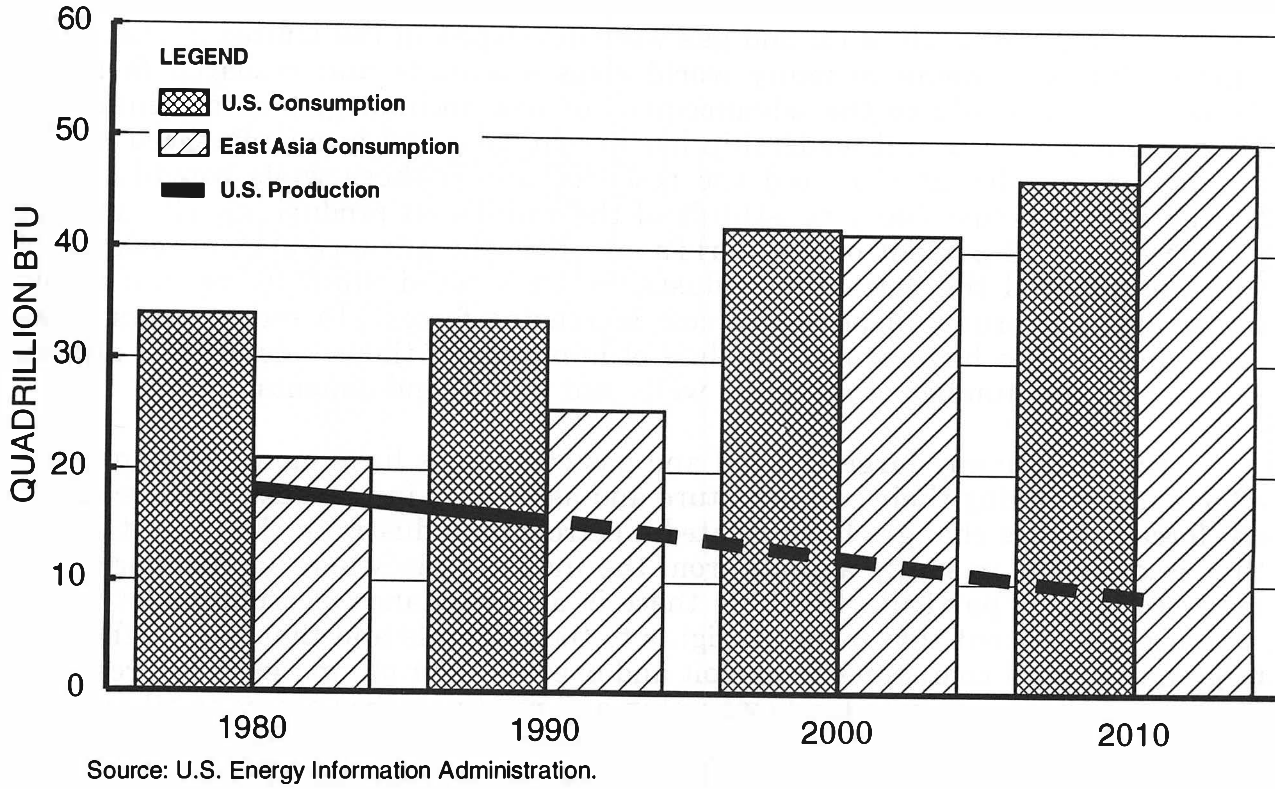


Figure 1-2. Future Competition for Petroleum Resources.

U.S. trade deficit, further weaken a declining and vulnerable U.S. dollar, exacerbate inflation, lead to an increase in interest rates, jeopardize global stock and bond markets, and undermine the U.S. economic recovery. To illustrate with 1992 data, if the United States had to replace marginal oil production with imports, then crude oil imports would have been up by $12.75 billion, or 33 percent. This increase in oil imports would have raised the total U.S. current account deficit by almost 20 percent. Such a change would undoubtedly put downward pressure on the dollar, leading to the series of debilitating effects upon the economy described above. In particular, the United States would lose the jobs associated with the shutdown of the marginal production and the jobs associated with a slowdown in economic activity due to higher interest rates and the decline in global capital markets.

The NPC marginal well study has identified several areas where changes in national policies/approaches can improve the nation's energy security and reduce imports. A reduction in crude oil cost structure (e.g., reducing environmental and regulatory costs) and the preservation of marginally producing oil wells are all positive steps toward reducing imports and improving our nation's energy security. Additionally, promoting domestic natural gas as an alternative to imported crude oil, encouraging exploration and infill/development drilling, and improving land access for exploration are recognized as means to improve energy security.

The U.S. domestic oil and gas industry has a significant impact on oil and gas related activities throughout the world, since many of the companies that are based in the United States also have significant foreign oil and gas operations outside the United States. Many of the technologies used throughout the world to explore, drill, and produce oil and gas were developed in the United States. The United States is home to many world class scientists and research facilities dedicated exclusively to the advancement of new technologies in the industry. This position of technical leadership has arisen from and been influenced by the number of producing wells and the resource access these wells provide. The United States holds nearly two-thirds of the world's oil producing wells and yet produces only 12 percent of the world's oil. It is the advancement of technology that has allowed the petroleum industry in the United States to remain viable under external crude oil price and cost increasing forces. In recent years, however, these forces have caused the loss of hundreds of thousands of jobs, and an increase in the number of marginal wells and well abandonments.

Recently, many large U.S. oil and gas companies have mounted significant efforts in realigning their cost structure and asset base in response to these external forces. These changes have created a petroleum industry in the United States that is different in many aspects from the industry elsewhere in the world. In many countries, particularly where there is an abundance of crude oil, it is the nation's government that owns all rights to the minerals and that has established large national oil companies to exploit and operate their oil and gas resources. In the United States, private land ownership and relatively free access to oil and gas minerals have created a large number of diverse mineral owners. It is this private mineral ownership, unique to the United States, that has allowed individual leases in the United States to be developed and produced as small businesses, and provided a major contribution to the rapid development of the industry in the last half of this century.

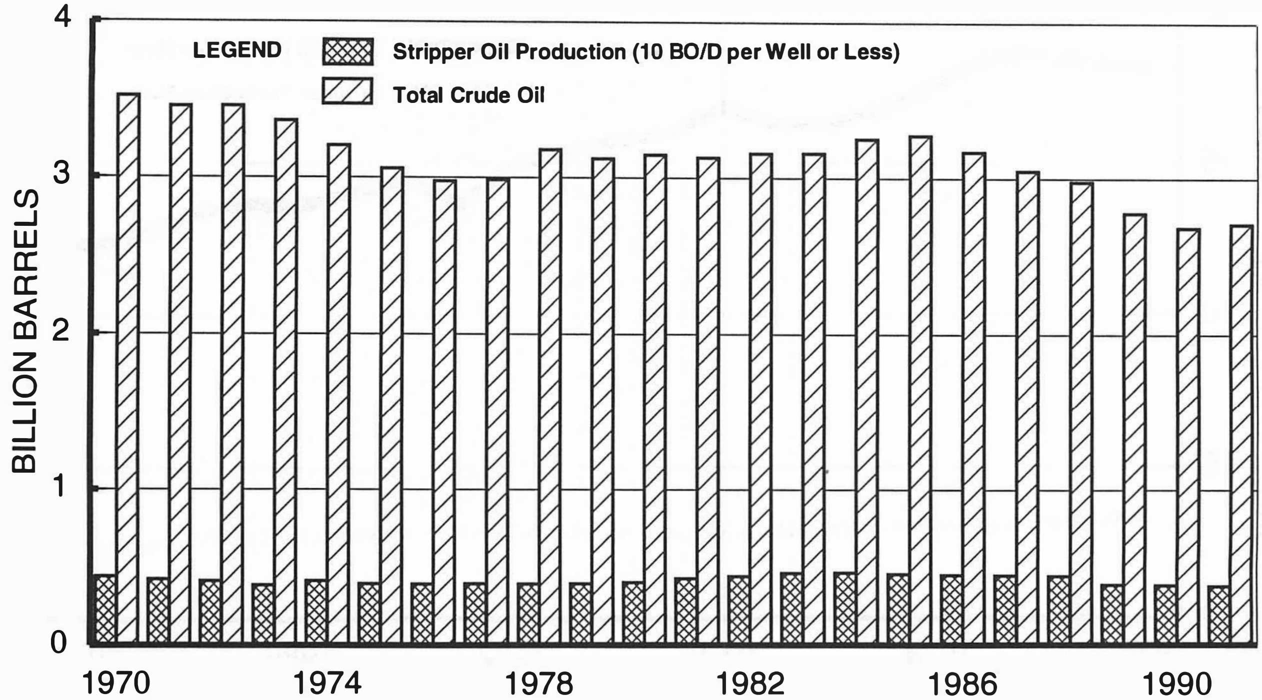
In order for the United States to maintain its world-class technical leadership in the oil and gas industry, it is important that industry, large corporations, small business and government alike, be able to successfully compete against the challenges of the global marketplace. In the next sections of this chapter, several of the technical and economic challenges the industry faces are described. Integral to these challenges is the issue of maintaining economic production from marginal wells and the access these wells provide to a large and important national resource base.

PHYSICAL CHARACTERISTICS

The physical characteristics that are discussed below include oil and gas production rate, oil gravity, number of producing wells, reserves, reserve life, well abandonments, and new well drilling. The following discussion will primarily focus on *oil* production, wells, and reserves. Characteristics associated with natural gas wells are addressed in Chapter Two.

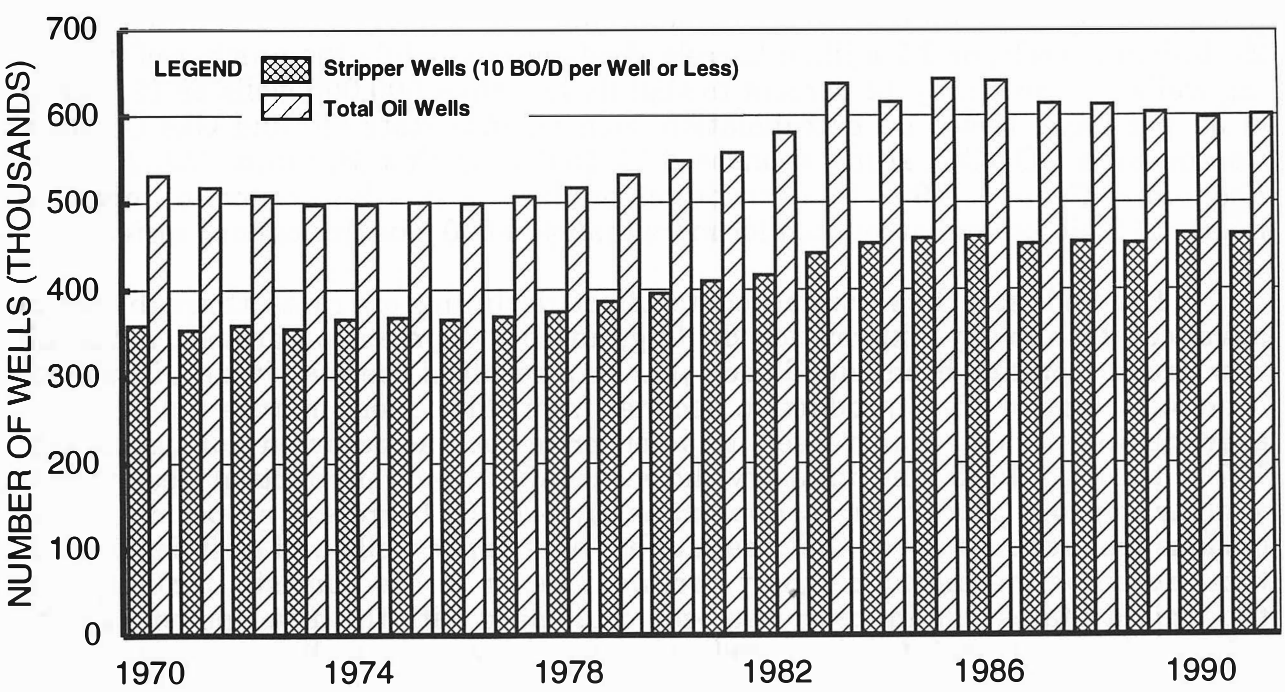
Production and Wells

Figures 1-3, 1-4, and 1-5 illustrate annual crude oil production (including lease condensate), well count, and production per well from 1970 to 1991. In 1970, annual domestic crude oil production was 3.5 billion barrels or 9.6 million barrels of oil per day from 525,000 producing oil wells, or approximately 18 barrels per day per well. Data on stripper wells (defined as wells producing less than 10 barrels of oil per day) and production are shown to demonstrate its significance. Of the



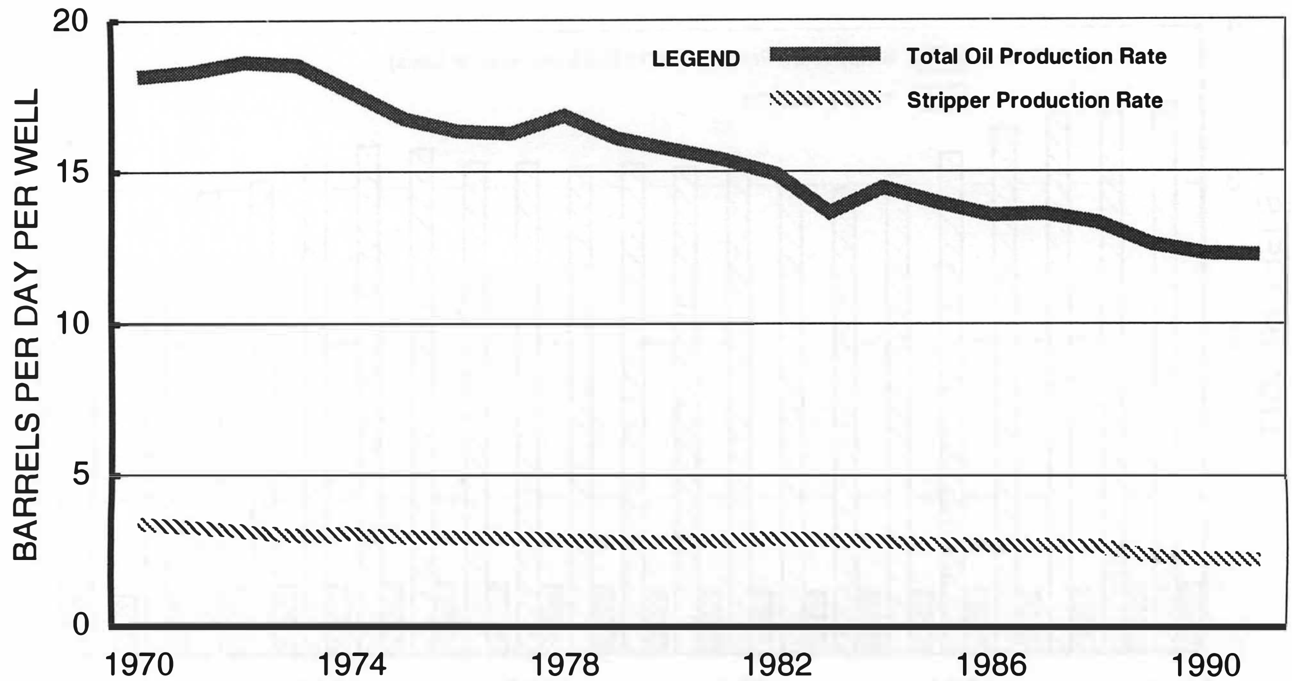
Source: National Stripper Well Association; National Stripper Well Survey; Energy Information Administration *Petroleum Supply Annual.*

Figure 1-3. U.S. Stripper Production versus Total U.S. Oil Production.



Source: National Stripper Well Association; National Stripper Well Survey; Energy Information Administration *Petroleum Supply Annual; World Oil Magazine*, Forecast Review Issue, February 1994.

Figure 1-4. U.S. Stripper Well Count versus Total Oil Well Count.



Source: National Stripper Well Association; National Stripper Well Survey; Energy Information Administration *Petroleum Supply Annual; World Oil Magazine*, Forecast Review Issue, February 1994.

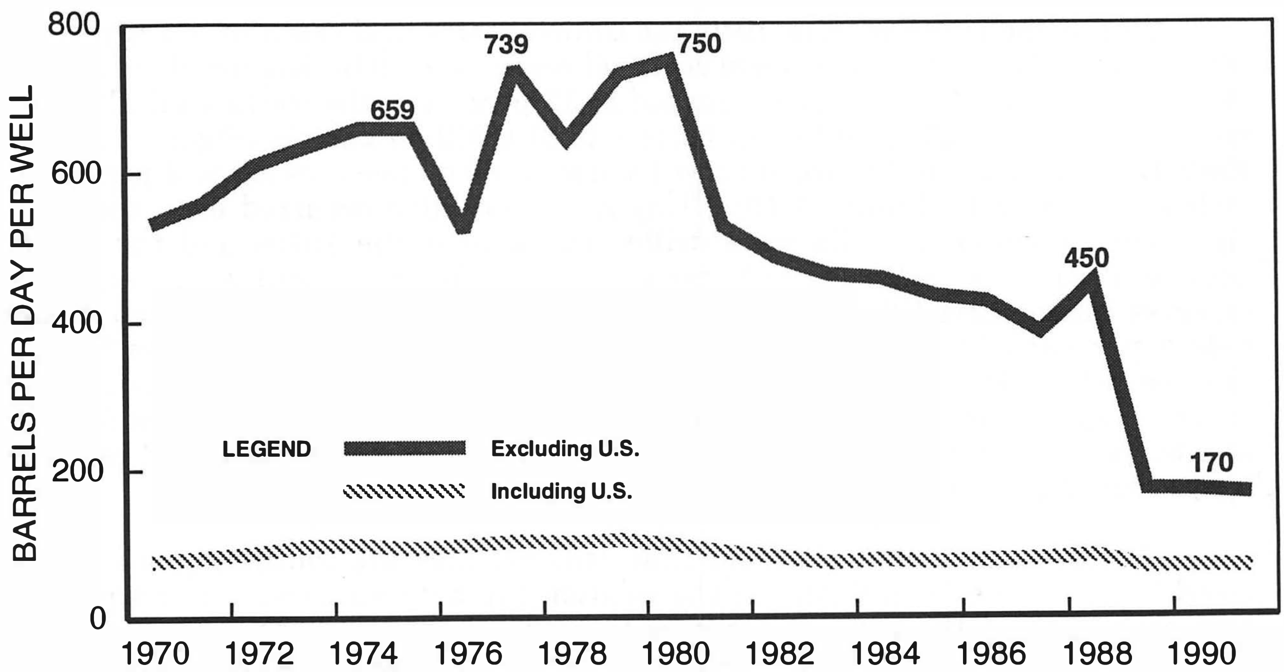
Figure 1-5. U.S. Stripper Production versus Total U.S. Oil Production.

525,000 producing oil wells in 1970, approximately 360,000 were classified as stripper wells. By 1992, total production had declined by 26 percent to an annual rate of 2.6 billion barrels, or 7.2 million barrels of oil per day, while the number of producing wells had grown by 14 percent to slightly less than 600,000 wells or 12 barrels of oil per day. Based on extrapolation from an Interstate Oil and Gas Compact Commission (IOGCC) study sponsored by DOE, entitled *Marginal Oil: Fuel for Economic Growth*, 1992 total crude oil production had an economic impact of nearly $72 billion and accounted for more than 430,000 jobs throughout society.

The industry has attempted to offset declining oil rates through use of advanced technology, exploration drilling, and development programs. Although new production has been added each year as a result of these activities, it has not been sufficient to offset production declines from older, more mature fields. However, during periods of increased crude oil price such as occurred during the late 1970s through 1985, the industry did successfully halt production decline and slightly improve production by approximately 400,000 barrels of oil per day. It is obvious from these figures that the number of stripper wells and stripper production are becoming an increasingly dominant factor in the domestic industry. In the United States, the industry has been challenged with the development of technology aimed at maintaining production from low rate wells and minimizing production costs.

A comparison of daily average oil production rate per well between the United States and several other countries illustrates that the industry in the United States has been successful in maintaining global competitiveness with low average well producing rates compared to the more prolific producing provinces and higher average well rates that are found within other countries of the world. In part, this is also influenced by the maturity of the domestic oil and gas production in the United States, where production was first recorded in 1859. In other countries, first production was generally recorded from the early 1900s to the 1960s. During the years 1970 through 1980, Middle East countries' production averaged more than 10,000 barrels per day per well. Most recently, this average has fallen within the range of 2,000 to 6,000 barrels of oil per day per well, which is still significantly more than the 12 barrels of oil per day per well average for the United States. Other significant oil-producing countries such as Mexico and Indonesia currently have average well rates of 600 and 200 barrels of oil per day per well, respectively.

A further illustration of the unique challenges facing producers in the United States, compared to the international oil and gas industry, can be seen in Figure 1-6. In 1970, outside of the United States, daily average oil production was approximately 525 barrels per day per well. When production from wells in the United States are included in this average, the world total average drops to just under 80 barrels of oil per day per well in 1970. In 1980, the world average rose to 750 barrels per day per well when the United States is excluded and is approximately 100 barrels per day per well when the United States is included. In 1991, the world average fell to 170 barrels per day per well, excluding the United States, and is approximately 65 barrels per day per well when production from the United States is included. Although the domestic industry is addressing the challenges of low producing rates per well, there is an incentive to direct efforts overseas where oil wells produce, on average, ten times that of a domestic oil well.



(Total incomplete because amounts from some countries not available.)

Sources: Degolyer & MacNaughton, *Twentieth Century Petroleum Statistics 1991;* API, *Petroleum Facts & Figures 1971;* Gulf Publishing Co., *World Oil;* PennWell Publishing Co., *Oil & Gas Journal;* EIA, *Annual Energy Review 1991*; Petroconsultants S.A., *World Production & Reserves Statistics 1991.* United States—1970-1980: U.S. Energy Information Administration, *Annual Petroleum Statements.* 1981-1982: *World Oil Magazine;* 1983-1991: *Oil and Gas Journal,* "Worldwide Report" Issue. Rest of World—1970-1991: *Oil and Gas Journal,* "World Report" Issue.

Figure 1-6. World Daily Average Oil Production Per Well.

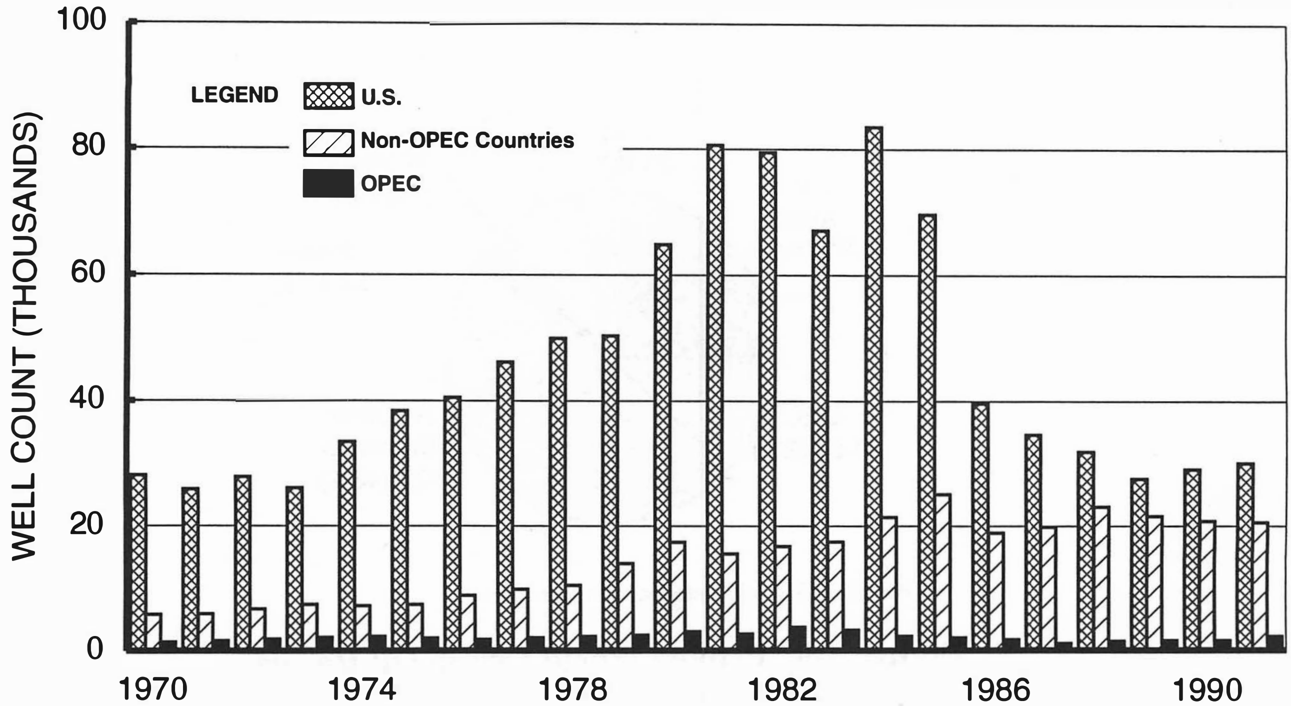
In Figure 1-7, the number of wells drilled annually in the U.S., non-OPEC, and OPEC countries is shown. From 1970 through 1985, the United States outpaced the combined drilling efforts of OPEC and non-OPEC countries by a factor of between three and four. Only during the past four years has drilling in non-OPEC countries approached that of the United States. As stated previously, the production benefits of this drilling activity resulted in a 400,000 barrels of oil per day increase above level production between 1979 and 1985. Figure 1-8 illustrates the cumulative number of new wells drilled by the U.S., non-OPEC, and OPEC countries during 1970–1991. By 1991, the United States outdrilled OPEC countries by a factor of 20 and non-OPEC countries by a factor of nearly three. The decline in average oil rate per well for the world during the last 20 years is impacted more by the increasing number of wells in the United States and decreasing average rate per well than any foreign country's production or well count; a significant indicator of the domestic industry's activity in a mature, well-developed environment.

Reserves

Although there have been far more wells drilled in the United States than in other countries, excluding the Commonwealth of Independent States, the United States' share of proved world crude oil reserves has continued to decline. However, these numerous wells provide access to proved reserves of 24 billion barrels and a known remaining resource base of 350 billion barrels. This resource base, although only partially producible with today's technology, provides a large target for future activity. The next series of figures indicates the history of the United States' share of proved world crude oil reserves and provides, for comparison, an illustration of the United States' remaining resource potential.

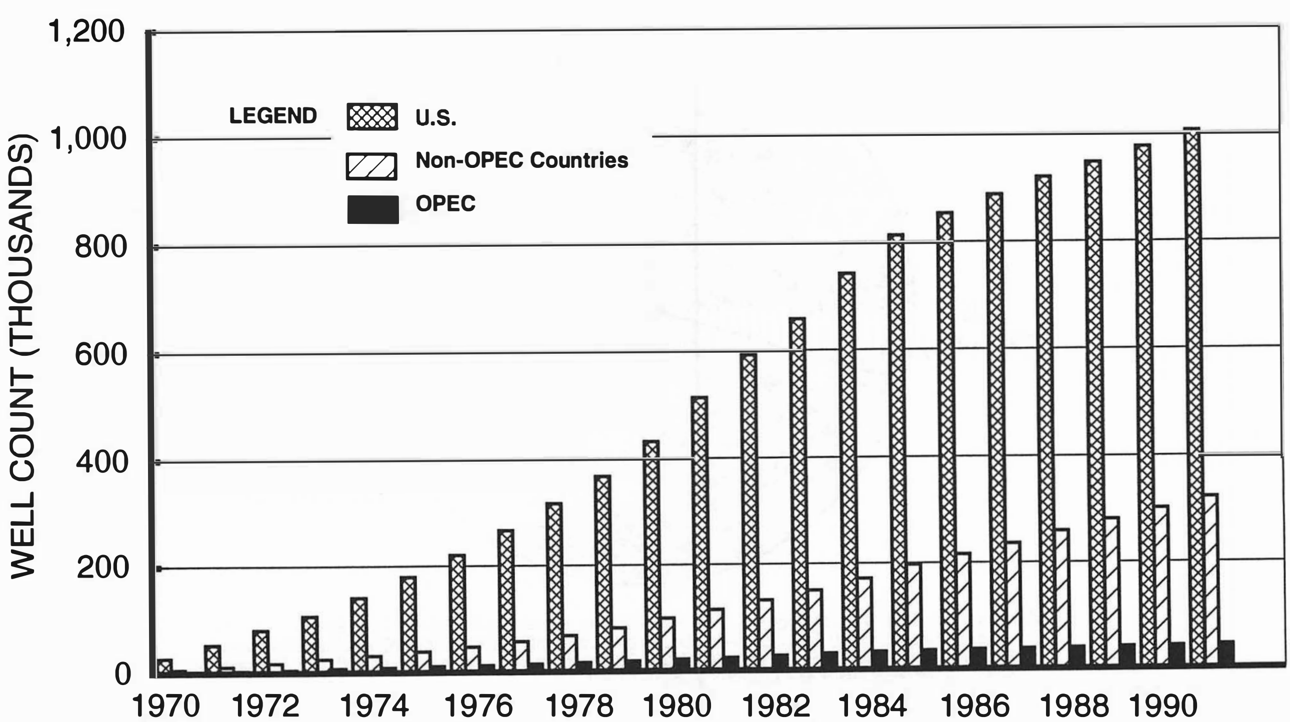
At the end of the year, in 1940, the United States held essentially 100 percent of the *reported* known proved world crude oil reserves of 19 billion barrels of oil. By 1960, the United States' reserve dropped to 12 percent of the world total although reserves increased from 19 billion barrels to 31.6 billion barrels (Figure 1-9). By 1980, the United States' share of proved world crude oil reserves fell to 4 percent or 29.9 billion barrels (Figure 1-10). This reserve decline occurred even though a significant number of wells were drilled throughout the 1970s and the use of advanced recovery technologies became more prevalent. A continued decline in reserves has occurred through the end of 1993, at which time the United States held 2 percent of the world's proved crude oil reserves with 23.7 billion barrels (Figure 1-11). However, the United States still retains a significant known resource base of more than 350 billion barrels (approximately 66 percent of 533 billion barrels of original oil in place) that remains as a target for advanced recovery technology (Figure 1-12).

Another significant attribute that demonstrates the continuing challenges faced by the domestic industry is the relationship between reserves and production expressed as the ratio of reserves to production (R/P) ratio. For a mature producing area, the R/P ratio tends to be reasonably stable, so that the proved reserves at the end of a year serve as a rough indicator of the production level that can be maintained during the following year. R/P ratios are an indication of the state of development in an area and, over a period of time, the ratios change. The U.S. R/P ratio went from roughly 11-to-1 to 9-to-1 between 1977 and 1982, as Alaskan North Slope production reached high levels. The Appalachian area of the country, which has been drilled since Drake's 1859 well came in, has many



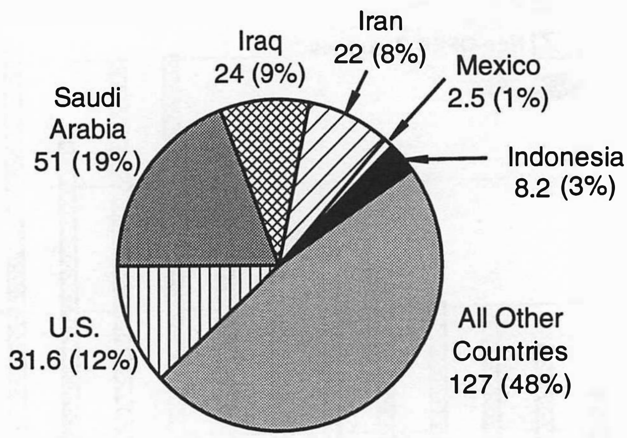
Sources: Gulf Publishing Co., *World Oil;* PennWell Publishing Co., *International Petroleum Encyclopedia;* PennWell Publishing Co., *International Energy Statistics Sourcebook 1991.*

Figure 1-7. Wells Drilled—U.S. versus All Other Countries (Excludes CIS Wells).



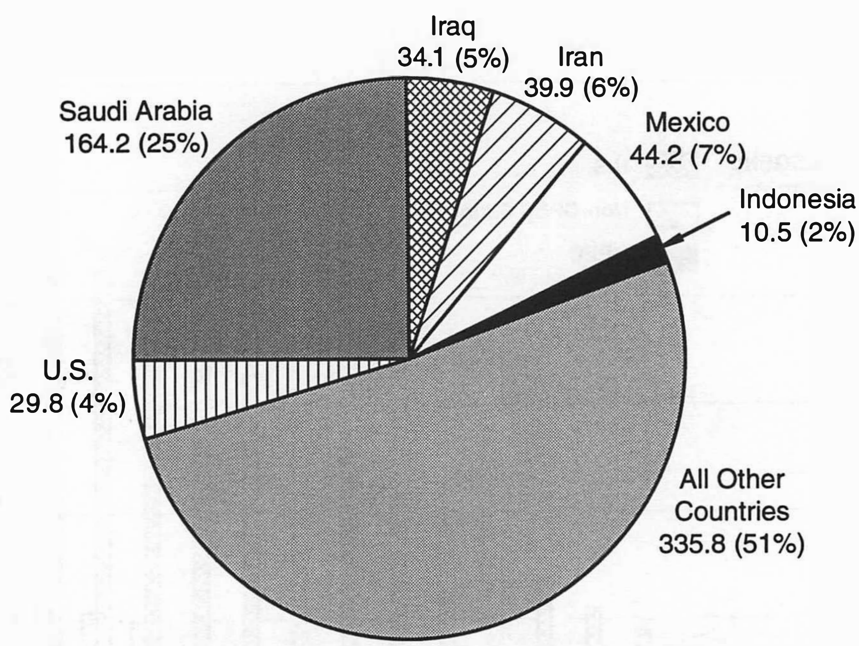
Sources: Gulf Publishing Co., *World Oil;* PennWell Publishing Co., *International Petroleum Encyclopedia;* PennWell Publishing Co., *International Energy Statistics Sourcebook 1991.*

Figure 1-8. Cumulative Wells Drilled—U.S. versus All Other Countries (Excludes CIS Wells).



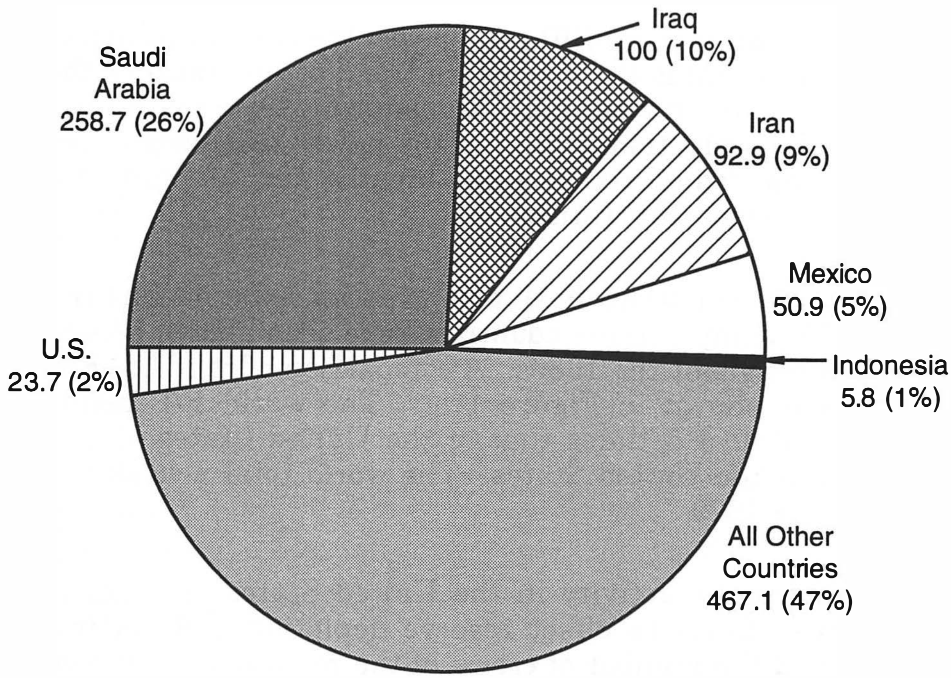
Source: U.S. Energy Information Administration.

Figure 1-9. Proved World Crude Oil Reserves (266.3 Billion Barrels as of 12/31/60).



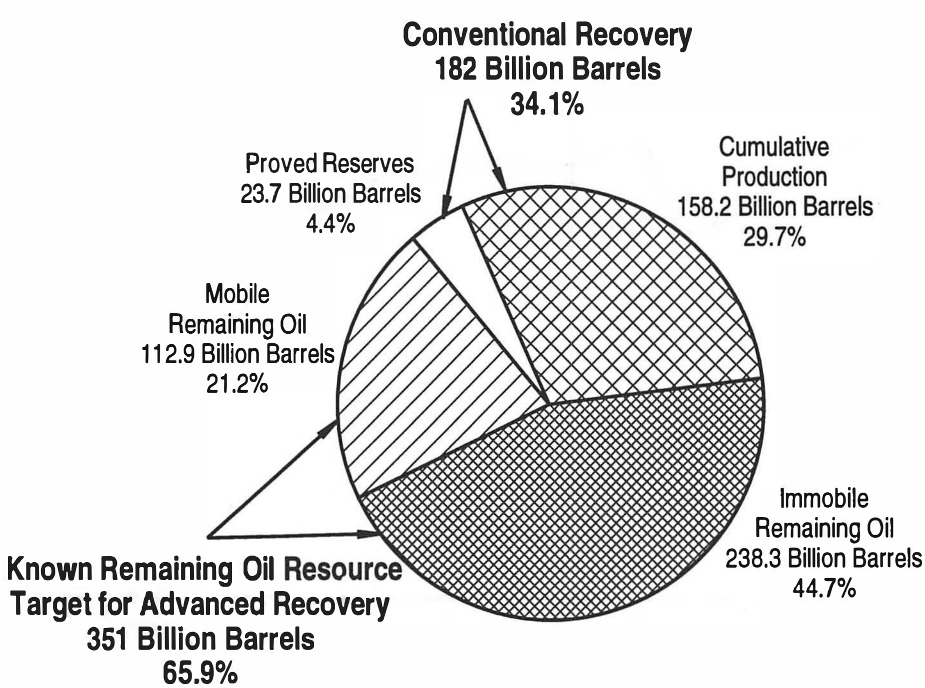
Sour es: Degolyer & MacNaughton, *Twentieth Century Petroleum Statistics 1945-1991;* API, *Petroleum Facts & Figures 1971;* Gulf Publishing Co., *World Oil;* PennWell Publishing Co., *Oil & Gas Journal;* PennWell Publishing Co., *Oil and Gas Journal Energy Statistics Sourcebook 1990;* EIA; Petro onsultants S.A., *World Production and Reserve Statistics 1991.*

Figure 1-10. Proved World Crude Oil Reserves (658.6 Billion Barrels as of 12/31/80).



Sources: Degolyer & MacNaughton, *Twentieth Century Petroleum Statistics 1945-1991;* API, *Petroleum Facts & Figures 1971;* Gulf Publishing Co., *World Oil;* PennWell Publishing Co., *Oil & Gas Journal;* PennWell Publishing Co., *Oil and Gas Journal Energy Statistics Sourcebook 1990;* EIA; Petroconsultants S.A., *World Production and Reserve Statistics 1991.*

Figure 1-11. Proved World Crude Oil Reserves (999.1 Billion Barrels as of 12/31/93).



Note: Nearly Two-Thirds of the U.S. Oil Resource Will Remain After Conventional Production
Total Original Oil In Place = 533 Billion Barrels

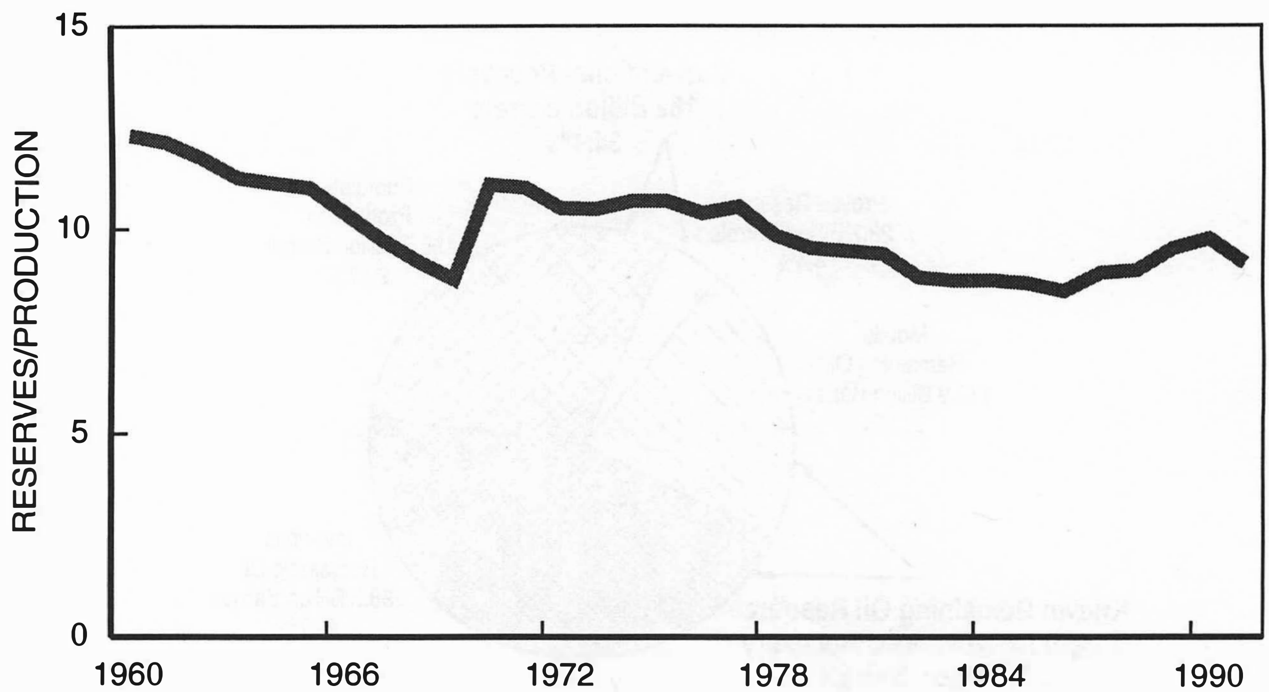
Source: American Petroleum Institute, 1980; Energy Information Administration,1992; BPO, 1992.

Figure 1-12. Domestic U.S. Oil Production, Reserves, and Known Remaining Resource.

marginal oil wells that have an R/P ratio below the current national average of 9.7 to 1. Figure 1-13 illustrates the downward trend of this ratio as the U.S. industry is unable to overcome the physical and economic forces to build the reserve base at a pace that exceeds production. Many of the newer technologies, such as horizontal drilling and enhanced oil recovery can breathe new life into an area and result in significantly increased R/P ratios.

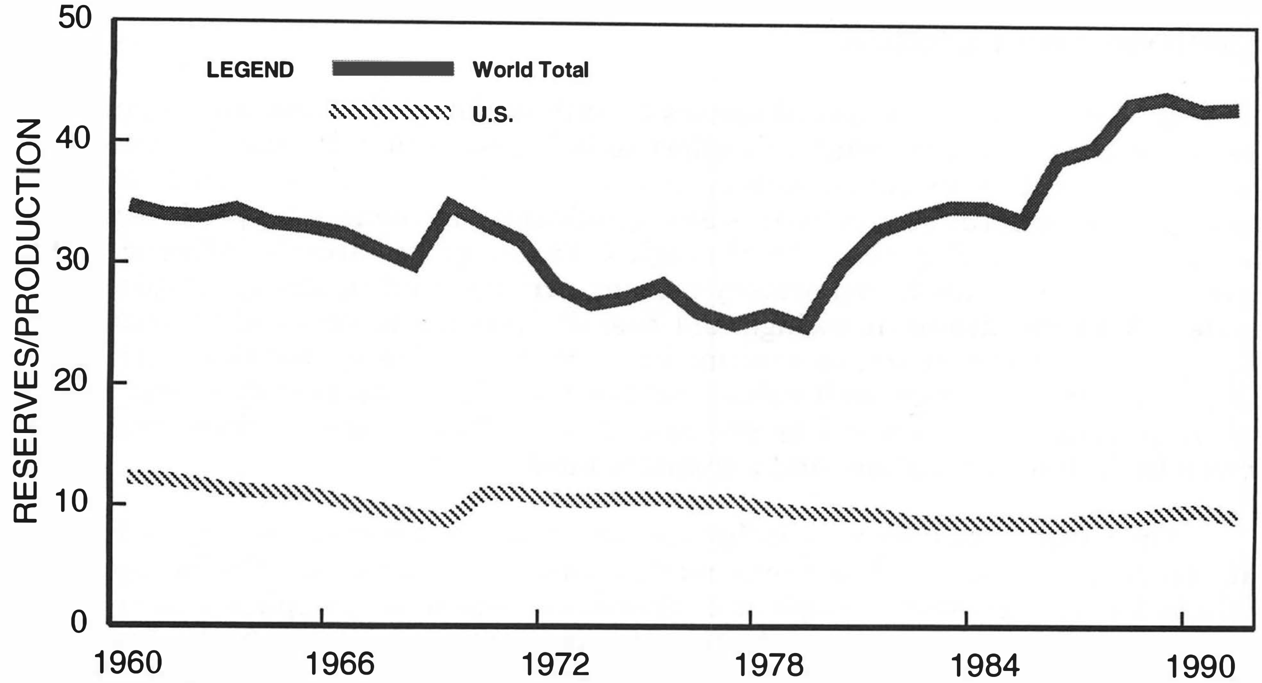
Although other countries have also experienced a decline in R/P ratio from 1970 through 1978, many of these countries have been able to reverse or flatten the declining trend throughout the 1980s. A comparison of the U.S. R/P ratio with the world R/P ratios is shown in Figure 1-14. The world R/P ratio, including the United States, is almost 5 times that of the United States alone, reflecting the relative maturity of the United States. The world total also shows an increasing R/P ratio trend since 1979.

Land seismic crew activity in the United States, another important indicator of industry's efforts to offset reserve depletion and declining production, equaled or exceeded the number of crews in the remainder of the world from 1976 to 1984, as shown in Figure 1-15. Throughout the latter half of the 1980s, U.S. land crews were only about 50 percent of the level in the rest of the world. While the decline in reserves and R/P ratio has not gone without a diligent effort on the domestic industry's part, the results of the efforts have not allowed the United States to maintain the pace of the rest of the world.



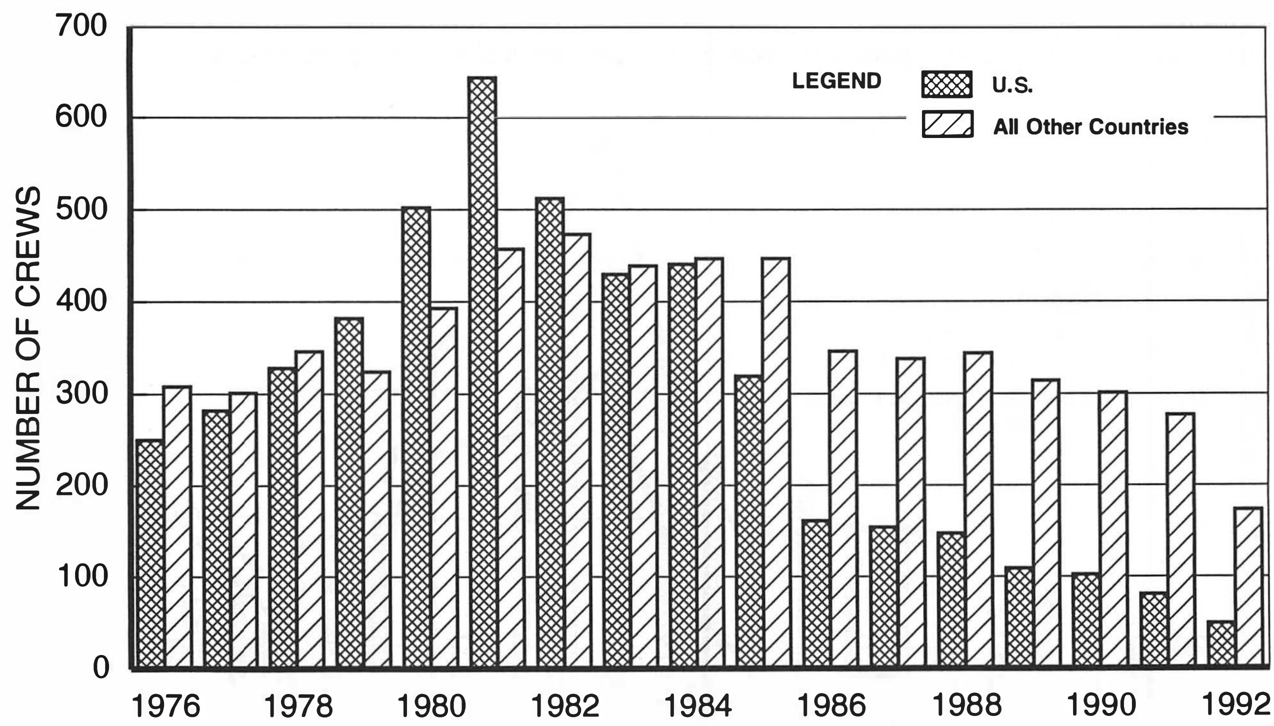
Sources: Degolyer & MacNaughton, *Twentieth Century Petroleum Statistics 1945-1991;* API, *Petroleum Facts & Figures 1971;* Gulf Publishing Co., *World Oil;* PennWell Publishing Co., *Oil & Gas Journal;* PennWell Publishing Co., *Oil & Gas Journal Energy Statistics Sourcebook 1990;* EIA; Petroconsultants S.A., *World Production & Reserve Statistics 1991.*

Figure 1-13. Reserves to Production Ratios (U.S.).



Sources: Degolyer & MacNaughton, *Twentieth Century Petroleum Statistics 1945-1991*; API, *Petroleum Facts & Figures 1971;* Gulf Publishing Co., *World Oil;* PennWell Publishing Co., *Oil & Gas Journal;* PennWell Publishing Co., *Oil & Gas Journal Energy Statistics Sourcebook 1990;* EIA; Petroconsultants S.A., *World Production & Reserve Statistics 1991.*

Figure 1-14. Reserves to Production Ratios (U.S. Compared to World Total).



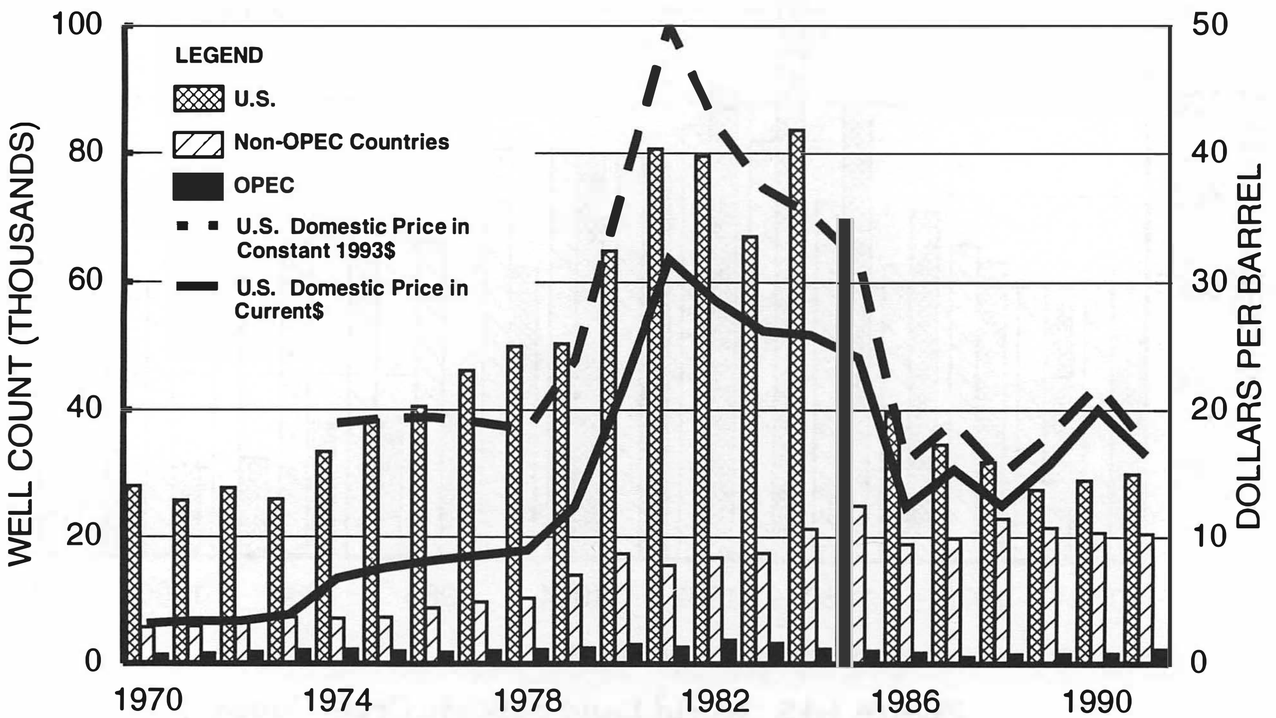
Source: Society of Exploration Geophysicists, Annual Reports.

Figure 1-15. World Land Seismic Crew Count (U.S. versus All Other Countries).

ECONOMIC DISCUSSION

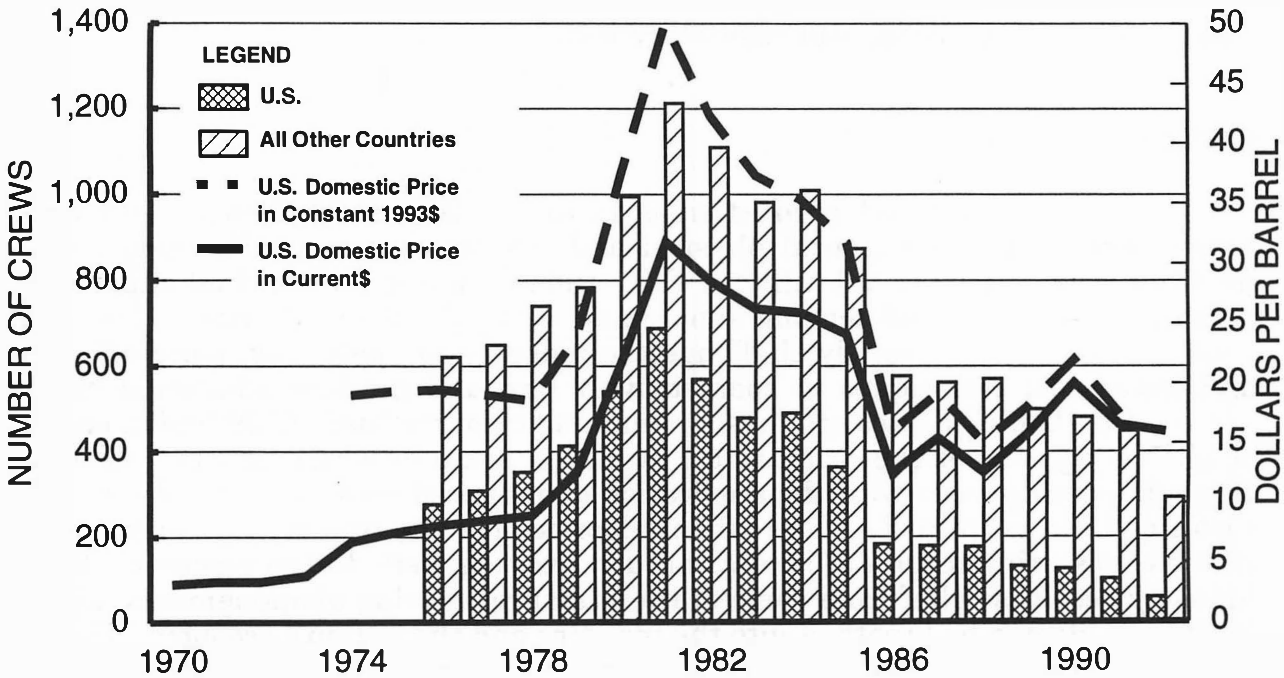
In addition to the physical factors described above, economic and regulatory pressures challenge the industry's effort to halt production decline, increase R/P ratio, and maintain marginal well production. In a commodities market such as crude oil and natural gas, activities are significantly influenced by product prices. As can be seen in Figures 1-16 through 1-18, oil price directly influences the number of wells drilled, exploratory seismic activity, and upstream employment levels. With the dramatic swings and overall decrease in commodity price seen during the past ten years, in conjunction with the declining physical attributes (i.e., production, average well rates, and reserves) of a maturing domestic industry, it is clear that survival is precarious in an environment where costs are driven by inflation, taxation, and regulatory burdens.

Operating costs directly influence the economic limit or lowest production rate from a well at which a profit margin can be maintained. Operating costs include labor, regulatory compliance, chemicals, and other supplies and services necessary to maintain well production, transportation for labor and equipment used on wells, and fuel, power, and water associated with fluid handling. Maintenance and repair costs for surface and subsurface equipment are incurred as required. As oil prices decline, minimizing operating costs pose a significant challenge for producers, because these costs typically escalate with inflation and are not directly linked to oil price. Therefore, as prices decline, all producers from the smallest to the largest have greatly reduced opportunity for profit and they must operate more and more marginal wells; and as environmental regulations have been imposed on the domestic industry, costs associated with compliance of these regulations have greatly increased the normal daily operating costs and the



Sources: Gulf Publishing Co., *World Oil;* PennWell Publishing Co., *International Petroleum Encyclopedia;* PennWell Publishing Co., *International Energy Statistics Sourcebook 1991;* Independent Petroleum Association of America.

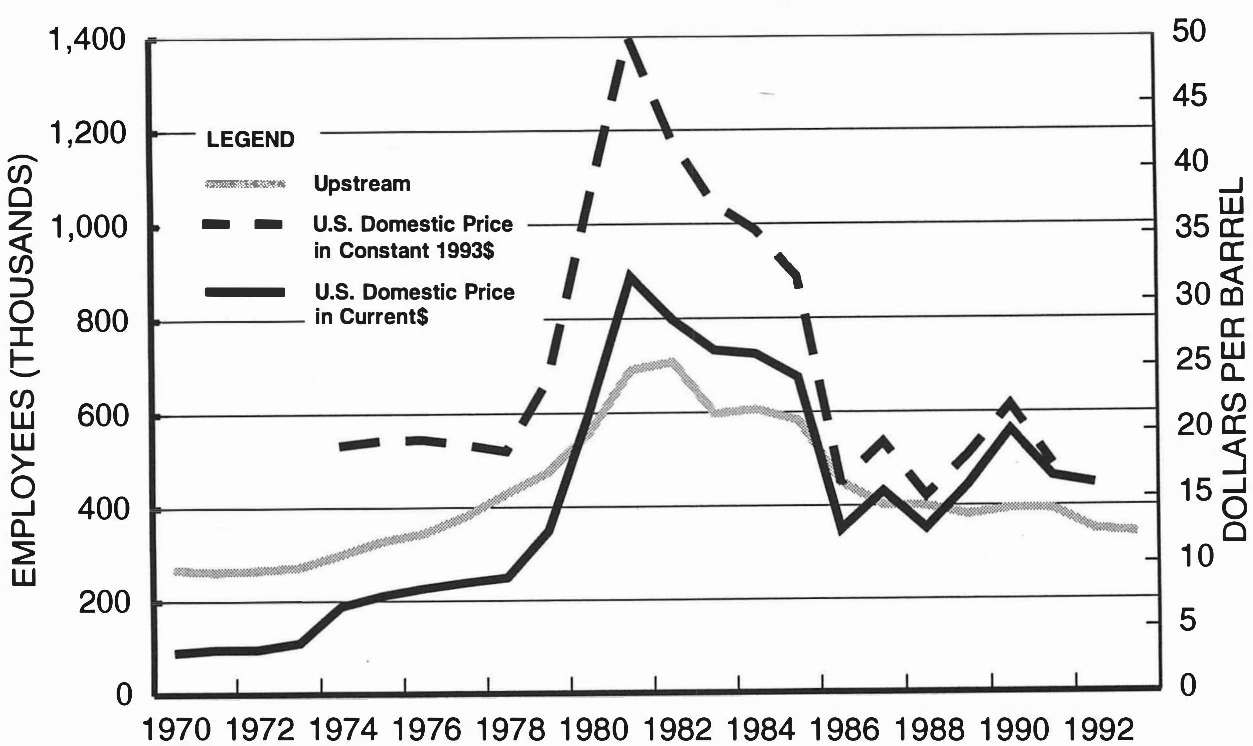
Figure 1-16. Wells Drilled (U.S. versus All Other Countries).



Note: Seismic crew data not available for 1970 through 1975.

Sources: Society of Exploration Geophysicists, Annual Reports; Independent Petroleum Association of America.

Figure 1-17. Total Land and Marine Seismic Crew Count (U.S. versus All Other Countries).



Source: Independent Petroleum Association of America.

Figure 1-18. Industry Employment.

equipment repair and maintenance costs. Chapter Seven has a more detailed discussion of environmental and regulatory issues.

CONCLUSIONS

Domestic crude oil production is facing significant challenges and pressures imposed by detrimental physical and economic factors. The global commodities market causes volatility in U.S. crude oil prices as world oil supply and demand, and events influencing supply and demand, affect oil prices. Low well production rates continually challenge the industry to apply new, more efficient, and lower cost techniques to competitively find and produce additional oil reserves. The United States still has a remaining resource base of 350 billion barrels of oil (66 percent of the original oil in place), some of which can be recovered through existing wells with the application of enhanced recovery technology. This resource base is at risk of loss when oil prices decline and well abandonments increase resulting in loss of access through existing wells to the resource. If the industry receives relief from some of the pressures driving abandonments, significant new life can be breathed into the industry and the nation's economy. Unique to the U.S. industry, each oil and gas producing lease in the United States can be viewed as a small business attempting to recover a piece of this resource base. Economic challenges faced by each of these small businesses and the industry as a whole include maintaining profitability from low rate wells as inflation and regulatory pressures increase operating costs. Protecting marginal wells from the full impact of these economic pressures is vital to maintaining the viability of the domestic industry, reducing oil imports, and preserving jobs.

Chapter Two

Natural Gas

In the past, natural gas has been the "other" hydrocarbon, neglected in many cases as an unwelcome and troublesome byproduct associated with oil. Unable to be stored on location, and not easily transported, its value was so low it was often flared or burned at the well. This scenario has changed dramatically and natural gas is now a major force in the industry as an energy source and in the economic picture of the United States.

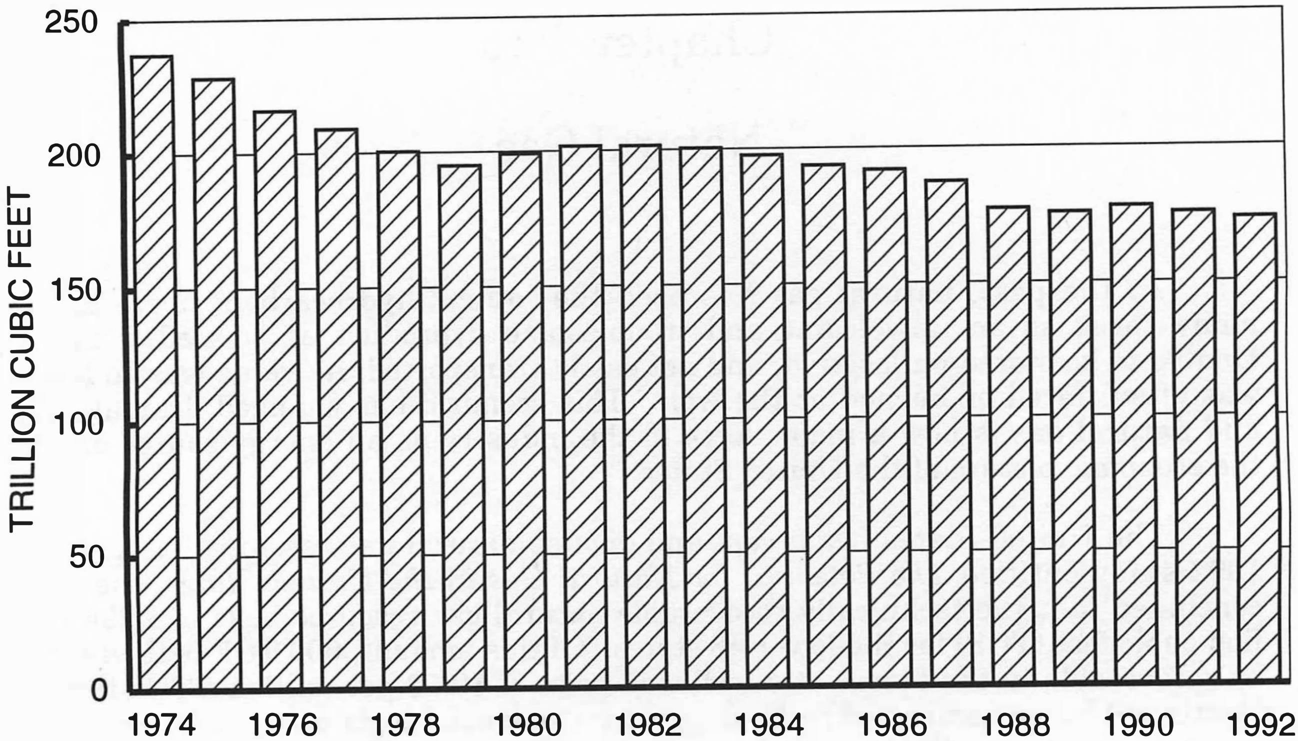
The United States has a vast and diverse natural gas resource base. In its 1992 study entitled *The Potential for Natural Gas in the United States*, the NPC concluded that the technically recoverable natural gas resource base is 1,295 trillion cubic feet (TCF) for the lower-48 states. Of this amount, 600 TCF is thought to be recoverable in the future at a wellhead price of $2.50 per million BTU (1990$). Continued advancement of technology and a balanced legislative and regulatory process are essential if the natural gas resources are to be developed in a timely and cost-effective manner.

The nation's inventory of proved gas reserves, which is defined as the volume of gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, for the 1974-1992 period, is shown in Figure 2-1. Proved natural gas reserves have trended downward from 237.1 TCF in 1974, to the 165.0 TCF level during the 1988-1992 period.

Natural gas accounts for one-third of the energy produced in the United States from all sources. It is a relatively clean-burning fuel, meeting a variety of environmental requirements. It is a secure, abundant, and primarily domestic source of energy. From a national energy security perspective, natural gas represents a far more secure energy supply than does crude oil. Currently, over 50 percent of U.S. crude oil needs are being supplied from foreign sources. In contrast, only about 10 percent of U.S. natural gas consumption is being imported. Canada supplies the vast majority of current imported natural gas, with a minor amount coming from Mexico. Another aspect of energy security is that domestic *natural gas* prices are not directly influenced by significant changes in the global marketplace, which immediately impact domestic *crude oil* prices.

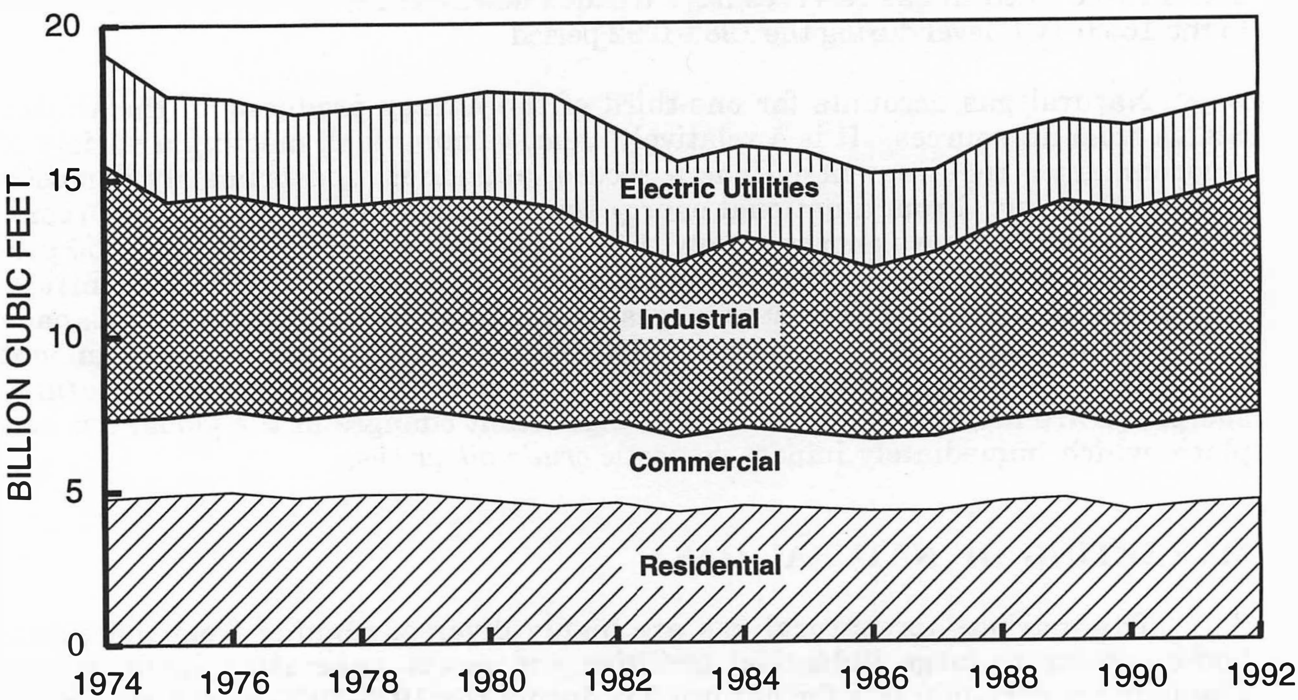
MARKETING OF NATURAL GAS

The markets for natural gas are highly diverse, ranging from individual home owners to large industrial facilities and power generation installations. The four primary markets for natural gas during the 1974-1992 period are shown in Figure 2-2. Over the entire period, the industrial sector accounted for nearly one-half of the total, while the residential sector represented nearly one-fourth of the total. The commercial and electric power generation markets accounted for the remainder.



Source: Energy Information Administration.

Figure 2-1. U.S. Proved Natural Gas Reserves (Dry Gas)—1974-1992.



Source: Energy Information Administration.

Figure 2-2. U.S. Consumption of Natural Gas—1974-1992.

Most natural gas markets are located at great distances from the gas source points, so natural gas pipeline companies developed gas storage fields near local distribution companies to handle greater than normal gas requirements during peak demand periods, insuring a reliable and steady supply. Consumer demand for gas varies widely and is contingent on any number of factors beyond the gas purchasers ability to predict.

The natural gas industry has experienced more changes in the past decade than in the previous 50 years. Prior to the 1986 partial deregulation, interstate natural gas pipeline companies controlled the natural gas from the wellhead point of purchase to delivery at the local distribution company. Natural gas producers signed long-term contracts and pipeline planners told the producers when and how much gas to deliver at each point along the pipeline.

Today, because of changes brought about by the Federal Energy Regulatory Commission (FERC), environmental concerns, and market access, interstate pipelines now serve mainly as transporters of natural gas. Currently, producers, brokers, and in some cases, pipeline marketing affiliates acting on behalf of producers, market directly to end users. Local distribution companies, along with producers and other marketers, may selectively purchase desired services that the pipelines previously included in their regulated gas sales price. Pipelines now essentially perform a transportation function rather than contractually owning and marketing the natural gas in its system. Consequently, gas producers, gas brokers, local distribution companies, and large commercial natural gas users manage their own gas supplies, and find access to transportation markets and appropriate gas storage facilities. For gas producers the transportation, storage, and administrative costs associated with this process, previously reflected in the netback price, now show up as cost of purchasing services.

PRODUCTION OF NATURAL GAS

Natural gas is produced in large quantities from several regions of the United States. These regions, in descending order, are the Gulf of Mexico, Mid-continent, Gulf Coast, Permian Basin, Rocky Mountains, Eastern United States, and West Coast (see Figure 2-3).

Since 1974, natural gas has provided approximately one-third of the overall production of energy in the United States, as seen in Figure 2-4. Petroleum, coal, nuclear, and hydroelectric account for the other two-thirds.

The number of producing gas wells in the United States since 1974 are shown in Figure 2-5. Starting at 126,997 in 1974, the number of producing gas wells increased to 280,899 by the end of 1992.

MARGINAL WELLS

Before its repeal, the Natural Gas Policy Act of 1978 (NGPA) defined a "stripper" gas well as one producing 60 thousand cubic feet per day (MCF/D) or less of non-associated natural gas. This equates to 10 barrels per day or less. Currently, Section 613A(c)(6)(E) of the Internal Revenue Code defines "stripper"

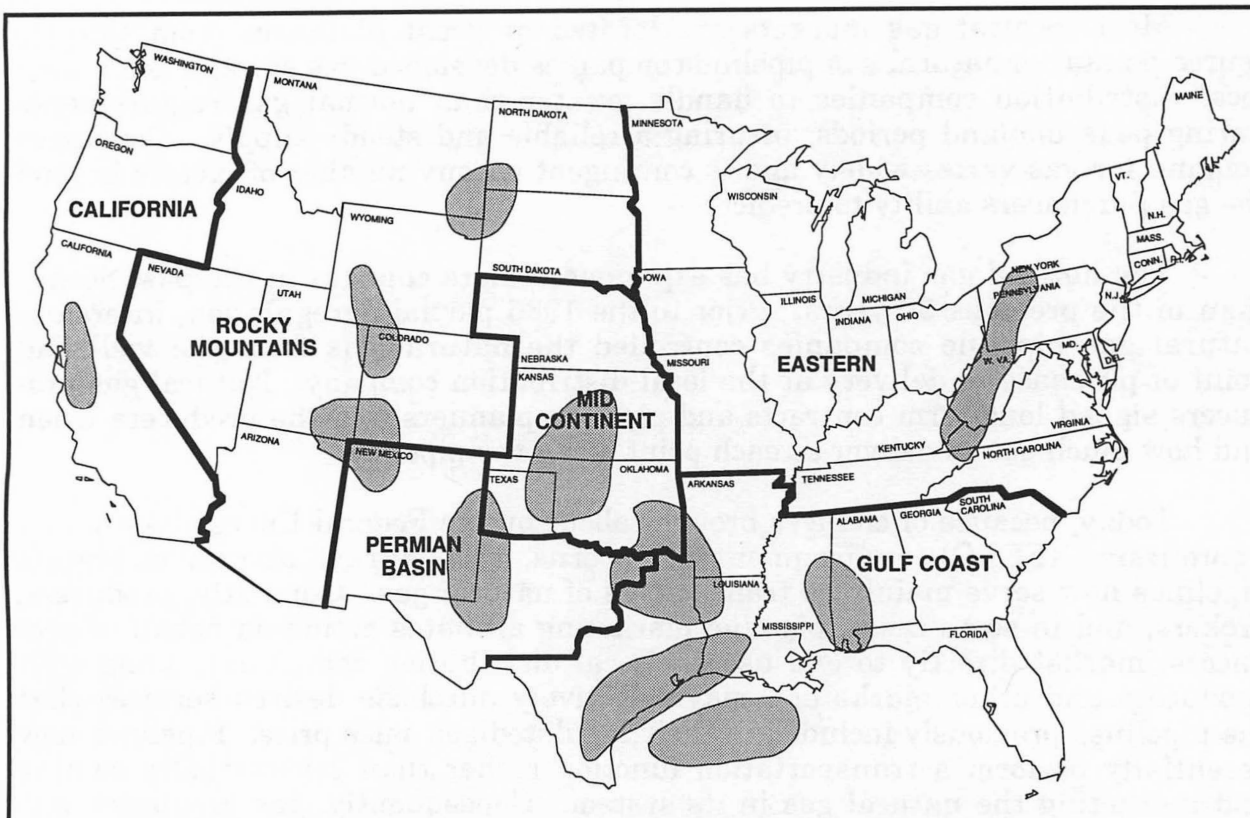
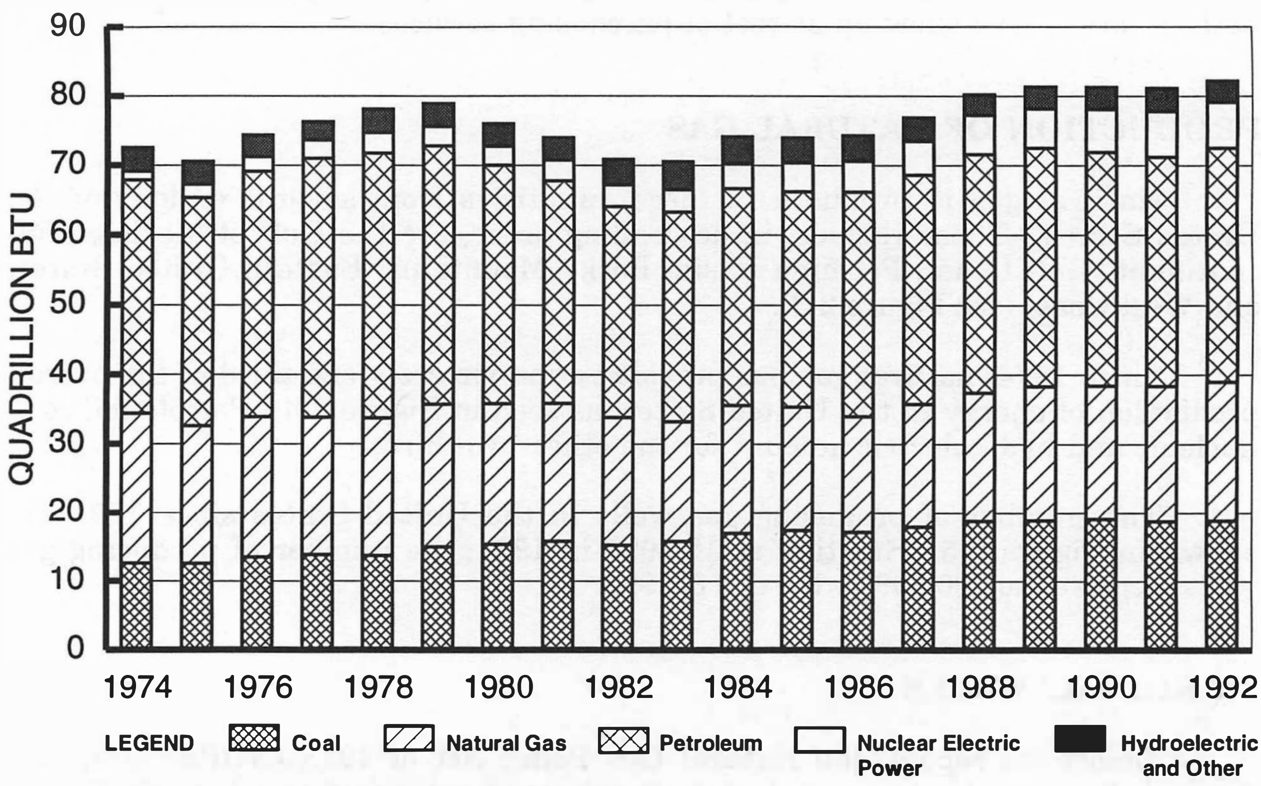


Figure 2-3. Location of Key Natural Gas Producing Areas (Lower-48 States).



Source: Energy Information Administration.

Figure 2-4. U.S. Energy Production—1974-1992.

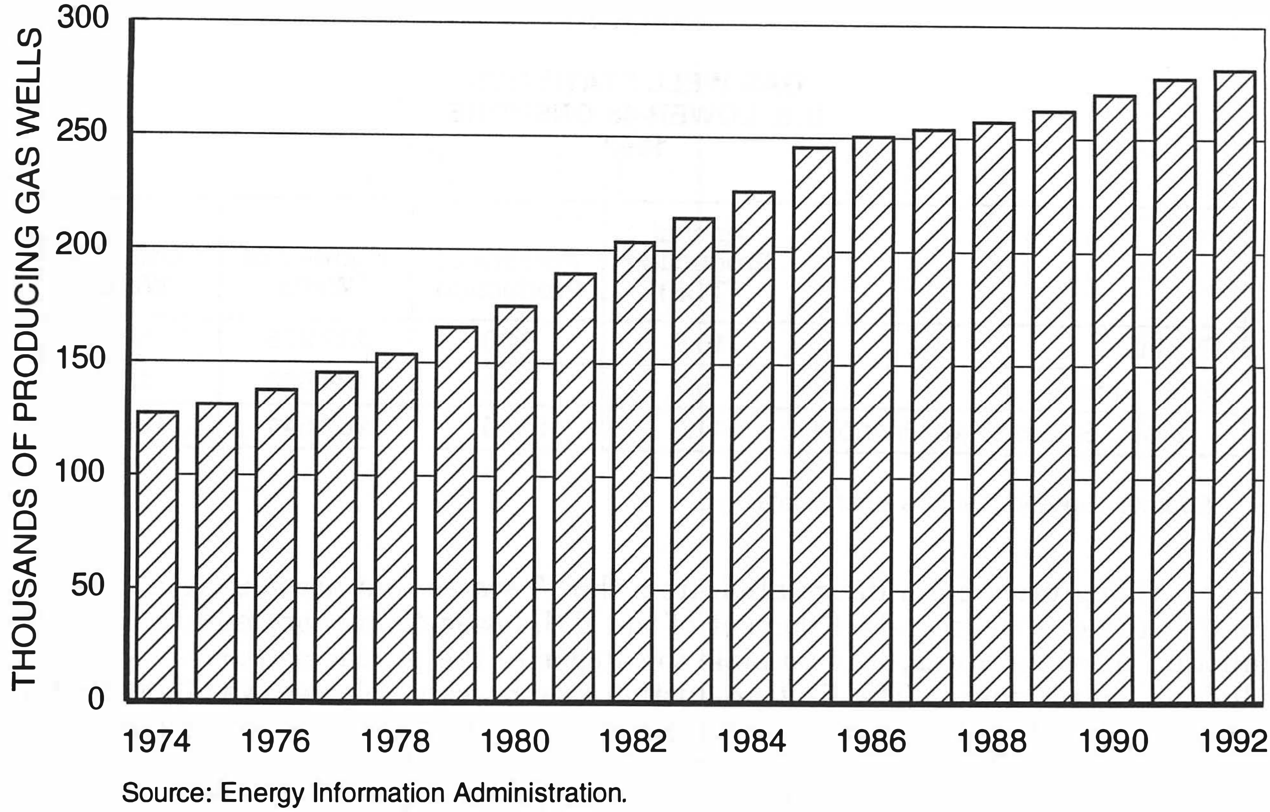


Figure 2-5. U.S. Producing Gas Wells—1974-1992.

wells as wells which produce 15 barrels of oil equivalent per day or less. (This equates to about 90 MCF/D.) Such definitions recognize and imply that a well that produces such a small volume provides a relatively small margin of profit or, in many cases, does not cover the cost to operate the well. This is generally true, but it should be pointed out that there are wells with intermediate to high producing rates that can also be marginally profitable due to low price and/or an unusually high operating cost environment; e.g., in coastal wetlands, extreme depths, remote and isolated locations, etc.

In an effort to quantify the number of marginal producing gas wells in the United States, a review of available information on the 280,899 producing gas wells reported by the EIA for 1992 was undertaken. Income and operating expense by individual gas well were not available. Based on a commercial well data firm, however, individual gas well production rates were found for 139,276 producing gas wells located in 17 states. The data collected are based primarily on state required well information filings.

The states included were Alabama, Arkansas, California, Colorado, Kansas, Louisiana, Mississippi, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Texas, Utah, and Wyoming. Using commercial data sources, relatively little information has been collected on the other 128,568 producing gas wells located in 15 other states, primarily Kentucky, Ohio, Pennsylvania, and West Virginia, commonly referred to as Appalachia. The breakdown of the data collected thus far is shown in Table 2-1. Alaska and the federal offshore was not included. Gas produced from oil wells (casinghead gas) is also not included.

TABLE 2-1

GAS WELL STATISTICS
U.S. LOWER-48 ONSHORE
1992

	Annual Production (TCF)	Percent of Production	Number of Wells	Percent of Wells
17 States	10.9	94.0	139,276	52.0
Other States	0.7	6.0	128,568	48.0
Total U.S. Lower-48 Onshore	11.6	100.0	267,844	100.0

Source: EIA and Dwight's Energydata, Inc.

Using production information from the 17 states that account for about one-half of the gas wells and 94 percent of the U.S. lower-48 onshore natural gas production from gas wells, it is possible to categorize the producing gas wells by production rate bracket. The first production rate bracket selected was 0-60 MCF/D and was based on the former NGPA definition of "stripper" gas well. The breakdown from the states collected thus far indicates that gas wells producing less than 60 MCF/D represent 50.1 percent of the producing gas wells in the 17 state group and 4.9 percent of the production as shown in Table 2-2. However, it should be pointed out that if the uncollected gas well data on the 128,568 gas wells in the Appalachia area were added to Table 2-2, the number of marginal gas wells and the percentage of U.S. production from these wells would increase significantly, since the average gas well rate from the uncollected data is 15 MCF/D.

TABLE 2-2

DISTRIBUTION OF GAS WELLS BY PRODUCTION RATE
17 STATE GROUP
U.S. LOWER-48 ONSHORE

Production Rate Bracket (MCF/D)	Number of Wells	Annual Production (BCF)	Percent of Wells	Percent of Production	Average Annual Production Rate per Well (MCF/D)
0 - 60	69,728	531	50.1	4.9	20.8
60 -90	13,843	364	9.9	3.3	72.7
90 - 300	35,590	2,081	25.6	19.2	188.8
> 300	20,115	7,915	14.4	72.6	1,075.2
Total	139,276	10,911	100.0	100.0	217.0

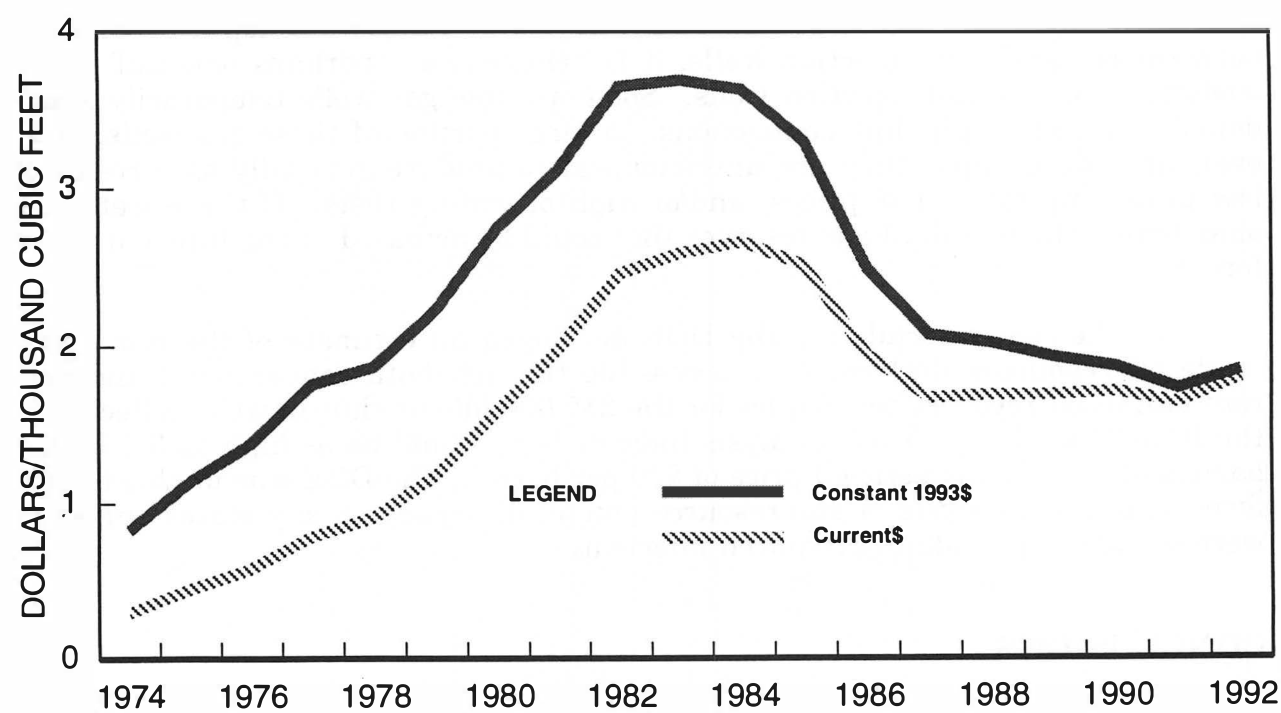
Source: EIA and Dwight's Energydata, Inc.

The number of gas wells producing less than 90 MCF/D (equivalent to 15 barrels per day) increased to 83,571 or 60 percent of the producing gas wells in the 17 states, and accounted for 8.2 percent of natural gas production from those states. There are 35,590 gas wells producing an average of 90-300 MCF/D, which account for 25.6 percent of the wells reported and 19.2 percent of production reported. The higher rate gas wells, which produce in excess of an average of 300 MCF/D, only represent 14.4 percent of the wells but account for 72.6 percent of total U.S. lower-48 onshore natural gas production from the 17 states.

PREMATURE ABANDONMENT OF GAS WELLS

There are three primary factors that influence a producing gas well's economic condition: wellhead price, operating cost, and the rate of production. The price natural gas commands in the marketplace is of particular importance. The average wellhead price of natural gas in the United States since 1974 is shown in Figure 2-6. For comparison, prices are displayed on current and constant 1993$ bases. The wellhead price on a current basis trended upward to a high of $2.66 per MCF during the 1974-1984 period, and has declined to the $1.60–$1.80 per MCF level over the last eight years. A similar trend can be seen using constant 1993$. In the past, domestic gas prices have equated to approximately 40 percent of domestic crude oil price on an equivalent BTU basis.

Various factors contribute to an increase in a gas well's operating cost and/or a decrease in the well's gas production rate often leading to a premature abandonment of the gas well and the loss of the natural gas resource. One of the more common is the mechanical failure of casing, tubing, or other downhole equipment requiring a repair expenditure that can't be economically justified.



Source: Energy Information Administration.

Figure 2-6. U.S. Natural Gas Prices—1974-1992 (Current and Constant Dollars).

Similarly, a workover attempt may fail and the well must be abandoned. Another common occurrence is when large amounts of water enter the wellbore, requiring purchase and installation of expensive pumping equipment and associated high disposal costs. Frequently, gas wells reach the point where equipment such as pumping units, separators, compressors, etc., can be put to better or more profitable use on a different well.

Gas stream contamination may exist where hydrogen sulfide, carbon dioxide, or other impurities may have to be removed prior to pipeline acceptance. This requires additional surface equipment and increases both operating and processing costs. A low pressure gas well may need compression to get into a high pressure pipeline. Poor economics may not justify the expenditure for a compressor. One or more isolated marginal wells may be too far from other wells to be profitably operated, due to increased costs associated with the additional distance and labor costs required to monitor and make repairs. Environmental concerns such as ground water, surface runoff, noise, odors, etc., and the associated regulatory and compliance costs may cause a marginal well to become uneconomical, resulting in abandonment of the well.

IDLE GAS WELLS

The Interstate Oil and Gas Compact Commission (IOGCC) completed an analysis of idle wells in 1992 and determined there are approximately 215,000 idle or shut-in oil, gas, and injection wells in the United States. These wells provide the reservoir access through which the remaining potential oil and gas reserves can be tapped.

Although the IOGCC's 1992 analysis was unable to develop a breakdown between oil, gas, and injection wells, it is believed that perhaps one-half of the wells may be gas and injection wells. Some are idle gas wells temporarily abandoned, waiting on pipeline connections. A large portion of these gas wells, however, are idle because they are uneconomical to produce generally as a result of low producing rates, low prices, and/or high operating costs. If these wells are abandoned, the potential gas reserves that could be accessed in the future are lost forever.

In the case of crude oil, the DOE developed an estimate of the remaining crude oil resources that could be accessible through both conventional and current enhanced recovery techniques for the 215,000 idle or shut-in wells collected in the IOGCC analysis. Their analysis indicated this could be as high as 3.1 billion barrels of oil at a domestic oil price of $20 per barrel. The DOE was unable to perform a similar analysis of gas resource potential, because many states surveyed were unable to provide the required information.

CONCLUSIONS

Various problems were encountered in attempting to assess the cost and benefits of preserving production from marginal gas wells. First, production information has not been collected on a large segment of producing gas wells in the United States. A total of 128,568 producing gas wells fit into this category and are located in 15 states, primarily Kentucky, Ohio, Pennsylvania, and West Virginia. These wells represent nearly one-half of the total producing gas wells and 6 percent of the total marketed production of natural gas in the onshore lower-48 states. Since it appears that a substantial portion of these wells are low rate (less than 60 MCF/D), they should be included in any analysis of marginal gas wells.

The most significant problem encountered in analyzing marginal gas wells, however, was the absence of a gas well economic model that describes with reasonable accuracy the interrelationship between gas well producing rates, operating costs, and wellhead prices. The analysis of marginal wells utilized an oil well economic model, which is described in greater detail in Chapter Five. The development of the oil well economic model, along with the industry survey and calibration process, took a major portion of the EIA and NPC's time over the relatively short study period. Consequently, there was insufficient time to undertake the development of a gas well economic model.

To adequately perform an analysis of marginal gas wells would require a substantial amount of time, the development of a reasonably comprehensive gas well database, and the design and development of a detailed integrated gas well economic model. The analysis would be complicated by the fact that the cost for treating and delivering natural gas generally has a significant impact on gas well economics. In addition, as part of the operations involved with the delivery of natural gas, well pressure data would be required to determine compression requirements and well abandonment timing.

