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ECONOMICS OF OIL AND GAS PRODUCTION FROM ANWR FOR THE DETERMINATION OF MINIMUM ECONOMIC FIELD SIZE

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PREFACE

This Report was prepared in support of the geologic assessment for the Arctic National Wildlife Refuge, Alaska, coastal plain. The results of the economic investigations contained herein provide the baseline economic analysis that was required for the determination of economically recoverable oil and gas resources. Chapter-number citations herein are to the appropriate chapter in the draft legislative environmental impact statement.

U.S. Fish and Wildlife Service, U.S. Geological Survey, and Bureau of Land Management, 1986, Arctic National Wildlife Refuge, Alaska, coastal plain resource assessment--Draft report and recommendation to the Congress of the United States and legislative environmental impact statement (N. K. Clough, P. C. Patton, and A. C. Christiansen, editiors): Washington, D. C., XIV + 172 p., 5 pls., 34 figs., 23 tables, November 1986.

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ABBREVIATIONS AND ACRONYMS

ACRS	Accelerated Cost Recovery System
ANGTS	Alaska Natural Gas Transportation System
ANWR	Arctic National Wildlife Refuge
API	American petroleum Institute
Bbl	barrel
BCFD	billion cubic feet (of natural gas) per day
Btu	British thermal unit
DCF	discounted cash flow
DWT	deadweight tons
LNG	liquefied natural gas
MBbl	thousand barrels
MBPD	thousand barrels per day
MCF	thousand cubic feet (of natural gas)
MEFS	minimum economic field size
MMB	million barrels
MMBPD	million barrels per day
MMS	[U.S.] Minerals Management Service
NEPP	National Energy Policy Plan [Department of Energy]
PRESTO	Probabilistic Resource Estimates—Offshore
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
TCF	trillion cubic feet (of natural gas)
TSM	Trans-Alaska Pipeline System Settlement Methodology

ECONOMICS OF OIL AND GAS PRODUCTION FROM THE COASTAL PLAIN OF THE ARCTIC NATIONAL WILDLIFE REFUGE, ALASKA FOR THE DETERMINATION OF MINIMUM ECONOMIC FIELD SIZE

by John S. Young and William S. Hauser

SUMMARY

Section 1002 of the Alaska National Interest Lands Conservation Act of 1980 required an interagency evaluation of the wildlife and energy resources of the 1.5-million-acre coastal plain area of the Arctic National Wildlife Refuge. The results of these investigations are to be published in a draft legislative environmental impact statement and report to the Congress of the United States. The economic study reported herein was undertaken to establish the baseline data to be used in the assessment of economically recoverable oil and gas resources. A "Monte Carlo" computer simulation model (PRESTO--Probabilistic Resource Estimates, Offshore) integrated the economic and engineering considerations of petroleum development with the area's geologic potential. Specifically, a minimum economic field size estimate was required to set the lower limit on economic development for each of the 26 prospects identified. Minimum economic field size is defined herein as the smallest volume of hydrocarbon reserves that will pay the cost of extraction and marketing under expected economic conditions and provide the investor with a rate of return on capital that equals or exceeds the rate anticipated for projects of similar risk. As part of the economic analysis, alternatives for transporting and marketing potential natural gas resources from the Arctic Refuge coastal plain were reviewed. The conclusion was reached that there would be no demand for leasing prospects in the early 1990's for the purpose of finding and producing natural gas. The conclusion was based on: the high cost of North Slope natural gas at market, uncertainties associated with developing a transportation system, and the large quantities of known gas resources elsewhere on the North Slope that presumably would be developed before the Arctic Refuge coastal plan. Accordingly, crude oil was the principal energy resource of economic interest in the economically recoverable resource assessment, and any gas resources discovered during oil exploration are assumed to remain undeveloped or be used only locally as fuel.

The major economic factors considered in this analysis were: exploration, development, production, and transportation costs; market prices; inflation; minimum rates of return; State and Federal taxes; and Federal royalties. These economic factors were integrated with the appropriate engineering considerations for the Arctic Refuge area, into a discounted cash flow computer model. For each prospect, the minimum economic field size was set when the volume of hydrocarbon resource was sufficient that the after-tax net present value of projected revenues less costs was zero at the minimum rate of return.

Site-specific minimum economic field size estimates were derived for each of the 26 prospects. To test the significance, validity, and sensitivity of the economic factors used in the three-agency report to the Congress, two hypothetical prospects were developed, representing the differing geologic conditions in the western and eastern parts of the 1002 area. Results presented herein are based on the two representative prospects. Under the most likely economic scenario (the intermediate values from the range of likely values specified for the economic factors), the minimum economic field sizes for the western and eastern parts respectively were estimated at 425 million barrels and 575 million barrels of crude oil. Under the more optimistic case (higher price and lower cost, lower inflation rate, Federal royalty rate, and minimum rate of return), minimum economic field size estimates were lowered to 150 million barrels and 200 million barrels, respectively. Of the economic variables analyzed, oil prices and unified changes in exploration, development, production, and transportation costs most affected the minimum economic field size.

INTRODUCTION

In December 1980, the United States Congress passed the Alaska National Interest Lands Conservation Act (ANILCA); Section 1002 of that act required an evaluation of wildlife and energy values of the 1.5-million-acre coastal plain area of the Arctic National Wildlife Refuge. The findings of the investigations required by section 1002 were to be reported to the Congress, along with the Secretary of the Interior's recommendation for future management of the area. The economics of oil production from the coastal plain's 1002 area was analyzed to provide the necessary economic data for estimation of economically recoverable oil resources, to be reported in the draft legislative environmental impact statement. Locations of the Arctic Refuge and the 1002 area are shown on figure 1. The economic analysis presented in this report is based on data available as of January 1986.

Economically recoverable oil resources for the 1002 area were estimated using the computer simulation model PRESTO II. PRESTO, the acronym for Probabilistic Resource Estimates--Offshore, is currently used by the Minerals Management Service for estimating economically recoverable hydrocarbon resources for Outer Continental Shelf planning areas. PRESTO II requires user input of economic and geologic variables which enter into the calculation of economically recoverable hydrocarbon volumes for each prospect in the area being considered. The economic parameter estimate is referred to as the minimum economic field size (MEFS). The model also may use an area-wide MEFS. For assessing resources of the 1002 area, the area-wide minimum was set equal to the lowest single-prospect MEFS. The concept and application of minimum economic field size were discussed by Cooke (1985).

This report describes the method used to generate estimates of minimum economic field sizes, and demonstrates the effects of variations in economic assumptions on MEFS for typical prospects in the 1002 area.

Minimum economic field size is defined herein as the smallest volume of hydrocarbon reserves which will pay the cost of extracting and marketing the resource under expected economic conditions and will provide the investor a rate of return on capital equal to or greater than the rate anticipated from projects of similar risk. Many factors influence the level of recoverable resources required for an economic field, including geologic, engineering, and economic considerations. The assumptions and specific economic parameters used in this analysis are discussed in this report. Sensitivity analyses are included to demonstrate the influence of each parameter on field-size economics.

On the Alaskan North Slope, crude oil is currently being produced and marketed from Prudhoe Bay, Kuparuk River, and Milne Point fields. Therefore, the technology exists to develop hydrocarbon resources in ANWR, if discovered, provided economic incentive is sufficient. The analysis presented here most closely relates to the economics of development after leasing. Costs of preleasing geological and geophysical work and the lease bonus are not included. Accordingly, no depletion allowance is considered to recapture pre-leasing and lease bonus costs. The

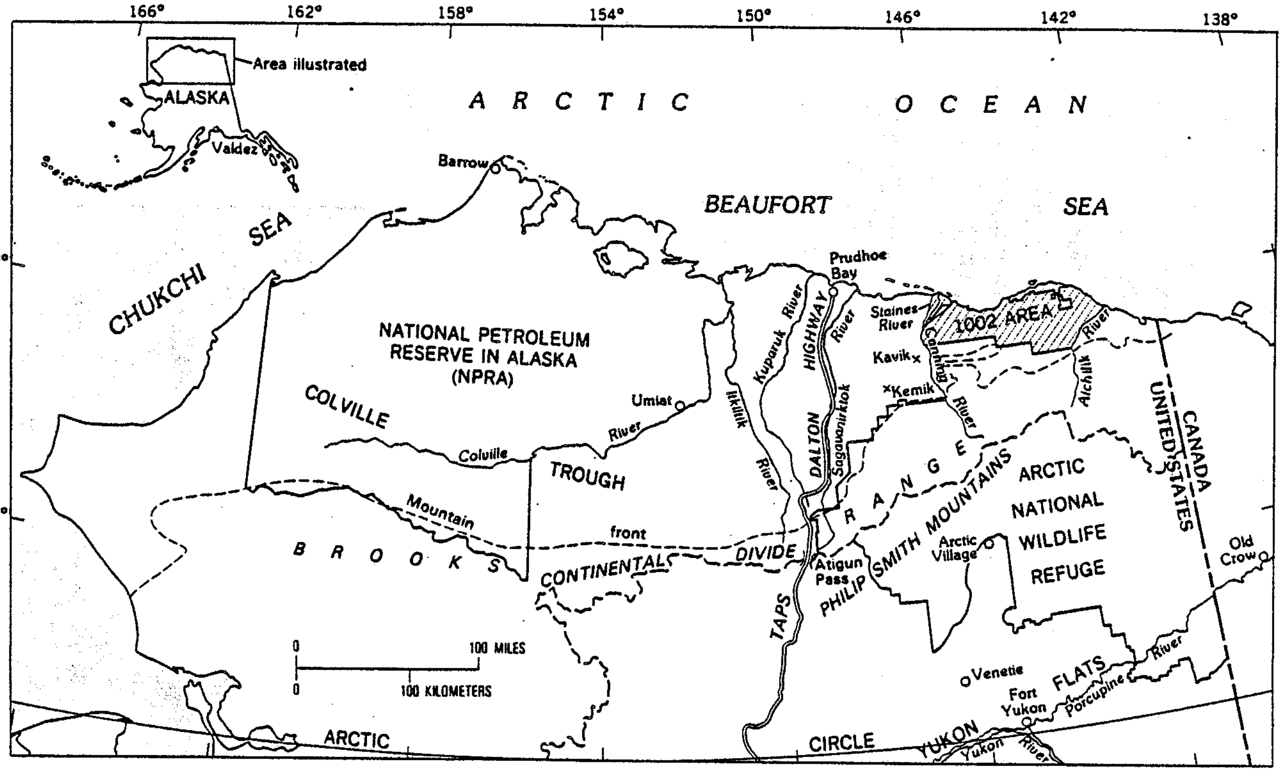

Figure 1.--Index map of northern Alaska showing location of 1002 area in relation to the Arctic National Wildlife Refuge, the National Petroleum Reserve in Alaska, and Prudhoe Bay.

economic evaluation process for determining minimum economic field size is assumed to begin when the lease is issued. For determining minimum economic field size, the costs of exploration and delineation wells are included as a portion of total costs, rather than as sunk costs. Estimates of the economically recoverable resource potential might be increased by treating all exploration and delineation well costs as sunk costs.

In the economically recoverable resource assessment, a minimum economic field size was determined for each prospect to be considered. Thereby the minimum economic field size was tailored to the specific geologic and economic aspects of each prospect. Among the prospect-specific geologic, engineering, and economic aspects considered are: reservoir depth, recovery rates, well spacing, number of delineation and development wells required, well cost, and transportation cost. Prospect characteristics and production scenarios are discussed in chapters III and IV of the draft LEIS.

Discounted cash flow (DCF) procedures were used to determine the economic viability of prospects. Published literature and data collected as of January 1986 provided the primary information for the analyses. All DCF evaluations were on a nominal dollar (see glossary) after-tax basis, so it was necessary to assume future price, cost, and inflation rates. Sensitivity analyses on minimum economic field size illustrate the impact of alternative price, cost, and inflation assumptions. Throughout this discussion the intermediate level is selected as the most likely estimate for each parameter, and the sensitivity analysis shows the incremental difference in results from variations of the level of each parameter. Also, an optimistic estimate was made on the basis of more optimistic estimates for selected price, cost, and economic factors and assumptions. (See chapter III.) The optimistic economically recoverable resource estimate illustrates the effect of improved economic conditions on the recoverable resource potential. Sensitivity analyses are also useful for further interpretation, if interest groups disagree on the level of a parameter used in the base case analysis.

The most likely case minimum economic field size is calculated on the basis of stand-alone prospects. On a stand-alone basis each prospect must contain sufficient technically recoverable hydrocarbon reserves that can be produced at a low enough cost and marketed at a high enough price, to pay all the regional infrastructure development and transportation costs to extract the resource, move it to market, and still yield a suitable return to the investor. To date, Prudhoe Bay is the only field discovered on the Alaskan North Slope that meets this criterion. The Kuparuk River field would not have been economic if it had not been located near enough to Prudhoe Bay to share the existing Trans-Alaska Pipeline System (TAPS). TAPS offers the most economically efficient means of transporting other North Slope crude oil to the south-central coast of Alaska. Therefore, as defined in this analysis, a stand-alone prospect must be able to bear the cost of building the crude oil transportation infrastructure to Pump Station 1 of TAPS and the TAPS pipeline tariff, not the cost of building a completely new crude oil transportation system to the southern coast of Alaska. The economics of crude oil transportation on TAPS throughput and carrying capacity are discussed below under "Crude oil transportations."