Coalbed methane and gas from tight formations could require special considerations due to the different producing characteristics and current tax incentive structure. Particular attention would need to be directed to developing a solid understanding of gas well operating costs and practices in the Appalachian area. A careful assessment and calibration would have to be undertaken of any resulting economic analyses.

In conclusion, the overall cost and benefits of such a complex and timely joint industry and government study needs to be examined thoroughly. However, it is clear that whatever combination of price and cost factors currently define the economic limit of a marginal gas well, production based incentives (on BTU equivalents) will improve gas well economics and extend the life of otherwise marginally uneconomic gas wells. Since premature abandonment of marginal wells results in the loss of domestic resources, marginal oil and gas well incentives are a means to maintain the economic viability of the production and resources that these wells represent.

Chapter Three

Stripper and Heavy Oil Well Contribution

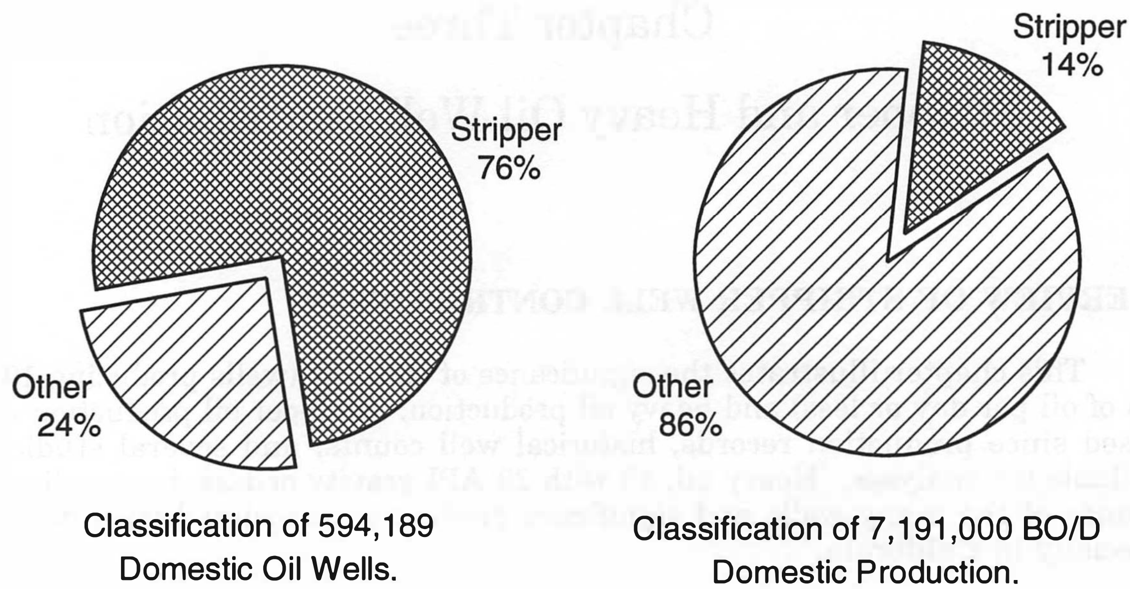
OVERVIEW OF STRIPPER WELL CONTRIBUTION

This chapter illustrates the significance of stripper (wells producing 10 barrels of oil per day or less) and heavy oil production. Stripper oil production is discussed since production records, historical well counts, and several studies are available for analyses. Heavy oil, oil with 20°API gravity or less, is also discussed because of the many wells and significant production associated with heavy oil, especially in California.

Stripper wells are not typically thought to be significant contributors in terms of production, reserves, or revenues. However, an average well in the United States produces only 12 barrels of oil per day, and stripper wells comprise a significant part of the more than 590,000 total lower-48, onshore producing wells and 7,200,000 barrels of oil that these wells produce daily. In an effort to quantify the number of stripper wells and production from these wells, the Interstate Oil and Gas Compact Commission (IOGCC) published the most recent National Stripper Well Survey in January 1993. For the purposes of IOGCC's survey, stripper wells were defined as wells that produce 10 or less barrels of oil per day. The survey indicates that, in 1992, 453,277 stripper wells out of a total of 594,189 wells (76 percent of all U.S. wells) produced slightly over 1,000,000 barrels of oil per day (14 percent of the U.S. total). Note that approximately 4 percent of the stripper wells and 11 percent of stripper production are heavy oil wells and heavy oil production, which are discussed later in this chapter. Figure 3-1 reflects the distribution of stripper wells and production. During 1992, this stripper production component had an estimated total economic impact of $9.9 billion.

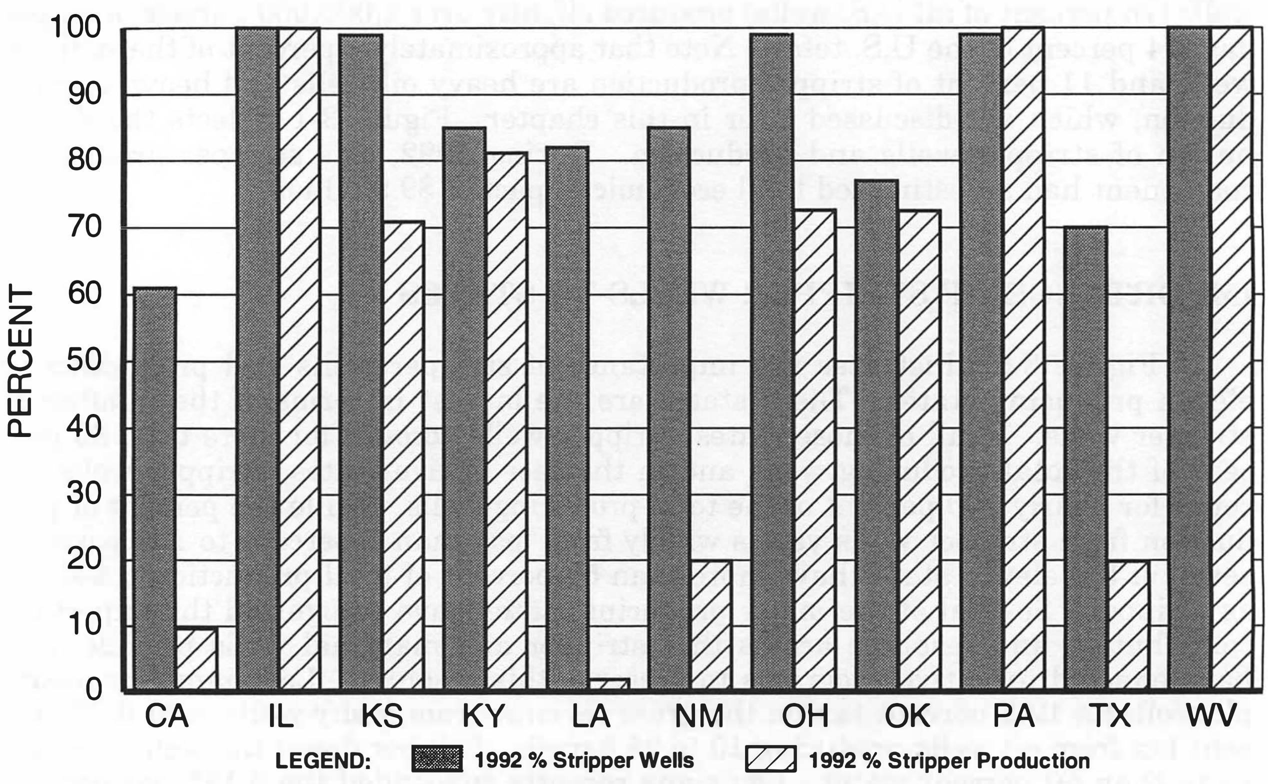
IMPORTANCE OF STRIPPER WELLS TO STATES

Figure 3-2 illustrates the importance of stripper wells and production to eleven producing states. These states are the largest in terms of the number of stripper wells. In all of these states, stripper wells account for more than 50 percent of the total producing wells and in the case of five states, stripper wells account for nearly 100 percent of the total producing wells. While the percent of production from stripper wells varies widely from less than 5 percent to 100 percent, seven of the eleven states have more than 50 percent of total production classified as stripper. Several of the major producing states have recognized the important contribution and resource access that stripper and marginal wells provide, and have enacted incentive programs to preserve this resource. Louisiana, for example, collects 12.5 percent tax on the gross revenue from many wells, and 6.25 percent tax from oil wells producing 10 to 25 barrels of oil per day if the wells produce more than 50 percent water. Louisiana recently suspended the 3.125 percent tax on wells producing less than 10 barrels of oil per day when the domestic price of oil falls below $20 per barrel. This incentive program is discussed further in



Source: National Stripper Well Association; National Well Survey; Energy Information Administration, *Petroleum Supply Annual; World Oil Magazine*, Forecast Review Issue, February 1994.

Figure 3-1. Distribution of Stripper Wells and Production.



Source: National Stripper Well Association; National Stripper Well Survey.

Figure 3-2. Stripper Wells and Production in Eleven Producing States.

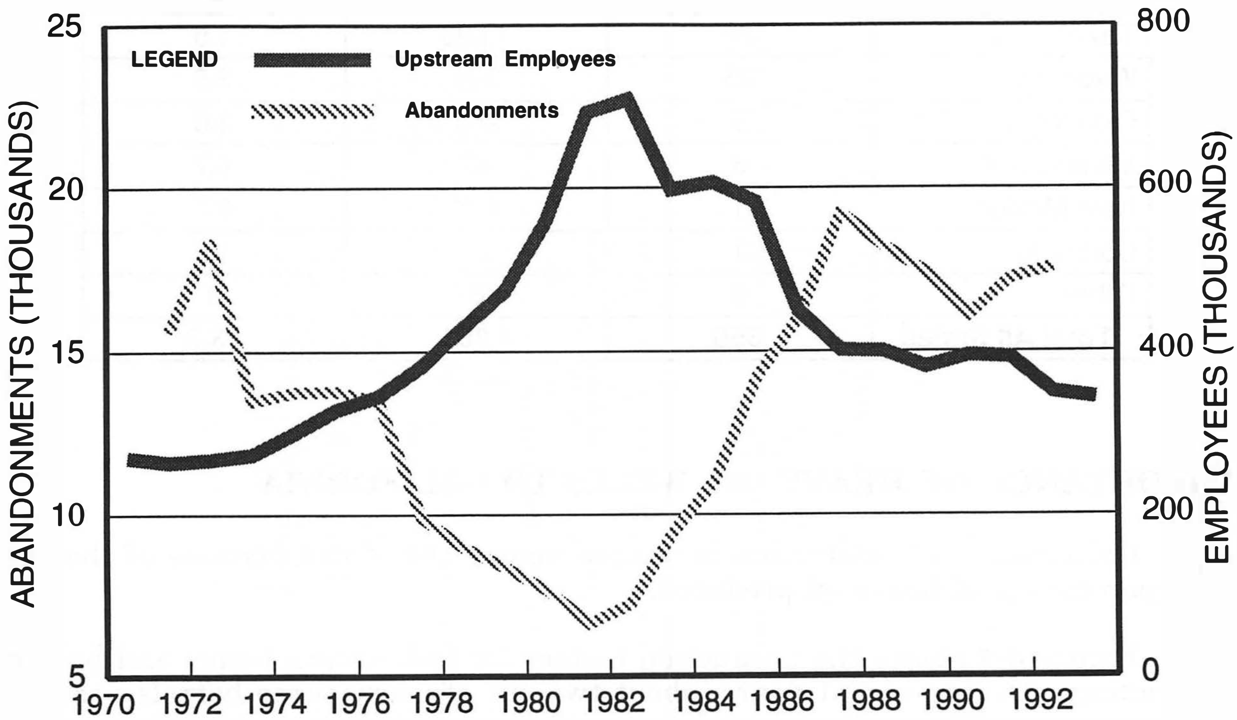
Chapter Six. As production naturally declines over time, the percentage of stripper wells in all states will increase as long as they generate a positive cash flow. In some situations, operators will delay abandonment and continue to produce wells in a negative cash flow status in order to preserve leaseholds and investments. This is discussed in greater detail in Chapter Five. During periods of low oil price, wells can fall into a negative cash flow situation before declining to the stripper well rate of 10 barrels per day, therefore discussion of marginal wells after this chapter will not be limited to the stripper well classification.

STRIPPER WELLS' ECONOMIC CONTRIBUTION

In February 1994, the IOGCC published a report entitled *Fuel for Economic Growth*, which addressed the value of production and total economic impact generated by stripper wells. Their analyses indicated the value of stripper well production in 1992 exceeded $6.5 billion and had a total economic impact of over $9.9 billion. Including jobs directly dependent on production from stripper wells and jobs outside the oil and gas industry, approximately 59,000 jobs can be attributed to the 453,000 stripper wells and the 1,000,000 barrels of oil produced daily from these wells.

STRIPPER WELL ABANDONMENTS AND JOBS

A further demonstration of the economic impact of stripper wells is illustrated through an analysis of the relationship of stripper well abandonments and upstream employment trends. Figure 3-3 shows the close correlation of these two



Source: Interstate Oil and Gas Compact Commission; National Stripper Well Association; National Stripper Well Survey; Independent Petroleum Association of America.

Figure 3-3. Industry Employment.

factors, underscoring the importance of the number of active wells on employment levels. As abandonments fell to approximately 7,000 wells in 1981 and 1982, employment peaked at just over 700,000. This supports the conclusion that to maintain production from a well requires a certain level of employment, regardless of the amount of oil being produced from the well.

OVERVIEW OF HEAVY OIL WELL CONTRIBUTION

While exact figures on heavy oil production are difficult to obtain, the approximate breakdown of domestic heavy oil production from the onshore lower-48 states is shown in Table 3-1. Heavy oil represents about 15 percent of "lower-48" oil production and about 10 percent of total U.S. production. The vast majority of domestically produced heavy oil occurs in California, with small amounts produced in several states, most notably Texas and Wyoming. Therefore, while heavy oil production is somewhat significant vis a vis total domestic production, heavy oil production is very significant in California where it represents about two out of every three barrels produced.

TABLE 3-1

1993 DISTRIBUTION OF HEAVY OIL PRODUCTION ONSHORE LOWER-48 STATES (Thousands of Barrels per Day)

State	Heavy Oil Production	Total Oil Production	% Heavy Oil
California	592	803	737
Texas	25	1,696	1.5
Wyoming	23	240	9.6
Oklahoma	8	265	3.0
Mississippi	6	62	9.7
New Mexico	1	187	0.5
Colorado	1	81	1.2
Other	0	967	0
Total All States	**656**	**4,301**	**15.3**

IMPORTANCE OF HEAVY OIL WELLS TO CALIFORNIA

California's oil production is unique among the states because of the very high percentage of heavy oil produced.

Figure 3-4 shows the production history for California's heavy and light oil production. During recent years, about two out of every three barrels produced was heavy oil. The percentage of heavy oil increased during the 1960s and, as shown in the figure, continued to increase in the 1970s and 1980s. This increase was the result of many thermal enhanced oil recovery (EOR) development projects during this period. In the last few years, this heavy oil/light oil percentage mix

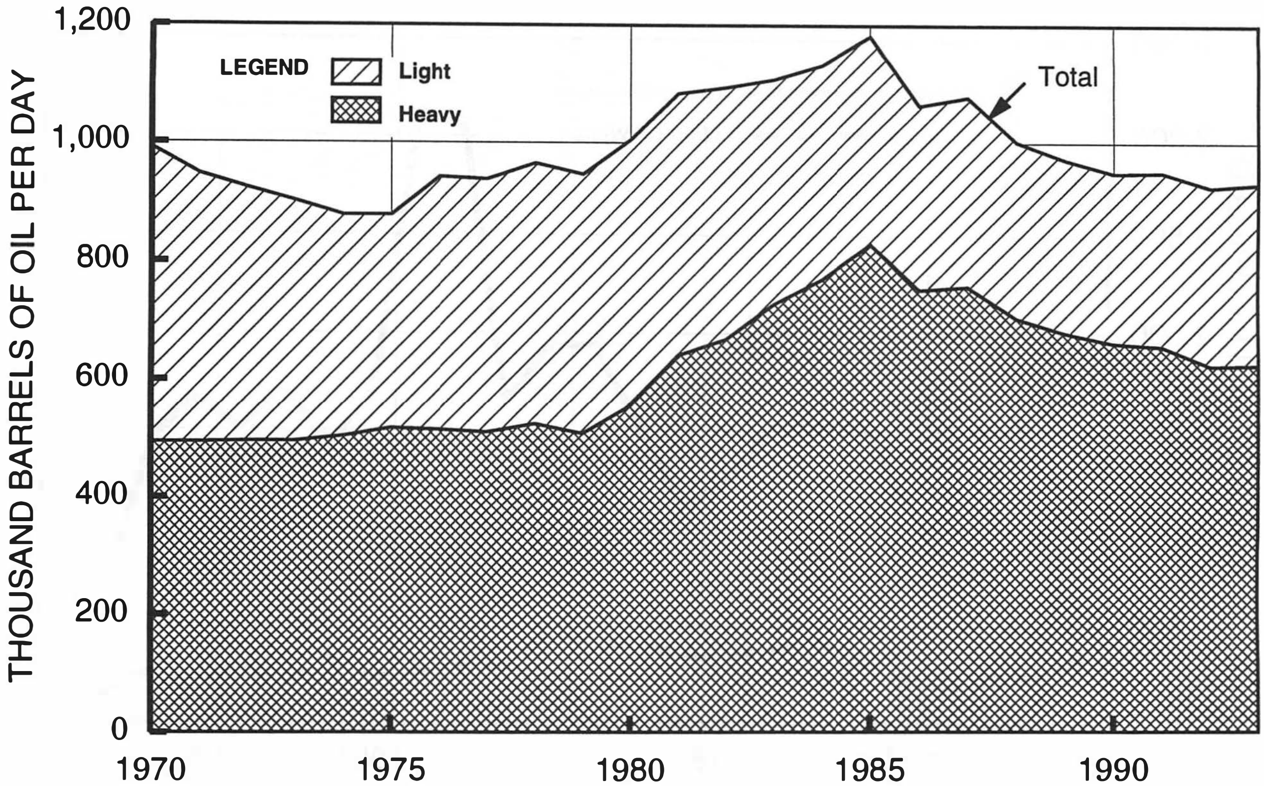


Figure 3-4. California Oil Production.

has remained relatively steady due to a reduction in capital intensive thermal development projects caused by the crude oil price collapse in 1986. Figure 3-5 provides a history of the number of California oil wells drilled broken down by heavy and light wells. The number of new wells provides an indication of the capital development expenditures associated with heavy and light oil development projects. As can be clearly seen, the 1986 crude oil price decline reduced the number of wells drilled, which resulted in a very significant reduction in the capital expenditures by the industry in California. This has had a significant impact on employment by the industry in California and the latest employment figures available (first half of 1993) indicate a 36 percent reduction in direct and indirect upstream industry employees from 1985 employment. This represents a loss of over 32,000 jobs during this period.

In addition to a significant employment job loss, state and local revenues from upstream activities fell from $1.1 billion in 1985 to $0.4 billion in 1992. This reduction has contributed to the general economic recession that currently exists in California. Because of the distribution of oil production within California, this loss of jobs and revenue impacts certain areas more heavily than others. In Kern County, where over 60 percent of California's oil production is located, ad valorem taxes from oil properties, measured as a percentage of total property assessment, has fallen from 55 percent in 1985 to just over 30 percent currently.

OWNERSHIP OF WELLS BY SOCIETY

In addition to the employment supported by wells, wells in the United States have an ownership chain that is unlike any other in the world. This ownership

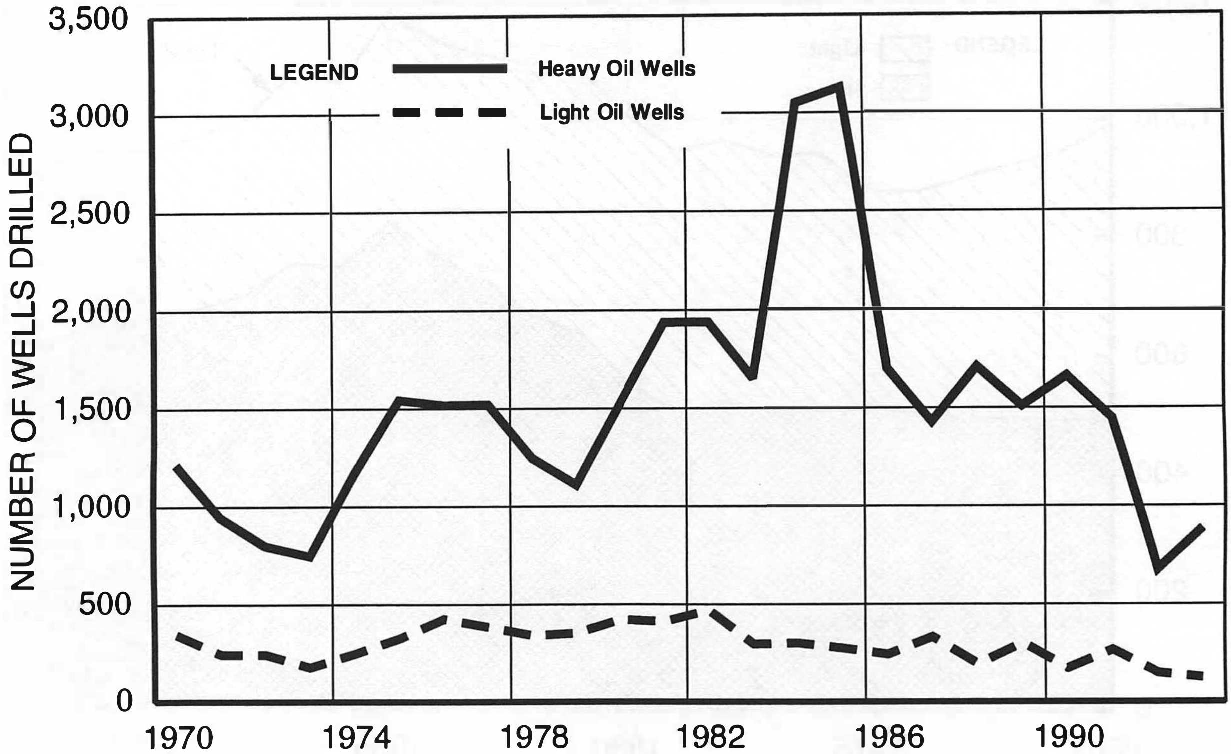


Figure 3-5. California Wells Drilled.

chain can involve state or federal government, small independent operators (ranging in size from a family run operation to the small company with 10 to 100 employees), individual land and mineral royalty owners, and large integrated companies. General statements about operatorship of wells in various producing rate classifications can be made based on work completed by the Energy Information Administration. This work indicates that the very low rate wells, 0 to 3 barrels of oil equivalent per day (BOE/D), are typically operated by the small independent operators. Once above the 3 BOE/D rate, wells are operated by both large companies and the small independents. The Texas Railroad Commission states that "Texas has over 7,000 companies with active oil wells. Some 3,300 of these companies (47 percent) produce less than one barrel a day from each well. These small producers are vital to Texas. Of the state's 184,000 producing oil wells, over 130,000 produce less than 10 barrels of oil a day."

Royalty mineral owners cover the complete spectrum of demographics. The National Association of Royalty Owners membership is composed of nearly 5,000 individual members and represents an additional 38,500 mineral owners belonging to regional and county affiliations. One of the major oil companies participating in this study stated that it sends over 80,000 royalty checks monthly. Although some operators are also mineral owners, there are nearly 23,000 additional corporations involved in the domestic gas and oil industry. All 50 states have royalty owner representation, demonstrating the influence and variety of ownership of gas and oil wells throughout society. The above numbers refer primarily to the upstream or producing segment of the industry and does not consider the significant downstream, refining, and end product beneficiaries.

In light of the diverse and numerous ownership of wells and leases, considering each lease to be a small business is much more appropriate than the stereotypical view of a large oil company.

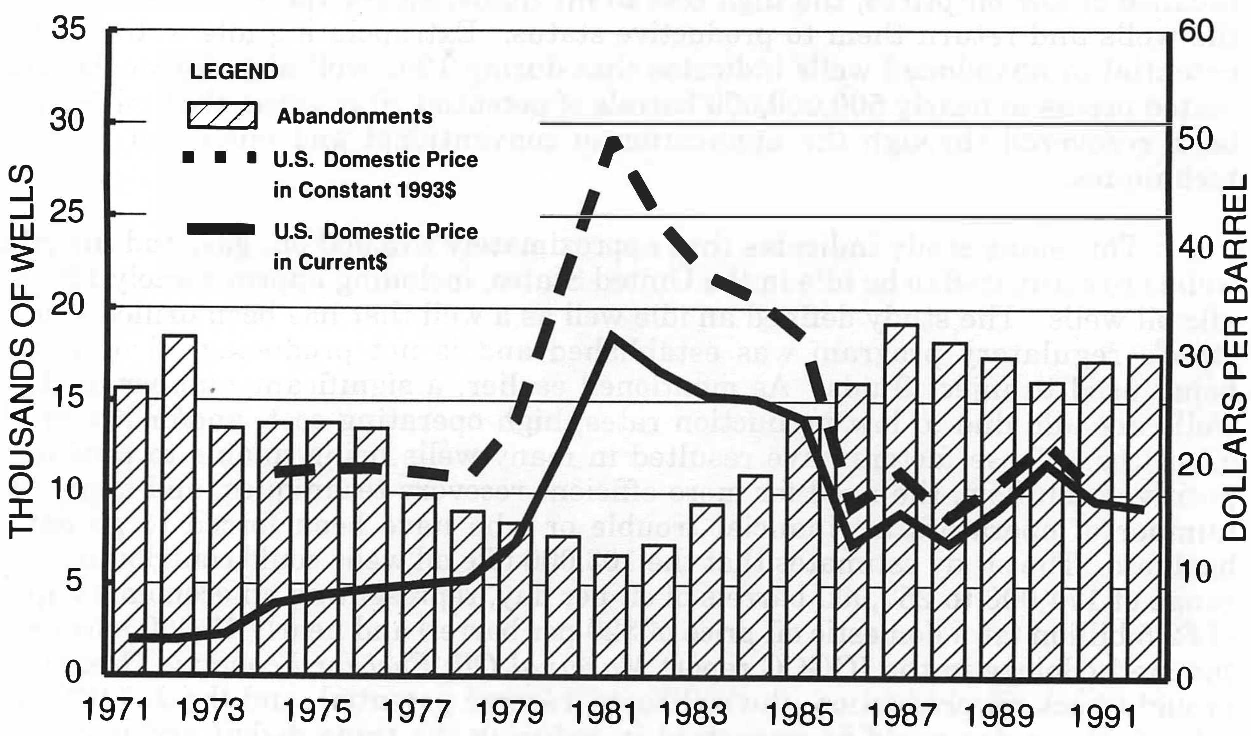
WELL ABANDONMENTS, IDLE WELLS, AND LOSS OF RESOURCE ACCESS

The previously referenced IOGCC stripper well survey also addresses stripper well abandonments and indicates that 16,211 wells were abandoned during 1992. The abandonment of wells, which contribute less than 2 barrels of oil per day per well, is significant not only in terms of economic impact and employment, but also because once these wells are abandoned, access to the resource base tapped by these wells is gone forever. Many of the advanced recovery technologies employed in the U.S. industry today rely on access to existing resources through these wells. Without this existing access, many technologies are not economically viable because of the high cost to replace the wells. In a separate IOGCC study sponsored by the U.S. Department of Energy, entitled *A Study of Idle Oil and Gas Wells in the United States*, an estimate was made of the resource potential associated with idle wells. Idle wells are wells that are not producing—in most cases because of low oil prices, the high cost to lift fluids, and/or the high cost to repair the wells and return them to productive status. Extrapolating idle well resource potential to abandoned wells indicates that during 1992 well abandonments eliminated access to nearly 500,000,000 barrels of potential oil reserves that might have been recovered through the application of conventional and enhanced recovery techniques.

This same study indicates that approximately 215,000 oil, gas, and injection wells are estimated to be idle in the United States, including approximately 103,000 idle oil wells. The study defined an idle well as a well that has been drilled since a state's regulatory program was established and is not producing oil or gas or being used to inject fluids. As mentioned earlier, a significant number of these wells are idle due to low production rates, high operating cost, and/or low crude oil prices. These factors have resulted in many wells being unable to produce a positive cash flow, the need for more efficient recovery techniques, and a growing number of operators in financial trouble or who have been forced to go out of business. The study estimates that the 103,000 idle oil wells could contribute in the range of 174,000 to 257,000 barrels of oil per day, representing an economic impact of $2.5 billion (at a domestic oil price of $20 per barrel) and nearly 15,000 jobs using the methodology in the IOGCC report *Marginal Oil: Fuel for Economic Growth*. If brought back on production, the wellbores, reserve potential, and the 257,000 barrels of oil per day could be important in reducing the trade deficit and maintaining jobs in the United States. The DOE has estimated that these idle wells could provide as much as 2.6 billion barrels of oil using conventional recovery technology if the average domestic oil price was approximately $20 per barrel. An additional 500,000,000 barrels of potential reserves could result from the application of enhanced recovery techniques which would utilize these same wellbores. The report indicates that these estimates could be optimistic due to the methodology utilized by the DOE, but the potential is not insignificant under any methodology.

The idle well study also addressed environmental issues associated with these wells. The report states that the idle wells *do not* represent an environmental threat; however, these wells *do* represent a financial liability. At some point in time, the owner of the well will be required to expend funds for abandonment of these wells. The report states that of the total estimated 215,000 idle wells, approximately 50,000 have no identifiable operator. Abandonment of these wells may ultimately be the burden of state governments. Efforts to preserve these wells and the access to potential reserves may provide partial abandonment funding for the future, but this is by no means certain. The Idle Well Report indicates that over $43 million of state-controlled funds have been used to abandon 8,700 wells. An additional 21,000 wells have been identified as abandonment candidates.

Under the current oil price environment, it is expected that significantly more well abandonments will occur as operators find that their wells generate insufficient revenues to offset operating expenses or fall into a negative cash flow situation. With the increase in well abandonments that has occurred since the early 1980s, a large reserve potential will continue to be lost as will the opportunity to further develop the resource tapped by these wells under new technology and/or higher oil prices. Figure 3-6 illustrates the relationship between oil price and well abandonments. At price levels around $15 per barrel, abandonments are expected to approach 20,000 wells per year.



Source: Interstate Oil and Gas Compact Commission; National Stripper Well Association; National Stripper Well Survey; Independent Petroleum Association of America.

Figure 3-6. Well Abandonments versus Crude Oil Price.

CONCLUSIONS

Stripper (10 or less barrels of oil per day) and heavy oil (less than 20 degrees API gravity) wells provide approximately 21 percent of the nation's daily oil production and account for 79 percent of the nation's wells. More than half of the oil production from seven producing states is derived from stripper wells. More than two-thirds of California's production is heavy oil. Stripper wells have been estimated to contribute $9.9 billion annually in economic benefit to the nation and provide approximately 59,000 jobs. As oil price falls, stripper and heavy oil wells generate negative cash flow and are idled and many are abandoned. Provided the proper economic incentives, these idled and abandoned wells could provide access to billions of barrels of oil resource that could be produced in an improved economic environment or under advanced recovery technology.

Chapter Four

Marginal Oil Well Characteristics

DEFINITION

An appropriate definition for a marginal oil well or property is the production rate where the future revenue is equal to or less than the future costs. Marginal wells and properties have normal operating costs relatively close to the revenue generated. The production, reserves, jobs, and other resources are at risk if oil prices decline or operating costs increase. Oil price and operating costs are influenced by many factors, which vary significantly from region to region. Therefore, the price and rate defining the initiation of marginal status will vary from property to property.

Generally, there are three distinct categories of marginal properties: those with continuous operations (Class 1), those with intermittent operations (Class 2), and heavy oil (Class 3). Within the Class 1 and Class 2 categories, production methods include primary, secondary, enhanced oil recovery (EOR), and fully matured operations. Primary production involves operations where no extraneous energy has been provided to the reservoir and the natural reservoir drive mechanism prevails. In secondary recovery operations, an extraneous energy source is provided through injection of fluids into the reservoir that improve oil recovery, primarily by improving oil displacement (sweep efficiency) and pressure maintenance, but does not affect immobile hydrocarbon saturations. Enhanced oil recovery operations involve injection of an extraneous energy source such as steam, gases, or chemicals, which can reduce immobile hydrocarbon saturations. These operations are prevalent in Class 3 properties. The fully matured properties are those that have previously been produced under one or more of the aforementioned operations. As a result of production decline, increased costs, or a decrease in oil price, the operation (primary, secondary, or enhanced oil recovery) is no longer economically viable and the properties are being "milked" of the last drops of oil production. Typically, smaller operators have acquired these properties from the larger companies and have developed very efficient methods to profitably operate properties producing very low oil volumes.

Continuous Operations

The continuously operating property (Class 1) has specific characteristics commonly found in water drive reservoirs. The most significant of these characteristics is that extended periods of downtime appreciably reduce recoverable reserves. In active waterfloods, downtime of both injection and producing wells will cause oil to be bypassed and reserves lost. Intermittent operation (Class 2) is impractical for waterfloods and active water drive reservoirs. Because of the scale of the operation and the issue of lost reserves, these properties may operate in an uneconomic mode for more than one year when unexpected drops in oil price occur. Additional discussion of properties operating below an economic limit is provided in Chapter Five. Another trait common to the Class 1 wells is the relatively high daily operating cost (not necessarily high cost per barrel of oil) associated with the production and disposal of substantial volumes of water. These costs can, however, vary significantly from field to field. As Class 1 properties become marginal, ownership may transfer to smaller operators who can efficiently operate the property in a Class 2 mode.

Since the Class 1 wells are produced continuously and operations are generally initiated by the larger producing companies, it is easier to estimate the impact of low oil prices, declining production, increased costs, and incentives that could help sustain the operation. Most of the known EOR reserves recoverable by miscible and chemical methods are located in fields with Class 1 wells. Development of new EOR technology, under higher oil price scenarios, will likely occur in these fields since there is a well-developed base production level which can better absorb additional costs.

Intermittent Operations

The intermittently operated (Class 2) marginal wells generally represent a class of wells producing smaller volumes of oil and water. This class of wells may be produced only a few days every month or may operate on time clocks that allow the wells to run for short periods of time each day. The majority of these wells may be produced intermittently without significant loss of reserves. Continuously operated properties producing small volumes of oil with low water handling costs (or other operating characteristics that differentiate the cost structure from Class 1 and Class 3 wells) may also be considered part of this class. Since Class 2 wells require very efficient low cost operations, they are not amenable to harsh conditions such as corrosive fluids, high fluid volumes, or other situations that would preclude maintaining low operating costs (not necessarily low cost per barrel of oil produced).

All producers have Class 2 properties, but they are most often owned by small operators. In 1992, 193,172, or 33 percent, of the wells in the lower-48 onshore states averaged less then one barrel per day of oil production, yet intermittent production operations can perpetuate the life of these wells for many years. It is difficult, however, to evaluate the economics of this type of marginal production since most public production records do not contain the well information necessary to determine the number of producing days and the corresponding product price received during each month. A small change in producing rate or any incremental cost can significantly influence the cost per barrel of oil production for this class of wells. An example of this is provided in the economics discussion in Chapter Five. The analysis of the Class 2 wells undertaken in this study is based on the assumption that most were economic in 1993. Generally, Class 2 wells cannot operate as long as Class 1 wells when unexpected drops in the oil price cause them to become uneconomic. The upcoming discussion of marginal wells in the Eastern United States is particularly pertinent to Class 2 wells.

Heavy Oil

The heavy oil (Class 3) marginal wells represent a separate and diverse class of wells. As discussed in the previous chapter, most heavy oil producers are located in California. Thermal enhanced recovery (primarily steam injection) technology is utilized in many of the wells. A number of distinct features qualify heavy oil as marginal production. Each characteristic is generally unique when compared to other oil operations. It is this distinctiveness that lead to the inclusion of heavy oil as part of the existing marginal well definition in the federal tax code.

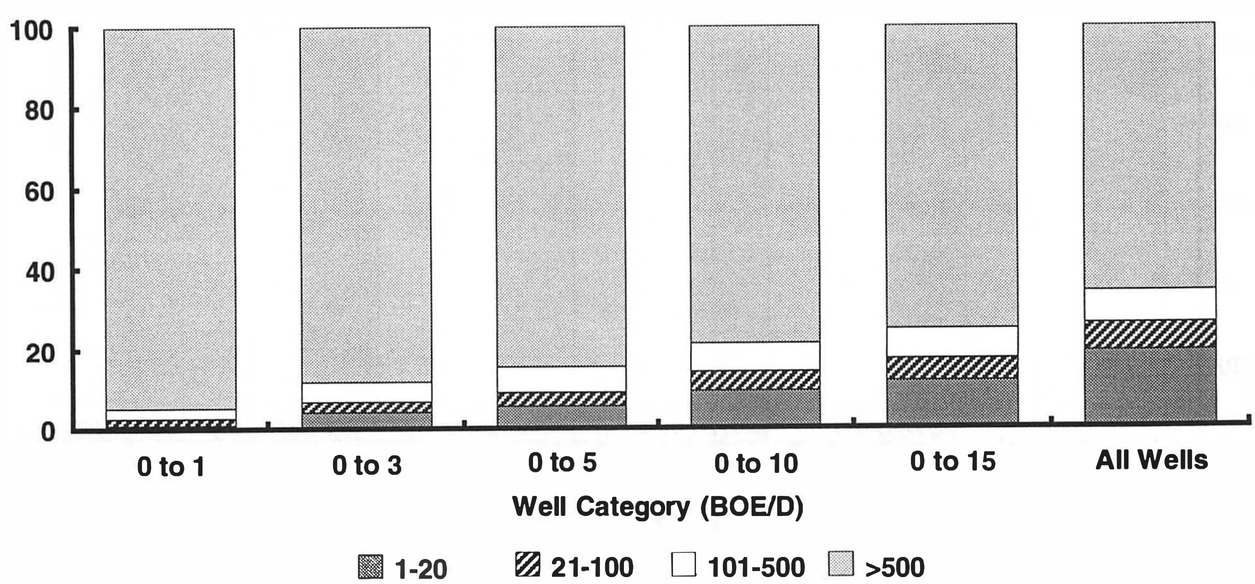
Heavy oil operations are discussed in greater detail as part of the report on marginal well characteristics in the California region. Additional information regarding California production and heavy oil is available in Appendix E.

REGIONAL FACTORS

The following sections describe the special production, reservoir, and market factors contributing to the marginality of wells and the acceleration of their abandonment in the Eastern United States, Gulf Coast, Permian Basin, Midcontinent, Rocky Mountains, and California regions. Essentially all of the factors mentioned are present, to a certain extent, in each region; however, the upcoming regional discussion attempts to focus on those that are found to be most prevalent within a particular area.

At the beginning of each section discussing regional factors, a map outline of the region is shown with a barrel that compares the first half 1994 average domestic oil price to the first half 1994 regional oil price. Also shown is the percentage distribution of well ownership by operator class size for various production rate categories. Operator size is based on annual domestic BOE's produced during 1993. For example, the operators producing the most BOE's would be in the 1 to 20 class. The operators producing the fewest BOE's would be in the greater than 500 class. The total lower-48 onshore states well ownership distribution in shown below.

TOTAL U.S.
Well Percentage by Operator Size and Production Category

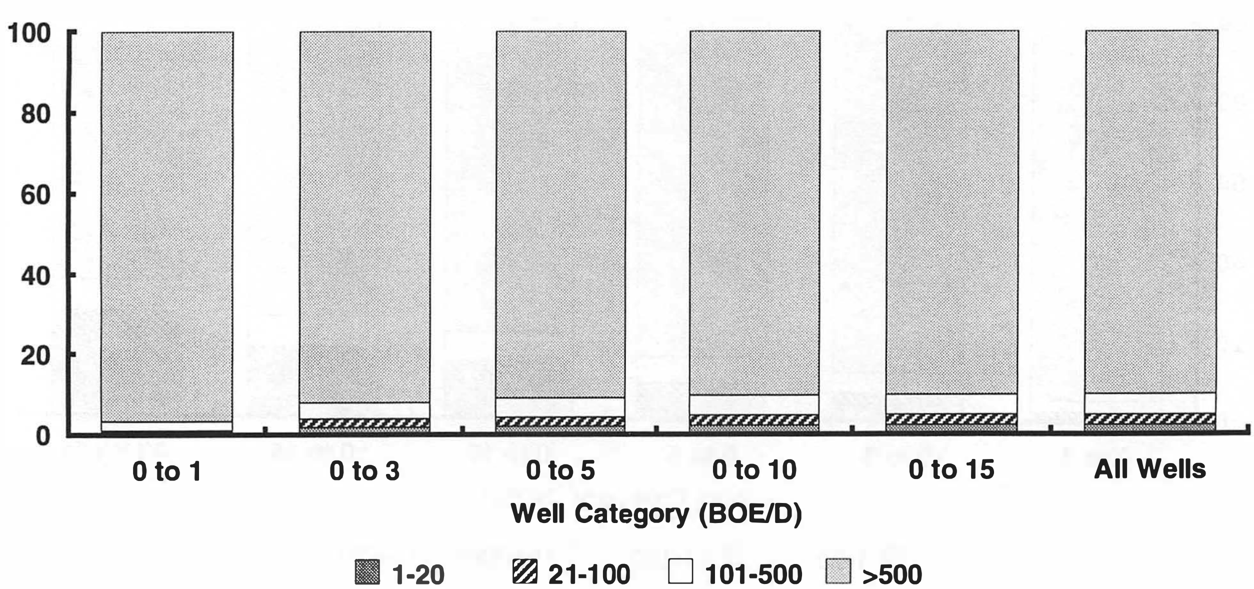


Eastern United States

This is the most mature producing region in the United States. If there is an outstanding characteristic that typifies the marginal nature of the wells in this region, it is the low production rate. The wells average less than one barrel of oil per day. In three states, the average is about one-third of a barrel of oil per day. The region contains approximately 133,000 active oil wells, of which 84,995 produce one barrel or less of oil each day. Class 2 wells are predominant in the region as is evidenced by the fact that over 90 percent of the wells produce less than three barrels of oil per day.

It is hard to imagine how a company could make money operating wells producing less than a barrel of oil per day, but the operators in this region are very proficient at getting every drop of oil out of a well at the lowest possible cost. There are two fundamental groups of marginal wells in the region, those in fields currently being waterflooded (this includes enhanced recovery operations) and those producing on a primary basis or in a fully mature operation. Following is a description of the producing characteristics of both classes of wells that distinguish them from other wells throughout the country and cause them to be marginal.

EASTERN U.S.
Well Percentage by Operator Size and Production Category



Waterflood Operations

Production Factors

- Power Costs – Most fields lack an abundant supply of lease gas. This requires the operator to buy gas or purchase electricity, many times from expensive rural electric cooperatives, to run the equipment necessary to operate the property. This is a considerable problem for wells under active waterflood since a substantial amount of energy is needed to produce and inject the large volumes of water associated with this type of operation. In some instances, the electric bill can run as much as 30 to 40 percent of a property's direct operating cost.

- Age of Production Equipment – It is not uncommon for equipment on the leases and in the wells to be at least 40 to 50 years old. The same equipment continues to be utilized since the low production rates will not support the installation of new equipment. The wear and tear of waterflooding is exceedingly difficult on the older equipment, making failures and costly repairs a common occurrence.

Reservoir Factors

- High Volume Water Production – Some of the more mature water injection projects in the Eastern U.S. produce 25,000 or more barrels of water each day. Oil production, as a percentage of total fluid production (oil cut) during the later stages of waterflood operations, most often is less than five (in some cases less than one) percent. The corrosive tendencies of the water produced out of and injected into the reservoirs are not as extreme as in some regions; still, it must be chemically treated to prevent corrosion and the formation of scale. The water also must be treated and filtered prior to injection in order to achieve the quality needed to maintain the desired injection pressures and rates. If produced water is not reinjected as part of the effort to sustain reservoir pressure, it is usually injected into nonproductive formations approved (by the appropriate regulatory authority) for water disposal.

- Commingled Producing Horizons – The lack of prolific production from individual reservoirs compels operators to produce from multiple zones in a wellbore simultaneously. This increases daily production, but also creates the potential for damage to the wellbore. The damage is brought about by a reaction from the mixing of different reservoir fluids. The result is usually the formation of scales such as iron sulfide and barium sulfate, which must be removed or inhibited with the use of high-cost chemical treatments. This practice also makes it difficult to maintain good water quality for injection into the various producing horizons and to monitor the effectiveness of the water injection profile.

Market Factors

- Limited Access to Crude Oil Markets – In many parts of the region, there are few alternatives for operators to market their oil. There are only a small number of buyers and access to common carrier pipelines is limited. Therefore, the producer receives a lower oil price than would be realized in a more competitive market such as the Gulf Coast region. A small producer's market options are even more restricted in that they are not able to achieve the economy of supply (large production volumes) needed to command a more favorable price from oil buyers. The lack of production volume also makes it difficult for them to individually utilize the commodity futures markets in order to minimize downside price risk by "locking in" an acceptable future oil price.

Primary Production Operations

The problems created by old equipment, commingled zones, and power costs are the same for primary wells as described previously with regard to waterflooded wells. They are not as extreme in nature, but since the primary wells produce such small volumes of oil, the problems still are capable of threatening a well's economic viability. The market factors discussed in the preceding paragraph dealing with waterflood operations also are applicable to primary operations in the region. The operating characteristics attributable specifically to primary production operations are stated below.

Production Factors

- Water Disposal – Unlike waterflood operations, many of the wells in the region are located on isolated leases and are unable to access field-wide water disposal systems. Produced water usually must be trucked from the lease and injected in commercial disposal wells at a cost that can be as high as $1.80 per barrel of water. The economic viability of these wells is extremely sensitive to the amount of water produced. The example below shows the difference in the cost per barrel of oil related to water disposal for a one barrel of oil per day (BO/D) well making one, five, and ten barrels of water (assuming that the cost to dispose of the water is $1.80 per barrel of water).

Barrels of Oil per Day	Barrels of Water per Day	Disposal Cost $/BO/D
1	1	1.80
1	5	9.00
1	10	18.00

- Hostile Environment – Many wells are located in hilly and mountainous regions. The wells can be inaccessible for several months each year due to the severity of the weather in the winter and early spring and due to a lack of good roads. Excessive downtime on such low volume wells severely impacts their economic status.

Reservoir Factors

- Nature of the Reservoirs – In some areas, the reservoirs are highly fractured and can be restricted in size. If these conditions exist, or if the reservoir matrix is poor (low porosity and permeability), waterflooding and currently known enhanced recovery operations are impractical. Therefore, the reserves must be recovered by primary production over a prolonged period of time. The wells in this type of reservoir are most often Class 2.

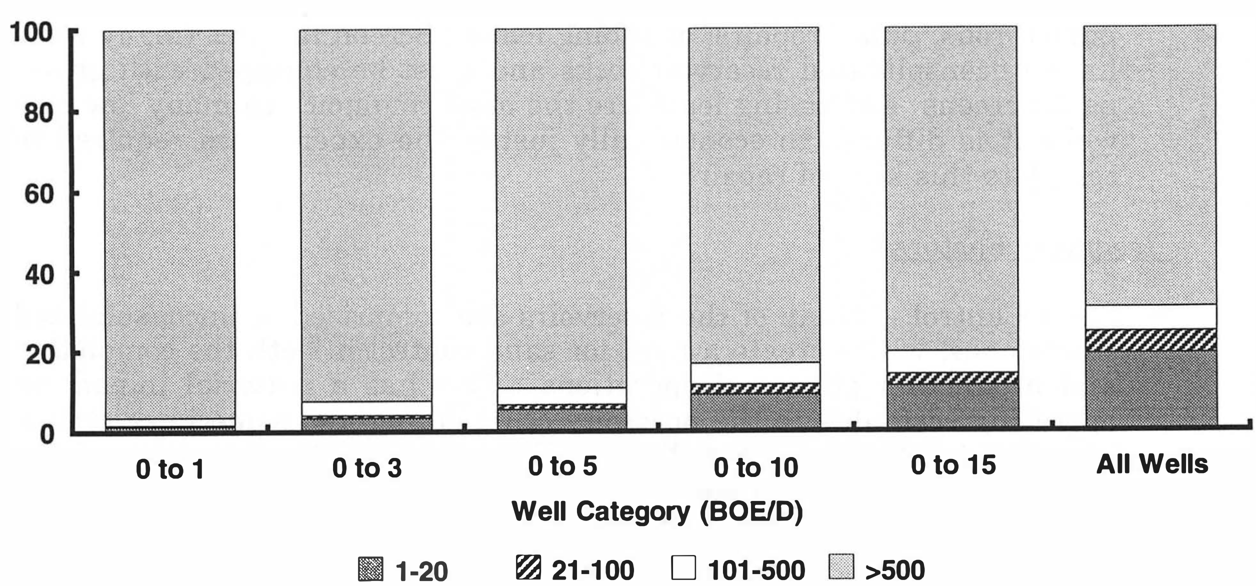
- Paraffin Formation – The combination of small amounts of produced water, certain components of crude oil, and temperature can cause paraffin to form in the wellbore and gathering lines. This inhibits the already precariously low production rate of the well. It is difficult and very costly to chemically prevent paraffin development, so the problem must be dealt with symptomatically with solvent soaks and hot oil treatments.

Gulf Coast

First Half 1994
Average Oil Price

Wells in the Gulf Coast region cover the entire spectrum of production depths, rates, and reservoir types. The region contains over 86,000 producing oil wells, including 34,625 that produce one barrel or less of oil per day. Most of the wells producing less than one barrel of oil per day are considered to be in the Class 2 category. Secondary and enhanced recovery projects are common in the region, and many of the marginal wells are produced on a primary basis. Gulf Coast marginal well characteristics in both onshore and inland water operations are discussed in the following paragraphs.

GULF COAST
Well Percentage by Operator Size and Production Category



Onshore Operations

Production Factors

- Corrosion – Many areas produce highly corrosive waters and gases. This usually results from the presence of H_2S (hydrogen sulfide), CO_2 (carbon dioxide), or oxidation. This creates an environment that is very hard on production equipment. Expensive chemicals are needed to minimize damage, but even with the use of chemicals and other preventative measures (i.e., coated rods and fiberglass tubing), the cost and frequency of equipment repairs and replacement is much higher where corrosion is prevalent.

- Wellbore Damage – Wells that produce large amounts of water are prone to the accumulation of calcium carbonate, iron sulfide, and barium sulfate scales throughout the wellbore and production equipment. The presence of these scale deposits further reduces the ability of marginal wells to produce. The cost associated with the removal of scales can be prohibitive since it may require expensive acid jobs or mechanical removal by a workover rig.

- Naturally Occurring Radioactive Materials (NORM) Contamination – NORM is a natural byproduct of hydrocarbon production and occurs when radium is coprecipitated from produced water with barium and strontium based scales, and when radon gas is produced with natural gas. This leads to contamination of produced scales, sludge byproducts, and production equipment. NORM contamination exists, to some degree, at many production facilities in the region. Potential health hazards are mitigated through the use of prudent safety procedures. The cost of dealing with and disposing of NORM waste is considerable. A typical charge to dispose of one barrel of NORM contaminated waste at a licensed disposal site is $400 to $600.

- Major Equipment Failures – Many of the problems discussed in this section ultimately result in major equipment failures. These are repairs requiring a workover rig and would involve something more severe than parted rods, pump repairs, or tubing leaks. Screen failures (many wells have unconsolidated reservoir rocks and must be equipped with gravel pack screens) and casing leaks are the most common. In many low rate wells it is difficult to economically justify the expenditure required to complete this kind of repair.

Reservoir Factors

- Sand Control – Many of the reservoirs are comprised of unconsolidated sandstones, which create a need for sand control in both the completion and production phases of operations. This has a material impact on operating costs due to the necessity of installing and sometimes replacing downhole screens and liners. The unconsolidated nature of the reservoir sands also causes additional wear and tear on subsurface and surface equipment when loose sand works its way into the production stream.

- High Volume Water Production – A great number of the Gulf Coast reservoirs produce by either a full or partial water drive. These wells will produce significant amounts of water in the later stages of their productive history. It is not uncommon for wells in fully matured reservoirs to produce several hundred or even thousands of barrels of water each day for a few barrels of oil. The cost associated with water disposal can be considerable because of the initial capital required to install and operate disposal facilities plus the cost of maintaining compliance with environmental regulations regarding water disposal. The power cost associated with high water production is sizable since it takes power to pump the water out of the ground and then additional power to pump it back into the ground.

- Well Depth – Many of the productive horizons in the region exceed 5,000 feet in depth. Some reservoirs are, in fact, greater than 15,000 feet deep. The cost of operating the wells increases with the depth of the well even if production volumes are constant. The cost to bring fluid to the surface is greater, and it takes more expensive equipment to run and to repair the wells. In addition, the deeper reservoirs in the region can be abnormally pressured. Costly precautionary measures must be taken to safely operate these high pressure wells.

Market Factors

- Crude Oil Quality – In some areas, particularly on top of salt domes, the quality of the crude oil significantly affects the wellhead price. The gravity is low and in some cases the oil may be considered sour (high sulfur content). It is not uncommon to have oil with an API gravity of 25 degrees or less. The resulting reduction in the wellhead price can be as much as $2.00 to $3.00 per barrel. For example, on February 16, 1994, Scurlock Permian's South Louisiana posted price for a barrel of 25 degree gravity sour crude oil was $9.40. Their posted price on that same day for a barrel of 40 degree gravity West Texas intermediate crude oil was $12.25.

Inland Water Operations

All of the characteristics and problems related to marginal onshore wells in the Gulf Coast region are also applicable to inland water operations. The difficulties are magnified, however, by some of the factors discussed below which are unique to inland water operations.

Production Factors

- Logistics – Operating costs are higher because all materials, labor, and services must be delivered by boat. This means that goods and services are generally more expensive and it takes more man and equipment hours to complete a project in inland waters than it would if the same project was onshore.

- Artificial Lift Mechanism – Almost all marginal wells require some kind of artificial lift. Gas lift is usually the most economically viable artificial lift method for inland water operations since the cost of installing and maintaining rod pumps (the primary onshore method) is prohibitive. Multiple well gas lift systems are complex and can also be very expensive and difficult to maintain. Rising natural gas prices can increase the cost of gas lift operations, since many of the fields, most notably marginal ones, do not have enough produced gas to supply the gas lift system. Additional gas must then be purchased, if it is available, to replace gas consumed in operations.

- Regulatory Compliance – Inland water operators must deal with a large number of regulatory agencies at the federal, state, and local levels of government. The cost of keeping up with the reporting requirements and paying the assorted fees is high and can impact the commercial viability of marginal wells. Listed below are some of the agencies a typical inland water operator in Louisiana has to deal with.

Regulatory Agency	Level of Government
Department of Natural Resources	State
Department of Environmental Quality	State
Department of Wildlife and Fisheries	Federal
Louisiana State Mineral Board	State
U.S. Corps of Engineers	Federal
Local Levee Districts	Local
Environmental Protection Agency	Federal
U.S. Coast Guard	Federal
Department of Energy	Federal
Occupational Safety and Health Administration	Federal
Bureau of Land Management	Federal
Various Other Local Governmental Bodies	Local

- Corrosion of Surface Equipment – The corrosive environment caused by damp salty air and bay water increases the cost of maintaining surface equipment. Frequent cleaning and painting are required to prevent corrosion. Special equipment and divers are often needed to complete repairs and maintenance below the surface of the water.

- Insurance Cost – The potential liability associated with operating a well on water requires a higher premium to be paid than if the same well was located on land.

Market Factors

- Oil Transportation Fees – Crude oil purchasers and transporters typically charge more to transport oil from inland water locations than on land. This is particularly true if the oil is transported by barge. The transportation fee is usually \$.50 to \$1.00 per barrel.

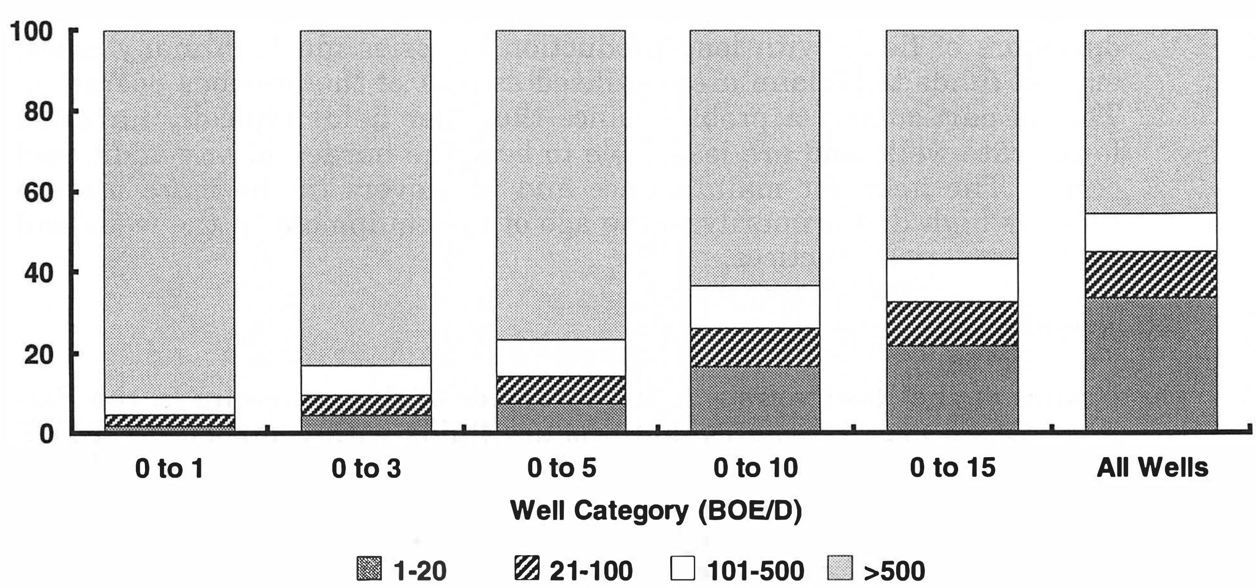
Permian Basin

First Half 1994
Average Oil Price

The Permian Basin contains approximately 115,000 active oil wells, including 16,273 that produce one barrel or less of oil per day. There are more miscible (CO_2) enhanced oil recovery projects in the Permian Basin than anywhere else in the world. A 1993 IOGCC report estimated the Permian Basin EOR reserves to be in excess of 3 billion barrels at a price of \$20 per barrel.

There are a number of factors, both operational and otherwise, that accelerate the abandonment of marginal wells in the region. The permanent abandonment of wells in the Permian Basin has a greater negative impact on the U.S. EOR reserves than any other geologic province. The factors contributing to the well abandonments are stated below.

PERMIAN BASIN
Well Percentage by Operator Size and Production Category



Production Factors

- Power Costs – Secondary and enhanced recovery operations consume large amounts of power as part of their daily operations. Many times, producers are faced with meeting their power needs through the purchase of electricity from higher cost suppliers such as rural electric cooperatives. The current structure of regulations, particularly those dealing with the certification of service areas, limit the ability of the operators to lower per unit power costs. This could be accomplished through the negotiation of volume discounts or purchasing electricity for less cost and transporting it to the property through the existing power grid system much in the same way natural gas is transported to end users via common carrier pipelines.

- Water Supply Availability – During the past 20 to 30 years, competition has grown between the oil and agricultural industries for the region's fresh water supply. The water available in the deeper fresh water aquifers works very well when used as a supplemental water source for injection into both secondary and enhanced recovery projects. Since this water is also needed for irrigation, operators are now utilizing other, more expensive, water supplies, such as produced water from extraneous reservoirs and non-potable water found in shallower aquifers. The incompatibility of the commingled waters can significantly increase the cost of chemically treating and filtering the water prior to injection.

- Naturally Occurring Radioactive Materials (NORM) Contamination – The composition of the reservoir fluids combined with the large amounts of produced water can cause NORM contamination to occur in the production and surface equipment. As discussed previously in the study, the cost of disposing of these materials and complying with the associated regulations adversely affects marginal well economics.

- Mature Province – Many of the fields in the region have been in production for over 50 years. During that period, the methodology used to complete, operate, and abandon wells has improved substantially. The operators of fields with long production histories must, in many cases, expend funds to reclaim areas utilized as part of the previous operation. This is particularly a problem since the older fields typically have the lower rate wells and are least able to bear the burden of any additional costs. The need for maintenance and workovers in the more mature fields is high due primarily to the age of the equipment in the wells and past completion practices.

Reservoir Factors

- Nature of the Reservoirs – A large number of the reservoirs in the Permian Basin are carbonates and produce fluids with components of H_2S and CO_2. These fluids are excessively corrosive and also have calcium carbonate and other scale-forming tendencies. Expensive chemical treatments are necessary to mitigate the problems which ultimately will lead to costly workovers and equipment failures.

treatments are necessary to mitigate the problems which ultimately will lead to costly workovers and equipment failures.

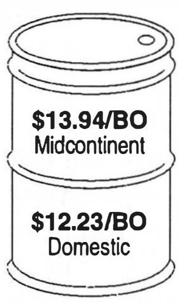
- High Volume Water Production – Most reservoirs are under waterflood and produce large amounts of water. In many instances, the reservoirs can produce thousands of barrels of fluid each day with only a one to five percent oil cut. The wells in these fields are expensive to operate primarily because of the costs (such as electricity) associated with handling the large volumes of water.

- Well Depth – Most of the productive horizons are at least 4,000 feet in depth and many are 8,000 to 10,000 feet deep. The combination of the depth and the large fluid volumes puts a great deal of stress on the production equipment. In order to prevent excessive downtime, a higher grade of equipment must be utilized in these wells, which increases both the initial installation and subsequent repair cost.

Market Factors

- Crude Oil Quality – Much of the crude oil production in the region has a high enough sulfur content to be classified as sour. The market penalty for sour crude oil customarily runs \$2.00 to \$3.00 per barrel. For example, on February 16, 1994, Koch Oil Company's posted price for West Texas/New Mexico sour oil (40 degree gravity) was \$10.00 per barrel, whereas the posted price for West Texas/New Mexico sweet oil (40 degree gravity) was \$12.25 per barrel.

Midcontinent

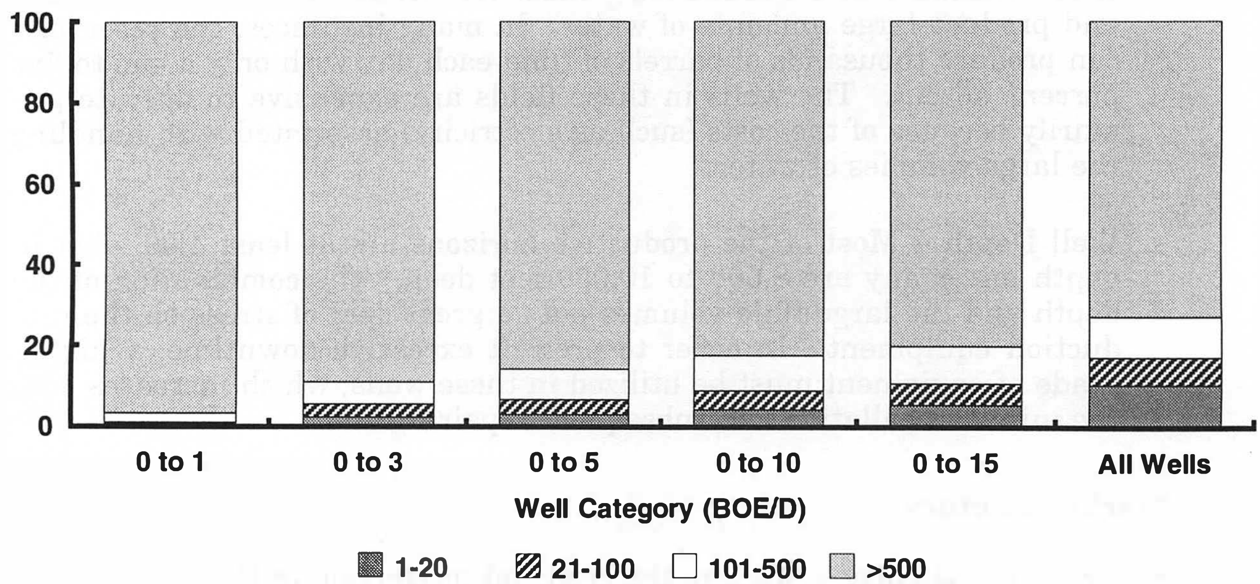


First Half 1994
Average Oil Price

The Midcontinent region contains approximately 174,000 producing oil wells. Most of the 48,522 wells that produce one barrel or less of oil each day are included in the Class 2 category. The region also has a number of Class 3 wells. Many of the major reservoirs are candidates for the application of enhanced oil recovery technology. However, there are only a few currently active EOR projects.

Sandstone reservoirs are more typical in the Midcontinent states. The corrosion and sour crude oil problems created by the carbonate reservoirs in West Texas and New Mexico tend to be less severe in this region. Nonetheless, marginal wells in this locale are faced with various operational factors that can hasten abandonment.

MIDCONTINENT
Well Percentage by Operator Size and Production Category



Production Factors

- Power Costs – The power costs in the Midcontinent area are a problem for marginal well operators. Costs can be as much as 30 percent higher than other regions. The primary reason is that the Midcontinent power grid system has a large component of nuclear power plant cost. Another contributing factor is that many of the marginal well properties are in remote locations and are serviced by the more expensive rural electric cooperatives.

- Mature Province – There are many older fields in the Midcontinent region. Some of the fields are 60 to 80 years old and have a long production history. Present day operators often find it necessary to expend funds to take care of problems that were the result of early day operational practices. In some cases, operators must reenter and plug a previously improperly plugged wellbore. Surface remediation of pits, utilized historically for the storage of produced fluids, is also a problem faced by operators of the older fields.

- Age of the Production Equipment – The advanced age of fields in the region brings with it the same problems experienced by the other older producing provinces throughout the country. The older the equipment, the more difficult and costly it is to maintain. The problem for marginal wells is made worse by the fact that the least profitable wells tend to be the older wells with the older equipment. The difficulty of economically justifying the repair or replacement of the equipment on a marginal well can lead to abandonment.

- Logistics – A great number of the wells in this region are located in high use agricultural areas. Producers must take precautions to minimize the chance of interfering with farming and ranching operations. This adds to the cost of operations, particularly during the months when the crops are in the field and access to property is limited. The cost of easements or surface leases needed to lay pipelines, build roads, and construct facilities can be prohibitive since the farm land is so valuable that it is desirable to keep as much of it in agricultural production as possible.

- Hostile Environment – The cost of operation in all the areas of the Midcontinent increases in the winter months. This is especially true in the high plains area of Kansas and Nebraska and in the panhandle area of Oklahoma and Texas. Costs of repairs and maintenance rise significantly during the winter because of the extremely harsh weather experienced regularly in these parts of the region. Even with precautionary measures taken to insulate the production equipment, the severe cold can freeze water-handling facilities and rupture flow lines and surface vessels.

Reservoir Factors

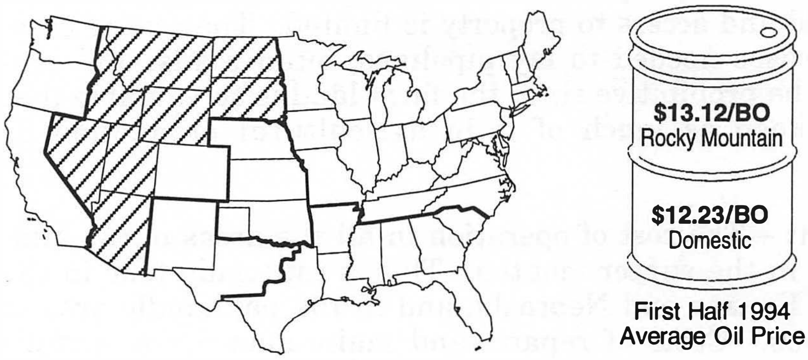
- Nature of the Reservoirs – There are an abundance of reservoirs in the Midcontinent area that lack continuity. Typically, they are stream channel and sand bar deposits that have a high content of silt and clay. The length of time needed to extract the recoverable reserves, in these heterogeneous reservoirs, is extended significantly since their nature limits the sweep efficiency of waterflood operations. A more homogenous, similarly sized reservoir (such as those found in the Gulf Coast region) would recover the same amount of oil in a much shorter period of time.

- Low Production Rates – The shallower reservoirs in some areas of the region have very low reservoir pressures. This is a major contributing factor to the low oil production rates (less than one barrel per day) of this group of marginal wells. Small changes in the oil price and operating costs can significantly impair the profitability of these wells.

Market Factors

- Limited Access to Markets – Small operators of marginal wells in certain areas suffer from a scarcity of competition for their oil. They lack an economy of supply and experience problems similar to those described in the discussion of market limitations realized by marginal well operators in the Eastern U.S. region. Most of the oil from the low production properties must be trucked since the small volumes will not justify the cost of a pipeline connection. This problem not only increases operating costs but can actually lower the oil price in areas where there are a preponderance of low volume properties. This is true in southeastern Kansas as evidenced by the fact that Koch Oil Company's February 1994 average posted price for Southeastern Kansas 40 degree gravity crude oil was $11.85 per barrel versus the $12.60 per barrel posting for 40 degree gravity West Texas Intermediate crude oil.

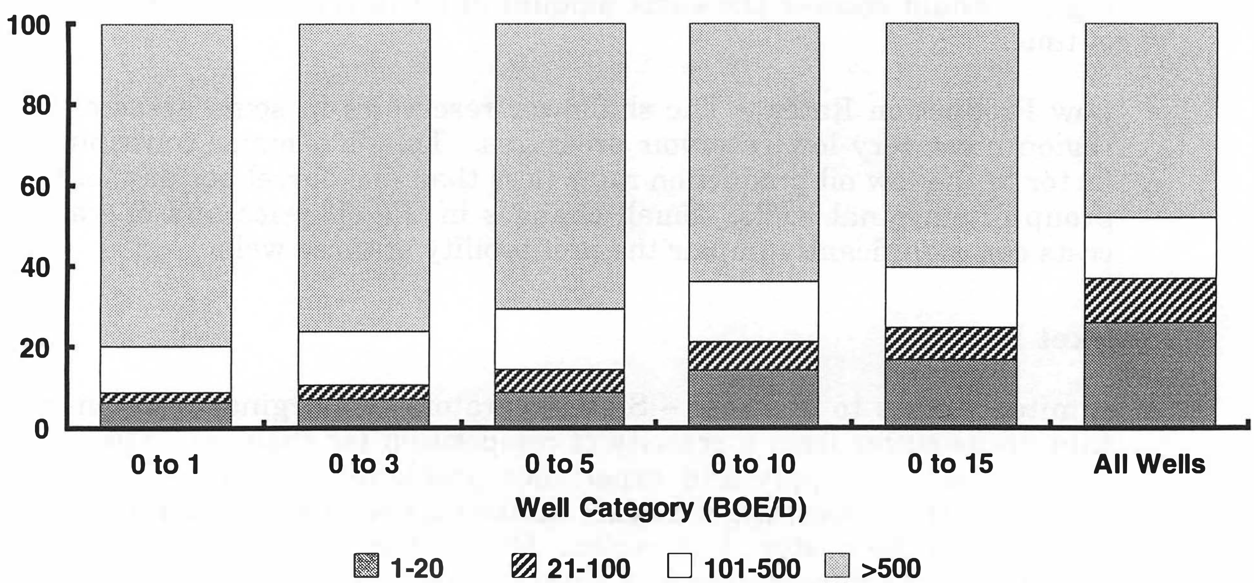
Rocky Mountains



Approximately 32,000 active oil wells can be found in the Rocky Mountain region. Class 1, Class 2, and Class 3 operation are present. Most of the Class 2 wells are included in the 4,292 wells that produce one barrel of oil or less each day. Many of the reservoirs have active water drive mechanisms and are sandstone.

There are several major miscible (CO_2) EOR projects currently underway in the region. In a 1993 IOGCC report, it was estimated that approximately 500 million barrels of EOR reserves are recoverable with existing technology. Marginal wells in the Rocky Mountains are faced with several unique challenges in addition to those commonly experienced in other regions.

ROCKY MOUNTAINS
Well Percentage by Operator Size and Production Category



Production Factors

- Federal Leasehold Interests – The cost of operating wells on publicly held lands can be higher due primarily to additional reporting requirements, regulatory overlap, delays in the permit approval process, and excessive public intervention.

- Hostile Environment – The severe winter weather combined with the remote location of the fields and difficult terrain increases the cost of operations. It is sometimes difficult to gain access to wells when repairs are needed. The long winter increases costs because of additional expenses incurred treating the oil in preparation for sale when the temperature is below freezing. It is also necessary to take steps to protect the production equipment from the severe cold and to keep the produced water from freezing. Downtime can be excessive since weeks may pass before wells with mechanical problems can be repaired and returned to production.

- Logistics – Most of this region suffers from the lack of a good rural road system. This is partly due to the rough terrain. However, road construction is also restricted by the Bureau of Land Management and the Forest Service's common desire to limit the number of roads built on public lands. This lack of roads affects costs in much the same way as they are increased by logistical problems in the inland water properties. In the Rocky Mountains, goods and services must be delivered, to what are in many cases remote locations, by truck. The rough terrain and lack of good roads drive up costs of projects since the time required to deliver goods and services is much higher than if the property was in a more easily accessible location.

Reservoir Factors

- High Volume Water Production – A number of fields in parts of the Rocky Mountain region produce vast amounts of water with oil accounting for, in some cases, less than one percent of the total fluid produced. Fields in this region can produce in excess of 100,000 barrels of water each day. Water handling systems must be extremely cost-effective for these fields to be produced profitably. Because of the high volume of produced water, property economics are extremely sensitive to changes in water handling cost. For example, in a field producing 500 barrels of oil per day and 100,000 barrels of water per day (99.5 percent water cut), a one cent change in the cost of handling one barrel of water increases the total operating cost per barrel of oil by $2.00.

- Nature of the Reservoir – The region contains many reservoirs that are highly faulted, fractured, or have a great deal of lenticular porosity. The reservoirs also can have low permeability, which means that in most cases the amount of the reservoir that can be drained by one well is relatively small. Costs, in fields consisting of these types of reservoirs, tend to be higher since the nature of these reservoirs require the operation of more wells and an extended period of time to recover reserves.

- Nature of the Crude Oil – In some areas, particularly parts of Utah, Montana, and Nevada, the crude oil has a very high paraffin content. It creates a number of problems since it is very difficult to keep the paraffin from forming in the production stream. Production equipment must be heated during the winter months to keep the waxy substance from plugging up the equipment and to allow for the sale of the oil.

- Well Depth – Most of the marginal production in the Rocky Mountain region comes from formations that are 4,000 to 10,000 feet deep. The high cost of maintenance and repairs at these depths can lead to the premature abandonment of low-rate wells.

Market Factors

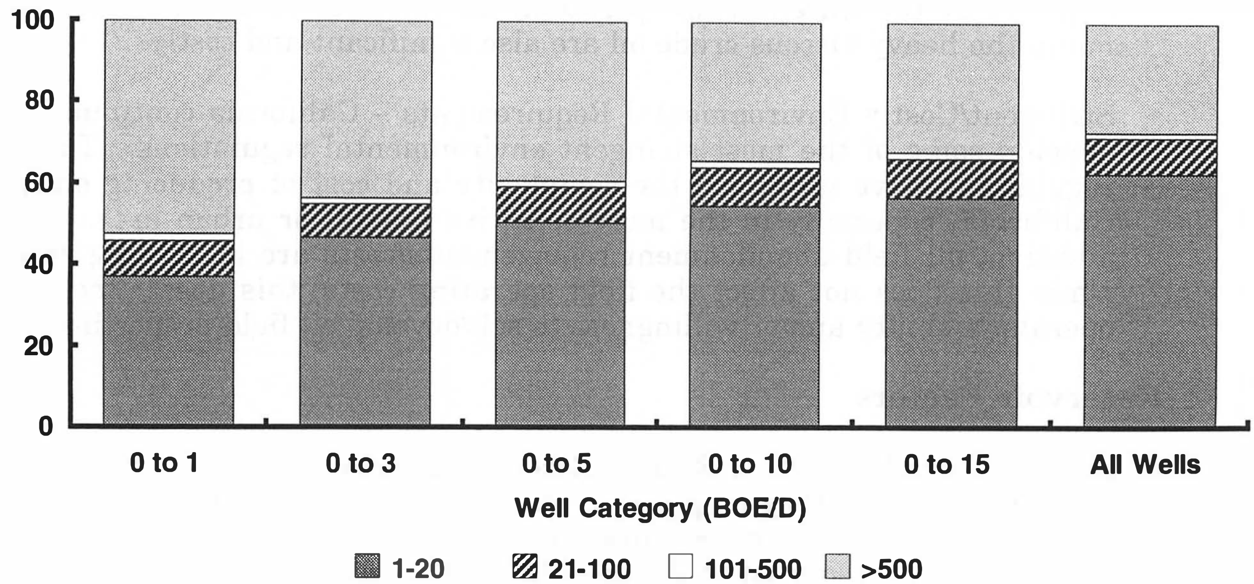
- Crude Oil Quality – A large percentage of the crude oil is sour and of lower gravity. As in other areas, the market price for this type of crude oil often is $2.00 to $3.00 per barrel less than the West Texas Intermediate posted price. On February 16, 1994, Scurlock Permian's posted price for Wyoming general sour crude (40 degree gravity) was $8.75 per barrel. The posted price for Wyoming sweet crude (40 degree gravity) on that same day was $11.75 per barrel.

- Limited Access to Crude Oil Markets – There are fewer pipelines, refineries, and market opportunities in the Rocky Mountain area than found in most other regions. This restriction of markets often results (with the exception of a few high quality crude oil types) in a price of $0.50 to $1.00 per barrel less than other areas. Koch Oil company's February 1994 average posted price for West Texas Intermediate 40 degree gravity sweet crude was $13.10 per barrel. Their average posted price for Wyoming 40 degree gravity sweet crude oil was $12.60 per barrel.

California

California, not including the federal OCS, produces about 850,000 barrels of oil per day, which amounts to 12 percent of the U.S. domestic production. About two out of every three of these California barrels is heavy crude oil, most of which is less than 16 degrees API. The majority of the producing fields in California were discovered in the first half of the century and enjoyed a revitalization in the 1970s and early 1980s as secondary and enhanced recovery methods were economically justified by relatively high and stable crude oil prices. However, continued development of California's significant known reserves has slowed to a standstill in recent years due to the poor economics resulting from the following unique set of factors affecting California's predominantly heavy crude oil producing sector. These factors have contributed to the transformation of California's heavy oil industry from a robust, expanding industry that was actively developing reserves to more of a stripper well operation with most of the attention directed towards reducing operating costs so that revenues would at least cover direct field operating costs and production could continue.

CALIFORNIA
Well Percentage by Operator Size and Production Category



Production Factors

- High Energy Requirements/Costs – The common method of EOR associated with California's heavy crude oil involves injecting large quantities of steam into the reservoir to reduce the high viscosity of the heavy oil so that it flows more easily and rapidly to the wellbore. Generally three to four barrels of steam are injected for every barrel of oil produced. Most of this steam is produced in large boilers that have been largely converted from burning crude oil to natural gas due to the increasingly stringent air emission regulations. The injected steam is eventually recovered as produced water, which needs to be treated to the high standards required for heating and injection as steam. It takes considerable initial steam injection to begin this recovery process and, once started, the steam injection must be continued or significant injected steam value/heat will be lost to the surrounding formations.

  Because of the high total cost of the steam generation and injection process (commonly about $4 per barrel of oil produced), significant attention has been directed towards the facilities in order to reduce the overall cost of the steam. One relatively new method of reducing steam costs has been the installation of significant electrical/steam cogeneration capacity in the oil fields. The waste exhaust heat is used to generate steam, while the electrical output is either used to displace purchased electricity or sold to the local utility. In Kern County, where 60 percent of California's oil is produced, over 1,500 megawatts of cogenerated power has been installed in oil fields during the past ten years.

- High Capital Development Costs – The cost of drilling a single typical heavy oil well is relatively low. However, the cost of drilling the many wells required to develop a heavy oil field and the cost of associated facilities required to treat the large amounts of produced water (water cuts of 90 percent are normal) to boiler standard, to heat the water, and to distribute the steam are significant. While most of the capital expense is required by the water/steam operation, the facilities to treat, store, and pump the heavy viscous crude oil are also significant and costly.

- Stringent/Costly Environmental Requirements – California continues to develop some of the most stringent environmental regulations. These regulations have increased the complexity and cost of producing oil in California, especially in the more sensitive coastal or urban areas. In addition, oil field abandonment requirements/costs are increasing and, while this does not affect the field operating costs, this does affect an operator's ability and/or willingness to sell/develop oil field properties.

Reservoir Factors

- High Reserve/Production Ratio – Reserves in heavy oil fields are recovered over an unusually long period of time (usually several decades) due to the low production rates caused by the very viscous crude oil. This additional time required to produce the oil in place contributes to higher operating and capital costs as well as results in a delayed return on investment capital. In addition, as a result of this protracted productive life, heavy oil price fluctuations cause an increased risk in regard to capital recovery and adequate return on investment.

Market Factors

- Low Crude Oil Prices – Historically, California's 13 degree heavy crude oil has sold for about 60 to 70 percent of a West Texas 40 degree crude oil (the average price for Kern River crude oil in February 1994 was $9.25 per barrel compared to $13.00 for West Texas Intermediate). This lower value is primarily based on the poorer crude oil quality, which results in a lower valued refined products mix from each barrel due to the limited refinery conversion capacity in California. California's refineries produced about 270,000 barrels per day of low value #6 fuel oil in 1993, most of which can be attributed to California's heavy oil.

  The California crude oil market is also affected negatively by the large volume of Alaskan crude oil that is "dumped" on the West Coast due to the federal ban on exporting Alaskan North Slope (ANS) crude oil. Currently about half of the approximately 1.7 million barrels per day of ANS production is landed and stays in California due to the high cost of moving this crude oil to other non-Pacific coast domestic markets. Since a natural market for this ANS crude oil is the Far East, critics of this ban argue that this export ban forces an unnatural crude oil market to exist in California which lowers California crude oil prices and thereby hurts the California production industry. While it is difficult to determine because of the many complex market issues, it is expected that the price of California crude oil would increase if this ANS crude oil export ban is repealed.

CONCLUSIONS

A variety and number of operating factors drive wells to become marginal. The factors are not the same for all regions and in some cases the factors differ within the same region. Marginal wells are operated by all producers, regardless of size. This makes it difficult to pinpoint a definition for marginal wells. Nonetheless, they do share a common attribute, in that, their continued existence under a high operating cost/low oil price environment is threatened. Each dollar decline, each new regulation, and each increase in costs will eliminate another portion of marginal well production and resource availability as more wells are abandoned.

Chapter Five

Economic Analyses

OVERVIEW AND DISCUSSION

In order to adequately analyze marginal wells, the NPC determined that an economic evaluation considering cash flow is required to assess the marginality of producing wells in the United States. All wells operate with varying cash flow margins; however, as described in the previous chapter, many wells provide insufficient cash flow to cover current and future costs. Determining the number of wells unable to meet lease level operating costs at various prices is the first step in understanding marginality of producing wells. Continued production from uneconomic wells is discussed later in this chapter. The increase in the number of wells not meeting lease operating costs at decreasing prices will provide insight into the population of marginal wells and the role of policy initiatives to maintain production from these wells. The economics evaluation was conducted in two interrelated stages—first, the cash flow from all producing wells before federal income taxes was estimated, and second, cash flow after federal income tax considerations was estimated. It is important to note that in these first stages of economic evaluation, individual well/lease and company operations cash flow were the primary evaluation parameters and not typical project type economics where return on investment is calculated.

The first step of the economic evaluation does not address many non-well-specific costs in the same manner as well/lease costs; however, these are real cash costs that every company incurs, and they will be considered as an addition to well/lease level costs. Included in this additional cost category are items such as administrative and management costs, accounting and finance costs, research and development, product marketing, government and public affairs, environmental and regulatory affairs, insurance, health and safety, and debt repayment —just to mention a few of the costs that are not captured at or pushed down to the individual well or lease level.

The discussion concerning well economics will focus initially on individual well cash flow and not the company level cash flow. In this study, individual well cash flow was evaluated since much of the available production data are reported on a well or lease level and an operator's decisions to produce or to shut in wells generally are based on each well's ability to generate a positive cash flow. However, production accounting and tax calculations are generally performed at a lease or property level as opposed to the well level. In the Findings, Conclusions, and Recommendations section of this report, the discussion more appropriately deals with properties for accounting and tax reasons. Total cash flow from domestic oil and gas company operations have not been rigorously quantified in this study since debt, capital recovery, overhead, and other costs mentioned above are not readily accessible for use in the evaluation; however, the NPC developed a sound methodology to demonstrate the range of impact of these costs. Many companies do not allocate or burden individual leases or wells with these costs, but retain them at a higher organizational level for ease of administration.

The Energy Information Administration's model titled "Economics Evaluation Model" was used for the calculations of the before federal income tax (BFIT) cash flow of individual wells. ICF Resources, a management consulting firm, provided the modeling to evaluate after federal income tax (AFIT) cash flow and the tax implications and federal costs and benefits of the incentives considered.

ECONOMIC DATA REQUIREMENTS

Overview

The EIA Economic Evaluation Model contains 4 major input parameters. First and foremost are the individual well production rate data for each state. Detailed data on 20 producing states for the year 1992 is available from Dwight's Energydata, Inc., and Petroleum Information Corp. For all oil wells in these states, production rate data on a barrel of oil equivalent basis were generated by converting associated gas using a 6,000 standard cubic foot (6 MSCF) per barrel ratio. Detailed well production data are not commercially available for 10 states. In addition to the barrels of oil equivalent (BOE) production data, water cut and depth information on individual oil producing wells were used in generating the operating costs based on explicit costing algorithms.

Second, royalty and state and local production (severance and ad valorem) tax data are required in order to quantify the net revenue realized after deductions for these items. A simplified approach was used for these calculations and was subsequently verified through a survey of producing companies that participated in the marginal well study.

Individual well operating expenses are the third significant input to the economic evaluation performed by the Energy Information Administration (EIA) model. The EIA has constructed cost algorithms that have been calibrated using industry survey data for use in the model.

Fourth, using 7 *domestic* oil prices of $8, $10, $12, $14, $16, $18, and $20 per barrel of oil, before-tax cash flow for all wells in the lower-48 states was calculated. The average domestic wellhead price is a volume weighted average for all of the U.S. crude oil production.

Each of the model input parameters is discussed in more detail in the following sections.

Production Data

Detailed production data are available for 20 producing states representing 452,990 (77 percent) of the total 586,058 producing oil wells and 1,991,182,551 (97 percent) annual barrels of oil equivalent (BOE) production out of the total 2,045,729,772 annual BOE production from all wells in the lower-48 onshore states that produced in 1992. For these 20 states, Table 5-1 illustrates the distribution of oil wells and BOE production by production rate bracket. In 10 states where detailed production rate data were not available, a production rate distribution function and mean production rate were used to construct the well distribution and BOE production, shown in Table 5-2. Table 5-3 shows the distribution of oil wells and BOE

TABLE 5-1

DISTRIBUTION OF OIL WELLS AND BOE PRODUCTION BY PRODUCTION RATE BRACKET FOR TOTAL ONSHORE U.S. EXCLUDING EASTERN STATES, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percentage of Wells	Percentage of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	108,176	15,100,174	23.88	0.76	0.38
1-2	50,401	25,408,713	11.13	1.28	1.38
2-3	35,490	29,470,550	7.83	1.48	2.28
3-4	26,750	31,002,696	5.91	1.56	3.18
4-5	21,088	31,193,731	4.66	1.57	4.05
5-6	18,743	33,995,480	4.14	1.71	4.97
6-7	14,670	31,594,936	3.24	1.59	5.90
7-8	12,349	30,451,760	2.73	1.53	6.76
8-9	10,911	30,475,461	2.41	1.53	7.65
9-10	11,371	36,445,032	2.51	1.83	8.78
Subtotal 0-10	**309,949**	**295,138,533**	**68.42**	**14.82**	**2.61**
10-11	8,685	30,532,817	1.92	1.53	9.63
11-12	7,802	29,508,417	1.72	1.48	10.36
12-13	6,668	27,377,249	1.47	1.37	11.25
13-14	6,270	28,275,123	1.38	1.42	12.36
14-15	6,400	30,715,314	1.41	1.54	13.15
Subtotal 0-15	**345,774**	**441,547,453**	**76.33**	**22.18**	**3.50**
15-20	21,604	122,313,885	4.77	6.14	15.51
20-25	17,776	130,505,329	3.92	6.55	20.11
25-30	13,039	119,022,650	2.88	5.98	25.01
30-35	9,096	92,024,375	2.01	4.62	27.72
35-40	5,296	62,241,382	1.17	3.13	32.20
40-45	4,181	53,163,757	0.92	2.67	34.84
45-50	3,273	49,154,165	0.72	2.47	41.15
>50	32,951	921,209,556	7.27	46.26	76.59
Total	**452,990**	**1,991,182,552**	**100.00**	**100.00**	**12.04**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half would be in the 9 to 10 bracket, not the 4 to 5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table do not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; and Dwight's Energydata, Inc.

TABLE 5-2

DISTRIBUTION OF OIL WELLS AND BOE PRODUCTION BY PRODUCTION RATE BRACKET FOR EASTERN STATES, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percentage of Wells	Percentage of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	84,996	11,754,680	63.87	21.55	0.38
1-2	26,142	12,597,820	19.65	23.10	1.32
2-3	10,352	8,631,746	7.78	15.82	2.28
3-4	4,822	5,684,521	3.62	10.42	3.22
4-5	2,515	3,841,878	1.89	7.04	4.17
5-6	1,427	2,679,663	1.07	4.91	5.13
6-7	863	1,885,134	0.65	3.46	5.97
7-8	550	1,413,054	0.41	2.59	7.02
8-9	365	1,033,211	0.27	1.89	7.73
9-10	251	818,683	0.19	1.50	8.91
Subtotal 0-10	**132,283**	**50,340,390**	**99.41**	**92.29**	**1.04**
10-11	178	642,369	0.13	1.18	9.87
11-12	129	506,390	0.10	0.93	10.72
12-13	96	411,550	0.07	0.75	11.75
13-14	72	338,558	0.05	0.62	12.79
14-15	56	278,460	0.04	0.51	13.69
Subtotal 0-15	**132,814**	**52,517,717**	**99.81**	**96.28**	**1.08**
15-20	145	864,952	0.11	1.59	16.27
20-25	54	414,996	0.04	0.76	21.13
25-30	24	225,549	0.02	0.41	25.82
30-35	12	132,613	0.01	0.24	30.08
35-40	7	85,959	0.01	0.16	35.23
40-45	4	59,034	0.00	0.11	40.76
45-50	2	40,671	0.00	0.07	44.78
>50	6	205,728	0.00	0.38	92.33
Total	**133,068**	**54,547,219**	**100.00**	**100.00**	**1.12**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half would be in the 9 to 10 bracket, not the 4 to 5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table do not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Note 4: The 10 states are constructed from a production rate distribution function and a mean production rate. These 10 states are: Illinois, Indiana, Kentucky, Missouri, Ohio, Pennsylvania, Tennessee, Virginia, and West, Virginia.

Source: Energy Information Administration, Office of Oil and Gas; and Dwight's Energydata, Inc.

TABLE 5-3

DISTRIBUTION OF OIL WELLS AND BOE PRODUCTION BY PRODUCTION RATE BRACKET FOR LOWER-48 STATES ONSHORE, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percentage of Wells	Percentage of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	193,172	26,854,854	32.96	1.31	0.38
1-2	76,543	38,006,533	13.06	1.86	1.36
2-3	45,842	38,102,296	7.82	1.86	2.27
3-4	31,572	36,687,217	5.39	1.79	3.17
4-5	23,603	35,035,609	4.03	1.71	4.06
5-6	20,170	36,675,143	3.44	1.79	4.97
6-7	15,533	33,480,070	2.65	1.64	5.89
7-8	12,899	31,864,814	2.20	1.56	6.75
8-9	11,276	31,508,672	1.92	1.54	7.63
9-10	11,622	37,263,715	1.98	1.82	8.76
Subtotal 0-10	**442,232**	**345,478,923**	**75.46**	**16.89**	**2.13**
10-11	8,863	31,175,186	1.51	1.52	9.61
11-12	7,931	30,014,807	1.35	1.47	10.34
12-13	6,764	27,788,799	1.15	1.36	11.22
13-14	6,342	28,613,681	1.08	1.40	12.33
14-15	6,456	30,993,774	1.10	1.52	13.12
Subtotal 0-15	**478,588**	**494,065,170**	**81.66**	**24.15**	**2.82**
15-20	21,749	123,178,837	3.71	6.02	15.47
20-25	17,830	130,920,325	3.04	6.40	20.06
25-30	13,063	119,248,199	2.23	5.83	24.94
30-35	9,108	92,156,988	1.55	4.50	27.65
35-40	5,303	62,327,341	0.90	3.05	32.11
40-45	4,185	53,222,791	0.71	2.60	34.75
45-50	3,275	49,194,836	0.56	2.40	41.04
>50	32,957	921,415,284	5.62	45.04	76.39
Total	**586,058**	**2,045,729,771**	**100.00**	**100.00**	**9.54**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half would be in the 9 to 10 bracket, not the 4 to 5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table do not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; and Dwight's Energydata, Inc.

production by production rate bracket for all 30 of the lower-48 onshore producing states. Figures 5-1 and 5-2 graphically depict the rate bracket distribution of wells and production. Detailed production data tables for each of the six regions are provided in Appendix F, Section I.

It is important to realize that the individual well production rate information is not as precise as the tables may indicate. This stems from the fact that there are a number of differences in data reporting requirements from state to state. Many states do not require individual well information, but require that production data be reported at the lease level. There are also a number of states that do not require the reporting of produced water. Where individual well data were not available, the lease level data were used in conjunction with well counts to estimate individual well producing rates. Also, where water cuts could not be calculated at the well level, average water cut data from field, reservoir, or state information were used to estimate individual well water production rates. Since average annual well counts were used, the impact of a well being shut in or abandoned after a partial year of production will not be accurately represented within the well production data base. Only wells classified as oil producers were considered in this evaluation. However, there are differences from state to state in the gas:oil ratio limitation utilized to classify wells as oil wells and the exact time that a well is no longer counted as a producing well.

Royalty and Taxes

In order to estimate a royalty and state/local tax rate, the NPC collected survey data which indicated that utilizing a 12.5 percent royalty and a 10 percent tax rate adequately represents an average for all wells in the United States. Data gathered in the survey of nine companies indicated average royalty values ranging from a low of 9.2 percent to a high of 20 percent. The combination of severance, ad valorem, and local taxes ranged from a low of 2.3 percent to a high of 11.2 percent. Average values from the survey were calculated to be 13.5 percent royalty, 4.9 percent severance tax, and 3.6 percent ad valorem tax. This translates to a 20.85 percent [1 – (86.5% x 91.5%)] revenue deduction compared to the 21.25 percent [1 – (87.5% x 90.0%)] assumed in the EIA Economic Model.

The royalty burden assumed in the EIA Economic Model may slightly understate the burden on marginal wells, since many marginal wells have gone through multiple ownerships where fractional royalties were retained by each of the former owners, resulting in a higher royalty burden for the current owner. Using the value of 12.5 percent royalty in the EIA Economic Model will closely approximate the average royalty burden for all wells. However, the higher royalty burden on the smaller operators will adversely impact their economics of operation.

Operating Costs

One of the most significant input parameters in the economics calculation is operating cost data for the individual wells. As discussed in Chapter Four, there are many factors that contribute to the total operating costs of wells. The costs for many of the factors vary from well to well and area to area. The EIA has gathered cost data and reported these data in its *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations* reports. These data

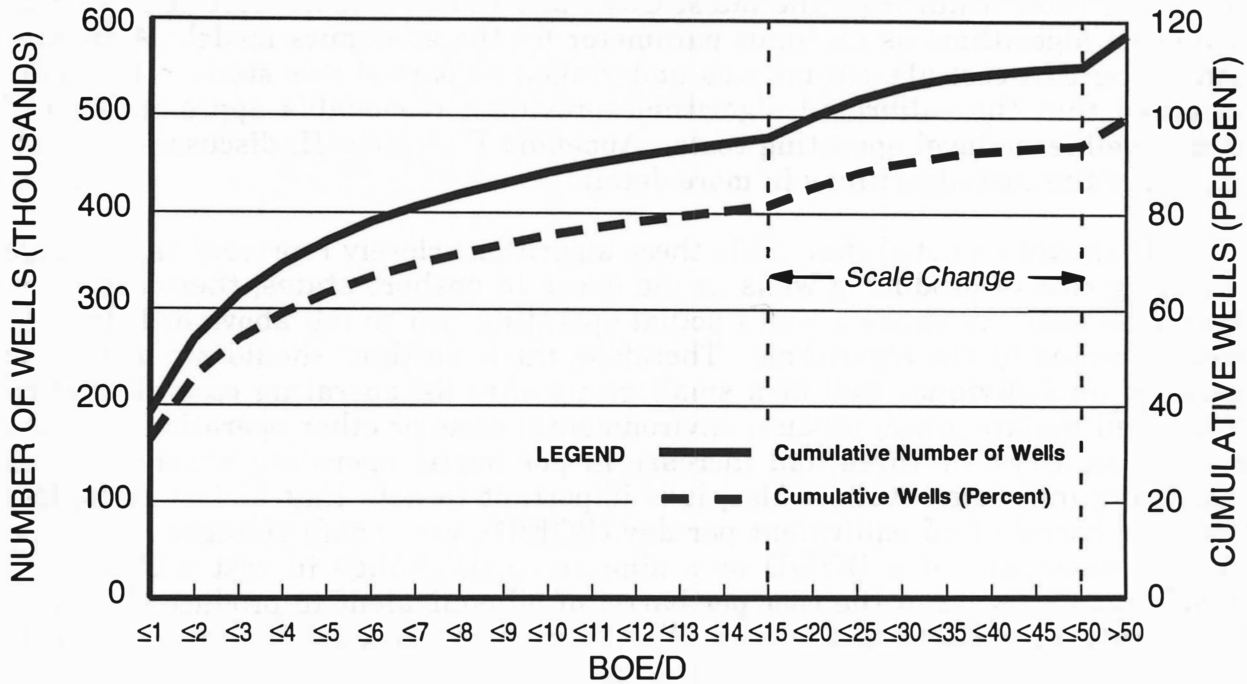


Figure 5-1. Statistics of Oil Wells by Rate Bracket—Onshore Lower-48 States, 1992.

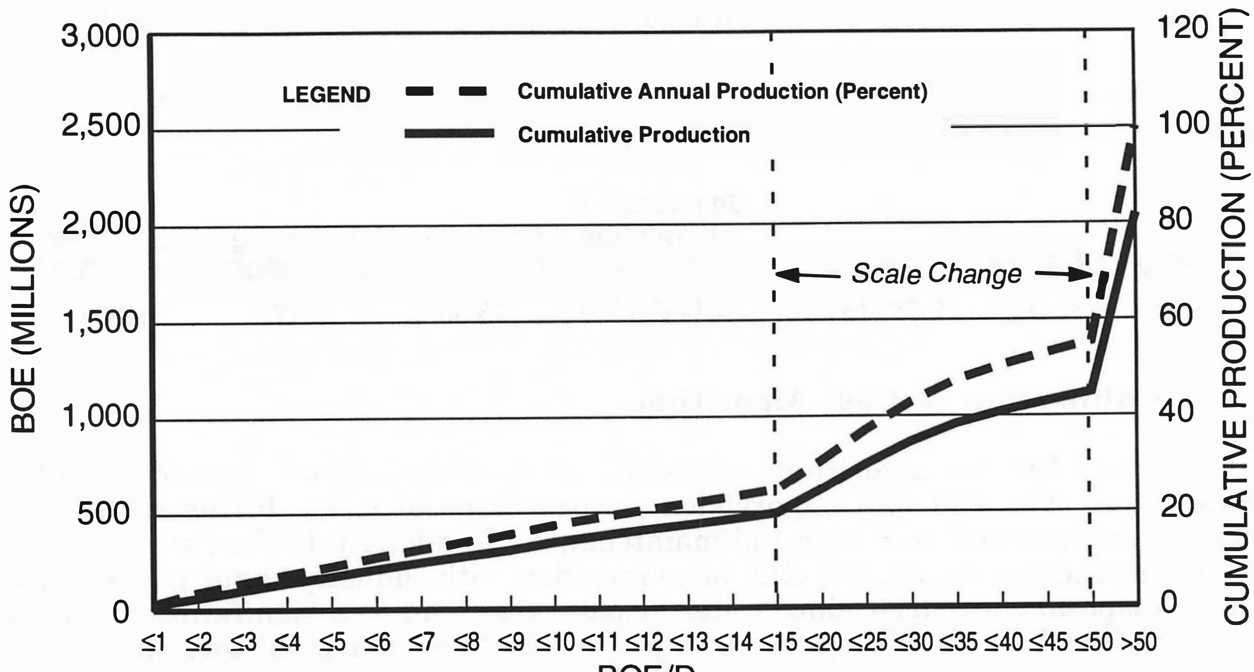


Figure 5-2. Statistics of Oil Well Production by Rate Bracket—Onshore Lower-48 States, 1992.

account for differences in operating costs by geographic area, well depth, and oil producing rate. Data from the latest Costs and Indices report were used to generate cost algorithms as an input parameter for the economics model. A calibration of the EIA cost algorithms was undertaken as part of this study. It was determined that the calibrated algorithms provide a reasonable approximation of actual well/lease level operating costs. Appendix F, Section II, discusses the calibration of the cost algorithms in more detail.

It should be noted that while these algorithms closely represent the average operating cost of producing wells in the lower-48 onshore states, there are many situations that can cause a well's actual operating cost to fall above or below the cost generated by the algorithms. Therefore, the algorithms should not be used to estimate an individual well or a small group of wells' operating cost. Unanticipated well maintenance, repairs, environmental costs or other operational factors may cause a two or three fold increase in per barrel operating expenses when comparing individual wells. Also, it is important to note that at low rates, less than one barrel of oil equivalent per day (BOE/D), very small changes in oil rate such as one-tenth of a BOE/D or a similar small change in cost will cause a significant variation in the cost per barrel of oil equivalent to produce that well. Even more significant is the cash flow margin generated from these low rate wells when a small increase in cost or decrease in rate occurs. This is demonstrated in the following example.

BOE/D	Oil Price	Royalty	Severance & Ad Valorem Taxes	Operating Costs/Day	Operating Costs/BOE	Cash Flow Margin/BOE
0.50	$10.00	12.5% ($1.25)	10% ($0.88)	$3.50	$7.00	$0.88
0.45	$10.00	12.5% ($1.25)	10% ($0.88)	$3.50	$7.78	$0.10

In the above example, a similar reduction in cash flow/BOE occurs when oil prices are decreased to $9.00 per barrel of oil as shown below.

BOE/D	Oil Price	Royalty	Severance & Ad Valorem Taxes	Operating Costs/Day	Operating Costs/BOE	Cash Flow Margin/BOE
0.50	$9.00	12.5% ($1.13)	10% ($0.79)	$3.50	$7.00	$0.09

Calibration of Cost Algorithms

The EIA cost algorithms address normal daily expense (which includes lease level overhead and supervision), water disposal costs, lifting costs, and surface and subsurface repair and maintenance. In addition to the data from the Cost and Indices report, the EIA in conjunction with industry input generated a water disposal cost curve, since water disposal costs can be a significant or even a dominant part of a well's operating expense. The water disposal cost curve indicates that as larger volumes of water are produced from a well, lease, or field, there are economies of scale that can be achieved for more efficient water disposal or injection operations. Figure 5-3 illustrates the cost components mentioned above.

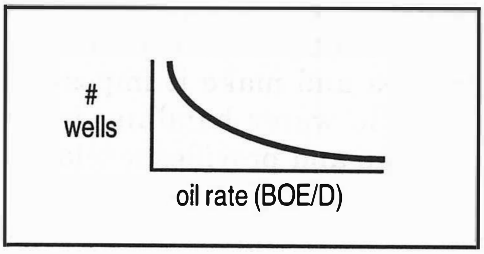
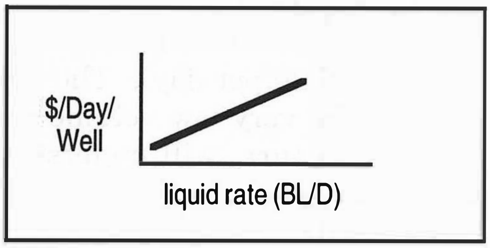
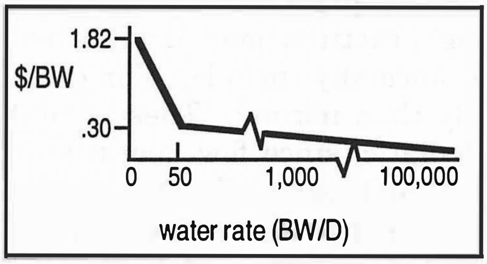
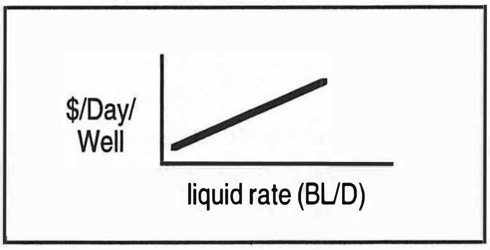
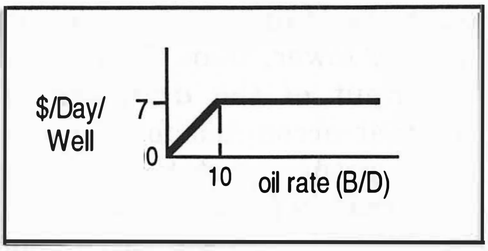
Item/Description	Curve	Source
1. Distribution of oil wells by production rate bracket for select well depths and geographic areas		Dwight's and EIA. In some cases, well production rates are based on lease/ field averages.
2. Well Lifting Cost (less water disposal cost)		EIA "Cost and Indices Report."
3. Well Water Disposal Cost		Developed by EIA. Calibrated by NPC.
4. Well Surface and Subsurface Maintainance Cost		EIA "Cost and Indices Report."
5. Normal Daily Expense (Including Well/Lease Level, Labor, Overhead, and Supervision)		EIA "Cost and Indices Report." Costs are based on "typical" 10 well oil lease producing 100 B/D/well of fluid.

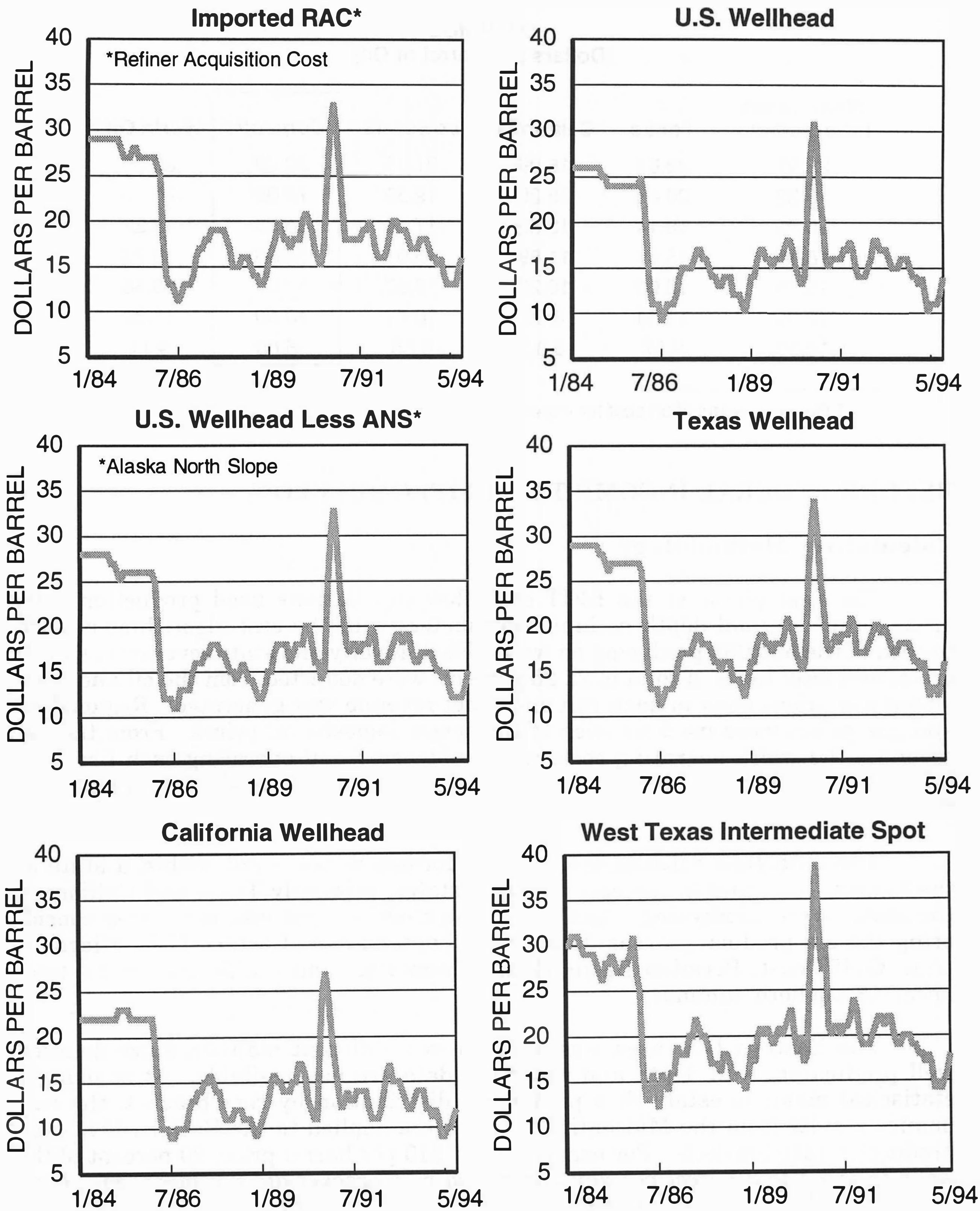
Figure 5-3. EIA Economic Model Operating Cost Components.

Results of the calibration efforts indicated that water handling (injection and disposal) costs vary significantly from area to area and, in some cases, from well to well within an area and make it impossible to precisely estimate each well's operating costs. The water handling information utilized in the cost curves represents an average and provides a relatively accurate cost over a broad spectrum of wells.

The cost algorithm used to determine normal daily expense (including lease level overhead and supervision) was adjusted to decrease costs for the lower rate wells, as shown in Figure 5-3. For example, the normal daily expense for a 1 barrel of oil per day (BO/D) well was estimated to be 10 percent ($0.72 per day) of a 10 BO/D well ($7.20 per day). The adjusted algorithm likely understates the cost of operating the very low volume wells (particularly those producing 1 BO/D or less), which, in turn, will understate the number of these wells that are unable to meet lease level costs at low oil prices. Very few cost data were provided by survey participants on wells with rates less than one barrel of oil equivalent per day—a majority of which are probably Class 2 intermittent producers. The small operators owning these very low rate wells have developed unique operating practices to maintain their production. When prices fall, these operating practices may deviate substantially from what optimum operations would normally include. For example, maintenance may be performed less frequently than normal. These conditions make considering a cash flow analysis problematic, since few operating cost data are available and the mode of operations for these wells is radically different from higher rate wells. As previously demonstrated, small cost increases or production rate decreases can cause significant swings in costs on a per BOE basis for these low rate wells.

Oil Price

Although oil price would seem to be a straightforward input parameter, the many reference prices considered throughout industry (such as world oil price, West Texas Intermediate, refiners' acquisition cost, lower-48 price, etc.) and quality, transportation and other adjustments, etc., complicate the issue. In the cash flow evaluations, all price references are based on the average realized domestic wellhead price. This price is a volume weighted average for all of the crude oil produced in the United States, including Alaska. This price is significantly different, usually lower, than the often referred to West Texas Intermediate price. After input of the ***average domestic price***, the corresponding average price that accounted for average regional gravity and sulfur content was used in each producing state. Table 5-4 provides a reference for several of the more commonly referred to oil prices. From left to right across the table, the effects of adding a lower price volume to the West Texas Intermediate crude oil can be seen. The prices since 1984 for these areas are shown in Figure 5-4—the U.S. wellhead price shown on the figure equates to the domestic price reference throughout this report.



Sources: West Texas Intermediate price data — *Platts Oilgram Price Report.*
All other price data — Energy Information Administration.

Figure 5-4. Monthly Crude Oil Prices.

TABLE 5-4

OIL PRICE
(Dollars per Barrel of Oil)

West Texas Intermediate	Texas	California	Lower-48	*Domestic*	World Oil*
25.91	22.67	16.99	21.45	*20.00*	22.77
23.32	20.40	15.29	19.30	*18.00*	20.49
20.73	18.14	13.59	17.16	*16.00*	18.22
18.13	15.87	11.89	15.01	*14.00*	15.93
15.54	13.60	10.20	12.87	*12.00*	13.66
12.95	11.34	8.50	10.72	*10.00*	11.39
10.36	9.07	6.80	8.58	*8.00*	9.11

* Refiner's acquisition cost for imported oil.

BEFORE FEDERAL INCOME TAX (BFIT) CASH FLOW

Calculation Methodology

The first phase of the BFIT cash flow calculations used production rate, area, water cut, and depth as input parameters with the cost algorithms applied to each of the 586,058 producing oil wells. Next, royalty and state severance, ad valorem, and local taxes, a total of 21.25 percent, were deducted from the oil and associated gas prices used in each run and a net revenue was generated. Regional oil and gas prices were used for each of the seven domestic oil prices. From the net revenue, the well's operating costs were subtracted and operating cash flow was calculated. Figure 5-5 provides a simple illustration of the models' data and logic flow.

The cash flow calculations were performed well-by-well within a state at the highest level and in the case of larger states, primarily Texas and California, the states were subdivided. Analysis of the model output was performed considering the six producing areas defined in Chapter Four—Eastern U.S., Midcontinent, Gulf Coast, Permian Basin, Rocky Mountains, and California—and a total lower-48 onshore summary.

The Eastern U.S. area was handled in a different manner, since detailed well production, well depth and water cut data are not available. After using a statistical mean to establish a production distribution by rate bracket, the economics results from the Midcontinent area were applied to the Eastern U.S. area production rate brackets. For example, if at $10 per barrel price, 20 percent of the wells in the 1 to 2 barrel per day production rate bracket did not meet lease level costs, then 20 percent of the wells in this bracket in the Eastern U.S. area were assumed to not meet lease costs. Similarly, for Oklahoma and Kansas, percentages of wells that did not meet lease operating costs in each production rate bracket of the other Midcontinent states were used due to a lack of water production data.

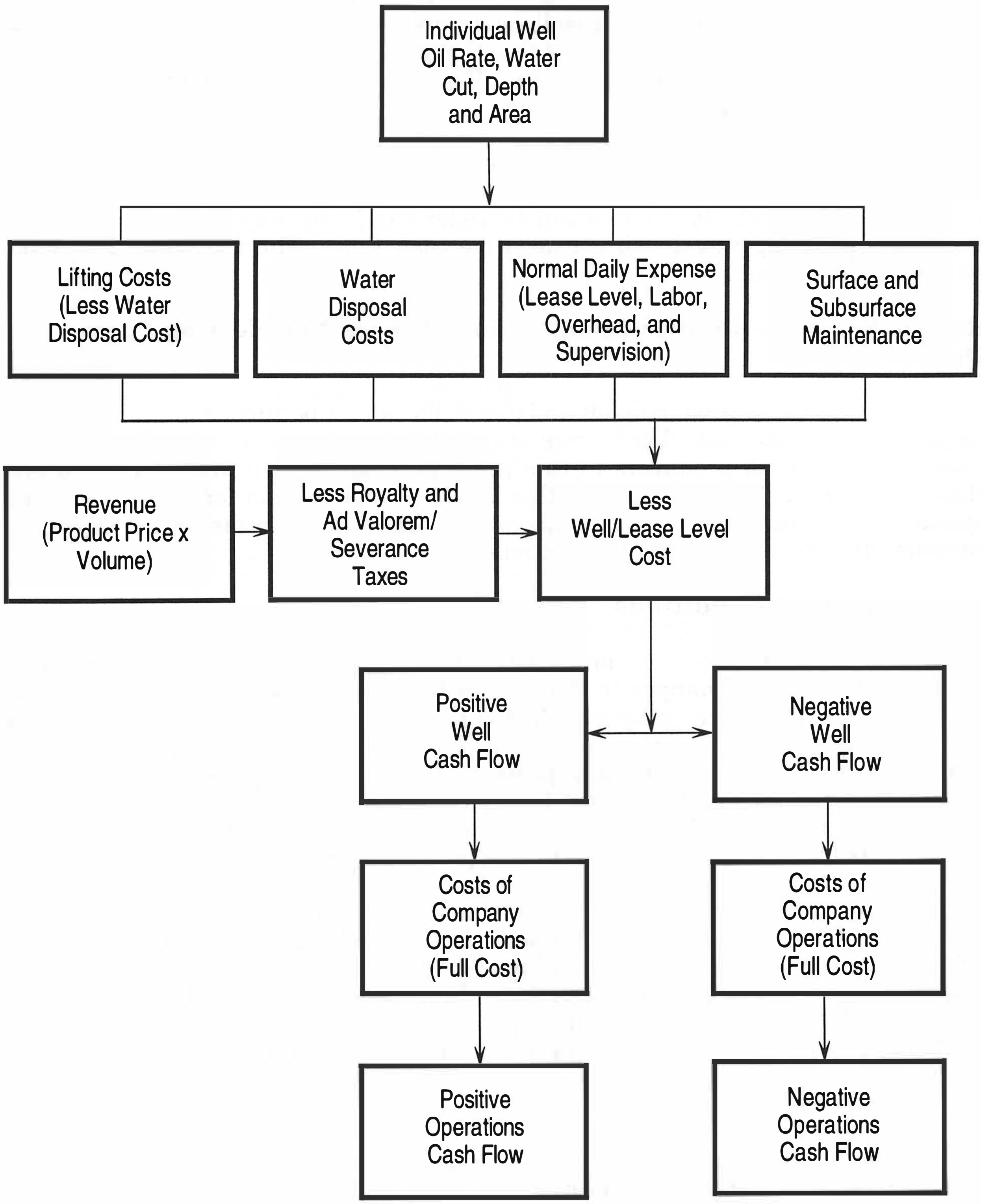


Figure 5-5. Before Federal Income Tax Cash Flow Well Level Cash Flow Calculation.

Several analyses were performed on the model output before proceeding to the next phase of the cash flow evaluation. This next phase involved including the additional costs incurred by oil well operators, as mentioned previously in this and other chapters, in order to determine the number of wells that do not meet the total cost of operations for a company. This is discussed in more detail in the Results section of this chapter.

At each oil price there are a number of wells that are not able to meet lease level costs and consequently would generate a negative cash flow, but that continue to be operated. It is important to understand why operators may choose to continue operating a well with a negative cash flow. The following discussion addresses this issue.

Rationale for the Continued Operation of Wells Not Meeting Lease Operating Costs

In most cases producing oil and gas wells cannot be turned on and off like a water faucet as the cash flow hovers at or below break-even levels. The question most often asked of producers in this precarious position is "Why don't you just shut the wells in?" Unfortunately, this is not a viable option for many wells and operators until the losses become unbearable. Following is a discussion of several reasons influencing an operator's actions.

Changing Conditions

The basic premise for a producer continuing to operate an uneconomic well is that something will happen in the foreseeable future to positively alter the profitability of the well or the property. The three most prevalent changing conditions are the production rate of the well, the price of the product, and operating costs. Generally, wells that generate a negative cash flow will be operated for as long as a producer can absorb the losses because the conditions described above can change very rapidly. However, an operator can not continue to operate uneconomic wells for a prolonged and indefinite period of time.

An example of the impact a nominally small change can have on a well's profitability is exhibited by a low rate well making 0.5 BO/D. At a $15 per barrel oil price and an $18.00 per barrel operating cost (fixed at $9.00 per day), this example well would generate a negative cash flow. However, a similar well producing at a rate of 1.5 BO/D with a $9.00 per day operating cost would have a lower per barrel operating cost of $6.00 and it would generate a positive cash flow.

Price Volatility

Since 1980, domestic oil (U.S. wellhead on Figure 5-4) has experienced price highs near $35.00 per barrel and lows of nearly $10.00 per barrel. The price of oil following its 1986 collapse has, for the most part, stayed within a range of $12.00 to $20.00 per barrel. However, as demonstrated since September 1993, crude oil prices can be extremely volatile within that range. Many producers saw a $4.00 per barrel positive cash flow turn to $4.00 per barrel negative cash flow in a period of a few months. Their motivation for continuing to operate these wells is based on the anticipation that prices will rebound to profitable levels as rapidly as they fell. Many operators, however, do not have the financial ability to sustain long periods of price anticipation and will shut in wells that generate negative cash flow unless one or more of the following situations influences them to continue producing.

Avoidance of Bypassed Reserves

In active waterfloods and waterdrive reservoirs, sustained downtime of producing wells will cause reserves to be bypassed. This ultimately lowers recoverable reserves since these types of reservoirs need to be produced continuously to achieve maximum recoveries. This knowledge makes it very difficult for prudent producers to shut in wells as they fall short of making a positive cash flow, because the resource and, ultimately, the value of the property, is negatively impacted.

Loss of Reservoir Heat

Most of California's heavy oil production is from reservoirs that are being heated with steam. If a significant number of producing wells are shut in, the heat in the formation is lost over time. Temporarily shutting in wells in a reservoir under steam injection to wait for higher prices is not normally a viable option.

Unrealized Potential

A currently uneconomic property may have potential that is yet to be exploited. This can include reserves to be recovered with new drilling (exploratory or development), waterflood development, enhanced recovery, or new stimulation/completion techniques. An operator may elect to continue operating uneconomic wells in order to develop unrecovered reserves at a later date. The delay in the reserve development may be necessary due to an unfavorable price environment, a lack of technological maturation or the prohibitive cost of the technology. Two recent examples of new technology utilized to exploit previously unattainable reserves are 3-D seismology and horizontal drilling.

Perpetuation of the Leasehold Interest

Some wells may be operated at a loss for a period of time in order to help maintain an operator's leasehold interest. However, if operations on a lease aren't continual, the terms of the lease may call for its termination with as little as 60 or 90 days of inactivity. Upon cancellation, the producer loses any potential value and is forced to begin abandonment procedures.

Postponement of Plugging and Abandonment

The cost of continued operations for wells generating a negative cash flow can be less costly than the immediate plugging and abandonment of a well or property. Under a scenario of continued normal operations, an operator can proceed with an orderly abandonment plan that can extend over a period of several years.

Maintenance of Organizational and Operational Infrastructure

Certain wells, properties or even fields are operated with negative cash flow for short periods of time in order to maintain the integrity of a company's organization and infrastructure. Many times, particularly with older fields, organizations and infrastructures have been built over long periods of time, and the investment of both time and capital can be substantial. Associated with these organizations and infrastructures, as in the case with California heavy oil operations, there is a large component of fixed operating costs that will be realized even if wells are shut in. It would be foolish for a company to shut down a property and discard something so difficult to replace without careful consideration. In addition to the lost investment, a short sighted decision could adversely affect the operation of other nearby fields or possibly hinder the operator's chances of selling the field.

Before Federal Income Tax Economic Results

Tables and plots were generated for the total lower-48 onshore states and each of the six regions, considering the seven oil price scenarios evaluated with the economics model. Tables of wells and production that do not meet lease operating costs at the seven oil prices are provided for each area evaluated. Additionally, a table comparing the effects of full costs and lease level costs for wells producing less than 20 BOE/D, using normalized wells and production, is included. An example of detailed data is included in Appendix F, Section III, with full details available in working papers. The initial set of two plots are useful for determining wells and production unable to meet lease operating expense at the lowest oil price evaluated of $8 per barrel and the highest price of $20 per barrel. These plots visually provide a basis for better defining the rate that characterizes marginal wells in each area.

A second set of plots were generated for each area to demonstrate the cash flow of a company's total operations above the lease level—full cost. These plots include a normalized curve to account for very low-rate (0 to 1 BOE/D) wells that were determined by the model to have a negative cash flow at $20 per barrel domestic oil price. The plots show a shaded area, which was used to demonstrate the range of full cost of company operations. This shaded area represents $4 per barrel, which the NPC agreed was a reasonable estimation of a company's costs which do not get allocated down to the lease or well level. These costs include administrative and management costs, accounting and finance costs, research and development, product marketing, government and public affairs, environmental and regulatory affairs, health and safety, insurance, and debt repayment costs. Every company, including the smallest family run operation to the largest integrated corporation, incurs these costs to varying degrees.

As further verification of the $4 per barrel cost, an analysis of 12 exploration and production company 1993 annual reports and data from the *Oil and Gas Journal* database was completed. Although there are considerable differences in category values between companies as a result of varying capital structures of the companies, the average indicates that these costs fall within the $4 per barrel range. It should not be interpreted from these data that any individual company or the average is representative of the industry average. Data from this analysis are shown in Table 5-5. All of the analysis in the remainder of this chapter addresses only the costs mentioned above and does not provide a margin for equity recapture or profit. ***Consideration of these factors is necessary if exploration and development activity in the domestic industry is to continue.***

TABLE 5-5

JUSTIFICATION OF OTHER COSTS USED IN FULL COST ANALYSES

Company	SG&A	Interest Exp.	Dividends
	$/Barrel of Oil Equivalent		
A	0.95	0.33	0.41
B	1.33	6.27	0.00
C	1.23	2.05	0.55
D	1.44	2.84	0.00
E	1.06	1.03	0.48
F	1.58	1.88	0.00
G	1.98	0.19	1.31
H	1.60	1.03	0.39
I	0.94	1.33	0.62
J	1.53	N/A	N/A
K	1.32	N/A	N/A
L	1.51	N/A	N/A
Average	1.37	1.88	0.42
	Total Average = $3.67/BOE		

Notes: SG&A is "selling, general, and administrative" costs; Companies included are Anadarko, Apache, Coho Energy, Inc., Enron Oil & Gas, Forest Oil Corp., Mesa, Noble Affiliates, Oryx, POGO Producing, Presidio Oil Company, Santa Fe Resources and Wiser Oil.

In the next section, the total U.S. lower-48 onshore summary will be discussed, followed by a detailed discussion of each region.

Lower-48 Onshore Wells and Production Analysis

Table 5-6 provides a summary of the total number of wells, percentage of total wells, annual production, and percentage of total production that do not meet lease operating costs at the seven domestic oil prices. It should be noted that all of these figures are based on 586,058 producing oil wells with an associated production of 2,045,729,760 BOE during 1992. The wells and associated production shown on this table are wells that can no longer produce sufficient cash flow to meet normal lease operating costs. ***These values do not account for the additional $4 per barrel of costs associated with a company's total operations.***

Figures 5-6 and 5-7 show the total oil wells and associated production for the U.S. lower-48 onshore wells that are unable to meet lease operating expenses in 5 BOE/D per well rate bracket increments from 0 to 50 BOE/D. Figure 5-6 indicates that at prices between $8 and $20 per barrel, wells unable to meet lease operating expense in 0 to 5 BOE/D category increase from 60,000 at $20 per barrel to slightly over 130,000 wells at $8 per barrel. The figure indicates that a majority of the wells not meeting their lease expense are in the 0 to 5 BOE/D rate bracket. It is important to note that at the $20 per barrel domestic oil price, approximately 47,700 wells in the 0 to 1 BOE/D rate bracket were unable to meet lease operating expense.

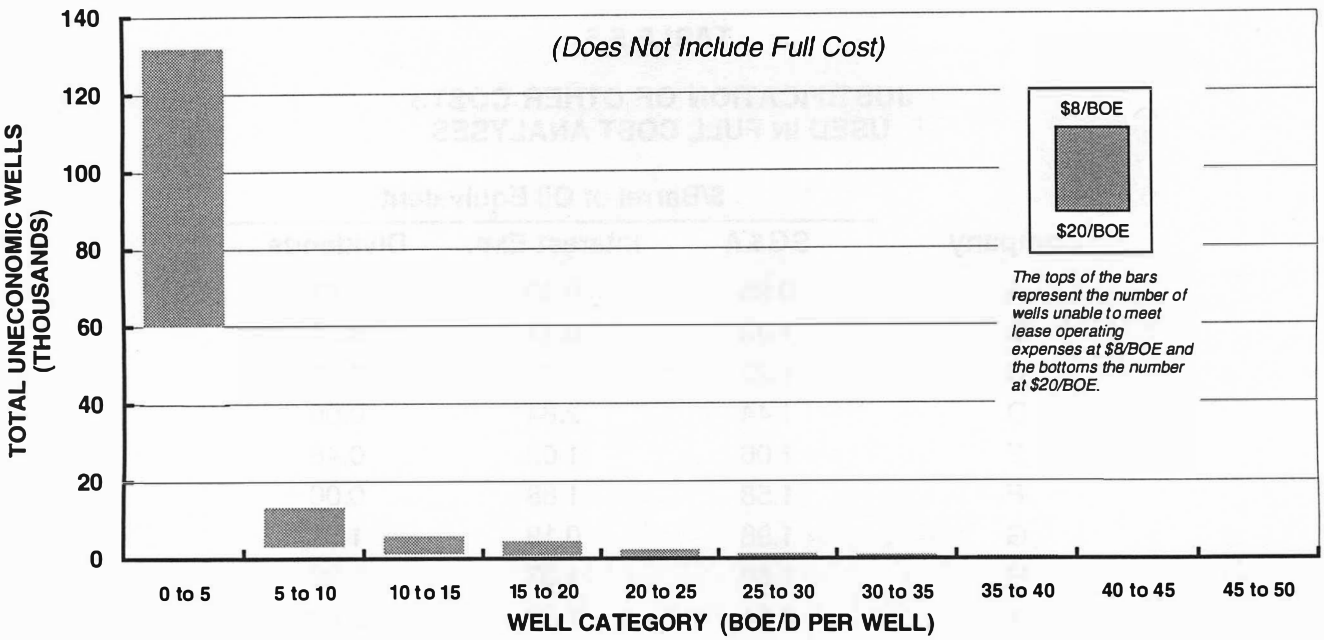


Figure 5-6. Wells Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Onshore Lower-48—586,058 Wells.

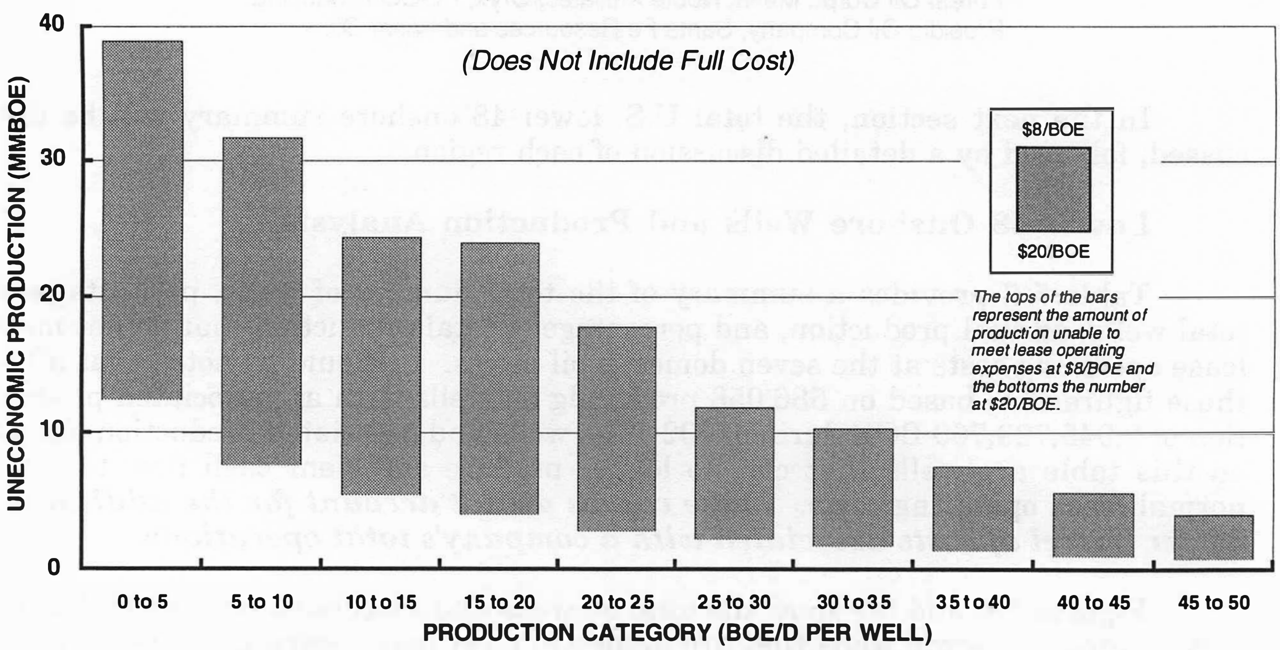


Figure 5-7. Production Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Onshore Lower-48—2,045,729,760 BOE.

TABLE 5-6

OIL WELLS AND PRODUCTION THAT DO NOT MEET LEASE OPERATING COSTS, FOR LOWER 48-STATES ONSHORE (See Table 5-7 for Full Cost Analysis)

Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	66,225	11.3	53	2.6
$18	73,843	12.6	61	3.0
$16	82,048	14.0	72	3.5
$14	95,527	16.3	92	4.5
$12	110,179	18.8	117	5.7
$10	130,691	22.3	155	7.6
$8	161,752	27.6	215	10.5

Note 1: Based on 586,058 wells and production of 2,045.730 million BOE in 1992.

Note 2: These wells can no longer produce enough income to meet normal lease operating costs.

Note 3: Gas production was converted to barrel oil equivalent (BOE) on the basis of 6 thousand cubic feet of gas per BOE.

Note 4: Oil prices vary by region, oil gravity, and sulfur content. An average domestic price of $16 per barrel is equivalent to a West Texas Intermediate spot price of $20.70 and a California price of $13.60 per barrel. For each domestic price, an equivalent regional price was used to determine the economic status of oil wells.

Source: Energy Information Administration, Office of Oil and Gas, Dwight's Energydata, Inc., and Petroleum Information Corp.

These wells account for 72 percent of the total 66,000 wells unable to meet lease operating expense shown on Table 5-6. However, annual production from these 47,7000 wells account for only 2.7 million BOE or 5 percent of the total 53 million BOE that are unable to meet lease operating cost at $20 per barrel. This demonstrates that even at higher oil prices, the model is unable to handle very low producing rate wells.

Production from the wells that are unable to meet lease operating expense illustrated in Figure 5-7 is a much different picture. Using this figure, it can be seen that moving from the high rate bracket of 45 to 50 BOE/D to lower rate brackets, ***a substantial change in the rate at which production in each category becomes unable to meet lease operating expense occurs in the 20 to 25 BOE/D rate bracket. This could provide adequate justification for defining marginal wells as those producing less than 20 or 25 BOE/D***. An alternative graphical analysis of the percentage of production and wells unable to meet lease operating costs in each production category bracket provides similar results. This analysis is provided in the working papers.

Figure 5-8 is a plot of the data provided in Table 5-6, with several modifications. First, the two upper lines illustrate the percentage of wells unable to meet lease operating expenses at the $8 to $20 per barrel range. The lowest of the two lines is for all wells and the upper line is only for wells that produce less than

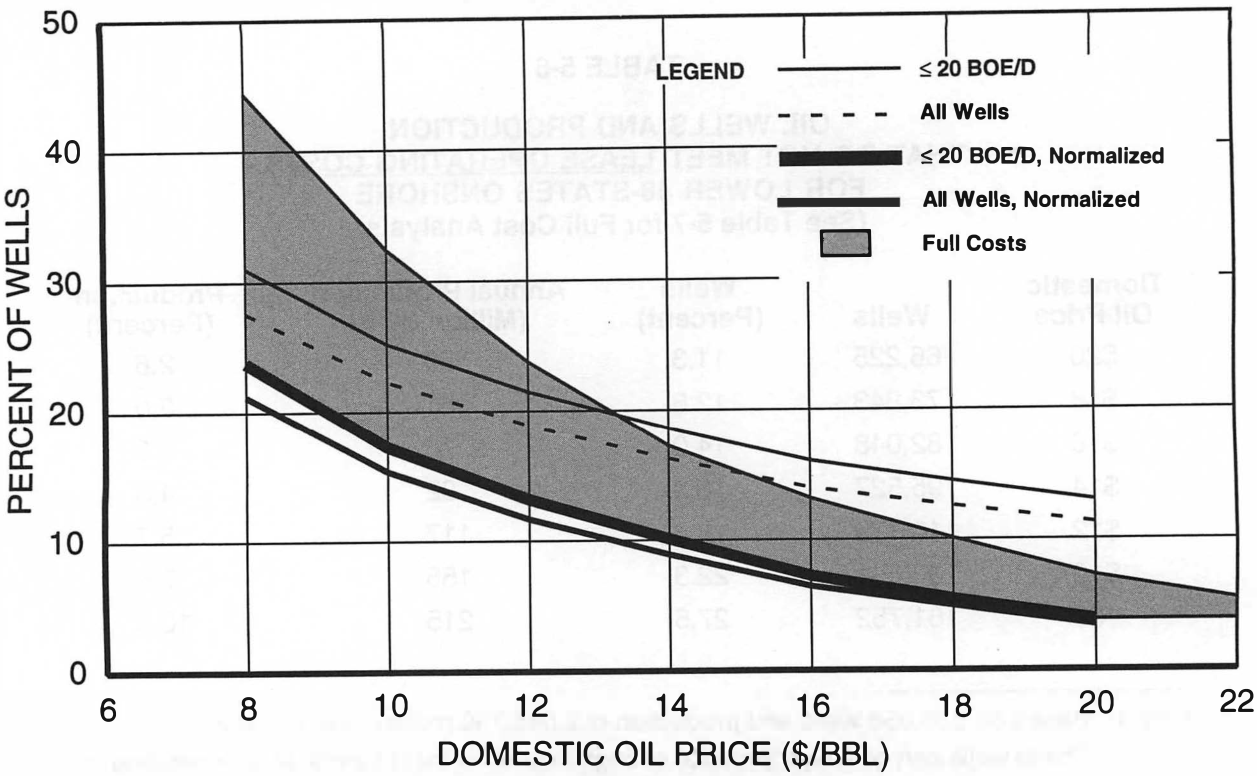


Figure 5-8. Wells Unable to Meet Lease Operating Expenses—Onshore Lower-48.

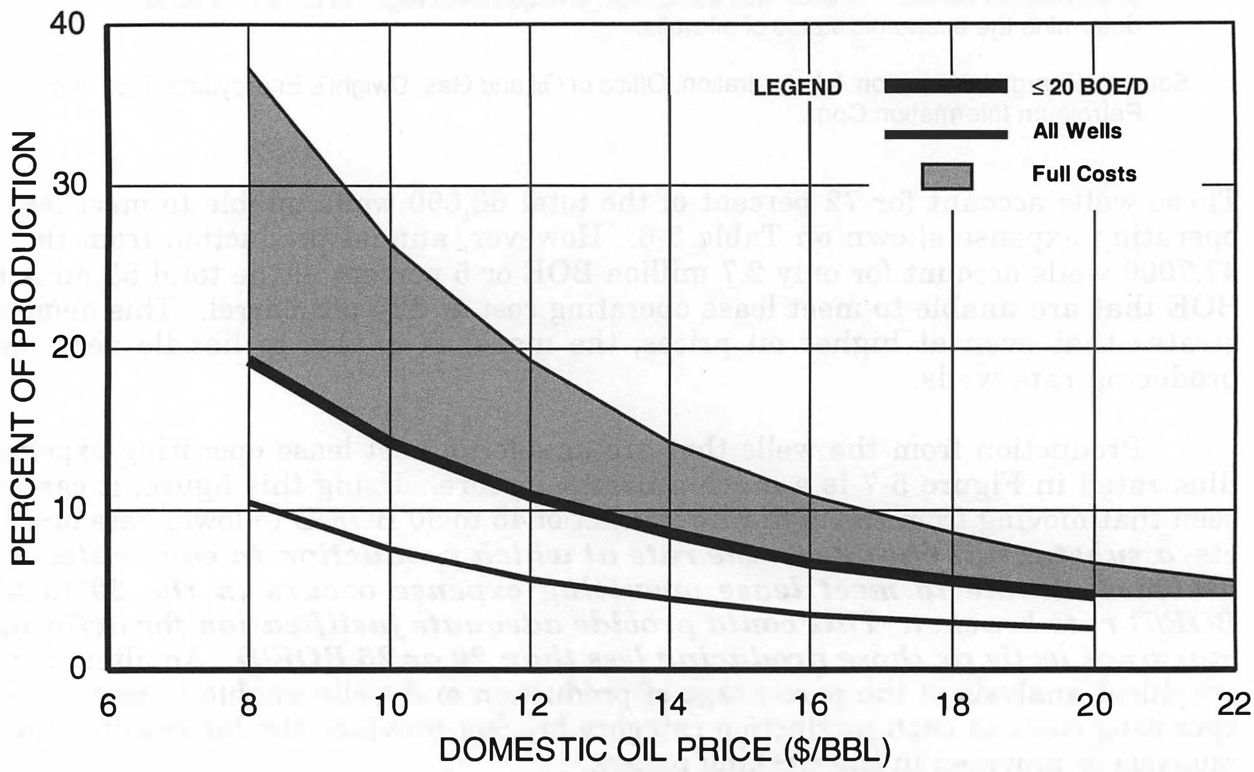


Figure 5-9. Production Unable to Meet Lease Operating Expenses—Onshore Lower-48.

20 BOE/D. Since 47,700 of the wells unable to meet lease operating expense at $20 per barrel are in the 0 to 1 BOE/D rate bracket, a normalization was used to exclude these wells from the percentages shown at all oil prices. The curves demonstrating the effects of normalization are the darker lowest curves on the graph. The bottom normalized curve is for all rate brackets excluding the 47,700 wells in the 0 to 1 BOE/D rate bracket. The darkest solid line illustrates the percentage of wells less than 20 BOE/D unable to meet lease operating expenses, also excluding the 47,700 wells. The shaded area demonstrates the additional costs a corporation incurs above costs that can be allocated to the lease or well level. For example, at $20 per barrel a company may have only 3.5 percent of the wells producing less than 20 BOE/D unable to meet lease operating expenses, as shown in the figure. However, when considering the total corporate costs (full cost), an additional 3 percent of the company's operations can be considered in a negative cash flow position. At lower oil prices, this percentage increases substantially as shown in the figure. At $12 per barrel, approximately 13 percent of the wells producing less than 20 BOE/D are unable to meet lease operating expenses and approximately 23 percent of the total wells are unable to meet total company operating expenses.

A similar figure for percentage of production unable to meet lease operating expenses is illustrated in Figure 5-9. The impact of normalizing the curves for the 47,700 wells in the 0 to 1 BOE/D rate bracket is not seen on this figure, since total production from these wells is a very small volume. When considering production, the impact of separating out wells producing less than 20 BOE/D is more significant than if all wells are considered. This again is an indicator that wells producing less than 20 BOE/D are marginal as prices decrease from $20 to $8 per barrel. Table 5-7 provides a summary of normalized data for wells producing less than 20 BOE/D and compares the effects of full costs to lease level costs.

The lower line of the shaded area on Figures 5-8 and 5-9 represents the point where operators will begin to shut in some of their wells. As prices persist at a low level, operators must begin to reduce the losses that will occur if properties and personnel associated with the shaded area costs are retained.

Eastern U.S. Wells and Production Analysis

Table 5-8 provides a summary of the total number of wells, percentage of total wells, annual production, and percentage of total production not meeting lease operating costs at the seven domestic oil prices. It should be noted that all of these figures are based on 133,068 producing oil wells with an associated production of 54,547,220 BOE during 1992. Percentages of wells not meeting lease costs in the Eastern U.S. area were derived from the Midcontinent area since a lack of detailed well level data precluded rigorous cash flow estimations. The wells and associated production shown on this table are wells that can no longer produce sufficient cash flow to meet normal lease operating costs. These values do not account for the additional $4 per barrel of costs associated with a company's total operations.

Figures 5-10 and 5-11 show the total oil wells and associated production for the Eastern U.S. wells that are unable to meet lease operating expenses in 5 BOE/D per well rate bracket increments from 0 to 50 BOE/D. Figure 5-10 indicates that at prices between $8 and $20 per barrel, wells unable to meet lease operating

TABLE 5-7

ONSHORE LOWER-48
OIL WELLS AND PRODUCTION

≤20 BOE/D, NORMALIZED

Not Meeting Lease Operating Costs					Not Meeting Full Costs				
Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)	Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	17,153	3.8	26.5	4.3	$20	32,809	7.2	38.5	6.3
$18	24,667	5.4	32.0	5.2	$18	45,581	10.1	50.5	8.2
$16	32,809	7.2	38.5	6.3	$16	59,611	13.2	64.5	10.5
$14	45,581	10.1	50.5	8.2	$14	78,342	17.3	85.0	13.8
$12	59,611	13.2	64.5	10.5	$12	107,535	23.8	116.5	18.9
$10	78,342	17.3	85.0	13.8	$10	146,392	32.4	162.9	26.4
$8	107,535	23.8	116.5	18.9	$8	200,566	44.4	229.7	37.3

TABLE 5-8

OIL WELLS AND PRODUCTION THAT DO NOT MEET <u>LEASE OPERATING COSTS</u>, FOR EASTERN STATES (See Table 5-9 for Full Cost Analysis)

Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	23,686	17.8	3	5.9
$18	26,214	19.7	4	6.8
$16	28,610	21.5	4	8.2
$14	32,469	24.4	5	10.0
$12	36,860	27.7	7	12.4
$10	42,316	31.8	8	15.4
$8	51,231	38.5	11	20.0

Note 1: Based on 133,068 wells and production of 54.547 million BOE in 1992.

Note 2: These wells can no longer produce enough income to meet normal lease operating costs.

Note 3: Gas production was converted to barrel oil equivalent (BOE) on the basis of 6 thousand cubic feet of gas per BOE.

Note 4: Oil prices vary by region, oil gravity, and sulfur content. An average domestic price of $16 per barrel is equivalent to a West Texas Intermediate spot price of $20.70 and a California price of $13.60 per barrel. For each domestic price, an equivalent regional price was used to determine the economic status of oil wells.

Note 5: Percentages of uneconomic wells from the Midcontinent area were used for the 10 Eastern States due to a lack of detailed well level data.

Source: Energy Information Administration, Office of Oil and Gas, Dwight's Energydata, Inc., and Petroleum Information Corp.

expense in the 0 to 5 BOE/D category increase from 23,000 at $20 per barrel to slightly over 50,000 wells at $8 per barrel. The figure indicates that nearly all of the wells that are unable to meet lease operating costs are in the 0 to 5 BOE/D rate bracket. It is important to note that at the $20 per barrel domestic oil price approximately 21,000 wells in the 0 to 1 BOE/D rate bracket (24.5 percent of the wells in this bracket) were unable to meet lease operating expense. These wells account for 15.6 percent of the total wells in the Eastern United States. Of the total 133,068 wells in this region, 97 percent are in the 0 to 5 BOE/D per well rate bracket. This is 35 percent of the total lower-48 wells in this rate bracket.

Figure 5-11 of the production from the wells that are unable to meet lease operating expense dramatically illustrates the marginality of wells in this region. At $20 per barrel, 3 million BOE, 6 percent of total production in the region is unable to meet lease operating costs. This increases to over 9 million BOE, 20 percent of total production at $8 per barrel.

Figure 5-12 is a plot of the data provided in Table 5-8, with several modifications. First, the upper line illustrates the percentage of wells unable to meet lease operating expenses at the $8 to $20 per barrel range. Since nearly all the wells produce less than 20 BOE/D, a second line for the less than 20 BOE/D wells

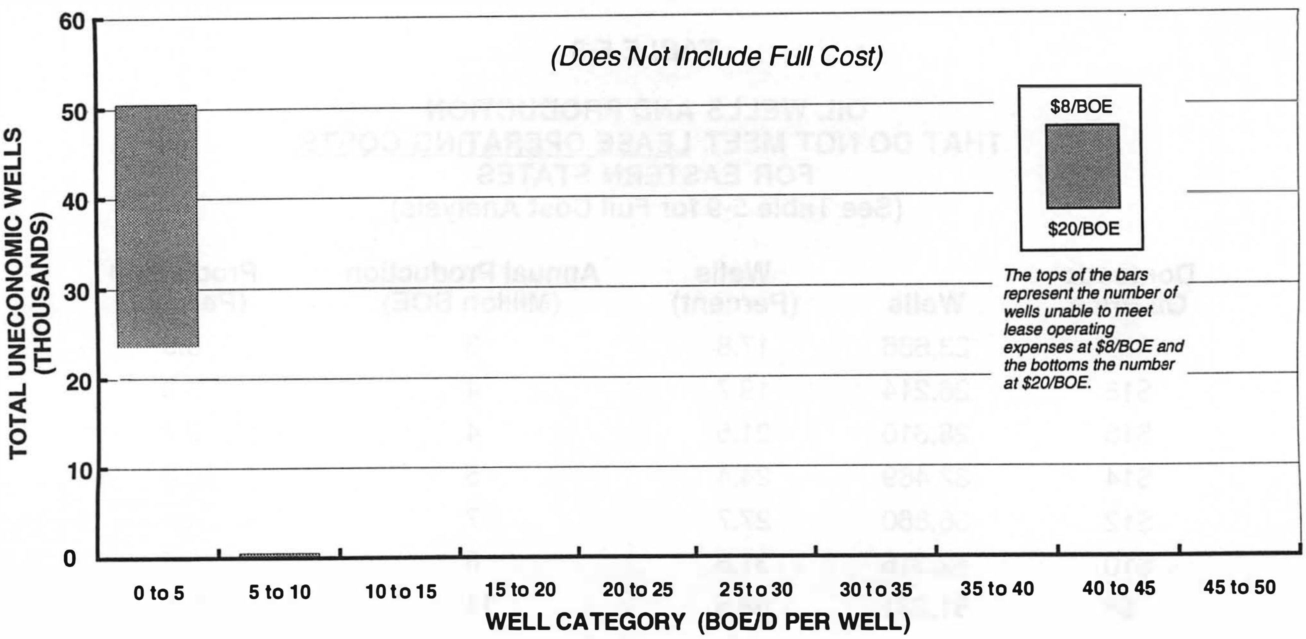


Figure 5-10. Wells Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Eastern U.S.—133,068 Wells.

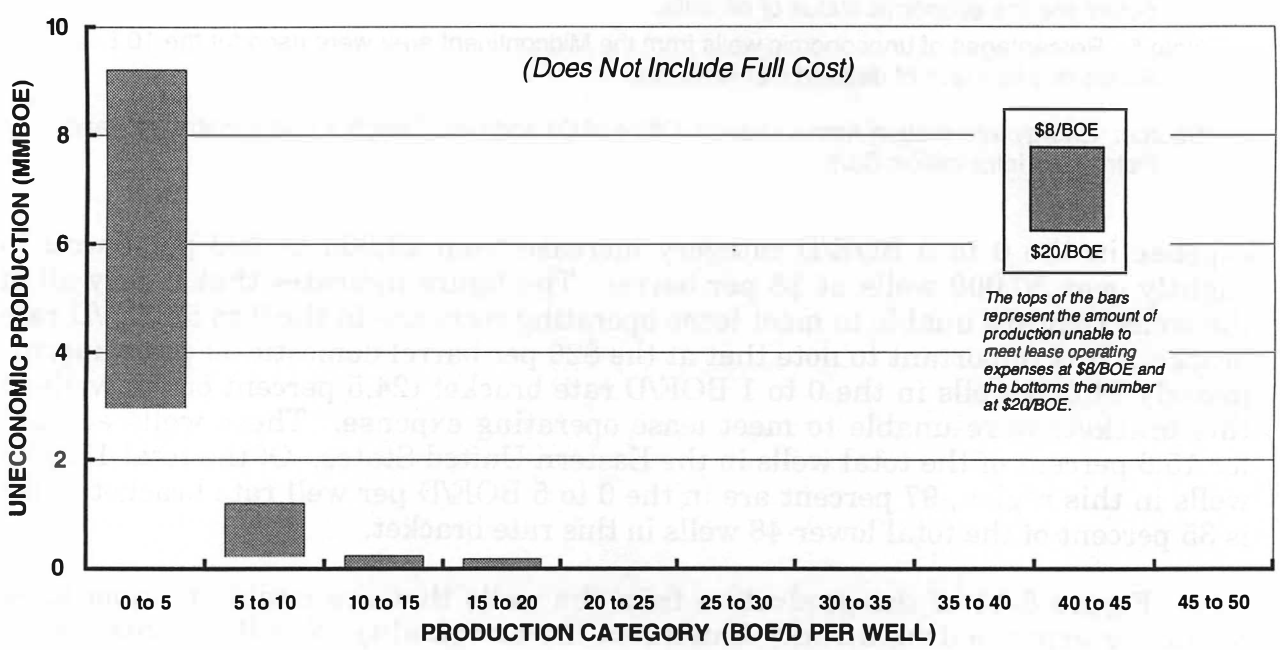


Figure 5-11. Production Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Eastern U.S.—54,547,219 BOE.

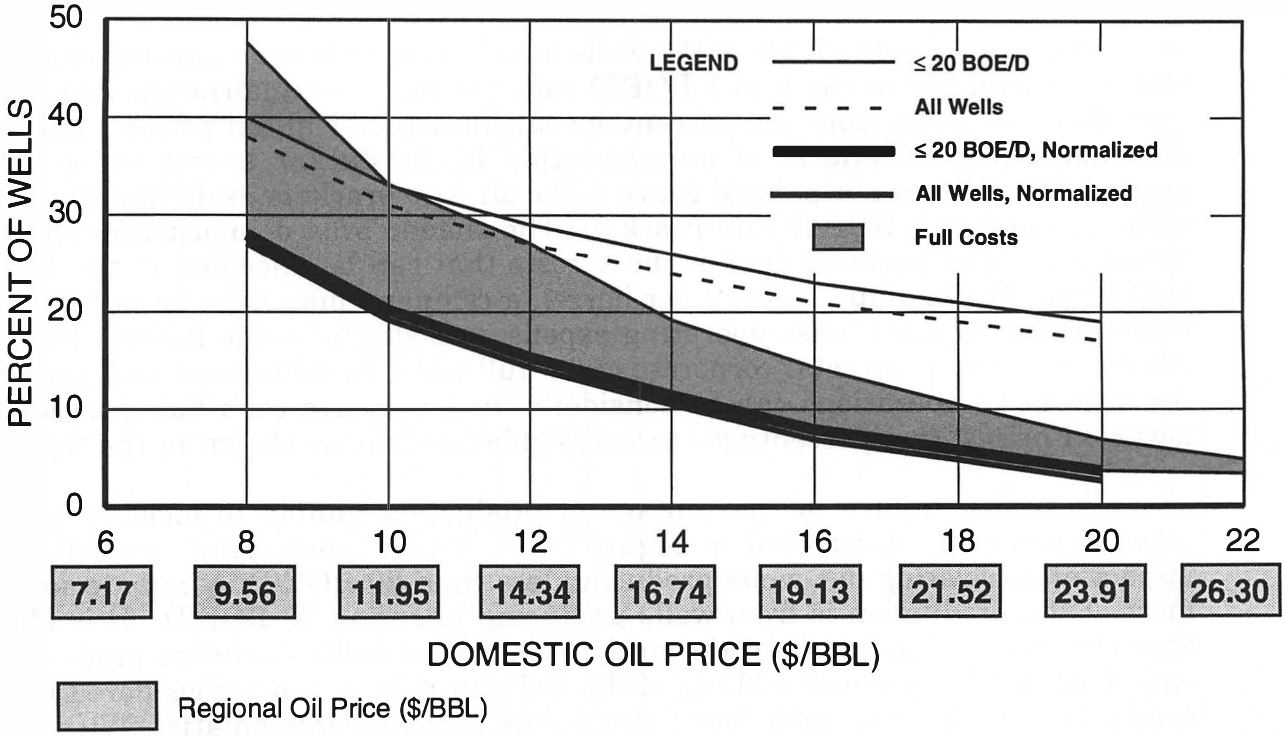


**Figure 5-12. Wells Unable to Meet Lease Operating Expenses—
Eastern U.S.**

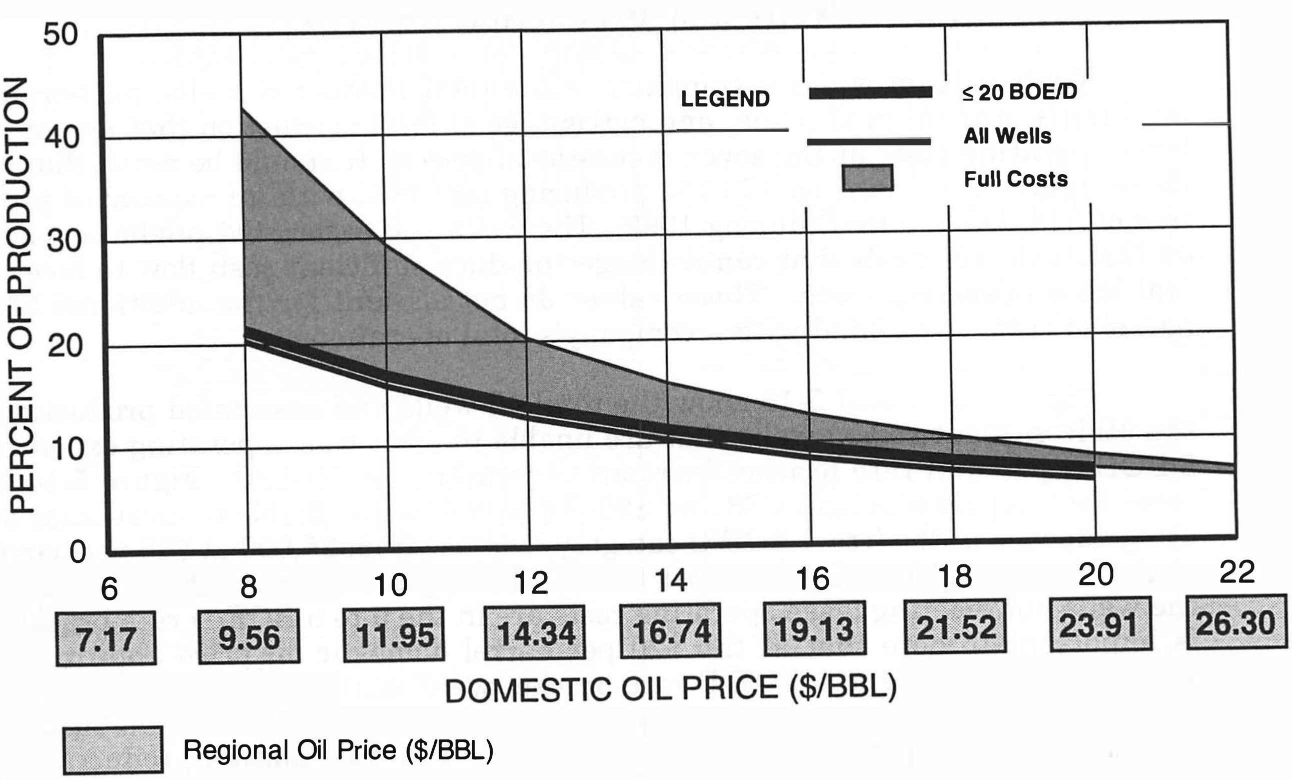


**Figure 5-13. Production Unable to Meet Lease Operating Expenses—
Eastern U.S.**

was not drawn. Since 21,000 of the wells unable to meet lease operating expense at $20 per barrel are in the 0 to 1 BOE/D rate bracket, a normalization was used to exclude these wells from the percentage calculations for all oil prices. The curve demonstrating the effects of normalization is the darker lowest curve on the graph. The bottom normalized curve is for all rate brackets excluding the 21,000 wells in the 0 to 1 BOE/D rate bracket. The shaded area demonstrates the additional costs a corporation incurs above costs that can be allocated to the lease or well level. For example, at $12 per barrel, a company may have 15 percent of its wells unable to meet lease operating expenses as shown in the figure. However, when considering the total corporate costs (full cost), an additional 12.5 percent of the company's operations can be considered in a negative cash flow position. At lower oil prices, this percentage increases substantially as shown in the figure.

A similar figure for percentage of production unable to meet lease operating expenses is illustrated in Figure 5-13. When considering production, the impact of separating out wells producing less than 20 BOE/D is immaterial since most of the production is from wells producing less than 20 BOE/D. It is obvious that this region has many of the nation's marginal wells—average production is only 1.12 BOE/D per well. Many of the wells in this area are considered Class 2 producers resulting in cash flow estimations that are problematic. With nearly 85,000 wells averaging 0.38 BOE/D it is hard to imagine how the operators generate a positive cash flow at any price realized during the last 10 years. Table 5-9 provides a summary of normalized data for wells producing less than 20 BOE/D and compares the effects of full costs to lease level costs.

Midcontinent Wells and Production Analysis

Table 5-10 provides a summary of the total number of wells, percentage of total wells, annual production, and percentage of total production that do not meet lease operating costs at the seven domestic oil prices. It should be noted that all of these figures are based on 173,753 producing oil wells, with an associated production of 318,639,332 BOE during 1992. The wells and associated production shown on this table are wells that can no longer produce sufficient cash flow to meet normal lease operating costs. These values do not account for the additional $4 per barrel of costs associated with a company's total operations.

Figures 5-14 and 5-15 show the total oil wells and associated production for the Midcontinent region wells that are unable to meet lease operating expenses in 5 BOE/D per well rate bracket increments from 0 to 50 BOE/D. Figure 5-14 indicates that at prices between $8 and $20 per barrel, wells unable to meet lease operating expense in the 0 to 5 BOE/D category increase from 25,000 at $20 per barrel to slightly over 35,000 wells at $8 per barrel. The figure indicates that a majority of the wells not meeting lease operating costs are in the 0 to 5 BOE/D rate bracket. It is important to note that at the $20 per barrel domestic oil price approximately 11,900 wells in the 0 to 1 BOE/D rate bracket were unable to meet lease operating expense. These wells account for 73 percent of the total 16,333 wells unable to meet lease operating expense shown on Table 5-10. However, annual production from these wells accounts for only 0.7 million BOE or 15 percent of the total 4.8 million BOE that are unable to meet lease operating cost at $20 per barrel.

Production associated with the wells that are unable to meet lease operating expense is illustrated in Figure 5-15 and is a different picture. Using this figure,

TABLE 5-9

EASTERN STATES
OIL WELLS AND PRODUCTION

≤20 BOE/D, NORMALIZED

Not Meeting Lease Operating Costs					Not Meeting Full Costs				
Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)	Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	2,915	2.6	2.0	3.9	$20	7,790	6.9	3.0	6.3
$18	5,376	4.8	2.5	5.0	$18	11,728	10.5	4.5	8.3
$16	7,790	6.9	3.0	6.3	$16	16,015	14.3	5.5	10.7
$14	11,728	10.5	4.5	8.3	$14	21,504	19.2	7.5	13.9
$12	16,015	14.3	5.5	10.7	$12	30,353	27.1	10.0	18.6
$10	21,504	19.2	7.5	13.9	$10	37,040	33.1	15.8	29.4
$8	30,353	27.1	10.0	18.6	$8	53,359	47.6	23.0	42.7

TABLE 5-10

OIL WELLS AND PRODUCTION THAT DO NOT MEET LEASE OPERATING COSTS, FOR MIDCONTINENT
(See Table 5-11 for Full Cost Analysis)

Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	16,333	9.4	5	1.5
$18	18,244	10.5	6	1.8
$16	20,677	11.9	7	2.3
$14	23,978	13.8	9	2.9
$12	27,974	16.1	12	3.8
$10	33,361	19.2	18	5.5
$8	41,527	23.9	25	7.8

Note 1: Based on 173,753 wells and production of 318.639 million BOE in 1992.

Note 2: These wells can no longer produce enough income to meet normal lease operating costs.

Note 3: Gas production was converted to barrel oil equivalent (BOE) on the basis of 6 thousand cubic feet of gas per BOE.

Note 4: Oil prices vary by region, oil gravity, and sulfur content. An average domestic price of $16 per barrel is equivalent to a West Texas Intermediate spot price of $20.70 and a California price of $13.60 per barrel. For each domestic price, an equivalent regional price was used to determine the economic status of oil wells.

Source: Energy Information Administration, Office of Oil and Gas, Dwight's Energydata, Inc., and Petroleum Information Corp.

it can be seen that moving from the high rate bracket of 45 to 50 BOE/D to lower rate brackets, a substantial change in the rate at which production in each bracket becomes unable to meet lease operating expense occurs in the 15 to 20 BOE/D rate bracket. This could provide adequate justification for defining marginal wells in the Midcontinent as those producing 20 BOE/D or less. A similar graphical analysis of the percentage of wells and production unable to meet lease operating expense in each production rate category also illustrates the marginal production rate for this area. These graphs are available in the working papers.

Figure 5-16 is a plot of the data provided in Table 5-10, with several modifications. First, the two upper lines illustrate the percentage of wells unable to meet lease operating expenses at the $8 to $20 per barrel range. The lowest of the two lines is for all wells and the upper line is for wells that produce less than 20 BOE/D. Since 11,900 of the wells unable to meet lease operating expense at $20 per barrel are in the 0 to 1 BOE/D rate bracket, a normalization was used to exclude these wells from the percentage calculations at all oil prices. The curves demonstrating the effects of normalization are the darker lowest curves on the graph. The bottom normalized curve is for all rate brackets excluding the 11,900 uneconomic wells in the 0 to 1 BOE/D rate bracket. The darkest solid line illustrates the percentage of wells less than 20 BOE/D unable to meet lease operating expenses, also excluding the 11,900 wells. The shaded area demonstrates the additional

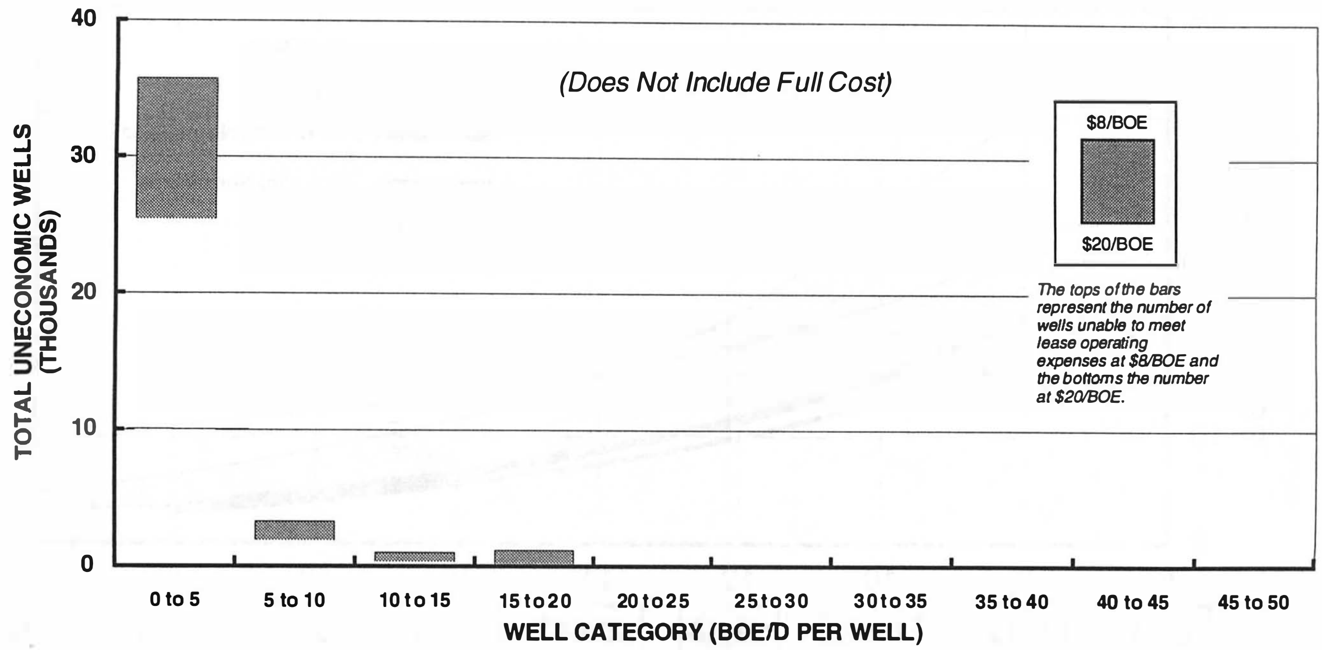


Figure 5-14. Wells Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Midcontinent—173,753 Wells.

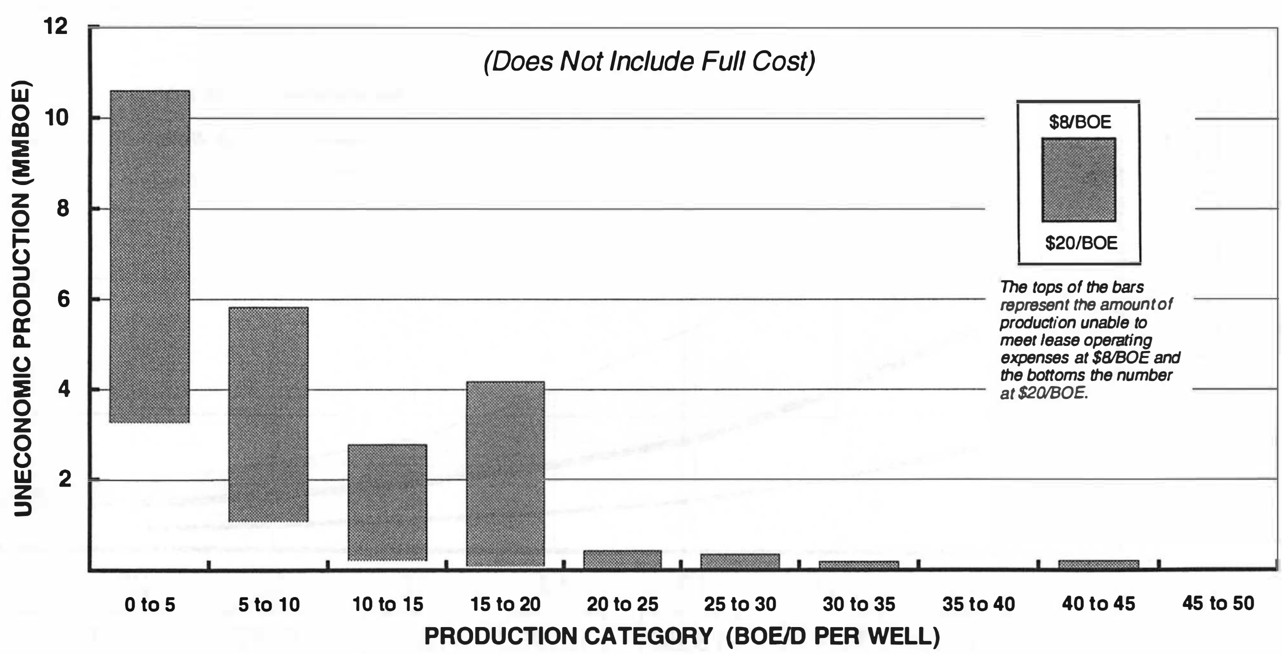


Figure 5-15. Production Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Midcontinent—318,639,332 BOE.

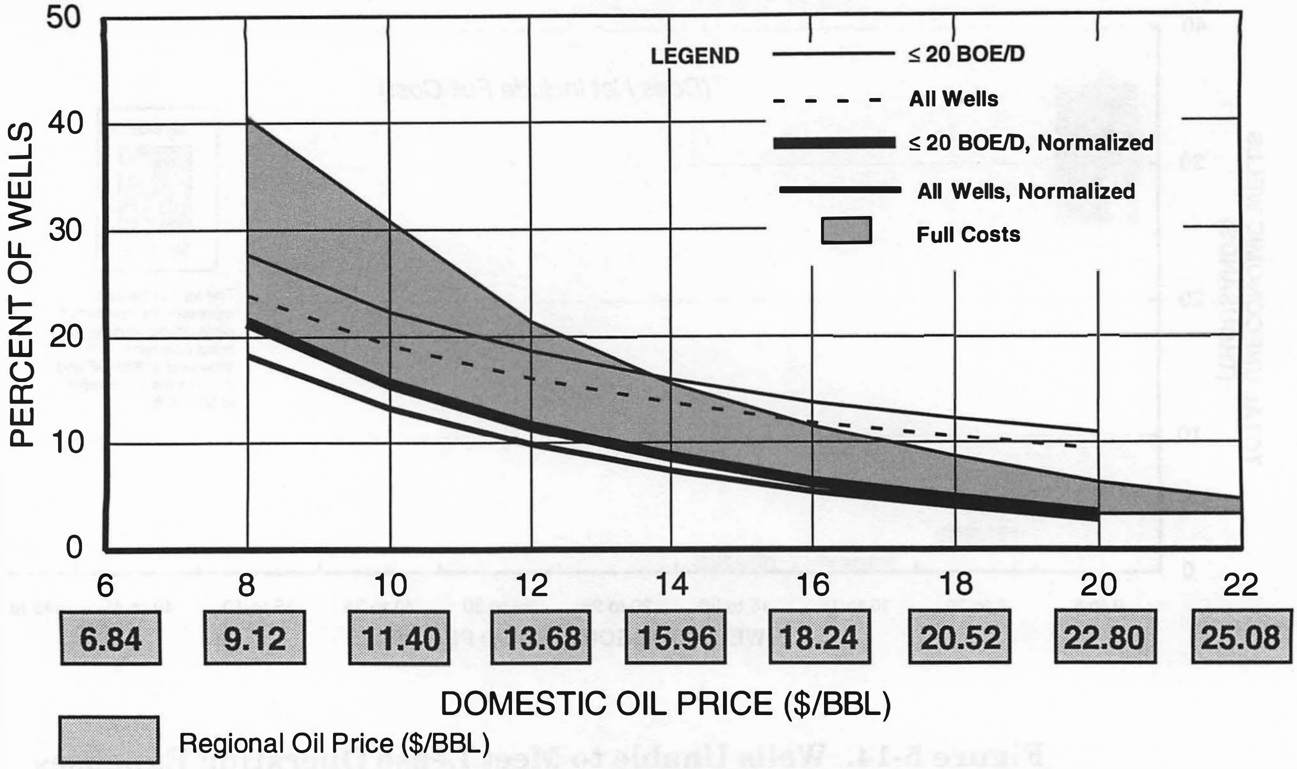


Figure 5-16. Wells Unable to Meet Lease Operating Expenses—Midcontinent.

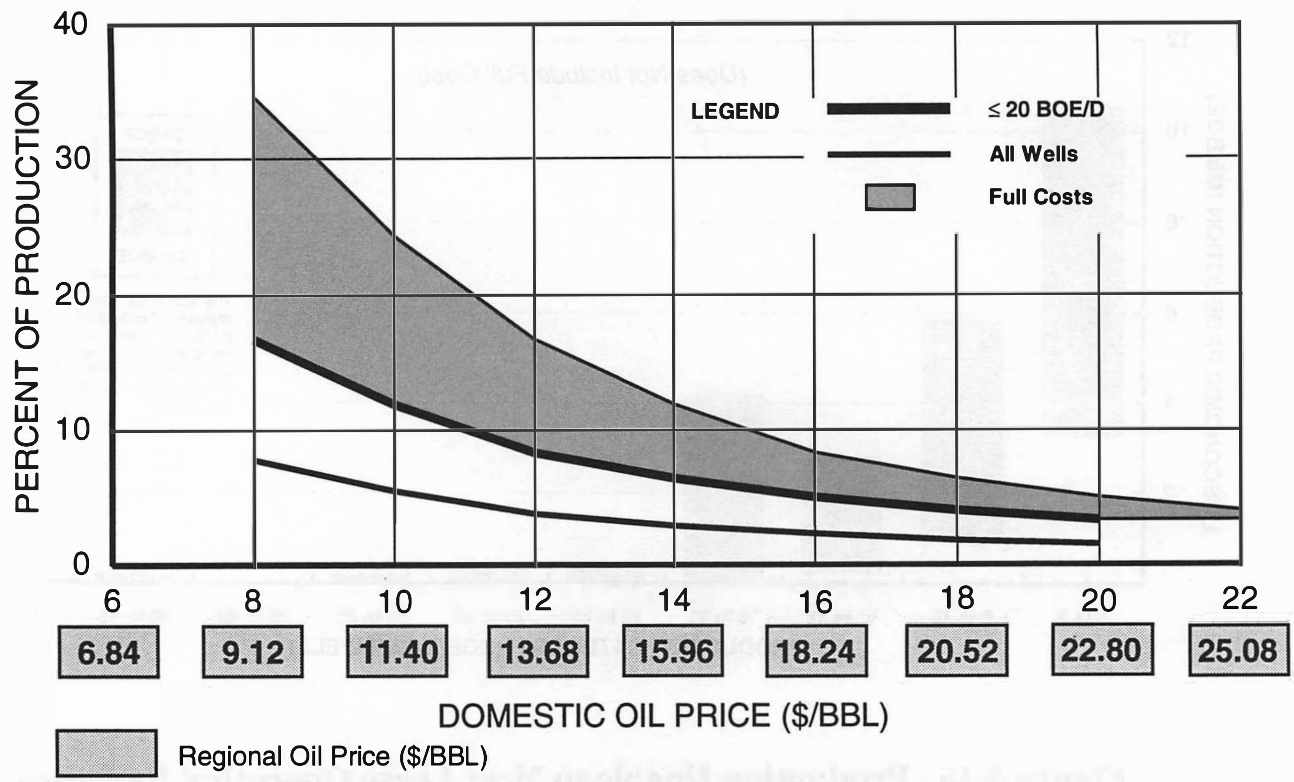


Figure 5-17. Production Unable to Meet Lease Operating Expenses—Midcontinent.

TABLE 5-11

MIDCONTINENT
OIL WELLS AND PRODUCTION

≤20 BOE/D, NORMALIZED

Not Meeting Lease Operating Costs					Not Meeting Full Costs				
Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)	Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	4,460	3.3	4.0	2.8	$20	8,660	6.3	6.5	4.5
$18	6,418	4.7	5.0	3.5	$18	11,952	8.7	8.5	5.9
$16	8,660	6.3	6.5	4.5	$16	15,892	11.6	11.0	7.9
$14	11,952	8.7	8.5	5.9	$14	21,304	15.6	16.0	11.4
$12	15,892	11.6	11.0	7.9	$12	29,353	21.4	23.0	16.3
$10	21,304	15.6	16.0	11.4	$10	41,152	30.8	34.3	24.3
$8	29,353	21.4	23.0	16.3	$8	54,095	40.5	49.0	34.7

costs a corporation incurs above costs that can be allocated to the lease or well level. For example, at $12 per barrel, a company may have 12 percent of the wells producing less than 20 BOE/D unable to meet lease operating expenses as shown in the figure. However, when considering the total corporate costs (full cost), an additional 10 percent of the company's operations can be considered in a negative cash flow position. At lower oil prices, this percentage increases substantially as shown in the figure.

A similar figure for percentage of production unable to meet lease operating expenses is illustrated in Figure 5-17. The impact of normalizing the curves for the 11,900 wells in the 0 to 1 BOE/D rate bracket is not seen on this figure, since total production from these wells is a very small volume. When considering production, the impact of separating out wells producing less than 20 BOE/D is more significant than if all wells are considered. This again is an indicator that wells producing less than 20 BOE/D are marginal as prices decrease from $20 to $8 per barrel. Table 5-11 provides a summary of normalized data for wells producing less than 20 BOE/D and compares the effects of full costs to lease level costs.

Gulf Coast Wells and Production Analysis

Table 5-12 provides a summary of the total number of wells, percentage of total wells, annual production, and percentage of total production not meeting

TABLE 5-12

OIL WELLS AND PRODUCTION
THAT DO NOT MEET LEASE OPERATING COSTS,
FOR GULF COAST
(See Table 5-13 for Full Cost Analysis)

Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	11,616	13.4	15	3.3
$18	13,176	15.2	16	3.7
$16	15,343	17.7	19	4.3
$14	17,857	20.6	22	5.1
$12	19,938	23.0	27	6.2
$10	22,885	26.4	33	7.5
$8	27,046	31.2	41	9.4

Note 1: Based on 86,686 wells and production of 440.348 million BOE in 1992.

Note 2: These wells can no longer produce enough income to meet normal lease operating costs.

Note 3: Gas production was converted to barrel oil equivalent (BOE) on the basis of 6 thousand cubic feet of gas per BOE.

Note 4: Oil prices vary by region, oil gravity, and sulfur content. An average domestic price of $16 per barrel is equivalent to a West Texas Intermediate spot price of $20.70 and a California price of $13.60 per barrel. For each domestic price, an equivalent regional price was used to determine the economic status of oil wells.

Source: Energy Information Administration, Office of Oil and Gas, Dwight's Energydata, Inc., and Petroleum Information Corp.

lease operating costs at the seven domestic oil prices. All of these figures are based on 86,686 producing oil wells with an associated production of 440,348,184 BOE during 1992. The wells and associated production shown on this table are wells that can no longer produce sufficient cash flow to meet normal lease operating costs. These values do not account for the additional $4 per barrel of costs associated with a company's total operations.

Figures 5-18 and 5-19 show the total oil wells and associated production for the Gulf Coast area wells that are unable to meet lease operating expenses in 5 BOE/D per well rate bracket increments from 0 to 50 BOE/D. Figure 5-18 indicates that at prices between $8 and $20 per barrel, wells unable to meet lease operating expense in the 0 to 5 BOE/D category increases from 10,000 at $20 per barrel to slightly over 20,000 wells at $8 per barrel. The figure indicates that a majority of the wells unable to meet lease operating costs are in the 0 to 5 BOE/D rate bracket. It is important to note that at the $20 per barrel domestic oil price, approximately 8,200 wells in the 0 to 1 BOE/D rate bracket were unable to meet lease operating expense. These wells account for 71 percent of the total 11,616 wells unable to meet lease operating expense shown on Table 5-12. However, annual production from these wells accounts for only 0.3 million BOE of the total 145 million BOE that are unable to meet lease operating cost at $20 per barrel.

Figure 5-19 of the production from the wells that are unable to meet lease operating expense illustrates a much different picture. Using this figure, it can be seen that moving from the high rate bracket of 45 to 50 BOE/D to lower rate brackets, a substantial change in the rate at which production in each bracket becomes unable to meet lease operating expense occurs in the 20 to 25 BOE/D rate bracket. This could provide adequate justification for defining marginal wells as those producing less than 20 or 25 BOE/D. Price decreases impact many more higher rate producing wells in this area than in the Eastern U.S. area—in part because this area has more higher rate wells. An alternative graphical analysis, available in the working papers, also demonstrates the production rate that could be used to define marginal wells.

Figure 5-20 is a plot of the data provided in Table 5-12, with several modifications. First, the two upper lines illustrate the percentage of wells unable to meet lease operating expenses at the $8 to $20 per barrel range. The lowest of these two lines is for all wells and the upper line is only for wells that produce less than 20 BOE/D. Since 8,200 of the wells unable to meet lease operating expense at $20 per barrel are in the 0 to 1 BOE/D rate bracket, a normalization was used to exclude these wells from the percentages illustrated at all oil prices. The curves demonstrating the effects of normalization are the darker lowest curves on the graph. The bottom normalized curve is for all rate brackets, excluding the 8,200 wells in the 0 to 1 BOE/D rate bracket. The darkest solid line illustrates the percentage of wells less than 20 BOE/D unable to meet lease operating expenses, also excluding the 8,200 uneconomic wells. The shaded area demonstrates the additional costs a corporation incurs above costs that can be allocated to the lease or well level. For example, at $18 per barrel, a company may have 8 percent of the wells producing less than 20 BOE/D unable to meet lease operating expenses, as shown in the figure. However, when considering the total corporate costs (full cost), an additional 7 percent of the company's operations can be considered in a negative cash flow position. At lower oil prices, this percentage increases substantially, as shown in the figure. At $12 per barrel approximately 18 percent of the wells producing less

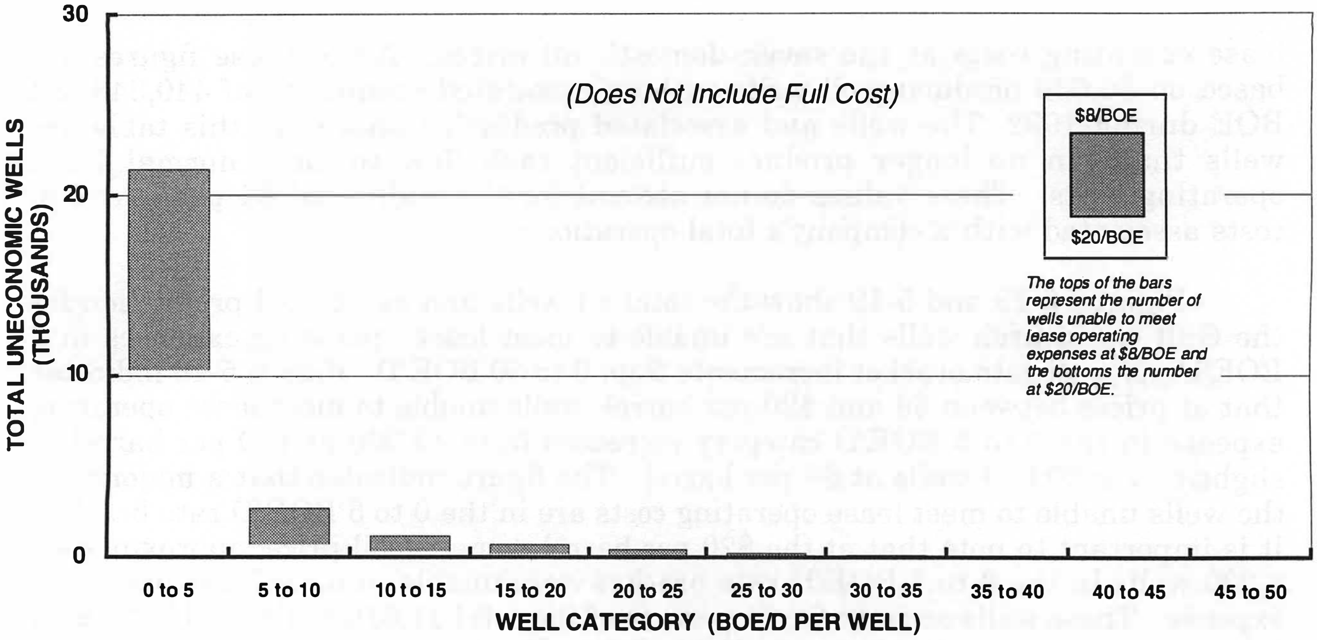


Figure 5-18. Wells Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Gulf Coast—86,686 Wells.