ECONOMICS OF NATURAL GAS PRODUCTION FROM ANWR

The economic potential of natural gas production from ANWR is contingent on locating a market for the gas and developing a transportation system that can deliver the gas to market at competitive prices and provide the producer a sufficient rate of return to attract investment. To date, none of these conditions have been met for the North Slope, so the huge gas reserves identified in and near the Prudhoe Bay field have not been commercially developed. Some North Slope natural gas is produced and used locally for field operations, power requirements for northern TAPS operations, and some enhanced recovery operations. Significant financial and human resources continues to be invested in analyzing the North Slope natural gas issue. Several transportation and marketing systems for North Slope gas have been proposed by industry, research groups, and the State of Alaska and studied to varying degrees.

North Slope Gas Transportation and Marketing Alternatives and Issues

Four major alternatives have been identified for transporting and marketing North Slope natural gas:

1. Alaska Natural Gas Transportation System (ANGTS)
2. All-Alaska pipeline system or the alternative Trans-Alaska Gas System (TAGS)
3. Conversion to methanol
4. Use in Alaska

The Prudhoe Bay field was discovered in 1968 with estimated recoverable oil and gas resources of 9.6 billion barrels and 28.50 trillion cubic feet (TCF), respectively (see chapter III). Other major gas resources identified in and around the Prudhoe Bay area are: Lisburne, 0.80 TCF; Kuparuk, 1.48 TCF; Point Thomson, 5.0 TCF; and Endicott, 0.73 TCF. These fields collectively amount to more than 36.5 TCF of known gas resources that exist in and near the Prudhoe Bay area. Since the discovery of Prudhoe Bay there has been interest in marketing the huge gas reserves.

The Alaska Natural Gas Transportation System (ANGTS) was proposed to transport North Slope gas from Prudhoe Bay south to Delta Junction, Alaska, and then eastward through Canada to United States markets in California and Illinois. In 1976, the U.S. Congress enacted the Alaska Natural Gas Transportation Act, setting up procedures for selection of a natural gas pipeline system. This transmission system was officially selected by the President and adopted by the Congress in 1977 (U.S. General Accounting Office, 1983). The pipeline system was originally scheduled to deliver gas to U.S. markets by 1983 (U.S. General Accounting Office, 1983), but has been delayed. The ANGTS pipeline was planned as a 4,794-mile overland system with an estimated cost of $24.8 billion (1982 dollars). The completed 1,500-mile segment of the pipeline from Alberta, Canada, to Iowa and Oregon transports Canadian natural gas to the lower 48. The original design of ANGTS provided for an average throughput of 2.0 billion cubic feet per day (BCFD), and early estimates of initial delivered gas prices of $10.00 to $12.00 (1982 dollars) per thousand cubic feet (MCF) and a 20-year average delivered cost of $5.56/MCF (U.S. General Accounting Office, 1983). Later cost estimates using a minimum charge analysis by the General Accounting Office (1983) projected these costs at $7.53/MCF, excluding taxes. This transportation cost estimate was still much more than 1984 domestic wellhead prices of $2.60/MCF or import prices of $4.08/MCF.

Among reasons for the delay were excess world energy supply, depressed crude oil prices, low levels of economic activity in the United States and abroad, and financing problems (U.S. General Accounting Office, 1983). The financial issues and problems posed by the ANGTS proposal for transportation of North Slope gas are discussed in "An Epitaph for the Alaska Gas Pipeline" (Tussing and others, 1983).

An "all-Alaskan" pipeline system was first proposed in 1974 as an alternative to ANGTS. The system was expected to extend from Prudhoe Bay to Prince William Sound where a gas liquefaction plant would be located; from there the liquefied natural gas (LNG) would be shipped by tanker to California. Because of the estimated higher cost of service, the liquefaction plant's location in an active seismic area, and the inability to tap Canadian gas resources, this proposal was rejected by the President.

A similar proposal to the "all Alaskan" pipeline system was made by the Yukon Pacific Corporation in September 1983 (U.S. Minerals Management Service, 1985). The Trans-Alaska Gas System (TAGS) would carry natural gas from Prudhoe Bay to the Kenai Peninsula south of Anchorage, Alaska. The gas would be processed and liquefied for shipment to various Pacific rim countries including Japan, Korea and Taiwan. The LNG could be shipped to West Coast locations in the U.S. if sufficient domestic markets develop. This proposal is for a 2.38-BCFD-capacity, 820-mile system with an estimated cost of $14 billion (1982 dollars) or an escalated cost of about $25 billion in current dollars (Oil and Gas Journal, 1985). A preliminary study by Brown and Root Incorporated for Alaskan gas pipeline LNG suggested that the initial $14 billion cost estimate could be lowered by several billion dollars (Oil and Gas Journal, 1985). Korean and Japanese groups are each helping finance studies on LNG demand during the 1990's. Originally the TAGS project was to deliver LNG to Japanese markets by 1990, but lowered forecasts of Japanese demand and increasing competition from Australian and Indonesian LNG have reduced early expectations. Accordingly, the potential markets being considered have been broadened to include Korea and Taiwan. Several potential problems could be encountered with the TAGS proposal. The export of Alaska's natural gas from Prudhoe Bay is restricted by law to small quantities (U.S. General Accounting Office, 1983). Large-scale exports to foreign countries would require Presidential authorization. The environmental impacts of TAGS would also need further analysis. The Atlantic Richfield Company (ARCO) has been the only major North Slope operator that has publicly registered support for TAGS, while Exxon USA and Sohio Alaska have remained committed to ANGTS (Oil and Gas Journal, 1983 and U.S. Minerals Management Service, 1985).

North Slope natural gas supplies could be converted into methanol and shipped out of Alaska. Methanol plants could be constructed on the North

Slope, and the product transported through the existing TAPS facilities (Corley and Marsden, 1984), or a separate pipeline could be laid in the TAPS right-of-way. In any event the methanol would be loaded on tankers for transportation to Far East nations and to United States west coast markets. The General Accounting Office (1983) evaluation of alternatives for North Slope gas stated that "North Slope producers have performed preliminary feasibility studies that indicate the methanol alternative is a poor third choice in their ranking of transportation systems." Potential problems, such as high energy loss through the methanol conversion process, doubtful marketability of a large methanol supply, and high cost may not allow competitive pricing and shipment of methanol through TAPS (U.S. General Accounting Office, 1983).

Petrochemical production was identified as another alternative use of North Slope gas. This alternative would have the advantage of diversifying Alaska's industrial base by adding value to a consumer good, instead of strictly exporting a natural resource. A 1981 study (Alaska Petrochemical Industry Feasibility Study) concluded that a natural gas liquids production project in Alaska would not be feasible (U.S. States General Accounting Office, 1983) unless oil prices rose to about $50 per barrel.

Alternative uses for North Slope natural gas within the State of Alaska have also been identified and evaluated. These include enhanced oil recovery in North Slope fields, marketing bottled gas (propane), marketing compressed natural gas for Alaska automobiles, and marketing methane fuel for Alaska homes and businesses (University of Alaska, Institute for Social and Economic Research, 1983). Enhanced oil recovery is the only identifiable demand identified for North Slope gas that was independent of developing a major north/south pipeline transmission system. Miscible gas injection is being used in tertiary recovery efforts in the Prudhoe Bay field, and gas-fired steam injection is being tested as a means of recovering low API gravity oil from North Slope reservoirs. If a gas pipeline is constructed, there may be some domestic and commercial demand for methane fuels in northern Alaska.

Discussion and Conclusions

Of the various alternative transportation and product marketing methods for North Slope natural gas, the most common problems for each alternative are summarized as uncertainties about (1) marketing potential and (2) delivery at competitive prices while providing a reasonable return on investment. Even the ANGTS and TAGS alternatives, the most widely accepted, are plagued by concerns identified above. Lack of financial support for a North Slope gas transportation system seems to reflect the financial community's skepticism that North Slope gas is marketable at competitive prices. At present excess deliverable capacity of natural gas exists in the lower 48 States (gas bubble) and oil price declines that began in 1981 have continued which could result in further gas price reductions.

Altogether, the outlook for the near-term market potential of North Slope natural gas is rather pessimistic, as confirmed in reports by Government agencies, private research firms, and industry. The Congress of the United States Office of Technology Assessment (1985) quoted the American Gas

Association's statement that does not expect any pipeline imports from Alaska to the lower 48 States by 1990 but expects imports of 0.7 to 1.2 TCF per year by 2000, assuming that a pipeline is built. The U.S. Department of Energy, Energy Information Administration (1985) in its 1984 long-term forecast through 1995 assumed that Alaska would not supply gas during the forecast period due to the financing uncertainties of the pipeline system and repeated postponement of the expected startup date of the project. In a 1984 baseline projections of U.S. energy supply and demand the Gas Research Institute (1984) assumed the Alaska natural gas pipeline would begin operation in 1998. The gas price estimate based on pipeline cost estimates and revenue requirements was $9.64 per million British Thermal Units (BTU) (1983 dollars) for annual deliveries of 0.7 TCF to the lower 48 States. Alaska gas prices in the year 2000 represented the highest-cost source of gas above coal gas, synthetic gas, LNG imports and gas imports to the lower 48 States. Alaska gas would certainly be a marginal source of supply. Chevron Corporation (1985) in its 1985 World Energy Outlook projected that, because of the very high development and transportation costs, Alaska natural gas would not be available to the lower 48 States until early in the next century.

The article entitled "An epitaph for the Alaska Gas Pipeline" (Tussing and others, 1983) summarized the issues facing the development of North Slope natural gas and conditions that must be met before North Slope gas can be a marketable commodity. An excerpt follows:

> "A conventional natural-gas pipeline across Canada, an "all-Alaska" gas-pipeline and LNG delivery system, and conversion to methanol are not the only plausible dispositions for North Slope natural gas. Given a sufficiently distant time horizon, the shipment of LNG by icebreaking tanker or submarine directly from the North Slope, for example, or use for thermally-enhanced recovery of heavy crude-oil, can not be ruled out. Future market and technological developments may well alter the economic ranking of ANGTS, pipeline-LNG, and methanol schemes. In every instance, however, development and marketing of gas from the arctic will require an eleven-figure initial investment, and have an irreducible fixed capital cost in Alaska of at least $2.00 per million btu in 1983 dollars. Unless investors are convinced that the level of world energy prices (as measured by real world oil prices) is certain to rise far above its 1981 peak and stay there, none of the options we have considered here will be a prudent investment.
>
> "In conclusion, it appears that something like ANGTS is still the strongest of the current proposals, but none of them is strong enough today to constitute a serious planning or investment option. It is indeed conceivable that Prudhoe Bay gas will never be a marketable commodity. Before it can become such a commodity, the worldwide energy situation, the technological menu, or both will have to change in ways that we cannot now foresee."

The economics of developing, transporting and marketing potential natural gas resources from ANWR are contingent on the same factors that currently preclude development of North Slope natural gas reserves. However, the geographic isolation of ANWR further reduces the near-term potential for economic development, because of the additional transportation cost. If constructed, a North Slope natural gas transportation system would logically begin at Prudhoe Bay where massive gas reserves are already known. Therefore, additional transportation costs would be incurred to move potential ANWR natural gas from the wellhead in ANWR to Prudhoe Bay. Depending on field locations, a gas transportation pipeline to ANWR could be longer than 150 miles.

If a gas transportation system is constructed for Prudhoe Bay, natural gas from the Prudhoe Bay area would be less expensive to develop than gas from other North Slope areas. Presumably Prudhoe Bay gas would be developed first, and gas resources from other areas would be developed sequentially in order of cost of production. But even this sequence presumes that the natural gas from Prudhoe Bay and the other North Slope areas can be produced and marketed at competitive prices. Natural gas currently supplies much of the energy required for North Slope field and transportation system operations. The amount of gas required to operate the Prudhoe Bay field, the proposed natural gas transportation facilities and TAPS (currently only the northern portion of TAPS fuel requirements are supplied by gas, but the assumption is made that if a gas transportation system is installed, all of TAPS operations could be fueled by natural gas) is estimated to be 5.7 TCF (University of Alaska Institute for Social and Economic Research, 1983). Given these gas fuel requirements, there would still be a balance of 22.8 TCF (28.5 less 5.7) of natural gas in the Prudhoe Bay field to be marketed. At annual production rates of 0.73 TCF for ANGTS (estimated throughput of 2.0 BCFD) or 0.87 TCF for TAGS (estimated throughput of 2.38 BCFD) there is an estimated 26 to 31 years of production in Prudhoe Bay alone. The other known resources in Lisburne, Kuparuk River, Point Thomson, and Endicott would likely be produced next. Only then would potential production from ANWR be considered.

With the high costs of North Slope natural gas at market, uncertainties associated with the development of a transportation system, additional costs of transporting potential ANWR gas resources, and the quantity of known reserves that would likely be developed prior to ANWR, it is assumed for this analysis that there would not be a demand for acquiring acreage in ANWR in the early 1990's for the purpose of finding and producing natural gas and any gas resources that are discovered through oil exploration activities would remain undeveloped or only be utilized as a local source of fuel and not be commercially marketable. This is not to say that potential ANWR natural gas resources are without value. At some point in the future, national or international economic conditions or technological advances may warrant exploration and development of potential natural gas resources in ANWR.

ECONOMICS OF CRUDE OIL PRODUCTION FROM ANWR

As discussed in the Introduction, estimates of minimum economic field size are required to determine the potentially economically recoverable hydrocarbon resources in ANWR. The present lack of a natural gas transportation infrastructure from the Alaskan North Slope and uncertainties associated with future market potential and construction of an economic gas transportation system result in low expectations for commercial gas production from ANWR. Crude oil is the only hydrocarbon currently being commercially produced and marketed from existing North Slope fields and crude oil is considered the hydrocarbon of economic importance for exploration and development in ANWR. The following discussion identifies the key assumptions and considerations used to estimate the minimum resource requirements for developing an economic oil field in ANWR. This analysis is based on economic conditions and data as of January 1986.

Assumptions

Assumptions used for this analysis are the best estimate based on information available for operations in other areas on the North Slope of Alaska and published literature sources. This analysis is conducted at a moderate level of detail, which is consistent with the limited quantity and the quality of data available. No oil and gas exploration drilling and development has occurred in ANWR, so specific data were not available; no detailed site-specific engineering studies have been made. This level of detail is considered sufficient for estimating aggregate economically recoverable resources in ANWR.

The specific assumptions used in this analysis are as follows:

1. Production rates are extrapolated from National Petroleum Council (1981) data as follows:

    a. Peak rate of 9.1 percent of reserves per year.
    b. Building up of peak rate from production startup is 20 percent in year 1, 70 percent in year 2.
    c. Peak rate occurs in years 3, 4 and 5.
    d. Starting in year 6, decline is 12 percent per year.
    e. All associated gas is reinjected or used for fuel.
    f. In a few cases, the buildup of production described in (b) above is extended.
    g. Water injection is the primary pressure-maintenance mode and begins in adequate time to avoid pressure depletion. Increasing gas/oil ratio or decreasing wellhead pressure requires artificial lift.

2. Production terminates when annual revenue equals annual cost or reserves are depleted.

3. Geological, geophysical or lease acquisition costs are excluded, but exploration drilling costs are included.

4. End-of-year discounting is used, and year one of the economic evaluation is the first year after a lease is acquired.

5. Income tax calculations include the following assumptions:

    a. Windfall profits taxes are not levied against properties within ANWR (Ernst and Whinney, 1984).

b. Depletion allowance is zero (see assumption 3).
c. Investment tax credit (ITC) is calculated at 10 percent of all tangible investments, with a deduction of 50 percent of ITC from the depreciable basis as required (Burke and Bowhay, 1984).
d. Eighty percent of intangible drilling costs are expensed in the year incurred and the remaining 20 percent of intangibles are amortized over 3 years (U.S. Office of Technology Assessment, 1985a).
e. All tangible drilling costs are written off using Accelerated Cost Recovery System (ACRS) depreciation rates for 5-year property (National Petroleum Council, 1984).
f. Income taxes are calculated at a rate of 9.4 percent (Alaska Department of Revenue, 1982) for State of Alaska Corporate Income Tax and 46 percent (Burke and Bowhay, 1984) for Federal Income Tax for an effective rate of 51.1 percent (see Stermole, 1982 for a description of calculating effective income tax rates).
g. Income tax credits that accrue as investment tax credits and all operating losses are assumed to offset the operators' taxable income elsewhere (National Petroleum Council, 1981).

6. State of Alaska severance tax is calculated on the basis of percentage of value or cents per barrel (Alaska Department of Revenue, 1982a), whichever method yields the greatest tax. Percentage-of-value tax is calculated on wellhead value of taxable production at a rate of 12.25 percent for the first 5 years of commercial production and 15 percent thereafter with an allowance for an economic limit factor. Cents-per-barrel tax is calculated at $0.80 per barrel of taxable production.

7. State of Alaska conservation tax is calculated at $0.00125 per barrel of taxable production (Alaska Department of Revenue, 1982a).

8. State of Alaska ad valorem property tax is calculated at 2 percent per year applied to current value of tangible property (Alaska Department of Revenue, 1982a).

9. Tangible portion of investments are assumed to be 10 percent of exploratory drilling, 30 percent of development drilling, and 100 percent of production facilities costs.

10. All capital is assumed to be 100-percent equity with no financial leverage (National Petroleum Council, 1981).

11. Unit costs for exploration, development, facilities and production are as shown on figures 3-6. All crude oil transportation costs and assumptions are presented under "Crude oil transportation."

12. Oil price assumptions and forecasts used in this analysis are as described under "Oil prices."

13. A cost inflation rate of 6 percent is assumed for the most likely scenario, with a low rate of 3.5 percent assumed for the optimistic recoverable resource scenario. The inflation rates to be considered for sensitivity analyses ranged from 3.5 percent to 9.5 percent.

14. A Federal royalty rate of 16.6 percent is assumed for the most likely case, and a royalty rate of 12.5 percent is assumed for the optimistic recoverable resource scenario. Royalty rates to be considered for sensitivity analyses ranged from a low of 12.5 percent to a high of 20.00 percent.

15. A real discount rate of 10 percent (equal to a nominal discount rate of 16.6 percent with a 6-percent inflation rate) is assumed to be acceptable to the Federal Government and great enough to attract private industry investment under the most likely case. A real discount rate of 8 percent (11.8 percent nominal with a 3.5-percent inflation rate) is assumed for the optimistic economically recoverable resource scenario. Discount rates considered for sensitivity analyses ranged from 8 percent real (11.8 percent nominal with 3.5-percent inflation) to 12 percent real (22.6 nominal with 9.5-percent inflation). Stermole (1982) discusses procedures to convert real discount rates to nominal discount rates.

Development Schedules

The timing, as well as magnitude of investments and revenues, can affect the results of economic evaluations using DCF analysis. A likely schedule for development of a 1-billion-barrel oil field in ANWR was outlined by the National Petroleum Council (1981) in its study of U.S. Arctic Oil and Gas (see figure 2). One year is assumed between lease acquisition and drilling the first exploration well. Four additional years are provided to complete exploration and delineation drilling, submit development plans and receive the necessary approval. Facilities construction, development drilling and pipeline design and development would begin in year six and continue until production starts at the end of year nine. Development drilling continues for a short time after production begins. This development schedule may be slightly lengthened or shortened for larger or smaller fields. The estimated production schedule was previously presented in the Assumption section.

Investment and Production Costs

Cost estimates for exploration, development, production and transportation of crude oil resources from ANWR are an integral part of the economic evaluation process for determination of minimum economic field size. The confidence that can be placed in the analysis is subject to the validity of cost estimates and assumptions used. A principal source of cost data was the study of U.S. Arctic Oil and Gas completed by the National Petroleum Council (1981). Cost estimates from that study were verified and supplemented, whenever possible, with other published literature for the North Slope region and information gathered through contact with petroleum industry representatives familiar with North Slope operations. All data provided by private industry were aggregated and combined with published data to avoid disclosure of individual industry responses. All other specific literature sources used are cited throughout this section.

FIGURE 2 - Projected development schedule for ANWR,
by number of years after lease is acquired.
(1.0 Billion Barrel Field)

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XXXXX PLANNING AND PERMITTING

     XXXXXXXXXXXXXXXXXXXXXXXX EXPLORATION AND DELINEATION DRILLING

            * DISCOVERY

            XXXXXXXX PREPARE AND SUBMIT PLANS

                    XXXXX APPROVAL OF PLANS

                         XXXXXXXXXXXXXXXXXXXXXXXX DEVELOPMENT DRILLING

                         XXXXXXXXXXXXXXXXXXX CONSTRUCTION OF FACILITIES

               XXXXXXXXX PREPARE TRANSPORT PLAN AND OBTAIN APPROVAL

                         XXXXXXXXXXXXXXXXXX DESIGN AND CONSTRUCT PIPELINE

                                            * FIRST PRODUCTION

                                                 * PEAK PRODUCTION
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1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17

Years After The Lease Is Acquired

Figure 3 presents the estimated total project capital facilities cost, excluding well costs. These costs are measured in thousands of dollars per barrel of peak daily production. Typical facilities are as follows:

- Drill pads and flowlines from the drill sites to the central production facility;

- Central production facility to separate and treat oil and associated gas;

- Gathering lines from the central production facility to the delivery point; and

- Operations center and construction camp consisting of sleeping, eating, and recreational facilities.

Costs decline as the peak production rate increases. This cost curve is consistent with principles of efficiency of scale, where per-unit costs decline rapidly at first as productive capacity increases, but decline more slowly as production capacity continues to increase. The scheduling of expenditures for capital facilities costs is shown in figure 2. Facilities construction is scheduled to begin in year six and be completed by the end of year nine. The capital facilities costs are assumed to be allocated equally over the 4-year period.

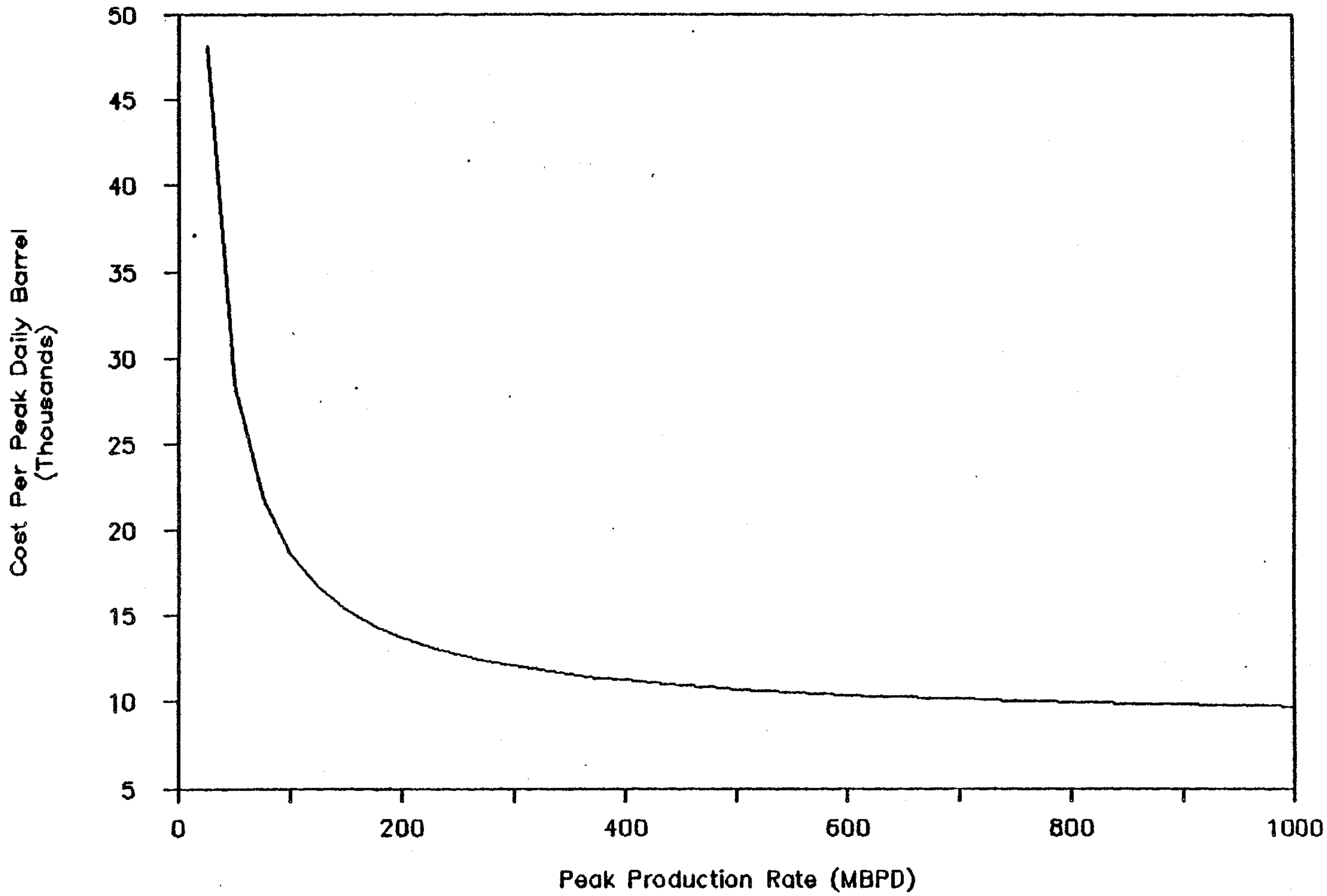
Estimated drilling costs for exploratory and development drilling are presented in figures 4 and 5. Estimated drilling costs were extrapolated from data provided by the National Petroleum Council (1981), American Petroleum Institute (1976-1984), Berman and others (1984), and private industry. For calculating minimum economic field size, exploration drilling is assumed to begin with one well completed during the second year after the lease is acquired. The first well is assumed to be a discovery, and delineation drilling begins the next year with two additional wells. Delineation drilling continues at the rate of two wells per year (figure 2). Cost for exploration and delineation drilling is allocated by the number of wells drilled per year. The delineation drilling process (figure 2) may be lengthened or shortened to accommodate variations in prospect size.

Development drilling is expected to begin in year six and continue through year 10. Drilling costs are allocated by the number of wells drilled per year over this time period. Development drilling will continue for a time after production begins. For the purposes of minimum economic field size calculations, production wells are assumed to be drilled on a 160-acre spacing and 0.4 injection wells are required per production well (National Petroleum Council, 1981).