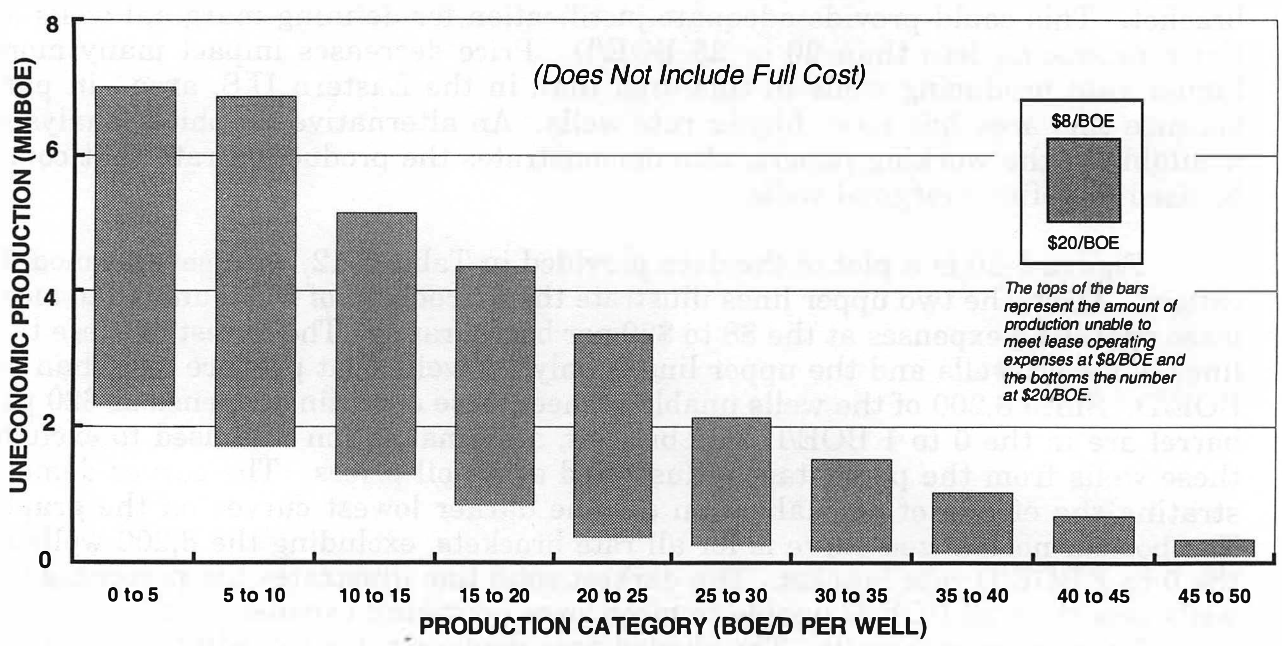


Figure 5-19. Production Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Gulf Coast—440,348,184 BOE.

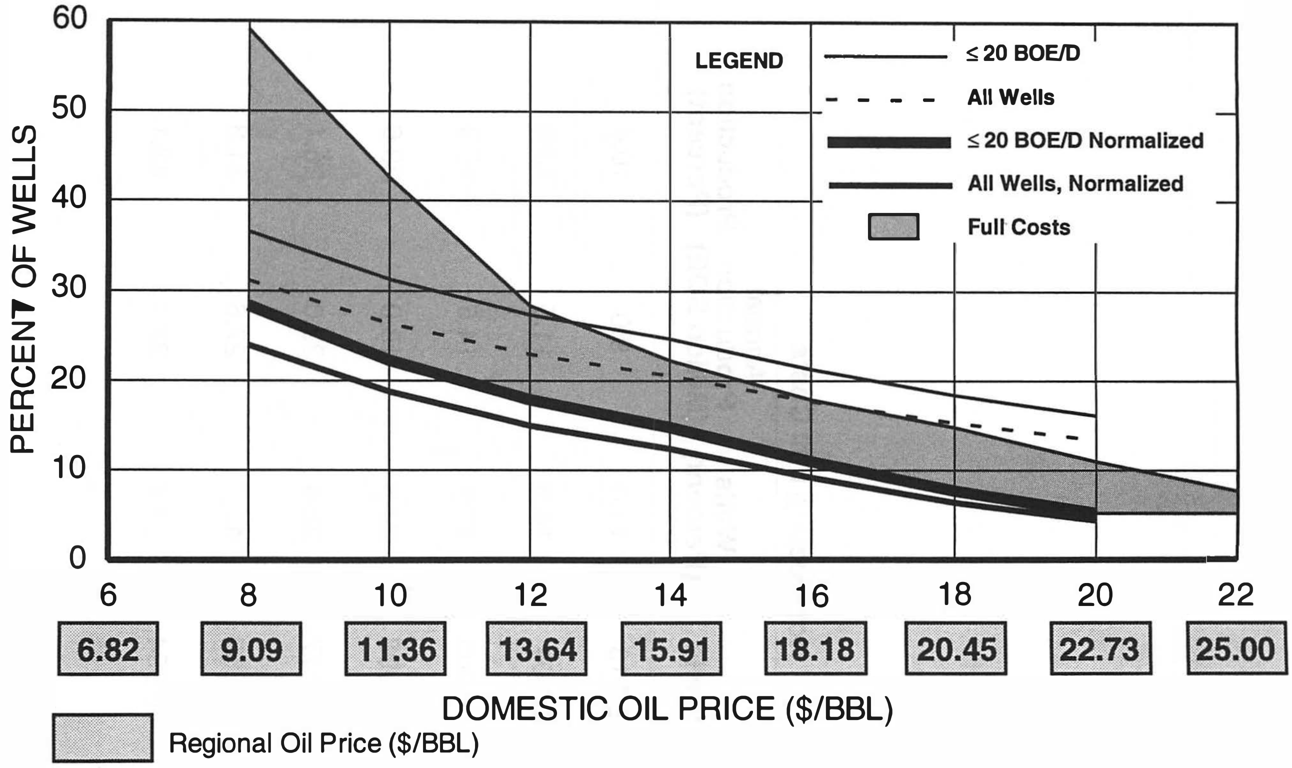


Figure 5-20. Wells Unable to Meet Lease Operating Expenses—Gulf Coast.

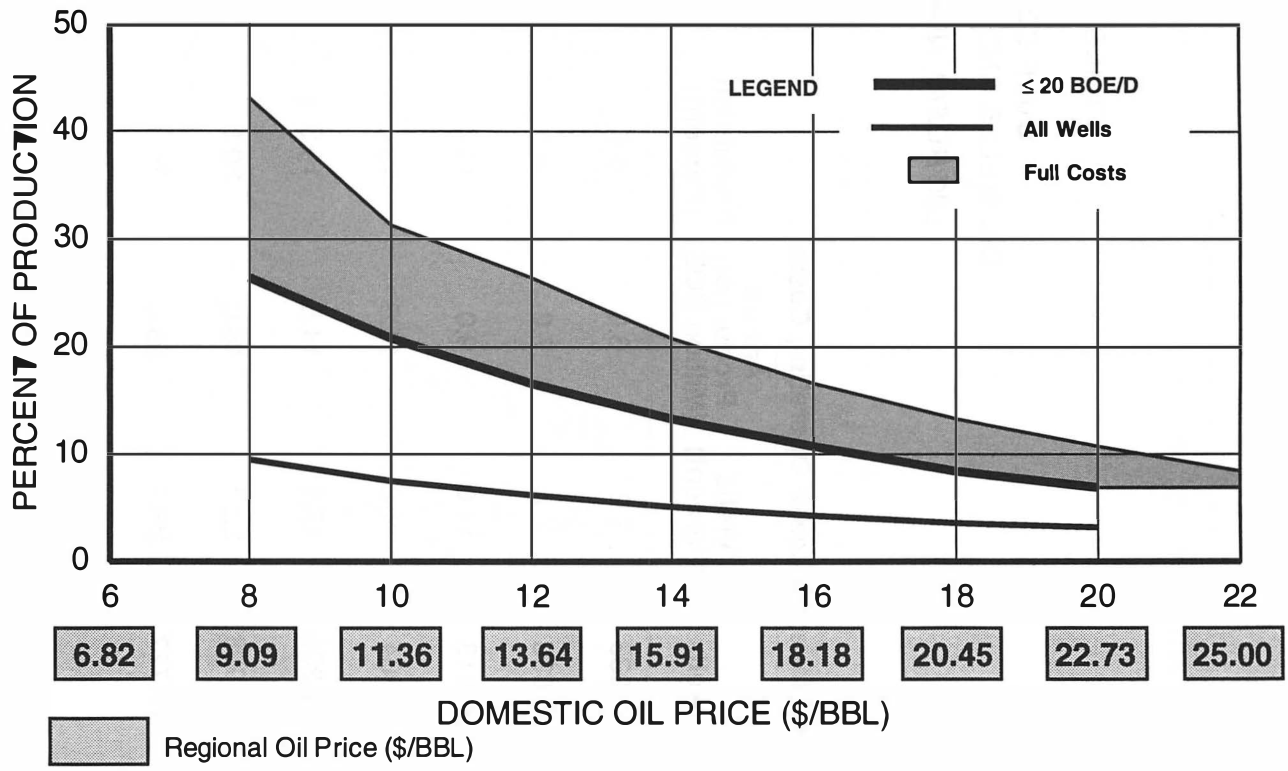


Figure 5-21. Production Unable to Meet Lease Operating Expenses—Gulf Coast.

TABLE 5-13

GULF COAST
OIL WELLS AND PRODUCTION

≤20 BOE/D, NORMALIZED

Not Meeting Lease Operating Costs					Not Meeting Full Costs				
Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)	Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	3,233	5.2	6.0	6.5	$20	6,913	11.0	9.0	10.4
$18	4,833	7.7	7.0	8.1	$18	9,304	14.8	11.5	13.0
$16	6,913	11.0	9.0	10.4	$16	11,205	17.9	14.5	16.3
$14	9,304	14.8	11.5	13.0	$14	13,998	22.3	18.0	20.6
$12	11,205	17.9	14.5	16.3	$12	17,777	28.4	23.0	26.1
$10	13,998	22.3	18.0	20.6	$10	26,653	42.6	27.6	31.3
$8	17,777	28.4	23.0	26.1	$8	36,994	59.1	37.9	43.1

than 20 BOE/D are unable to meet lease operating expenses and approximately 28 percent of the total wells are unable to meet total company operating expenses.

A similar figure for percentage of production unable to meet lease operating expenses is illustrated in Figure 5-21. The impact of normalizing the curves for the 8,200 wells in 0 to 1 BOE/D rate bracket is not seen on this figure, since total production from these wells is a small volume. However, when considering production, the impact of separating out wells producing less than 20 BOE/D is more dramatic than if all wells are considered. This again is an indicator that wells producing up to 20 BOE/D in the Gulf Coast area are marginal as prices decrease from $20 to $8 per barrel. Table 5-13 provides a summary of normalized data for wells producing less than 20 BOE/D and compares the effects of full costs to lease level costs.

Permian Basin Wells and Production Analysis

Table 5-14 provides a summary of the total number of wells, percentage of total wells, annual production, and percentage of total production not meeting lease operating costs at the seven domestic oil prices. It should be noted that all of these figures are based on 114,590 producing oil wells, with production of 622,444,654 BOE during 1992. The wells and production shown on this table are wells that can no longer produce sufficient cash flow to meet normal lease operating costs. These values do not account for the additional $4 per barrel of costs associated with a company's total operations (full costs).

TABLE 5-14

OIL WELLS AND PRODUCTION
THAT DO NOT MEET LEASE OPERATING COSTS,
FOR PERMIAN BASIN
(See Table 5-15 for Full Cost Analysis)

Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	4,813	4.2	2	0.4
$18	5,271	4.6	3	0.5
$16	6,073	5.3	4	0.7
$14	6,990	6.1	6	1.0
$12	8,365	7.3	8	1.3
$10	10,657	9.3	14	2.3
$8	14,095	12.3	22	3.5

Note 1: Based on 114,590 wells and production of 622.445 million BOE in 1992.

Note 2: These wells can no longer produce enough income to meet normal lease operating costs.

Note 3: Gas production was converted to barrel oil equivalent (BOE) on the basis of 6 thousand cubic feet of gas per BOE.

Note 4: Oil prices vary by region, oil gravity, and sulfur content. An average domestic price of $16 per barrel is equivalent to a West Texas Intermediate spot price of $20.70 and a California price of $13.60 per barrel. For each domestic price, an equivalent regional price was used to determine the economic status of oil wells.

Source: Energy Information Administration, Office of Oil and Gas, Dwight's Energydata, Inc., and Petroleum Information Corp.

Figures 5-22 and 5-23 show the total oil wells and associated production for the Permian Basin wells that are unable to meet lease operating expenses in 5 BOE/D per well rate bracket increments from 0 to 50 BOE/D. Figure 5-22 indicates that at prices between $8 and $20 per barrel, wells unable to meet lease operating expense in the 0 to 5 BOE/D category increase from 4,500 at $20 per barrel to over 10,000 wells at $8 per barrel. The figure indicates that a majority of the uneconomic wells are in the 0 to 5 BOE/D rate bracket. It is important to note that at the $20 per barrel domestic oil price, approximately 3,800 wells in the 0 to 1 BOE/D rate bracket were unable to meet lease operating expense. These wells account for 79 percent of the total 4,800 wells unable to meet lease operating expense shown on Table 5-14. However, annual production from these 3,800 wells accounts for only 7 percent of the total 2.5 million BOE unable to meet lease operating cost at $20 per barrel. A majority of the production that does not meet lease operating costs is in rate brackets greater than 1 BOE/D per well.

Production associated with the wells unable to meet lease operating expense is shown in Figure 5-23. Using this figure, it can be seen that moving from the high rate bracket of 45 to 50 BOE/D to lower rate brackets, a substantial change in the rate at which production in each category becomes unable to meet lease operating expense occurs in the 20 to 25 BOE/D rate bracket. This could provide adequate justification for defining Permian Basin marginal wells as those producing less than 20 or 25 BOE/D. A similar graphical analysis of the percentage of wells and production in each rate category also illustrates the rate defining marginal wells. This analysis is available in the working papers.

Figure 5-24 is a plot of the data provided in Table 5-14, with several modifications. First, the two upper lines illustrate the percentage of wells unable to meet lease operating expenses at the $8 to $20 per barrel range. The lowest of the two lines is for all wells and the upper line is only for wells that produce less than 20 BOE/D. Since 3,800 of the wells unable to meet lease operating expense at $20 per barrel are in the 0 to 1 BOE/D rate bracket, a normalization was used to exclude these wells from the percentages shown at all oil prices. The curves demonstrating the effects of normalization are the darker lowest curves on the graph. The bottom normalized curve is for all rate brackets excluding the 3,800 wells in the 0 to 1 BOE/D rate bracket. The darkest solid line illustrates the percentage of wells less than 20 BOE/D unable to meet lease operating expenses, also excluding the 3,800 wells. The shaded area demonstrates the additional costs a corporation incurs above costs that can be allocated to the lease or well level. For example, at $20 per barrel a company may have only 3.5 percent of the wells producing less than 20 BOE/D unable to meet lease operating expenses as shown in the figure. However, when considering the total corporate costs (full cost), an additional 4 percent of the company's operations can be considered in a negative cash flow position. At lower oil prices, this percentage increases substantially as shown in the figure.

A similar plot of the percent of production unable to meet lease operating expenses is illustrated in Figure 5-25. The impact of normalizing the curves for the 3,800 wells in the 0 to 1 BOE/D rate bracket is not seen on this figure, since total production from these wells is a small volume. When considering production, the impact of separating out wells producing less than 20 BOE/D is important in determining their marginality. This is an indicator that wells producing less than 25 BOE/D are marginal as prices decrease from $20 to $8 per barrel. Table 5-15 provides a summary of normalized data for wells producing less than 20 BOE/D and compares the effects of full costs to lease level costs.

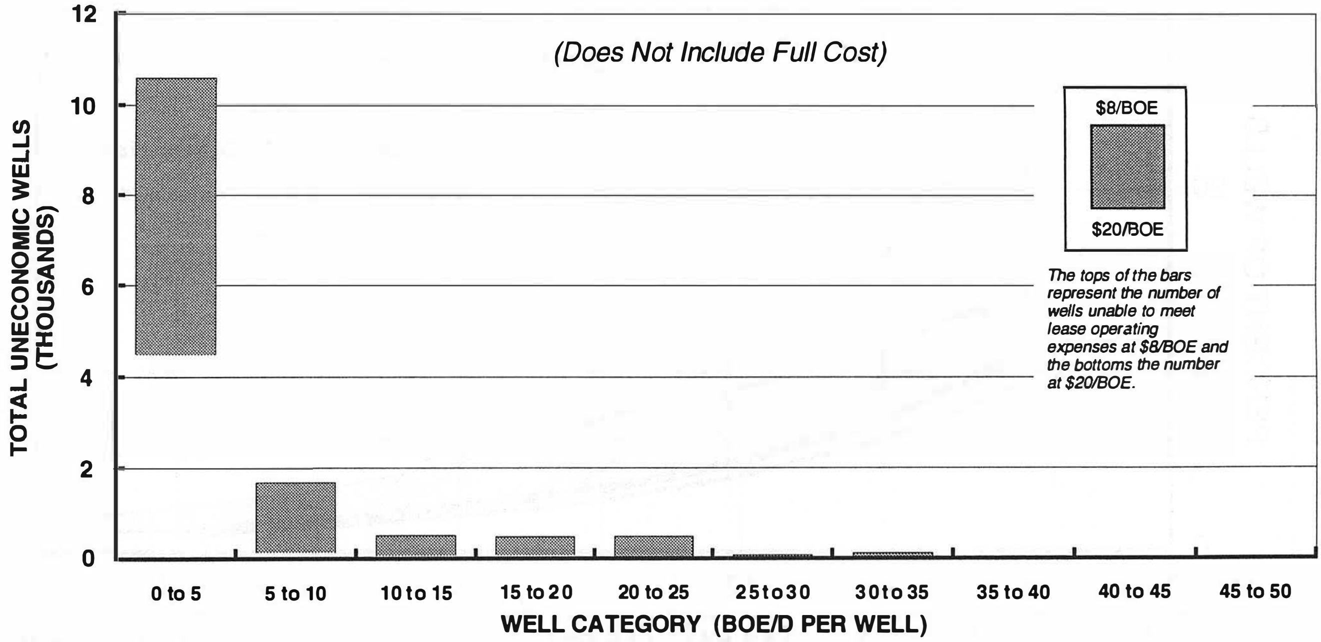


Figure 5-22. Wells Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Permian Basin—114,590 Wells.

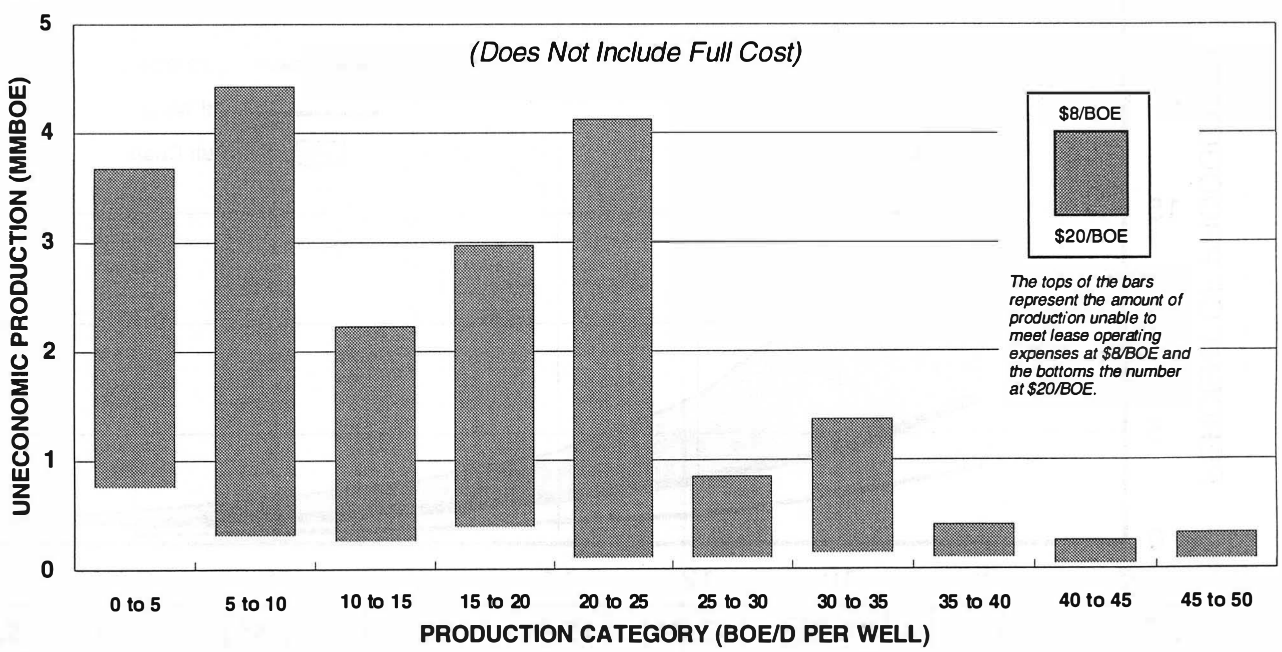


Figure 5-23. Production Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Permian Basin—622,444,654 BOE.

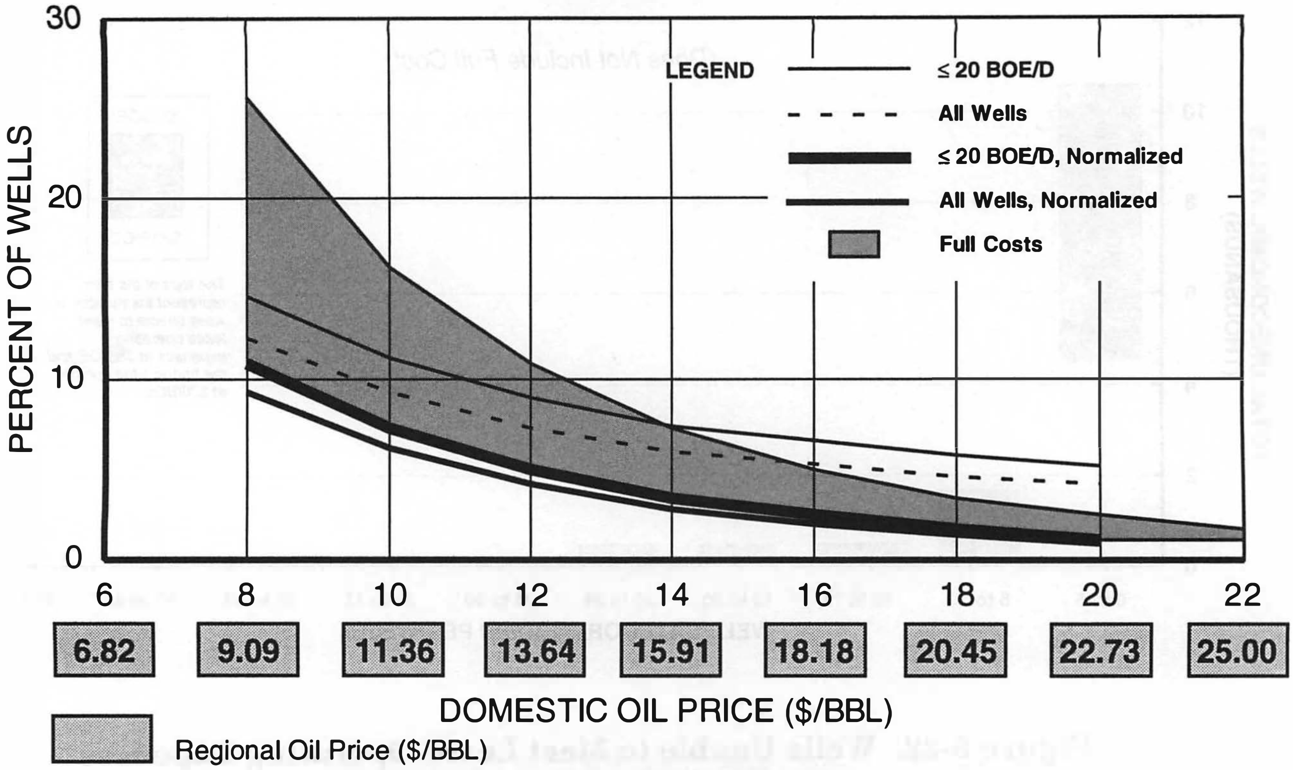


Figure 5-24. Wells Unable to Meet Lease Operating Expenses—Permian Basin.

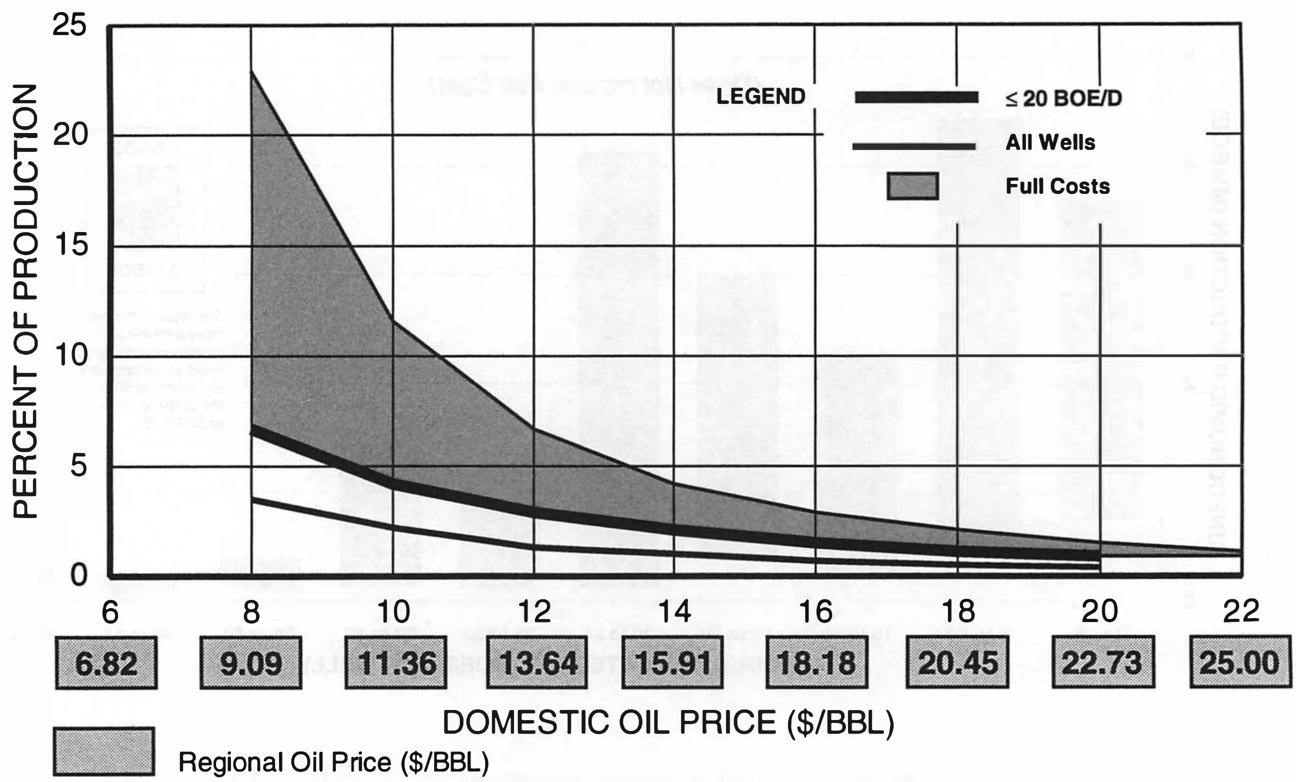


Figure 5-25. Production Unable to Meet Lease Operating Expenses—Permian Basin.

TABLE 5-15

PERMIAN BASIN
OIL WELLS AND PRODUCTION

≤20 BOE/D, NORMALIZED

Not Meeting Lease Operating Costs					Not Meeting Full Costs				
Domestic Oil Price	**Wells**	**Wells (Percent)**	**Annual Production (Million BOE)**	**Production (Percent)**	**Domestic Oil Price**	**Wells**	**Wells (Percent)**	**Annual Production (Million BOE)**	**Production (Percent)**
$20	937	1.1	1.5	0.8	$20	2,163	2.5	3.0	1.4
$18	1,439	1.7	2.0	1.0	$18	2,972	3.4	4.0	2.0
$16	2,163	2.5	3.0	1.4	$16	4,395	5.0	5.5	2.9
$14	2,972	3.4	4.0	2.0	$14	6,372	7.3	8.0	4.1
$12	4,395	5.0	5.5	2.9	$12	9,500	10.9	13.0	6.6
$10	6,372	7.3	8.0	4.1	$10	14,110	16.2	22.9	11.6
$8	9,500	10.9	13.0	6.6	$8	22,347	25.6	45.0	22.9

Rocky Mountain Wells and Production Analysis

Table 5-16 provides a summary of the total number of wells, percentage of total wells, annual production, and percentage of total production that do not meet lease operating costs at the seven domestic oil prices. All of these figures are based on 31,993 producing oil wells, with an associated production of 264,608,799 BOE during 1992. The wells and associated production shown on this table are wells that can no longer produce sufficient cash flow to meet normal lease operating costs. These values do not account for the additional $4 per barrel of costs associated with a company's total operations.

TABLE 5-16

OIL WELLS AND PRODUCTION THAT DO NOT MEET LEASE OPERATING COSTS, FOR ROCKY MOUNTAINS (See Table 5-17 for Full Cost Analysis)

Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	2,943	9.2	11	4.0
$18	3,295	10.3	12	4.4
$16	3,775	11.8	13	5.1
$14	4,351	13.6	16	6.0
$12	5,119	16.0	19	7.2
$10	6,015	18.8	23	8.8
$8	7,358	23.0	29	11.0

Note 1: Based on 31,993 wells and production of 264.609 million BOE in 1992.

Note 2: These wells can no longer produce enough income to meet normal lease operating costs.

Note 3: Gas production was converted to barrel oil equivalent (BOE) on the basis of 6 thousand cubic feet of gas per BOE.

Note 4: Oil prices vary by region, oil gravity, and sulfur content. An average domestic price of $16 per barrel is equivalent to a West Texas Intermediate spot price of $20.70 and a California price of $13.60 per barrel. For each domestic price, an equivalent regional price was used to determine the economic status of oil wells.

Source: Energy Information Administration, Office of Oil and Gas, Dwight's Energydata, Inc., and Petroleum Information Corp.

Figures 5-26 and 5-27 show the total oil wells and production for the Rocky Mountain area wells that are unable to meet lease operating expenses in 5 BOE/D per well rate bracket increments from 0 to 50 BOE/D. Figure 5-26 indicates that at prices between $8 and $20 per barrel, wells unable to meet lease operating expense in the 0 to 5 BOE/D category increase from 1,700 at $20 per barrel to slightly over 3,700 wells at $8 per barrel. The figure indicates that a majority of the uneconomic wells are in the 0 to 5 BOE/D rate bracket. However, the higher rate brackets up to 20 BOE/D contain a higher percentage of uneconomic wells than the previously discussed areas. It is important to note that at the $20 per

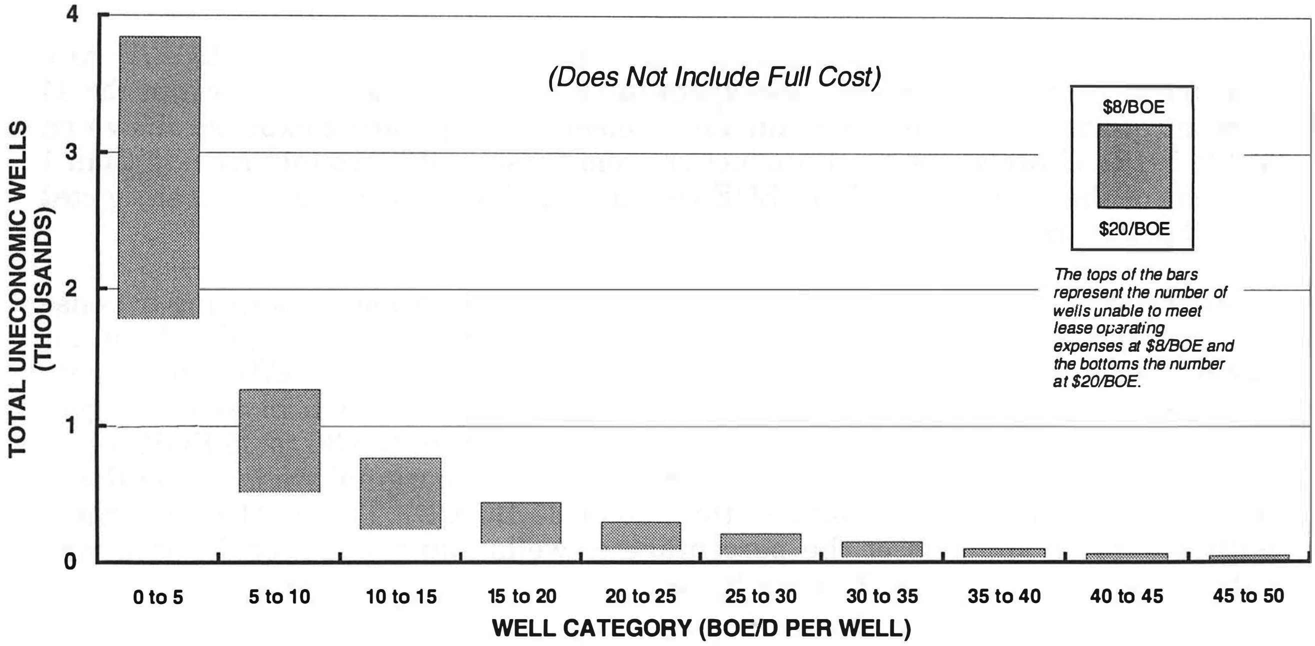


Figure 5-26. Wells Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Rocky Mountains—31,993 Wells.

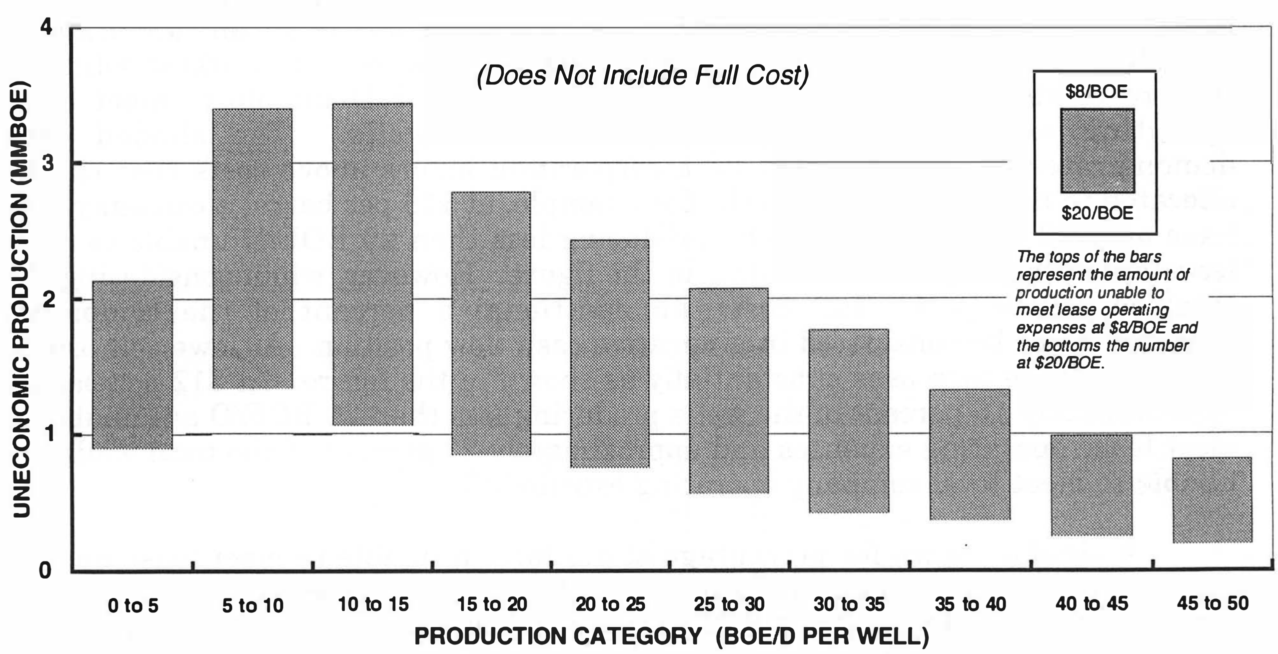


Figure 5-27. Production Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category Rocky Mountains—264,608,799 BOE.

barrel domestic oil price, approximately 1,000 wells in the 0 to 1 BOE/D rate bracket were unable to meet lease operating expense. These wells account for 34 percent of the total 2,900 wells unable to meet lease operating expense shown on Table 5-16. However, annual production from these wells accounts for less than 1 percent of the total 10.5 million BOE that are unable to meet lease operating cost at $20 per barrel.

Production from the wells that are unable to meet lease operating expense is illustrated in Figure 5-27 and is a much different picture. Using this figure, it can be seen that moving from the high rate bracket of 45 to 50 BOE/D to lower rate brackets, a substantial change in the rate at which production in each category becomes unable to meet lease operating expense occurs in the 30 to 35 BOE/D rate bracket. This could provide justification for defining marginal wells in the Rocky Mountains as those producing less than 30 or 35 BOE/D. This is also illustrated with a similar analysis of the percentage of wells and production in each rate category which are unable to meet lease expense. This analysis is provided in the working papers.

Figure 5-28 is a plot of the data provided in Table 5-16 with several modifications. First, the two uppermost lines illustrate the percentage of wells unable to meet lease operating expenses at the $8 to $20 per barrel range. The lowest of the two lines is for all wells and the upper line is only for wells that produce less than 20 BOE/D. Since 1,000 of the wells unable to meet lease operating expense at $20 per barrel are in the 0 to 1 BOE/D rate bracket, a normalization was used to exclude these wells from the uneconomic percentage calculations at all oil prices. The curves demonstrating the effects of normalization are the darker lowest curves on the graph. The bottom normalized curve is for all rate brackets excluding the 1,000 wells in the 0 to 1 BOE/D rate bracket. The darkest solid line illustrates the percentage of wells less than 20 BOE/D unable to meet lease operating expenses, also excluding the 1,000 wells. The shaded area demonstrates the additional costs a corporation incurs above costs that can be allocated to the lease or well level. For example, at $16 per barrel a company may have only 10 percent of the wells producing less than 20 BOE/D unable to meet lease operating expenses as shown in the figure. However, when considering the total corporate costs (full cost), an additional 5 percent of the company's operations can be considered in a negative cash flow position. At lower oil prices, this percentage increases substantially as shown in the figure. At $12 per barrel, approximately 15 percent of the wells producing less than 20 BOE/D are unable to meet lease operating expenses and approximately 23 percent of the total wells are unable to meet total company operating expenses.

A similar figure for percentage of production unable to meet lease operating expenses is illustrated in Figure 5-29. The impact of normalizing the curves for the 1,000 wells in the 0 to 1 BOE/D rate bracket is not seen on this figure, since total production from these wells is a small volume. When considering production, the impact of separating out wells producing less than 20 BOE/D is more significant than if all wells are considered. This again is an indicator that wells producing less than 20 BOE/D are marginal as prices decrease from $20 to $8 per barrel. Table 5-17 provides a summary of normalized data for wells producing less than 20 BOE/D and compares the effects of full costs to lease level costs.

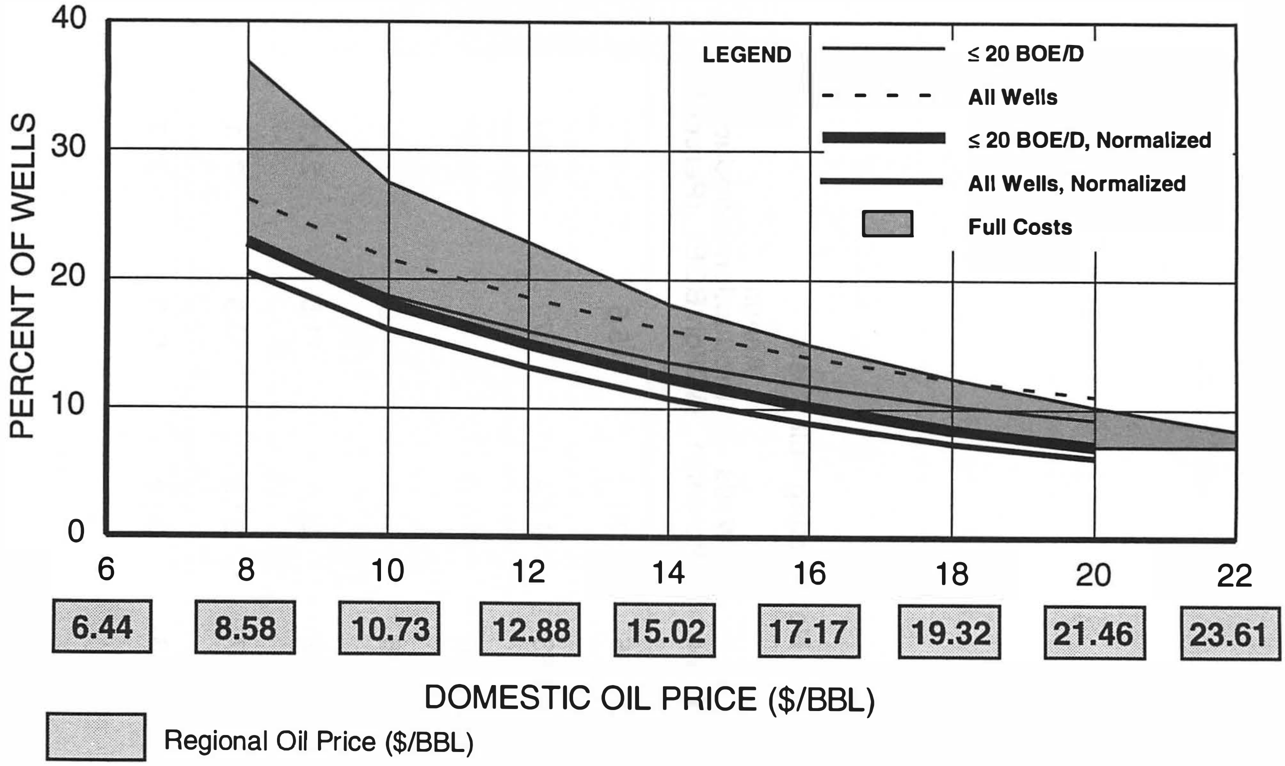


Figure 5-28. Wells Unable to Meet Lease Operating Expenses— Rocky Mountains.

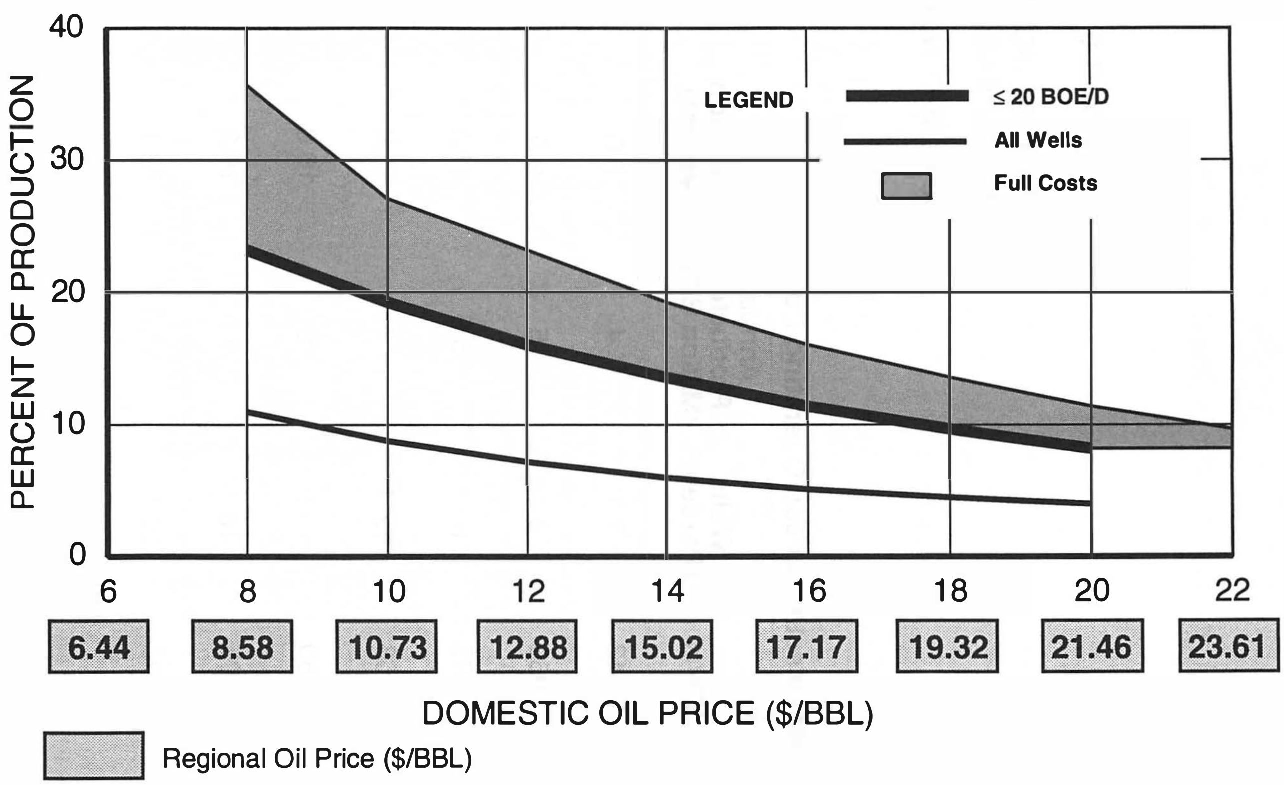


Figure 5-29. Production Unable to Meet Lease Operating Expenses— Rocky Mountains.

TABLE 5-17

ROCKY MOUNTAINS
OIL WELLS AND PRODUCTION

≤20 BOE/D, NORMALIZED

Not Meeting Lease Operating Costs					Not Meeting Full Costs				
Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)	Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	1,643	7.1	4	8.0	$20	2,365	10.2	5.5	11.2
$18	1,950	8.4	5	9.5	$18	2,863	12.4	7	13.4
$16	2,365	10.2	5.5	11.2	$16	3,480	15.0	8	16.0
$14	2,863	12.4	7	13.4	$14	4,195	18.1	9.5	19.2
$12	3,480	15.0	8	16.0	$12	5,302	22.9	11.5	23.1
$10	4,195	18.1	9.5	19.2	$10	6,367	27.5	13.5	27.1
$8	5,302	22.9	11.5	23.1	$8	8,548	36.9	17.8	35.7

California Wells and Production Analysis

Table 5-18 provides a summary of the total number of wells, percentage of total wells, annual production, and percentage of total production that does not meet lease operating costs at the seven domestic oil prices. It should be noted that all of these figures are based on 45,968 producing oil wells with production of 345,141,572 BOE during 1992. The wells and production shown on this table are wells that can no longer produce sufficient cash flow to meet normal lease operating costs. These values do not account for the additional $4 per barrel of costs associated with a company's total operations.

TABLE 5-18

OIL WELLS AND PRODUCTION THAT DO NOT MEET LEASE OPERATING COSTS, FOR CALIFORNIA
(See Table 5-19 for Full Cost Analysis)

Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	6,573	14.3	17	4.9
$18	7,493	16.3	21	6.1
$16	7,815	17.0	24	6.9
$14	10,113	22.0	33	9.7
$12	12,273	26.7	44	12.7
$10	15,353	33.4	59	17.1
$8	20,640	44.9	87	25.1

Note 1: Based on 45,968 wells and production of 345.141 million BOE in 1992.

Note 2: These wells can no longer produce enough income to meet normal lease operating costs.

Note 3: Gas production was converted to barrel oil equivalent (BOE) on the basis of 6 thousand cubic feet of gas per BOE.

Note 4: Oil prices vary by region, oil gravity, and sulfur content. An average domestic price of $16 per barrel is equivalent to a West Texas Intermediate spot price of $20.70 and a California price of $13.60 per barrel. For each domestic price, an equivalent regional price was used to determine the economic status of oil wells.

Source: Energy Information Administration, Office of Oil and Gas, Dwight's Energydata, Inc., and Petroleum Information Corp.

Figures 5-30 and 5-31 show the total oil wells and associated production for the California wells that are unable to meet lease operating expenses in 5 BOE/D per well rate bracket increments from 0 to 50 BOE/D. Figure 5-30 indicates that at prices between $8 and $20 per barrel, wells unable to meet lease operating expense in the 0 to 5 BOE/D category increase from 4,000 at $20 per barrel to slightly over 9,500 wells at $8 per barrel. The figure indicates that a majority of the uneconomic wells are in the 0 to 5 BOE/D rate bracket. However, similar to the Rocky Mountain area, there are high percentages of uneconomic wells in the higher rate brackets unlike the other four areas. It is important to note that at the $20 per barrel domestic oil price, approximately 2,000 wells in the 0 to 1 BOE/D rate bracket

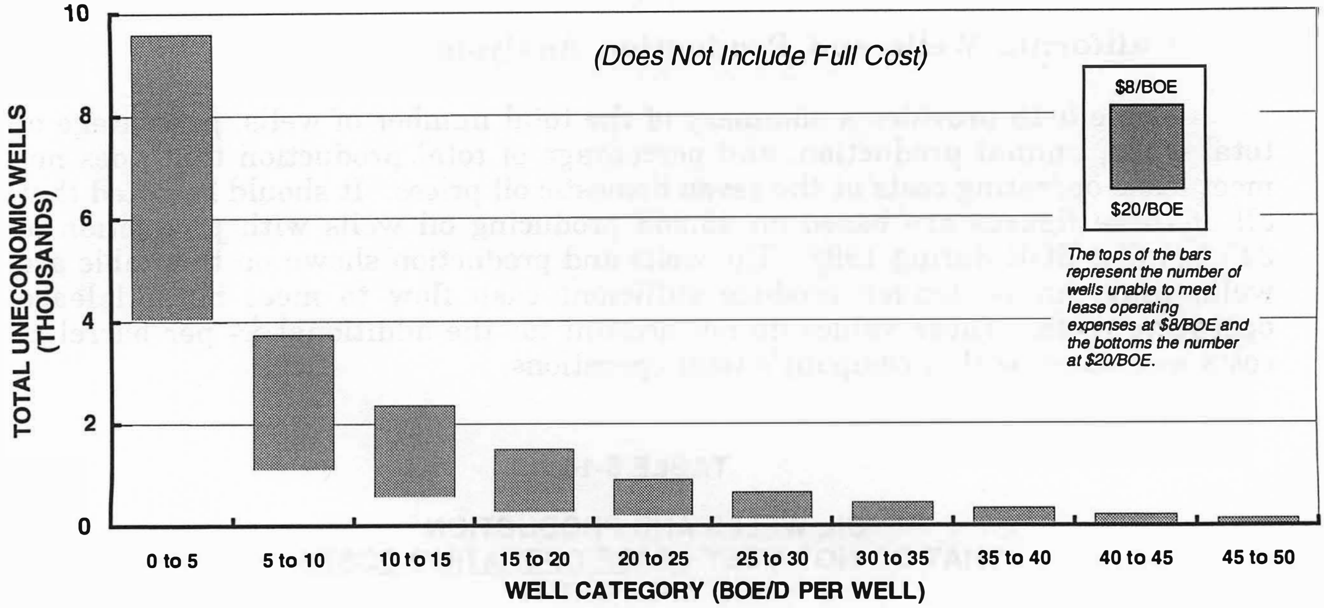


Figure 5-30. Wells Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category California—45,968 Wells.

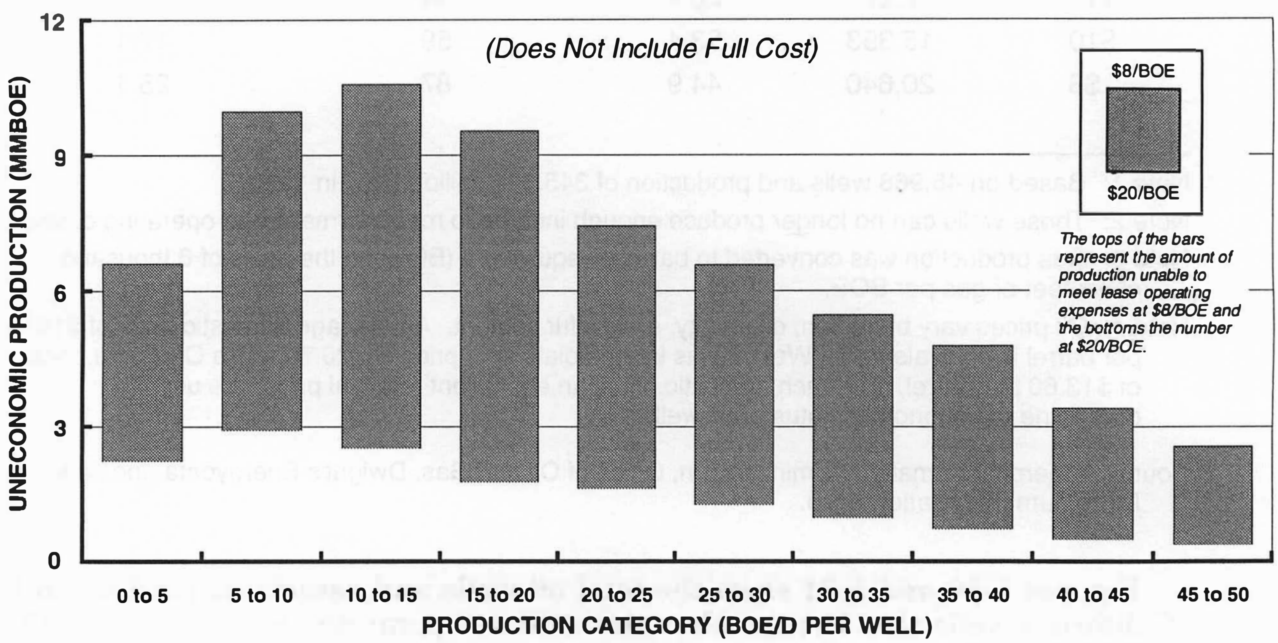


Figure 5-31. Production Unable to Meet Lease Operating Expenses $8–$20/BOE vs. Rate Category California—345,141,572 BOE.

were unable to meet lease operating expense. These wells account for 30 percent of the total 6,600 wells unable to meet lease operating expense shown on Table 5-18. However, annual production from these wells accounts for only 1 percent of the total 17 million BOE that are unable to meet lease operating cost at $20 per barrel.

Production from wells that are unable to meet lease operating expense, shown in Figure 5-31, illustrates a picture similar to the Rocky Mountain area. Using this figure, it can be seen that moving from the high rate bracket of 45 to 50 BOE/D to lower rate brackets a gradual increase in the production in each category unable to meet lease operating expense occurs through all of the rate brackets. This is due to the large heavy oil contribution which, because of the many factors previously discussed, cannot absorb price decreases in any of the rate brackets.

Figure 5-32 is a plot of the data provided in Table 5-18, with several modifications. First, the two upper lines (the lighter lines) illustrate the percentage of wells unable to meet lease operating expenses at the $8 to $20 per barrel range. The lowest of the two lines is for all wells and the upper line is only for wells that produce less than 20 BOE/D. Since 2,000 of the wells unable to meet lease operating expense at $20 per barrel are in the 0 to 1 BOE/D rate bracket, a normalization was used to exclude these wells from the percentage calculations at all oil prices. The curves demonstrating the effects of normalization are the darker lowest curves on the graph. The bottom normalized curve is for all rate brackets excluding the 2,000 wells in the 0 to 1 BOE/D rate bracket. The darkest solid line illustrates the percentage of wells less than 20 BOE/D unable to meet lease operating expenses, also excluding the 2,000 wells. The shaded area demonstrates the additional costs a corporation incurs above costs that can be allocated to the lease or well level. For example, at $14 per barrel, a company may have 23 percent of the wells producing less than 20 BOE/D unable to meet lease operating expenses as shown in the figure. However, when considering the total corporate costs (full cost), an additional 13 percent of the company's operations can be considered in a negative cash flow position. At lower oil prices this percentage increases substantially as shown in the figure. Because of the unique heavy oil related infrastructure and the portion of heavy oil operating costs that are fixed, California has a substantially higher percentage of wells and production that are unable to meet operating costs as prices decrease.

A similar figure for percentage of production unable to meet lease operating expenses is illustrated in Figure 5-33. The impact of normalizing the curves for the 2,000 wells in the 0 to 1 BOE/D rate bracket is not seen on this figure, since total production from these wells is a small volume. When considering production, the impact of separating out wells producing less than 20 BOE/D is more significant than if all wells are considered. This again is an indicator of the degree to which wells producing less than 20 BOE/D are marginal as prices decrease from $20 to $8 per barrel. Table 5-19 provides a summary of normalized data for wells producing less than 20 BOE/D and compares the effects of full costs to lease level costs.

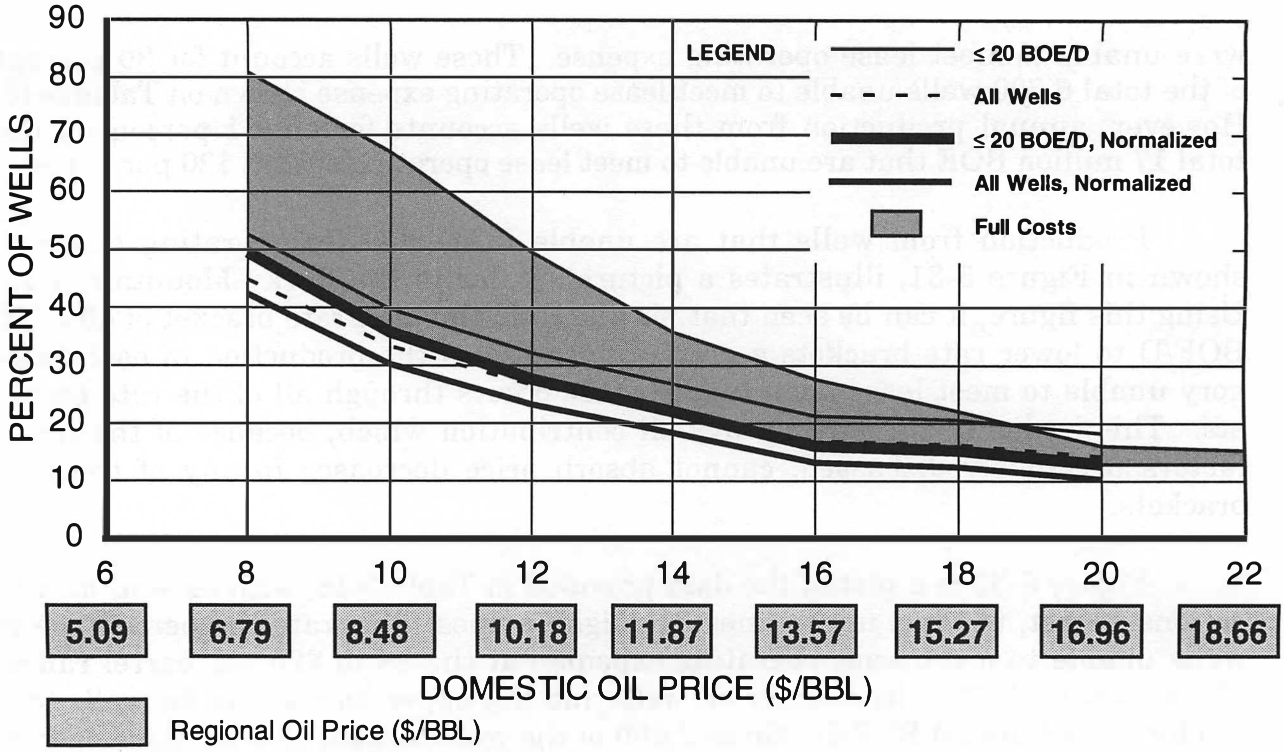


Figure 5-32. Wells Unable to Meet Lease Operating Expenses—California.

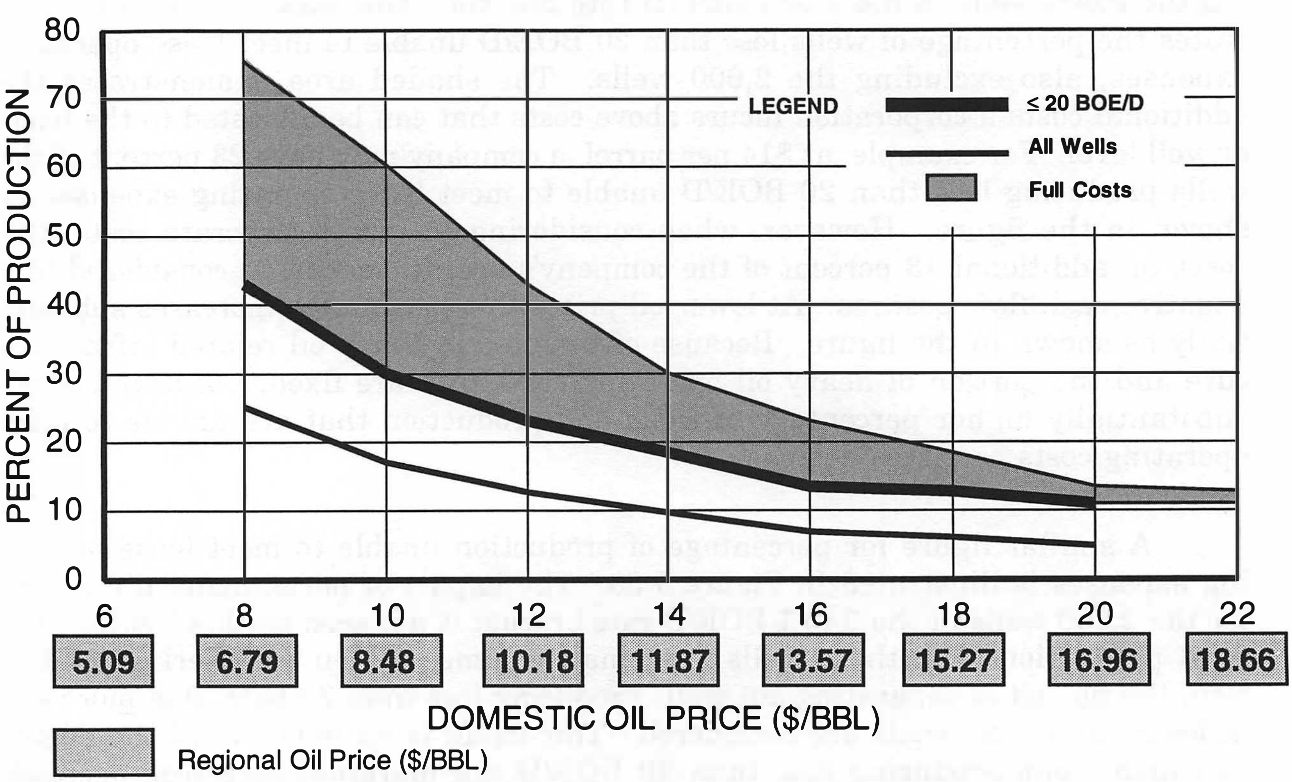


Figure 5-33. Production Unable to Meet Lease Operating Expenses—California.

TABLE 5-19

CALIFORNIA
OIL WELLS AND PRODUCTION

≤20 BOE/D, NORMALIZED

Not Meeting Lease Operating Costs					Not Meeting Full Costs				
Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)	Domestic Oil Price	Wells	Wells (Percent)	Annual Production (Million BOE)	Production (Percent)
$20	3,955	12.9	9	10.7	$20	4,930	16.1	11.5	13.3
$18	4,700	15.3	10.5	12.6	$18	6,777	22.1	15.5	18.2
$16	4,930	16.1	11.5	13.3	$16	8,512	27.7	19.5	23.0
$14	6,777	22.1	15.5	18.2	$14	10,976	35.8	25.5	29.9
$12	8,512	27.7	19.5	23.0	$12	15,176	49.5	36.5	42.9
$10	10,976	35.8	25.5	29.9	$10	20,541	67.0	51.4	60.4
$8	15,176	49.5	36.5	42.9	$8	24,772	80.8	64.4	75.7

Summary of Before Federal Income Tax Evaluation

Output from the EIA model demonstrates that marginal wells and production exist in every producing area and over a large range of well rates. It also demonstrates that a rate which defines marginal wells varies from region to region. Considering all lower-48 onshore wells, using ***20 BOE/D or less per well, may be a more appropriate definition than the 15 BOE/D definition currently in the tax code***. All of the analysis of incentives for marginal wells in the next section uses the 15 BOE/D per well (and other parameters described later) definition for simplicity.

A company's total cash flow considerations should not be limited to an analysis of well/lease level cash flow—other cash costs must be accounted for in a full cost analysis. As prices decrease, every size company begins to consider shutting in and eventually abandoning wells that do not meet lease operating costs and crucial decisions regarding full cost cash flow must be considered in a persistent low price environment.

ECONOMIC ANALYSES OF FEDERAL INCOME TAX INCENTIVES

The following sections describe the three tax incentives evaluated in this report, using ICF Resources' after-tax economic evaluation model. A description of the incentive concept is provided followed by a discussion of the analytical approach and the evaluation of benefits and costs. Figures and tables for each incentive analysis referenced in the text are provided at the end of the chapter. Additional detail on the marginal well credit incentive is provided in Appendix F, Section IV. The MWC analyses are organized in three sections, A through C, and illustrate the ten-year output results from the various economic runs. Each of these sections include both the full and marginal cost incentive and base case evaluations. The cases are illustrated graphically, with tables of the incremental benefits included after the figures. The results were segregated into sections for ease of analysis. A complete review should include a comparison of results in all sections. Further detailed results and regional output are available in the working papers. Figures and graphs for the EOR and inactive well incentives are provided in Sections D and E respectively.

Marginal Well Credit

Description

To encourage continued production from marginal properties in periods of low prices, a specific dollar per barrel marginal well credit (MWC) could be implemented for federal income tax purposes. A specified number of barrel equivalents of production per day attributable to the working interest from each well in the marginal property could qualify for the credit. The MWC would be phased out over a range of prices. The MWC would be fully allowable as a credit against both regular federal income tax liability and alternative minimum tax (AMT) liability. Unused MWC could be carried back three years (at the election of the taxpayer), and carried forward 15 years.

Production qualifying for the Section 29 credit for nonconventional fuel would not also qualify for the MWC. A taxpayer could elect to utilize either, but not both, of the credits on marginal properties qualifying for both credits.

In order to ensure that the MWC will create cash flow for an owner of a marginal property having no taxable income for the taxable year in which the MWC is earned, the owner could monetize the MWC earned in that taxable year by selling it to an unrelated taxpayer by the end of the taxable year following the taxable year in which the MWC was earned. The purchaser could utilize the full amount of the MWC acquired against its federal income tax, or AMT, liability for the taxable year in which the MWC is acquired, and could carry unused MWC forward for 15 years. The seller would realize taxable income in the taxable year the MWC is sold to the extent of the value of the consideration received. The transaction would be evidenced by simple documentation as prescribed by the Internal Revenue Service.

As an example, assuming an MWC of $3 per barrel for the first 3 barrels of production in 1995, a producer owning a marginal property with five wells, each averaging 10 barrel equivalents of production per day would be entitled to an MWC of $16,425 (3 x 365 x $3 x 5 wells) from that property in 1995, which could be used to offset the producer's federal income tax, or AMT, liability. Unused MWC could be carried back to calendar year 1992 or forward as far as calendar year 2010. If production from the marginal wells averages only 2 barrel equivalents of production per day in 1995, the MWC would be $10,950 (2 x 365 x $3 x 5 wells).

To extend the example, if the producer had a total MWC for calendar year 1995 of $50,000 and had no taxable income that year, the producer could sell the $50,000 of MWC. If the producer sold its 1995 MWC for $40,000 in cash on December 31, 1996, the producer would have taxable income of $40,000 in calendar year 1996 and the buyer would be allowed to offset the full $50,000 of MWC against its federal income tax, or AMT, liability, in 1996 (or carry the unused portion of the MWC forward for use in future years).

Analytic Approach

The objective of analyzing the marginal well credit concept was to determine the cost and beneficial impact of a credit for domestic oil and gas production. Because of the dynamic nature of the domestic oil and gas industry, the analysis included modeling several different incentive approaches under various oil price scenarios. The model determines cash flows for all producing wells within the onshore lower-48 states and performs an economic limit test on these wells over a period of 25 years. Within the model, the distribution of producing wells in the onshore lower-48 states is categorized by region, depth, and production rates of oil and water based on data developed by the EIA, as discussed above. Detailed cost algorithms for operating and maintenance costs discussed previously in this chapter were used in estimating annual after tax cash flows for all sizes of operators (small independents, large independents, and integrated companies) under various tax situations (regular, AMT, and net operating loss).

The model calculates the annual after tax cash flow for each category of well and operator class by projecting future production, calculating annual operating and maintenance costs, and estimating taxes paid. Categories of wells which are unable to generate positive cash flow are abandoned over a three year period. Wells pending abandonment are returned to production if price increases cause their cash flow to become positive. Annual well counts and projected production rates are used to determine incremental production, public sector revenues, credit costs, and other parameters utilized in evaluating the costs and benefits for each MWC incentive. Model results are generated separately for each region and compiled for the lower-48 onshore states as a whole. The results for each incentive case are directly comparable; and can be compared to the base case assuming no incentive. It is important to note the variability between base cases when comparing different credit scenarios.

Details describing the intricacies of the after tax model approach and procedures are provided in Appendix F, Section IV.

Evaluation of Benefits and Costs

The fundamental premise behind the marginal well tax credit is to provide a safety net or "insurance" to producers of marginal wells to maintain production and resource access while prices are low. Long-term support of uneconomic production is probably not practical. The incentives evaluation involved analyzing several credit scenarios under various conceptual price tracks. This approach provides a broad range of potential outcomes and demonstrates the detrimental impact low prices have on the industry (base cases) and the incremental benefits provided by a marginal well credit serving as a safety net (incentive cases).

Table 5-20 provides a summary overview of all incentive analyses. For each run indicated on the table, four outputs are provided for evaluation: the "full cost" incremental incentive, the "full cost" base case, the "marginal cost" incremental incentive, and the "marginal cost" base case. Two credit scenarios were evaluated. The first assumes a $3 per BOE credit on the first 3 BOE/D produced from any marginal well, as previously described. The second assumes $6 credit for the first BOE, $2 credit for the second BOE, and $1 for the third BOE from any marginal well, as previously described.

The price track and phase-out scenarios shown in the table and discussed in the following section all refer to ***domestic oil prices***. Figure 5-34 illustrates the first ten years of each scenario's price track and phase-out schedule. Following is a brief discussion of each price track scenario:

- **The "flat" price scenario:** Prices remain at the lower end of the phase-out ranges forever, but the credit is limited to a period of five years. This scenario represents the "downside" of the insurance risk, where prices fail to recover after a fall.

- **The "step function" scenario:** Average domestic oil prices are assumed to drop to the lower value in the range in 1995 and 1996, and then jump to the higher value in 1997, remaining constant thereafter. Prices are low for only a short time period, during which the incentive delays the economic limit and abandonment, followed by a price recovery that benefits the production in the wells preserved by the incentive. For the analysis, however, this scenario assumes prices peak and remain at the credit phase-out level, resulting in a relatively conservative estimate of

TABLE 5-20

INCENTIVE CASES ANALYZED

Price Track	$3/BOE Credit Phase-Out $8-$16	$3/BOE Credit Phase-Out $10-$18	$3/BOE Credit Phase-Out $14-$20	$6-$2-$1 Credit Phase-Out $8-$16	$6-$2-$1 Credit Phase-Out $10-$18	$6-$2-$1 Credit Phase-Out $14-$20	No Negative Taxes $3/BOE Credit Phase-Out $10-$18	New Wells $3/BOE Credit Phase-Out $10-$18
$8 Flat (5 Yr. Expiration)	•							
$8-$16 Step	•	•	•	•	•	•		
$8-$20 Cycle	•	•	•	•	•	•	•	•
$14 Flat (5 Yr. Expiration)			•					
$14-$20 Step			•					
$14-$20 Sawtooth			•					
AEO 1994 Low	•	•	•		•		•	•
AEO 1994 High			•					

• Indicates incentive evaluation has been performed.

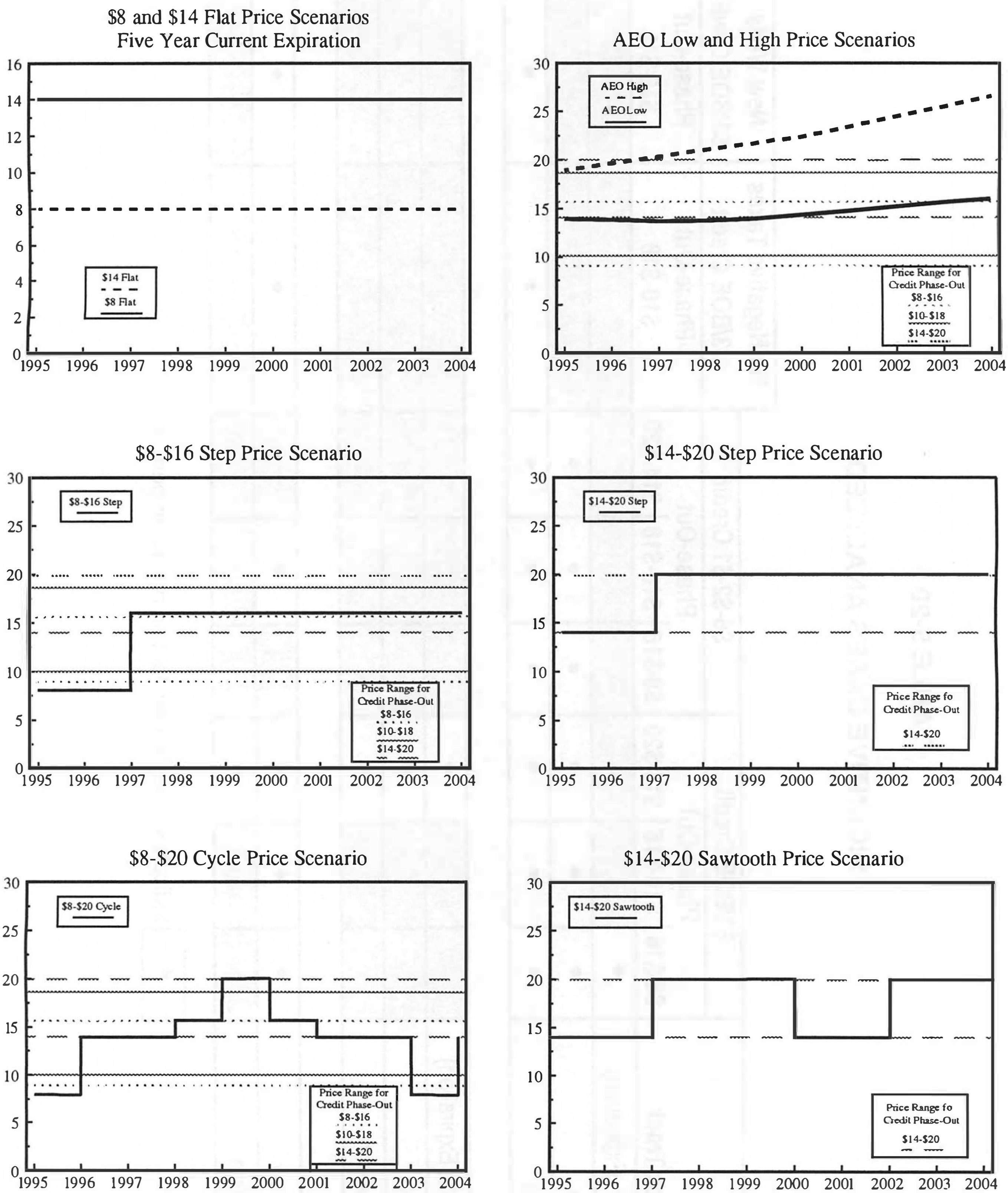


Figure 5-34. Price Scenarios and Credit Phase-Outs Used in MWC Analysis.

benefits. Benefits improve as the wells saved with an MWC realize prices above the phase-out maximum.

- **The "sawtooth" and "cyclical" scenarios:** Average domestic oil prices behave in a sawtooth or cyclical fashion where, beginning in 1995, prices drop to the lower end of the phase-out range for a period, then rise to the higher end of the phase-out range for a period and, in the case of the "cycle," prices can rise above the phase-out rate, with this pattern repeating throughout the analysis period. The incentive is applied each time the price falls. These scenarios probably best represent the safety net concept of the MWC. Prices drop to the point where the credit payments are the highest, and then rise to the point where the credit phases out, and in the case of the cycle, prices can rise several dollars above the maximum phase-out price.

- **AEO 1994 price scenarios:** Average domestic oil prices were assumed to track either the DOE/EIA Annual Energy Outlook 1994 low or high price track.

Section C, at the back of this chapter, contains figures and tables that describe "sensitivity" economic runs. Included in these runs was the evaluation of an after-tax scenario where it was assumed that companies generating a negative tax had no additional taxable income which could be used to offset the negative tax situation. These sensitivities are labeled "no negative taxes," while the remainder of the runs throughout Sections A and B assume that negative taxes are allowed. Also, a sensitivity analyzing the impact of future new wells (wells drilled after 1995) on the marginal well credit benefits and costs is shown. Historical drilling statistics, based on the average domestic price, were used to provide an estimate of the number of wells drilled for each price track. These wells were brought on production at the average rate of approximately 50 BOE/D. As these wells would decline and become marginal, as defined in this report, the marginal well credit and phase-out scenario being evaluated was applied to the new wells. The economic evaluation of the effect that new wells would have on a marginal well credit was then added to the corresponding evaluation which did not include the new wells in order to determine the full incremental impact of the new well assumption. In Section C, this is compared to a similar evaluation case excluding new wells. The analyses included in Sections A and B all assume no new wells.

Examination of the various credit scenarios provides a number of observations:

- In the absence of an incentive, large numbers of wells are likely to be abandoned when prices fall, with corresponding near-term losses of marginal production and possible future supplies producible with new technology.

- If federal tax incentives are provided, significant numbers of wells, quantities of domestic production, jobs, and other benefits (e.g., gross domestic product [GDP], federal revenues, etc.) can be saved through federal tax policies directed towards marginal wells.

- At the lower price scenarios, the benefits tend to be larger, while the costs tend to be smaller; hence, resulting in a higher benefit:cost ratio. This is due to higher production rate wells being preserved in the lower price scenarios, and indicates that the "insurance" provided by the incentives has greater value in the more dire situations.

- The estimates under the marginal cost economic limit criteria have uniformly lower benefits and greater costs than the corresponding full cost estimates. Because the full costs are always higher than the marginal costs, the wells preserved by the incentives under the full cost scenario are more productive, resulting in higher benefits relative to credit costs. This would suggest that the greater the number of companies at the margin, the more valuable the incentives to the industry and the nation.

- Where prices remain flat, the benefits are lowest and the costs are highest. These scenarios represent the case in which the hoped-for price recovery fails to occur. On a full-cost basis, even these show a positive ratio of imports avoided or GDP added to the cost of the credit. However, the ratio of incremental GDP or imports avoided to credit cost goes from greater than unity under a full cost consideration to less than unity for marginal cost consideration. This reversal might suggest that the incentives "break even" by these standards somewhere within the range of conditions that describe the financial condition of the industry as a whole.

- Where prices recover from their initially low level either permanently (the "step" case) or in a cycle (the "cyclical" case), the ratio of incremental GDP or imports avoided to credit costs tend to be significantly greater than unity, especially over a longer period of time under either the full or marginal cost basis. This indicates that, when the MWC insurance or safety net is effective, the benefits from the credit exceeds it costs across the full range of conditions affecting the industry.

- The ratio of benefits (imports avoided, additional GDP) to costs is higher for the low price scenarios relative to the comparable high price scenarios. Again, this is a result of higher production rate wells being preserved by the incentive when oil prices are lower. (The lower rate wells are abandoned during the longer evaluation periods, regardless of the availability of the incentive.)

- A credit structured to provide proportionally larger credits to the lowest rate marginal wells, such as the \$6-\$2-\$1 credit analyzed in this study, can significantly reduce the cost per well saved from abandonment, while only moderately increasing the total cost of the credit and the cost per barrel of incremental production.

- The impacts of allowing negative taxes and assuming no new wells are compared to a sensitivity which allows no negative taxes and provides for the drilling of new wells which become marginal during their life and have the MWC applied as they become marginal. These assumptions do slightly impact the cost and benefits; however, they are not deemed to be material in the overall analysis. The largest impact is the new well assumption under both the AEO Low and $8–$20 Cycle Price Tracks. The addition of new wells increases all evolution parameters, wells, production, costs, jobs, etc., and it reduces the cost per BOE and per well.

While no specific incentive design is recommended here, it is evident that an incentive for marginal wells, focused on the wells that can most benefit, will contribute to the well-being of the domestic petroleum industry and the nation.

The above analysis did not estimate one of the most important benefits attributable to preserving marginal wells—access to the resource remaining in reservoirs that could be produced through the application of advanced, more efficient technology. Limitations of the methods available in the time frame for the present study preclude systematic, explicit estimates of the amount of advanced technology reserves, but the next section (EOR) illustrates the implications of reducing the abandonment rate on future reserves and production.

The MWC analyses are organized in three sections and illustrate the ten-year output results from the various economic analysis runs. Each section includes both the base and incentive cases, considering both full and marginal cost economics. The cases are illustrated graphically with tabular data of the incremental benefits included after the graphs. The results were segregated in sections for ease of review and presentation. A complete review should include a comparison of results across many cases and not be limited to a single section. Detailed results and the regional output are available in the working papers.

Improved EOR Credit

Description

Several studies, including the National Petroleum Council's *Enhanced Oil Recovery* report (1984), have pointed to the significant potential additions to U.S. reserves that are possible through application of enhanced oil recovery (EOR). Efforts to implement EOR projects have been partially frustrated by lower oil prices. Roughly 70 percent of the reservoirs that might be developed as EOR candidates are currently marginal properties, by the definitions in this report. Nationally, access to these reservoirs is becoming endangered as approximately 3.5 percent per year of the resource is being abandoned by the plugging of marginal wells.

In 1990, Congress passed an EOR investment tax credit, equal to 15 percent of certain qualified investment and injection costs paid or incurred. However, eligibility for this tax credit is limited by the definition of qualified projects. The credit phases out between oil prices (in 1991 dollars) of $28 to $34 per barrel, adjusted for inflation. By IRS interpretation, the credit was neither allowable against alternative minimum tax (AMT) nor transferable. Thus, only regular taxpayers have been able to utilize the credit and then only on certain, more sophisticated, tertiary and other enhanced recovery technology processes.

To make the EOR credit available to a larger number of projects and encourage new investment in marginal properties with reserve potential and continued investment in marginal wells, the EOR credit could be expanded. The types of tertiary projects qualifying for the EOR credit could be modified to include additional forms of advanced technology, and the credit could be allowed on all marginal properties, whether new or existing.

The process for qualifying a project for the EOR credit could also be simplified. For example, state certification of a project as a qualified EOR project should be an acceptable alternative means of qualifying a project for the federal EOR credit.

The EOR credit could be allowable against both regular federal income tax liability and AMT liability in the same manner as the MWC. Excess EOR credit could be carried back three years and carried forward 15 years. The EOR credit would still not be transferable.

As an example, a producer owning a marginal property elects to undertake a new tertiary project on a marginal property in calendar year 1995 and incurs $100,000 of qualifying EOR costs during the year, the taxpayer would be allowed an EOR credit of $15,000 ($100,000 x 15 percent). The tax basis or deductions resulting from the $100,000 of EOR expenditures would be reduced by the $15,000 EOR credit claimed. The $15,000 EOR credit would be allowable against the taxpayer's federal income tax, or AMT, liability. Excess EOR credit could be carried back to calendar year 1992 or forward to calendar year 2010.

Analytic Approach

There are three fundamental uncertainties that must be addressed when evaluating the costs and benefits of an incentive which expands current EOR tax credit. The first is oil price; EOR is highly price-sensitive. The second is the level of technology assumed, that is, whether only currently available technology is employed or technology advances are assumed. The third pertains to the rate of abandonment of the resource with EOR potential. As prices remain low, or technologies are slow to develop, or abandonments continue unabated, the potential for EOR decreases.

In this analysis, the potential of expanding the EOR tax credit under two technology scenarios—a currently available technology case and an advanced technology case, made possible by successful research and development—was evaluated. Two rates of resource abandonment were also considered. The first corresponds to a rate where 3.5 percent of potential reserves are abandoned per year, which is consistent with historical rates of resource abandonment. The second rate assumes that the marginal well tax credit, aggressive technology transfer programs, and new technology developments can reduce this rate of abandonment substantially—in the extreme, to the level of zero resource abandonment. A range of oil prices was also considered.

For purposes of this analysis, due to limitations of the readily available analytical tools, the costs and benefits of only two categories of projects were evaluated:

- All new tertiary oil recovery projects, which include gas miscible projects (CO_2 and N_2), thermal (steam drive and in-situ combustion), and chemical (polymer, alkaline, and micellar/polymer). Continuation or expansion of ongoing EOR projects was excluded for purposes of analysis (but could be included in an actual incentive).

- All new infill drilling projects, including those using additives to influence the injection profile of the wellbore or the relative permeability of various reservoir layers. These projects were assumed to be in reservoirs undergoing waterflooding in conjunction with infill drilling.

The databases and models used for this analysis were originally developed by the NPC in its 1984 study of national EOR potential, and have since been continually maintained and updated by the DOE's Office of Fossil Energy, and include the Tertiary Oil Recovery Information System (TORIS) and the Crude Oil Policy Model (COPM). TORIS provides detailed engineering and economic analysis of potential reserves from infill drilling and EOR for about 2,400 individual domestic oil reservoirs, representing about two-thirds of the oil discovered in the United States. Since the system was developed, its capabilities have been substantially enhanced and updated, all with the guidance of a peer review committee made up largely of the original 1984 NPC study committee members. COPM translates the reservoir level evaluations from TORIS into forecasts of domestic reserve additions and production, specifically characterizing project initiation or expansion. The DOE regularly uses these models to estimate the impact of alternative policies (e.g., tax credits and environmental regulation) and technologies on domestic crude oil supplies.

The methodology used for this analysis consisted of the following steps:

Step 1. TORIS was used to generate a comprehensive database of all potential new EOR and infill drilling candidate reservoirs in the TORIS database. For EOR, both current and advanced technology were evaluated; for infill drilling only current technology was considered. For each reservoir analyzed, the database contains production, injection, and cost profiles for the life of the project.

Step 2. For each candidate reservoir, COPM was used to determine the net present value for each candidate reservoir for each technology case both with and without the proposed incentive. This analysis assumed constant average domestic oil prices of $10, $14, and $18 per barrel.

Step 3. COPM sequences the development of reservoirs determined to be economic at each price. The model forecasts future abandonments, reserve additions, production, investments, state and federal taxes paid, jobs created, and imports avoided for each scenario. The two cases (with and without the expanded credit) are compared to estimate the costs and benefits associated with the proposed incentive for each price, technology, and abandonment rate scenario.

Step 4. The results of these models are extrapolated to estimate national totals and adjusted to account for the incentive for only marginal properties.

Estimates of Benefits and Costs

The results of the analysis are reported separately for the two extensions of the current EOR credit: expansion of the AMT taxpayers credit as currently defined; and expansion of the credits to infill/waterflood projects for all taxpayers. The tables and figures referenced in this section are in Section D at the end of this chapter.

Tables 5-47, 5-48, and 5-49 (for $10, $14, and $18 per barrel of oil) summarize the results of the extension of the current EOR credit to AMT taxpayers. The 25-year estimates for all three prices are illustrated in Figures 5-53 through 5-56. In all cases, potential reserves and production are significantly increased by: (1) rising oil prices; (2) advances in technology; (3) reduced abandonment rates; and (4) expansion of the EOR tax credit to AMT taxpayers. In the most optimistic price/technology case, as much as 3.6 billion barrels of new reserves could be expected—2.1 billion barrels more than without the incentives. Reduced abandonment rates (possibly not fully to zero) is one of the major purposes of the MWC. The analysis in the Marginal Well Credit section suggests that the rate of abandonment might be reduced from 3.5 percent to, perhaps, 2 percent per year. The benefits would "scale" to any level of abandonment that results from the MWC and other efforts to slow the rate of abandonment. Expansion to AMT taxpayers also increases production and reserves; simultaneously decreasing abandonments and extending the credit creates certain synergies that make both the MWC and the EOR credit more valuable. The credit costs of the EOR incentive (Figure 5-55) and cost per barrel (Figure 5-56) suggest that this incentive can be a highly cost-effective means of stimulating new domestic reserves and production, in the range of 26 to 54 cents per barrel.

Tables 5-50, 5-51, and 5-52 (for $10, $14, and $18 per barrels of oil, respectively) summarize the estimates for extending the applicability of the credit to infill drilling (with waterflooding). Figures 5-57 through 5-60 illustrate the 25-year estimates for all three prices. As with tertiary recovery, both reducing the abandonment rate and extending the credit increases reserves and production, and synergies between the two policies are again evident. Infill drilling exhibits less price sensitivity than EOR, suggesting that a substantial portion of the potential becomes economic in the analyzed price range. The estimated credit costs and per-barrel costs reinforce this interpretation. At $18/BOE, the credit adds a relatively small increment at a considerable cost, for a relatively high cost per barrel, but at the lower oil prices, the incentive was considerably more cost-effective.

Inactive Well Incentive

Description

A recent survey by the Interstate Oil and Gas Compact Commission (IOGCC) estimated that the United States has approximately 142,000 wells that are inactive (i.e., the well has neither produced oil or gas nor been used as an injector in more than one month in the two previous taxable years) or orphaned (i.e., abandoned by an operator and taken over by a state regulatory agency). Table 5-53 (in Section E) shows the distribution of such wells by state. If some of these wells could be restored, reserves, production, revenues and jobs would ensue. Some of these could be returned to production if incentives were provided.

In Texas, such an incentive for idle wells has recently been offered which provides 100 percent severance tax relief for wells inactive for more than three years that are brought back on production between September 1, 1993, and August 31, 1995. This exemption from severance tax can be applied to 10 years of production.

In the first six months of the Texas incentive, 1,464 wells were reactivated (1,114 oil wells and 350 gas wells), compared to 368 reactivated for all of 1992, the year prior to the implementation of the incentive. According to the Texas Railroad Commission, there are an estimated 80,000 inactive wells in Texas. (Note that this differs from the 51,336 idle wells reported in the IOGCC report, as summarized in Table 5-53.) Typical initial annual production characteristics for wells brought back on line in Texas are reported as follows:

Oil well:	11.6 barrels/day oil 26.6 MCF/day casinghead gas
Gas well:	264.6 MCF/day gas 2.1 barrels/day condensate

The recommended incentive for orphaned and abandoned wells, which have not been active for two or more years, is to make certain costs incurred to reactivate those wells eligible for a 15 percent credit similar to the EOR credit. Intangible drilling cost workovers, recompletions, horizontal extensions, and other capital costs, on such properties would be subject to a 15 percent credit. The deductions or tax basis resulting from the expenditures qualifying for the credit would be reduced by the amount of the credit. This credit would phase out in the same manner as the EOR credit.

Costs qualifying for the inactive or orphaned well credit could not also be qualifying EOR expenditures. If a property qualifies for the marginal well credit after returning to production, both the MWC and the inactive or orphaned well credit could be claimed for such property.

The inactive or orphaned well credit would be allowable against both regular federal income tax and the AMT liability in the same manner as the MWC. Any excess credit could be carried back three years and carried forward 15 years. The credit would not be transferable. The incentive could be made available for a limited period, such as for wells returned to production in calendar years 1995 through 1997, to test its effectiveness.

As an example, if a producer returned a well to production which had not produced in the previous two taxable years, and incurred $15,000 of intangible drilling cost workover expense in reactivating the well, a credit of $2,250 (15% x $15,000) would be allowable against the taxpayer's federal income tax, or AMT, liability. Any excess credit could be carried back to calendar year 1992 or carried forward to calendar year 2010.

Analytic Approach

Using the Texas experience as an analog, estimates of costs and benefits of a federal incentive were estimated.

The total estimated number of wells reactivated due to the Texas state incentive are estimated for full year based on six-month results as follows:

(1,464) x (2) - 368 = 2,560
Oil wells: [1,114/(1,114 + 350)] 2,560 = 1,948 (76%)
Gas wells: [350/(1,114 + 350] 2,560 =612 (24%)

Assuming that a 12 percent annual production decline rate, a 7 to 1 water: oil ratio, and a 4,500 foot well depth is representative of a typical well brought back on production, a reactivated oil well will produce 40,000 barrels of incremental oil.

Assuming 80,000 inactive wells in Texas, then approximately 3.2 percent per year of the inactive wells in the state are reactivated as a result of the incentive, calculated as follows:

2,560/80,000 = 0.032

Assuming 142,000 idle oil wells in the United States, then 10,360 idle oil wells could be reactivated in the United States given a federal incentive comparable to the Texas state incentive, determined as follows:

(0.032)(0.76)(3)(142,000) = 10,360 oil wells

However, for a typical reactivated well, the value of the proposed federal tax credit would be approximately 15.5 percent of the value of 100 percent state severance tax relief. Consequently, if 10,360 new wells would be activated under an incentive like that in Texas, then 1,605 wells or 15.5 percent could be assumed to be reactivated under the proposed federal incentive.

The analyses in this study indicate, however, that a typical reactivated well in Texas may not be representative of the nation's average idle well production potential. Therefore, an analysis was also performed where the typical reactivated oil well produced only 4 BOE/D, assuming a decline rate of 5 percent and a water:oil ratio of 5.

Estimated Benefits and Costs

If the impacts of the federal inactive well incentive are comparable to those documented from the Texas incentive, 10,360 wells are estimated to be reactivated nationwide during the three-year initial period. These wells are estimated to account for over 400 million BOE of incremental oil reserves. The federal cost of this incentive, assuming that it would cost approximately $15,000 to reactivate an inactive well, and the first 3 BOE/D qualifies for the $3/BOE marginal well production credit, would be approximately $360 million, or a credit cost of about $0.91 per BOE of reserves.