Total capital investment costs for the project includes capital facilities costs, exploration well costs, and development well costs. The annual operating expenses of production are calculated separately. Figure 6 shows the estimated annual production costs for the project as a function of average daily production. The expenses constituting in annual production costs are:

Estimated total costs (in 1984 dollars) for production facilities, excluding well costs

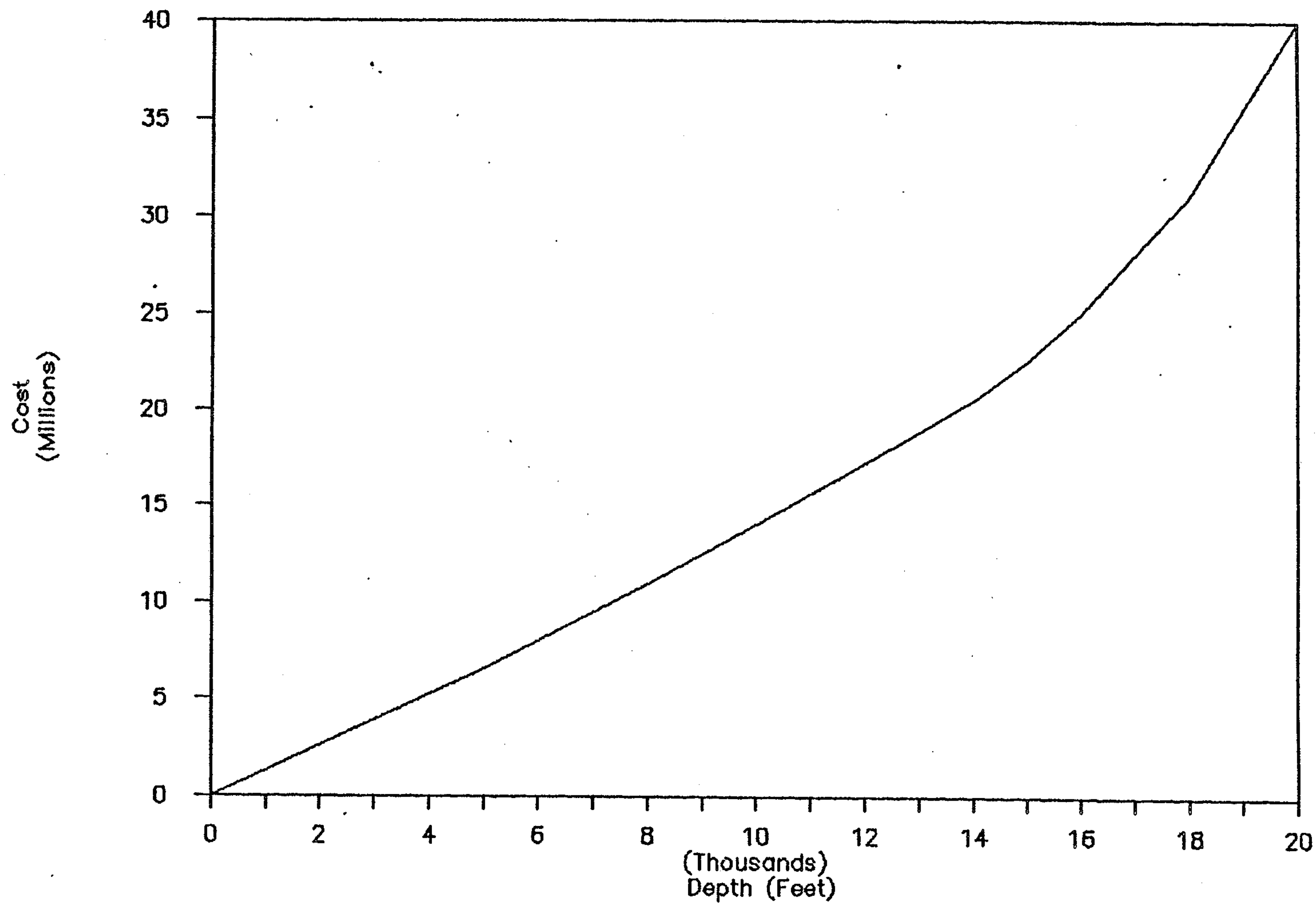
FIGURE 3



Source: National Petroleum Council (1981) estimates escalated to 1984 dollars using the Marshall Valuation Services (1985) index for petroleum equipment.

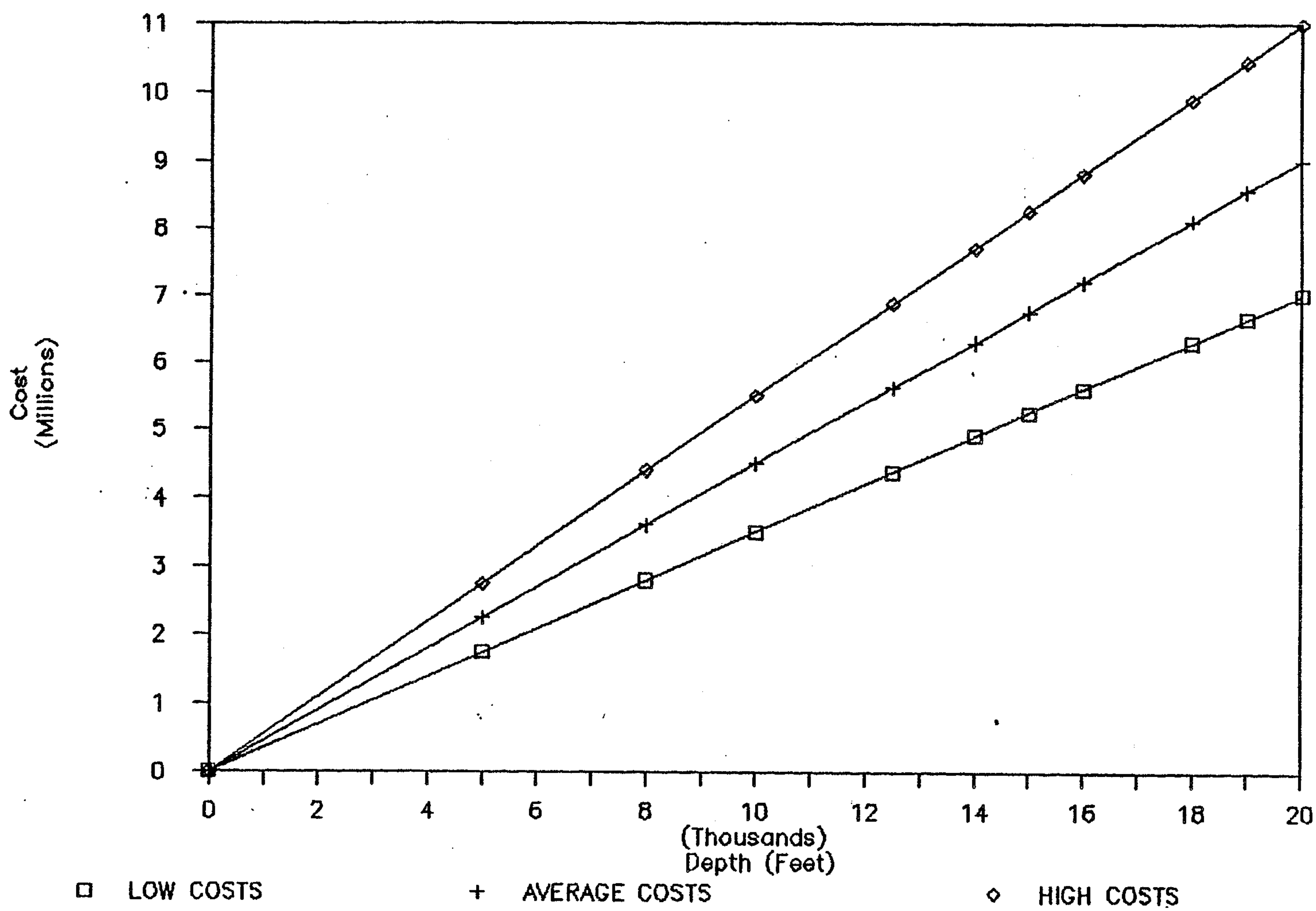
Estimated costs (in 1984 dollars) per well for exploration drilling

FIGURE 4



Estimated costs (in 1984 dollars) per well for development drilling

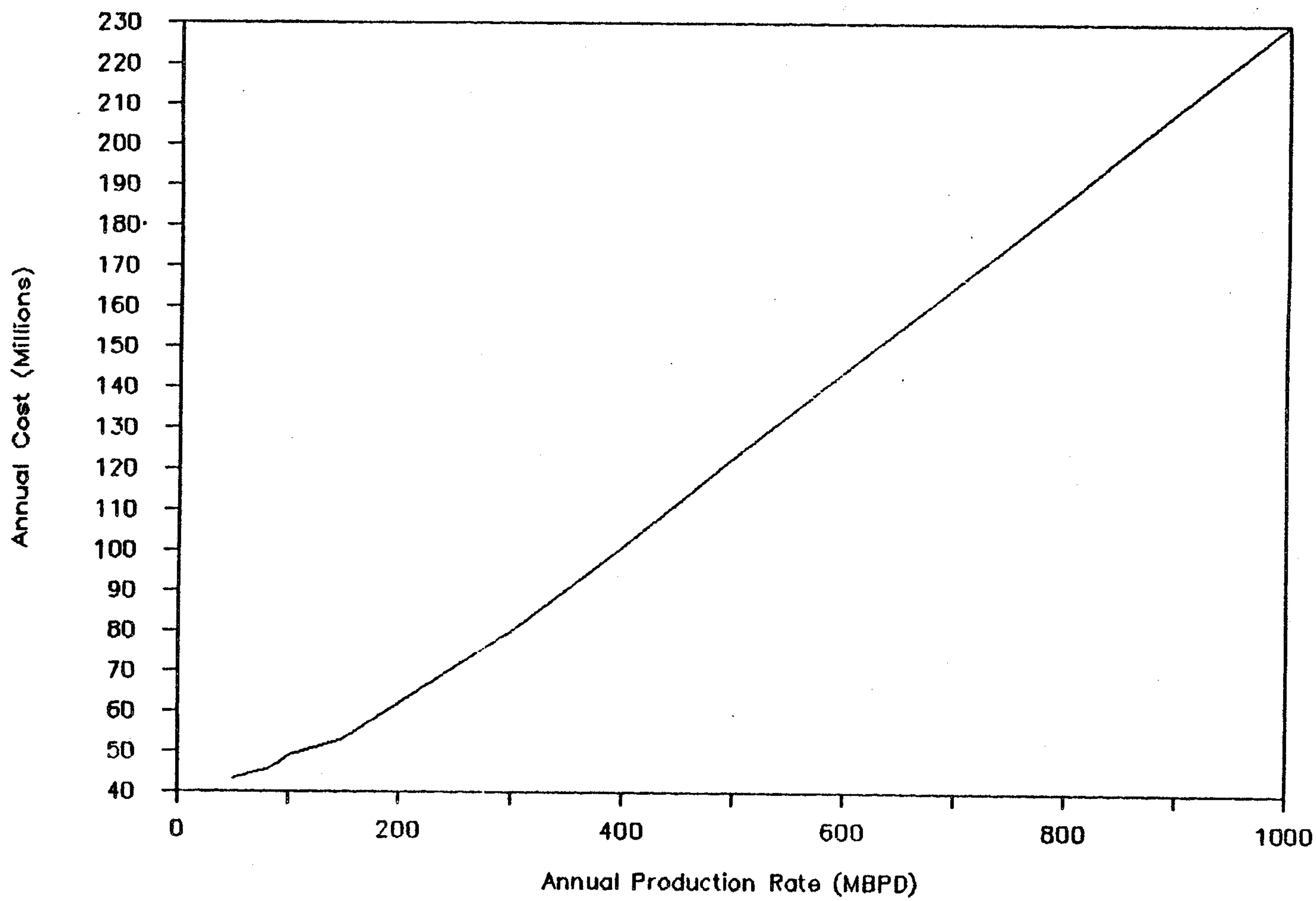
FIGURE 5



Source: Bureau of Land Management estimates, see the accompanying text for details.

Estimated annual costs (in 1984 dollars) for production

FIGURE 6



Source: National Petroleum Council (1981) estimates escalated to 1984 dollars using the Marshall Valuation Services (1985) index for petroleum equipment.

Labor, supervision, overhead and administrative costs
Communications, safety, catering
Supplies and consumables
Routine process and structural maintenance
Well service and workover
Insurance on facilities
Transportation of personnel and supplies

Transportation costs to ship crude oil from ANWR to market are also a major cost factor. However, estimating transportation cost requires more specific analysis to determine the cost and extent to which the existing North Slope crude oil transportation system can be utilized for crude oil from ANWR. A detailed discussion of this subject is provided in the Crude Oil Transportation Section of this report.

The investment and production costs shown include the cost of operating in a sensitive environment (National Petroleum Council, 1981). But if, because of the area's status as a wildlife refuge, stipulations become even more stringent than for typical arctic exploration and development, costs would be even higher, and presumably the minimum economic field size would increase accordingly.

Oil Prices

Oil prices are a primary consideration in performing the economic evaluation for determination of minimum economic field size, and prices reflect the commodity supply and demand forces within a region or market area. Most of North Slope crude oil produced from the Prudhoe Bay and Kuparuk River field is being shipped to refineries on the Western, Gulf and Eastern coasts of the United States. Some crude oil is shipped to Hawaii, the Virgin Islands, and Puerto Rico. Table 1 shows destinations during 1978-84. Panama though listed, is not actually a destination, but rather a transhipment point. West Coast refineries received more than 50 percent of North Slope crude oil shipped through 1984, except for 1982 and 1983 when only 47 percent of Alaskan North Slope crude was delivered to the West Coast.

Marketing North Slope crude on the West Coast has the advantage of higher netback (see glossary) wellhead prices through reduced transportation costs. The difference in transportation costs between ports on the Western and Gulf Coasts is discussed under "Crude oil transportation." No major crude oil transportation system exists to move North Slope crude from the West Coast to Gulf Coast or Eastern refineries (McDonald, 1984), so the West Coast market area is limited to the amount of North Slope crude oil that is required to meet regional demand. In his testimony before the Federal Energy Regulatory Commission on the Trans-Alaska Pipeline, Jeffery Leitzinger noted that self sufficiency in crude supply and lack of a crude oil transportation system from the West Coast to refineries east of the Rocky Mountains has resulted in rather distinct markets for the West Coast and the region east of the Rocky Mountains (Leitzinger, 1983). Construction has begun on a 500,000-barrel-per-day capacity pipeline from California to Texas, and this pipeline will likely affect future pricing patterns for the West Coast region. The additional transportation cost to market North Slope crude, in

TABLE 1 - Alaskan North Slope crude oil loadings at Valdez, Alaska
(In thousands of barrels per day)

Destination	Year 1978	1979	1980	1981	1982	1983	1984
U.S. West Coast-----	681	841	901	813	760	775	887
Alaska--------------	14	7	11	21	17	27	35
Hawaii--------------	15	30	44	34	34	34	46
Panama 1/-----------	344	306	459	528	694	698	572
Virgin Islands 2/---	38	81	106	126	101	106	118
U.S. Gulf 2/--------	-	4	13	14	3	6	2
Puerto Rico 2/------	-	-	-	-	-	1	-
US East Coast 2/----	-	-	-	-	-	-	1
Total---------------	1,092	1,269	1,534	1,536	1,609	1,647	1,661

Source: U.S. Department of Transportation, Maritime Administration 1983, 1984 and 1985.

U.S. Department of Commerce, Maritime Administration 1979, 1980 and 1981.

1/ Panama shipments may be transported to the Gulf Coast, East Coast, Virgin Islands and/or Puerto Rico.

2/ These direct shipments do not utilize the Panama Canal.

excess of the quantity demanded on the West Coast, on the Gulf Coast has a negative effect on wellhead prices. Therefore, a strong incentive exists to market North Slope crude on the West Coast, within the demand and supply constraints of that market.

Crude oil quality, potential West Coast production, and petroleum export limitations must be considered in evaluating future markets and prices for any crude oil discovered in ANWR. Crude oil quality can substantial affect where crude oil in marketed. North Slope crude currently produced is a relatively low gravity oil (approximately 27° API gravity) having a relatively high sulfur content of approximately 1.05 percent (Dames and Moore, 1982). This oil is less easily refined into lighter end products than the more desirable lighter gravity low-sulfur crudes such as Saudi light (34° API gravity). The West Coast is a crude oil surplus region, but still imports lighter gravity crude to satisfy the product slate demanded. Assuming oil produced from ANWR is comparable to that produced elsewhere on the North Slope, then marketing locations are expected to be similar.

Significant discoveries have been made in California's Outer Continental Shelf (OCS) areas of the Santa Barbara Channel and Santa Maria Basin, and development plans are underway. This production could effectively back-out a portion of the future North Slope production that would otherwise be marketed on the West Coast by the end of this century. North Slope production from known fields is projected to begin declining in 1987, and by the year 2000 will drop to approximately 29 percent of 1984 production (Alaska Department of Revenue Petroleum Revenue Division, 1985a). Crude oil production from any discoveries in ANWR would not be on-line until the late 1990s or after the year 2000. Therefore, the market opportunities for any ANWR crude oil are assumed to be available in roughly the same proportions as current markets are for North Slope crude, and wellhead prices are assumed to be affected by approximately the same volume weighted average proportion of transportation cost for sales in each market.

The Trans-Alaska Pipeline Authorization Act of 1973 restricts export of North Slope crude oil. That act extended provisions of the Minerals Lands Leasing Act (MLLA) of 1970 (U.S. Department of Energy Information Administration, 1984). The MLLA requires a Presidental finding that any export of crude oil would not diminish the quantity or quality of oil available to the United States. Therefore, Alaskan North Slope crude oil is not exported, except to the Virgin Islands and Puerto Rico, both territories of the United States. Opposition to this export ban has risen recently, due to the downward trend in crude oil market prices and the resulting reduction in revenues to the State of Alaska. There is potential for developing crude oil export markets in the Far Eastern nations such as Japan and Korea. Total transportation cost would be less to market North Slope oil in Far Eastern nations than on the Gulf Coast. The reduced transportation costs would result in higher netback wellhead prices, which would increase revenues for the producers and revenue collections by the State and Federal Governments. How North Slope crude oil producers would react to a lifting of this export ban is unknown. A considerable amount of capital has been invested in tankers and the Panama Pipeline to transport North Slope crude to existing markets, which would weigh on a producers' decisions to export crude to Far Eastern nations. It is outside the scope of this analysis to speculate on the effects of lifting the export ban on North Slope crude oil production and prices. Therefore, the market opportunities for any crude oil discovered in ANWR are limited to those markets available to North Slope producers. However, the effect of increased wellhead prices on minimum economic field size is shown in the sensitivity analysis section of this report.

Table 2 compares North Slope crude oil volume weighted average market and wellhead prices to wellhead and refiners' acquisition prices for domestic and foreign crude. No quality adjustments were made for the various types of crude. Domestic wellhead and North Slope wellhead prices diverged widely after full deregulation in 1981. These prices differed by $8.00 to $9.00 per barrel, reflecting the difference in transportation cost between crude oil produced on the Alaskan North Slope and crude oil produced in the contiguous lower 48 States. The market price trend for North Slope crude closely follows the price trend for domestic refiners' acquisition cost. In the past the heavier gravity crude oils, such as oil from the North Slope, have received lower prices because they yield less-desirable heavier products. Upgraded refineries can now produce more of the desired light products from heavy crude, so prices of heavier crude oil have been less affected by the recent decline in world crude oil prices.

Predicting future oil prices with any degree of certainty is very difficult and subject to many inaccuracies. Oil price forecasts that were completed during periods of rapid real price expansion such as occurred from 1979 to 1981 certainly do not reflect current market conditions. There is currently a downward trend in world oil prices, with the Organization of Petroleum Exporting Countries (OPEC) again being forced to reduce its official pricing scheme. In the spring of 1983 the OPEC official price for Saudi light (34° API gravity) dropped from $34.00 per barrel to $29.00 per barrel and in February 1985 the price for the marker crude was further lowered to $28.00 per barrel. Along with the last price adjustment for Saudi light, OPEC members altered price differentials between light and heavy grades of crude, to more closely reflect market conditions.

This analysis assumes that crude oil production from a discovery in ANWR would not begin until 9 or 10 years after leasing, and that there will be a significant time lag associated with the decision making process to determine the need for exploration of ANWR. Potential production from ANWR is not expected to begin until the late 1990's, and could continue through the year 2025 or 2030 and beyond. Therefore, oil price forecasts would be required as much as 45 years in the future. The accuracy of any price forecast that far in the future is questionable at best. Table 3 summarizes recent oil price forecasts by oil companies, private research firms, financial institutions and the Department of Energy. These forecasts are all reported on a constant dollar basis, and many of the forecasts contain price ranges. Some of the oil price projections in these forecasts were reported in graphic form, so some of the values presented in table 3 were interpreted from graphs and may vary slightly from the actual numerical values used to construct the graphs. Table 4 was prepared from table 3 in an effort to standardize these forecasts on a 1984 constant dollar basis. The forecast oil prices based on 1980 dollars were escalated by 25.2 percent, the 1982 dollar forecasts were escalated by 8.0 percent, and the 1983 dollar forecast were escalated by 3.6 percent. This process attempts to make all the forecasts comparable on a constant dollar

TABLE 2 - Weighted Average Crude Oil Prices, 1977-84.
(In dollars per barrel)

N/A, not available

	Domestic wellhead1/	North Slope wellhead2/	North Slope Market2/	Refiner acquisition cost1/		
				Domestic	Imported	Composite
1977---	8.57	6.30	N/A	9.55	14.53	11.96
1978---	9.00	5.11	N/A	10.61	14.57	12.46
1979---	12.64	10.35	N/A	14.27	21.67	17.72
1980---	21.59	16.83	N/A	24.23	33.89	28.07
1981---	31.77	23.27	32.55	34.33	37.05	35.24
1982---	28.52	19.82	28.94	31.22	33.55	31.87
1983---	26.19	17.55	26.74	28.87	29.30	28.99
1984---	25.88	17.86	26.71	28.53	28.88	28.63

1/ U.S. Department of Energy, Energy Information Administration 1985a.

2/ Alaska Department of Revenue Petroleum Revenue Division (1985). Monthly reported volume weighted average price and quantities delivered ANS. unpublished data.

TABLE 3 - Future constant dollar oil price forecasts
(In dollars per barrel)

Forecast[1/]	Price Indicator	Dollar Basis	Year 1990	1995	2000	2005	2010
Texaco 1983	Arabian Light	1982	27.25	28.50	30.50	N/A	N/A
Chase Manhattan Bank 1984	World Oil	1982					
Low			22.75	N/A	N/A	N/A	N/A
Most Likely			25.25	N/A	N/A	N/A	N/A
High			29.75	N/A	N/A	N/A	N/A
Ashland 1984	World Oil	1984					
Low			21.00	N/A	N/A	N/A	N/A
Most Likely			23.50	N/A	N/A	N/A	N/A
High			32.55	N/A	N/A	N/A	N/A
Chevron Corporation 1985	Arabian Light	1984					
Low Price Trend			23.50	24.25	28.50	N/A	N/A
High Price Trend			34.25	39.75	48.00	N/A	N/A
Gas Research Institute 1984	World Oil	1983	30.68	N/A	39.27	N/A	52.77
Data Resources Incorporated 1984	Refiner's Acquisition Cost	1983	24.17	N/A	34.60	N/A	39.83
U.S. Dept of Energy Energy Information Administration 1985	Refiner's Acquisition Cost	1984					
Low Scenario			25.00	30.00	N/A	N/A	N/A
Moderate Scenario			30.00	40.00	N/A	N/A	N/A
High Scenario			40.00	55.00	N/A	N/A	N/A
U.S. Dept of Energy 1985	Refiner's Acquisition Cost	1984					
Low NEPP[2/]			20.27	25.94	31.31	40.29	47.42
Moderate NEPP[2/]			22.89	29.79	36.75	46.92	56.77
High NEPP[2/]			25.02	33.65	42.17	54.38	67.12
Stanford Research Institute[3/]	World Oil	1984	N/A	N/A	28.75	N/A	N/A
PACE[3/]	World Oil	1984	N/A	N/A	37.00	N/A	N/A
Oil Company A[3/]	World Oil	1984	N/A	N/A	24-48	N/A	33-66
Manne and Rowley 1985	IEW Poll, Median Percentage Change	1980	89.5%		109.0%		141.0%

1/ See references list for complete citations.

2/ NEPP, the National Energy Policy Plan by the U.S. Department of Energy.

3/ These reports were used as comparisons with the Department of Energy's oil price forecast, and the original reference was not available for this document.

TABLE 4 - Standardized 1984 constant dollar Oil price forecasts[1/]
(In dollars per barrel)

Standardized Forecast	Price Indicator	1990	1995	Year 2000	2005	2010
Texaco-----------------	Arabian Light	29.43	30.18	32.94	N/A	N/A
Chase Manhattan Bank	World Oil					
Low------------------		24.57	N/A	N/A	N/A	N/A
Most Likely----------		27.27	N/A	N/A	N/A	N/A
High-----------------		32.13	N/A	N/A	N/A	N/A
Ashland	World Oil					
Low------------------		21.00	N/A	N/A	N/A	N/A
Most Likely----------		23.50	N/A	N/A	N/A	N/A
High-----------------		32.55	N/A	N/A	N/A	N/A
Chevron Corporation	Arabian Light					
Low Price Trend------		23.50	24.25	28.50	N/A	N/A
High Price Trend-----		34.25	39.75	48.00	N/A	N/A
Gas Research Institute		31.78	N/A	40.68	N/A	54.67D
Data Resources Incorporated----------	Refiner's Acquisition Cost	25.04	N/A	35.84	N/A	41.26U
U.S. Dept of Energy Energy Information Administration	Refiner's Acquisition Cost					
Low Scenario---------		25.00	30.00	N/A	N/A	N/A
Moderate Scenario----		30.00	40.00	N/A	N/A	N/A
High Scenario--------		40.00	55.00	N/A	N/A	N/A
U.S. Dept of Energy	Refiner's Acquisition Cost					
Low NEPP[2/]----------		20.27	25.94	31.31	40.29	47.42
Moderate NEPP[2/]-----		22.89	29.79	36.75	46.92	56.77
High NEPP[2/]---------		25.02	33.65	42.17	54.38	67.12
Stanford Research Institute-----------	World Oil	N/A	N/A	28.75	N/A	N/A
PACE-----------------	World Oil	N/A	N/A	37.00	N/A	N/A
Oil Company A--------	World Oil	N/A	N/A	24-48	N/A	33-66
Manne and Rowley------	Refiner's Acquisition Cost	37.98	N/A	46.26	N/A	59.84

1/ All forecasts reported in table 3 that were not in 1984 dollars were inflated to 1984 dollars using the average annual implicit price deflators from table 5.

2/ National Energy Policy Plan by the U.S. Department of Energy.

basis, but recent oil price changes cannot be incorporated into the older price forecasts. The forecast reported by Manne and Rowley (1985) represents the consolidated responses for the International Energy Workshop poll, and the percentage changes shown in table 3 represent the median response from participants in the poll.