Over 10 years, the wells reactivated during the three-year period when the credit would be available, would result in 297 million barrels of incremental production. The financial benefits resulting from the incentive would vary considerably with oil prices, as shown in Table 5-54 (in Section E at the end of this chapter).

For example, at a domestic oil price of $14 per barrel, the proposed incentive would result in an increase in state and local revenues of $421 million over a ten-year time period. The incentive would result in about a $4,528 million reduction in the trade deficit over this ten-year time period, and would result in an increase of approximately 42,000 labor-years of additional employment.

Similarly, if the wells reactivated under the proposed federal credit were more like a typical marginal well in the United States, producing at an initial rate of about 4 BOE/D, then the credit would still stimulate the reactivation of 10,360 wells, and nearly 140 million BOE of reserves or about $2.30 per BOE at a cost of about $320 million. Over a ten-year period, this would equate to over 100 million barrels of production.

The financial benefits resulting from this incentive varies with oil prices, as shown in Table 5-55 (in Section E at the end of this chapter). At an oil price of $14 per barrel, the proposed incentive would result in an increase in state and local revenues of $114 million over a ten-year period. A $1,559 million reduction in the trade deficit would occur over the ten-year time period, and result in an increase of nearly 15,400 labor-years of employment.

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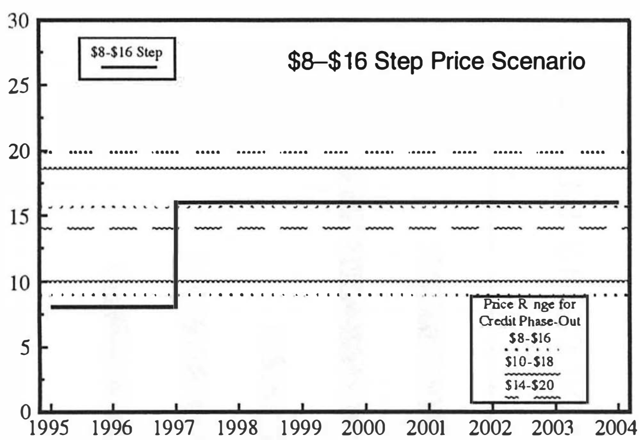
MARGINAL WELL CREDIT ANALYSIS

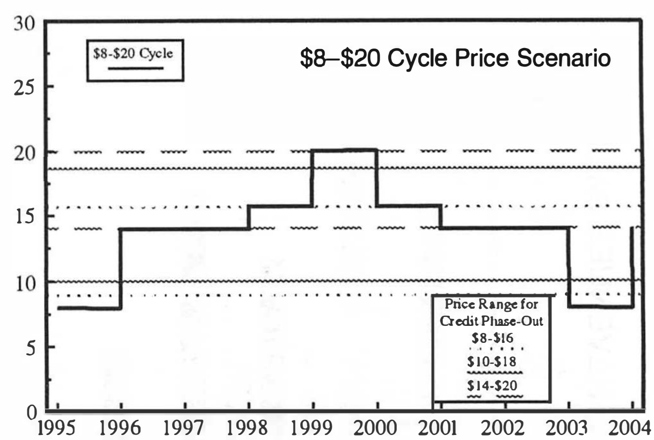
Section A

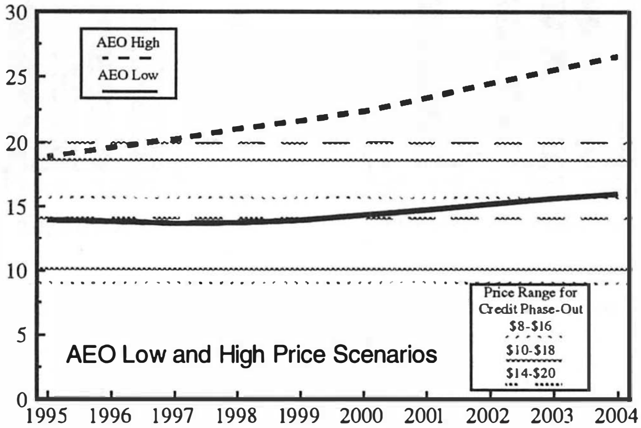
Incremental Full Cost Analysis - Figures and Tables
Full Cost Base Case - Figures
Incremental Marginal Cost Analysis - Figures and Tables
Marginal Cost Base Case - Figures

Price Track	$3/BOE Credit Phase-Out $8-$16	$3/BOE Credit Phase-Out $10-$18	$3/BOE Credit Phase-Out $14-$20	$6-$2-$1 Credit Phase-Out $8-$16	$6-$2-$1 Credit Phase-Out $10-$18	$6-$2-$1 Credit Phase-Out $14-$20
$8-$16 Step	•	•	•	•	•	•
$8-$20 Cycle	•	•	•	•	•	•
AEO 1994 Low	•	•	•		•	

• Indicates incentive evaluation results in this section.







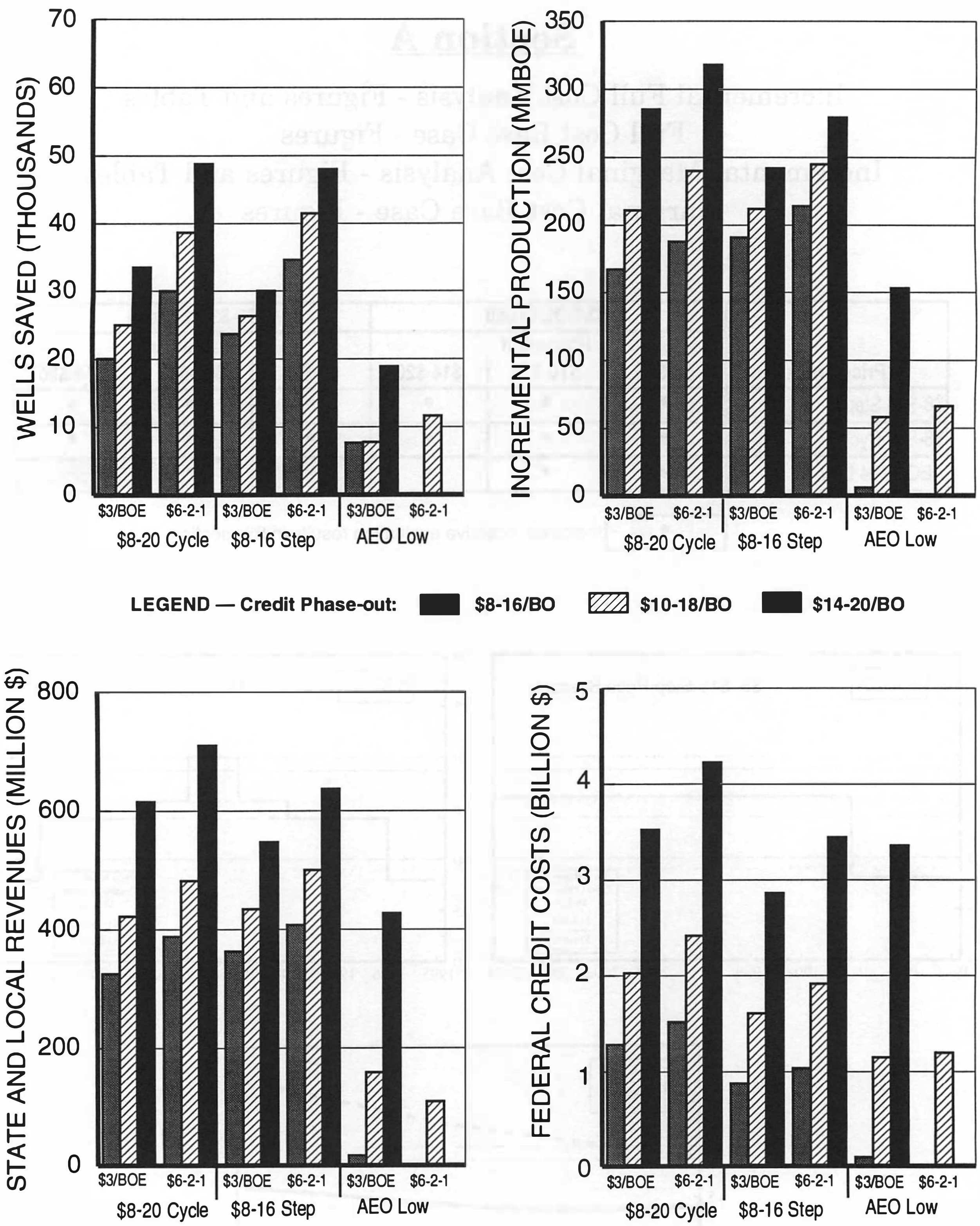


Figure 5-35. Ten Year Summary—Incremental MWC Analysis (Full Cost).

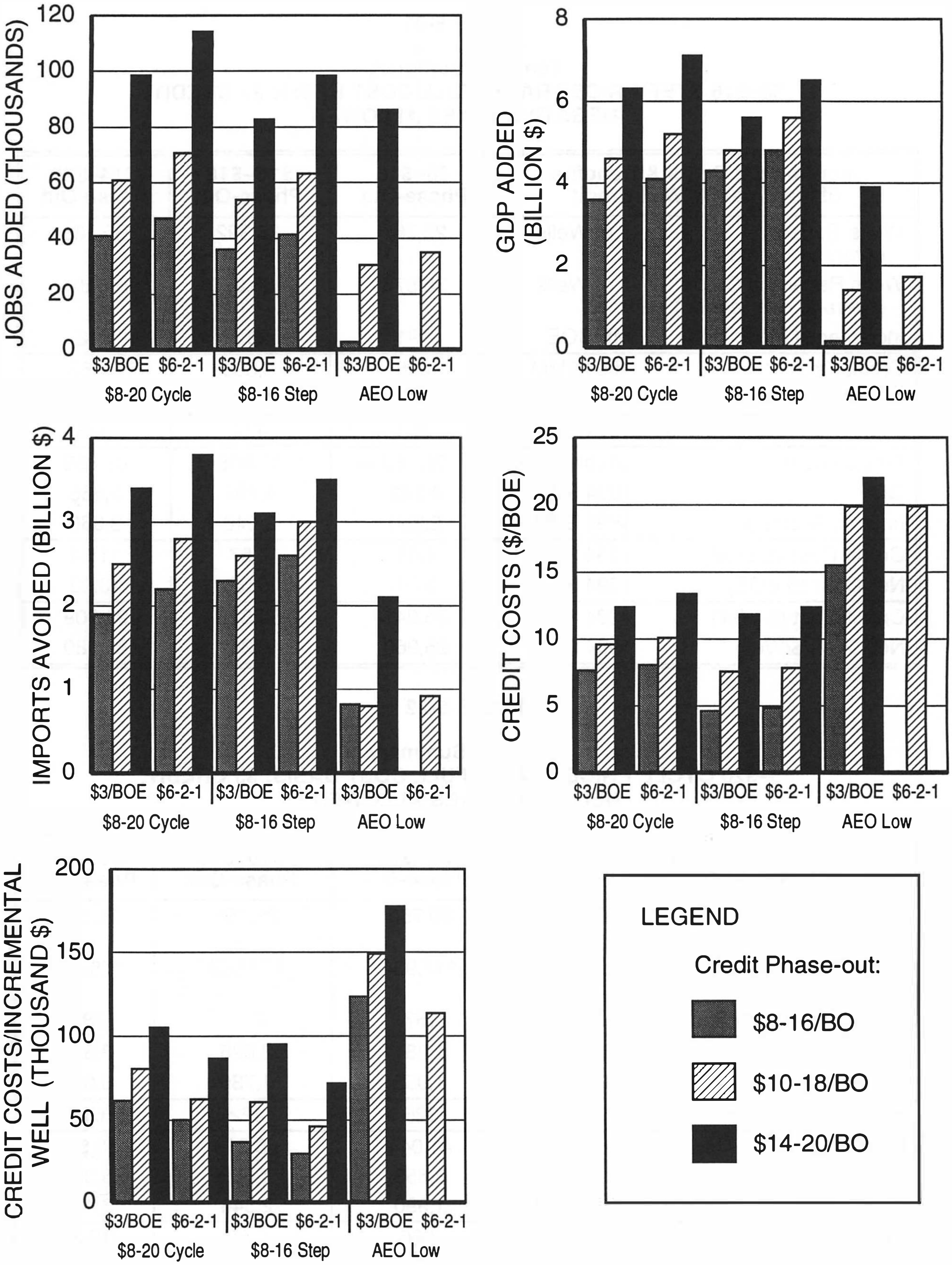


Figure 5-36. Ten Year Summary—Incremental MWC Analysis (Full Cost).

TABLE 5-21

Ten Year Summary
$8–$16 STEP PRICE TRACK; FULL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	23,767	26,392	30,166
Wells Receiving Credit (average over period)	# of Wells	36,576	163,075	166,849
Incremental Production	MMBOE	191	212	242
Credit Paid	1994 $MM	878	1,605	2,863
Net Federal Cost	1994 $MM	617	1,276	2,425
State & Local Revenues	1994 $MM	363	434	548
Employment	Labor-Years	36,189	53,808	82,858
GDP	1994 $MM	4,342	4,894	5,665
Imports Avoided	1994 $MM	2,350	2,646	3,060
Credit Cost ($/BOE)	1994 $	4.61	7.57	11.84
Net Cost ($/BOE)	1994 $	3.24	6.02	10.03
Credit Cost ($/Well)	1994 $	36,941	60,813	94,909
Net Cost ($/Well)	1994 $	25,960	48,347	80,380

TABLE 5-22

Ten Year Summary
$8–$20 CYCLE PRICE TRACK; FULL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	20,752	25,156	33,571
Wells Receiving Credit (average over period)	# of Wells	117,934	159,063	166,446
Incremental Production	MMBOE	167	211	285
Credit Paid	1994 $MM	1,281	2,026	3,530
Net Federal Cost	1994 $MM	1,055	1,736	3,094
State & Local Revenues	1994 $MM	325	422	615
Employment	Labor-Years	41,044	60,815	98,531
GDP	1994 $MM	3,653	4,650	6,398
Imports Avoided	1994 $MM	1,990	2,544	3,481
Credit Cost ($/BOE)	1994 $	7.66	9.60	12.39
Net Cost ($/BOE)	1994 $	6.31	8.23	10.86
Credit Cost ($/Well)	1994 $	61,729	80,537	105,150
Net Cost ($/Well)	1994 $	50,838	69,009	92,163

TABLE 5-23

Ten Year Summary
1994 AEO LOW PRICE TRACK; FULL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	776	7,712	18,939
Wells Receiving Credit (average over period)	# of Wells	111,233	221,411	232,638
Incremental Production	MMBOE	6	58	153
Credit Paid	1994 $MM	96	1,150	3,363
Net Federal Cost	1994 $MM	89	1,046	3,054
State & Local Revenues	1994 $MM	17	159	427
Employment	Labor-Years	2,838	30,557	86,150
GDP	1994 $MM	159	1,493	3,932
Imports Avoided	1994 $MM	82	806	2,137
Credit Cost ($/BOE)	1994 $	15.50	19.90	22.02
Net Cost ($/BOE)	1994 $	14.37	18.10	19.99
Credit Cost ($/Well)	1994 $	123,648	149,112	177,570
Net Cost ($/Well)	1994 $	114,632	135,628	161,255

TABLE 5-24

Ten Year Summary
$8–$16 STEP PRICE TRACK; FULL COST BASIS; $6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	34,628	41,546	48,075
Wells Receiving Credit (average over period)	# of Wells	39,234	178,229	184,758
Incremental Production	MMBOE	214	245	279
Credit Paid	1994 $MM	1,038	1,915	3,452
Net Federal Cost	1994 $MM	751	1,548	2,967
State & Local Revenues	1994 $MM	407	500	636
Employment	Labor-Years	41,425	63,240	98,360
GDP	1994 $MM	4,867	5,654	6,544
Imports Avoided	1994 $MM	2,626	3,041	3,525
Credit Cost ($/BOE)	1994 $	4.85	7.83	12.38
Net Cost ($/BOE)	1994 $	3.51	6.33	10.64
Credit Cost ($/Well)	1994 $	29,976	46,093	71,804
Net Cost ($/Well)	1994 $	21,688	37,260	61,716

TABLE 5-25

Ten Year Summary
$8–$20 CYCLE PRICE TRACK; FULL COST BASIS; $6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14-$20 Phase-Out
Wells Saved (average over period)	# of Wells	30,166	38,716	48,827
Wells Receiving Credit (average over period)	# of Wells	125,075	171,229	180,405
Incremental Production	MMBOE	188	240	316
Credit Paid	1994 $MM	1,515	2,420	4,225
Net Federal Cost	1994 $MM	1,159	2,090	3,622
State & Local Revenues	1994 $MM	388	482	710
Employment	Labor-Years	47,350	70,864	114,290
GDP	1994 $MM	4,098	5,298	7,082
Imports Avoided	1994 $MM	2,237	2,885	3,848
Credit Cost ($/BOE)	1994 $	8.05	10.08	13.36
Net Cost ($/BOE)	1994 $	6.16	8.71	11.45
Credit Cost ($/Well)	1994 $	50,222	62,507	86,530
Net Cost ($/Well)	1994 $	38,421	53,984	74,181

TABLE 5-26

Ten Year Summary
1994 AEO LOW OIL PRICE TRACK; FULL COST BASIS; $6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Phase-Out
Wells Saved (average over period)	# of Wells	11,651
Wells Receiving Credit (average over period)	# of Wells	225,350
Incremental Production	MMBOE	66
Credit Paid	1994 $MM	1,323
Net Federal Cost	1994 $MM	1,197
State & Local Revenues	1994 $MM	110
Employment	Labor-Years	35,029
GDP	1994 $MM	1,726
Imports Avoided	1994 $MM	916
Credit Cost ($/BOE)	1994 $	19.92
Net Cost ($/BOE)	1994 $	18.02
Credit Cost ($/Well)	1994 $	113,551
Net Cost ($/Well)	1994 $	102,736

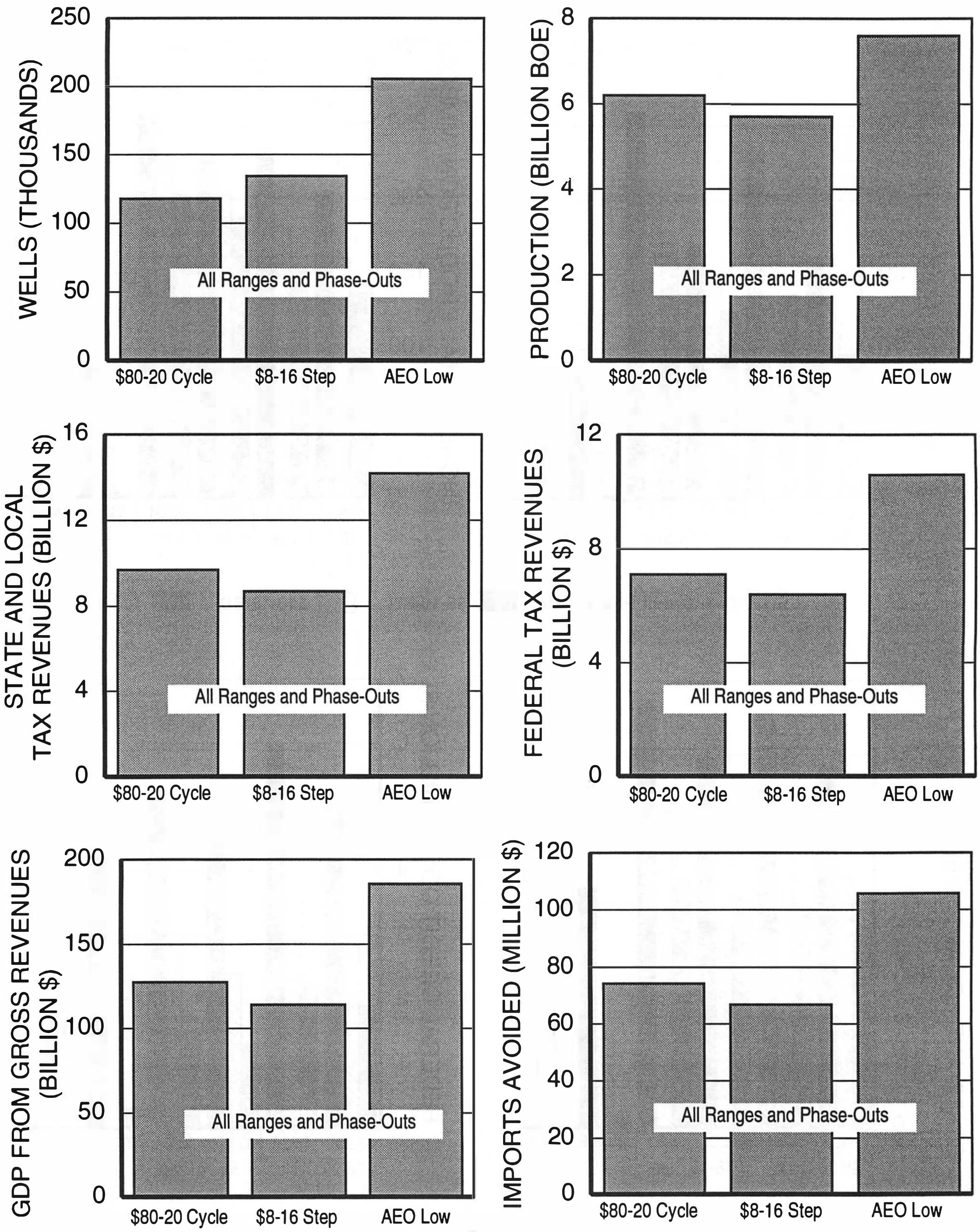


Figure 5-37. Ten Year Summary—Base Case Analysis, No MWC (Full Cost).

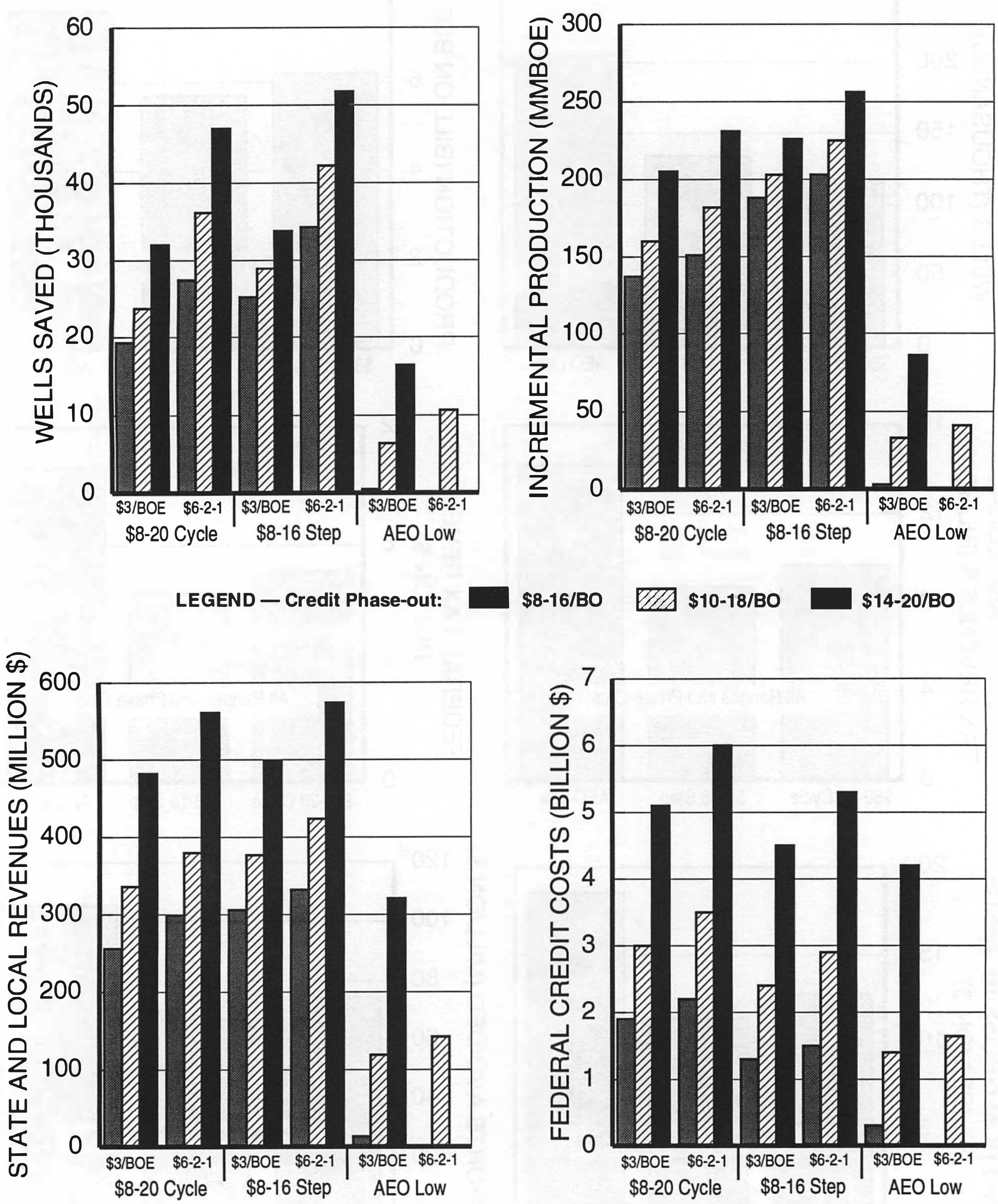


Figure 5-38. Ten Year Summary—Incremental MWC Analysis (Marginal Cost).

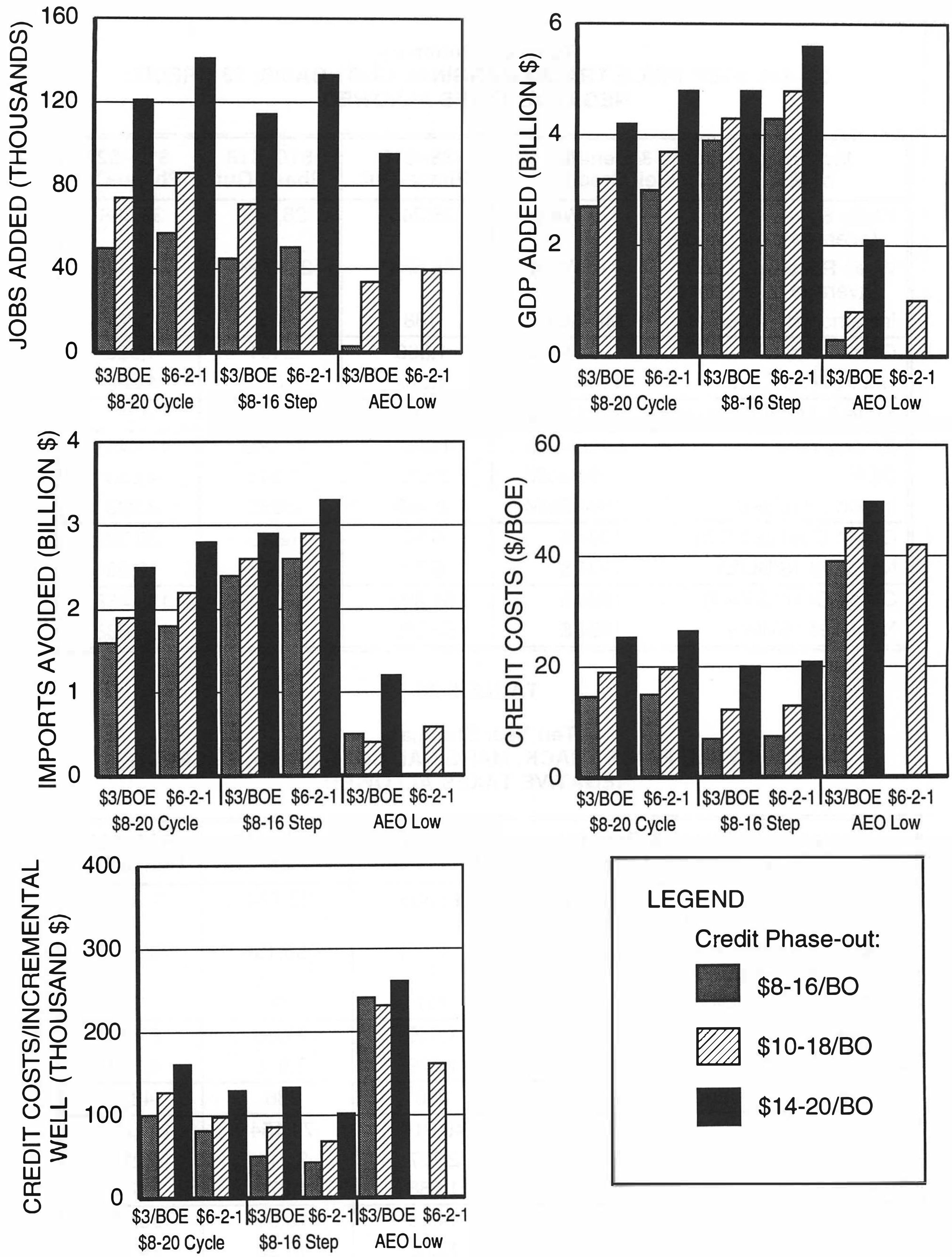


Figure 5-39. Ten Year Summary—Incremental MWC Analysis (Marginal Cost).

TABLE 5-27

Ten Year Summary
$8–$16 STEP PRICE TRACK; MARGINAL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	25,246	28,947	33,868
Wells Receiving Credit (average over period)	# of Wells	59,584	281,194	286,115
Incremental Production	MMBOE	188	203	226
Credit Paid	1994 $MM	1,300	2,491	4,520
Net Federal Cost	1994 $MM	1,277	2,396	4,289
State & Local Revenues	1994 $MM	306	377	498
Employment	Labor-Years	44,964	71,043	114,451
GDP	1994 $MM	3,963	4,341	4,883
Imports Avoided	1994 $MM	2,460	2,685	2,993
Credit Cost ($/BOE)	1994 $	6.91	12.25	20.02
Net Cost ($/BOE)	1994 $	6.79	11.78	19.00
Credit Cost ($/Well)	1994 $	51,493	86,053	133,458
Net Cost ($/Well)	1994 $	50,582	82,771	126,638

TABLE 5-28

Ten Year Summary
$8–$20 CYCLE PRICE TRACK, MARGINAL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	19,339	23,794	32,066
Wells Receiving Credit (average over period)	# of Wells	192,998	256,138	263,535
Incremental Production	MMBOE	137	160	205
Credit Paid	1994 $MM	1,945	3,036	5,172
Net Federal Cost	1994 $MM	1,879	2,916	4,938
State & Local Revenues	1994 $MM	256	336	482
Employment	Labor-Years	49,917	74,154	121,239
GDP	1994 $MM	2,727	3,211	4,214
Imports Avoided	1994 $MM	1,688	1,977	2,574
Credit Cost ($/BOE)	1994 $	14.16	19.01	25.25
Net Cost ($/BOE)	1994 $	13.68	18.26	24.11
Credit Cost ($/Well)	1994 $	100,573	127,597	161,294
Net Cost ($/Well)	1994 $	97,160	122,553	153,997

TABLE 5-29

Ten Year Summary
1994 AEO LOW PRICE TRACK; MARGINAL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	544	6,458	16,454
Wells Receiving Credit (average over period)	# of Wells	160,047	314,075	324,071
Incremental Production	MMBOE	3	33	86
Credit Paid	1994 $MM	131	1,494	4,294
Net Federal Cost	1994 $MM	141	1,423	4,048
State & Local Revenues	1994 $MM	13	119	321
Employment	Labor-Years	3,048	33,822	95,432
GDP	1994 $MM	76	808	2,101
Imports Avoided	1994 $MM	54	485	1,246
Credit Cost ($/BOE)	1994 $	39.09	44.96	49.71
Net Cost ($/BOE)	1994 $	42.08	42.83	46.86
Credit Cost ($/Well)	1994 $	240,853	231,359	260,968
Net Cost ($/Well)	1994 $	259,239	220,364	246,018

TABLE 5-30

Ten Year Summary
$8–$16 STEP PRICE TRACK; MARGINAL COST BASIS; $6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	34,389	42,247	51,702
Wells Receiving Credit (average over period)	# of Wells	61,954	294,194	303,949
Incremental Production	MMBOE	203	225	256
Credit Paid	1994 $MM	1,517	2,916	5,324
Net Federal Cost	1994 $MM	1,490	2,815	5,074
State & Local Revenues	1994 $MM	332	424	574
Employment	Labor-Years	50,470	28,775	133,250
GDP	1994 $MM	4,310	4,857	5,616
Imports Avoided	1994 $MM	2,634	2,946	3,378
Credit Cost ($/BOE)	1994 $	7.47	12.94	20.82
Net Cost ($/BOE)	1994 $	7.34	12.49	19.84
Credit Cost ($/Well)	1994 $	44,113	69,022	102,974
Net Cost ($/Well)	1994 $	43,328	66,632	98,139

TABLE 5-31

Ten Year Summary
$8–$20 CYCLE PRICE TRACK; MARGINAL COST BASIS;
$6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out	$10–$18 Phase-Out	$14-$20 Phase-Out
Wells Saved (average over period)	# of Wells	27,489	36,214	47,048
Wells Receiving Credit (average over period)	# of Wells	198,853	267,312	277,249
Incremental Production	MMBOE	151	182	231
Credit Paid	1994 $MM	2,257	3,558	6,095
Net Federal Cost	1994 $MM	2,113	3,427	5,762
State & Local Revenues	1994 $MM	299	380	561
Employment	Labor-Years	57,240	86,155	141,050
GDP	1994 $MM	3,031	3,726	4,815
Imports Avoided	1994 $MM	1,838	2,243	2,873
Credit Cost ($/BOE)	1994 $	14.95	19.58	26.37
Net Cost ($/BOE)	1994 $	13.99	18.85	24.93
Credit Cost ($/Well)	1994 $	82,107	98,250	129,549
Net Cost ($/Well)	1994 $	76,869	94,633	122,471

TABLE 5-32

Ten Year Summary
1994 AEO LOW OIL PRICE TRACK; MARGINAL COST BASIS;
$6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Phase-Out
Wells Saved (average over period)	# of Wells	10,655
Wells Receiving Credit (average over period)	# of Wells	318,272
Incremental Production	MMBOE	41
Credit Paid	1994 $MM	1,719
Net Federal Cost	1994 $MM	1,643
State & Local Revenues	1994 $MM	142
Employment	Labor-Years	39,387
GDP	1994 $MM	1,007
Imports Avoided	1994 $MM	581
Credit Cost ($/BOE)	1994 $	41.97
Net Cost ($/BOE)	1994 $	40.12
Credit Cost ($/Well)	1994 $	161,331
Net Cost ($/Well)	1994 $	154,198

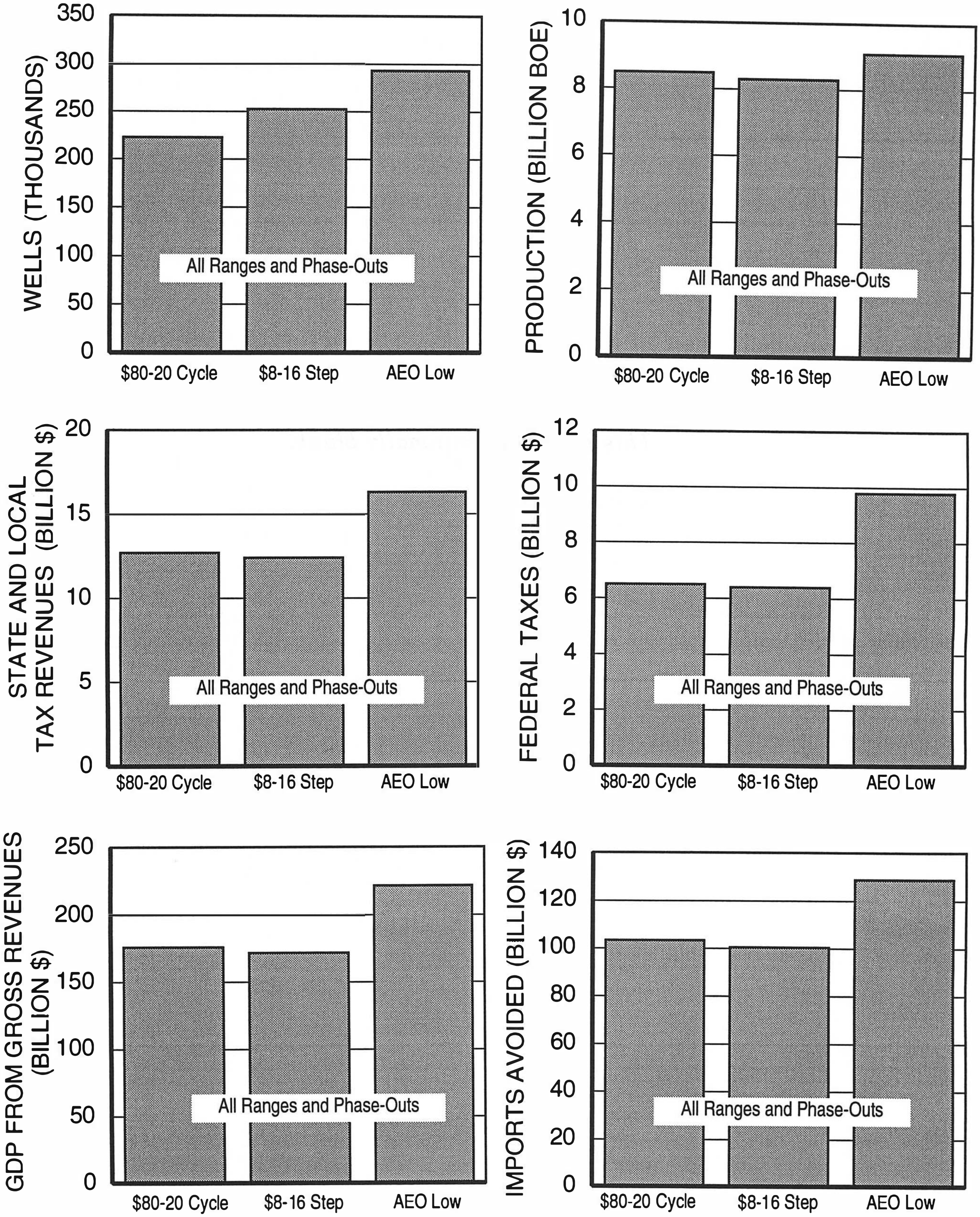


Figure 5-40. Ten Year Summary—Base Case Analysis, No MWC (Marginal Cost).

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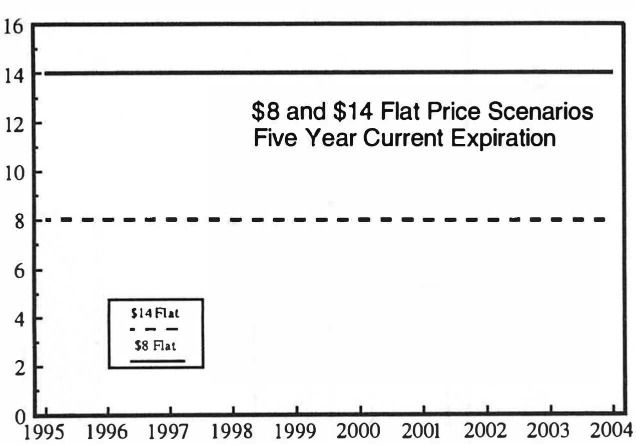
MARGINAL WELL CREDIT ANALYSIS

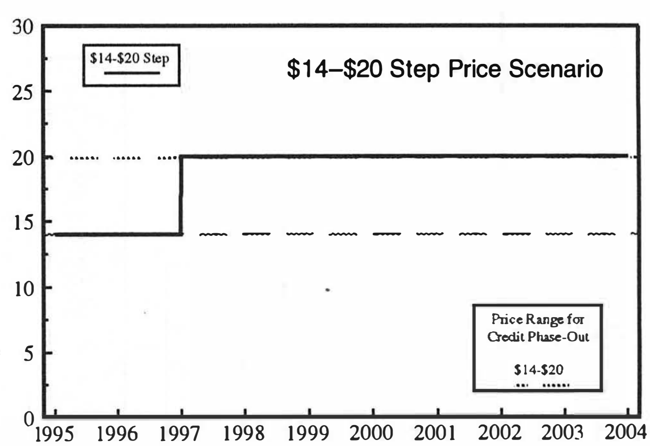
Section B

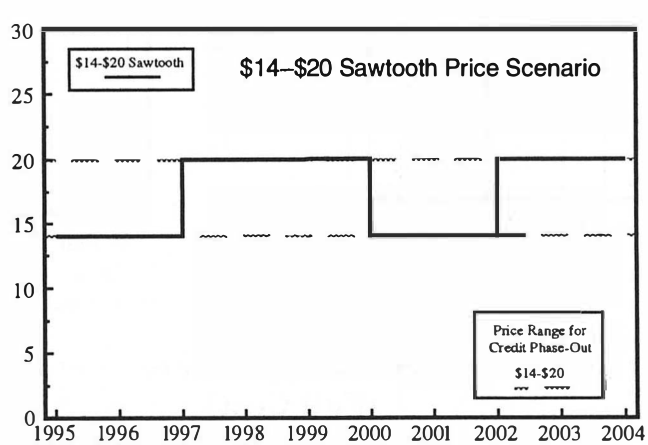
Incremental Full Cost Analysis - Figures and Tables
Full Cost Base Case - Figures
Incremental Marginal Cost Analysis - Figures and Tables
Marginal Cost Base Case - Figures

	$3/BOE Credit			$6-$2-$1 Credit		
	Phase-Out			Phase-Out		
Price Track	$8-$16	$10-$18	$14-$20	$8-$16	$10-$18	$14-$20
$8 Flat (5 Yr. Expiration)	•					
$14 Flat (5 Yr. Expiration)			•			
$14-$20 Step			•			
$14-$20 Sawtooth			•			

• Indicates incentive evaluation results in this section.







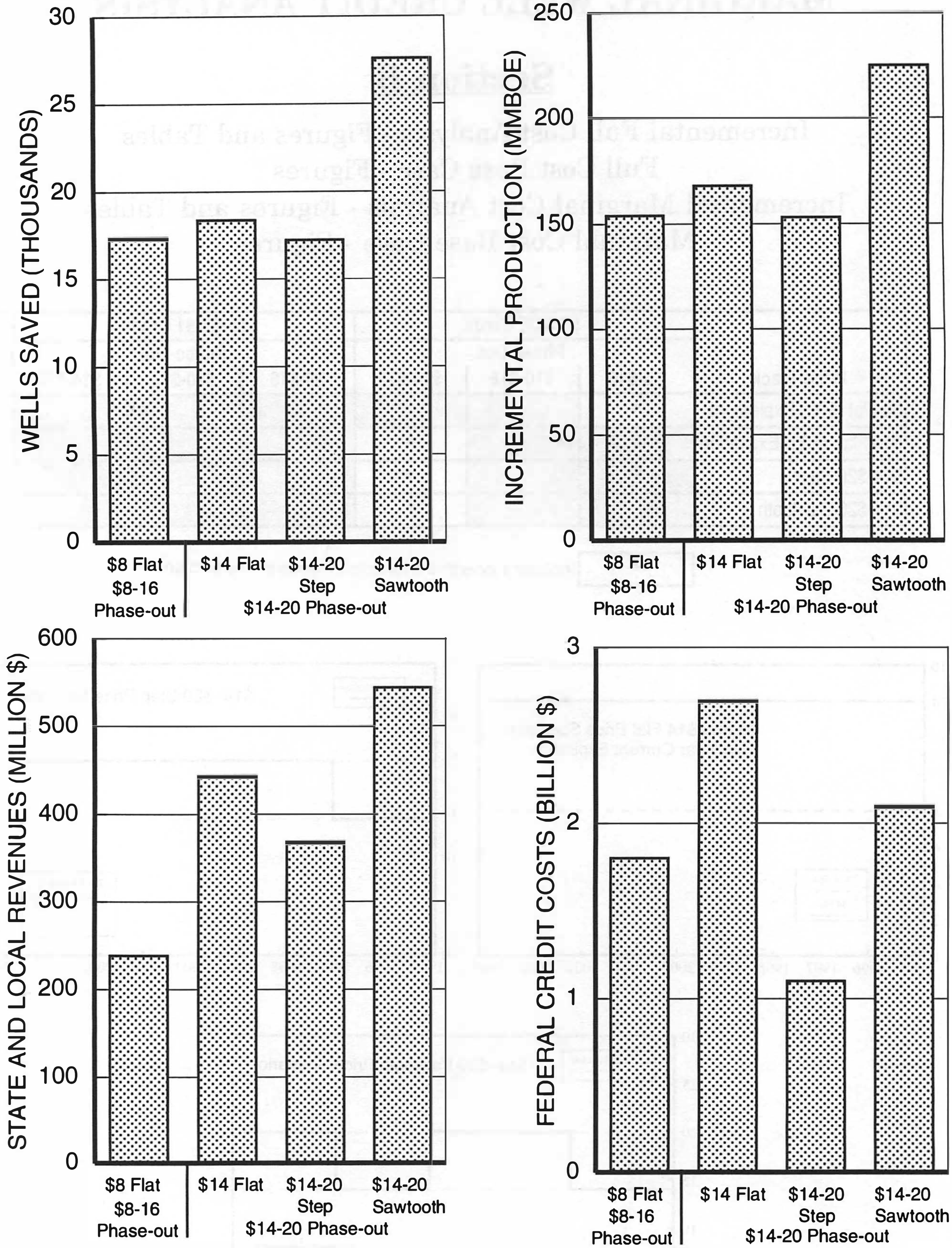


Figure 5-41. Ten Year Summary—Incremental MWC Analysis (Full Cost).

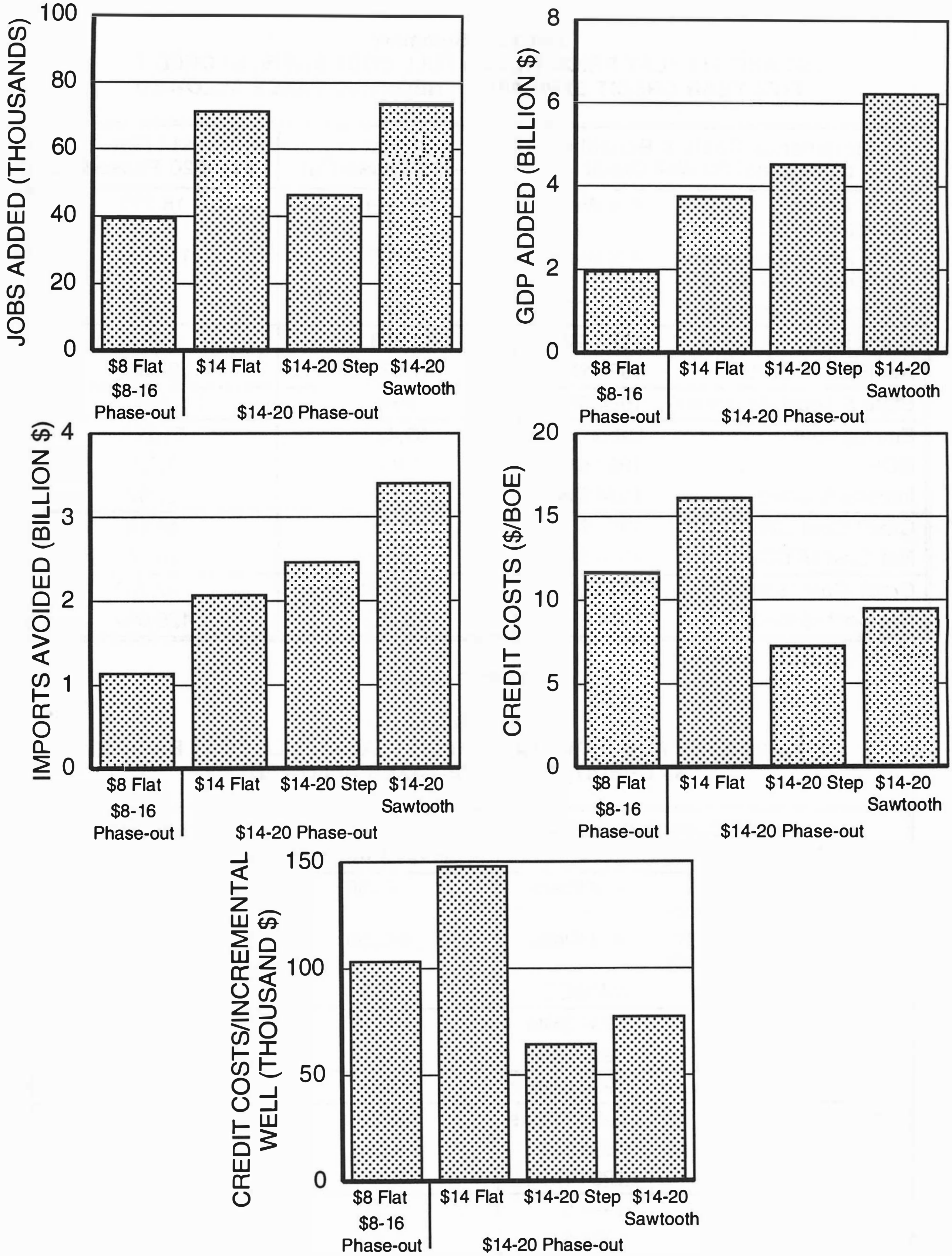


Figure 5-42. Ten Year Summary—Incremental MWC Analysis (Full Cost).

TABLE 5-33

Ten Year Summary
$8 AND $14 FLAT PRICE TRACK; FULL COST BASIS; $3 CREDIT; FIVE YEAR CREDIT EXPIRATION; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8 Flat $8–$16 Phase-Out	$14 Flat $14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	17,474	18,390
Wells Receiving Credit (average over period)	# of Wells	74,527	116,554
Incremental Production	MMBOE	154	168
Credit Paid	1994 $MM	1,803	2,717
Net Federal Cost	1994 $MM	1,633	2,385
State & Local Revenues	1994 $MM	239	444
Employment	Labor-Years	39,420	71,275
GDP	1994 $MM	1,956	3,755
Imports Avoided	1994 $MM	1,139	2,067
Credit Cost ($/BOE)	1994 $	11.71	16.14
Net Cost ($/BOE)	1994 $	10.60	14.16
Credit Cost ($/Well)	1994 $	103,181	147,747
Net Cost ($/Well)	1994 $	93,453	129,694

TABLE 5-34

Ten Year Summary
$14–$20 STEP AND SAWTOOTH PRICE TRACK; FULL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		Step $14–$20 Phase-Out	Sawtooth $14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	17,256	27,627
Wells Receiving Credit (average over period)	# of Wells	47,380	92,635
Incremental Production	MMBOE	153	225
Credit Paid	1994 $MM	1,111	2,135
Net Federal Cost	1994 $MM	871	1,777
State & Local Revenues	1994 $MM	369	544
Employment	Labor-Years	46,291	73,942
GDP	1994 $MM	4,518	6,259
Imports Avoided	1994 $MM	2,455	3,403
Credit Cost ($/BOE)	1994 $	7.26	9.48
Net Cost ($/BOE)	1994 $	5.69	7.89
Credit Cost ($/Well)	1994 $	64,383	77,280
Net Cost ($/Well)	1994 $	50,475	64,322

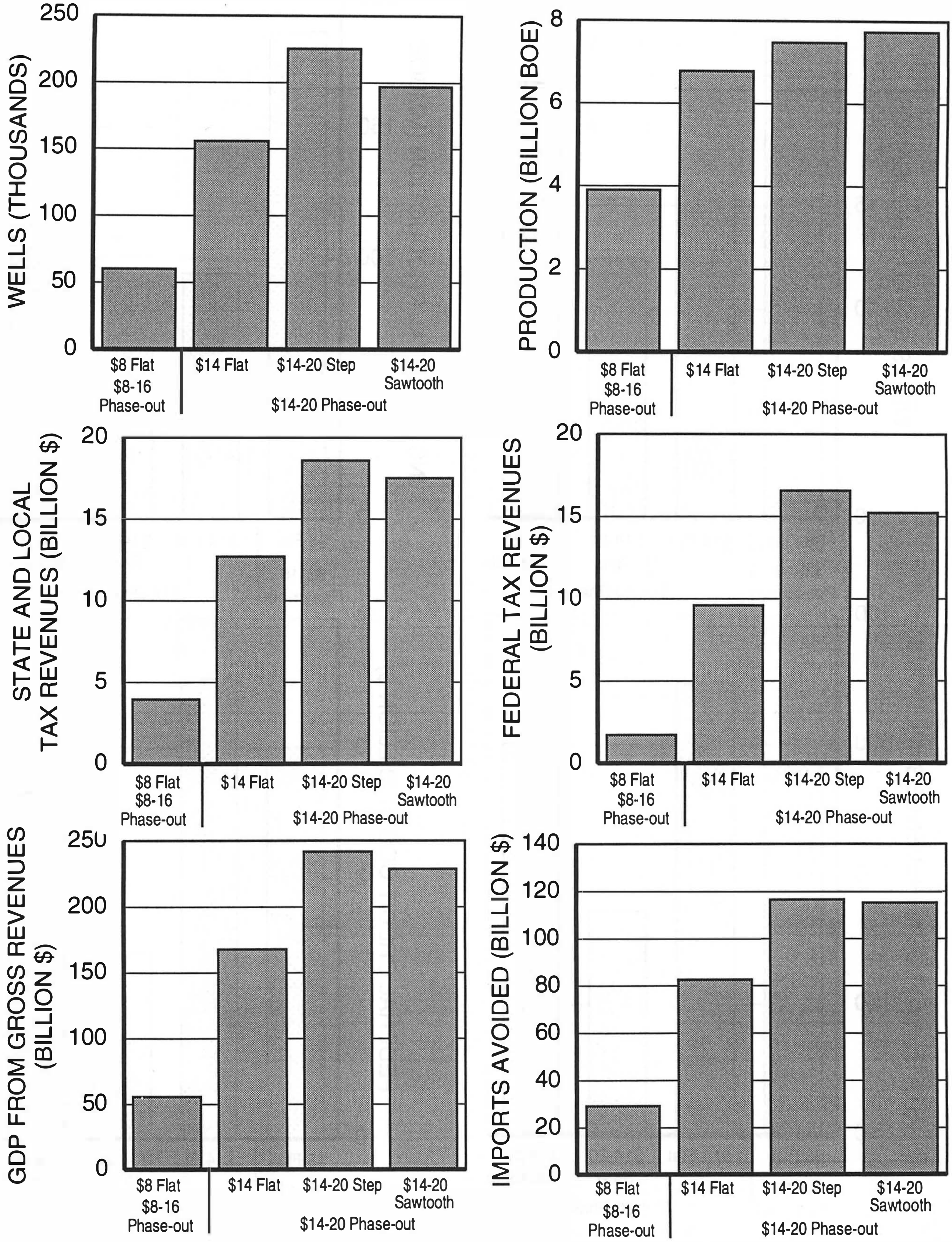


Figure 5-43. Ten Year Summary—Base Case Analysis, No MWC (Full Cost).

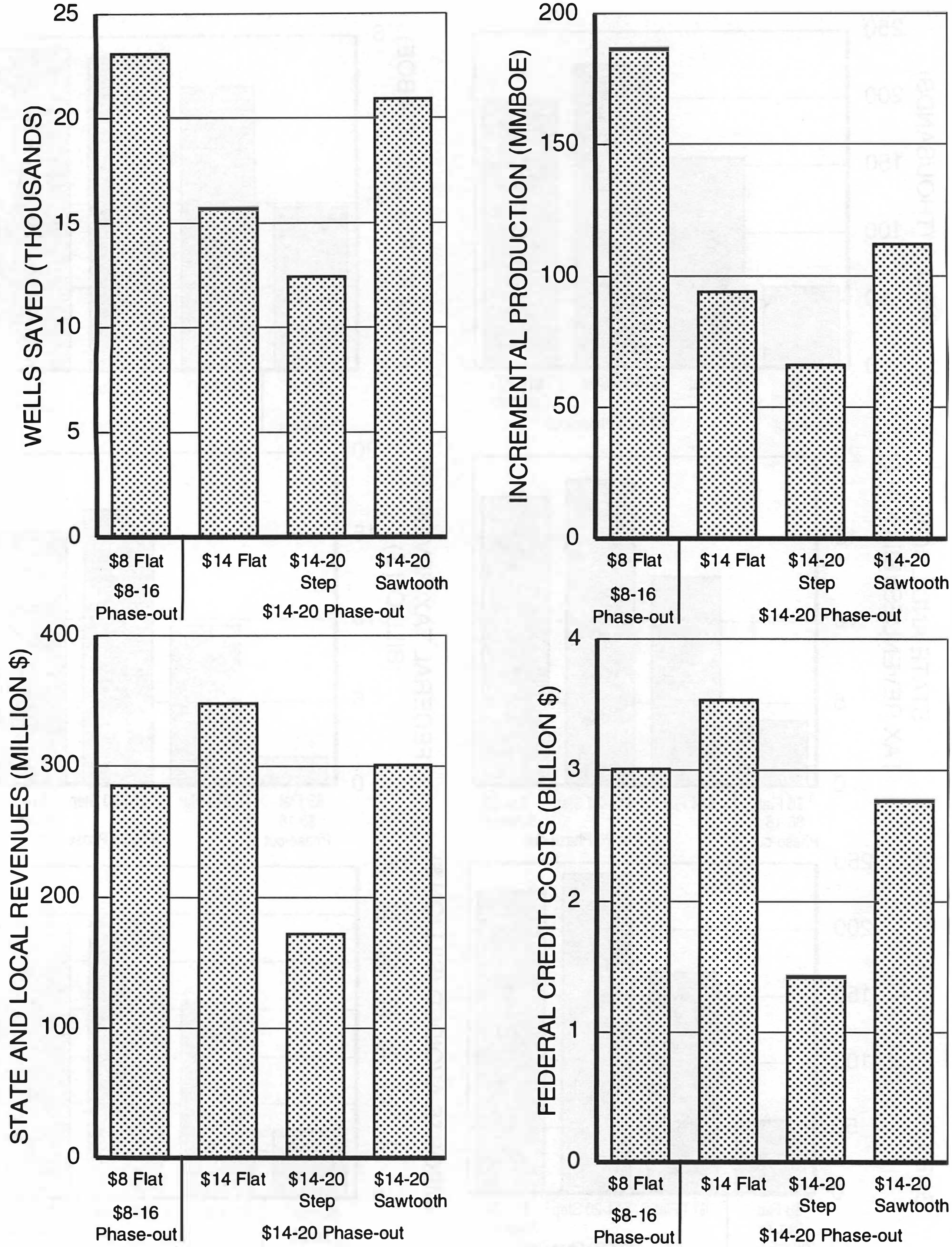


Figure 5-44. Ten Year Summary—Incremental MWC Analysis (Marginal Cost).

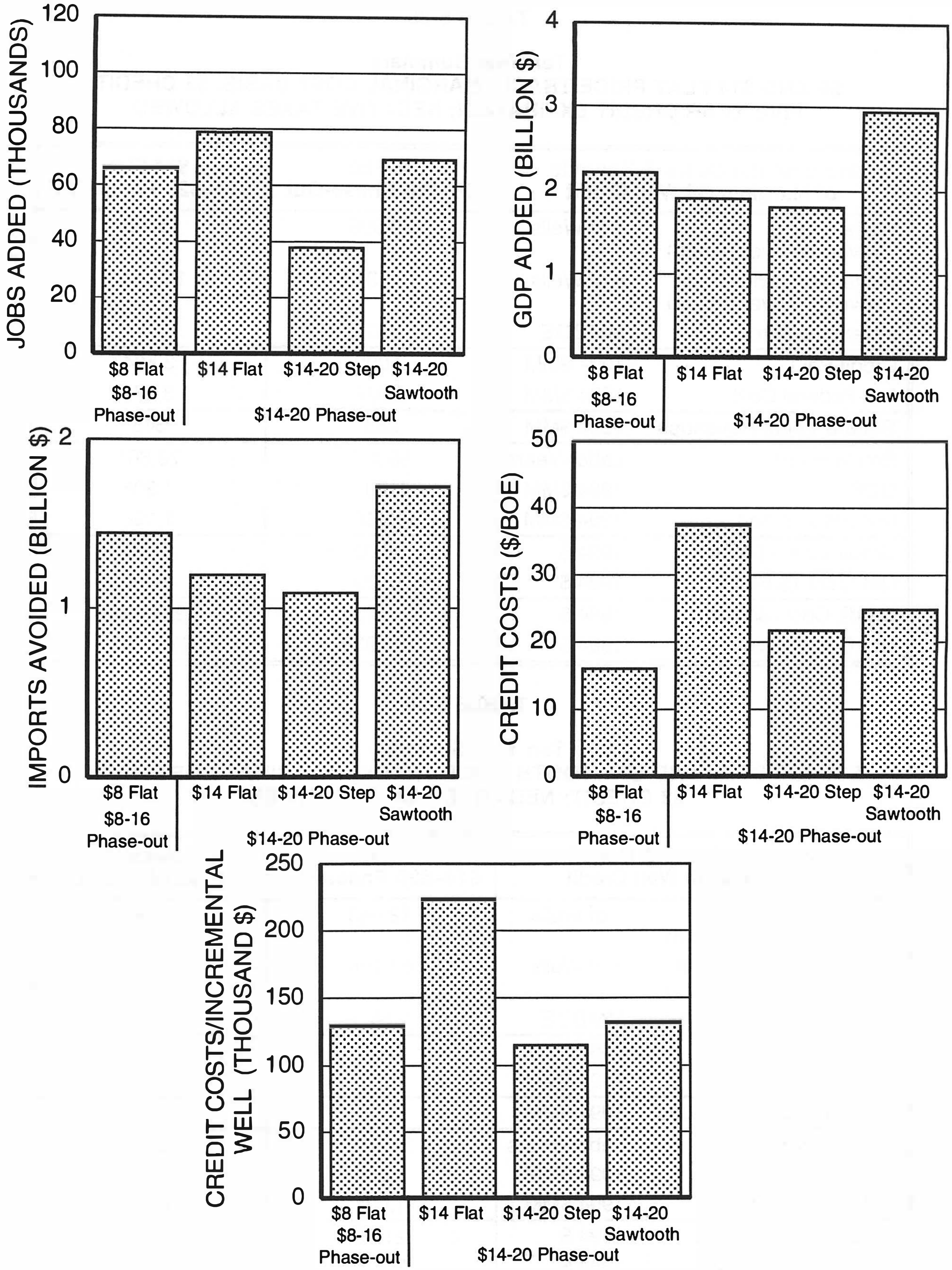


Figure 5-45. Ten Year Summary—Incremental MWC Analysis (Marginal Cost).

TABLE 5-35

Ten Year Summary
$8 AND $14 FLAT PRICE TRACK; MARGINAL COST BASIS; $3 CREDIT
FIVE YEAR CREDIT EXPIRATION; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8 Flat $8–$16 Phase-Out	$14 Flat $14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	23,096	15,746
Wells Receiving Credit (average over period)	# of Wells	135,313	166,442
Incremental Production	MMBOE	187	94
Credit Paid	1994 $MM	3,008	3,534
Net Federal Cost	1994 $MM	2,978	3,271
State & Local Revenues	1994 $MM	285	348
Employment	Labor-Years	66,417	78,801
GDP	1994 $MM	2,209	1,905
Imports Avoided	1994 $MM	1,446	1,198
Credit Cost ($/BOE)	1994 $	16.05	37.71
Net Cost ($/BOE)	1994 $	15.89	34.90
Credit Cost ($/Well)	1994 $	130,238	224,435
Net Cost ($/Well)	1994 $	128,939	207,733

TABLE 5-36

Ten Year Summary
$14–$20 STEP AND SAWTOOTH PRICE TRACK; MARGINAL COST BASIS;
$3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		Step $14–$20 Phase-Out	Sawtooth $14–$20 Phase-Out
Wells Saved (average over period)	# of Wells	12,443	20,905
Wells Receiving Credit (average over period)	# of Wells	67,196	131,874
Incremental Production	MMBOE	66	112
Credit Paid	1994 $MM	1,431	2,775
Net Federal Cost	1994 $MM	1,335	2,615
State & Local Revenues	1994 $MM	172	301
Employment	Labor-Years	37,936	69,301
GDP	1994 $MM	1,804	2,946
Imports Avoided	1994 $MM	1,091	1,729
Credit Cost ($/BOE)	1994 $	21.69	24.80
Net Cost ($/BOE)	1994 $	20.24	23.37
Credit Cost ($/Well)	1994 $	115,006	132,741
Net Cost ($/Well)	1994 $	107,291	125,087

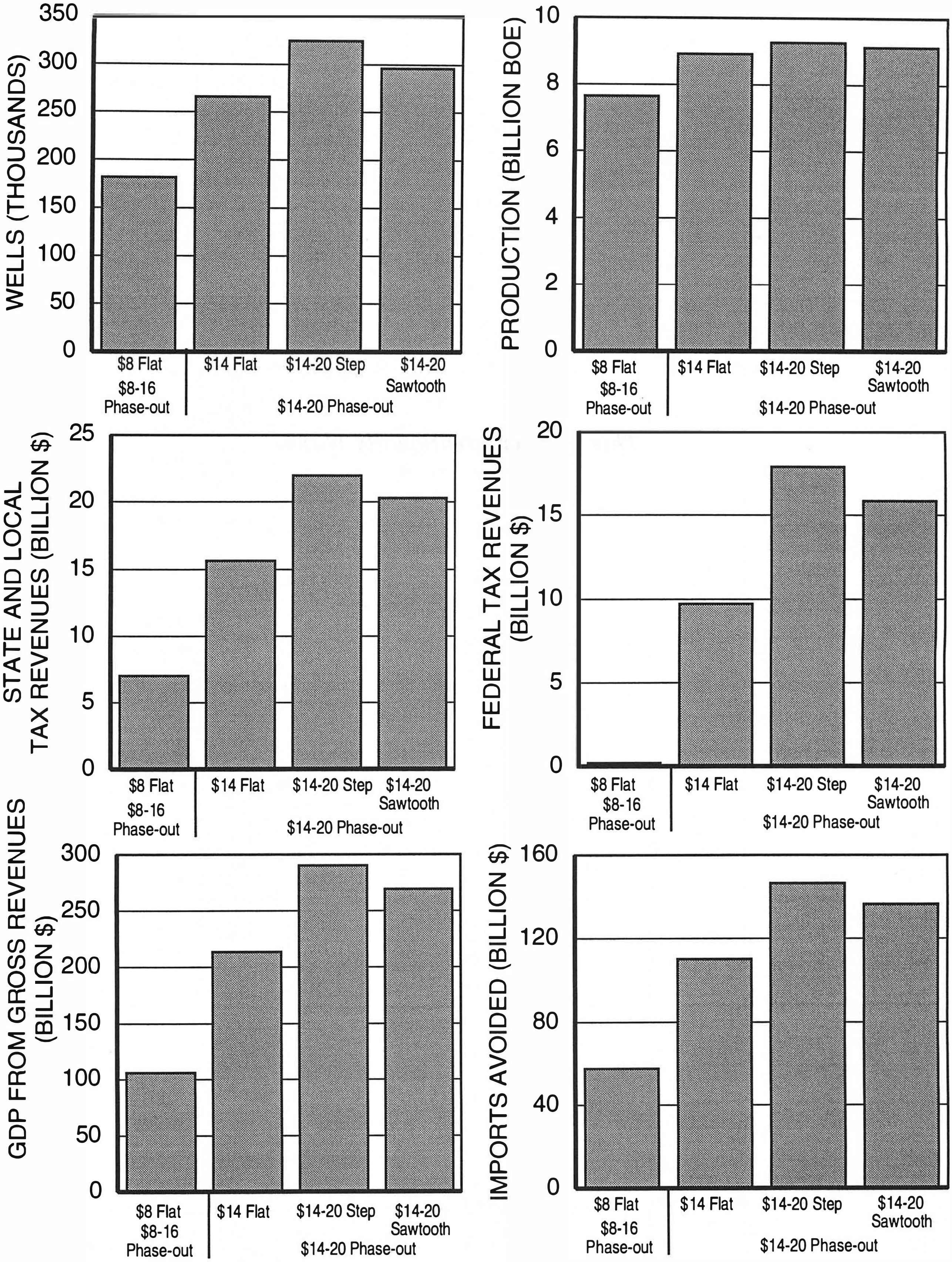


Figure 5-46. Ten Year Summary—Base Case Analysis, No MWC (Marginal Cost).

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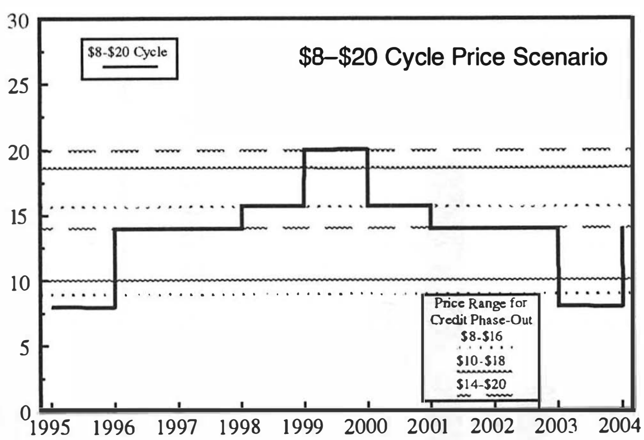
MARGINAL WELL CREDIT ANALYSIS

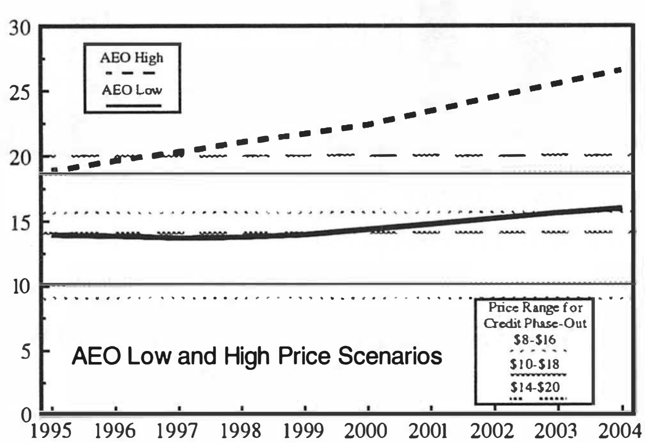
Section C

Incremental Full Cost Analysis - Figures and Tables
Full Cost Base Case - Figures
Incremental Marginal Cost Analysis - Figures and Tables
Marginal Cost Base Case - Figures

Price Track	$3/BOE Credit Phase-Out $8-$16	$3/BOE Credit Phase-Out $10-$18	$3/BOE Credit Phase-Out $14-$20	$6-$2-$1 Credit Phase-Out $8-$16	$6-$2-$1 Credit Phase-Out $10-$18	$6-$2-$1 Credit Phase-Out $14-$20	No Negative Taxes $3/BOE Credit Phase-Out $10-$18	New Wells $3/BOE Credit Phase-Out $10-$18
$8-$20 Cycle		•					•	•
AEO 1994 Low		•	•				•	•
AEO 1994 High			•					

• Indicates incentive evaluation results in this section.





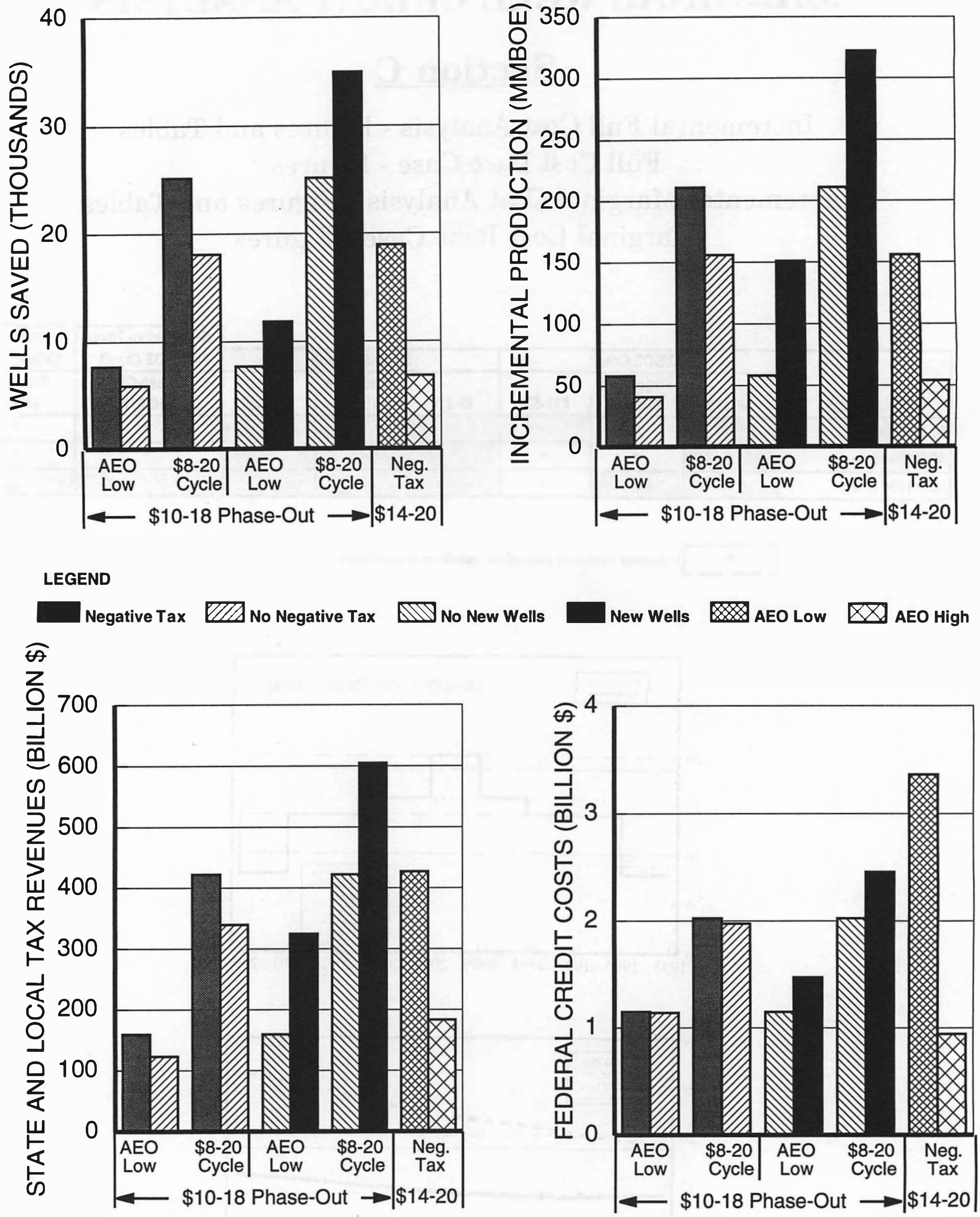


Figure 5-47. Ten Year Summary—Incremental MWC Analysis Sensitivity (Full Cost).

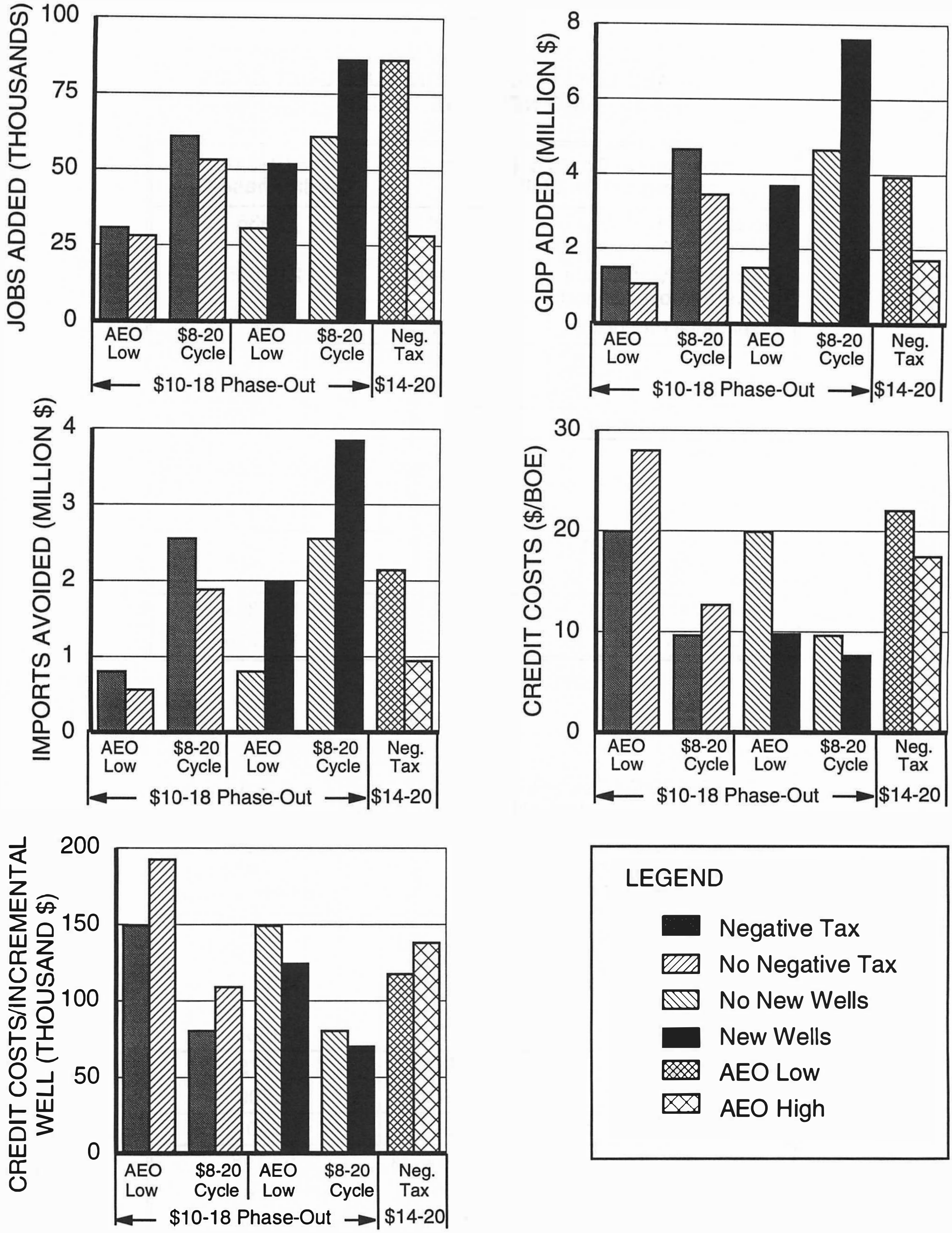


Figure 5-48. Ten Year Summary—Incremental MWC Analysis Sensitivity (Full Cost).

TABLE 5-37

Ten Year Summary
1994 AEO LOW PRICE TRACK; FULL COST BASIS
(NO NEGATIVE TAXES)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out
Wells Saved (average over period)	# of Wells	5,936
Wells Receiving Credit (average over period)	# of Wells	219,635
Incremental Production	MMBOE	41
Credit Paid	1994 $MM	1,142
Net Federal Cost	1994 $MM	1,043
State & Local Revenues	1994 $MM	123
Employment	Labor-Years	27,950
GDP	1994 $MM	1,057
Imports Avoided	1994 $MM	564
Credit Cost ($/BOE)	1994 $	27.96
Net Cost ($/BOE)	1994 $	25.54
Credit Cost ($/Well)	1994 $	192,395
Net Cost ($/Well)	1994 $	175,716

TABLE 5-38

Ten Year Summary
$8–$20 CYCLE PRICE TRACK; FULL COST BASIS
(NO NEGATIVE TAXES)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out
Wells Saved (average over period)	# of Wells	18,108
Wells Receiving Credit (average over period)	# of Wells	153,687
Incremental Production	MMBOE	156
Credit Paid	1994 $MM	1,975
Net Federal Cost	1994 $MM	1,709
State & Local Revenues	1994 $MM	340
Employment	Labor-Years	53,148
GDP	1994 $MM	3,445
Imports Avoided	1994 $MM	1,882
Credit Cost ($/BOE)	1994 $	12.67
Net Cost ($/BOE)	1994 $	10.96
Credit Cost ($/Well)	1994 $	109,070
Net Cost ($/Well)	1994 $	94,380

TABLE 5-39

Ten Year Summary
1994 AEO LOW OIL PRICE TRACK; FULL COST BASIS
(WELLS DRILLED AFTER 1995 ONLY)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out
Wells Saved (average over period)	# of Wells	3,869
Wells Receiving Credit (average over period)	# of Wells	27,885
Incremental Production	MMBOE	93
Credit Paid	1994 $MM	323
Net Federal Cost	1994 $MM	185
State & Local Revenues	1994 $MM	166
Employment	Labor-Years	21,203
GDP	1994 $MM	2,190
Imports Avoided	1994 $MM	1,178
Credit Cost ($/BOE)	1994 $	3.49
Net Cost ($/BOE)	1994 $	2.00
Credit Cost ($/Well)	1994 $	83,484
Net Cost ($/Well)	1994 $	47,816

TABLE 5-40

Ten Year Summary
$8–$20 CYCLE PRICE TRACK; FULL COST BASIS
(WELLS DRILLED AFTER 1995 ONLY)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out
Wells Saved (average over period)	# of Wells	4,894
Wells Receiving Credit (average over period)	# of Wells	25,671
Incremental Production	MMBOE	111
Credit Paid	1994 $MM	430
Net Federal Cost	1994 $MM	278
State & Local Revenues	1994 $MM	183
Employment	Labor-Years	25,350
GDP	1994 $MM	2,411
Imports Avoided	1994 $MM	1,297
Credit Cost ($/BOE)	1994 $	3.88
Net Cost ($/BOE)	1994 $	2.50
Credit Cost ($/Well)	1994 $	87,863
Net Cost ($/Well)	1994 $	56,804

TABLE 5-41

Ten Year Summary
1994 AEO HIGH PRICE TRACK; FULL COST BASIS
(NEGATIVE TAXES ALLOWED)

Incremental Costs & Benefits of Marginal Oil Well Credit		$14–$20 Credit Phase-Out
Wells Saved (average over period)	# of Wells	6,822
Wells Receiving Credit (average over period)	# of Wells	100,151
Incremental Production	MMBOE	54
Credit Paid	1994 $MM	942
Net Federal Cost	1994 $MM	850
State & Local Revenues	1994 $MM	183
Employment	Labor-Years	28,241
GDP	1994 $MM	1,710
Imports Avoided	1994 $MM	941
Credit Cost ($/BOE)	1994 $	17.47
Net Cost ($/BOE)	1994 $	15.25
Credit Cost ($/Well)	1994 $	138,079
Net Cost ($/Well)	1994 $	120,489

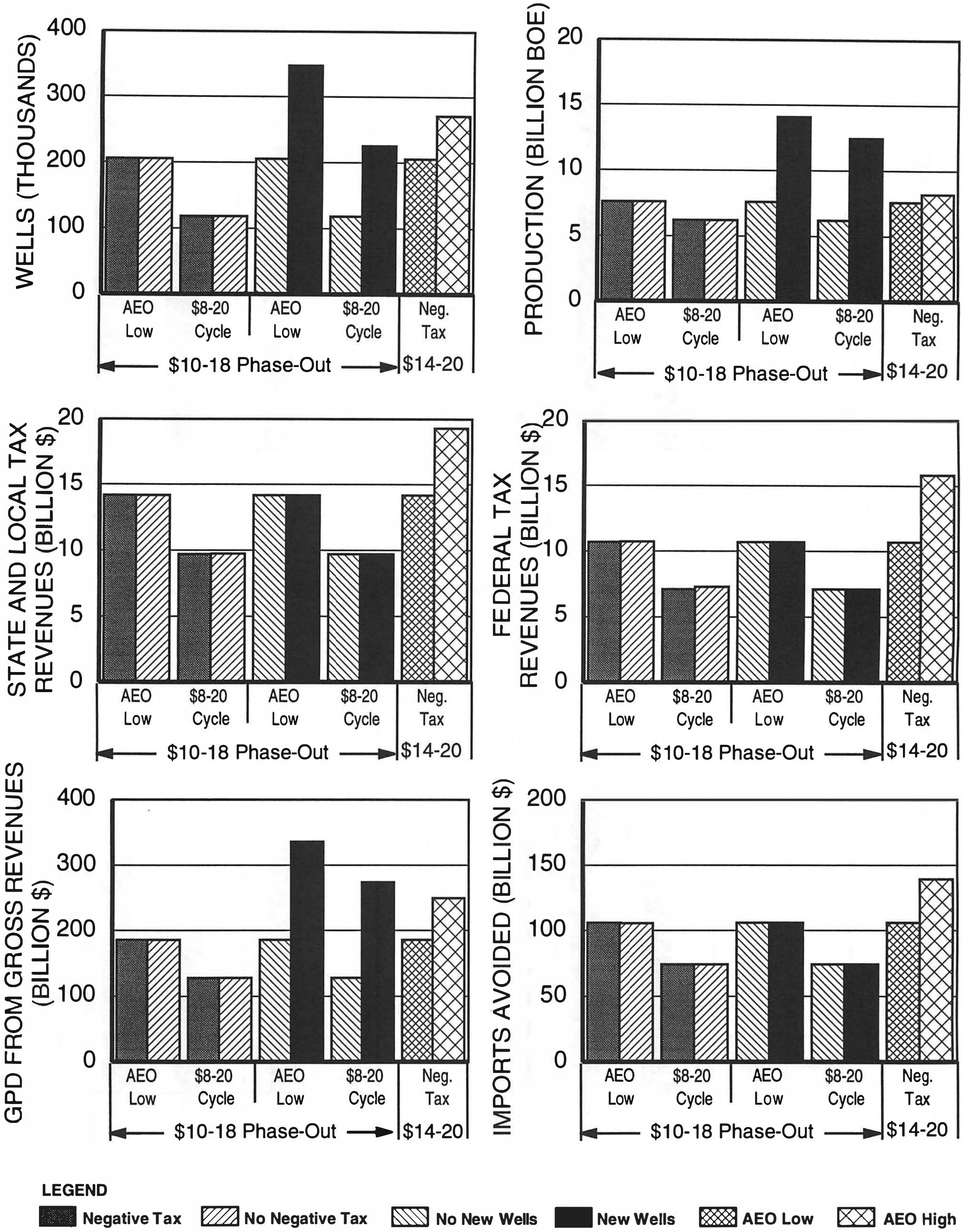


Figure 5-49. Ten Year Summary—Base Case Analysis, No MWC (Full Cost).

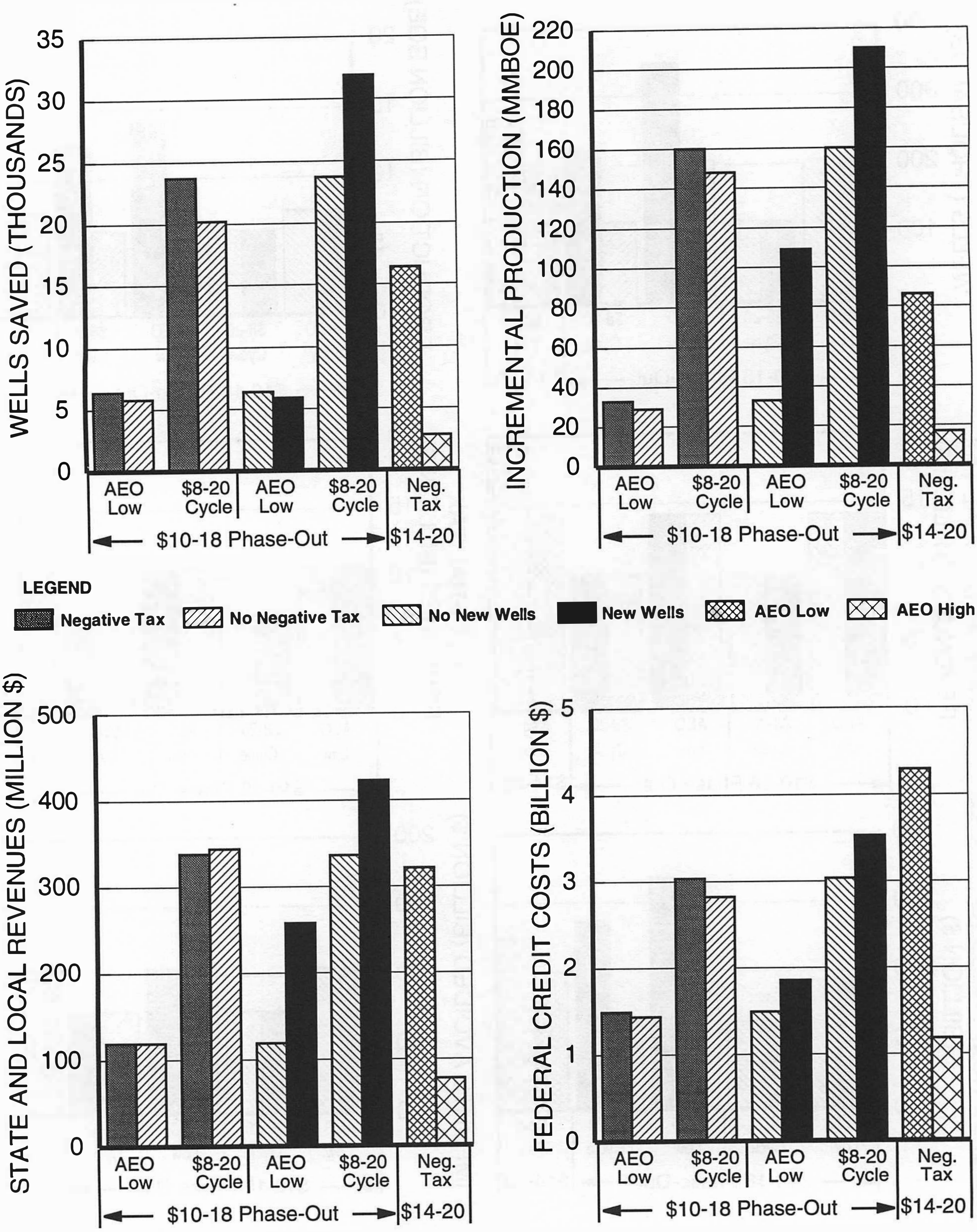


Figure 5-50. Ten Year Summary—Incremental MWC Analysis Sensitivity (Marginal Cost).

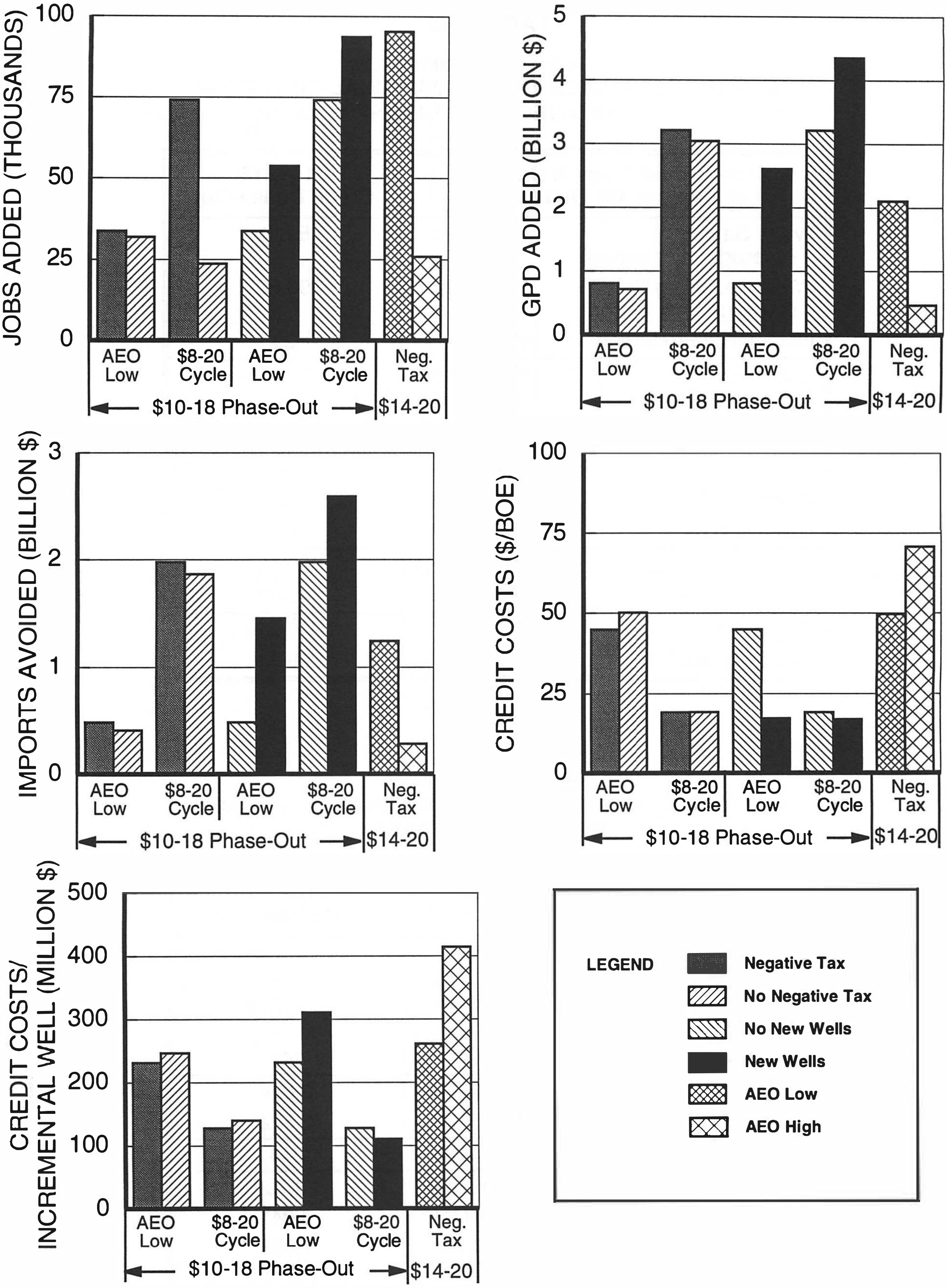


Figure 5-51. Ten Year Summary—Incremental MWC Analysis Sensitivity (Marginal Cost).

TABLE 5-42

Ten Year Summary
1994 AEO LOW PRICE TRACK; MARGINAL COST BASIS
(NO NEGATIVE TAXES)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out
Wells Saved (average over period)	# of Wells	5,841
Wells Receiving Credit (average over period)	# of Wells	296,802
Incremental Production	MMBOE	29
Credit Paid	1994 $MM	1,440
Net Federal Cost	1994 $MM	1,321
State & Local Revenues	1994 $MM	119
Employment	Labor-Years	31,999
GDP	1994 $MM	715
Imports Avoided	1994 $MM	409
Credit Cost ($/BOE)	1994 $	50.18
Net Cost ($/BOE)	1994 $	46.03
Credit Cost ($/Well)	1994 $	246,516
Net Cost ($/Well)	1994 $	226,144

TABLE 5-43

Ten Year Summary
$8–$20 CYCLE PRICE TRACK; MARGINAL COST BASIS
(NO NEGATIVE TAXES)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out
Wells Saved (average over period)	# of Wells	20,209
Wells Receiving Credit (average over period)	# of Wells	232,829
Incremental Production	MMBOE	148
Credit Paid	1994 $MM	2,824
Net Federal Cost	1994 $MM	2,522
State & Local Revenues	1994 $MM	344
Employment	Labor-Years	23,736
GDP	1994 $MM	3,041
Imports Avoided	1994 $MM	1,865
Credit Cost ($/BOE)	1994 $	19.02
Net Cost ($/BOE)	1994 $	16.99
Credit Cost ($/Well)	1994 $	139,737
Net Cost ($/Well)	1994 $	124,793

TABLE 5-44

Ten Year Summary
1994 AEO LOW OIL PRICE TRACK; MARGINAL COST BASIS
(WELLS DRILLED AFTER 1995 ONLY)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out
Wells Saved (average over period)	# of Wells	3,869
Wells Receiving Credit (average over period)	# of Wells	32,718
Incremental Production	MMBOE	76
Credit Paid	1994 $MM	364
Net Federal Cost	1994 $MM	250
State & Local Revenues	1994 $MM	137
Employment	Labor-Years	20,101
GDP	1994 $MM	1,802
Imports Avoided	1994 $MM	970
Credit Cost ($/BOE)	1994 $	4.77
Net Cost ($/BOE)	1994 $	3.29
Credit Cost ($/Well)	1994 $	94,081
Net Cost ($/Well)	1994 $	64,616

TABLE 5-45

Ten Year Summary
$8–$20 CYCLE PRICE TRACK; MARGINAL COST BASIS
(WELLS DRILLED AFTER 1995 ONLY)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out
Wells Saved (average over period)	# of Wells	4,894
Wells Receiving Credit (average over period)	# of Wells	30,081
Incremental Production	MMBOE	50
Credit Paid	1994 $MM	484
Net Federal Cost	1994 $MM	412
State & Local Revenues	1994 $MM	87
Employment	Labor-Years	19,603
GDP	1994 $MM	1,146
Imports Avoided	1994 $MM	616
Credit Cost ($/BOE)	1994 $	9.60
Net Cost ($/BOE)	1994 $	8.24
Credit Cost ($/Well)	1994 $	98,897
Net Cost ($/Well)	1994 $	84,185

TABLE 5-46

Ten Year Summary
1994 AEO HIGH PRICE TRACK; MARGINAL COST BASIS
(NEGATIVE TAXES ALLOWED)

Incremental Costs & Benefits of Marginal Oil Well Credit		$14–$20 Credit Phase-Out
Wells Saved (average over period)	# of Wells	2,851
Wells Receiving Credit (average over period)	# of Wells	137,754
Incremental Production	MMBOE	17
Credit Paid	1994 $MM	1,181
Net Federal Cost	1994 $MM	1,099
State & Local Revenues	1994 $MM	78
Employment	Labor-Years	25,937
GDP	1994 $MM	463
Imports Avoided	1994 $MM	279
Credit Cost ($/BOE)	1994 $	70.71
Net Cost ($/BOE)	1994 $	65.80
Credit Cost ($/Well)	1994 $	414,226
Net Cost ($/Well)	1994 $	385,465

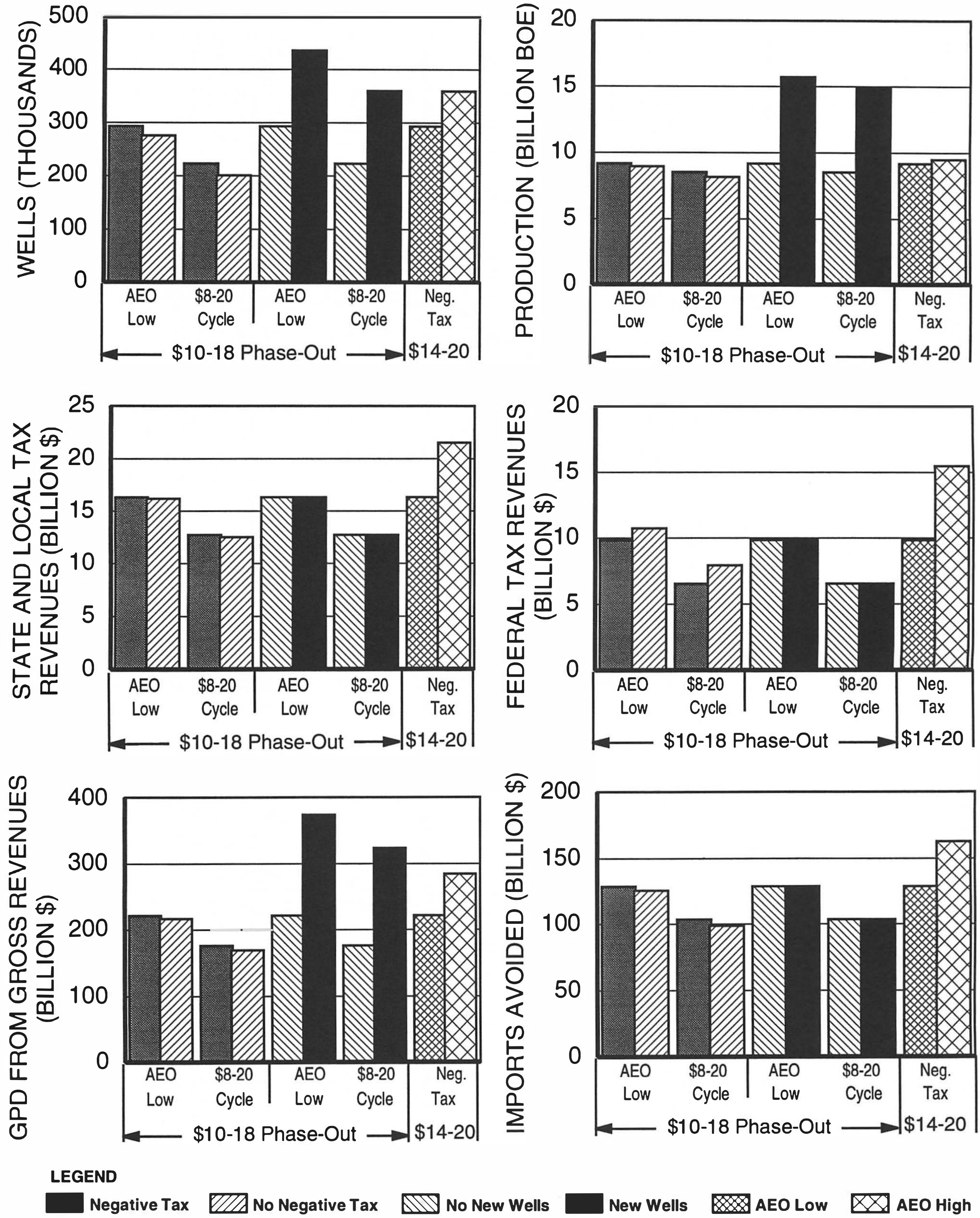


Figure 5-52. Ten Year Summary—Base Case Analysis, No MWC (Marginal Cost).

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Section D

Improved EOR Credit Analysis

TABLE 5-47

POTENTIAL IMPACT OF EXTENDING THE EOR TAX CREDIT TO AMT TAXPAYERS
(Constant $10.00 per Barrel Oil Price)

	10 Year				25 Year			
	Base	Increment			Base	Increment		
Credit:	**Current**	**Current**	**Expanded**	**Expanded**	**Current**	**Current**	**Expanded**	**Expanded**
Abandonment Rate:	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**
Cumulative Reserves Developed (MMBOE):	10	3	6	11	38	21	22	56
Cumulative Incremental Oil Produced (MMBOE):	3	1	2	3	26	14	15	37
Cumulative Jobs Added (Labor-Years):	489	139	294	517	4,155	2,180	2,435	5,869
Cumulative State/Local Taxes ($Millions):	4	1	3	5	23	13	15	36
Cumulative Imports Avoided ($Millions):	34	10	21	36	292	153	171	413
Cumulative GDP Added ($Millions):	54	15	33	57	462	242	271	652
Cumulative Credit Cost ($Millions):	1.51	0.46	1.51	2.43	9.88	5.21	9.88	20.29
Credit Cost ($/Incremental BOE):	0.15	0.14	0.25	0.21	0.26	0.24	0.45	0.37

TABLE 5-48

POTENTIAL IMPACT OF EXTENDING THE EOR TAX CREDIT TO AMT TAXPAYERS
(Constant $14.00 per Barrel Oil Price)

	10 Year				25 Year			
	Base	**Increment**			**Base**	**Increment**		
Credit:	**Current**	**Current**	**Expanded**	**Expanded**	**Current**	**Current**	**Expanded**	**Expanded**
Abandonment Rate:	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**
Cumulative Reserves Developed (MMBOE):	77	26	24	58	465	334	195	682
Cumulative Incremental Oil Produced (MMBOE):	23	7	7	15	284	182	113	374
Cumulative Jobs Added (Labor-Years):	4,894	1,418	1,457	3,306	61,499	39,531	24,413	81,147
Cumulative State/Local Taxes ($Millions):	35	11	12	27	291	192	130	418
Cumulative Imports Avoided ($Millions):	344	100	102	233	4,325	2,780	1,717	5,707
Cumulative GDP Added ($Millions):	544	158	162	367	6,833	4,392	2,713	9,016
Cumulative Credit Cost ($Millions):	11.69	3.71	11.69	19.11	147.28	106.09	147.28	359.45
Credit Cost ($/Incremental BOE):	0.15	0.14	0.49	0.33	0.32	0.32	0.76	0.53

TABLE 5-49

POTENTIAL IMPACT OF EXTENDING THE EOR TAX CREDIT TO AMT TAXPAYERS
(Constant $18.00 per Barrel Oil Price)

	10 Year				25 Year			
	Base	**Increment**			**Base**	**Increment**		
Credit:	**Current**	**Current**	**Expanded**	**Expanded**	**Current**	**Current**	**Expanded**	**Expanded**
Abandonment Rate:	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**
Cumulative Reserves Developed (MMBOE):	224	77	78	181	1,523	1,137	542	2,087
Cumulative Incremental Oil Produced (MMBOE):	65	19	22	48	909	606	322	1,145
Cumulative Jobs Added (Labor-Years):	17,869	5,211	6,159	13,170	248,856	165,982	88,081	313,327
Cumulative State/Local Taxes ($Millions):	124	40	44	98	1,181	813	445	1,569
Cumulative Imports Avoided ($Millions):	1,257	366	433	926	17,500	11,672	6,194	22,034
Cumulative GDP Added ($Millions):	1,985	579	684	1,463	27,651	18,442	9,787	34,814
Cumulative Credit Cost ($Millions):	43.43	13.73	43.43	70.89	538.49	384.45	538.49	1,307.40
Credit Cost ($/Incremental BOE):	0.19	0.18	0.56	0.39	0.35	0.34	0.99	0.63

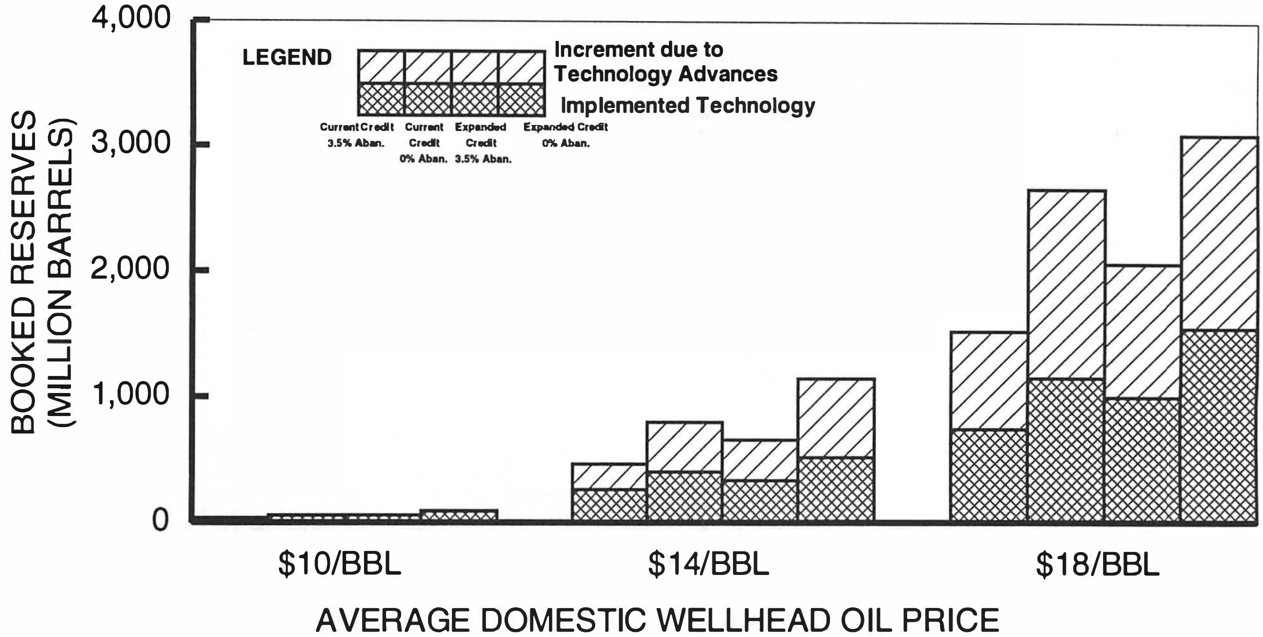

Figure 5-53. Impacts on Booked Reserves of Extending EOR Credit to AMT Taxpayers (Cumulative Over 25 Years).

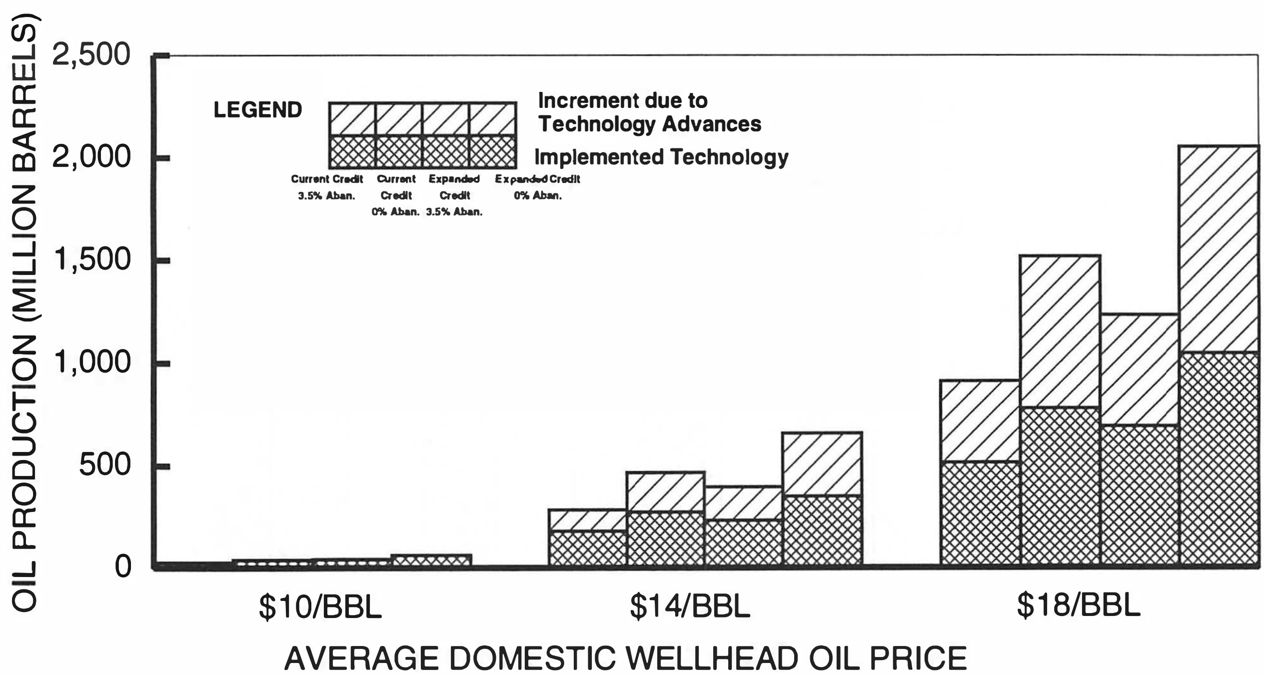

Figure 5-54. Impacts on Oil Production of Extending EOR Credit to AMT Taxpayers (Cumulative Over 25 Years).

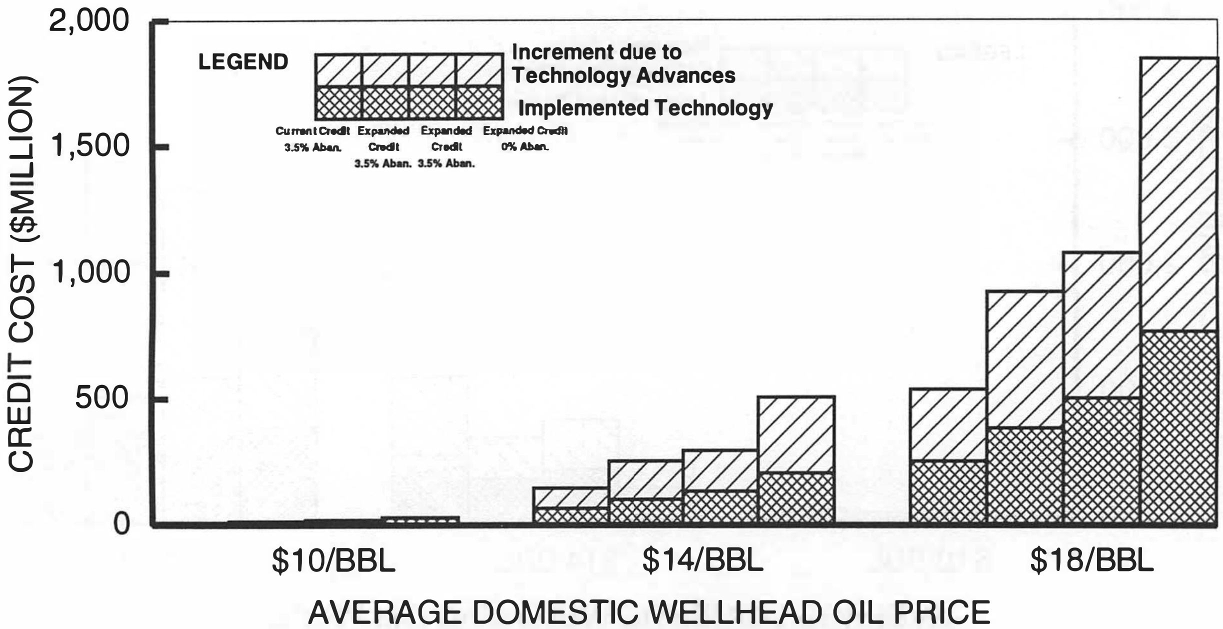

Figure 5-55. Impacts on Credit Cost of Extending EOR Credit to AMT Taxpayers (Cumulative Over 25 Years).

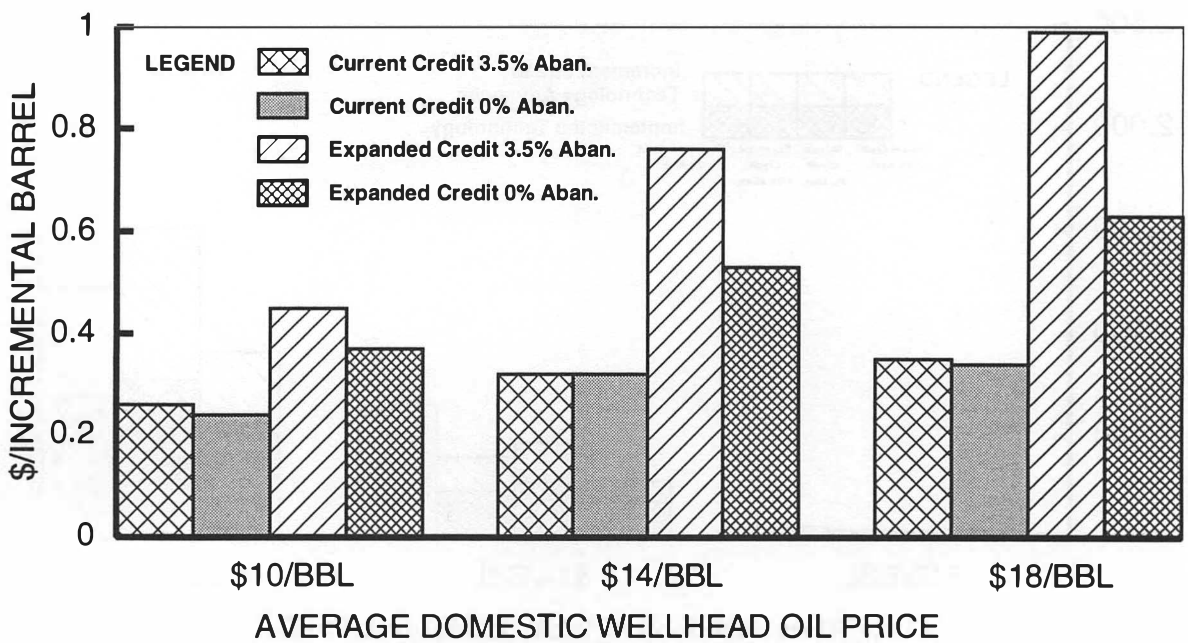

Figure 5-56. Impacts on Cost per Incremental Barrel of Extending EOR Credit to AMT Taxpayers (Cumulative Over 25 Years).

TABLE 5-50

POTENTIAL IMPACTS OF EXTENDING THE EOR TAX CREDIT TO INFILL DRILLING/WATERFLOOD PROJECTS
(Constant $10.00 per Barrel Oil Price)

	10 Year				25 Year			
	Base	**Increment**			**Base**	**Increment**		
Credit:	**Current**	**Current**	**Expanded**	**Expanded**	**Current**	**Current**	**Expanded**	**Expanded**
Abandonment Rate:	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**
Cumulative Reserves Developed (MMBOE):	535	162	101	294	984	483	186	760
Cumulative Incremental Oil Produced (MMBOE):	174	46	33	87	804	347	152	565
Cumulative Jobs Added (Labor-Years):	27,869	7,307	5,258	13,944	128,624	55,581	24,266	90,332
Cumulative State/Local Taxes ($Millions):	75	18	16	39	450	190	72	292
Cumulative Imports Avoided ($Millions):	1,960	514	370	981	9,045	3,909	1,706	6,352
Cumulative GDP Added ($Millions):	3,097	812	584	1,549	14,292	6,176	2,696	10,037
Cumulative Credit Cost ($Millions):	0.00	0.00	298.74	389.26	0.00	0.00	549.11	818.55
Credit Cost ($/Incremental BOE):	0.00	0.00	2.96	1.32	0.00	0.00	2.96	1.08

TABLE 5-51

POTENTIAL IMPACTS OF EXTENDING THE EOR TAX CREDIT TO INFILL DRILLING/WATERFLOOD PROJECTS (Constant $14.00 per Barrel Oil Price)

	10 Year				25 Year			
	Base	Increment			Base	Increment		
Credit:	**Current**	**Current**	**Expanded**	**Expanded**	**Current**	**Current**	**Expanded**	**Expanded**
Abandonment Rate:	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**
Cumulative Reserves Developed (MMBOE):	678	205	70	296	1,246	611	128	802
Cumulative Incremental Oil Produced (MMBOE):	221	58	23	86	1,018	440	105	590
Cumulative Jobs Added (Labor-Years):	47,840	12,544	4,917	18,750	220,794	95,411	22,694	127,912
Cumulative State/Local Taxes ($Millions):	128	32	22	59	750	317	93	450
Cumulative Imports Avoided ($Millions):	3,364	882	346	1,319	15,527	6,710	1,596	8,995
Cumulative GDP Added ($Millions):	5,316	1,394	546	2,083	24,533	10,601	2,522	14,212
Cumulative Credit Cost ($Millions):	0.00	0.00	489.90	638.35	0.00	0.00	900.49	1,342.35
Credit Cost ($/Incremental BOE):	0.00	0.00	7.03	2.15	0.00	0.00	7.03	1.67

TABLE 5-52

POTENTIAL IMPACTS OF EXTENDING THE EOR TAX CREDIT TO INFILL DRILLING/WATERFLOOD PROJECTS
(Constant $18.00 per Barrel Oil Price)

	10 Year				25 Year			
	Base	Increment			Base	Increment		
Credit:	**Current**	**Current**	**Expanded**	**Expanded**	**Current**	**Current**	**Expanded**	**Expanded**
Abandonment Rate:	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**	**3.50%**	**0.00%**
Cumulative Reserves Developed (MMBOE):	785	238	28	275	1,443	708	52	786
Cumulative Incremental Oil Produced (MMBOE):	255	67	9	79	1,179	509	43	571
Cumulative Jobs Added (Labor-Years):	69,924	18,335	2,536	21,536	322,721	139,456	11,702	156,214
Cumulative State/Local Taxes ($Millions):	197	49	17	71	1,135	480	68	578
Cumulative Imports Avoided ($Millions):	4,917	1,289	178	1,514	22,695	9,807	823	10,986
Cumulative GDP Added ($Millions):	7,769	2,037	282	2,393	35,858	15,495	1,300	17,357
Cumulative Credit Cost ($Millions):	0.00	0.00	638.28	831.68	0.00	0.00	1,173.22	1,748.90
Credit Cost ($/Incremental BOE):	0.00	0.00	22.42	3.02	0.00	0.00	22.42	2.22

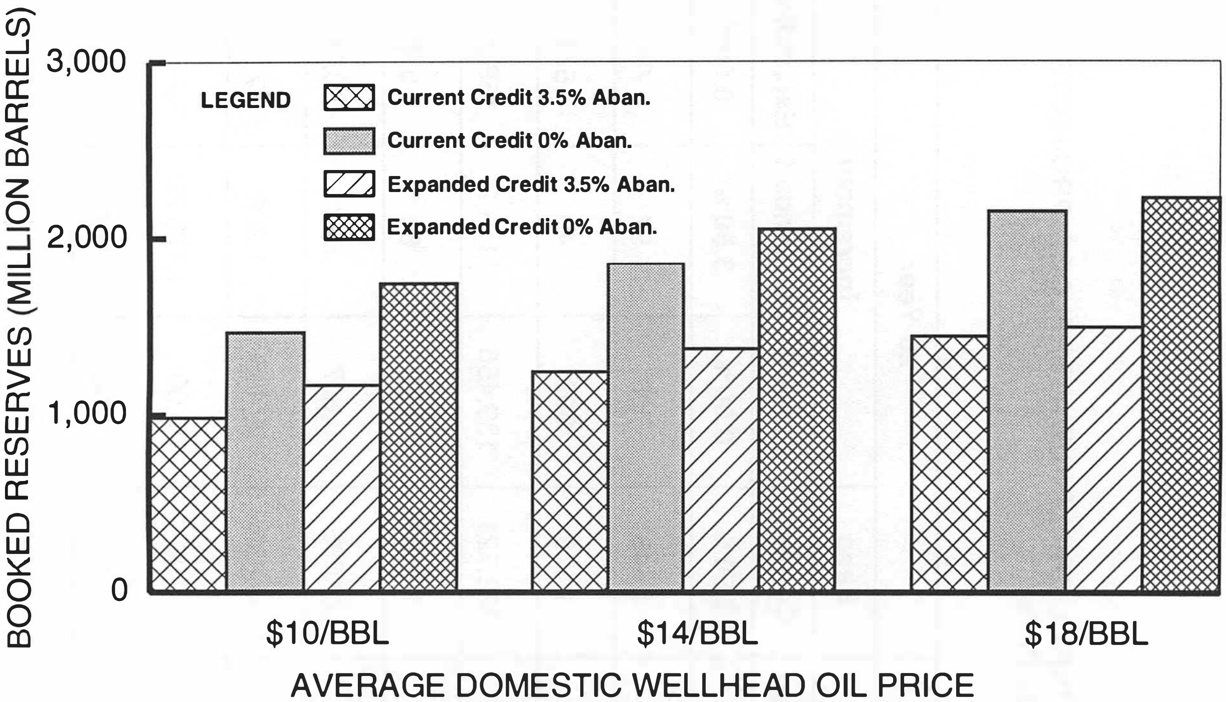

Figure 5-57. Impacts on Booked Reserves of Extending EOR Credit to Infill Drilling/Waterflooding (Cumulative Over 25 Years).

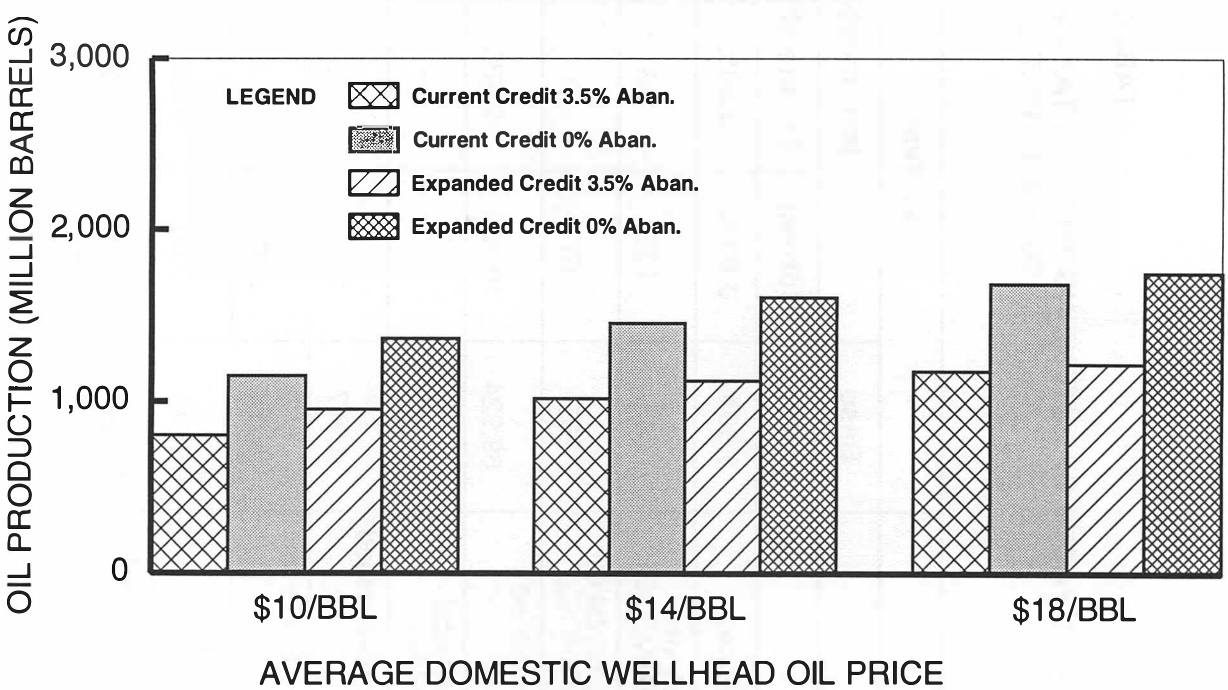

Figure 5-58. Impacts on Oil Production of Extending EOR Credit to Infill Drilling/Waterflooding (Cumulative Over 25 Years).

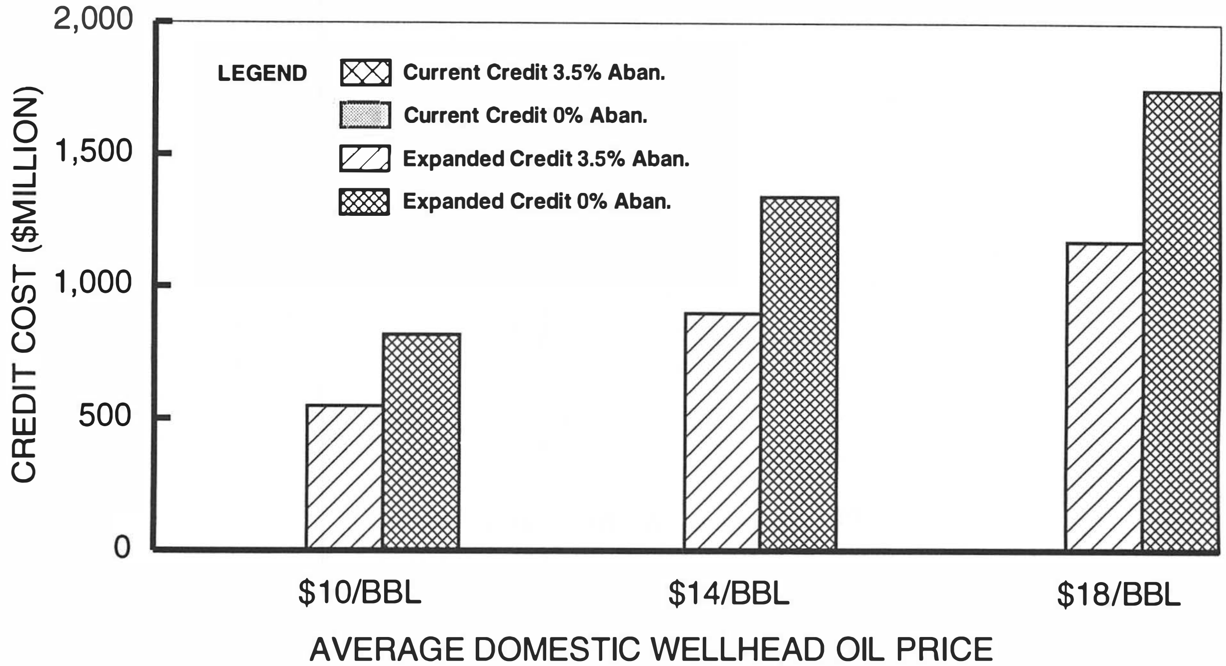

Figure 5-59. Impacts on Credit Cost of Extending EOR Credit to Infill Drilling/Waterflooding (Cumulative Over 25 Years).

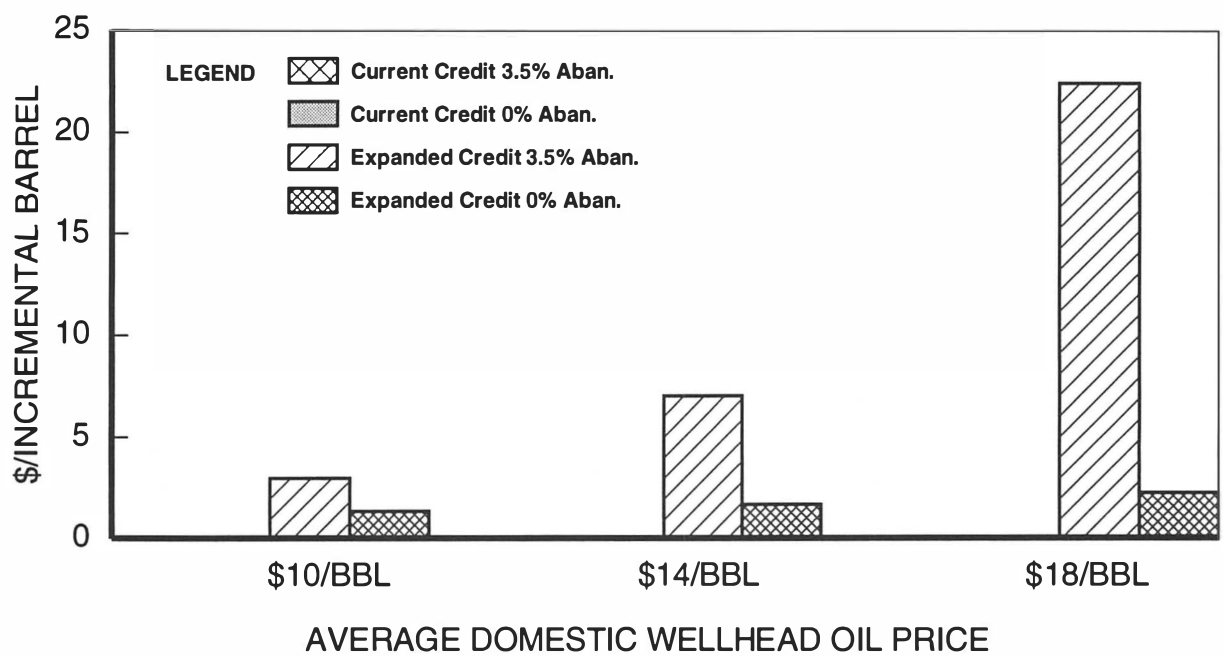

Figure 5-60. Impacts on Cost per Incremental Barrel of Extending EOR Credit to Infill Drilling/Waterflooding (Cumulative Over 25 Years).

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Section E

Inactive Well Incentive Analysis

TABLE 5-53

ESTIMATED ORPHANED AND IDLE WELLS IN THE UNITED STATES

	Oil	Gas	Injection	Total
Alabama	231 (13%)	1,490 (82%)	95 (5%)	1,817
Alaska	15 (55%)	11 (41%)	1 (4%)	27
Arizona	14 (82%)	2 (12%)	1 (6%)	17
Arkansas	NO DATA			
California	29,191 (80%)	850 (2%)	6,451 (18%)	36,492
Colorado	1,224 (40%)	1,650 (54%)	188 (6%)	3,062
Florida	99 (89%)	12 (11%)	0	111
Illinois	4,374 (86%)	N/A	727 (14%)	5,101
Indiana*	887	0	109	996
Kansas*	11,390	3,027	1,782	16,200
Kentucky	15,500 (83%)	3,200 (17%)	N/A	18,700
Louisiana*	11,793	6,634	2,277	20,705
Michigan	1,010 (77%)	299 (23%)	N/A	1,309
Mississippi*	1,921	542	304	2,768
Missouri	134 (100%)	0	0	134
Montana	2,800 (68%)	1,300 (32%)	N/A	4,100
Nebraska	504 (65%)	39 (5%)	229 (30%)	772
Nevada	15 (100%)	0	0	15
New Mexico	3,025 (68%)	1,250 (28%)	150 (3%)	4,425
New York*	1,326	1,909	400	3,636
North Dakota	714 (85%)	28 (3%)	100 (12%)	842
Ohio*	872	1,023	234	2,130
Oklahoma	1,957 (73%)	215 (8%)	500 (19%)	2,672
Pennsylvania	299 (57%)	218 (42%)	8 (1%)	525
South Dakota	13 (57%)	218 (42%)	8 (1%)	525
Tennessee	N/A	N/A	9 (100%)	9
Texas*	36,552	9,138	5,646	51,336
Utah	613	250	106	970
Virginia*	8	275	35	319
West Virginia*	6,232	14,543	2,567	23,343
Wyoming	9,404	1,488	1,482	12,374
TOTAL	**142,118**	**49,403**	**23,401**	**214,894**

* Breakdown between oil and gas wells not reported by state; distribution based on the number of producing oil and gas wells in the state. Injection well estimates based on fraction in those states reporting breakdown.

Source: Interstate Oil and Gas Compact Commission, *A Study of Idle Oil and Gas Wells in the United States*, December 1992.

TABLE 5-54

ESTIMATED BENEFITS FROM THE INACTIVE WELL INCENTIVE ASSUMING SAME TYPICAL WELL, REDUCED VALUE OF THE INCENTIVE

Incremental Costs and Benefits of the Inactive Well Incentive	**5 Year**			**10 Year**		
	$10/bbl	**$14/bbl**	**$18/bbl**	**$10/bbl**	**$14/bbl**	**$18/bbl**
Incremental Production (MMBOE)	180	180	180	263	297	306
Incremental Federal Revenues ($ Millions)	-137	90	319	-320	-53	317
Corporate Income	-227	-39	148	-453	-269	22
Personal Income	40	56	72	59	93	123
Royalty Holder	50	74	100	74	124	171
Incremental State and Local Revenues ($ Millions)	163	271	379	223	421	615
Production	184	258	331	273	431	569
Corporate Income	-35	-6	23	-70	-42	3
Personal Income	13	19	24	20	31	41
Royalty Holder	8	11	15	12	19	27
Reduction in Trade Deficit ($ Millions)	2,025	2,746	3,466	2,957	4,528	5,885
Incremental Employment (Labor-Years)						
Direct	7,363	9,718	12,072	9,566	14,879	19,598
Total	20,752	27,375	33,997	26,929	41,880	55,162

TABLE 5-55

ESTIMATED BENEFITS FROM THE INACTIVE WELL INCENTIVE ASSUMING A LOWER RATE TYPICAL WELL, REDUCED VALUE OF THE INCENTIVE

Incremental Costs and Benefits of the Inactive Well Incentive	**5 Year**			**10 Year**		
	$10/bbl	**$14/bbl**	**$18/bbl**	**$10/bbl**	**$14/bbl**	**$18/bbl**
Incremental Production (MMBOE)	48	53	53	53	102	107
Incremental Federal Revenues ($ Millions)	-106	-56	8	-120	-152	-35
Corporate Income	-128	-93	-40	-145	-222	-131
Personal Income	10	16	20	11	30	40
Royalty Holder	13	21	28	14	40	56
Incremental State and Local Revenues ($ Millions)	30	63	93	33	114	178
Production	46	72	92	51	138	185
Corporate Income	-20	-14	-6	-22	-34	-20
Personal Income	3	5	7	4	10	13
Royalty Holder	2	3	4	2	6	9
Reduction in Trade Deficit ($ Millions)	540	817	1,031	598	1,559	2,050
Incremental Employment (Labor-Years)						
Direct	2,573	3,772	4,435	2,645	5,456	7,361
Total	7,270	10,652	12,518	7,467	15,375	20,746

Chapter Six

State Incentives

OVERVIEW

Over the years, state legislators and governors have acknowledged the importance of commercial activities to their state and local economies. In return, the oil and gas industry has enjoyed economic support granted by state officials who understand how these benefits promote local commerce and economic growth. There is a long history of effective regulation of the oil and natural gas industry by state governments. Oil and gas revenues have been important sources of general revenue collections flowing into state coffers. Importantly, in many oil producing regions of our nation the revenues derived from state royalties on oil and gas properties have provided significant funding for educational systems.

The cooperation among oil and gas producers and state officials has been recognized as an important strength in helping local economies prosper and grow. This tradition of cooperation continues today. To preserve the fragile nature of the oil and gas industry in today's environment of low oil prices, many state governments have instituted programs to preserve domestic oil and gas fields. These programs typically take on one of two forms. The first and most widely used are tax reduction schemes based on production levels. Second, several states have well reactivation and investment incentive programs.

The following represents information collected from a review of the activities and programs in 29 producing states. These 29 states claim 509,292 oil wells within their borders, representing 87 percent of the 586,058 total wells in the lower-48 states. Many of the states have varying definitions of marginal wells; therefore, in the following discussion, the term "marginal" applies generically to marginal wells and not a specific definition. Over 72 percent or 21 of these states have recognized the need and value of taking actions to help preserve marginal oil and gas properties and the important domestic reserves yet to be produced by granting relief, in one form or another, from state production taxes. Sixteen states have enacted some form of tax relief for marginal wells and seven of the sixteen states have completely eliminated state taxes on at least a portion of marginal well production. The sixteen states protecting their 149,000 marginal wells represent approximately 30 percent of the wells producing 15 barrels of oil equivalent per day (BOE/D) or less in the United States. The nation's remaining 329,000 marginal wells, producing 15 BOE/D or less, do not receive any special tax treatment.

The most common method of providing continued economic viability for marginal wells into the future is through a reduction in the state production taxes. However, some of the largest producing states (and those most dependent on the tax revenue) have not enacted any special tax relief for marginal oil or gas production. Another method adopted to help stimulate production on marginal properties is providing some economic incentive to producers to undertake enhanced oil recovery (EOR) projects. Eleven states have some EOR incentives that can apply to nearly 368,000 oil wells, or 63 percent of all the oil wells in the United States.

Other tax incentives currently provided to industry are designed to encourage new drilling, new field discoveries, horizontal drilling, and 3-D seismic exploration. In fact, several states believe that there are important local benefits to be gained by adopting aggressive tax treatment aimed at returning shut-in or idle wells to a producing status.

At this time, only eight of the states surveyed have not enacted some form of tax relief to the oil and gas industry. These eight states have 77,032, or 13 percent, of the oil wells in production. Generally, these states would be classified as low volume producers, although three states—West Virginia, Kentucky, and Ohio—represent 68,430 of the 77,032 wells in this group.

Certainly every incentive passed provides an economic boost for some part of the ailing oil and gas industry. It is important that state and federal government recognize the global economic competition for oil and gas investment capital. Incentives attract investors by making the industry more competitive in the state. However, the United States seems to be falling behind in the global race for exploration and development capital when compared to other countries. For example, Alberta, Canada, provides a variable tax scheme that fluctuates with oil price, oil production levels, and other factors such as water produced.

MARGINAL WELL INCENTIVE PROGRAMS

To date, state activities to protect marginal wells have focused on reductions in the production taxes collected from these wells (see Table 6-1). Sixteen of the states surveyed have taken some steps to ensure the longevity of their marginal wells.

While the most prevalent action consists of a reduction in the tax rate, seven states have taken some action to eliminate the tax burden for various combinations of their marginal wells. Three states with very marginal production (New York, Pennsylvania, and Illinois) do not collect production taxes. Kansas is the largest producing state to eliminate production taxes on some wells. Kansas has eliminated taxes on oil wells making two barrels a day or less, and on oil wells more than 2,000 feet deep that make less than six barrels a day. In another example, in Utah, oil wells producing less than 20 barrels per day and gas wells making less than 60 thousand cubic feet a day are exempt from production taxes. Table 6-1 provides additional detail for Kansas and the remaining two states, Colorado and Montana.

The remaining nine of the sixteen states have also taken significant steps to reduce the oil and gas industry's tax burden. The tax reductions range from 20 to 75 percent in these states, but it is difficult to evaluate the impact and compare the different state tax regimes, because of the wide variations in the production taxing schemes. Louisiana, for example, collects 12.5 percent of the gross revenue from many wells, and 6.25 percent from oil wells lifting between 10 and 25 barrels a day if the wells produce more than 50 percent water. Louisiana recently suspended the 3.125 percent tax on wells producing less than 10 barrels of oil per day when the price of oil falls below $20 per barrel.

Table 6-1

State Oil and Gas Tax Structures and Incentives

State	Corporate Income Tax	Production Taxes	Special Treatment for Marginal and Stripper Production	Special Treatment for Secondary/Tertiary Recovery Projects	Special Treatment for New Development Workovers, Idle Wells, etc.
AL	5.0% of taxable income with 27.5% depletion allowance.	Oil and Gas--If drilled before 7/1/88: Onshore--8.0%, offshore--6.0% of revenue, "privilege tax." If drilled after 7/1/88: Onshore--6.0%, offshore--6.0% of revenue, "privilege tax." The above, plus 2.0% of revenue, "production tax."	6.0% of revenue on wells <25 BO/D or 200 MCF production.	Incremental production from approved secondary or tertiary projects involving injection of fluids is taxed at 6.0% (4.0% privilege, 2.0% production).	Offshore production from greater than 18,000 feet below sea level taxed at 6.0% (4.0% privilege and 2.0% production). A proposal by the Alabama Task Force on exploration and production supports a 5-year severance tax exemption for "new discoveries," and a 50% exemption for development wells drilled in connection with the discovery.
AK	9.4%	Oil--12.25% of market value for the first 5 years, 15.0% thereafter or $0.80 per barrel, whichever is greater. Gas--10.0% of market value or $0.064 per MCF, whichever is greater. The result is multiplied by an oil economic limit factor to adjust for high cost or low production wells. + $0.00125 per barrel conservation tax + 20.0% of tangible investment.	The economic limit factor takes into account production volumes from the lease in question and adjusts the effective tax rate accordingly. Wells with low production rates receive significant tax reductions. However, most low production wells in Alaska would not be considered stripper wells.	None	None
AR	1.0% to 6.0% incremental rate on net income under $100,000. Flat rate of 6.5% over $100,000.	Oil--5.0% of revenue, Gas--$0.005 per MCF (gas); + $0.045 per barrel + $0.025 per barrel conservation tax + $300 per pattern drilling tax.	4.0% of revenue if <10 BO/D during calendar month.	None	Production from discovery wells is 75% exempt from severance taxes for 5 years after the date of certification.
CA	9.6%	$0.026109 per barrel oil or 10 MCF gas conservation tax + 2.7% of revenue local tax.	None	None	Gas used in pressure-maintenance or other producing operations is tax exempt.
CO	5.0%	Oil and Gas--2.0% on first $25,000, 3.0% on next $75,000, 4.0% on next $200,000, and 5.0% on greater than $300,000. 0.0015% of value conservation tax.	Wells <10 BO/D exempt.	Value of oil and gas leaseholds and lands employing secondary or tertiary recovery assess at 75% of selling price of oil and gas sold therefrom.	None
FL	6.0%	Oil--8.0% of revenue, Gas--$0.128 per MCF (effective 7/1/94).	5.0% of revenue for "small wells" (<100 BO/D).	Tertiary oil production taxed at 5.0% of revenue.	Oil and gas produced and used on-site is exempt.
IL	6.5%	None	None	None	None
IN	7.0%	1.0% of revenue or oil at $0.24 per barrel, gas at $0.03 per MCF, whichever is greater.	None	None	None
KS	6.75%	Oil and Gas--8.0% of revenue + $0.0225 per barrel conservation tax.	Oil - wells <2 BO/D exempt; <6 BO/D at depths >2,000 ft. exempt; Gas - wells with average daily production <$81 per day exempt.	Tertiary production is exempt from severance tax. Wells with completion depth of less than 2,000 feet and production of less than 3 B/D by waterflood are exempt.	Production from discoveries in new pools exempt for a period of 24 months.
KY	6.0%	Oil and Gas--4.5% of revenue.	None	None	None

LA	4.0% 1st 25K, 5.0% 2nd 25K, 6.0% next 50K, 7.0% next 100K, 8.0% >200K.	Oil--12.5% of revenue, Gas--$0.03 per MCF (oil well) or $0.075 per MCF (gas well).	Oil--6.25% if <25 BO/D/50% saltwater, 3.12% if <10 BO/D. Gas--$0.013/MCF if <250 MCF daily. A proposal before the state legislature would exempt wells producing <10 BO/D from severance taxes during any month during which oil prices average less than $20.	None	A proposal before the state legislature would add the following incentives: Production from wells that had 30 days or fewer of production over the last 2 years or that have been returned to service after 2 years of inactivity would be exempt from state severance taxes for 5 years. Any horizontally drilled well or any well drilled to a depth of >15,000 feet would be granted a 24-month severance tax reprieve beginning on the effective date of the legislation.
MI	2.35%	Oil--6.6% of revenue, Gas--5.0% of revenue + 1.0% of revenue privilege tax.	4.0% of revenue if production <5 BO/D.	None	None
MS	3.0% 1st 5K, 4.0% 2nd 5K, 5.0% >10K.	Oil and Gas--6.0% of revenue + $0.035 per barrel or $0.004 per MCF conservation tax.	None	State approved secondary or tertiary production taxed at 3.0%.	Oil or gas produced from a discovery well for which drilling commenced 4/1/94 to 6/30/99 is exempt from taxation for 5 years. Oil or gas produced from a 2-year inactive well is exempt from severance taxes for 3 years. Oil or gas produced from development wells associated with a new pool discovery well taxed at 3.0% for 3 years. Oil or gas production from a well drilled using 3-D seismic technology, taxed at 3.0% for 5 years.
MT	6.75%	Oil--5.0% of revenue, Gas--2.65% of revenue, "state severance tax," + 0.7% "privilege and indemnity tax." Oil--7.0% of revenue, Gas--12.0% of revenue, "local net proceeds tax." Oil--8.4% of revenue, Gas--15.25% of revenue, "local severance tax."	State severance tax: Oil--none; Gas--<60 MCF, first 30 MCF exempt, rest taxed at 1.59% of revenue. Local severance tax: Oil--<10 BO/D taxed at 5.0%; Gas--<60 MCF per day taxed at 10%.	State severance tax: Incremental secondary production taxed at 3.0%; incremental tertiary production taxed at 2.0%. Local net proceeds tax: Incremental secondary production taxed at 5.0%; incremental tertiary production taxed at 3.3%. Local severance tax: Incremental secondary production taxed at 5.0%; incremental tertiary production taxed at 3.3%. In proposals before the state legislature, local severance taxes on incremental production from waterfloods would be reduced by 5.0%.	Horizontal wells are exempt from net proceeds tax for first 18 months. Crude oil or gas used by operator in connection with operations is tax exempt. A proposed rule before the state legislature would reduce state severance taxes on new production to 3.3%, and local severance taxes on new production to 2.0%.
NE	6.65%	3.0% of revenue (oil and gas) + 0.1% of revenue conservation tax.	2% of revenue if production <10 BO/D.	None	Operators may qualify for tax reductions based on capital investments.
NV		Oil--$0.050 per barrel, Gas--$0.050 per 50 MCF.	None	None	None
NM	4.8% 1st 500K, 6.4% 2nd 500K, 7.6% >1 million.	Oil and Gas--3.75% of revenue, severance tax. + 3.15% (oil) or 4.0% (gas) of revenue privilege tax + 0.18% of revenue conservation tax + 1.125% of revenue local tax.	None	State approved secondary or tertiary production taxed at 1.88%.	None
NY		None. However, oil and gas properties are taxed at the local level, and production is a factor in assessing the value of a property.	None	None	None

ND	7.5%	Oil--11.5% of revenue, Gas--$0.04 per MCF.	5.0% of revenue if qualify as stripper well: (1) <6,000 feet and <10 B/D. (2) 6,000 to 10,000 feet and <15 B/D. (3) >10,000 feet and <20 B/D.	Production from qualifying secondary and tertiary recovery projects is taxed at 9.0%. Incremental production from secondary recovery operations taxed at 5.0% for 5 years, and incremental production from tertiary recovery operations taxed at 5.0% for 10 years. Thereafter, taxed at 9.0%.	Production from new wells completed after 4/27/87 taxed at 5.0% for 15 months and 9.0% thereafter. Oil produced from a well that is worked over is taxed at 5.0% for one year and 9.0% thereafter.
OH		Oil--$0.10 per barrel, Gas--$0.25 per MCF.	None	None	None
OK	6.0%	Oil and Gas--7% of revenue "gross production tax" + 0.095% "petroleum excise tax"	None	Incremental production from qualified secondary or tertiary recovery projects is tax exempt until payback is achieved.	New production for 2-year abandoned wells is taxed at 1% "gross production tax," for a period of 28 months. Production must commence between 7/1/94 and 7/1/97. Incremental production attributable to workovers, recompletions, or other production enhancement projects is taxed at 1% "gross production tax" for a period of 28 months. Production enhancement must commence between 7/1/94 and 7/1/97. Production form deep wells (>15,000 feet) spudded between 7/1/94 and 7/1/97 are taxed at 1% "gross production tax" for 28 months or until project payback is achieved, whichever comes first. Incremental production from drilling horizontal wells is exempt from the gross production tax until project payback is achieved. Qualification under this program expires 7/1/94.
PA	10.5%	None	None necessary	None	None
SD		Oil and Gas--4.5% of revenue + conservation tax of $0.024 of revenue.	None	None	None
TN		3.0% of revenue.	None	None	None
TX	None	Oil--the greater of 4.6% of revenue or $0.046 per barrel + $0.00188 per barrel conservation tax. Gas--7.5% of revenue + $0.00003 per MCF conservation tax.	None	State approved secondary and tertiary recovery projects taxed at 2.3%. Production of high-cost gas, including gas from co-production projects, is exempt from severance taxes until 2001.	Oil and gas produced from 3-year inactive wells and certified before 8/31/95 is exempt from severance taxes for a period of 10 years. $10,000 tax credit per discovery well spudded during 1994 if # spudded statewide is greater than 521 but less than 721. $25,000 tax credit per discovery well if # spudded exceeds 721. If over 842 discoveries are made, each discoverer will receive an additional $25,000 for each well drilled into the discovery reservoir, regardless of who drills it.
UT	5.0%	Oil--3.0% up to first $13 per barrel, 5.0% thereafter, Gas--3.0% up to first $1.50 per MCF, 5.0% thereafter of revenue over $50,000 (exempt if <20 BO/D) + 0.2% of revenue conservation tax.	Wells producing <20 BO/D or 60 MCF gas are exempt.	None	The first $50,000 annually in gross value of each well or wells is exempt from severance taxes. The first 12 months of production from wildcat wells is exempt. The first 6 months of production from development wells is exempt. For workover/completion projects, operators can receive a tax credit equal to 20% of expenses for enhancing production.

VA		Oil–0.05% of revenue, Gas–up to 2.0% of revenue; + 1.0% of revenue road tax.	None	None	None
WV	7.0%	Oil and gas--5.0% of revenue.	None	None	None
WY	None	Oil and gas–6.0% of revenue + 0.06% of revenue conservation tax.	4.0% of revenue for production <10 BO/D.	Tertiary production taxed at 4.0% for a period of 5 years. In the case of CO_2 injection projects, severance taxes paid on the CO_2 gas are deducted from taxable value of the produced oil.	New well workover and recompletion production taxed at 4.0% for a period of 2 years. Wildcat well production taxed at 2.0% for a period of 4 years.

Alberta, Canada, Oil and Gas Tax Structures and Incentives

Corporate Income Tax	Production Taxes	Special Treatment for Marginal and Stripper Production	Special Treatment for Secondary/Tertiary Recovery Projects	Special Treatment for New Development Workovers, Idle Wells, etc.
15.5% of taxable income.	Crown royalty and free hold taxes using various formulas that are price, production, quality, and vintage of the production.	Low productivity wells pay 5% or the oil royalty formula, whichever is less.	Approved costs deducted from Crown royalty.	As permanent policy, wildcats and deeper pool test wells have 12 month royalty holiday or $1,000,000 (whichever first). Deep gas receives a scaled benefit not to exceed $3.6 million. Horizontal wells receive 24 month royalty adjustment tied to vertical wells replaced. Existing wells converted to horizontal receive benefits tied to production volume.

Sources:

1. Corporate income tax figures were taken from "Production = Jobs & Revenues" (CLEER 1993), and Table II-1 from the IOGCC Project on Advanced Oil Recovery and the states.
2. Production tax figures were taken from the IOGCC "Summary of State Statutes and Regulations for Oil and Gas Production," or from CLEER 1993, and verified with phone calls to relevant state agencies.
3. The tax incentives and proposals were gleaned from the IOGCC summary, phone correspondence, and the other sources provided.
4. Canadian data from "Production = Jobs & Revenues" prepared for Center for Legislative Energy and Environmental Research, December 1993.
5. *Oil and Gas Fiscal Regimes of the Western Canadian Provinces and Territories*, Alberta Energy, Draft Report 1994.

Many states have taken action to exempt marginal gas wells from taxes, reflecting local concern for the viability of the domestic gas industry and the value placed on sustaining domestic production for the benefit of local economic needs and energy security. It appears these measures were enacted in response to the depressed prices experienced for gas until mid-1992, and to address state concerns about the loss of marginal gas production and reserves.

There is no standard state tax regime for the husbanding or guardianship of oil and gas properties. While the desire to protect production from marginal wells in most states, has existed for some time, the consequence of implementing such policies (an apparent loss of some tax revenue at the state level) has made it difficult for states to implement programs to protect marginal production. This dilemma manifests itself as follows: states with the most to gain economically from the protection of the marginal wells are also the most dependent on industry tax revenues.

At this time, thirteen producing states (45 percent) have not enacted measures to protect marginal wells. Although several of these thirteen states have enacted EOR, drilling, well reactivation, etc., incentives, no specific action aimed at protecting marginal production has been taken. This group of states includes Oklahoma, Texas, New Mexico, Ohio, West Virginia, Kentucky, and California—all with large production bases providing a significant percentage of state revenues. These seven states represent 334,902 marginal oil wells (wells producing 15 BOE/D or less) or 68 percent of the marginal oil wells in the United States.

SECONDARY AND ENHANCED RECOVERY INCENTIVES

Eleven of the 29 states surveyed have adopted measures to encourage EOR projects. The states providing preferential treatment of EOR projects represent 63 percent of the oil wells in this country. These incentives are different from the marginal well incentives in that they encourage new capital investment activity and are viewed as a means to generate incremental oil production which contributes a net positive cash flow to the state treasury. Some of the largest producing states—including Oklahoma and Texas have adopted this kind of tax incentive.

The most common approach to the special tax treatment involves a reduction in the taxes collected, principally limited to the incremental oil attributable to the project. Generally, the incentives are designed to encourage initiation of EOR projects where substantial capital investment is required. Only three states have adopted elimination of taxes in some form. Kansas eliminates taxes on EOR oil, and allows a 100 percent exemption for wells producing less than 3 barrels of oil per day in water flood projects at depths less than 2,000 feet. Oklahoma's recent law eliminates taxes on incremental production until payback of project costs is achieved. Texas provides a 50 percent severance tax reduction on all oil produced from new EOR projects and a 50 percent tax reduction is allowed on the incremental oil produced from reworked and expanded EOR projects. Some states, such as California, Montana, and Florida, provide tax exemptions for hydrocarbons used in pressure maintenance projects or consumed on-site in lease operations. Additional detail on EOR incentives in the remaining eight states is shown in Table 6-1.

OTHER STATE TAX INCENTIVES

Idle Well Incentives

It is in this area that the desire of the producing states to do something to assist the industry most clearly manifests itself. A review of the state incentives reflects a recognition of the global competition for oil and gas investment capital. This may be characterized as a fairly robust competition among the states to provide the most attractive investment environment. Texas was the first to adopt an incentive for the return of shut-in or inactive wells to beneficial production. In less than 10 months after the legislation was effective, similar proposals had already been adopted by five states and were being considered in others.

Several states (Texas, Kansas, Mississippi, Oklahoma, and Louisiana) have passed tax incentives to return shut-in wells to production. These generally grant a 100 percent severance tax break for a period of time that varies from three years to ten years. In order to qualify for the incentive, a well must be certified as inactive for a period that ranges from two to three years. Early results of the Texas program indicate that 1,852 wells were returned to productive status in 1993 and early 1994. Benefits of this program are estimated to provide a net annual economic gain of $692 million.

Drilling and Well Work Incentives

Six states are encouraging new exploration by passing incentives for new discoveries. This list includes Arkansas with a 75 percent five-year tax reduction on new discovery wells; Kansas with a 100 percent tax reduction for two years; a 100 percent five-year tax exemption in Mississippi; Utah exempts production from wildcat wells for the first year; Wyoming has a 66 percent tax reduction on wildcats for four years; and Texas has a variable tax credit depending on discoveries exceeding a threshold level of 520.

Several states have seen the benefits from encouraging in-fill or developmental drilling. Among these are Mississippi, which grants a three-year 50 percent tax reduction for development wells. North Dakota grants a 56 percent reduction for 15 months for all new wells, and a 22 percent reduction thereafter. Utah grants a 100 percent exemption for 6 months on development wells, as well as exempting the first $50,000 in the gross value from each well from taxes.

Other tax breaks are given for horizontally drilled wells, "workovers," and in one case (Mississippi) for wells drilled using 3-D seismic technology. Alabama allows a tax reduction for offshore wells deeper than 18,000 feet.

OTHER PROPOSALS

Three states have recently enacted or have additional incentive proposals pending before their legislatures. The states are Alabama, Oklahoma, and Montana. These packages focus on new drilling and new production incentives. Louisiana, however, is seeking to encourage the return of their inactive wells to production, and provides a two year exemption for horizontal wells or any well drilled to a depth greater than 15,000 feet. The wide-ranging Oklahoma proposal has all the above features, and includes a two-year exemption for "workovers" and re-completions.

The Texas Railroad Commission is developing a package (currently in draft) to introduce in their next legislative session in January of 1995, that proposes 100 percent tax exemptions for wells making less than three barrels a day. It will also include a no-cost incentive for marginal wells. This program would grant a one-barrel "chit" for each BOE of production from each new well drilled. That chit could then be used to exclude one BOE of production from any existing marginal well in the state.

Texas is also considering a program to reduce well abandonments by delaying them into the future to await technological changes and improved prices by acting as a holding company. Any sound well about to be plugged, could be given to the state to hold by paying 75 percent of the plugging cost into a fund. Wells could be purchased from the state by anyone owning a valid lease and paying the full plugging cost. The wells would be made available for research in the interim.

ALBERTA, CANADA

The province of Alberta has adopted virtually every type of incentive that has been discussed so far. In the global competition for economic resources, they clearly are one of the leaders. The production taxes and the Crown royalty vary according to the price and other factors, which provide relief to producers during periods of low oil prices and producers with marginal wells. They also factor in age of the wells and type of crude oil as part of the determination of taxes owed. Once a prospect is drilled, the taxes and crown royalties paid will fluctuate upward and downwards during high and low price cycles. In addition, wells receive reduced tax treatment when they become marginal.

CONCLUSIONS

The range of programs that have been enacted by the states to revitalize their oil and gas industry are as diverse as the states themselves. Of the 29 states surveyed, only Indiana, Nevada, New York, Ohio, Tennessee, Virginia, West Virginia, and South Dakota have yet to respond to the current industry plight with any incentives. At the same time, 72 percent of the states have taken positive action on behalf of the industry. Although this group includes most of the major producing states, several states such as California and Kentucky have substantially smaller programs than the more active states.

State legislatures and committees are deliberating tax incentives for marginal wells (or for other oil and gas activities). Many states have taken the lead in providing oil and gas well incentives to help maintain production and to protect the reserves they represent. Even in these times of growing budget priorities and pressure to increase revenues, many state governments have recognized the economic benefits of providing incentives for businesses, while perhaps forgoing some income in the short term. They have taken these actions because they recognize that a supply-side approach, will in the longer run, sustain and generate greater state revenues than would have been achievable in the absence of providing such incentives. States that have undertaken supply-side incentives are aware that they are dynamic in nature, and that there is a lag in the time it takes to realize increased revenues. The states are willing to propose programs that grow in return over time. By contrast, the federal government's budget process requires that any revenue decline (or incentive expense) must be offset with new income.

Importantly, some states are at the forefront of protecting domestic oil and gas exploration and production. It is critical that these wells be given the economic opportunity to maintain their beneficial production for our country. Indeed, some combination of benefits from every level of government may represent the maximum realization of what is possible for marginal production.

Chapter Seven

Regulatory Issues

OVERVIEW

Environmental and regulatory compliance costs impact the operation of marginal wells and can influence premature abandonment of marginal wells. A recent study in California concludes that environmental compliance has been estimated to range from 9 to 27 percent of lifting costs.[1]

There are three important messages in this chapter. The first is that regulatory requirements can have a profound impact on the economics of marginal wells. The requirements placed on domestic oil and gas operators with the intent of environmental protection and regulatory compliance are becoming increasingly complex and costly. Compliance costs are a large portion of total operating costs for marginal producers and are one of the items over which the operator has the least control.

The second message is that regulatory simplification can benefit the industry and government without compromising environmental protection. This can be accomplished by eliminating unnecessary duplicative or overlapping requirements, streamlining reporting, and similar measures that can generate cost savings for marginal producers.

Finally, the third and most important message is that the government's statutory and regulatory processes affecting the oil and gas industry must be reformed. There needs to be a fundamental re-examination of the manner in which statutory mandates are set and agencies approach and carry out their statutory requirements. At both the legislative and regulatory levels, there is a need to develop procedures and regulatory approaches that better consider the risks posed and the costs and benefits of environmental protection requirements. Balancing these costs and benefits more effectively will generate additional savings that benefit production from marginal wells without endangering the environment.

The exploration and production (E&P) community is increasingly concerned that the relationship between regulatory action, evaluation of benefits, and economic consequences is not adequately defined or a concern among regulators. Many regulatory actions discussed in this section lack this connection. Risk and benefits analyses should be applied to environmental controls imposing significant costs to the oil and gas industry. Consequences, both social and economic, should be quantified. Command and control type environmental regulations are generally less efficient than market incentive type controls; and their use should be minimized to the extent practical.

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[1] Foster Associates, *California Production Profile*, 1993.

There are a number of recent developments in the federal government that are obvious attempts to move in this direction. The recent effort of Environmental Protection Agency (EPA) Administrator Browner to develop a "holistic" approach to regulation, commonly referred to as the "Green Sectors" initiative is a starting point for regulatory reform in the environmental area. This effort is designed to bring together the various federal, state, and regulatory authorities and disciplines within each group (air, water, etc.) and integrate them into project teams to:

- Identify the need to change EPA priorities, generally driven by federal statute, to better target the most serious risks
- Enhance efforts to address high risks through near-term actions, such as multi-media enforcement efforts, outreach activities, and technical assistance
- Increase the cost-effectiveness of particular rulemakings through the use of innovative, multi-media approaches such as pollution prevention and economic incentive approaches
- Improve management efficiency by reducing duplication of effort with the EPA and other agencies, eliminating redundant regulatory requirements, and jointly collecting data
- Improve communication with outside groups by enhancing information on EPA activities available to interested groups and providing a forum for comprehensive discussion of particular problem areas
- Examine broad strategic questions and set the EPA's overall agenda for the problem area.

This initiative will serve as a beginning for serious discussion relating to regulatory flexibility, cost/benefit analysis, and risk assessment. However, the fundamental problem in the Green Sector program is the limits, established in law, on what can be achieved. For example, the effort most often cited as a success of this approach, the Amoco Yorktown study, was, in many ways, the opposite. Many, if not most, of the recommendations cannot be implemented due to the inflexible language in the law, i.e., mandated actions, no requirement for cost/benefit balancing, etc.

The efforts on the part of the Department of Energy to streamline overly complex regulatory processes, without compromising protection of the environment and the public interest are also steps in the right direction. In the Domestic Oil and Gas Initiative, the DOE outlined a plan, in response to the Vice President's National Performance Review, for improving coordination among regulatory agencies, eliminating redundant or unnecessary regulation, and avoiding duplication. Also, President Clinton's directive to establish an interagency team to examine the cost burdens that environmental regulation places on industry are additional attempts by the federal government to achieve balance in regulation.

The domestic oil and gas industry of today faces a wide range of federal, state, and local environmental regulations, which continue to evolve and become more stringent. The domestic industry overall has been in decline since 1985 as evidenced by the decline in active rig counts, production, loss of jobs, and diminished revenues. It is important to note that during this period of unpredictable conditions, the number of wells being abandoned has reached an alarming rate due to increasing costs and decreasing revenue. Many of these abandonments involved wells still capable of producing, some of which had considerable remaining reserves and resource access for current or future enhanced recovery technologies. However, as new legislative and regulatory requirements have been imposed and costs have increased the number of marginally economic wells, the production from those wells, and the future resource potential represented by those wells has been lost as producers can no longer afford to operate. Once a well is plugged, it is highly unlikely that a replacement well for EOR will be drilled at some future date in the same reservoir. The loss of such resources, and the production from them, has serious negative implications on our nation's energy security.

As mentioned in a recent Department of Energy study of the impacts of future environmental regulatory requirements on the industry:

> ...the future recovery of this resource presupposes that existing wells, producing reservoirs, and the existing infrastructure will be available, and that operators can retain the rights to produce oil from specific reservoirs. Once these reservoirs are abandoned, the resource associated with the reservoirs becomes essentially inaccessible to future development within the range of prices generally considered likely over the next 15 to 20 years, even with further improvements in recovery technologies.
>
> As well abandonments erode access to the remaining resource, fewer future recovery projects, particularly those utilizing advanced recovery technologies, will be economically justifiable. These projects will not recover sufficient oil to justify both the high start-up costs associated with advanced recovery technologies and the costs of redrilling new wells or re-entering old wells in abandoned reservoirs. As the costs of compliance with environmental regulations increase, the costs of operating marginally economic wells in producing reservoirs will increase, resulting in the accelerated abandonment of these wells. The impact of the increased and present compliance costs are consequently two-fold. First, reserves are lost because of the earlier abandonment of these wells. Second, access to the remaining resources associated with these abandoned wells will be lost, and hence, the potential future production from advanced recovery technologies in reservoirs containing these wells will be economically prohibitive.[2]

It is difficult to analyze and quantify the impact of current environmental regulatory requirements because many of the costs are not recorded as unique features of overall operating expenditures. These costs are a routine day-to-day part of operations. Quantifying regulatory cost is further aggravated by the fact that many regulations (particularly land use regulations) add an unrecognized

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[2] U.S. Department of Energy, *Potential Cumulative Impacts of Environmental Regulatory Initiatives on U.S. Crude Oil Exploration and Production*, 1990.

burden in lost opportunities. These costs are incurred where projects are abandoned or not pursued to completion because permit costs, delays, and requirements cause the project to become uneconomic. To the extent that this is true, the costs reported for this category of environmental regulations are lower than the actual lost opportunity costs to the industry. For a variety of reasons, therefore, it is extremely difficult to quantify the cost of current regulation on the E&P community.

REFORM NEEDED IN COMPLEX REGULATORY ENVIRONMENT

Federal, state, and local agencies manage dozens of regulatory requirements for the E&P industry. As mentioned previously in this chapter, regulatory reform could benefit the industry without compromising protection for the environment. A good example of regulatory overlap contributing to regulatory inefficiencies and high compliance costs was noted in a 1992 study commissioned by the U.S. DOE to evaluate the economic viability of small independent producers in Kern County, California.[3] This study indicated that over 40 different regulatory agencies have jurisdiction over some aspect of the petroleum industry in California. In addition, over 150 different statutes and regulations impact oil and gas operations; 32 percent of the 150 regulations are subject to multiple jurisdictional levels; and 33 percent of the 150 regulations overlap each other in terms of the activities that they regulate.

On the federal level alone, there are a vast number of laws and regulations that energy producers must deal with. It should be noted that many of these laws and regulations have additional state and local authorities claiming redundant enforcement responsibility. Tables 7-1 through 7-7 are general listings that demonstrate the multitude of agencies and issues with which the industry must concern itself.

These various agencies, regulating oil and gas activity, exercise jurisdiction under a complex set of laws and administrative regulations. Over time, the incremental development of such a regulatory system can result in overlapping regulatory jurisdictions and duplication. This problem is apparent with laws and regulations applying to the exploration and production of oil and gas.

This "patchwork" of agencies and different regulatory authorities leads to regulatory and enforcement overlaps and duplication as agencies move to implement the perceived extent of their authority. Resource management, water quality protection, waste management controls, air emissions controls, or employee safety, when broadly defined, are all interrelated. Consequently, one agency's authority is likely to lead directly into the regulations and authority of another agency as they expand their sphere to fully oversee operations within their primary responsibility.[4]

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[3] Jack Caufield, *Regulatory Economic Impact on Independent Oil Producers in Kern County, California*, Submitted to U.S. Department of Energy under Contract No. DA-AA01-92FE62540.A000, December 1992.

[4] Foster Associates, *California Production Profile*, 1993.

TABLE 7-1

PRODUCED WATER MANAGEMENT

Law or Regulation	Requires	Responsible Federal Agencies
Federal Safe Drinking Water Act	Injection Well Permits and Controls	U.S. EPA; (states with primacy are authorized to develop programs)
Clean Water Act	Surface Water Discharge Permits: • NPDES Permit & Discharge Waste Requirement • NPDES & Hazardous Substance Reporting • Liability Financial Assurance	U.S. EPA; USCG

TABLE 7-2

WASTE MANAGEMENT

Law or Regulation	Requires	Responsible Federal Agencies
Resource Conservation & Recovery Act (RCRA)	Solid Waste Management Controls: Hazardous Waste Management Controls: • H/W Treatment, Storage & Disposal Facility Permits & Controls (Permit-by-Rule) • Cleanup & Remedial Actions • H/W Manifests • H/W Transport Controls • H/W Source Reduction Audit & Plans • Biennial Reporting	U.S. EPA
Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)	• Cleanup & Remedial Actions • Liability Financial Assurance	U.S. EPA
Toxic Substances Control Act (TSCA)	PCB Waste Controls; Asbestos Waste Controls	U.S. EPA
Clean Water Act Dredge and Fill Regulations	Permits for dredge and fill disposal on waters of the United States	U.S. Army Corps of Engineers; U.S. EPA

TABLE 7-3

EMERGENCY PREPAREDNESS AND RESPONSE

Law or Regulation	Requires	Responsible Federal Agencies
Federal Comprehensive Environmental Response, Compensation and Liability Act (CERCLA)	Hazardous Substance Release Reporting; Cleanup & Remedial Actions; Liability Financial Assurance	U.S. EPA
Emergency Planning and Community Right-to-Know Act (EPCRA & SARA Title III)	Updating of Material Safety Data Sheets; Inventory Reporting; Release Reporting	U.S. EPA
Clean Water Act	Spill Prevention, Control, and Countermeasure Plan; Spill Reporting	U.S. EPA; USCG
U.S. Code; 49 CFR 394; Vehicle Code	Hazardous Material Transport; Accidental Spills of Waste or Hazardous Substance	Federal – D.O.T.
Resource Conservation and Recovery Act (RCRA)	Hazardous Waste Emergency Response and Reporting Plan	U.S. EPA
Code of Federal Regulations 40 CFR 3160 & 3162.4	Drilling Operations Permit, including safety, blowout & discharge prevention and containment; well abandonment	Bureau of Land Management
U.S. Hazardous Materials Regulations	Hazardous Material Transportation Manifesting; Emergency Response Procedures & Reporting	U.S. – D.O.T.

TABLE 7-4

AIR QUALITY CONTROL AND AIR TOXICS

Law or Regulation	Requires	Responsible Federal Agencies
Federal Clean Air Act	Air Pollution Control including air quality standards; emissions controls & reporting; permitting; new source review; prevention of significant deterioration. National Emissions Standards for Hazardous Air Pollutants; Maximum Achievable Control Technology for federal Hazardous Air Pollutants.	U.S. EPA

TABLE 7-5

LAND ACCESS AND LAND-USE PERMITS

Law or Regulation	Requires	Responsible Federal Agencies
NEPA	State Environmental Quality Regulations including the Environmental Impact Report to assess and mitigate environmental impacts; NEPA requires EIS on federal land	Lead agency is designated, usually a city or county planning agency; all other agencies with project oversight responsibility are involved in the EIS/EIR and the mitigation. On federal land, BLM or DOE is lead agency.
Endangered Species Act	Land-Use Permit for any activity on public land that could affect endangered species	U.S. Fish & Wildlife Service, Department of Fish & Game
Federal Land Policy and Management Act	Right-of-way permits for projects on public lands. Construction, operations & rehabilitation plans	BLM
Coastal Zone Management Act	Coastal Development Permits for facilities in the state coastal zone	State Lands and/or Coastal Commissions

TABLE 7-6

HAZARDOUS MATERIAL HANDLING AND STORAGE

Law or Regulation	Requires	Responsible Federal Agencies
Emergency Planning and Community Right-to-Know (EPCRA & SARA Title III)	Submittal of Material Safety Data Sheets, Chemical Inventory Reporting, Release Reporting	U.S. EPA
US Code; 49 CFR 394; Vehicle Code	Hazardous Material Transport Controls & Manifesting; Accidental Spills of Waste or Hazardous Substance	Federal – D.O.T.
Occupational Safety and Health Act (OSHA)	Personnel Health and Safety Standards including training and records keeping	Federal – OSHA
Federal Resource Conservation and Recovery Act (RCRA)	Regulations controlling the storage of hazardous substances including petroleum in underground storage tanks	U.S. EPA

TABLE 7-7

OIL SPILL PREVENTION AND RESPONSE

Law or Regulation	Requires	Responsible Federal Agencies
Federal Water Pollution Control Act, Federal Oil Pollution Act	Oil Spill Pollution Prevention, Preparedness, and Response	U.S. EPA; USCG; MMS
Clean Water Act	Spill Prevention, Control, and Countermeasure Plan; Spill Reporting	U.S. EPA; USCG
Code of Federal Regulations 40 CFR 3160	Blowout & discharge prevention and containment; well drilling, plugging and abandonment	BLM

A study of the effects of the regulatory environment on California producers recently found that "(a)n outgrowth of this regulatory scheme are the administrative costs associated with it. These costs are transaction costs necessary to collect information between regulators and producers. They are, by definition, unproductive in and of themselves. Inefficient administration can result when: (1) an agency loses sight of improving environmental quality and, instead, focuses on compliance for compliance sake; (2) there are multiple and overlapping jurisdictions; (3) agencies administer industries they only partially understand."[5]

SUMMARY OF OTHER PREVIOUS STUDIES

There have been a number of studies and papers commissioned by both industry and government examining the problems associated with regulatory compliance in California. Although regulatory standards in California are in many ways more stringent than in the rest of the nation, they do characterize the general problems faced by industry throughout the United States. Many of the major findings of these studies are summarized below.

In a follow-up study, Environ Corp. found that this multi-jurisdictional approach has significant potential for regulatory inefficiency, and that the impact of this inefficiency can be substantial for petroleum companies.[6] This study included oil producers, oil pipeline companies, oil refiners, and service stations. The study showed that multiple agencies at the federal, state, and local level have jurisdiction enforcing multiple federal, state, and local statutes and regulations. Environ found that jurisdiction rests with at least 38 agencies or groups responsible for enforcing at least 153 statutes and regulations.

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[5] Foster Associates, *California Production Profile*, 1993.

[6] Environ Corp., *Analysis of Environmental Regulatory Reporting Requirements for Petroleum Companies*, Prepared for Western States Petroleum Assn., April 1992.

The study found that this multi-jurisdictional approach to regulation almost inevitably provides a high potential for regulatory inefficiency and duplication, and consequently, higher costs. In many instances, there may be:

- More than one statute or regulation at different government levels, addressing the same activity
- Different reporting schedules and requirements placed on an operator by various levels of government for the same activity
- No requirement for the different jurisdictions to coordinate their efforts either in time or in the process by which the requirements are met.

The California Department of Conservation commissioned another study by Foster Associates to examine the costs of regulatory compliance on the petroleum industry in California.[7] The Foster study reported a number of major findings centered around the decline of the California petroleum industry and the high cost of regulatory compliance in the state. The study concluded that the California crude oil and gas exploration and production industry is in decline, which has major implications for:

- Decreasing federal, state, and local revenues from the industry
- Decreasing state employment and the concomitant loss of personal income tax
- Increasing vulnerability to foreign politics and events as imports increase, as well as increasing risk of oil spills.

This study concluded with a series of recommendations aimed at:

- Reducing the cost of regulatory compliance
- Reducing the cost of government regulatory programs
- Requiring a positive benefit/cost ratio for regulatory proposals.

All of these recommendations centered around the need for interagency coordination and streamlining in California, with specific state agencies being given the lead in different areas. Given that compliance with air pollution control regulations is such a large component of compliance costs in the state, Foster Associates specifically recommended that cost and benefit analyses be employed in this area.

The 1992 NPC report, *The Potential for Natural Gas in the United States*, also concluded that there are a number of significant environmental constraints to domestic gas development. These conclusions are consistent with difficulties experienced in maintaining marginal oil and gas production and development.

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[7] Foster Associates, et al, *Status of Petroleum Production Industry in California: The Cost of Regulatory Compliance*, submitted to the California Dept. of Conservation, August 16, 1993.

The environmental legislative and regulatory decision-making process in the United States, coupled with the industry's currently inward-focused culture, inhibits the full utilization of natural gas as an environmentally preferred fuel in the national energy mix. Legislation, regulation, and government policy does not adequately balance the direct upstream costs and benefits of regulations and does not include an analysis of the downstream benefits of natural gas.

The end result has been an increasing economic burden from environmental regulations relative to benefits, drilling moratoria, the cancellation or deferral of government lease sales, lack of access for exploration, production, and pipeline right-of-ways, and federal and state legislative and regulatory policies that inhibit the use of natural gas. All of these results impact oil-related operations similarly.

IMPACT OF POTENTIAL REGULATORY REFORM

Without focusing on specific initiatives to be reformed, it is still possible to demonstrate, with reasonable accuracy, the numbers of marginal wells and barrels of production which could be saved under various levels of incremental environmental compliance cost reductions. While this will only be an approximation, it will be of value in demonstrating the overall importance of reducing compliance costs.

Chapter Five provides an evaluation of the impact of oil price changes on marginal wells and production. This analysis is appropriate for estimating the impact of compliance costs under various oil price scenarios. For example, at a domestic oil price of $14 per barrel, if compliance costs accounted for an additional $1 to $2 per barrel of operating costs, Figures 5-8 and 5-9 indicate that the full cost impact of compliance could result in 4 to 7 percent more wells and 3 to 5 percent more production that is unable to meet lease operating expenses.

CONCLUSIONS

As a recent study of the regulatory environment for producers in California concluded, the industry believes that there is a lack of coordination and excessive duplication among the different jurisdictions regulating the same activity, waste streams, etc. Compliance and permitting processes are slow, excessive, and often with unnecessary record-keeping requirements. Permitting delays, along with project denials in some instances, also result in high costs due to lost opportunities. Legislation and regulations are often overly prescriptive with alternatives to achieving the defined levels of environmental protection constrained or not even considered. The validity of data on which regulations are based is often questionable or at least contestable.

There needs to be, therefore, a method of agreeing on data so that unnecessarily high compliance costs are not imposed. Regulators need to conduct constant analytic review to determine if regulations are achieving the results they intended. Therefore, since legislative and regulatory requirements can have a profound impact on marginal wells, the government should pursue:

- Industry/regulatory partnerships to facilitate agreements, implementation efficiency, and reduced costs

- Regulatory streamlining and simplification to benefit the industry without compromising environmental protection

- Reform of the process by which the federal government regulates industry to adequately reflect risks posed, the costs of, and benefits to society and industry of environmental regulations impacting the petroleum industry.

This chapter illustrates that real problems exist, and it suggests areas where legislative and regulatory improvements can equally benefit the regulators and industry. If situations such as those in California are allowed to persist, premature abandonments will only escalate. Although these figures seem definitive, on a nationwide basis, no studies are available to characterize these costs accurately. Unnecessarily high environmental costs must be viewed as more than a burden on the regulated community. Ultimately if resources are lost and production declines, the nation and the industry suffer from reduced energy security, lost jobs, and reduced tax revenues.

Several recommendations with respect to regulatory compliance reform are presented in the Regulatory and Administrative Relief section of this report's Findings, Conclusions, and Recommendations. Some of these recommendations are addressed in the DOE's Domestic Natural Gas and Oil Initiative. All of the recommendations can be accomplished without compromising environmental protection.

APPENDICES

Appendix A

Request Letter and Description of the National Petroleum Council

The Secretary of Energy
Washington, DC 20585
December 20, 1993

Mr. Ray L. Hunt
Chairman
National Petroleum Council
1625 K Street, NW
Washington, D.C. 20006

Dear Mr. Hunt:

The Administration has just announced its Domestic Natural Gas and Oil Initiative, a plan we believe will be a significant step forward in revitalizing the Nation's exploration and production industry. It is only a first step, however, and it is important that we continue to examine every aspect of our domestic gas and oil industry to ensure that no potential contributor to our energy security and economic prosperity is overlooked.

In this regard, I am requesting that the National Petroleum Council accept the assignment, described in the Gas and Oil Initiative, of a new study to examine the role of marginal wells in the Nation's energy and economic future. Specifically, the study should consider the costs and benefits of tax incentives for maintaining production from marginal and stripper wells.

America is unique among oil and natural gas producing nations in many respects. Perhaps the most significant distinction is the vast number of marginal wells operated by our domestic industry. These wells are economically marginal because of their low-volume production or because of their relatively high operating costs. Although marginal wells account for more than half of all oil production in 13 states and supply a substantial percentage of domestic production, industry representatives have expressed concern that there is insufficient data maintained on marginal wells to make technically and economically sound policy decisions.

To begin resolving this problem, our Energy Information Administration is scheduled to complete a study in February 1994 dealing with the "Economic Analysis of Domestic Oil Production" which will contain a significant amount of data. This study can provide a foundation for the National Petroleum Council and allow your study to focus on additional data needs and analyses.

Specifically, I would like the Council to undertake an analysis of economic and other challenges that domestic producers face in maintaining marginal production. Also, the Council should identify improvements that should be made in the Federal Government's informational resources, and provide specific policy recommendations that may be helpful in preserving access to oil and natural gas reserves from marginal wells. I would also like your assessment of actions taken by the Federal Government and States in recent years to preserve marginal production, for instance, royalty rates reduction for stripper wells on Federal lands.

This is an extremely important issue that, in my view, deserves an expedient but thorough analysis. I would ask that the Council establish a schedule that would provide this analysis to the Administration within the next six months.

Thank you for your continued assistance on these important energy and economic matters.

Sincerely,

Hazel R. O'Leary

Hazel R. O'Leary

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by the Secretary, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. This request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary of Energy include:

- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil & Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986)
- *Factors Affecting U.S. Oil & Gas Outlook* (1987)
- *Integrating R&D Efforts* (1988)
- *Petroleum Storage & Transportation* (1989)
- *Industry Assistance to Government* (1991)
- *Short-Term Petroleum Outlook* (1991)
- *The Potential for Natural Gas in the United States* (1992)
- *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries* (1993)
- *The Oil Pollution Act of 1990—Issues and Solutions* (1994).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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Appendix B

Study Group Rosters

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SUBCOMMITTEE ON MARGINAL WELLS

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Petroleum Engineer
Dallas Field Office
Energy Information Administration
U.S. Department of Energy

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Deputy Director
Oil and Gas Exploration
and Production
Office of Fossil Energy
U.S. Department of Energy

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U.S. Department of Energy

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Columbia Gas Development

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Appendix C
Data Resources Discussion

Data Resources Discussion

OVERVIEW

As requested by the Secretary of Energy, the NPC has addressed information resources focusing primarily on data requirements specific and unique to the marginal well study. The following discussion will address data requirements for a marginal well study as if it were conducted in an ideal world. Although the NPC found certain areas where data is lacking, it is not recommended that the government or industry pursue further reporting requirements or data gathering efforts to make all of the required data available.

DATA REQUIREMENTS FOR MARGINAL WELL STUDY

Many of the data requirements for conducting this study are discussed throughout the chapters in the body of the report. In order to conduct a marginal well study there are four major data elements required. Table C-1 provides an overview of each of the four major data elements and sub-levels of information required for each of these data elements.

DATA SHORTCOMINGS

For each of the major data elements, the following discusses problems encountered throughout the course of this study with data availability. It should be noted that although these data were found to be lacking for this study, efforts to gather additional data or improve its availability will compound the problem of marginality for many wells.

Production Data

During the course of this study, commercial data bases were relied on as the source for production data. Data from these sources are based on production information gathered by state agencies. Requirements for production data vary considerably from state to state and in many cases, particularly the eastern area states where production volumes are small, data are not available in electronic or digital form. There are also variations from state to state on what is included in the production data. For instance, several states provide production data by well while others provide it by lease. Some states require only the reporting of hydrocarbon production data and not water production. Another crucial piece of information which would allow a more complete analysis of the low rate producing wells is the number of producing days throughout the year. This information is only available for wells in several states.

Table C-1

Upstream Data Requirements For Marginal Well Study

A. PRODUCTION DATA. Additional detail in Table C-2.
   1. Reservoir information (depth, fluid gravity, name of horizon).
   2. Wellbore information (gas, condensate, oil and water volumes produced).
   3. Location information.

B. ECONOMICS DATA.
   1. Lease/Reservoir royalty rates.
   2. Lifting costs (detailed cost data as shown in Chapter 5 and Appendix F, Section II).
   3. Processing/Fluid handling costs.
      a. Cost to process/produce hydrocarbons (chemicals, labor/supervision, etc.).
      b. Cost to produce non-hydrocarbons.
      c. Cost to dispose of non-hydrocarbons.
   4. Sub-surface repair and maintenance costs.
   5. Surface repair and maintenance costs.
   6. Environmental costs.
   7. Produced products value (this item is particularly important for gas since marketing conditions from state to state and fields or areas within a state can vary considerably).

C. PRODUCER TAX STATUS FOR EACH WELL BY YEAR.
   1. Independent or majors.
   2. Exploration and production (only) taxable income or no taxable income.
   3. Regular or AMT tax payer.
   4. Other tax related items such as tax bases for property, etc.

D. RESOURCE DATA.
   1. Estimate of resource associated with wellbore.
   2. Estimate of reserves associated with wellbore.

Economics Data

Almost none of the data required under Economics Data are available through state records or a commercial data base. Detailed survey or data gathering efforts would be required to provide a comprehensive analysis of each of the economics data elements; however, a generalized approach and broad sweeping surveys provided a sound basis for the information used throughout the course of this study. Chapter Seven of this study deals more specifically with the environmental costs and only qualitatively addresses the impact these costs can have on marginal well production.