Table 4 illustrates the inherent uncertainty in price forecasting. For the year 2000 when production from ANWR might begin, oil price projections range from $24.00 per barrel to $48.00 per barrel. The price spread among forecasts is even greater for those projections to the year 2010, the farthest point for any of the forecasts. Many forecasts ended on or before the year 2000, which leads to a lack of data consistency when comparing prices. Some of the forecasts have been made periodically (Data Resources Incorporated; Manne and Rowley; U.S. Department of Energy, Energy Information Administration; and U.S. Department of Energy, National Energy Policy Plan), with lower oil price expectations reported in the current edition (table 3) than the previous edition. Manne and Rowley (1985) termed this phenomenon "adaptive expectations," where future projections are overwhelmingly shaped by current circumstances.

The purpose of this report is not to critique existing oil price forecasts or develop additional price projections, but rather to analyze the level of economically recoverable hydrocarbon resources that exist in ANWR. Therefore, a range of possible oil prices will be used to illustrate the potentially economically recoverable resources. The year 2000 has been assumed to be the base year when production from ANWR would begin, so in the sensitivity analysis, the range of initial oil prices considered (using refiner's acquisition price of imported crude oil as the marker) will be $24.00 minimum to $42.00 maximum per barrel in constant 1984 dollars. The high-range price projection for the forecasts shown in table 4 was $48.00 per barrel, but real 1984 dollar prices paid for imported crude oil only slightly exceeded $42.00 per barrel. Therefore, the high-range price in the year 2000 is assumed to be $42.00 per barrel, not $48.00. The oil prices for the most likely and optimistic economically recoverable resource scenarios are assumed to be $35.00 and $42.00 per barrel (1984 dollars), respectively, in the year 2000, and future real oil price growth of 1 percent per year compound annual rate is assumed for both scenarios. Sensitivity analyses of future oil price growth rates on minimum economic field size will illustrate the effects of variations in the future oil price growth rate between a negative 1 percent and positive 2 percent compound annual real price growth rate using the same oil prices assumed for the most likely and optimistic economically recoverable resource scenarios. By 1984 the price differential between refiners' acquisition cost of imported crude and North Slope crude (table 2) had narrowed to $2.17 per barrel. For this analysis a constant $2.00 per barrel lower differential in market price is assumed between Alaskan North Slope crude oil sold in existing markets and refiners' acquisition cost of imported crude. Given this assumption, the projected oil prices translate into real 1984 dollar market prices of $33.00 and $40.00 per barrel in the year 2000 for ANWR crude oil comparable in quality to existing North Slope crude under the most likely and optimistic economically recoverable resource scenarios, respectively.

Inflation Rates

Future cost escalation rates for exploration, development and transportation costs and the general rate of inflation in the economy are extremely difficult, if not impossible, to predict with any degree of accuracy or certainty. As with oil price forecasts, future cost escalation and inflation forecasts would be required through the year 2025 or 2030. The validity of any single growth rate forecast that far into the future is questionable. So the approach for this analysis is to estimate, as part of the sensitivity analysis economically recoverable resources at separate inflation rates for the most likely and optimistic economically recoverable resource scenarios and present the effects of a range of inflation rates on minimum economic field size. Individual cost components such as drilling costs, facilities costs and transportation costs are all escalated at the same rate. The most likely case analysis utilizes a moderate level of inflation, and the optimistic case utilizes a lower rate of inflation.

Several standard indices are used by the Federal Government to measure inflation. The Gross National Product (GNP) Implicit Price Deflator is commonly used, because of its broad base measure of goods and services. The GNP Deflator is used herein as the measure of inflation. Data Resources Incorporated (1984) performed long-term economic forecasts through the year 2010 which include projections for the GNP Deflator. Data Resources Incorporated forecasts the annual compound rate of change in the GNP Implicit Price Deflator to be 6.02 percent in the year 2000 and 5.74 percent in the year 2010. These inflation rates are slightly below the long-term compound annual average rate of change in the GNP Deflator of 6.6 percent from 1970 to 1984. For the most likely case, the inflation rate is assumed to be a constant 6.0 percent throughout the field development and production life. For the optimistic economically recoverable resource case, the inflation rate is based on historical data (table 5).

Table 5 presents the annual average GNP Implicit Price Deflator and compound annual rates of change in the Deflator for 1970-84. The highest annual compound rate of change was recorded in 1981 at 9.4 percent and the lowest annual rate of change, in 1984 at 3.6 percent. For the optimistic economically recoverable resource scenario the inflation rate is assumed at a constant 3.5 percent and sensitivity analysis of the effects of inflation on minimum economic field size considers the range of inflation rates from 3.5 to 9.5 percent to bracket the historical low and high rates recorded during 1970-84.

Crude Oil Transportation

Crude oil transportation systems to deliver to market any crude oil discovered in ANWR were discussed in Chapter IV. The most economically viable method for transporting commercial quantities of ANWR crude oil is through TAPS. The investment costs, operation costs and returns on TAPS are currently being amortized over the massive reserves of the Prudhoe Bay and Kuparuk River fields and future reserves of any other new fields that can be commercially produced from the North Slope region. Therefore, the unit cost of

TABLE 5 - Annual Average Gross National Product Implicit Price Deflator and Annual Rate of Change From 1970-84 (1972 = 100)

Year	Annual Average GNP Deflator	Compound Annual Rate of Change
1970	91.4	5.4
1971	96.0	5.0
1972	100.0	4.2
1973	105.8	5.8
1974	115.1	8.8
1975	125.8	9.3
1976	132.3	5.2
1977	140.1	5.9
1978	150.4	7.4
1979	163.4	8.6
1980	178.4	9.2
1981	195.1	9.4
1982	206.9	6.0
1983	215.6	4.2
1984	223.4 1/	3.6 1/

Source: U.S. Department of Commerce, Bureau of the Census (1984, p. 486; 1983, p. 454; 1976, p. 433).

1/ Quarterly GNP Implicit Price Deflator indices for 1984 provided by: Federal Reserve Bank of St. Louis 1985. National economic trends by Federal Reserve Bank of St. Louis, February 1985.

transporting additional oil through TAPS is much less than building an entirely new transportation system from ANWR to the south-central coast of Alaska.

Utilization of TAPS as part of the crude oil transportation system entails three separate transportation components to move the crude oil from the wellhead in ANWR to coastal transportation and refining networks on the West, Gulf, and East coasts of the United States: (1) the construction and operation of a pipeline system from field production facilities in ANWR to Pump Station 1 of TAPS; (2) TAPS and the loading terminal at Valdez; and (3) the marine transportation system from Valdez to ports on the West, Gulf, and East coasts of the United States. Several assumptions are required to estimate the crude oil transportation costs for each of these three components. Each component is discussed below.

ANWR To Pump Station 1 of the Trans-Alaska Pipeline System

The design of a crude oil transportation pipeline and associated facility was discussed in Chapter IV, and the estimated investment costs for a pipeline from ANWR to TAPS are shown in figure 7. The pipeline investment costs include the cost of the pipeline and associated facilities, road and workpad, and all intermediate pump stations required. For this analysis, intermediate pump stations are assumed to be required every 90 to 100 miles in the coastal plain terrain. An additional simplifying assumption was used to lessen the range of possible alternative pipeline size and pump-station capacity requirements. Only three pipeline diameters will be utilized for the range of recoverable resources up to 3.5 billion barrels:

Recoverable Resource	Pipeline diameter (In Inches)
Less than 1 billion barrels	20
1 billion to 1.75 billion barrels	24
More than 1.75 billion barrels	28

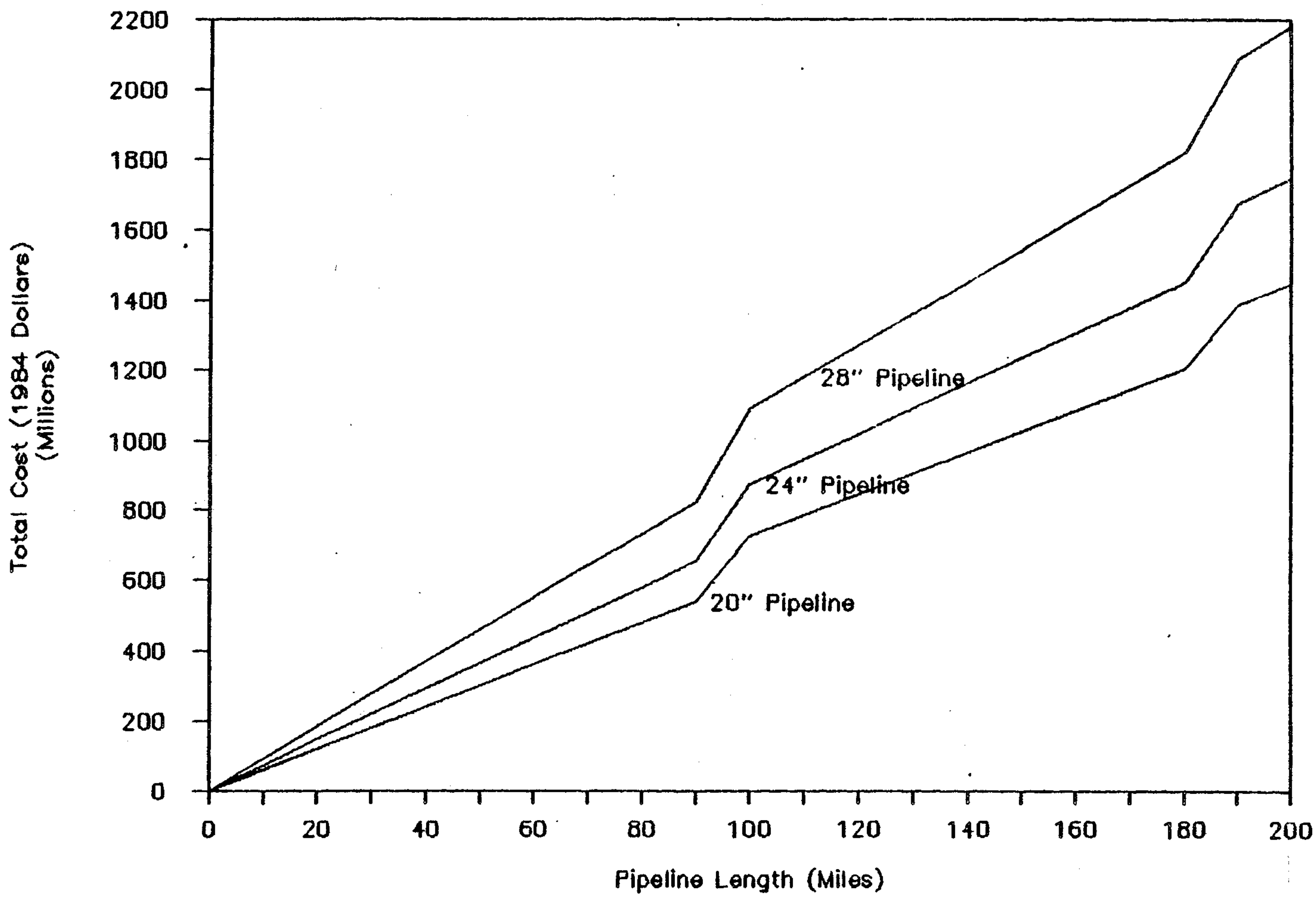
Cost estimates for the pipeline facility, road and pad, pump station and annual operation and maintenance were extrapolated from data by the National Petroleum Council (1981), Dames and Moore (1982a), and private industry. The kinked curves each at 90-100 mile interval (fig. 7) reflect the added pump station costs required at that distance.

Operation of this pipeline would be similar to management of TAPS. This pipeline would transport interstate shipments of crude oil, so it would be under the jurisdiction of the Federal Energy Regulatory Commission. Ownership of the pipeline would be structured as a separate business entity, similar to the Alyeska Pipeline Service Company or Kuparuk Transportation Company. The pipeline owner would be a common carrier for all producers in the area.

Considerable controversy exists over the proper rate base method of calculating pipeline tariffs, as evident from the continuous litigation since initial tariffs for TAPS were filed in 1977 with the Interstate Commerce Commission (ICC). The specific issue of TAPS tariffs is discussed in more detail in the next section. Rather than using the old ICC method or other

Estimated total costs (in 1984 dollars) for pipeline construction

FIGURE 7



Source: Bureau of Land Management estimates, see the accompanying text for details.

rate-based methods this analysis uses an alternative method. For this analysis, pipeline tariffs from ANWR to TAPS are calculated as the minimum levelized cost per recoverable barrel of crude oil that would yield an after-tax internal rate of return, over the life of the field, equal to the discount rate of 10 or 8 percent, respectively, selected, for the most likely and optimistic economically recoverable resource analysis. The implicit assumption is that the same company undertaking the investment in the field would also begin operations of a new pipeline service company to transport the crude oil reserves to TAPS, and the same real rate of return would be required for the combined projects. The specific assumptions used to estimate tariffs from ANWR to TAPS are:

1. Pipeline throughput will be equal to field production.

2. Investment costs for the pipeline, facilities, equipment, roads and workpad are as shown in figure 7.

3. Pipeline design begins in year seven and primary construction of the pipeline occurs in years eight and nine of the development schedule (figure 2), with 50 percent of total construction expenditures accruing in each year.