Tax Status

In considering federal level incentives, the after-federal income tax impacts are important. The complexity of the federal tax code complicates and hinders the ability to adequately describe these impacts. Further complicating this issue is the impact changing prices may have on producers' tax status.

Resource Data

Although there is a significant amount of the U.S. resource which has been characterized by the DOE in previous efforts, linking this resource to existing producing wells will greatly improve the ability to determine what impact losing wells and production has on resource access. Additionally, the projection of production and an estimate of future reserves influences the cost and benefit estimates for federal level incentives. Providing estimates of reserves for each well would allow more accurate determination of the incentives' costs and benefits.

CONCLUSIONS AND RECOMMENDATIONS

Although there were a number of data shortcomings when compared to an ideal world situation, the available data was adequate to address the marginality of oil wells in an overall manner. Individual wells or fields may not be perfectly modeled with the efforts of this study; however, the aggregate of oil wells throughout the six producing areas has been adequately addressed. The DOE has recently received a uniform production reporting study which addresses the issue of data variances and reporting formats between the producing states. In order for producer states with the most marginal wells to institute this type of reporting format, adequate incentives must be provided to relieve the cost burden associated with the proposed uniform reporting program. Furthermore, costs associated with these efforts could be burdensome to the companies' having to comply with these alternative reporting requirements.

TABLE C-2

PRODUCTION DATA

	Reservoir Information	
Total Well Depth Completion Date		Well Type (Oil, Gas, Water Injection, Salt Water Disposal)
Reservoir Name Reservoir Depth Fluid Type Liquid Gravity	Date Production Began Date Production Ceased	
	Wellbore Information	
Cumulative Oil Cumulative Cond. Cumulative Gas Cumulative Water Cumulative Inj.	Oil Production Cond. Production Gas Production Water Production Water Injection	Days On
	Location Information	
State County/Parish Field Lease Name	Section Township Range	Operator Type Well No./Name API Number

APPENDIX D

MARGINAL PROPERTY DEFINITION

EXCERPTED FROM
INTERNAL REVENUE CODE OF 1986
TITLE 26, SUBTITLE A
CHAPTER 1, SUBCHAPTER I, PART I
SECTION 613A

Marginal Property Definition

(Excerpted from Internal Revenue Code of 1986
Title 26, Subtitle A, Chapter 1, Subchapter I, Part I, Section 613A)

(D) MARGINAL PRODUCTION.—The term "marginal production" means domestic crude oil or domestic natural gas which is produced during any taxable year from a property which—

(i) is a stripper well property for the calendar year in which the taxable year begins, or

(ii) is a property substantially all of the production of which during such calendar year is heavy oil.

(E) STRIPPER WELL PROPERTY.—For purposes of this paragraph, the term "stripper well property" means, with respect to any calendar year, any property with respect to which the amount determined by dividing—

(i) the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year, by

(ii) the number of such wells, is 15 barrel equivalents or less.

(F) HEAVY OIL.—For purposes of this paragraph, the term "heavy oil" means domestic crude oil produced from any property if such crude oil had a weighted average gravity of 20 degrees API or less (corrected to 60 degrees Fahrenheit).

(G) AVERAGE DAILY MARGINAL PRODUCTION.—For purposes of this subsection—

(i) the taxpayer's average daily marginal production of domestic crude oil or natural gas for any taxable year shall be determined by dividing the taxpayer's aggregate marginal production of domestic crude oil or natural gas, as the case may be, during the taxable year by the number of days in such taxable year, and

(ii) in the case of a taxpayer holding a partial interest in the production from any property (including any interest held in any partnership), such taxpayer's production shall be considered to be that amount of such production determined by multiplying the total production of such property by the taxpayer's percentage participation in the revenues from such property.

APPENDIX E

CALIFORNIA PRODUCTION

California Production[1]

During 1993, California, including the federal OCS, produced approximately 941,000 barrels of oil a day, which represents 13 percent of the total production in the United States. The majority of this production is heavy oil, mostly located in the San Joaquin Valley. The state overview (Figure E-1) shows the distribution of the 1993 production within the six districts of the State Division of Oil, Gas & Geothermal Resources.

California oil production was on a steady increase for a decade during the late 1970s and early 1980s. This reflected the strong capital investment associated with developing reserves in a stable and profitable market. However, with the sharp market adjustment in the mid-1980s, production has steadily declined from its peak of 1,200,000 to a 1993 average of 941,000 barrels per day. Figure E-2 shows both this growth and the decline in California production. Also shown is the breakdown between heavy oil (less than 20 degrees API) and light oil. In 1993, heavy oil represented over 67 percent of the total California production.

Note that increased production from the federal OCS has offset a large percentage of the decline in onshore production during the past few years. The investment decisions associated with much of this increasing offshore production were made a number of years ago in a somewhat different economic environment.

Figure E-3 shows the oil production from the three most significant geographical areas within the state. Most of the production is from the San Joaquin Valley. Although not specifically shown in Figure E-3, Kern County, located in the San Joaquin Valley, accounts for approximately 60 percent of the state's production and 8 percent of the nation's production.

Three of the top ten fields in the United States (Midway-Sunset, South Belridge, and Kern River) are located in Kern County, as shown in Table E-1. Another Kern County field, Elk Hills, was recently displaced from the number 10 spot it held in 1992 to number 12. Most of this production from Kern County and the San Joaquin Valley is also heavy oil.

Of the approximately 42,000 producing wells in California, about half are classified as stripper wells (less than 10 barrels of oil per day). Generally these low production wells have higher operating costs per barrel of production. This fact, along with the high energy costs associated with producing heavy oil, results in high operating costs for California production. Figure E-4 shows the distribution of the California wells by well production rates.

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[1] Basic data from (1) Foster Associate, Inc., *The Effect of the Proposed BTU Tax on California's Heavy Oil Production and the State Economy*, May 17, 1993, and (2) various published and unpublished data developed by the California Conservation Committee of Oil and Gas Producers.

TABLE E-1

TOP TEN U.S. PRODUCING OIL FIELDS

Field	Location	Prod. Rate (MB/D)	Cumulative Prod. (MMB)
1. Prudhoe Bay	Alaska	1,100	8,650
2. Kuparuk River	Alaska	313	1,100
3. Midway-Sunset	Kem	165	2,190
4. South Belridge	Kem	126	947
5. Kern River	Kem	125	1,440
6. Point McIntyre	Alaska	98	16
7. Endicott	Alaska	90	258
8. East Texas	Texas	82	5,180
9. Wasson	Texas	78	1,850
10. Giddings	Texas	77	363

California has a large reserve base of oil. Similar to the current production distribution, most of these reserves consist of heavy oil and most are located in the San Joaquin Valley. Table E-2 shows the 1992 California proven oil reserves. (Although not shown in these figures, there are also significant heavy oil reserves in the California offshore.) In addition, many companies have a cadre of unproven and/or undeveloped reserves that represent a significant additional potential for development. The large reserve base and the high reserve to production (R/P) ratio means that there are development opportunities for years into the future if the cost of production and crude oil price will allow development of this resource.

It is important to note that reserves in heavy oil fields are recovered over an unusually long period of time (usually several decades) due to the low production rates caused by the very viscous crude oil. This additional time required to produce the oil in place contributes to higher operating and capital costs as well as results in a delayed return on investment capital. In addition, during this protracted productive life, heavy oil price fluctuations cause an increased risk in regard to capital recovery and adequate return on investment.

TABLE E-2

1992 CALIFORNIA PROVED OIL RESERVES
(Millions of Barrels)

Region	Reserves	Reserves/Production
San Joaquin	2,607	11.1
Long Beach	777	17.9
Ventura	206	13.8
Santa Maria	208	18.3
Total California	3,798	12.4
Total United States	24,700	9.5

Figure E-5 shows California oil reserve additions by year. The decline in additions that started with the sharp market change in 1986 actually culminated in 1991 and 1992 with negative adjustments to the total reserve base. Without reserve additions, production will obviously continue to decline.

This trend of reduced activity is also represented in the number of new California heavy oil wells drilled each year, shown in Figure E-6. Note that over a third of the wells drilled in both 1990 and 1991 were associated with specific activity at South Belridge Field driven by other dynamics. When this is taken into account, starting in 1990, a new and lower level of drilling activity is clearly evident.

Average field lifting costs for California heavy oil were approximately $6.90 per barrel in 1991. This average "lifting cost" does not include the additional costs associated with capital amortization, overhead, royalty, research, etc. These additional costs are often of the same order of magnitude as the field lifting costs themselves. The total of these costs represent the real costs associated with producing heavy oil. Figure E-7 shows the historical price for Kern River crude oil (13 degrees API) against field lifting costs and an estimate of total costs. Even though most companies have reduced their lifting costs below this 1991 composite cost, the basic economic structure of the heavy oil industry, as shown by this graph, does not encourage development even in the $12 to $13 per barrel price range.

The important and specific cost factors affecting California's predominantly heavy oil market are:

- High Energy Requirements/Costs – The common method of EOR associated with California's heavy crude oil involves injecting large quantities of steam into the reservoir to reduce the high viscosity of the heavy oil so that it flows more easily and rapidly to the wellbore. Generally three to four barrels of steam are injected for every barrel of oil produced. Most of this steam is produced in large boilers that have been largely converted from burning crude oil to natural gas due to the increasingly stringent air emission regulations. The injected steam is eventually recovered as produced water, which needs to be treated to the high standards required for heating and injection as steam. It takes considerable initial steam injection to begin this recovery process and, once started, the steam injection must be continued or significant injected steam value/heat will be lost to the surrounding formations.

  Because of the high total cost of the steam generation and injection process (commonly about $4 per barrel of oil produced), significant attention has been directed towards the facilities in order to reduce the overall cost of the steam. One relatively new method of reducing the steam costs has been the installation of many electrical/steam cogeneration plants in the oil fields. The waste exhaust heat from turbine powered generators is used to generate steam, while the electrical output is either used to displace purchased electricity or sold to the local utility. In Kern County, where 60 percent of California's oil is produced, over 1,500 megawatts of cogenerated power has been installed in the oil fields over the past ten years.

- High Capital Development Costs – The cost of drilling a single typical heavy oil well is relatively low. However, the cost of drilling the many wells required to develop a heavy oil field and the cost of associated facilities required to treat the large amounts of produced water (cuts of 90 percent are normal) to boiler standard, to heat the water, and to distribute the steam are significant. While most of the capital expense is required by the water/steam operation, the facilities to treat, store, and pump the heavy viscous crude oil are also significant and costly.

- Stringent/Costly Environmental Requirements – California continues to develop some of the most stringent environmental regulations. This has increased the complexity and cost of producing oil in California, especially in the more sensitive coastal or urban areas. In addition, oil field abandonment requirements/costs are increasing and, while this does not affect the field operating costs, this does affect an operator's ability and/or willingness to sell/develop oil field properties.

Figure E-7 highlights several other important features associated with the production of heavy oil in California.

1. When the price for heavy oil in the early 1980s was in the mid to low $20's, many California reserves could be economically developed. In fact, much of today's production is from development projects that took place during this time frame.

2. A key feature of the post-1986 price adjustment, beyond just the significantly lower price, has been the extreme and rapid nature of the price fluctuation. Price can and has frequently changed by 30, 40, and even 50 percent within weeks or months.

3. Historically, California 13 degree heavy crude oil has sold for about 60 to 70 percent of a West Texas 40 degree crude oil (the average price for Kern River Crude in February 1994 was $9.25 per barrel compared to $13.00 for West Texas Intermediate). This low value is primarily based on the poorer crude oil quality, which results in a lower valued refined products mix from each barrel due to the limited refinery conversion capacity in California. California's refineries produced about 270,000 barrels per day of low value #6 fuel oil in 1993, most of which can be attributed to California's heavy oil.

4. The period of low price and extreme fluctuation has been in place since 1986 and has to be viewed as the normal environment in which investment decisions now need to be made.

5. Since 1985, with the price fluctuating between $8 and $15, many operators have had significant difficulty making an adequate return on their investment.

6. During the lower prices, such as in December, 1993 when Kern River Crude was at $8.00 per barrel, many operators were operating at a negative cash flow even at the field operating level and faced difficult decisions to shut in or continue production.

Data gathered from producers throughout the state by the Conservation Committee of California Oil & Gas Producers estimates the amount of production that was not profitable based on December 9, 1993 postings (Kern River Crude was at $8.00 per barrel on 12/9/93). Figures E-8 and E-9 show these data both at the field level and with all costs including overhead and amortization of capital included. Considering just field level costs, 20 percent or 164,000 barrels per day was being operated with a negative cash flow in December, 1993. If total costs are included, 67 percent or 534,000 barrels per day was not profitable.

The reality of California production is that it is a lower value product with high operating costs and large capital investment requirements which results in thin margins. This, combined with the erratic and low crude oil prices since 1986, has caused the California oil production industry to decline significantly over the last eight years. In 1985 there were approximately 89,000 people with either direct or indirect employment associated with producing oil in California. An approximate 20 percent reduction in this employment took place in the mid-1980s associated with the sharp market adjustment in 1986. This decline has continued so that in 1993 the total employment has been reduced to just over 57,000, as shown in Table E-3. This represents a 36 percent decline in employment over the last eight years.

TABLE E-3

CALIFORNIA'S UPSTREAM OIL & GAS INDUSTRY EMPLOYMENT

	1985	1990	1993*	Decline from 1985
Direct	39,500	31,700	25,300	(14,200)
Indirect	49,770	39,942	31,880	(17,890)
Total	89,270	71,642	57,180	(32,090)
Percent Change from 1985		(19.8%)	(36.0%)	

* First six months of 1993.

Production and the resulting jobs represent a significant source of revenue to the state and local governments, as shown in Table E-4. In 1985 this revenue was over one billion dollars. By 1990 it had fallen to 600 million and by 1992 to just over 400 million. While the 42 percent decline between 1985 and 1990 represents a major shift, the continued decline of 29 percent from 1990 represents the continued distress of the industry and one measure of the impact that distress is having on the embattled California economy. On a more local level, in Kern County, the oil and gas property assessment represented 55 percent of the county's property assessment in 1985. This percentage has fallen over the years to where oil and gas properties now represents only 30 percent of the county's property assessment.

TABLE E-4

STATE AND LOCAL REVENUE FROM CALIFORNIA OIL & GAS PRODUCTION
(Millions of Dollars)

Revenue Source	1985	1990	1992
State Sources			
Royalties and Production Revenues	$425.4	$172.3	$87.6
CA Income Tax – Corporate, Unitary	140.6	34.8	25.4
Personal Income Taxes	80.8	82.0	75.7
Oil Production Tax	7.3	8.4	8.1
Other Environment Taxes & Fees	0.3	0.9	0.9
State Sales & Use Taxes	87.5	58.8	42.6
Payroll Tax	11.0	5.9	4.7
Subtotal STATE	$752.9	$363.1	$245.0
Regional APCD Fees	NA	$15.9	$15.9
Local & County Sources			
Property Tax	$274.6	$206.7	$150.2
Local Sales & Use Taxes	28.6	19.2	13.9
Local APCD Fees	0.0	4.7	4.7
Other Environmental Permit Fees	0.0	3.7	3.7
Subtotal LOCAL	$303.2	$234.3	$172.5
GRAND TOTAL	$1,056.1	$613.3	$433.4

CALIFORNIA
1993 Oil Production
(1,000 B/D)

DOG District Boundaries

Summary	
State Onshore	746
State Tidelands	57
Federal OCS	138
Total	941

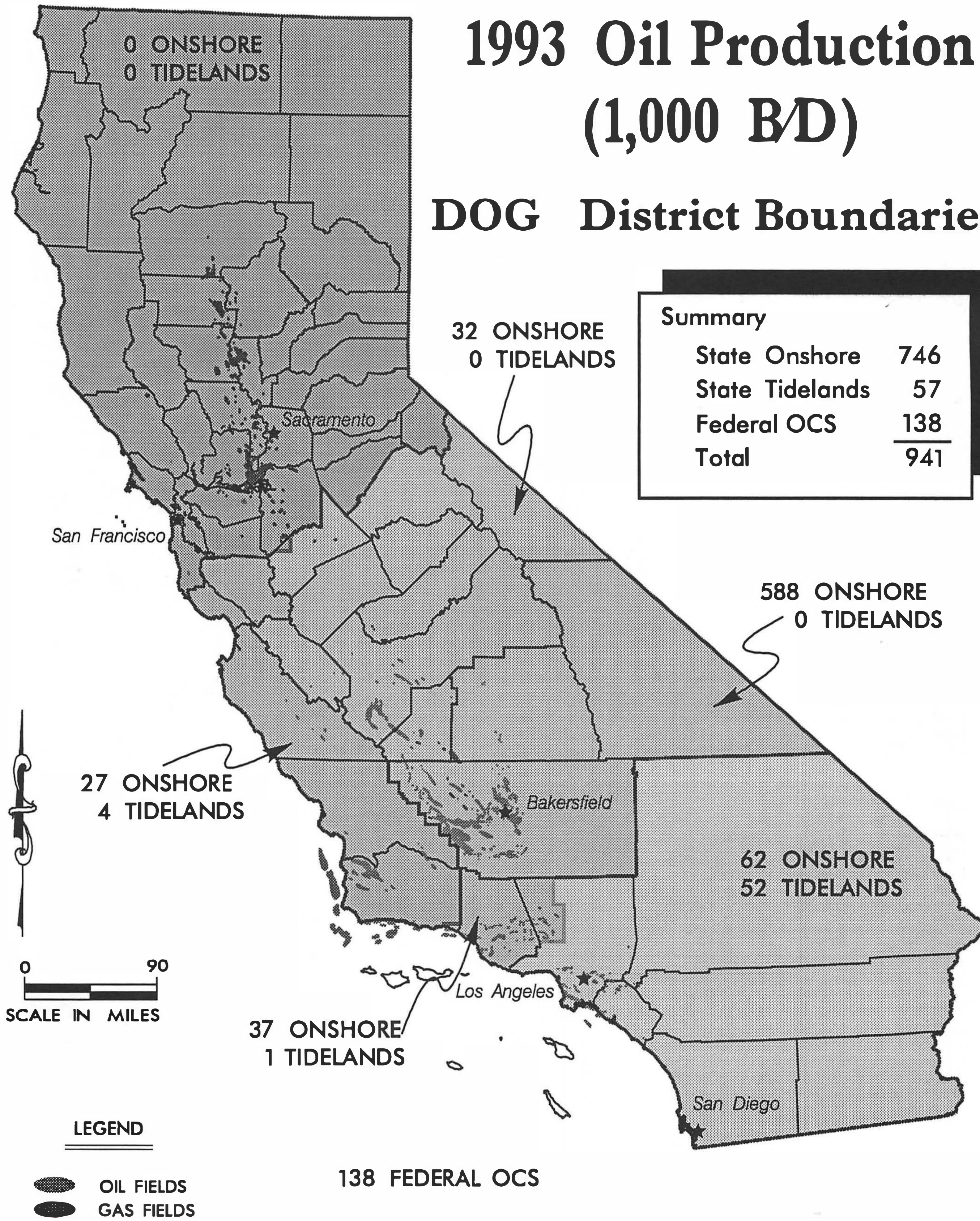
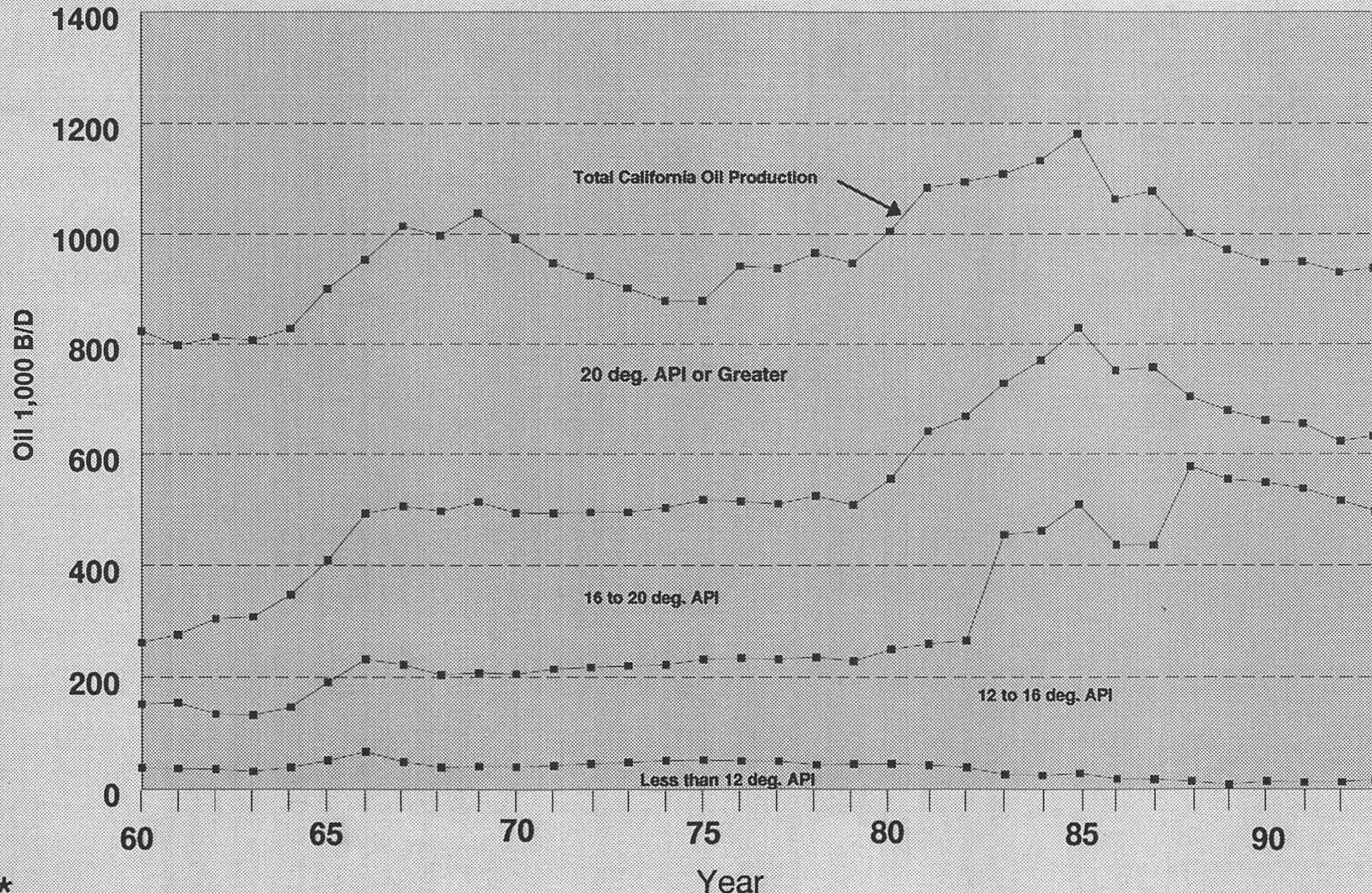


Figure E-1

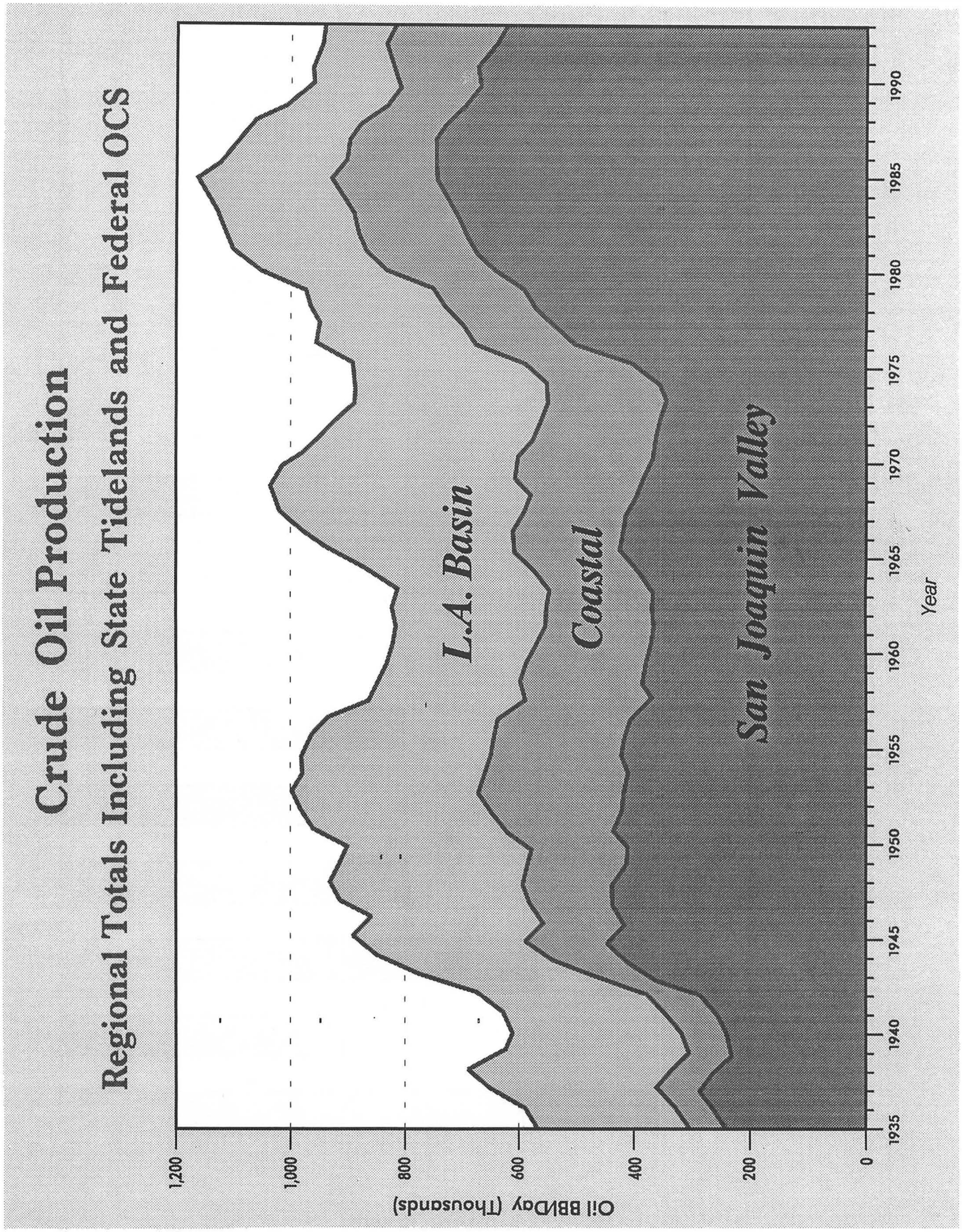
CALIFORNIA OIL PRODUCTION* BY GRAVITY (INCLUDING STATE TIDELANDS AND FEDERAL OCS)



* Based on January Production

Fig. 2

Figure E-2



Crude Oil Production
Regional Totals Including State Tidelands and Federal OCS
Oil BBl/Day (Thousands)
0
200
400
600
800
1,000
1,200
1935
1940
1945
1950
1955
1960
1965
1970
1975
1980
1985
1990
Year
L.A. Basin
Coastal
San Joaquin Valley

Figure E-3

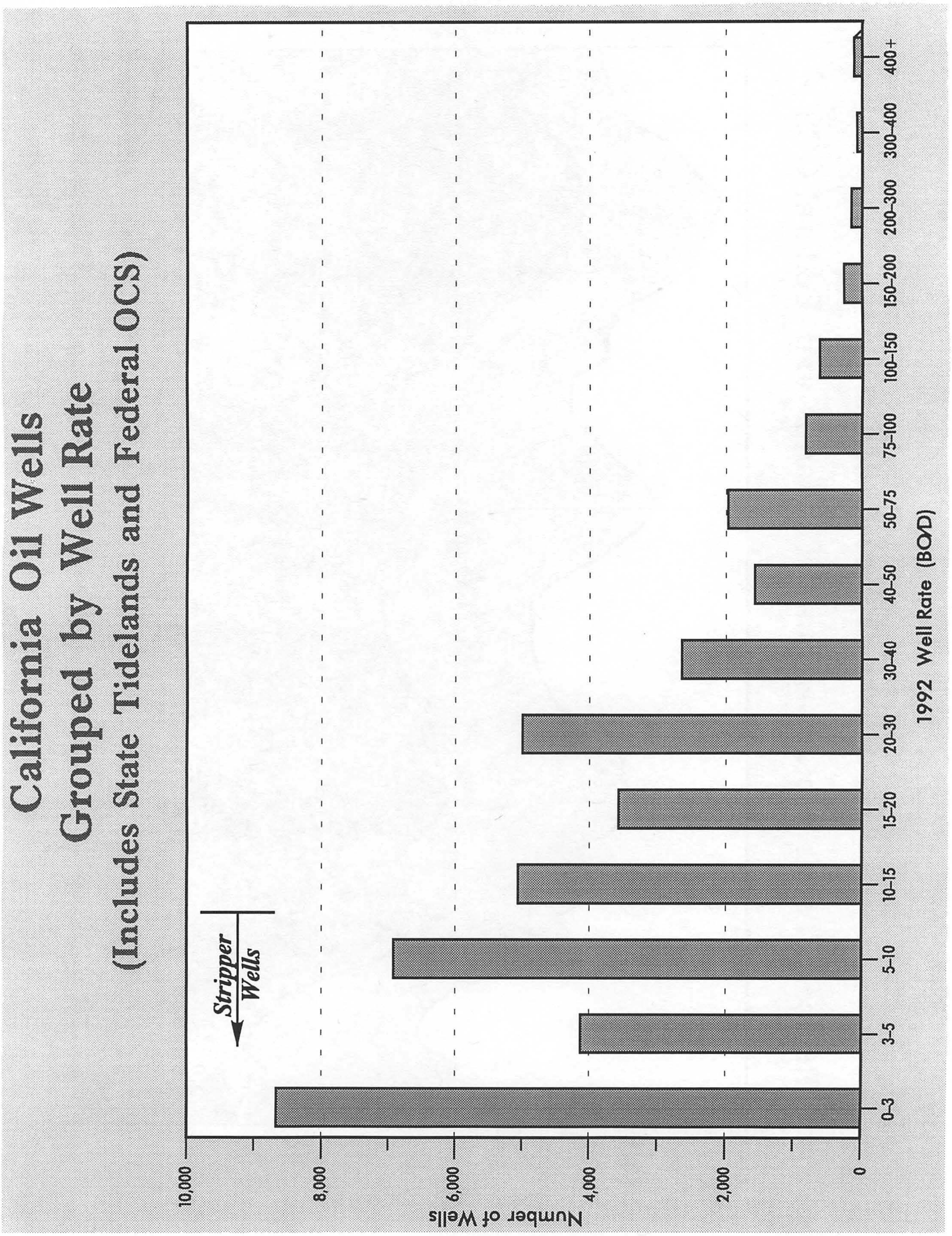

California Oil Wells
Grouped by Well Rate
(Includes State Tidelands and Federal OCS)
Stripper Wells
Number of Wells
0
2,000
4,000
6,000
8,000
10,000
0–3
3–5
5–10
10–15
15–20
20–30
30–40
40–50
50–75
75–100
100–150
150–200
200–300
300–400
400+
1992 Well Rate (BO/D)

Figure E-4

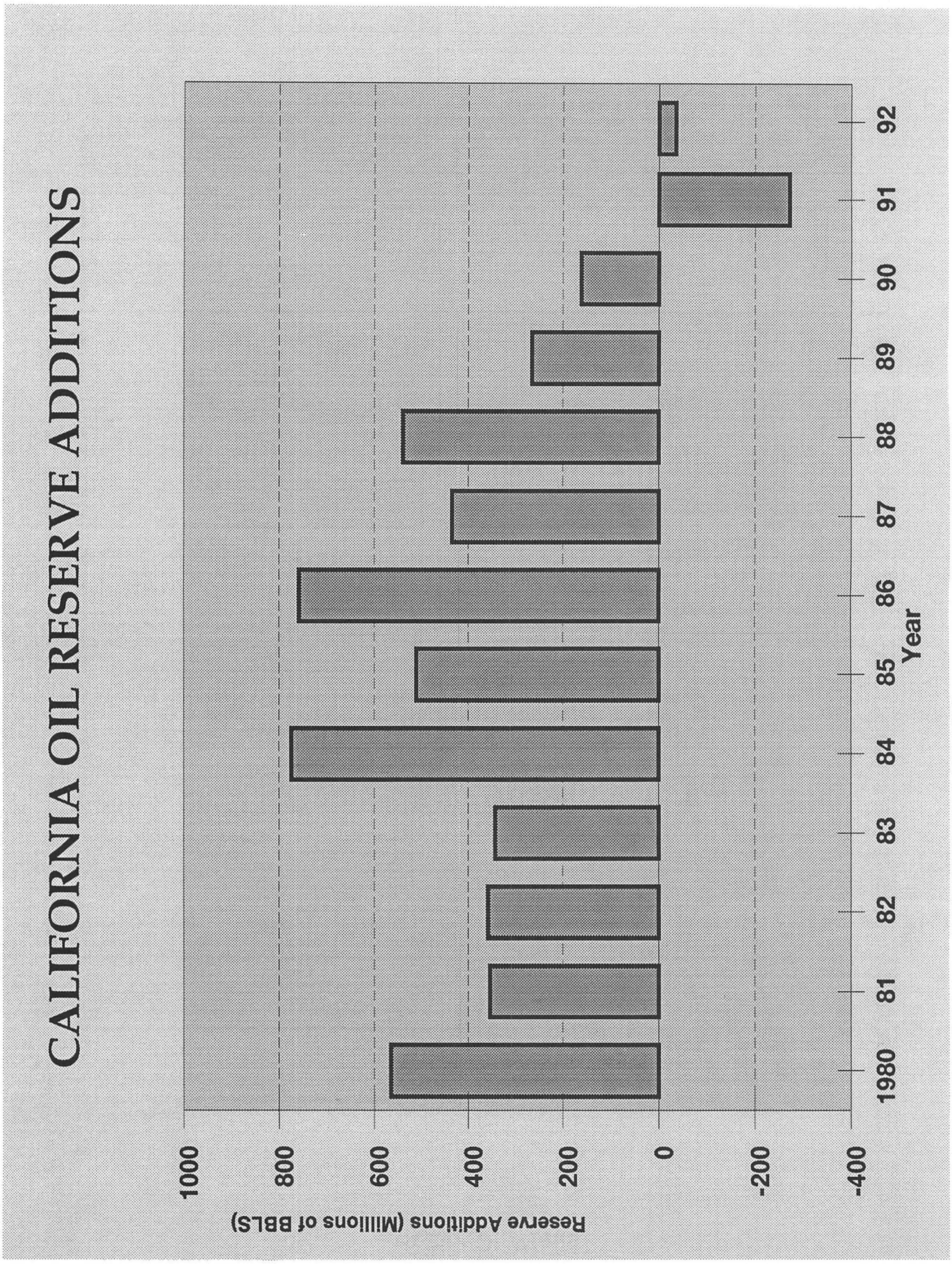

CALIFORNIA OIL RESERVE ADDITIONS
Reserve Additions (Millions of BBLS)
1000
800
600
400
200
0
-200
-400
1980
81
82
83
84
85
86
87
88
89
90
91
92
Year

Figure E-5

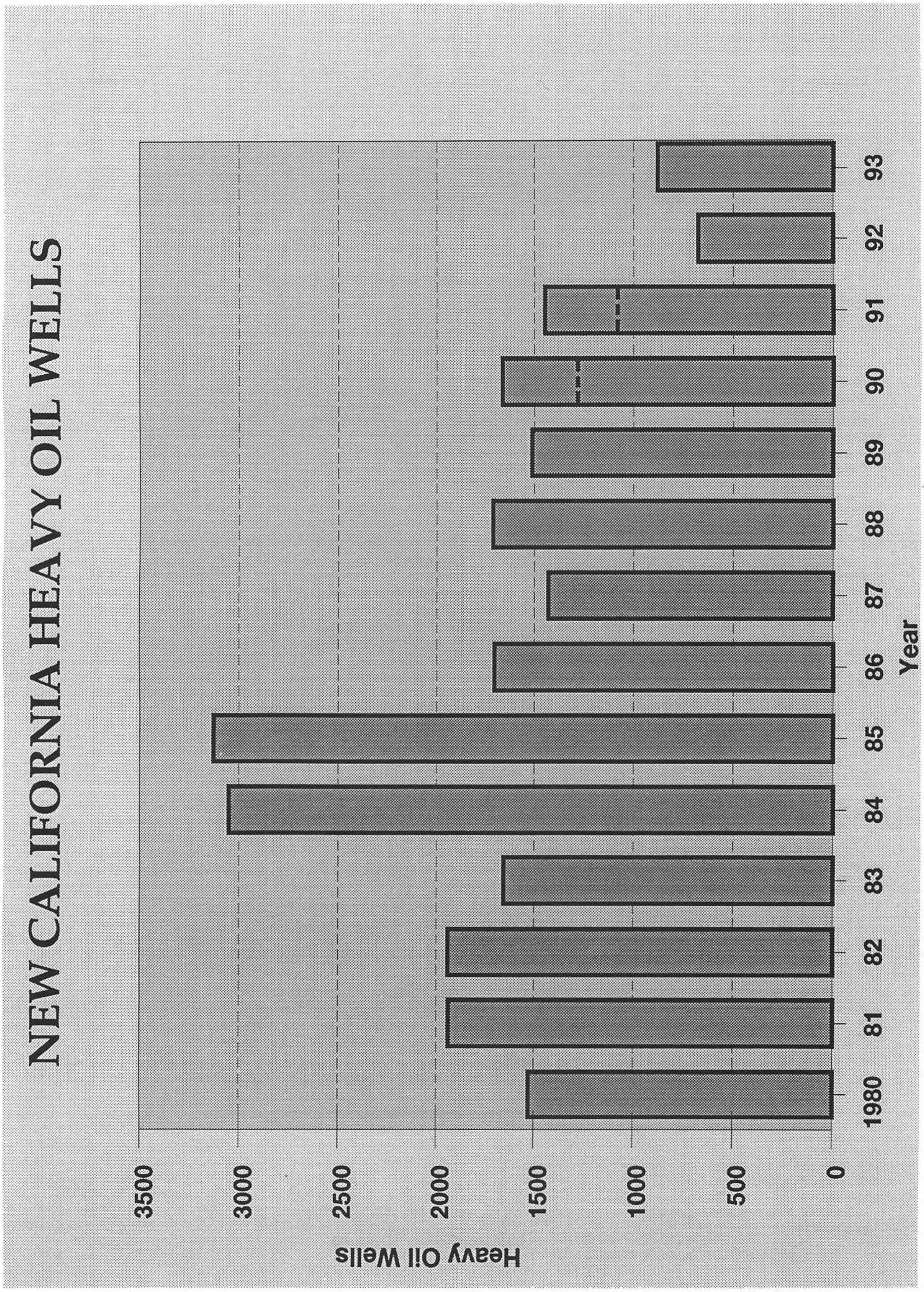

NEW CALIFORNIA HEAVY OIL WELLS
Heavy Oil Wells
0
500
1000
1500
2000
2500
3000
3500
Year
1980
81
82
83
84
85
86
87
88
89
90
91
92
93

Figure E-6

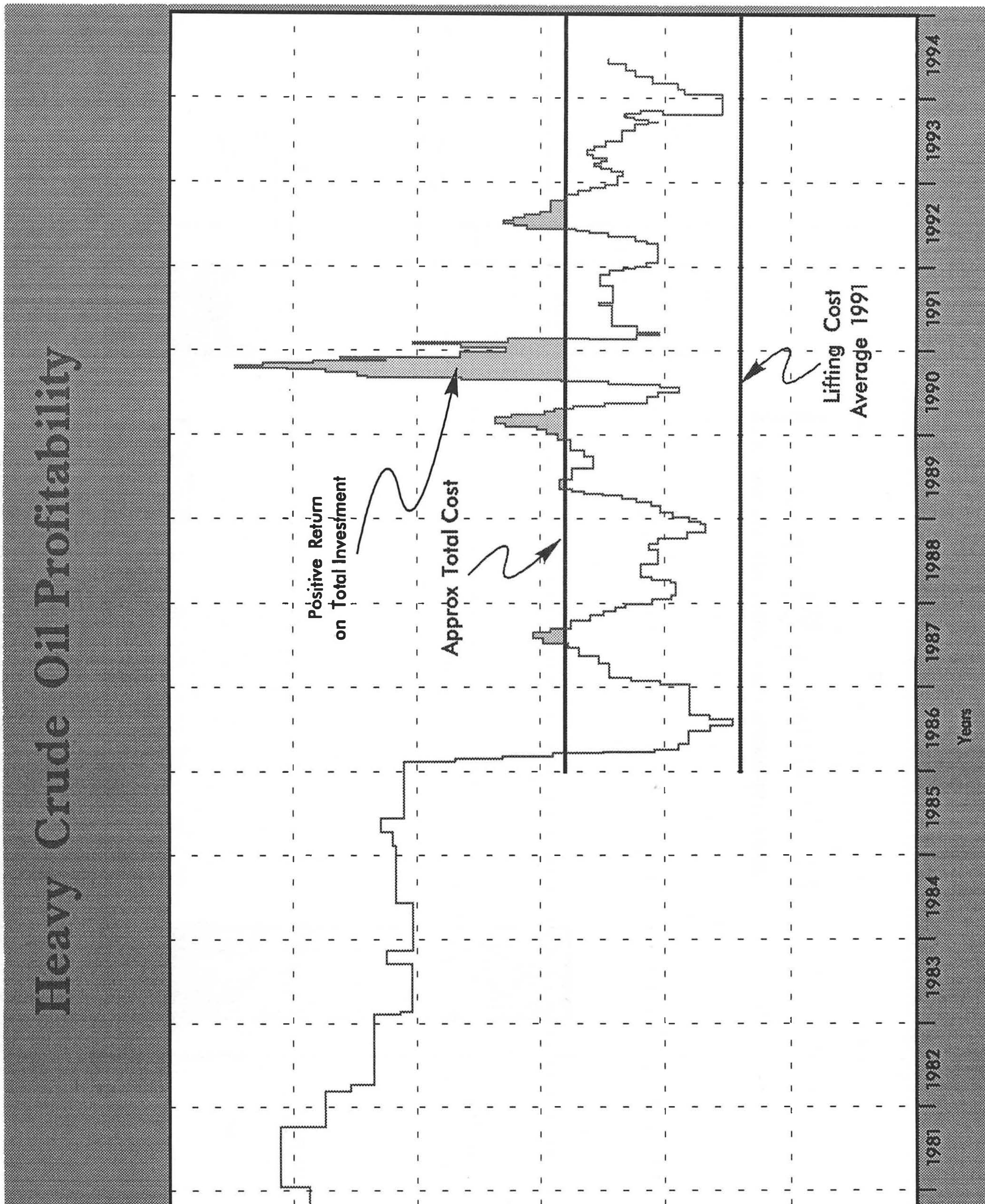
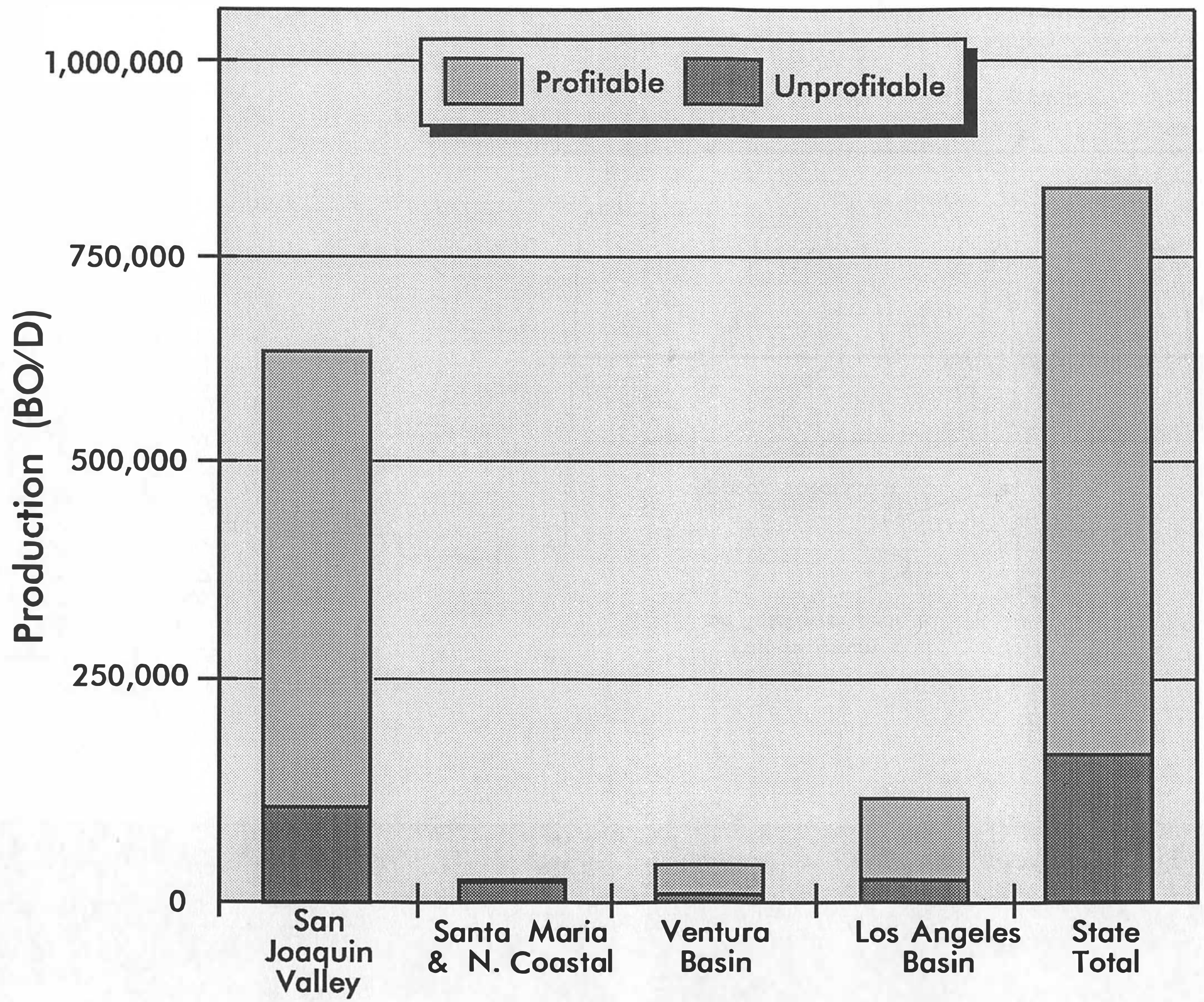

Heavy Crude Oil Profitability
Positive Return
on Total Investment
Approx Total Cost
Lifting Cost
Average 1991
Dollars Per Barrel
Years
0
5
10
15
20
25
30
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994

Figure E-7

Profitability of California Crude Production*

(Excludes overhead and amortization costs)



*Per Conservation Committee of California Oil and Gas Producers
Based on 12/9/93 Price Postings

Figure E-8

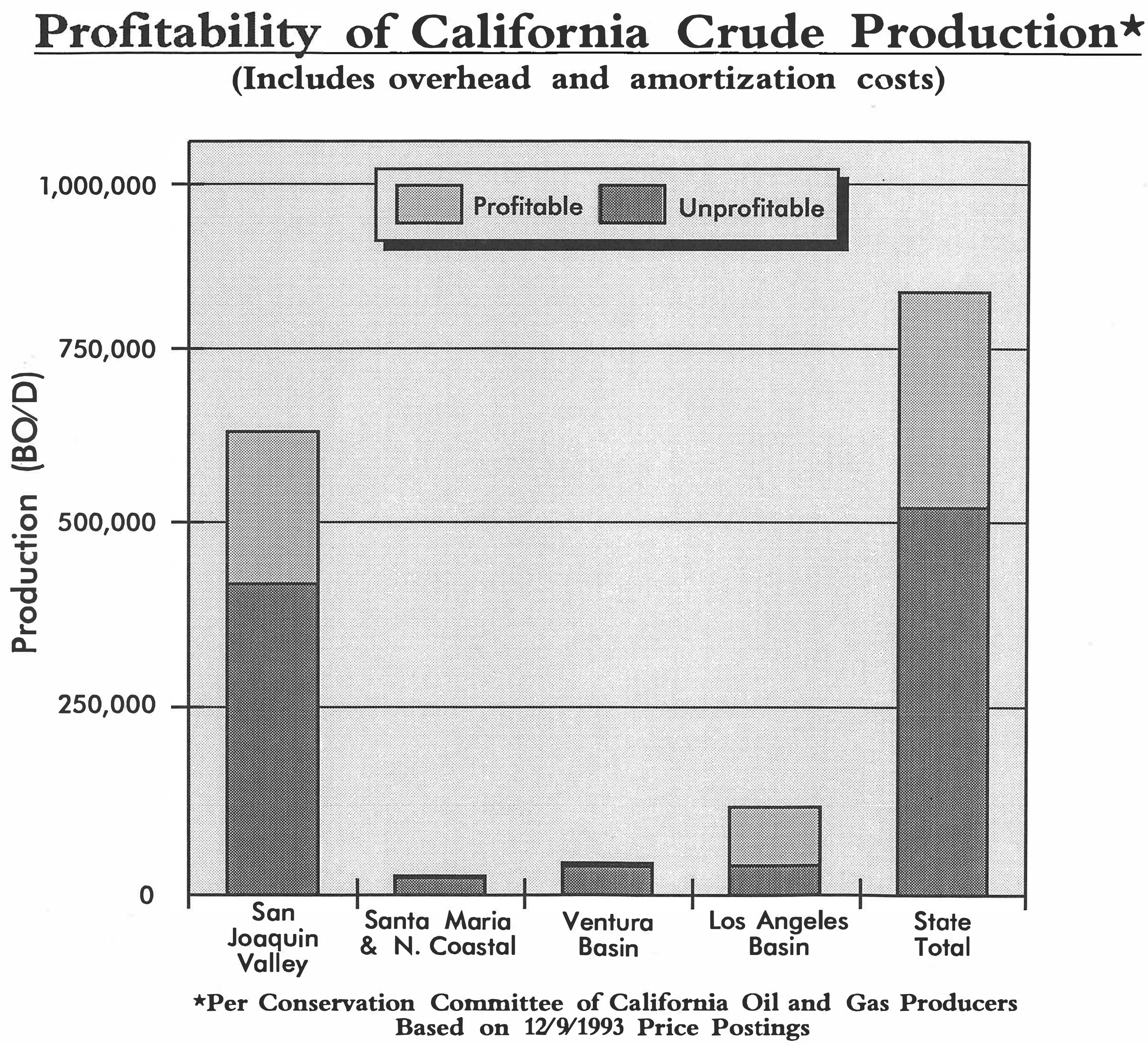

Profitability of California Crude Production*
(Includes overhead and amortization costs)
Profitable
Unprofitable
Production (BO/D)
1,000,000
750,000
500,000
250,000
0
San Joaquin Valley
Santa Maria & N. Coastal
Ventura Basin
Los Angeles Basin
State Total
*Per Conservation Committee of California Oil and Gas Producers
Based on 12/9/1993 Price Postings

Figure E-9

APPENDIX F

ECONOMIC ANALYSES

- SECTION I: WELL DATA
- SECTION II: OPERATING COSTS
- SECTION III: WELL LEVEL ECONOMIC ANALYSES
- SECTION IV: AFTER TAX ECONOMIC ANALYSES

APPENDIX F

SECTION I

WELL DATA

MATERIAL IN APPENDIX

DISTRIBUTION OF WELLS AND BOE PRODUCTION BY PRODUCTION RATE BRACKET, 1992

- LOWER-48 STATES ONSHORE
- EASTERN STATES
- MIDCONTINENT
- GULF COAST
- PERMIAN BASIN
- ROCKY MOUNTAINS
- CALIFORNIA

MATERIAL IN WORKING PAPERS

WATER CUT DISTRIBUTION PAPERS BY RATE BRACKET

Distribution of Wells and BOE Production by Production Rate Bracket for Lower 48 States Onshore, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percent of Wells	Percent of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	193,172	26,854,854	32.96	1.31	0.38
1-2	76,543	38,006,533	13.06	1.86	1.36
2-3	45,842	38,102,296	7.82	1.86	2.27
3-4	31,572	36,687,217	5.39	1.79	3.17
4-5	23,603	35,035,609	4.03	1.71	4.06
5-6	20,170	36,675,143	3.44	1.79	4.97
6-7	15,533	33,480,070	2.65	1.64	5.89
7-8	12,899	31,864,814	2.20	1.56	6.75
8-9	11,276	31,508,672	1.92	1.54	7.63
9-10	11,622	37,263,715	1.98	1.82	8.76
Subtotal 0-10	**442,232**	**345,478,923**	**75.46**	**16.89**	**2.13**
10-11	8,863	31,175,186	1.51	1.52	9.61
11-12	7,931	30,014,807	1.35	1.47	10.34
12-13	6,764	27,788,799	1.15	1.36	11.22
13-14	6,342	28,613,681	1.08	1.40	12.33
14-15	6,456	30,993,774	1.10	1.52	13.12
Subtotal 0-15	**478,588**	**494,065,170**	**81.66**	**24.15**	**2.82**
15-20	21,749	123,178,837	3.71	6.02	15.47
20-25	17,830	130,920,325	3.04	6.40	20.06
25-30	13,063	119,248,199	2.23	5.83	24.94
30-35	9,108	92,156,988	1.55	4.50	27.65
35-40	5,303	62,327,341	0.90	3.05	32.11
40-45	4,185	53,222,791	0.71	2.60	34.75
45-50	3,275	49,194,836	0.56	2.40	41.04
>50	32,957	921,415,284	5.62	45.04	76.39
Total	**586,058**	**2,045,729,771**	**100.00**	**100.00**	**9.54**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; Dwight's EnergyData, Inc.; and Petroleum Information Corp.

Distribution of Wells and BOE Production by Production Rate Bracket for Eastern States, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percent of Wells	Percent of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	84,996	11,754,680	63.87	21.55	0.38
1-2	26,142	12,597,820	19.65	23.10	1.32
2-3	10,352	8,631,746	7.78	15.82	2.28
3-4	4,822	5,684,521	3.62	10.42	3.22
4-5	2,515	3,841,878	1.89	7.04	4.17
5-6	1,427	2,679,663	1.07	4.91	5.13
6-7	863	1,885,134	0.65	3.46	5.97
7-8	550	1,413,054	0.41	2.59	7.02
8-9	365	1,033,211	0.27	1.89	7.73
9-10	251	818,683	0.19	1.50	8.91
Subtotal 0-10	**132,284**	**50,340,390**	**99.41**	**92.29**	**1.04**
10-11	178	642,369	0.13	1.18	9.87
11-12	129	506,390	0.10	0.93	10.72
12-13	96	411,550	0.07	0.75	11.75
13-14	72	338,558	0.05	0.62	12.79
14-15	56	278,460	0.04	0.51	13.69
Subtotal 0-15	**132,814**	**52,517,717**	**99.81**	**96.28**	**1.08**
15-20	145	864,952	0.11	1.59	16.27
20-25	54	414,996	0.04	0.76	21.13
25-30	24	225,549	0.02	0.41	25.82
30-35	12	132,613	0.01	0.24	30.08
35-40	7	85,959	0.01	0.16	35.23
40-45	4	59,034	0.00	0.11	40.76
45-50	2	40,671	0.00	0.07	44.78
>50	6	205,728	0.00	0.38	92.33
Total	**133,068**	**54,547,220**	**100.00**	**100.00**	**1.12**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Note 4: The 10 States are constructed from a production rate distribution function and a mean production rate. These 10 States are: Illinois, Indiana, Kentucky, Missouri, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia.

Source: Energy Information Administration, Office of Oil and Gas; and Dwight's EnergyData, Inc.

Distribution of Wells and BOE Production by Production Rate Bracket for Mid-Continent, 1992

Production Rate Bracket *(BOE/Day)*	*Wells*	*Annual Production (BOE)*	*Percent of Wells*	*Percent of Production*	*Average Annual Production Rate Per Well (BOE/Day)*
0-1	48,522	6,942,737	27.93	2.18	0.39
1-2	26,182	12,413,026	15.07	3.90	1.30
2-3	17,380	12,956,929	10.00	4.07	2.04
3-4	11,819	11,917,290	6.80	3.74	2.75
4-5	8,662	10,758,223	4.99	3.38	3.39
5-6	6,453	9,369,442	3.71	2.94	3.97
6-7	5,145	8,977,374	2.96	2.82	4.77
7-8	4,112	7,895,467	2.37	2.48	5.25
8-9	3,238	6,658,302	1.86	2.09	5.62
9-10	2,869	7,023,730	1.65	2.20	6.69
Subtotal 0-10	**134,382**	**94,912,520**	**77.34**	**29.79**	**1.93**
10-11	2,399	6,347,344	1.38	1.99	7.23
11-12	2,045	5,283,106	1.18	1.66	7.06
12-13	1,885	5,527,044	1.08	1.73	8.01
13-14	1,481	4,589,727	0.85	1.44	8.47
14-15	1,428	4,405,998	0.82	1.38	8.43
Subtotal 0-15	**143,620**	**121,065,739**	**82.66**	**37.99**	**2.30**
15-20	5,233	19,373,626	3.01	6.08	10.12
20-25	3,511	13,382,098	2.02	4.20	10.41
25-30	2,306	10,872,830	1.33	3.41	12.88
30-35	2,067	9,073,634	1.19	2.85	11.99
35-40	1,239	6,797,933	0.71	2.13	14.99
40-45	1,130	5,867,271	0.65	1.84	14.19
45-50	718	5,026,097	0.41	1.58	19.13
>50	13,929	127,180,104	8.02	39.91	24.95
Total	**173,753**	**318,639,332**	**100.00**	**100.00**	**5.01**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; Dwight's EnergyData, Inc.; and Petroleum Information Corp.

Distribution of Wells and BOE Production by Production Rate Bracket for Gulf Coast, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percent of Wells	Percent of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	34,625	4,233,336	39.94	0.96	0.33
1-2	7,966	4,241,875	9.19	0.96	1.45
2-3	4,354	3,980,602	5.02	0.90	2.50
3-4	3,614	4,615,246	4.17	1.05	3.49
4-5	2,866	4,722,042	3.31	1.07	4.50
5-6	2,738	5,454,873	3.16	1.24	5.44
6-7	1,866	4,422,101	2.15	1.00	6.47
7-8	1,564	4,283,187	1.80	0.97	7.48
8-9	1,699	5,294,063	1.96	1.20	8.51
9-10	1,513	5,281,264	1.75	1.20	9.54
Subtotal 0-10	**62,805**	**46,528,589**	**72.45**	**10.57**	**2.02**
10-11	1,159	4,444,848	1.34	1.01	10.48
11-12	939	3,941,420	1.08	0.90	11.47
12-13	1,044	4,782,760	1.20	1.09	12.52
13-14	838	4,133,271	0.97	0.94	13.48
14-15	675	3,575,965	0.78	0.81	14.47
Subtotal 0-15	**67,460**	**67,406,853**	**77.82**	**15.31**	**2.73**
15-20	3,374	21,379,470	3.89	4.86	17.31
20-25	3,969	32,684,996	4.58	7.42	22.50
25-30	2,705	27,045,472	3.12	6.14	27.32
30-35	1,579	18,827,207	1.82	4.28	32.58
35-40	903	12,258,603	1.04	2.78	37.09
40-45	673	10,402,158	0.78	2.36	42.23
45-50	795	13,675,761	0.92	3.11	47.00
>50	5,228	236,667,666	6.03	53.75	123.69
Total	**86,686**	**440,348,186**	**100.00**	**100.00**	**13.88**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; and Dwight's EnergyData, Inc.

Distribution of Wells and BOE Production by Production Rate Bracket for Permian Basin, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percent of Wells	Percent of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	16,273	2,558,496	14.20	0.41	0.43
1-2	10,406	5,609,945	9.08	0.90	1.47
2-3	8,467	7,719,013	7.39	1.24	2.49
3-4	6,704	8,595,670	5.85	1.38	3.50
4-5	5,626	9,252,160	4.91	1.49	4.49
5-6	6,202	12,449,250	5.41	2.00	5.48
6-7	4,765	11,315,407	4.16	1.82	6.49
7-8	4,000	10,945,130	3.49	1.76	7.48
8-9	3,519	10,890,841	3.07	1.75	8.46
9-10	4,733	16,311,882	4.13	2.62	9.42
Subtotal 0-10	**70,695**	**95,647,794**	**61.69**	**15.37**	**3.70**
10-11	3,093	11,932,723	2.70	1.92	10.54
11-12	2,862	12,049,023	2.50	1.94	11.50
12-13	2,081	9,479,256	1.82	1.52	12.45
13-14	2,371	11,745,454	2.07	1.89	13.53
14-15	2,783	14,706,877	2.43	2.36	14.44
Subtotal 0-15	**83,885**	**155,561,127**	**73.20**	**24.99**	**5.07**
15-20	6,957	43,131,273	6.07	6.93	16.94
20-25	6,052	49,685,486	5.28	7.98	22.43
25-30	4,924	49,976,716	4.30	8.03	27.73
30-35	3,100	36,236,395	2.71	5.82	31.94
35-40	1,234	16,950,852	1.08	2.72	37.53
40-45	994	15,392,728	0.87	2.47	42.31
45-50	686	11,828,070	0.60	1.90	47.11
>50	6,758	243,682,003	5.90	39.15	98.52
Total	**114,590**	**622,444,650**	**100.00**	**100.00**	**14.84**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; and Dwight's EnergyData, Inc.

Distribution of Wells and BOE Production by Production Rate Bracket for Rocky Mountains, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percent of Wells	Percent of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	4,292	666,760	13.42	0.25	0.42
1-2	2,859	1,517,478	8.94	0.57	1.45
2-3	2,583	2,353,800	8.07	0.89	2.49
3-4	2,224	2,825,848	6.95	1.07	3.47
4-5	1,784	2,922,344	5.58	1.10	4.48
5-6	1,414	2,833,278	4.42	1.07	5.47
6-7	1,144	2,721,096	3.58	1.03	6.50
7-8	1,037	2,835,350	3.24	1.07	7.47
8-9	952	2,967,101	2.98	1.12	8.52
9-10	917	3,177,235	2.87	1.20	9.47
Subtotal 0-10	**19,206**	**24,820,290**	**60.03**	**9.38**	**3.53**
10-11	708	2,715,173	2.21	1.03	10.48
11-12	741	3,124,178	2.32	1.18	11.52
12-13	527	2,415,772	1.65	0.91	12.52
13-14	522	2,579,318	1.63	0.97	13.50
14-15	513	2,716,024	1.60	1.03	14.47
Subtotal 0-15	**22,217**	**38,370,755**	**69.44**	**14.50**	**4.72**
15-20	1,923	12,277,109	6.01	4.64	17.44
20-25	1,405	11,496,831	4.39	4.34	22.36
25-30	1,001	10,030,326	3.13	3.79	27.38
30-35	718	8,514,594	2.24	3.22	32.40
35-40	685	9,347,197	2.14	3.53	37.28
40-45	479	7,460,671	1.50	2.82	42.56
45-50	391	6,794,150	1.22	2.57	47.48
>50	3,174	160,317,168	9.92	60.59	138.00
Total	**31,993**	**264,608,801**	**100.00**	**100.00**	**22.60**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; and Dwight's EnergyData, Inc.

Distribution of Wells and BOE Production by Production Rate Bracket for California, 1992

Production Rate Bracket (BOE/Day)	Wells	Annual Production (BOE)	Percent of Wells	Percent of Production	Average Annual Production Rate Per Well (BOE/Day)
0-1	4,464	698,845	9.71	0.20	0.43
1-2	2,988	1,626,389	6.50	0.47	1.49
2-3	2,706	2,460,206	5.89	0.71	2.48
3-4	2,389	3,048,642	5.20	0.88	3.49
4-5	2,150	3,538,962	4.68	1.03	4.50
5-6	1,936	3,888,637	4.21	1.13	5.49
6-7	1,750	4,158,958	3.81	1.21	6.49
7-8	1,636	4,492,626	3.56	1.30	7.50
8-9	1,503	4,665,154	3.27	1.35	8.48
9-10	1,339	4,650,921	2.91	1.35	9.49
Subtotal 0-10	**22,861**	**33,229,340**	**49.73**	**9.63**	**3.97**
10-11	1,326	5,092,729	2.88	1.48	10.49
11-12	1,215	5,110,690	2.64	1.48	11.49
12-13	1,131	5,172,417	2.46	1.50	12.50
13-14	1,058	5,227,353	2.30	1.51	13.50
14-15	1,001	5,310,450	2.18	1.54	14.49
Subtotal 0-15	**28,592**	**59,142,979**	**62.20**	**17.14**	**5.65**
15-20	4,117	26,152,407	8.96	7.58	17.36
20-25	2,839	23,255,918	6.18	6.74	22.38
25-30	2,103	21,097,306	4.57	6.11	27.41
30-35	1,632	19,372,545	3.55	5.61	32.43
35-40	1,235	16,886,797	2.69	4.89	37.36
40-45	905	14,040,929	1.97	4.07	42.39
45-50	683	11,830,087	1.49	3.43	47.32
>50	3,862	153,362,615	8.40	44.43	108.50
Total	**45,968**	**345,141,583**	**100.00**	**100.00**	**20.51**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: For Average Annual Production Rate, the total annual production of all the wells in a Production Rate Bracket were divided by all the wells that produced for some period during the year.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; and Dwight's EnergyData, Inc.

Appendix F

Section II

Operating Costs

Material in Appendix

Cost Algorithm Calibration Examples

Material in Working Papers

The following information is available from the NPC in the form of working papers:

- All Cost Algorithms and Survey Data
- Tables of Cost Survey Data

Operating Costs

The Energy Information Administration (EIA) used its Cost and Indices report data as a basis for generating the initial economic model cost algorithms. These data are gathered annually from industry service providers and are assimilated into a report that details the costs for producing a hypothetical lease. In order to validate these data, the NPC surveyed producers within the study group in addition to producers associated with the Independent Petroleum Association of America, the National Stripper Well Association, and the Interstate Oil and Gas Compact Commission, to gather actual operating cost data. The data requested were for costs to produce marginal properties so that an upper bound could be placed on the EIA cost algorithms. However, the data received covered a wide range of properties including those that are marginal as well as those that operators deem to be non-marginal properties (based on average 1993 realized oil price).

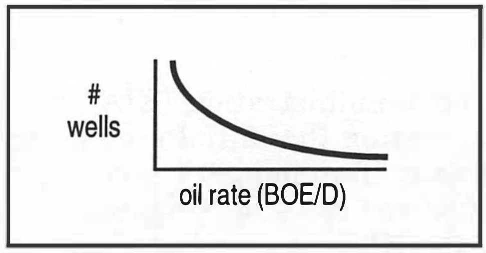
The EIA cost algorithms address normal daily expense (which includes lease level overhead and supervision), water disposal costs, lifting costs, and surface and subsurface repair and maintenance. In addition to the data from the Cost and Indices report, the EIA in conjunction with industry input generated a water disposal cost curve, since water disposal costs can be a significant portion of a well's operating expense. The water disposal cost curve indicates that as larger volumes of water are produced from a well, lease, or field, there are economies of scale that can be achieved for more efficient water disposal or injection operations. The figure on the next page illustrates the cost components mentioned above.

After integrating the cost and indices and water disposal data, cost curves were generated by depth for areas that correspond to data in the Cost and Indices report. Cost curves were generated for an isolated lease producing at 1, 5, 10, and 20 barrels per day and plotted on a cost per barrel of oil equivalent (BOE) versus water cut graph. The cost curves indicate increasing costs at higher water cuts and lower well production rates. In addition to the isolated lease scenario, it was recognized that large field operations realize economies of scale. These economies occur primarily in water disposal costs and infrastructure advantages and are shown as a separate curve on the cost curve graph. In order to accurately model costs from wells producing at rates below 10 BOE/D, daily costs (including lease level supervision and overhead) were proportionally reduced to represent a lower frequency of well monitoring. For example, a well producing 10 BOE/D or more incurred the full cost ($7.20/day) of daily supervision, while a well producing at 2 BOE/D incurred only 20 percent of the full cost ($1.44/day).

The algorithm calibration/verification process included several steps. Each step is illustraed with a series of four graphs for several areas, as shown on pages F.II-5 through F.II-26. Initially all of the survey data were used to determine if the general trend of the curves was correct. For several sets of data, this included plotting data where no depth information was provided. With this level of verification accomplished, the data were plotted in a more detailed manner separating the data by state, depth, and water cut. Portions of the data were omitted where no depth or water cut information was available. These plots provided guidance for

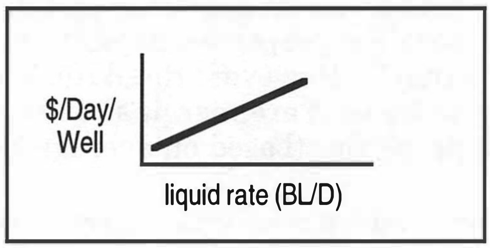
Item/Description	Curve	Source

1. Distribution of oil wells by production rate bracket for select well depths and geographic areas



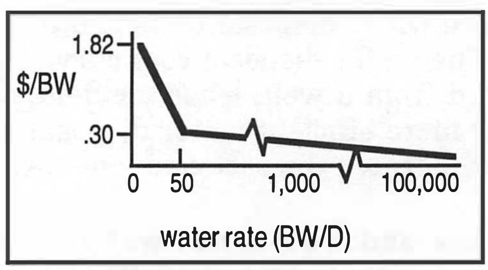
Dwight's and EIA. In some cases, well production rates are based on lease/ field averages.

2. Well Lifting Cost (less water disposal cost)



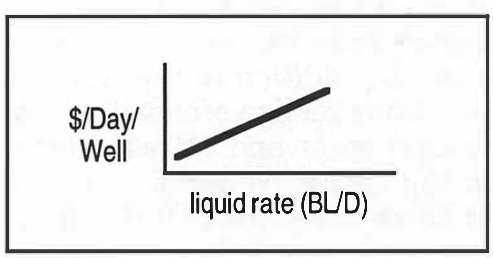
EIA "Cost and Indices Report."

3. Well Water Disposal Cost



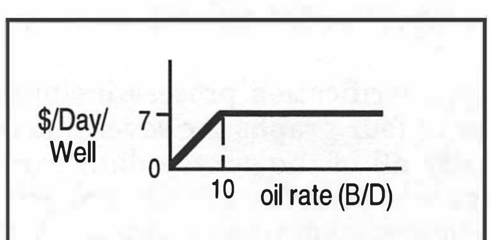
Developed by EIA. Calibrated by NPC.

4. Well Surface and Subsurface Maintainance Cost



EIA "Cost and Indices Report."

5. Normal Daily Expense (Including Well/Lease Level, Labor, Overhead, and Supervision)



EIA "Cost and Indices Report." Costs are based on "typical" 10 well oil lease producing 100 B/D/well of fluid.

EIA Economic Model Operating Cost Components.

further refining of the EIA cost algorithms. The final step of the calibration process was to eliminate all data where rate information was not provided, eliminate survey data with rates greater than 21 BOE/D and include full-field water handling cost curves. Survey data were then segregated into rate brackets so that a closer correspondence to the EIA rate curves could be established.

Results of the calibration efforts indicated that water handling (injection and disposal) costs vary significantly from area to area and, in some cases, from well to well within an area and make it impossible to precisely estimate each wells operating costs. The water handling information utilized in the cost curves represents an average and provides a relatively accurate cost over a broad spectrum of wells. Very few cost data were provided by survey participants on wells with rates less than one barrel of oil equivalent per day—a majority of which are probably Class 2 intermittent producers. The small operators owning these very low rate wells have developed unique operating practices to maintain their production. When prices fall, these operating practices may deviate substantially from what optimum operations would normally include. For example, maintenance may be performed less frequently than normal. These conditions make considering a cash flow analysis problematic, since few operating cost data are available and the mode of operations for these wells is radically different from higher rate wells. As previously demonstrated, small cost increases or production rate decreases can cause significant swings in costs on a per BOE basis for these low rate wells.

Although survey information and the calibration process had several shortcomings, it is believed that an adequate correlation between actual cost data and the cost algorithms exists to provide a high degree of confidence that the general population of wells can be represented with the EIA cost algorithms.

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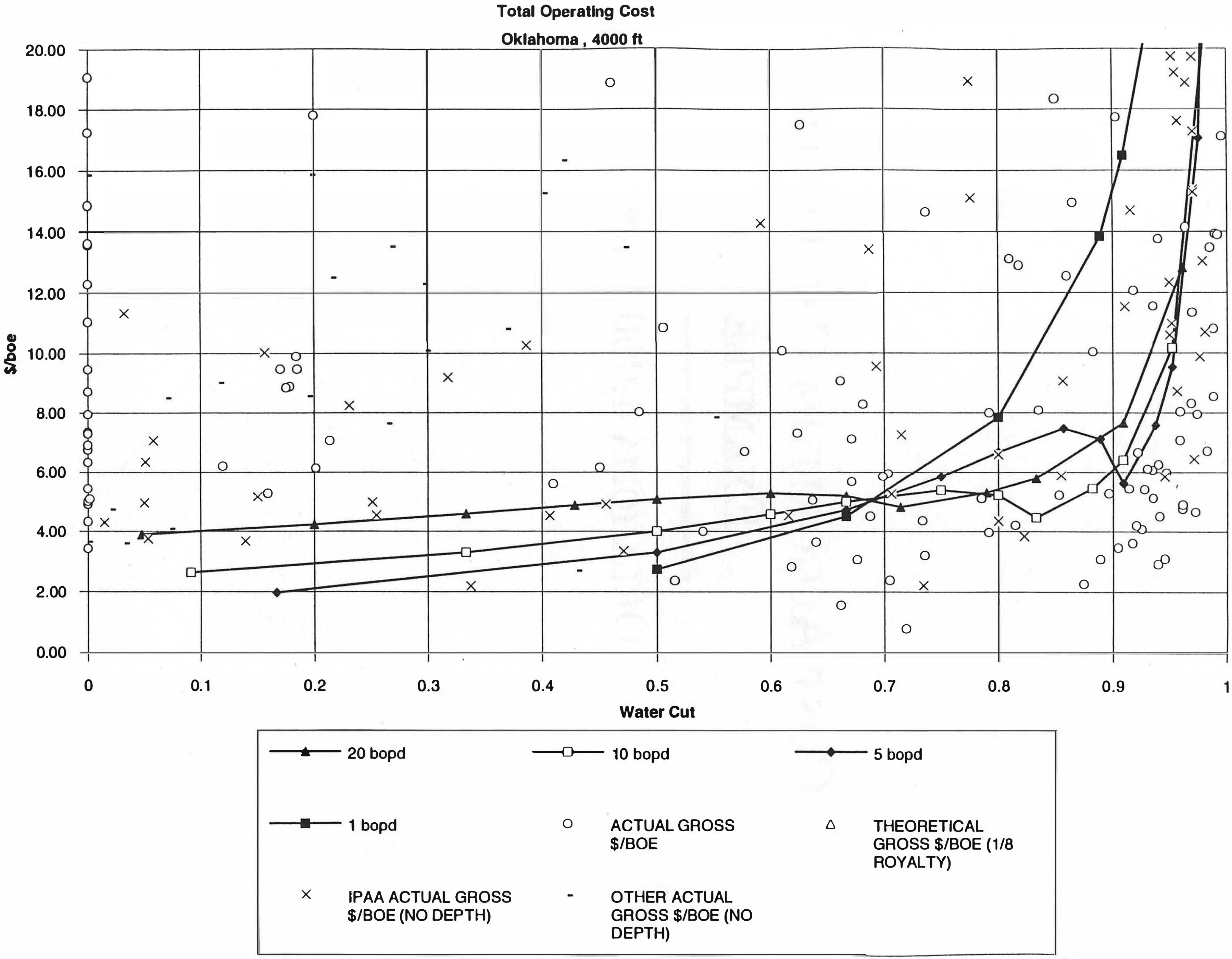
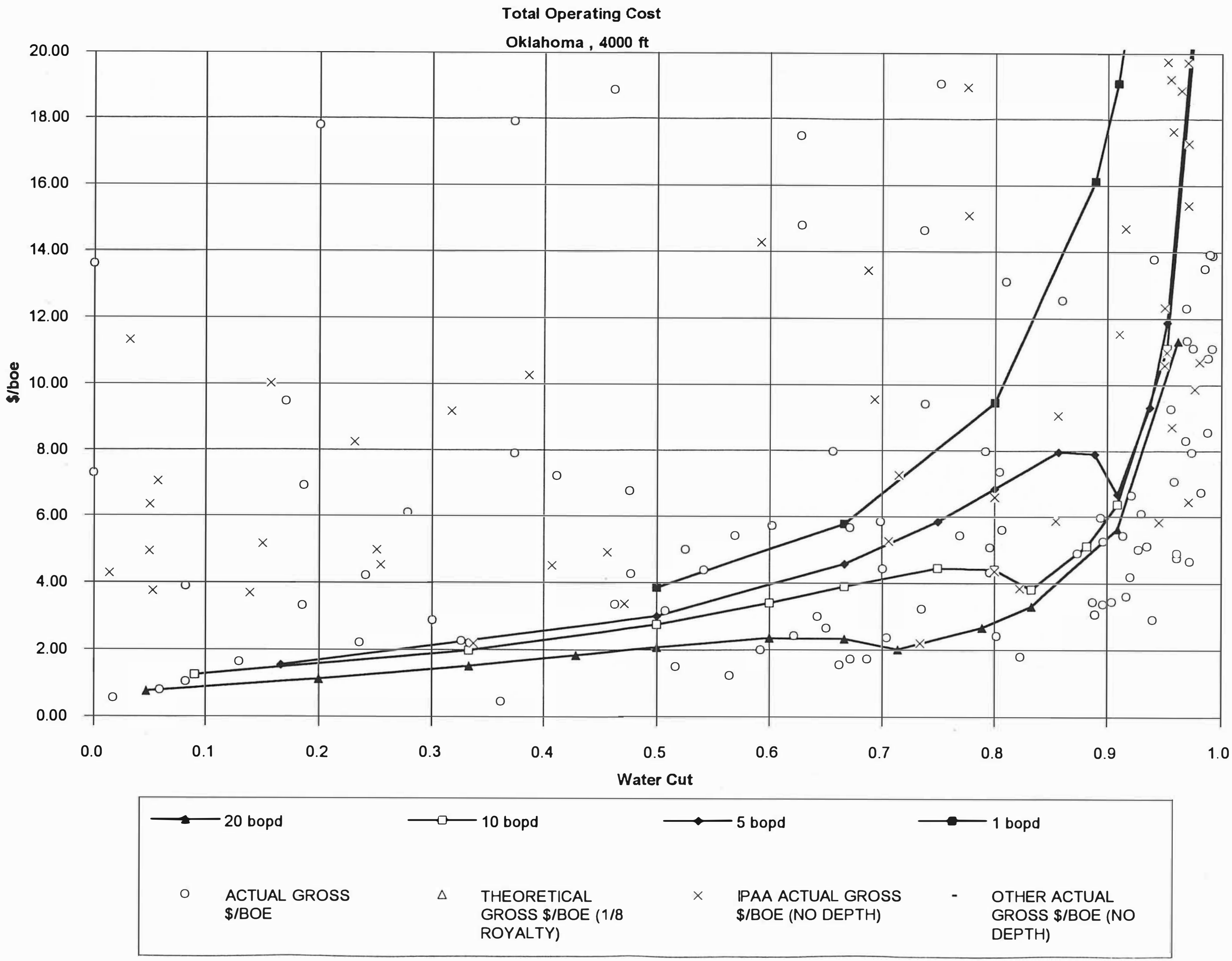
Cost Algorithm Calibration Example

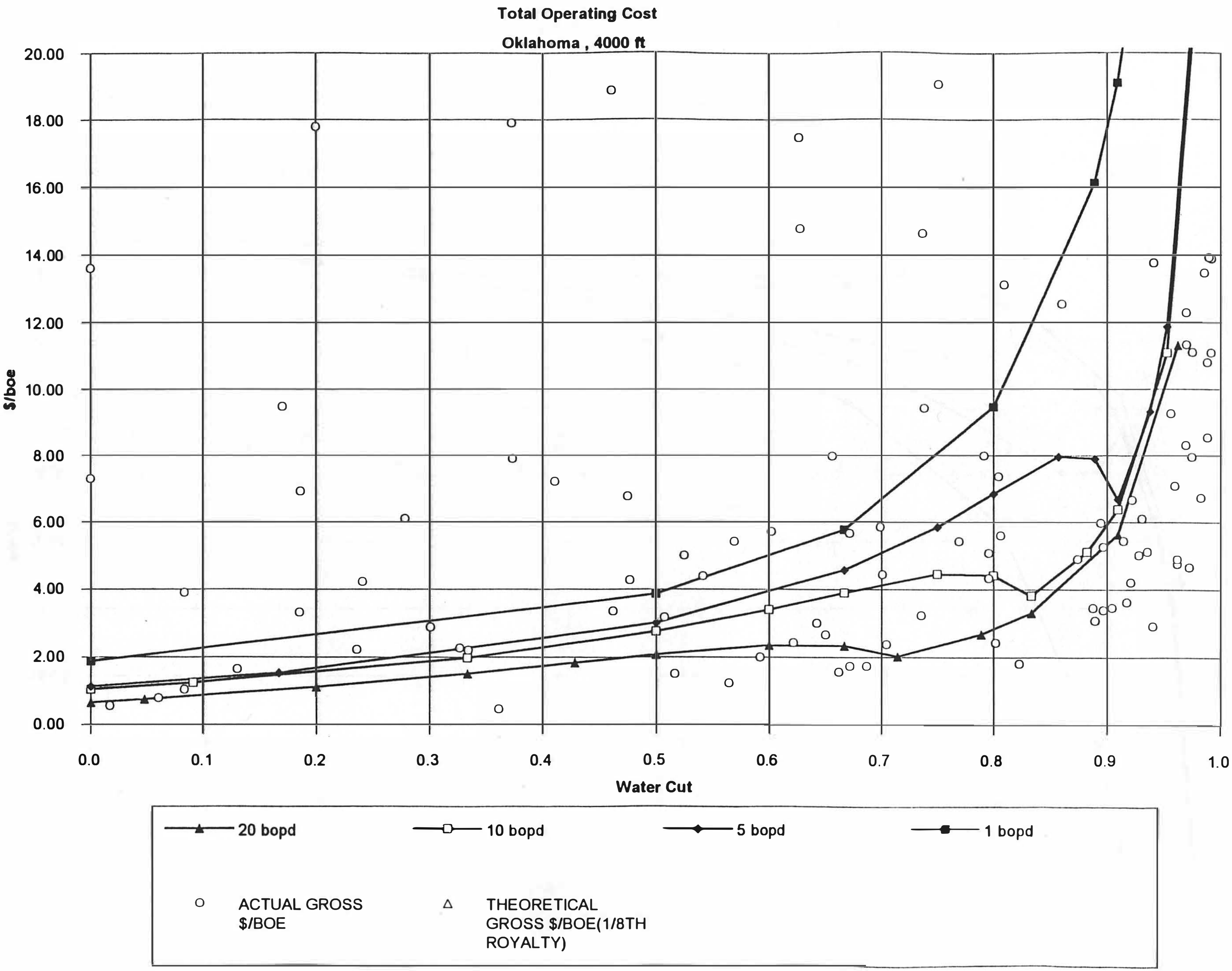
Oklahoma 4,000 Feet

F.II-6



Total Operating Cost
Oklahoma , 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE (1/8 ROYALTY)
IPAA ACTUAL GROSS $/BOE (NO DEPTH)
OTHER ACTUAL GROSS $/BOE (NO DEPTH)

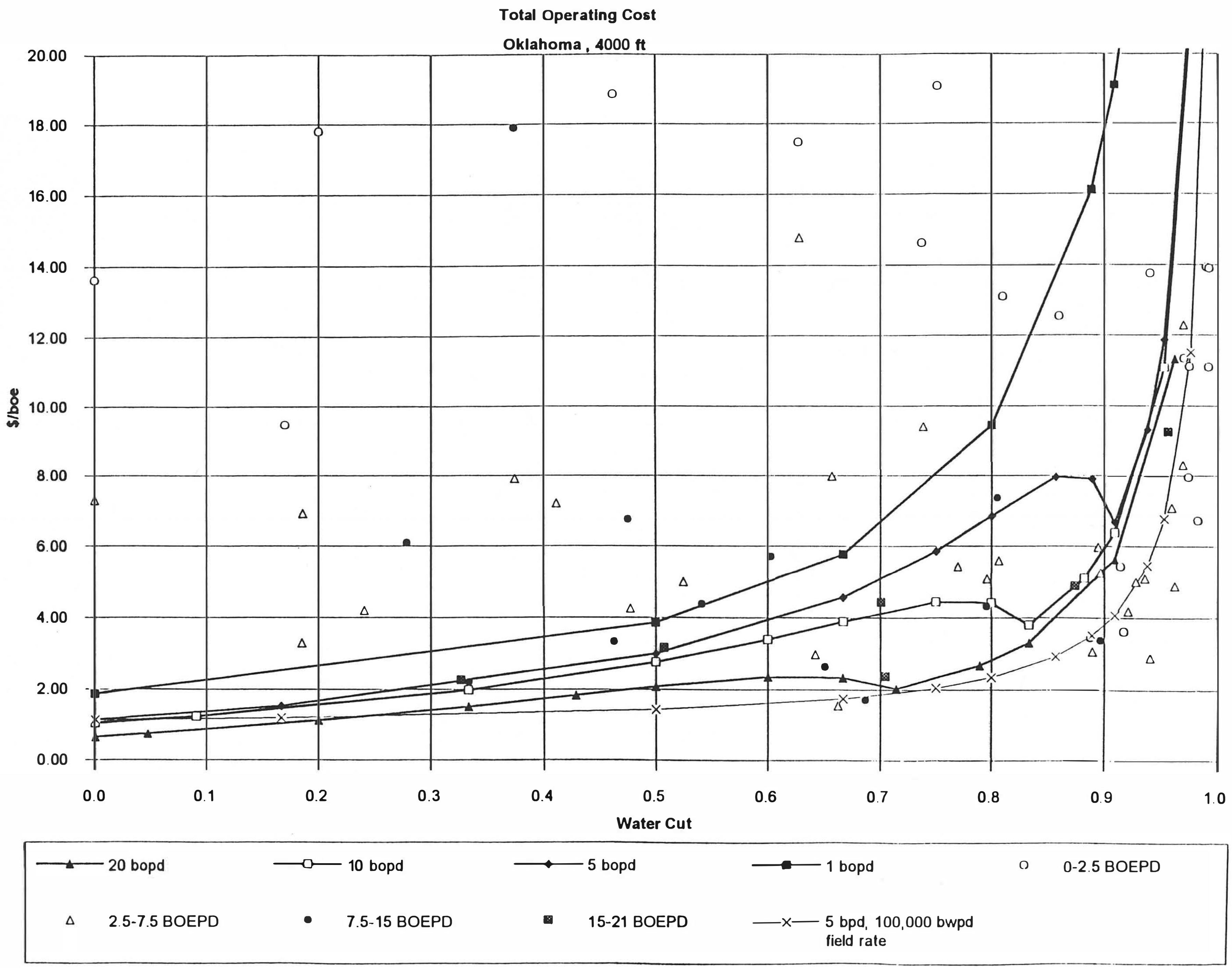

Total Operating Cost
Oklahoma , 4000 ft
$/boe
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE (1/8 ROYALTY)
IPAA ACTUAL GROSS $/BOE (NO DEPTH)
OTHER ACTUAL GROSS $/BOE (NO DEPTH)



Total Operating Cost
Oklahoma , 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE(1/8TH ROYALTY)

F.II-8

F.II-9



Total Operating Cost
Oklahoma , 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
0-2.5 BOEPD
2.5-7.5 BOEPD
7.5-15 BOEPD
15-21 BOEPD
5 bpd, 100,000 bwpd field rate

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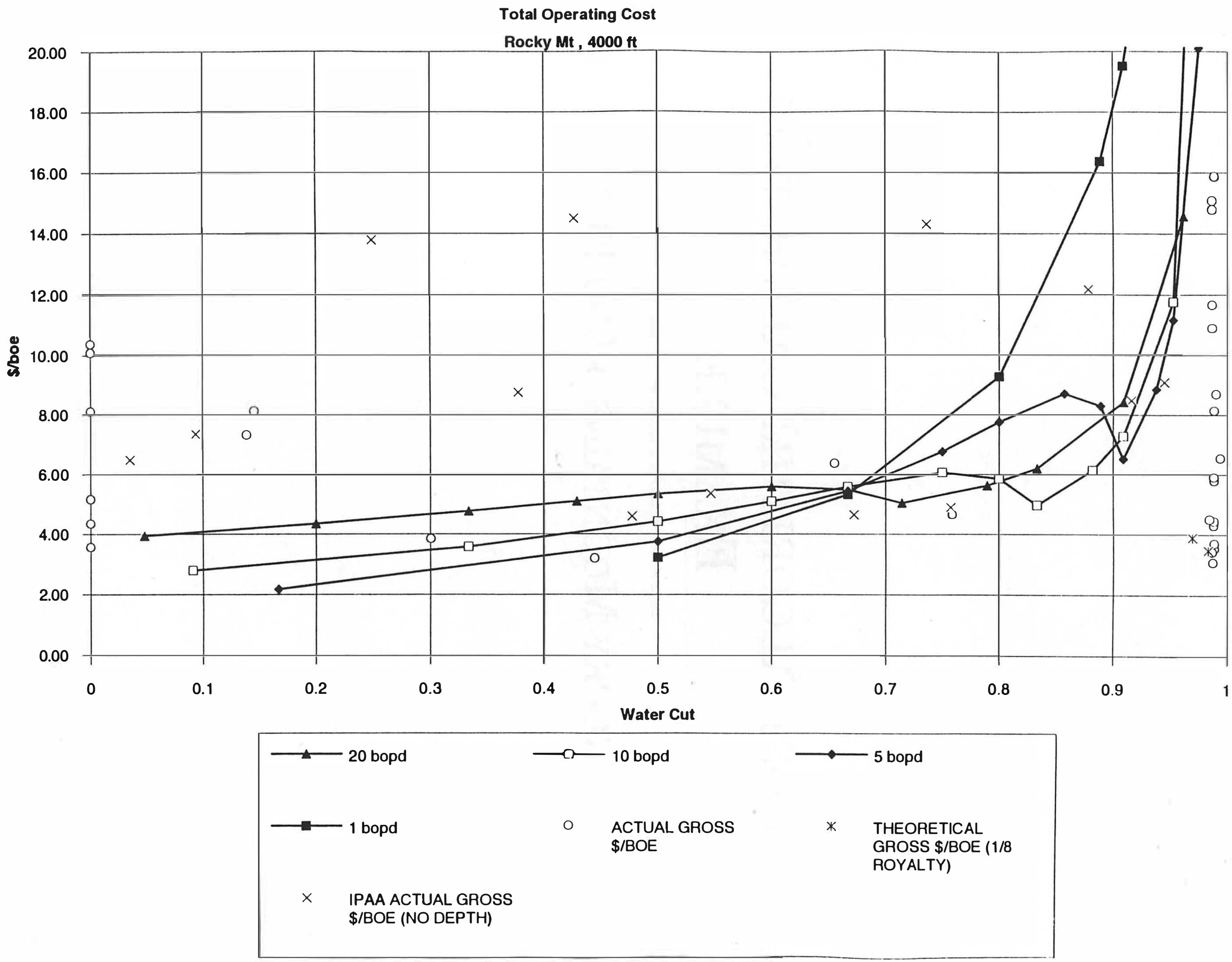
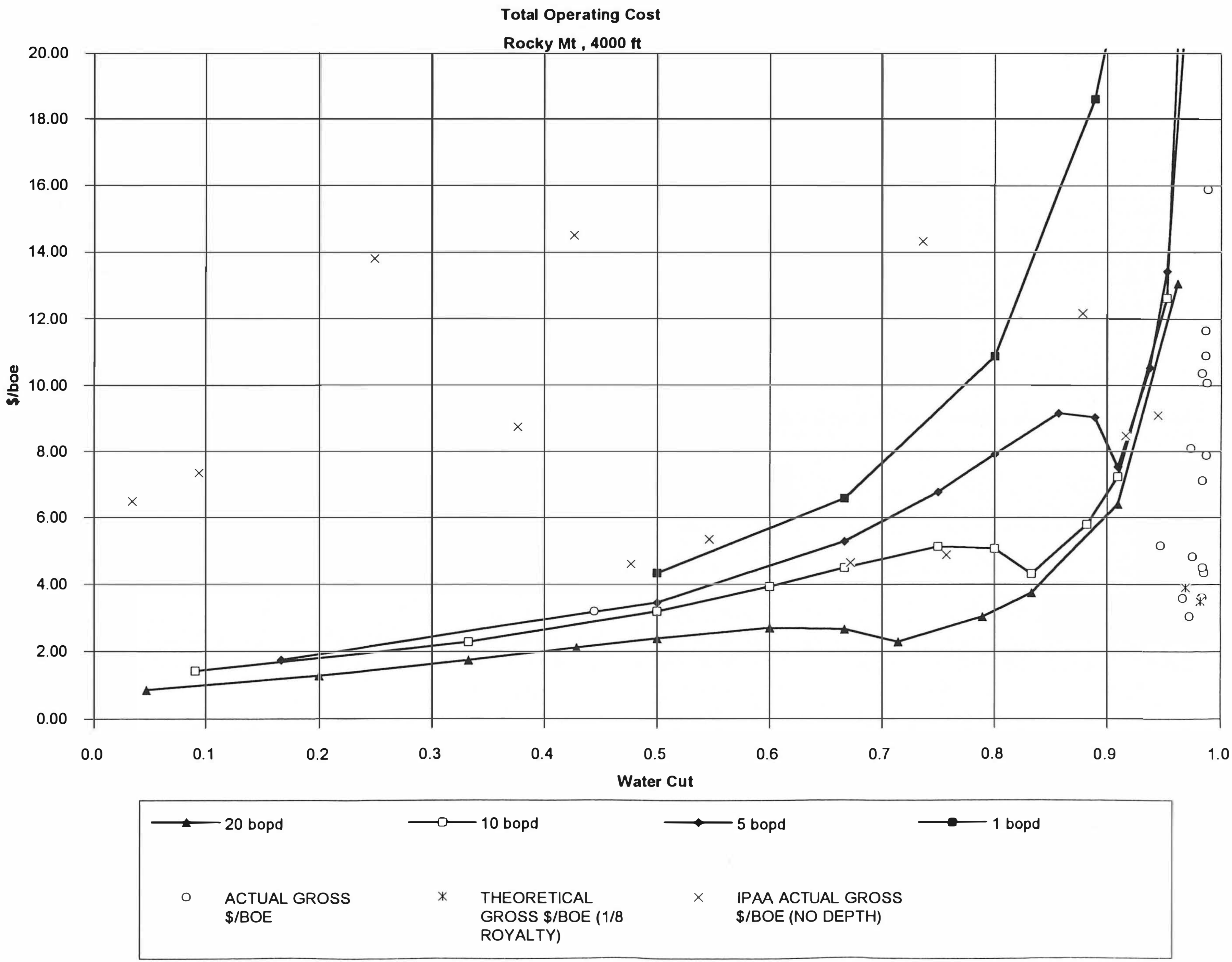
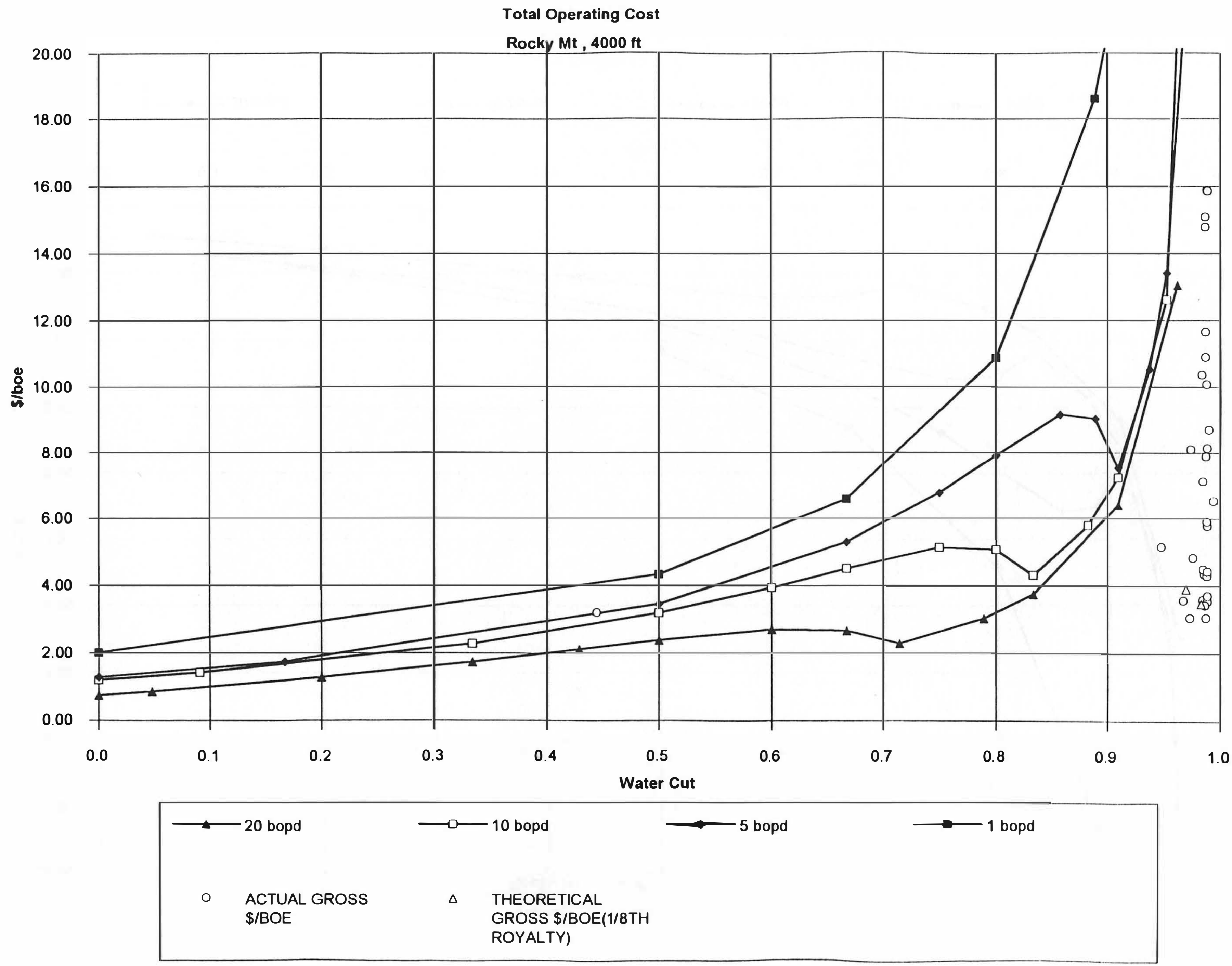
Cost Algorithm Calibration Example

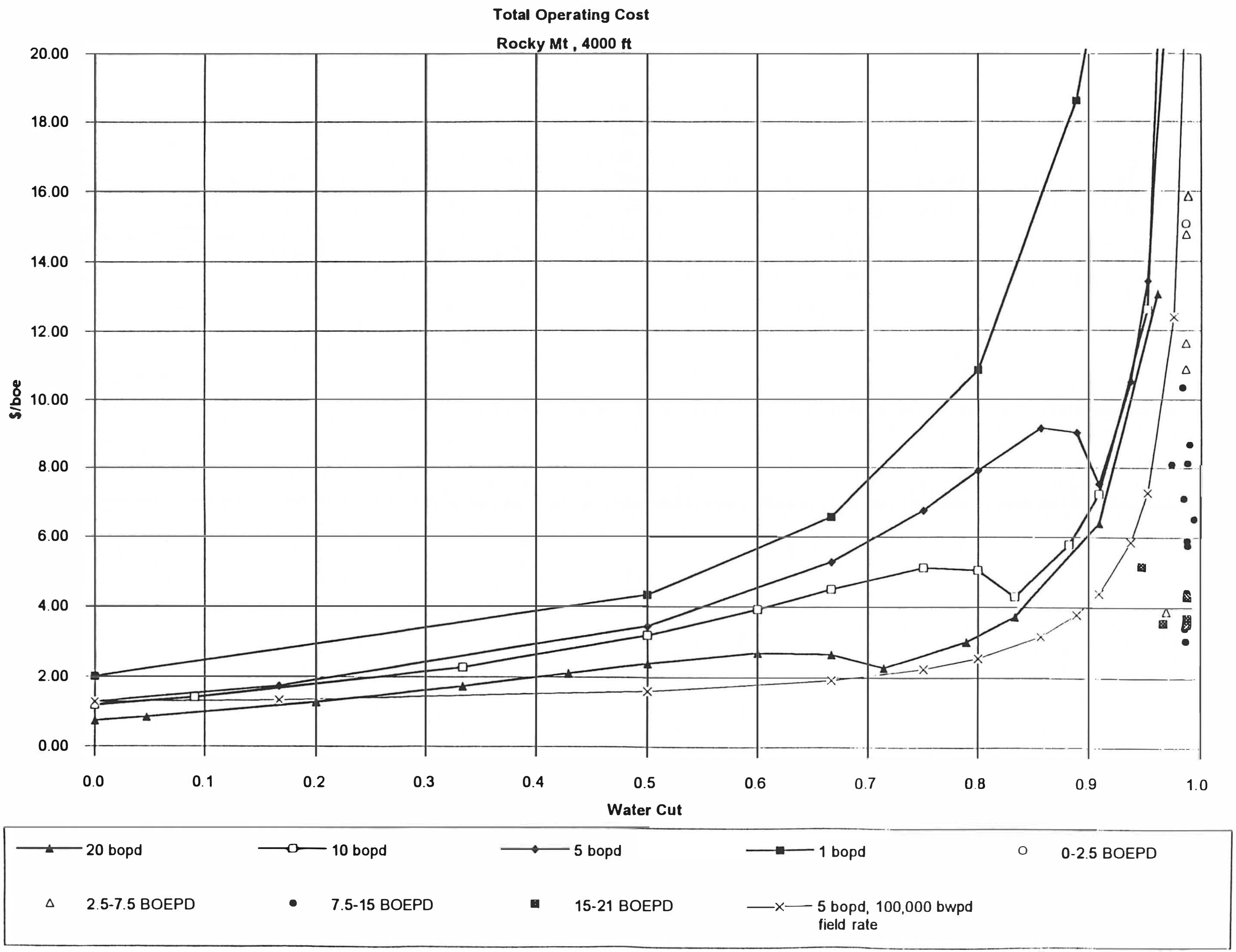
Rocky Mountains 4,000 Feet


Total Operating Cost
Rocky Mt , 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE (1/8 ROYALTY)
IPAA ACTUAL GROSS $/BOE (NO DEPTH)


Total Operating Cost
Rocky Mt , 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE (1/8 ROYALTY)
IPAA ACTUAL GROSS $/BOE (NO DEPTH)



Total Operating Cost
Rocky Mt , 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE(1/8TH ROYALTY)



Total Operating Cost
Rocky Mt , 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
0-2.5 BOEPD
2.5-7.5 BOEPD
7.5-15 BOEPD
15-21 BOEPD
5 bopd, 100,000 bwpd field rate

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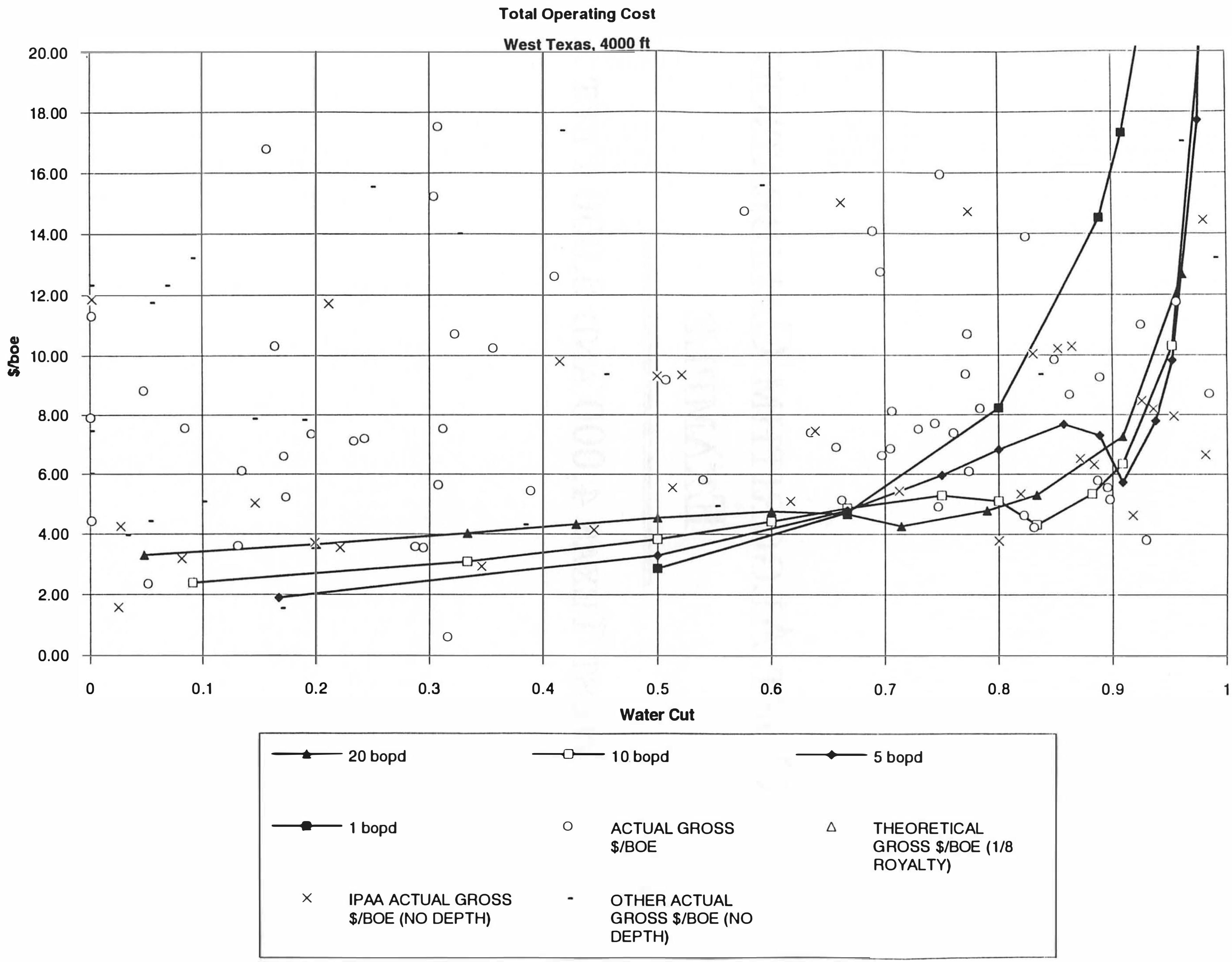
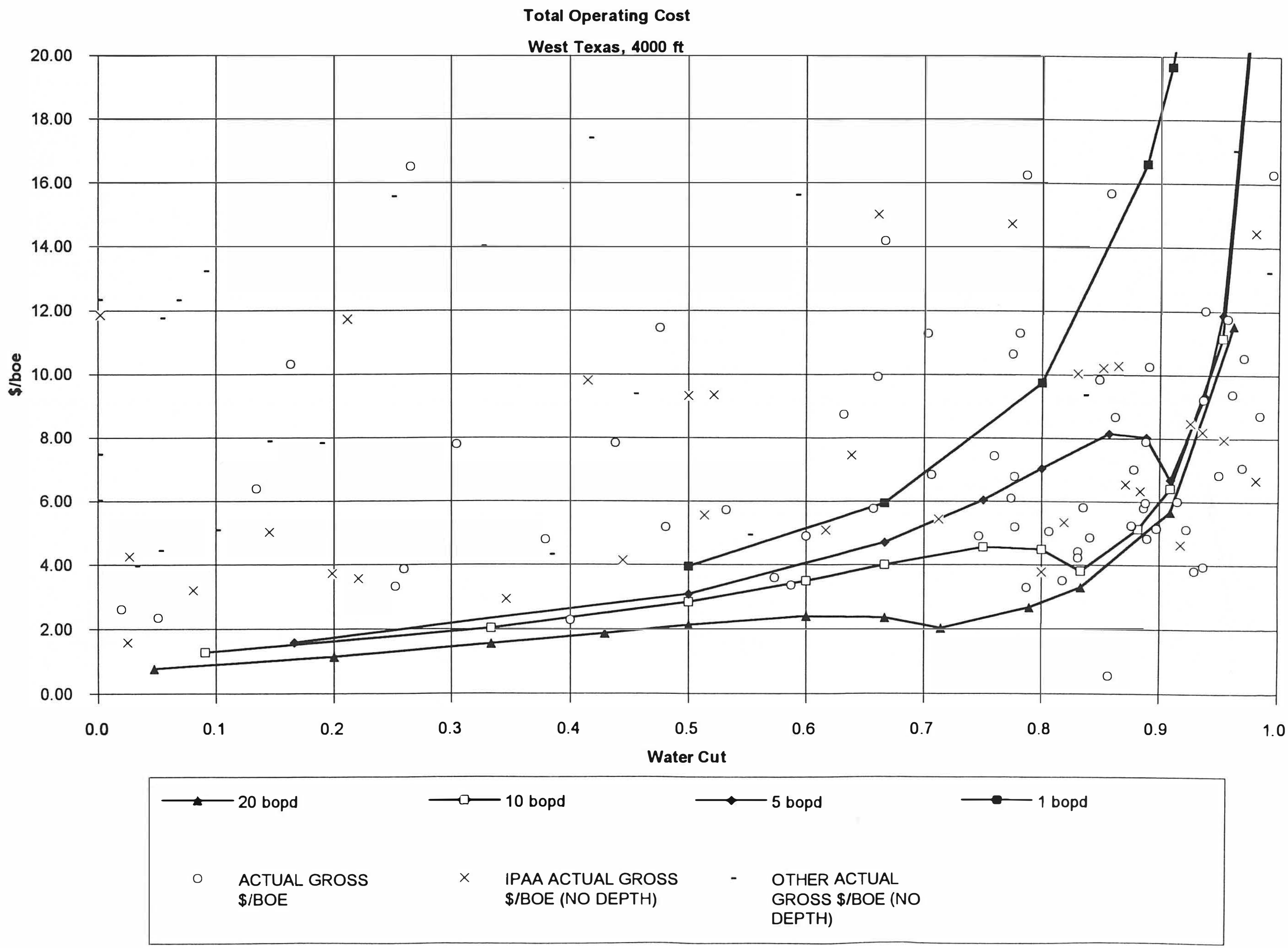
Cost Algorithm Calibration Example

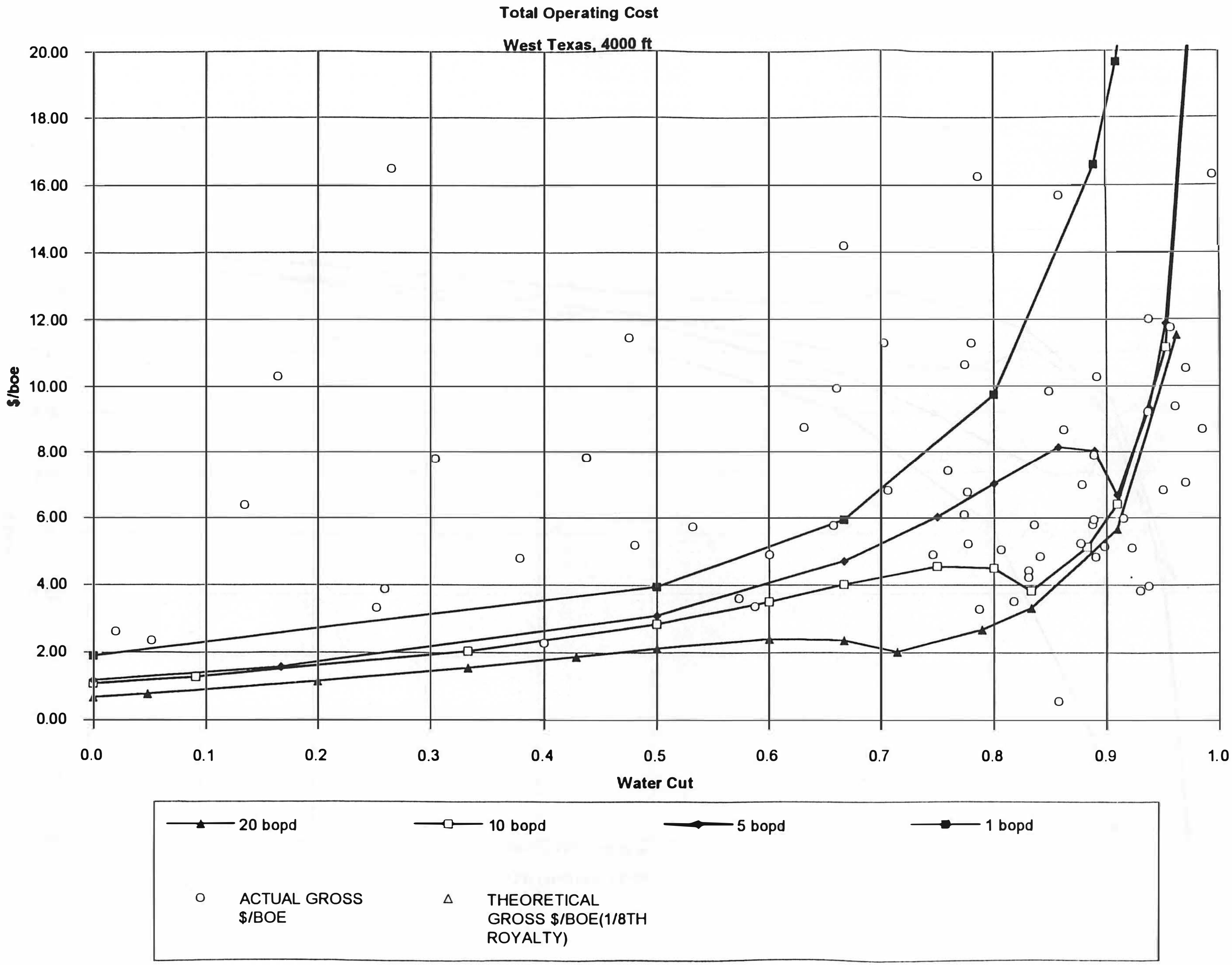
West Texas 4,000 and 6,000 Feet



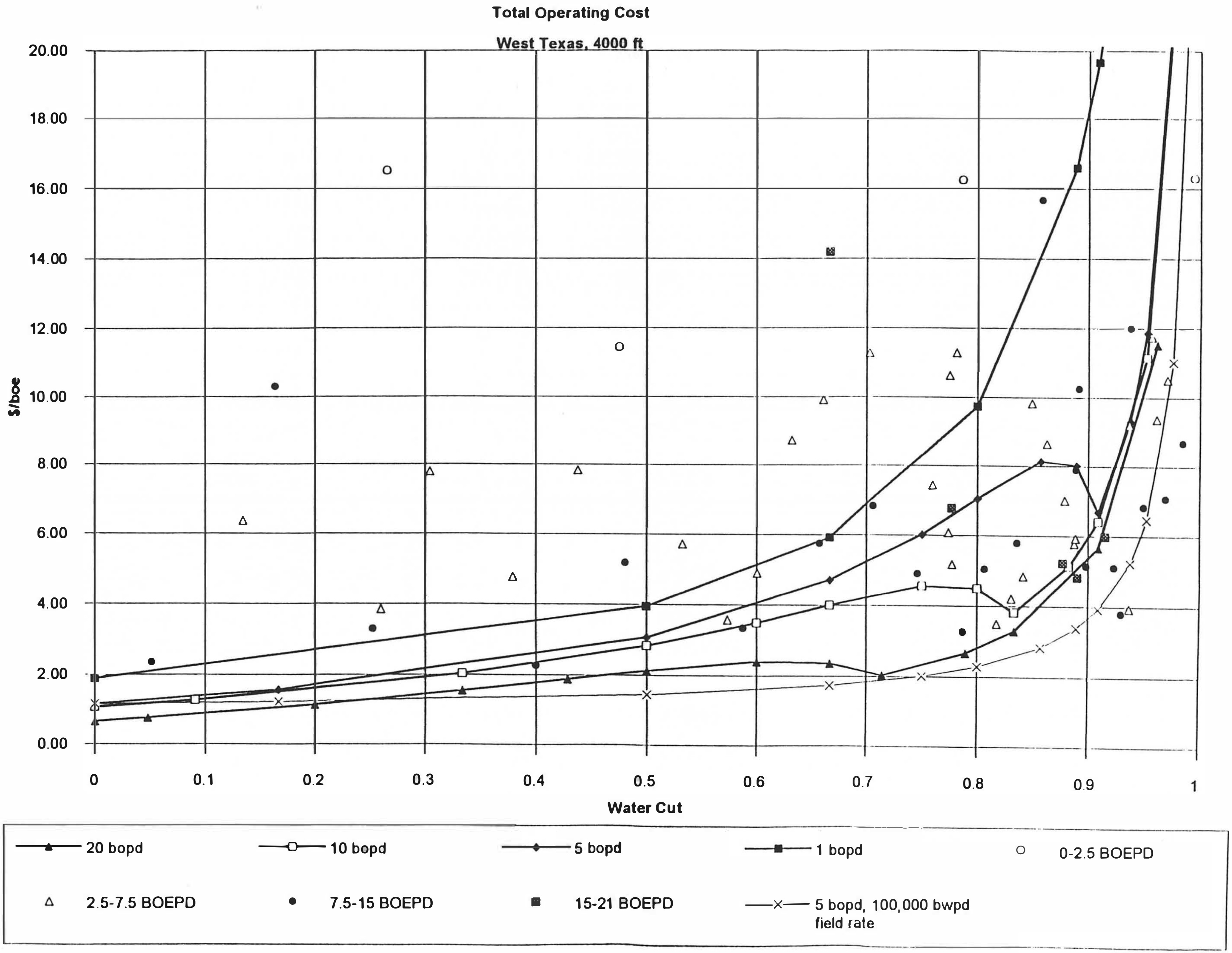
Total Operating Cost
West Texas, 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE (1/8 ROYALTY)
IPAA ACTUAL GROSS $/BOE (NO DEPTH)
OTHER ACTUAL GROSS $/BOE (NO DEPTH)



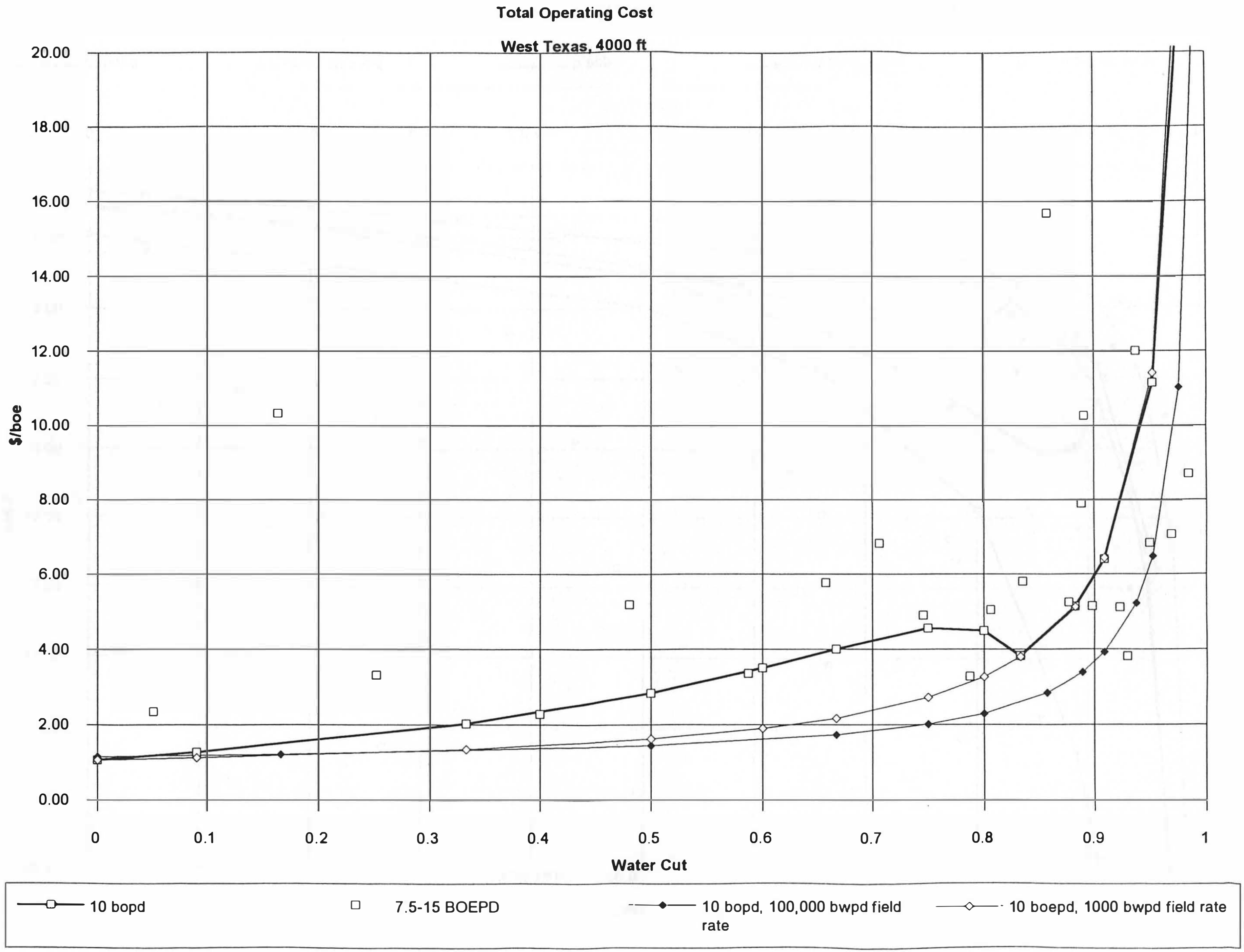
Total Operating Cost
West Texas, 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
IPAA ACTUAL GROSS $/BOE (NO DEPTH)
OTHER ACTUAL GROSS $/BOE (NO DEPTH)



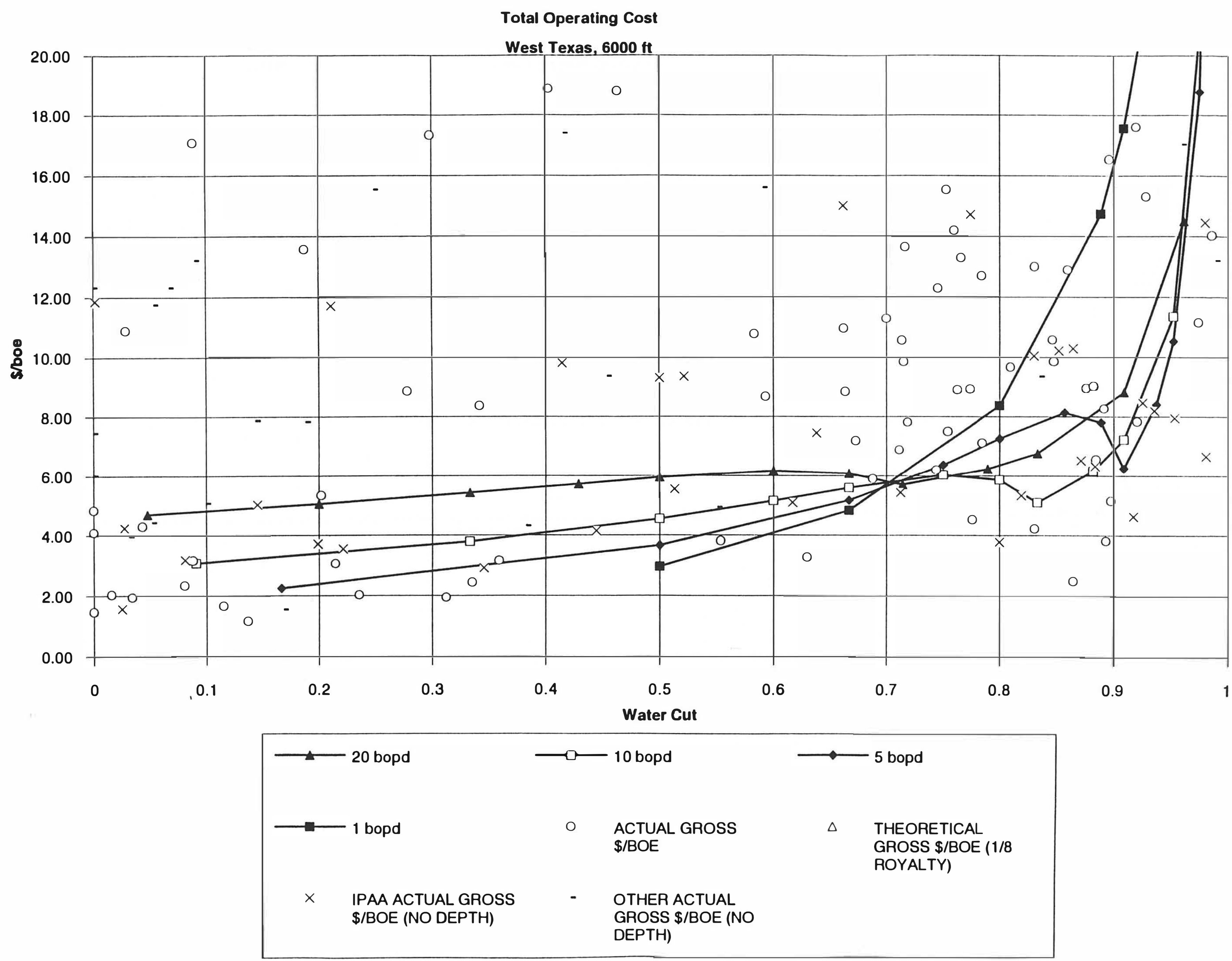
Total Operating Cost
West Texas, 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE(1/8TH ROYALTY)

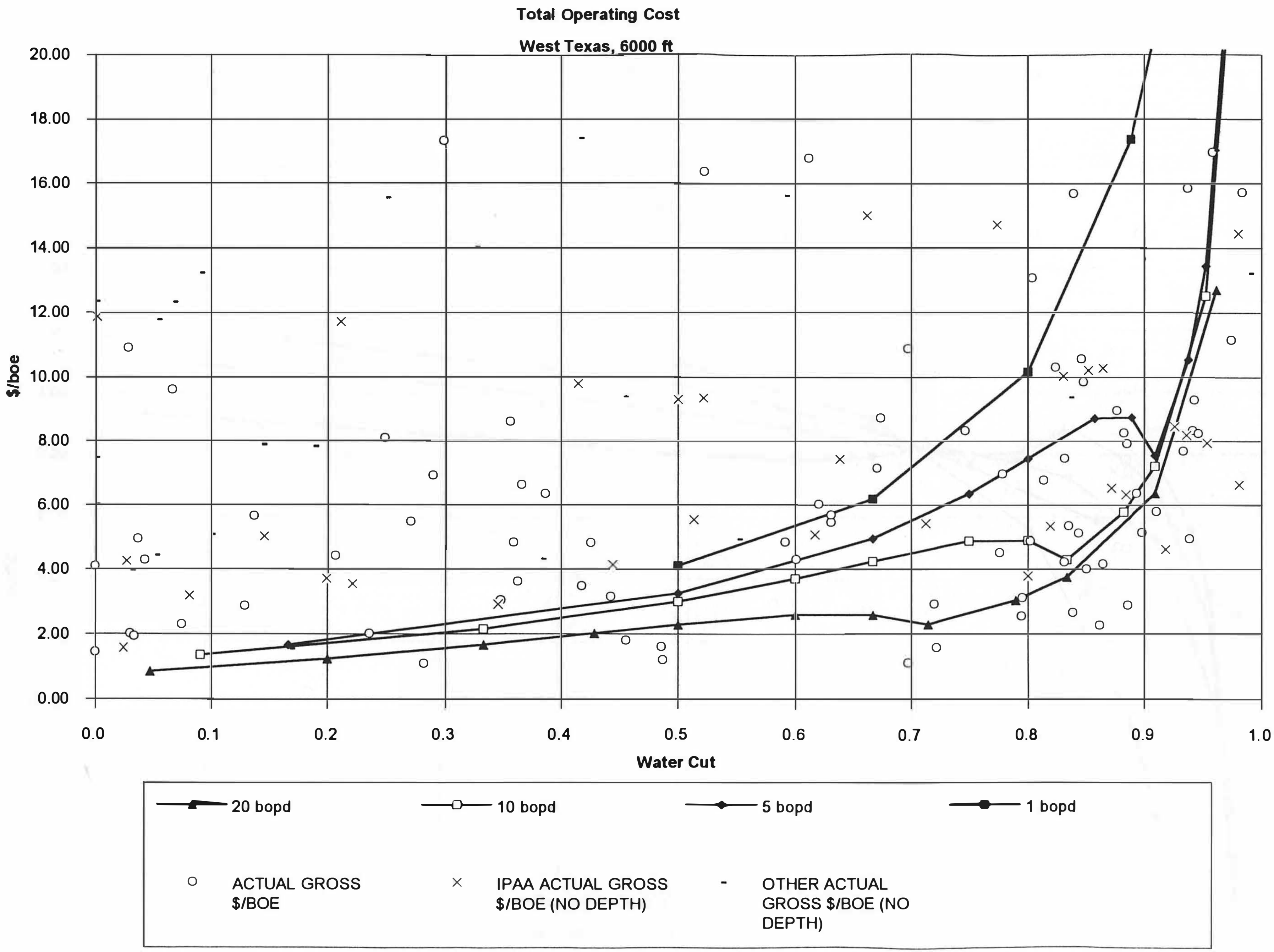


Total Operating Cost
West Texas, 4000 ft
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
$/boe
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
0-2.5 BOEPD
2.5-7.5 BOEPD
7.5-15 BOEPD
15-21 BOEPD
5 bopd, 100,000 bwpd field rate



Total Operating Cost
West Texas, 4000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Water Cut
10 bopd
7.5-15 BOEPD
10 bopd, 100,000 bwpd field rate
10 boepd, 1000 bwpd field rate


Total Operating Cost
West Texas, 6000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE (1/8 ROYALTY)
IPAA ACTUAL GROSS $/BOE (NO DEPTH)
OTHER ACTUAL GROSS $/BOE (NO DEPTH)



Total Operating Cost
West Texas, 6000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
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0.1
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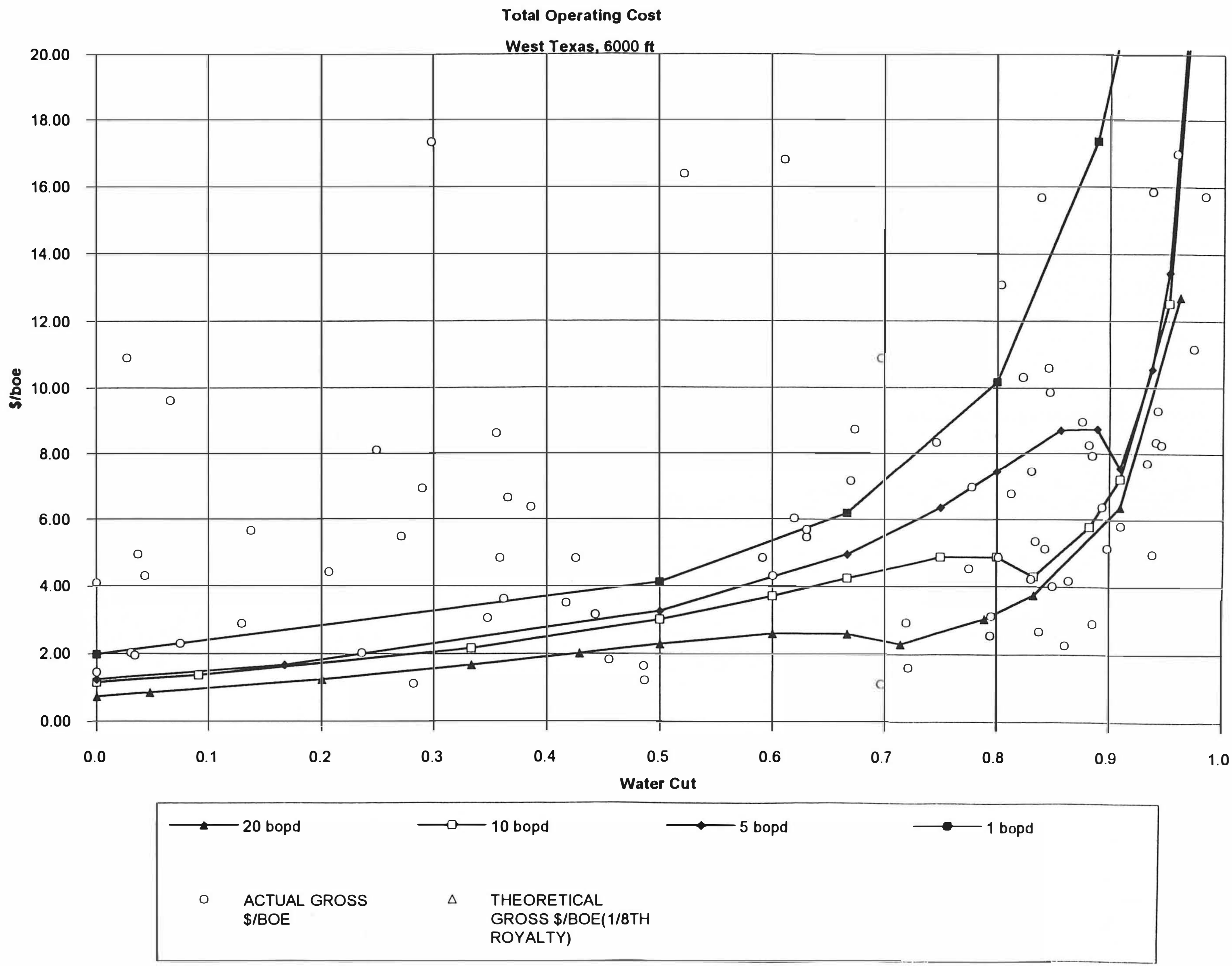
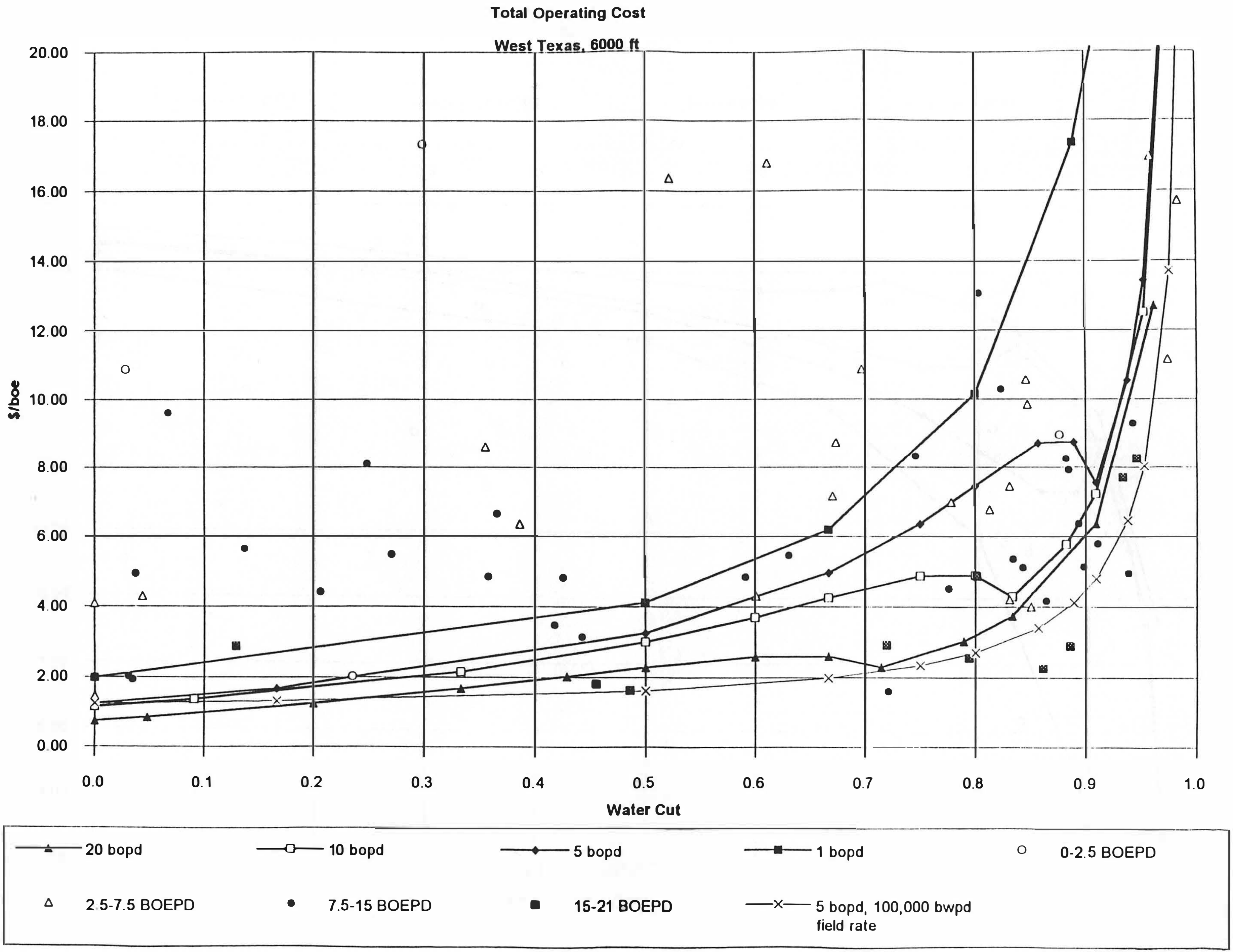
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
IPAA ACTUAL GROSS $/BOE (NO DEPTH)
OTHER ACTUAL GROSS $/BOE (NO DEPTH)



Total Operating Cost
West Texas, 6000 ft
$/boe
Water Cut
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
20 bopd
10 bopd
5 bopd
1 bopd
ACTUAL GROSS $/BOE
THEORETICAL GROSS $/BOE(1/8TH ROYALTY)



Total Operating Cost
West Texas, 6000 ft
$/boe
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
0.0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1.0
Water Cut
20 bopd
10 bopd
5 bopd
1 bopd
0-2.5 BOEPD
2.5-7.5 BOEPD
7.5-15 BOEPD
15-21 BOEPD
5 bopd, 100,000 bwpd field rate

F.II-26

Appendix F

Section III

Well Level Economic Analyses

These data deal with well/lease level before federal income tax cash flow only and do not address full costs of operations.

Material in Appendix

Example of Economic Status of Oil Wells by Production Rate Bracket, 1992—Production and Wells at $14 per Barrel Domestic Oil Price

- Lower-48 States Onshore

Material in Working Papers

The following analytical results are available from the NPC in the form of working papers:

Economic Status of Oil Wells by Production Rate Bracket, 1992—Production and Wells at $8, $10, $12, $14, $16, $18, and $20 per Barrel Domestic Oil Price

- Lower-48 States Onshore
- Eastern States
- Midcontinent
- Gulf Coast
- Permian Basin
- Rocky Mountains
- California

Economic Status of Oil Wells by Production Rate Bracket for 1992, Onshore Lower-48 States ($14.00/ Bbl Domestic Oil Price)

Production Rate Bracket *(BOE/Day)*	*Wells*	*Annual Production (BOE)*	*Economic Production (Percent)*	*Uneconomic Production (Percent)*
0-1	193,171	26,854,848	84.3	15.7
1-2	76,543	38,006,537	88.4	11.6
2-3	45,842	38,102,298	88.0	12.0
3-4	31,571	36,687,215	88.8	11.2
4-5	23,604	35,035,606	89.6	10.4
5-6	20,169	36,675,144	91.6	8.4
6-7	15,534	33,480,067	91.7	8.3
7-8	12,899	31,864,813	91.6	8.4
8-9	11,277	31,508,673	91.8	8.2
9-10	11,622	37,263,716	93.2	6.8
Subtotal 0-10	**442,232**	**345,478,917**	**90.0**	**10.0**
10-11	8,862	31,175,187	93.1	6.9
11-12	7,931	30,014,809	92.7	7.3
12-13	6,764	27,788,799	93.2	6.8
13-14	6,343	28,613,679	93.6	6.4
14-15	6,455	30,993,773	93.7	6.3
Subtotal 0-15	**478,587**	**494,065,164**	**91.0**	**9.0**
15-20	21,750	123,178,837	93.0	7.0
20-25	17,830	130,920,323	95.3	4.7
25-30	13,063	119,248,198	96.1	3.9
30-35	9,108	92,156,990	95.8	4.2
35-40	5,303	62,327,340	95.7	4.3
40-45	4,185	53,222,790	96.3	3.7
45-50	3,275	49,194,837	96.6	3.4
>50	32,957	921,415,281	98.0	2.0
Total	**586,058**	**2,045,729,760**	**95.5**	**4.5**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: An Uneconomic well can no longer produce enough income to meet normal lease operating costs.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; Dwight's EnergyData, Inc.; and Petroleum Information Corp.

Economic Status of Oil Wells by Production Rate Bracket for 1992, Onshore Lower-48 States ($14.00/ Bbl Domestic Oil Price)

Production Rate Bracket *(BOE/Day)*	*Wells*	*Annual Production (BOE)*	*Economic Wells (Percent)*	*Uneconomic Wells (Percent)*
0-1	193,171	26,854,848	66.9	33.1
1-2	76,543	38,006,537	88.6	11.4
2-3	45,842	38,102,298	88.1	11.9
3-4	31,571	36,687,215	89.1	10.9
4-5	23,604	35,035,606	89.7	10.3
5-6	20,169	36,675,144	91.7	8.3
6-7	15,534	33,480,067	92.0	8.0
7-8	12,899	31,864,813	92.0	8.0
8-9	11,277	31,508,673	92.2	7.8
9-10	11,622	37,263,716	93.3	6.7
Subtotal 0-10	**442,232**	**345,478,917**	**79.7**	**20.3**
10-11	8,862	31,175,187	93.6	6.4
11-12	7,931	30,014,809	93.3	6.7
12-13	6,764	27,788,799	93.6	6.4
13-14	6,343	28,613,679	94.1	5.9
14-15	6,455	30,993,773	94.2	5.8
Subtotal 0-15	**478,587**	**494,065,164**	**80.8**	**19.2**
15-20	21,750	123,178,837	93.5	6.5
20-25	17,830	130,920,323	95.8	4.2
25-30	13,063	119,248,198	96.3	3.7
30-35	9,108	92,156,990	96.3	3.7
35-40	5,303	62,327,340	96.3	3.7
40-45	4,185	53,222,790	97.0	3.0
45-50	3,275	49,194,837	97.0	3.0
>50	32,957	921,415,281	98.7	1.3
Total	**586,058**	**2,045,729,760**	**83.7**	**16.3**

Note 1: For determining Production Rate Brackets, a well's production rate is its annual production divided by the number of days the well produced during the year. A well that averaged 9.5 barrels per day for half of the year and nothing for the other half year would be in the 9-10 bracket, not the 4-5 bracket.

Note 2: An Uneconomic well can no longer produce enough income to meet normal lease operating costs.

Note 3: The oil production data in this table does not include lease condensate from gas wells. The official Energy Information Administration production data for crude oil production (including lease condensate) in 1992 is published in the Petroleum Supply Annual 1992, DOE/EIA-0340(92).

Source: Energy Information Administration, Office of Oil and Gas; Dwight's EnergyData, Inc.; and Petroleum Information Corp.

Appendix F

Section IV

After Tax Economic Analyses

Material in Appendix

- Marginal Well Credit Methodolgy
- Detailed Marginal Well Credit Results

Material in Working Papers

Detailed base case and regional analyses tables are available from the NPC in the form of working papers.

After Tax Economic Analyses

MARGINAL WELL CREDIT METHODOLOGY

Each category of marginal wells is allocated among three operator classes: small independents (producing less than 1,000 BOE per day), large independents, and integrated companies, based on classifications provided by the Energy Information Administration (EIA). The operator class allocation is used to determine the proportion of wells in each category that are currently entitled to percentage depletion and other federal tax benefits.

For each category of wells, the average oil equivalent production rate (6 MCF of gas set equal to 1 BOE), water production rates, and well depth was used to construct a representative typical well. For purposes of revenue estimation, the value ratio of a barrel of oil to an MCF of gas was assumed to be 10 MCF to one barrel, with associated gas production estimated using average gas:oil ratios for each region. The production, revenues, costs, and taxes were calculated for each year of the analysis and used to determine the after-tax cash flow for each operator/tax situation.

The 1992 average production rate for each typical well was determined from the data provided by the EIA. Production in future years for each representative well was projected using a characteristic decline rate. This formula decreases decline rates as the production rate decreases. The decline formula was calibrated using EIA published reserve data for lower-48 oil and associated gas and published Interstate Oil and Gas Compact Commission (IOGCC) data for remaining reserves from existing oil wells producing less than 10 barrels per day.

The 1992 average water production rate for wells in each category was provided by the EIA. Future water production was projected separately for low water cut wells and high water cut wells. The dividing line between low cut and high cut wells was assumed to be a 60 percent water cut. Water production from low cut wells was assumed to decrease each year in proportion to the decrease in oil and gas production. Water production from high cut wells was assumed to increase each year such that gross fluid production remains constant.

Operating and maintenance cost equations were supplied by the EIA for each region. The operating and maintenance costs supplied by the EIA were divided into four components: water disposal costs, daily operating costs (including lease-level labor and supervision), lifting costs, and maintenance costs. Additional costs for thermal oil recovery were also supplied for California heavy oil wells. The correlation equations for these costs are a function of oil equivalent production rate, water production rate, and well depth. Using the projections for oil equivalent and water production for each category of wells, and the mid-point depth for the category, annual operating and maintenance costs were calculated for each representative well.

Depreciation, depletion, and amortization (DD&A) costs are input as $4.00 per barrel, which is based on companies reporting in the EIA FRS database and for companies profiled in the *Oil and Gas Journal* top companies database.

Lease-level general and administrative (G&A) costs are included in the EIA operating and maintenance costs. This includes only the component of G&A that are attributable to operations at the lease level and excludes that associated with fixed corporate overhead and administration. In order to address the range of economic circumstances U.S. operators currently find themselves in, two cost approaches to determining economic limit were used, as follows:

- As a "marginal cost" economic limit: the individual well or property has negligible effect on overall company cash flow or profitability. The after-tax cash flow is the before-tax cash flow less state and federal taxes, plus tax credits. That is, corporate overhead and DD&A reduce tax liability but do not reduce cash flow after taxes.

- As a "full cost" economic limit: the well or property (or a large number of properties with comparable economics) is central to the company's cash flow or financial viability. In this case, the after-tax cash flow recognizes corporate overhead (estimated at $1.00/BOE) and other costs (estimated at $4.00/BOE, as discussed in Chapter Five) as items that directly reduce cash flow after taxes.

The former is the "textbook" definition of economic limit and may in some cases be appropriate for companies with diversified activities. The latter is representative of a company whose properties are predominantly marginal, and that the company's overhead structure is at risk, or when properties can't generate positive cash flow. Taken together, they represent the range of situations facing operators; this range is used for estimating all benefits and costs.

Royalty costs are based on an average royalty rate of 12.5 percent. Severance and ad valorem taxes are calculated using a combined rate of 10 percent.

For each operator class, it was assumed that 50 percent of producers are subject to alternative minimum tax (AMT). Moreover, 45 percent of the independent operators were assumed to have no tax liability. The wells allocated to each operator size class were further allocated to taxable situations based on these percentages.

Before-tax cash flow was determined annually, for a typical producer representing the average production and costs for wells in each category, by subtracting operating and maintenance costs, royalties, production taxes, and lease level overhead expenses from gross revenues. Taxable income was determined annually for each typical producer by subtracting corporate overhead, depreciation, depletion, and amortization from before-tax cash flow.

State income tax was calculated annually for each typical producer by multiplying taxable income by an assumed 5 percent state income tax rate. No state income tax was assessed for the fraction of wells that are assumed to have no tax liability. "Negative taxes" resulting from negative taxable income on the project are assumed to be used to offset other taxable operations of the company. Two sensitivity runs with no "negative taxes" illustrate the impact of this assumption. Federal income tax was calculated annually for each typical producer by multiplying state taxable income less state income tax paid by a federal income tax rate. The federal income tax rate for operators not in AMT was 34 percent for independents and a 35 percent for integrated companies. For operators in AMT the tax was to be 20 percent. No federal income tax was assessed for the fraction of wells assumed to have no tax liability. As with state taxes, "negative taxes" are assumed to offset other taxable activities.

In cases where federal tax credits are made available, tax credits were calculated annually for each typical well based on the well production, specified credit qualification criteria, credit value ($/BOE), credit phase-out formula, and oil price. For wells allocated to the standard federal tax category, 100 percent of the federal tax credit was added to the after-tax cash flow.

For wells allocated to the no taxable income category, the credit was still applied to the after-tax cash flow, since the credit is specified to be transferable. In this case, the value of the credit was reduced to a market price and adjusted for taxes on the credit sales revenue (sales of credits would be taxable income). The market price was assumed to be 80 percent of the credit amount. The effective tax rate for credit sales was assumed to be 20 percent, and was allocated proportionally between state and federal taxes.

A category of wells (i.e., rate, depth, water cut, operator size, and tax situation) was assumed to be abandoned when its after-tax cash flow turns negative. That is, when the well reaches its economic limit. The abandonment of the entire category is not assumed to occur in a single year, because the typical well used in the cash flow analysis represents a distribution of wells in the category. Abandonment of a well category are instead distributed evenly over three years.

Once the number of remaining wells and the production of oil, gas, and water have been calculated annually for each category of wells, overall costs and benefits were estimated. Total production, gross revenues, state and federal taxes, federal credit costs, total operating and maintenance expenditures, and well abandonments were determined directly by aggregating the results for each well category.

The total additional employment for the economy as a whole (direct and indirect) was estimated based on imports avoided by virtue of the credit. Each million dollars in imports avoided was assumed to result in 3.2 direct industry jobs and 9.0 total incremental jobs in the nation. These employment multipliers are those suggested by the Department of Commerce in the Regional Input-Output Modeling System (RIMSII), and are comparable to those assumed by Coopers & Lybrand in their study of marginal well employment impacts for the IOGCC. Personal income taxes paid per typical petroleum industry employee was assumed to be $9,000 per year, with $2,250 paid in state income taxes, and $6,750 paid in federal income taxes.

DETAILED MARGINAL WELL CREDIT RESULTS

The following tables contain detailed results that correspond to the incremental and full cost summary tables found in Sections A, B, and C at the end of Chapter Five. Detailed base case and regional analyses tables are available as working papers.

$8–$16 STEP PRICE TRACK; FULL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	23,145	23,767	18,794	24,463	26,392	21,338	26,717	30,166	25,640
Wells Receiving Credit (average over period)	# of Wells	73,151	36,576	14,068	170,707	163,075	144,954	172,961	166,849	149,256
Incremental Production	MMBOE	105	191	311	112	212	362	122	242	441
Credit Paid	1994 $MM	878	878	878	1,169	1,605	2,616	1,666	2,863	5,677
Net Federal Cost	1994 $MM	732	617	472	996	1,276	2,064	1,453	2,425	4,844
State & Local Revenues	1994 $MM	197	363	592	221	434	767	265	548	1,046
Employment	Labor-Years	23,773	36,189	53,825	30,619	53,808	95,876	41,906	82,858	166,494
GDP	1994 $MM	2,165	4,342	7,452	2,349	4,894	8,731	2,606	5,665	10,740
Imports Avoided	1994 $MM	1,180	2,350	3,993	1,281	2,646	4,702	1,417	3,060	5,791
Credit Cost ($/BOE)	1994 $	8.40	4.61	2.82	10.47	7.57	7.23	13.70	11.84	12.86
Net Cost ($/BOE)	1994 $	7.00	3.24	1.52	8.92	6.02	5.70	11.94	10.03	10.98
Credit Cost ($/Well)	1994 $	37,934	36,941	46,717	47,786	60,813	122,598	62,357	94,909	221,412
Net Cost ($/Well)	1994 $	31,626	25,960	25,115	40,714	48,347	96,729	54,385	80,380	188,924

$8–$20 CYCLE PRICE TRACK; FULL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	18,485	20,752	20,959	21,455	25,156	23,988	28,607	33,571	28,867
Wells Receiving Credit (average over period)	# of Wells	115,224	117,934	50,539	154,475	159,063	71,572	159,564	166,446	75,078
Incremental Production	MMBOE	82	167	333	100	211	398	132	285	513
Credit Paid	1994 $MM	701	1,281	1,351	1,045	2,026	2,245	1,733	3,530	4,047
Net Federal Cost	1994 $MM	576	1,055	821	1,097	1,736	1,617	1,496	3,094	3,217
State & Local Revenues	1994 $MM	174	325	710	222	422	853	315	615	1,145
Employment	Labor-Years	20,961	41,044	71,216	30,203	60,815	97,408	47,982	98,531	147,369
GDP	1994 $MM	1,908	3,653	8,712	2,364	4,650	10,319	3,202	6,398	13,233
Imports Avoided	1994 $MM	1,034	1,990	4,653	1,287	2,544	5,542	1,727	3,481	7,108
Credit Cost ($/BOE)	1994 $	8.52	7.66	4.05	10.44	9.60	5.64	13.09	12.39	7.89
Net Cost ($/BOE)	1994 $	7.00	6.31	1.46	8.83	8.23	4.06	11.30	10.86	6.27
Credit Cost ($/Well)	1994 $	37,922	61,729	64,458	48,707	80,537	93,588	60,580	105,150	140,193
Net Cost ($/Well)	1994 $	31,160	50,838	39,171	41,203	69,009	67,409	52,295	92,163	111,441

1994 AEO LOW PRICE TRACK; FULL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	1,040	776	351	6,928	7,712	3,332	17,266	18,939	10,124
Wells Receiving Credit (average over period)	# of Wells	180,091	111,233	42,782	232,919	221,411	85,158	243,257	232,638	120,519
Incremental Production	MMBOE	4	6	7	32	58	63	75	153	198
Credit Paid	1994 $MM	89	96	96	770	1,150	1,150	2,000	3,363	3,750
Net Federal Cost	1994 $MM	82	89	87	696	1,046	1,042	1,821	3,054	3,365
State & Local Revenues	1994 $MM	15	17	17	94	159	169	223	427	537
Employment	Labor-Years	2,345	2,838	2,945	19,314	30,557	31,285	48,555	86,150	101,033
GDP	1994 $MM	103	159	182	822	1,493	1,624	1,867	3,932	5,265
Imports Avoided	1994 $MM	51	82	92	439	806	897	1,013	2,137	2,917
Credit Cost ($/BOE)	1994 $	21.93	15.50	13.83	23.71	19.90	18.35	26.78	22.02	18.90
Net Cost ($/BOE)	1994 $	20.21	14.37	12.53	21.43	18.10	16.63	24.38	19.99	16.96
Credit Cost ($/Well)	1994 $	85,544	123,648	273,624	111,150	149,112	345,142	115,832	177,570	370,424
Net Cost ($/Well)	1994 $	78,816	114,632	247,972	100,468	135,628	312,729	105,465	161,255	332,394

$8–$16 STEP PRICE TRACK; FULL COST BASIS; $6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	36,841	34,628	23,839	40,323	41,546	29,821	43,128	48,075	39,751
Wells Receiving Credit (average over period)	# of Wells	74,468	39,234	15,090	186,566	178,229	153,437	189,372	184,758	163,368
Incremental Production	MMBOE	121	214	337	130	245	402	140	279	501
Credit Paid	1994 $MM	1,038	1,038	1,038	1,388	1,915	3,180	1,985	3,452	6,996
Net Federal Cost	1994 $MM	872	751	605	1,188	1,548	2,566	1,743	2,967	6,066
State & Local Revenues	1994 $MM	225	407	642	261	500	856	307	636	1,196
Employment	Labor-Years	27,960	41,425	59,430	36,240	63,240	111,230	49,660	98,360	198,690
GDP	1994 $MM	2,508	4,867	8,039	2,738	5,654	9,685	3,006	6,544	12,190
Imports Avoided	1994 $MM	1,361	2,626	4,302	1,483	3,041	5,194	1,633	3,525	6,559
Credit Cost ($/BOE)	1994 $	8.58	4.85	3.08	10.68	7.83	7.91	14.15	12.38	13.97
Net Cost ($/BOE)	1994 $	7.21	3.51	1.80	9.14	6.33	6.38	12.43	10.64	12.12
Credit Cost ($/Well)	1994 $	28,175	29,976	43,543	34,422	46,093	106,636	46,026	71,804	175,994
Net Cost ($/Well)	1994 $	23,670	21,688	25,379	29,462	37,260	86,047	40,415	61,716	152,599

$8–$20 CYCLE PRICE TRACK; FULL COST BASIS; $6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	27,492	30,166	27,241	34,546	38,716	32,824	40,833	48,827	38,937
Wells Receiving Credit (average over period)	# of Wells	121,105	125,075	53,459	164,780	171,229	77,255	169,196	180,405	81,823
Incremental Production	MMBOE	94	188	362	115	240	439	146	316	559
Credit Paid	1994 $MM	819	1,515	1,605	1,229	2,420	2,697	2,036	4,225	4,874
Net Federal Cost	1994 $MM	601	1,159	934	1,044	2,090	2,015	1,689	3,622	3,851
State & Local Revenues	1994 $MM	211	388	791	256	482	941	364	710	1,280
Employment	Labor-Years	24,240	47,350	79,100	35,169	70,864	110,313	55,080	114,290	167,820
GDP	1994 $MM	2,165	4,098	9,373	2,708	5,298	11,308	3,506	7,082	14,336
Imports Avoided	1994 $MM	1,174	2,237	5,011	1,461	2,885	6,063	1,897	3,848	7,706
Credit Cost ($/BOE)	1994 $	8.75	8.05	4.44	10.72	10.08	6.14	13.99	13.36	8.71
Net Cost ($/BOE)	1994 $	6.42	6.16	2.58	9.10	8.71	4.59	11.61	11.45	6.88
Credit Cost ($/Well)	1994 $	29,791	50,222	58,919	35,576	62,507	82,166	49,861	86,530	125,177
Net Cost ($/Well)	1994 $	21,861	38,421	34,287	30,221	53,984	61,388	41,363	74,181	98,903

1994 AEO LOW OIL PRICE TRACK; FULL COST BASIS; $6-$2-$1 CREDIT SCENARIO; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	11,172	11,651	5,115
Wells Receiving Credit (average over period)	# of Wells	237,163	225,350	86,673
Incremental Production	MMBOE	37	66	72
Credit Paid	1994 $MM	878	1,323	1,323
Net Federal Cost	1994 $MM	797	1,197	1,193
State & Local Revenues	1994 $MM	59	110	122
Employment	Labor-Years	21,959	35,029	35,885
GDP	1994 $MM	923	1,726	1,880
Imports Avoided	1994 $MM	489	916	1,018
Credit Cost ($/BOE)	1994 $	24.03	19.92	18.36
Net Cost ($/BOE)	1994 $	21.81	18.02	16.56
Credit Cost ($/Well)	1994 $	78,591	113,551	258,659
Net Cost ($/Well)	1994 $	71,340	102,736	233,243

$8–$16 STEP PRICE TRACK; MARGINAL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	27,224	25,246	13,237	28,849	28,947	19,357	31,012	33,868	27,383
Wells Receiving Credit (average over period)	# of Wells	119,167	59,584	22,917	290,120	281,194	236,614	292,283	286,115	244,640
Incremental Production	MMBOE	106	188	243	110	203	319	116	226	439
Credit Paid	1994 $MM	1,300	1,300	1,300	1,765	2,491	4,073	2,556	4,520	8,921
Net Federal Cost	1994 $MM	1,254	1,277	1,290	1,693	2,396	3,940	2,427	4,289	8,548
State & Local Revenues	1994 $MM	180	306	376	206	377	603	250	498	990
Employment	Labor-Years	33,955	44,964	51,945	43,941	71,043	117,147	60,510	114,451	227,516
GDP	1994 $MM	2,043	3,963	5,114	2,137	4,341	7,033	2,264	4,883	10,035
Imports Avoided	1994 $MM	1,278	2,460	3,288	1,337	2,685	4,363	1,411	2,993	6,024
Credit Cost ($/BOE)	1994 $	12.25	6.91	5.36	16.03	12.25	12.76	22.11	20.02	20.33
Net Cost ($/BOE)	1994 $	11.82	6.79	5.32	15.38	11.78	12.35	20,99	19.00	19.48
Credit Cost ($/Well)	1994 $	47,752	51,493	98,213	61,181	86,053	210,417	88,420	133,458	325,787
Net Cost ($/Well)	1994 $	46,062	50,582	97,458	58,686	82,771	203,546	78,261	126,638	312,166

$8–$20 CYCLE PRICE TRACK; MARGINAL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	18,726	19,339	16,728	22,195	23,794	19,818	28,773	32,066	24,601
Wells Receiving Credit (average over period)	# of Wells	182,430	192,998	82,916	244,497	256,138	116,319	249,324	263,535	119,768
Incremental Production	MMBOE	67	137	270	76	160	309	94	205	376
Credit Paid	1994 $MM	998	1,945	2,066	1,499	3,036	3,407	2,463	5,172	6,008
Net Federal Cost	1994 $MM	943	1,879	1,974	1,410	2,916	3,250	2,307	4,938	5,716
State & Local Revenues	1994 $MM	135	256	510	172	336	632	239	482	832
Employment	Labor-Years	25,748	49,917	73,657	36,838	74,154	105,572	58,295	121,239	165,058
GDP	1994 $MM	1,404	2,727	6,471	1,615	3,211	7,440	2,067	4,214	9,024
Imports Avoided	1994 $MM	881	1,688	3,888	1,006	1,977	4,437	1,272	2,574	5,365
Credit Cost ($/BOE)	1994 $	14.92	14.16	7.65	19.81	19.01	11.02	26.13	25.25	16.00
Net Cost ($/BOE)	1994 $	14.09	13.68	7.31	18.63	18.26	10.51	24.47	24.11	15.22
Credit Cost ($/Well)	1994 $	53,294	100,573	123,504	67,538	127,597	171,911	85,600	161,294	244,214
Net Cost ($/Well)	1994 $	50,357	97,160	118,004	63,528	122,553	163,989	80,179	153,997	232,345

1994 AEO LOW PRICE TRACK; MARGINAL COST BASIS; $3 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	864	544	211	6,735	6,458	2,528	13,839	16,454	7,948
Wells Receiving Credit (average over period)	# of Wells	259,561	160,047	61,557	332,119	314,075	120,798	339,223	324,071	167,338
Incremental Production	MMBOE	2	3	3	18	33	34	38	86	106
Credit Paid	1994 $MM	118	131	131	987	1,494	1,494	2,528	4,294	4,794
Net Federal Cost	1994 $MM	124	141	141	937	1,423	1,423	2,371	4,048	4,531
State & Local Revenues	1994 $MM	10	13	13	75	119	121	171	321	376
Employment	Labor-Years	2,676	3,048	3,049	21,702	33,822	33,941	54,379	95,432	108,381
GDP	1994 $MM	54	76	76	428	808	831	905	2,101	2,644
Imports Avoided	1994 $MM	34	54	54	256	485	494	530	1,246	1,573
Credit Cost ($/BOE)	1994 $	50.64	39.09	38.99	55.29	44.96	43.95	66.25	49.71	45.29
Net Cost ($/BOE)	1994 $	53.22	42.08	41.96	52.49	42.83	41.86	62.14	46.86	42.81
Credit Cost ($/Well)	1994 $	136,574	240,853	620,288	146,544	231,359	590,945	182,677	260,968	603,153
Net Cost ($/Well)	1994 $	143,519	259,239	667,638	139,120	220,364	562,861	171,332	246,018	570,064

$8–$16 STEP PRICE TRACK; MARGINAL COST BASIS; $6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	40,134	34,389	16,926	43,854	42,247	26,816	47,124	51,702	42,062
Wells Receiving Credit (average over period)	# of Wells	123,909	61,954	23,829	305,125	294,194	244,074	308,395	303,949	259,320
Incremental Production	MMBOE	118	203	258	124	225	354	131	256	502
Credit Paid	1994 $MM	1,517	1,517	1,517	2,063	2,916	4,835	3,000	5,324	10,711
Net Federal Cost	1994 $MM	1,469	1,490	1,502	1,989	2,815	4,672	2,852	5,074	10,285
State & Local Revenues	1994 $MM	201	332	403	237	424	687	286	574	1,150
Employment	Labor-Years	39,010	50,470	57,050	17,950	28,775	47,837	70,480	133,250	268,390
GDP	1994 $MM	2,301	4,310	5,469	2,443	4,857	7,859	2,612	5,616	11,610
Imports Avoided	1994 $MM	1,411	2,634	3,468	1,491	2,946	4,784	1,594	3,378	6,854
Credit Cost ($/BOE)	1994 $	12.85	7.47	5.88	16.64	12.94	13.67	22.90	20.82	21.35
Net Cost ($/BOE)	1994 $	12.44	7.34	5.82	16.04	12.49	13.21	21.77	19.84	20.50
Credit Cost ($/Well)	1994 $	37,798	44,113	89,624	47,042	69,022	180,300	63,662	102,974	254,647
Net Cost ($/Well)	1994 $	36,602	43,328	88,738	45,355	66,632	174,222	60,521	98,139	244,520

$8–$20 CYCLE PRICE TRACK; MARGINAL COST BASIS; $6-$2-$1 CREDIT; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		$8–$16 Phase-Out			$10–$18 Phase-Out			$14–$20 Phase-Out		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	27,503	27,489	22,495	34,142	36,214	27,886	39,943	47,048	33,948
Wells Receiving Credit (average over period)	# of Wells	187,909	198,853	85,559	253,951	267,312	121,487	257,958	277,249	126,942
Incremental Production	MMBOE	75	151	293	88	182	341	105	231	414
Credit Paid	1994 $MM	1,161	2,257	2,399	1,749	3,558	3,998	2,876	6,095	7,099
Net Federal Cost	1994 $MM	1,050	2,113	2,218	1,655	3,427	3,826	2,651	5,762	6,702
State & Local Revenues	1994 $MM	160	299	571	198	380	695	277	561	938
Employment	Labor-Years	29,640	57,240	82,930	42,963	86,155	120,460	67,460	141,050	189,930
GDP	1994 $MM	1,597	3,031	7,049	1,918	3,726	8,234	2,328	4,815	9,962
Imports Avoided	1994 $MM	973	1,838	4,176	1,157	2,243	4,860	1,403	2,873	5,851
Credit Cost ($/BOE)	1994 $	15.47	14.95	8.19	19.91	19.58	11.73	27.41	26.37	17.13
Net Cost ($/BOE)	1994 $	13.99	13.99	7.58	18.84	18.85	11.22	25.27	24.93	16.18
Credit Cost ($/Well)	1994 $	42,213	82,107	106,644	51,227	98,250	143,272	72,003	129,549	209,117
Net Cost ($/Well)	1994 $	38,177	76,869	98,598	48,474	94,633	137,204	66,370	122,471	197,422

1994 AEO LOW OIL PRICE TRACK; MARGINAL COST BASIS
$6-$2-$1 CREDIT SCENARIO; NEGATIVE TAXES ALLOWED

Incremental Costs & Benefits of Marginal Oil Well Credit		**$10–$18 Phase-Out**		
		5 yrs	**10 yrs**	**25 yrs**
Wells Saved (average over period)	# of Wells	9,777	10,655	4,169
Wells Receiving Credit (average over period)	# of Wells	335,162	318,272	122,412
Incremental Production	MMBOE	21	41	42
Credit Paid	1994 $MM	1,136	1,719	1,719
Net Federal Cost	1994 $MM	1,077	1,643	1,643
State & Local Revenues	1994 $MM	87	142	144
Employment	Labor-Years	25,141	39,387	39,521
GDP	1994 $MM	515	1,007	1,031
Imports Avoided	1994 $MM	300	581	593
Credit Cost ($/BOE)	1994 $	52.97	41.97	41.11
Net Cost ($/BOE)	1994 $	50.22	40.12	39.29
Credit Cost ($/Well)	1994 $	116,186	161,331	412,352
Net Cost ($/Well)	1994 $	110,152	154,198	394,121

$8 FLAT PRICE TRACK; $8–$16 CREDIT PHASE-OUT (NEGATIVE TAXES ALLOWED)

Incremental Costs & Benefits of Marginal Oil Well Credit		Full Cost Basis			Marginal Cost Basis		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	28,647	17,474	6,721	37,247	23,096	8,883
Wells Receiving Credit (average over period)	# of Wells	149,054	74,527	28,664	270,625	135,313	52,043
Incremental Production	MMBOE	129	154	154	153	187	187
Credit Paid	1994 $MM	1,803	1,803	1,803	3,008	3,008	3,008
Net Federal Cost	1994 $MM	1,672	1,633	1,537	2,999	2,978	2,868
State & Local Revenues	1994 $MM	181	239	324	206	285	416
Employment	Labor-Years	37,625	39,420	39,420	64,030	66,417	66,417
GDP	1994 $MM	1,640	1,956	1,956	1,787	2,209	2,209
Imports Avoided	1994 $MM	958	1,139	1,139	1,186	1,446	1,446
Credit Cost ($/BOE)	1994 $	13.95	11.71	11.71	19.61	16.05	16.05
Net Cost ($/BOE)	1994 $	12.94	10.60	9.98	19.55	15.89	15.30
Credit Cost ($/Well)	1994 $	62,939	103,181	268,271	80,759	130,238	338,618
Net Cost ($/Well)	1994 $	58,366	93,453	228,693	80,517	128,939	322,858

$14 FLAT PRICE TRACK; $14–$20 CREDIT PHASE-OUT (NEGATIVE TAXES ALLOWED)

Incremental Costs & Benefits of Marginal Oil Well Credit		Full Cost Basis			Marginal Cost Basis		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	28,829	18,390	7,073	24,711	15,746	6,056
Wells Receiving Credit (average over period)	# of Wells	233,108	116,554	44,828	332,885	166,442	64,106
Incremental Production	MMBOE	134	168	168	75	94	94
Credit Paid	1994 $MM	2,717	2,717	2,717	3,534	3,534	3,534
Net Federal Cost	1994 $MM	2,466	2,385	2,257	3,333	3,271	3,096
State & Local Revenues	1994 $MM	327	444	579	242	348	526
Employment	Labor-Years	66,891	71,275	71,275	76,591	78,801	78,801
GDP	1994 $MM	2,982	3,755	3,755	1,519	1,905	1,905
Imports Avoided	1994 $MM	1,642	2,067	2,067	952	1,198	1,198
Credit Cost ($/BOE)	1994 $	20.28	16.14	16.14	47.36	37.71	37.71
Net Cost ($/BOE)	1994 $	18.41	14.16	13.40	44.67	34.90	33.03
Credit Cost ($/Well)	1994 $	94,244	147,747	384,143	143,011	224,435	583,531
Net Cost ($/Well)	1994 $	85,538	129,694	319,106	134,877	207,733	511,209

$14–$20 STEP PRICE TRACK; $14–$20 CREDIT PHASE-OUT
(NEGATIVE TAXES ALLOWED)

Incremental Costs & Benefits of Marginal Oil Well Credit		Full Cost Basis			Marginal Cost Basis		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	20,693	17,256	7,748	16,624	12,443	4,845
Wells Receiving Credit (average over period)	# of Wells	94,759	47,380	18,223	134,392	67,196	25,845
Incremental Production	MMBOE	91	153	173	46	66	67
Credit Paid	1994 $MM	1,111	1,111	1,111	1,431	1,431	1,431
Net Federal Cost	1994 $MM	945	871	849	1,336	1,335	1,335
State & Local Revenues	1994 $MM	231	369	411	135	172	173
Employment	Labor-Years	35,096	46,291	49,316	34,548	37,936	38,077
GDP	1994 $MM	2,556	4,518	5,049	1,209	1,804	1,826
Imports Avoided	1994 $MM	1,394	2,455	2,835	723	1,091	1,110
Credit Cost ($/BOE)	1994 $	12.19	7.26	6.42	31.40	21.69	21.37
Net Cost ($/BOE)	1994 $	10.37	5.69	4.90	29.32	20.24	19.94
Credit Cost ($/Well)	1994 $	53,690	64,383	143,397	86,078	115,006	295,375
Net Cost ($/Well)	1994 $	45,668	50,475	109,580	80,364	107,291	275,559

$14–$20 SAWTOOTH PRICE TRACK; $14–$20 CREDIT PHASE-OUT (NEGATIVE TAXES ALLOWED)

Incremental Costs & Benefits of Marginal Oil Well Credit		Full Cost Basis			Marginal Cost Basis		
		5 yrs	10 yrs	25 yrs	5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	20,693	27,627	20,189	16,624	20,905	15,995
Wells Receiving Credit (average over period)	# of Wells	94,759	92,635	50,310	134,392	131,874	71,781
Incremental Production	MMBOE	91	225	431	46	112	211
Credit Paid	1994 $MM	1,111	2,135	2,957	1,431	2,775	3,904
Net Federal Cost	1994 $MM	945	1,777	2,359	1,336	2,615	3,715
State & Local Revenues	1994 $MM	231	544	995	135	301	511
Employment	Labor-Years	35,096	73,942	121,095	34,548	69,301	105,242
GDP	1994 $MM	2,556	6,259	12,146	1,209	2,946	5,651
Imports Avoided	1994 $MM	1,394	3,403	6,633	723	1,729	3,300
Credit Cost ($/BOE)	1994 $	12.19	9.48	6.86	31.40	24.80	18.52
Net Cost ($/BOE)	1994 $	10.37	7.89	5.48	29.32	23.37	17.62
Credit Cost ($/Well)	1994 $	53,690	77,280	146,467	86,078	132,741	244,080
Net Cost ($/Well)	1994 $	45,668	64,322	116,846	80,364	125,087	232,264

$8–$20 CYCLE PRICE TRACK; FULL COST BASIS (NO NEGATIVE TAXES)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	15,916	18,108	19,441
Wells Receiving Credit (average over period)	# of Wells	149,561	153,687	68,722
Incremental Production	MMBOE	73	156	309
Credit Paid	1994 $MM	1,025	1,975	2,190
Net Federal Cost	1994 $MM	890	1,709	1,654
State & Local Revenues	1994 $MM	176	340	701
Employment	Labor-Years	26,197	53,148	83,839
GDP	1994 $MM	1,740	3,445	8,088
Imports Avoided	1994 $MM	945	1,882	4,335
Credit Cost ($/BOE)	1994 $	14.03	12.67	7.09
Net Cost ($/BOE)	1994 $	12.18	10.96	5.35
Credit Cost ($/Well)	1994 $	67,454	109,070	112,650
Net Cost ($/Well)	1994 $	58,570	94,380	85,079

1994 AEO LOW PRICE TRACK; FULL COST BASIS (NO NEGATIVE TAXES)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	5,130	5,936	2,507
Wells Receiving Credit (average over period)	# of Wells	231,121	219,635	84,475
Incremental Production	MMBOE	23	41	44
Credit Paid	1994 $MM	764	1,142	1,142
Net Federal Cost	1994 $MM	693	1,043	1,041
State & Local Revenues	1994 $MM	76	123	130
Employment	Labor-Years	17,837	27,950	28,453
GDP	1994 $MM	576	1,057	1,148
Imports Avoided	1994 $MM	306	564	635
Credit Cost ($/BOE)	1994 $	33.57	27.96	25.82
Net Cost ($/BOE)	1994 $	30.45	25.54	23.53
Credit Cost ($/Well)	1994 $	148,934	192,395	455,532
Net Cost ($/Well)	1994 $	135,093	175,716	415,244

1994 AEO HIGH PRICE TRACK; FULL COST BASIS
(NEGATIVE TAXES ALLOWED)

Incremental Costs & Benefits of Marginal Oil Well Credit		$14–$20 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	7,703	6,822	4,464
Wells Receiving Credit (average over period)	# of Wells	200,302	100,151	38,520
Incremental Production	MMBOE	32	54	73
Credit Paid	1994 $MM	942	942	942
Net Federal Cost	1994 $MM	850	850	850
State & Local Revenues	1994 $MM	116	183	238
Employment	Labor-Years	23,680	28,241	32,943
GDP	1994 $MM	908	1,710	2,532
Imports Avoided	1994 $MM	504	941	1,425
Credit Cost ($/BOE)	1994 $	29.25	17.47	12.86
Net Cost ($/BOE)	1994 $	26.40	15.25	10.80
Credit Cost ($/Well)	1994 $	122,287	138,079	211,023
Net Cost ($/Well)	1994 $	110,344	120,489	177,197

$8–$20 CYCLE PRICE TRACK; FULL COST BASIS
(WELLS DRILLED AFTER 1995 ONLY)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	1,883	4,894	5,742
Wells Receiving Credit (average over period)	# of Wells	13,002	25,671	12,287
Incremental Production	MMBOE	29	111	188
Credit Paid	1994 $MM	67	430	470
Net Federal Cost	1994 $MM	19	278	171
State & Local Revenues	1994 $MM	57	183	359
Employment	Labor-Years	6,079	25,350	39,615
GDP	1994 $MM	751	2,411	4,725
Imports Avoided	1994 $MM	404	1,297	2,542
Credit Cost ($/BOE)	1994 $	2.28	3.88	2.50
Net Cost ($/BOE)	1994 $	0.66	2.50	0.91
Credit Cost ($/Well)	1994 $	35,582	87,863	81,853
Net Cost ($/Well)	1994 $	10,090	56,804	29,781

1994 AEO LOW OIL PRICE TRACK; FULL COST BASIS
(WELLS DRILLED AFTER 1995 ONLY)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	2,131	3,869	4,451
Wells Receiving Credit (average over period)	# of Wells	18,580	27,885	57,568
Incremental Production	MMBOE	31	93	280
Credit Paid	1994 $MM	139	323	1,212
Net Federal Cost	1994 $MM	95	185	775
State & Local Revenues	1994 $MM	53	166	524
Employment	Labor-Years	7,697	21,203	72,020
GDP	1994 $MM	695	2,190	6,899
Imports Avoided	1994 $MM	374	1,178	3,712
Credit Cost ($/BOE)	1994 $	4.45	3.49	4.33
Net Cost ($/BOE)	1994 $	3.06	2.00	2.77
Credit Cost ($/Well)	1994 $	65,227	83,484	272,298
Net Cost ($/Well)	1994 $	44,580	47,816	174,118

$8–$20 CYCLE PRICE TRACK; MARGINAL COST BASIS
(NO NEGATIVE TAXES)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	19,674	20,209	17,330
Wells Receiving Credit (average over period)	# of Wells	225,095	232,829	105,378
Incremental Production	MMBOE	74	148	282
Credit Paid	1994 $MM	1,416	2,824	3,155
Net Federal Cost	1994 $MM	1,262	2,522	2,707
State & Local Revenues	1994 $MM	178	344	627
Employment	Labor-Years	12,013	23,736	33,742
GDP	1994 $MM	1,600	3,041	6,849
Imports Avoided	1994 $MM	989	1,865	4,070
Credit Cost ($/BOE)	1994 $	19.13	19.02	11.20
Net Cost ($/BOE)	1994 $	17.05	16.99	9.61
Credit Cost ($/Well)	1994 $	71,974	139,737	182,053
Net Cost ($/Well)	1994 $	64,146	124,793	156,202

1994 AEO LOW PRICE TRACK; MARGINAL COST BASIS (NO NEGATIVE TAXES)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	6,972	5,841	2,286
Wells Receiving Credit (average over period)	# of Wells	316,397	296,802	114,155
Incremental Production	MMBOE	14	29	29
Credit Paid	1994 $MM	952	1,440	1,440
Net Federal Cost	1994 $MM	876	1,321	1,321
State & Local Revenues	1994 $MM	69	119	121
Employment	Labor-Years	20,436	31,999	32,115
GDP	1994 $MM	346	715	732
Imports Avoided	1994 $MM	201	409	418
Credit Cost ($/BOE)	1994 $	66.03	50.18	48.95
Net Cost ($/BOE)	1994 $	60.76	46.03	44.91
Credit Cost ($/Well)	1994 $	136,554	246,516	629,847
Net Cost ($/Well)	1994 $	125,653	226,144	577,797

1994 AEO HIGH PRICE TRACK; MARGINAL COST BASIS (NEGATIVE TAXES ALLOWED)

Incremental Costs & Benefits of Marginal Oil Well Credit		$14–$20 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	5,297	2,851	1,186
Wells Receiving Credit (average over period)	# of Wells	275,508	137,754	52,982
Incremental Production	MMBOE	15	17	18
Credit Paid	1994 $MM	1,181	1,181	1,181
Net Federal Cost	1994 $MM	1,099	1,099	1,099
State & Local Revenues	1994 $MM	74	78	82
Employment	Labor-Years	25,625	25,937	26,177
GDP	1994 $MM	408	463	503
Imports Avoided	1994 $MM	234	279	312
Credit Cost ($/BOE)	1994 $	79.77	70.71	65.92
Net Cost ($/BOE)	1994 $	74.23	65.80	61.34
Credit Cost ($/Well)	1994 $	223,973	414,226	996,139
Net Cost ($/Well)	1994 $	207,492	385,465	926,975

$8–$20 CYCLE PRICE TRACK; MARGINAL COST BASIS
(WELLS DRILLED AFTER 1995 ONLY)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	1,883	4,894	5,742
Wells Receiving Credit (average over period)	# of Wells	16,026	30,081	14,448
Incremental Production	MMBOE	25	50	119
Credit Paid	1994 $MM	77	484	530
Net Federal Cost	1994 $MM	37	412	324
State & Local Revenues	1994 $MM	48	87	248
Employment	Labor-Years	5,671	19,603	32,926
GDP	1994 $MM	632	1,146	3,267
Imports Avoided	1994 $MM	340	616	1,757
Credit Cost ($/BOE)	1994 $	3.08	9.60	4.45
Net Cost ($/BOE)	1994 $	0.77	8.24	2.72
Credit Cost ($/Well)	1994 $	40,892	98,897	92,302
Net Cost ($/Well)	1994 $	19,650	84,185	56,426

1994 AEO LOW OIL PRICE TRACK; MARGINAL COST BASIS
(WELLS DRILLED AFTER 1995 ONLY)

Incremental Costs & Benefits of Marginal Oil Well Credit		$10–$18 Credit Phase-Out		
		5 yrs	10 yrs	25 yrs
Wells Saved (average over period)	# of Wells	2,131	3,869	4,451
Wells Receiving Credit (average over period)	# of Wells	20,864	32,718	73,053
Incremental Production	MMBOE	28	76	198
Credit Paid	1994 $MM	150	364	1,466
Net Federal Cost	1994 $MM	111	250	1,158
State & Local Revenues	1994 $MM	47	137	370
Employment	Labor-Years	7,569	20,101	67,297
GDP	1994 $MM	617	1,802	4,867
Imports Avoided	1994 $MM	332	970	2,618
Credit Cost ($/BOE)	1994 $	5.42	4.77	7.40
Net Cost ($/BOE)	1994 $	3.96	3.29	5.85
Credit Cost ($/Well)	1994 $	70,389	94,081	329,364
Net Cost ($/Well)	1994 $	52,088	64,616	260,166

Glossary of Terms

Abandonment – The temporary or permanent shutting-in of a well and ceasing further production, usually accomplished by placing cement in the well.

Barrels of Oil Equivalent (BOE) – Expressing produced hydrocarbon volumes, both oil and gas, as a 42 gallon barrel. Gas is converted on a BTU basis of 6 MCF per barrel of oil; therefore, 1 barrel of oil plus 6 MCF of gas would equate to 2 BOEs.

Capital Development Cost – Also called "Investment," these are costs incurred for the infrastructure, wells, and producing facilities required for oil and gas operations. Typically, operating costs or the expenses to produce hydrocarbons are not included in the capital development costs.

Cash Flow – This is the inflow or outflow of cash associated with the operation of producing hydrocarbons. The inflow of cash includes revenue from oil and gas, while outflows include payments of royalties, state and local taxes, and all the expenses associated with producing and marketing the hydrocarbon.

Economics – As used in this report, economics refers to cashflow calculations considering only the cost incurred to produce hydrocarbons and does not address any of the costs associated with capital investment for facilities or wells. The classical economics parameters of return on investment, payout, and net present value were not addressed in any fashion in this report.

Energy Security – Minimizing the amount of energy supplied from sources external to the country.

Enhanced Recovery Technology – Advanced techniques utilized in oil and gas production operations in order to recover a greater percentage of the resource base. Many of these technologies are described in greater detail in petroleum engineering literature.

Inactive Wells – Wells that have been temporarily or, in some cases, permanently idled and under foreseeable price conditions, there are no plans by the operator to re-establish production.

Independents – As established in the tax code, refers to oil and gas producers and refiners with less than 50,000 barrels of oil per day of recovery throughput and less than $5 million in annual gross retail sales.

Lease or property – An area of land on which wells are to be or have been drilled, usually having one owner, but may have multiple lessors. For the purpose of this report, a property or a lease may be used interchangeably.

Majors – Refers to producers that do not fit the classification of independents, used interchangeably with "integrated."

Operating Cost (Expense) – Costs incurred to produce and market oil and gas. Lease level costs are those costs which are allocated only to the well or lease (termed "Marginal Cost" in this report) while there are many additional administrative and other overhead costs (termed "Full Cost" in this report).

Original Oil or Gas in Place – The same as "Resource." This is the volume of hydrocarbons in a geologic strata prior to any production from the reservoir.

Primary Production – The stage of producing a reservoir prior to the use of advanced technologies for increasing recovery through secondary or enhanced oil recovery techniques.

Profit – For the purposes of this report, cashflow was the only factor considered as profit. This is the amount of cash remaining after royalty and state and local tax deductions and payment of all expenses associated with producing and marketing the hydrocarbons.

Regulatory – Dealing with federal, state, and local agencies which have jurisdiction over oil and gas operations and have established rules and regulations governing these operations.

Reserves – Reserves are that portion of the resource which, based on technology and economic criteria, are expected to be produced during the life of a well. Typically, these are termed proved reserves.

Resource – Used to describe the original, untapped oil or gas volume existing in geologic strata. This resource becomes a reserve as wells are drilled into the resource and begin to produce the portion of it that is recoverable. Varying levels of technology are required to increase the percentage of resource which is recoverable above certain levels. Due to the nature of oil and gas producing strata and the physics of producing the resource, there will always be some percentage of the resource which remains unproducible.

Resource Access – Refers to wellbores which have been drilled into and are producible from a resource base.

Secondary Recovery Operations – Operations following primary recovery where the natural energy of the reservoir is supplemented through the injection of water or gas for pressure maintenance and to improve the percentage of resource recovered. More detailed description and definition of this term can be found in petroleum engineering literature.

Seismic – An exploration technique using sound or vibrational waves emitted from the surface to aid in describing subsurface geologic strata and structure.

Index

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