4. Annual operation and maintenance cost are equal to 2 percent of total investment costs.

5. Income tax calculations include the following assumptions:

   a. All labor, facilities, equipment and transportation costs are capitalized into the value of the pipeline.

   b. Capitalized costs are written off over 15 years using ACRS depreciation (Ernst and Whinney, 1984).

   c. Investment tax credit is calculated at 10 percent with a reduction in depreciable basis of 50 percent of total investment tax credit (Burke and Bow, 1984).

   d. Income taxes are calculated at a rate of 9.4 percent (Alaska Department of Revenue, 1982) for State of Alaska Corporate Income Tax, and 46 percent for Federal Income Tax (Burke and Bow, 1984) for an effective rate of 51.1 percent (see Stermole, 1982, for procedures to calculate effective income tax rates).

   e. Income tax credits and all operating losses are carried forward and used against income in future years.

6. State of Alaska ad valorem property tax is calculated at 2 percent per year applied to the current value of tangible property (Alaska Department of Revenue, 1982a).

7. All capital is assumed to be 100 percent equity with no financial leverage (National Petroleum Council, 1981).

8. End-of-year discounting is used.

9. The same cost inflation and discount rates are used for the most likely and optimistic economically recoverable resource scenarios for calculating both pipeline tariffs from ANWR to TAPS and minimum economic field size.

Pipeline construction is assumed to take 2 years. Unexpected delays from environmental, engineering or unforeseen permitting problems would subsequently alter the initial tariff level. For example, the estimated initial tariff for a 150-mile, 24-inch pipeline would be 106, 115, or 94 percent, respectively, of the most likely tariff, if construction time was lengthened to 3 or 4 years or shortened to 1 year. However, 2 years was assumed to be the most likely construction time and the effects of other construction schedules on minimum economic field size are not considered further.

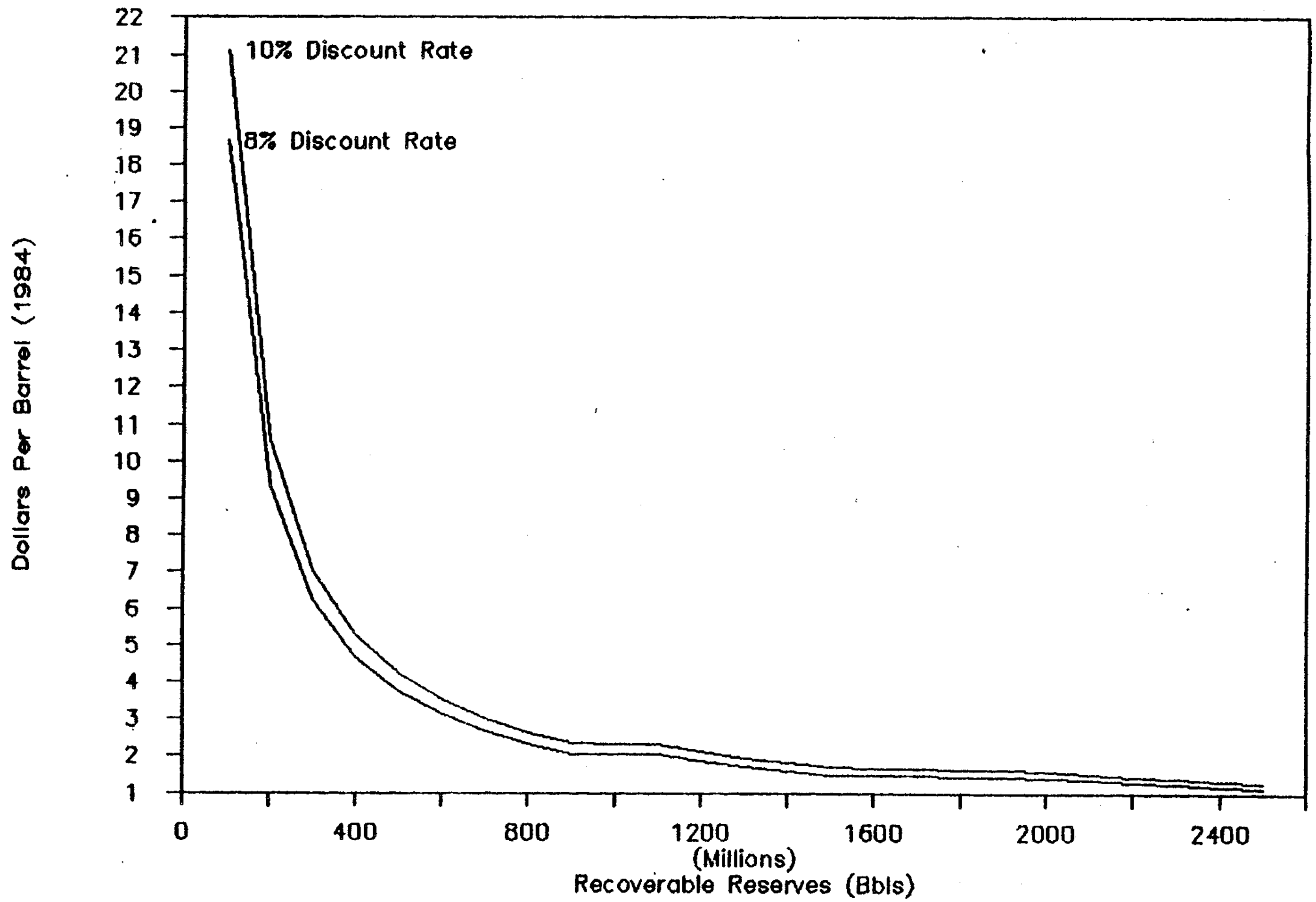
Viewing the western and eastern parts of ANWR separately illustrates the significance of distance on pipeline tariffs. Pipeline distances of 85 to 150 miles to pump station 1 are assumed for the western and eastern parts, respectively. Initial pipeline tariffs as a function of total recoverable resources, inflation rate, and discount rate are shown in figures 8-11. In all instances tariffs are much higher for smaller quantities of recoverable resources, because pipeline costs are amortized over fewer barrels of crude oil throughput. At equal throughput, inflation rate, and rate-of-return assumptions, the tariffs per-mile are higher for eastern ANWR, because an intermediate pump station is required. Higher inflation rate or higher minimum acceptable real-rate-of-return assumptions also lead to higher tariffs. Even when differences in per-barrel costs are small, the tremendous volume of production leads to substantial differences in annual transportation costs.

For of the DCF analysis, future pipeline tariffs from ANWR to TAPS were assumed to increase at the rate of inflation. This assumption effectively maintains a steady (leveled) tariff cost in real terms throughout the analysis period. The actual pipeline tariff for individual prospects or groups of prospects will depend on the distance from TAPS and the level of expected recoverable resources from each prospect.

Pump Station 1 of the Trans-Alaska Pipeline System to Valdez, Alaska

The Trans-Alaska Pipeline System is the potentially limiting factor of the crude oil transportation system from ANWR to market. This system is in place and restricted by the technical maximum and minimum capacity of its design. The current capacity of TAPS is reported to be 1.8 million barrels per day (Petroleum Economist, 1984). Feasible capacity expansions could enable the line to transport as much as 2.5 million to 2.7 million barrels per day (International Petroleum Encyclopedia, 1983). In 1984 TAPS transported an average of 1.66 million barrels per day, which is considerably less than capacity. Future throughput through TAPS depends on the economics of continued production from the Prudhoe Bay and Kuparuk River fields, development of existing discoveries on the North Slope, and potential new commercial discoveries on the North Slope. The Alaska Department of Revenue, Estimated initial pipeline tariffs (in 1984 dollars) for ANWR pipelines 85 miles to the Trans-Alaska Pipeline System, calculated at 6 percent inflation

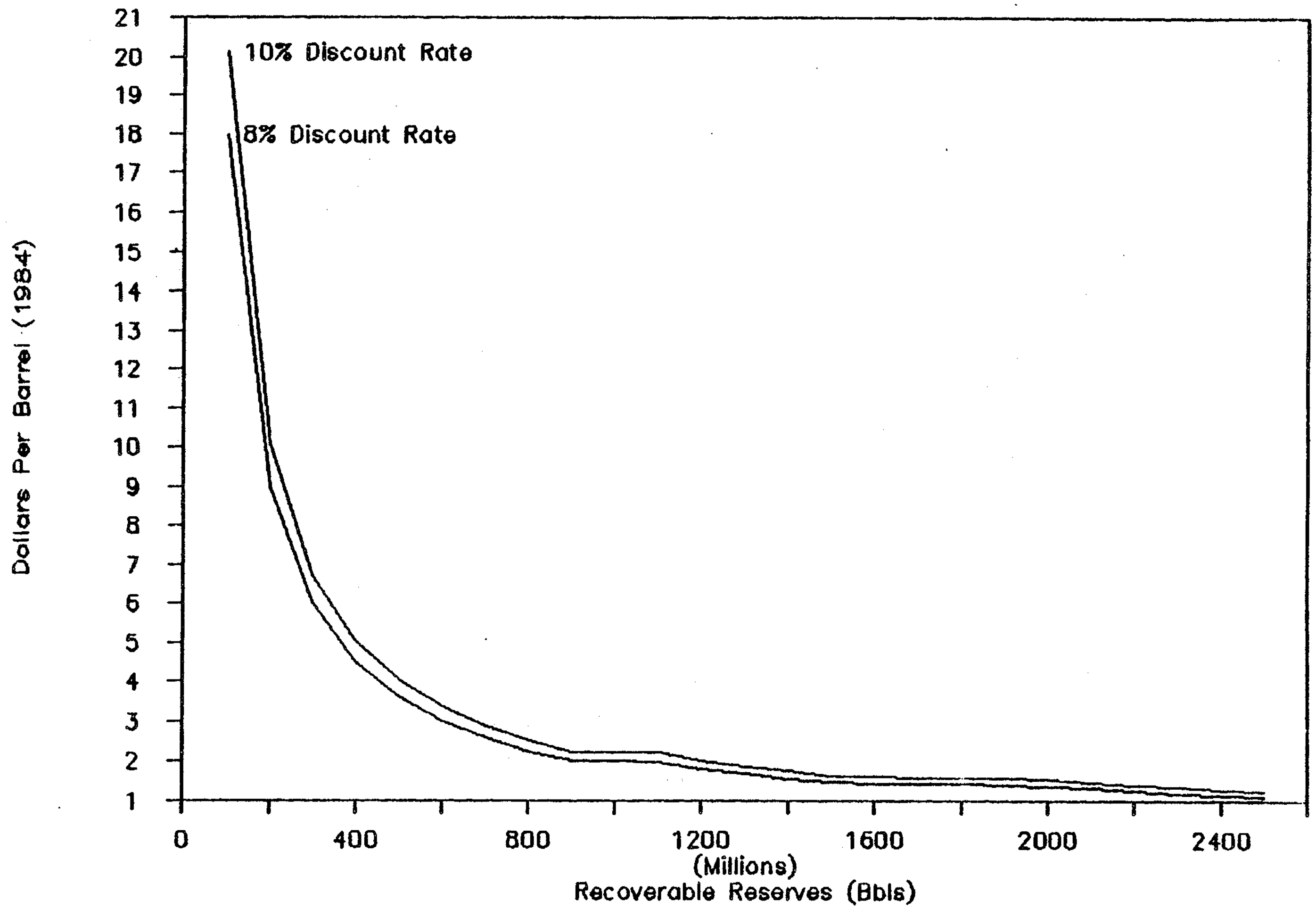
FIGURE 8



Source: Bureau of Land Management estimates, see the accompanying text for details.

Estimated initial pipeline tariffs (in 1984 dollars) for ANWR pipelines 85 miles to the Trans-Alaska Pipeline System, calculated at 3.5 percent inflation

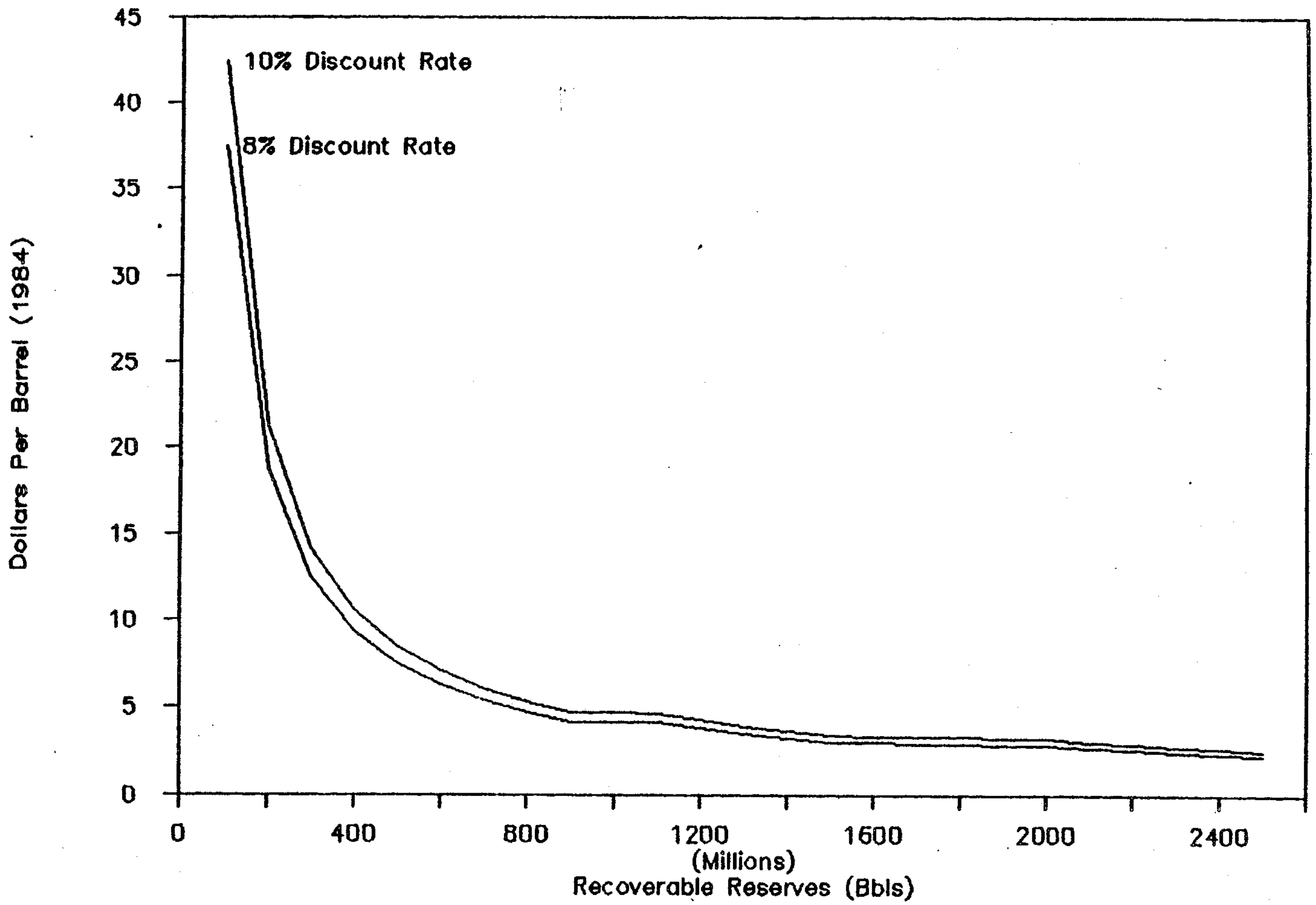
FIGURE 9



Source: Bureau of Land Management estimates, see the accompanying text for details.

Estimated initial pipeline tariffs (in 1984 dollars) for ANWR pipelines 150 miles to the Trans-Alaska Pipeline System, calculated at 6 percent inflation

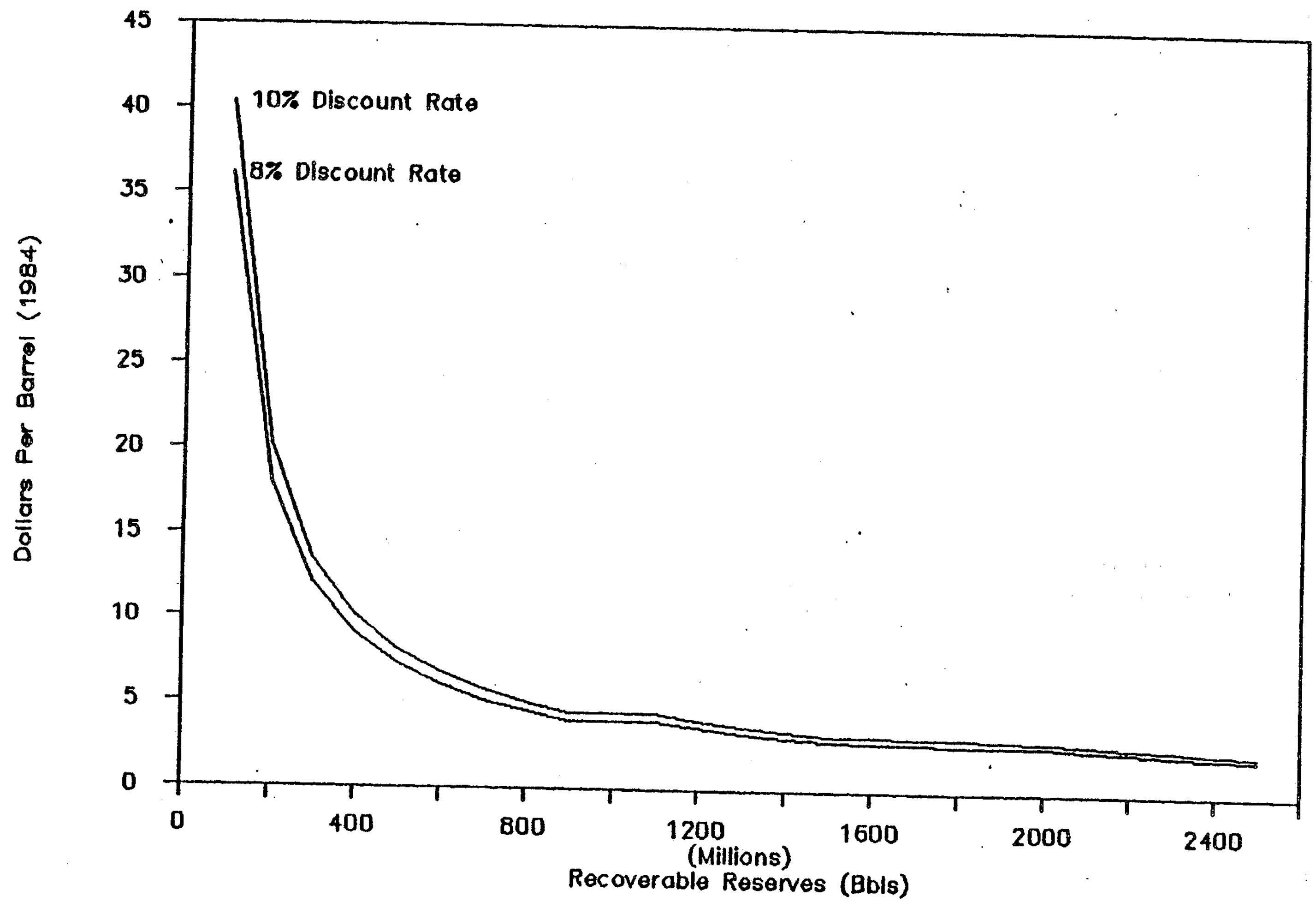
FIGURE 10



Source: Bureau of Land Management estimates, see the accompanying text for details.

Estimated initial pipeline tariffs (in 1984 dollars) for ANWR pipelines 150 miles to the Trans-Alaska Pipeline System, calculated at 3.5 percent inflation

FIGURE 11



Source: Bureau of Land Management estimates, see the accompanying text for details.

Petroleum Revenue Division (1985) forecasts future North Slope oil production from producing fields and discoveries that have not yet been developed, given their forecast of future crude oil prices. These estimates of total North Slope production from 1985 to 2001 (table 6) include projected production from Prudhoe Bay (including the Lisburne Formation underlying the producing Sadlerochit Formation), Kuparuk River, West Sak, Milne Point, Endicott, Point Thomson and other onshore and offshore areas (Alaska Department of Revenue Petroleum Revenue Division, 1985a). Table 6 also shows the projected excess throughput capacity of TAPS as compared to projected future production. These comparisons are made at the present 1.8-million-barrel-per-day capacity and potential maximum capacity of 2.7 million barrels per day. Projected North Slope production is not expected to exceed the present TAPS capacity. Instead, after a peak rate of 1.7 million barrels per day in 1987, North Slope production is projected to decline rapidly (Alaska Department of Revenue Petroleum Revenue Division, 1985a). Potential production from ANWR would not be expected to begin until the late 1990s or the year 2000. At that time, production is projected to be considerably less than the current maximum capacity. An excess capacity of more than 1.3 million barrels per day is projected to occur in the year 2000, even if TAPS capacity is not expanded beyond the present 1.8 million barrels per day. Therefore potential production from ANWR is not expected to be limited by total throughput capacity of TAPS.

Considerable controversy has existed over the tariff rate charged for transporting petroleum through TAPS from the North Slope to Valdez, Alaska. The TAPS tariff directly affects wellhead prices for North Slope crude oil, which are the basis for calculating royalties, severance taxes, income taxes and Federal windfall profits taxes (windfall profits taxes are limited to crude oil produced from Prudhoe Bay). Because of the high production volume from North Slope fields and the significance of wellhead prices, a substantial amount of money is at stake from past and future production. Understandably, all the concerned parties are interested in this issue. At the time this analysis was completed, six of the eight TAPS owners had entered into settlement agreements with the State of Alaska, and the Federal Energy Regulatory Commission approved the agreements. Amerada Hess and Sohio Alaska had not accepted the agreements, so litigation may continue. The agreements would reduce the 1985 tariff to $5.31 per barrel and refund an estimated $500 million for tariffs charged from 1982 through 1985 (Oil and Gas Journal, 1985a).

Table 7 presents the annual volume weighted average TAPS tariffs received for petroleum transportation from July 1981 through 1984 before the settlement agreements were completed. Independent TAPS owners charge different rates, and the rates shown in table 7 represent the average for all owners. Tariff rates charged prior to the settlement agreements declined in nominal terms from $6.21 per barrel in 1981 to the $6.01 per barrel rate which was effective in 1984. This decline is not surprising if viewed from the standpoint of a constant annual rate of return, given the increases in field production (table 1). The problem arises in projecting tariffs, with the uncertainty for acceptance of the settlement agreements by Amerada Hess and Sohio Alaska.

The settlement agreements embody a cost-based methodology that serves as a basis for calculating tariffs and the refund obligations of the TAPS owners

TABLE 6 - Projected North Slope Crude Oil Production From Producing and Discovered Areas and Trans-Alaska Pipeline System Capacity (Million Barrels Per Day)

MMPD: Million barrels Per Day

Year	Projected Average North Slope Production1/	Excess TAPS Throughput Capacity If: TAPS Throughput Is Limited to 1.8 MPD	TAPS Throughput Is Limited to 2.7 MPD
1985------	1.695	0.105	1.005
1986------	1.718	0.082	0.982
1987------	1.744	0.056	0.956
1988------	1.659	0.141	1.041
1989------	1.585	0.215	1.115
1990------	1.481	0.319	1.219
1991------	1.330	0.470	1.370
1992------	1.258	0.542	1.442
1993------	1.170	0.630	1.530
1994------	1.030	0.770	1.670
1995------	0.923	0.877	1.777
1996------	0.817	0.983	1.883
1997------	0.722	1.078	1.978
1998------	0.631	1.169	2.069
1999------	0.552	1.248	2.148
2000------	0.482	1.318	2.218
2001------	0.393	1.407	2.307

1/ Alaska Department of Revenue, Petroleum Revenue Division 1985a, Petroleum production revenue forecast, Quarterly Report, June 1985. North Slope production is reported on an annual basis and was converted to a daily basis for this report.

TABLE 7 - Annual volume weighted average charges for
Trans-Alaska Pipeline System and marine transportation
(In dollars per barrel)

Tariff rates shown predate the Trans-Alaska Pipeline System settlement agreement and do not reflect potential refunds.

Year	TAPS	Alaska to West Coast	Alaska to Gulf Coast	Weighted Average Marine	Total to Market
1981[1/]--	6.21	1.25	4.59	2.85	9.06
1982----	6.21	1.46	4.66	2.91	9.12
1983----	6.05	1.42	4.70	3.14	9.19
1984----	6.10	1.17	4.16	2.76	8.85

Source: Alaska Department of Revenue, Petroleum Revenue Division (1985). Monthly reported volume weighted average prices and quantities delivered of ANS. Unpublished data.

1/ July - December 1981.

through 1985, and provides a mechanism for determining the maximum tariffs that the TAPS owners may charge over the stipulated life of the pipeline (U.S. Federal Energy Regulatory Commission, 1985). For estimating future TAPS tariffs, this analysis assumed that the rate-based methodology from the settlement agreements will govern future TAPS tariffs for all owners. The terms of the settlement agreements extend to the year 2011, with a provision for renegotiation after the year 2006. Potential production from ANWR could extend to the year 2030. Therefore, a further assumption is that the terms of the settlement will be continued through the year 2030.

The TAPS settlement methodology (TSM) is cost-based, it requires estimates of investment costs; operation and maintenance expenses; taxes; depreciation; future dismantling, removal and restoration costs; allowance for return on capital; revenues from disposal of capital assets and other sources; and pipeline throughput. Each component is an intricate part of the TSM for projecting future TAPS tariffs. However, there is a considerable uncertainty in forecasting the value of each element through the year 2030. For expediency, the estimates of costs and revenues established for the settlement agreements through the year 2011 were used for the starting point. The more recent North Slope oil production projections by the Alaska Department of Petroleum Revenue (1985a) in its June 1985 forecast (table 6) were used to estimate future throughput. These projections terminate in the year 2001, so the average annual field production decline rate of 12 percent established in the Assumptions Section were used to estimate throughput to the year 2030. This estimate of future TAPS throughput is shown in figure 12 as the base case. The two additional throughput estimates presented include peak increases of 0.5 million and 1.0 million (intermediate case) (optimistic case) barrels per day of TAPS throughput. The argument for additional North Slope production and ultimate increase in TAPS throughput, above the levels projected by the Alaska Department of Revenue, is based on the following reasons:

1. Domestic demand for crude oil is expected to increase (Chapter VII);

2. Over the long-term crude oil prices are expected to stabilize and possibly increase;

3. Compared to the lower 48 States, the Alaska North Slope is relatively lightly explored. Further exploration may result in additional significant discoveries;

4. Oil exploration in Alaska will probably continue to dominate the U.S. petroleum industry's search for giant oil fields, and a significant discovery would accelerate this trend;

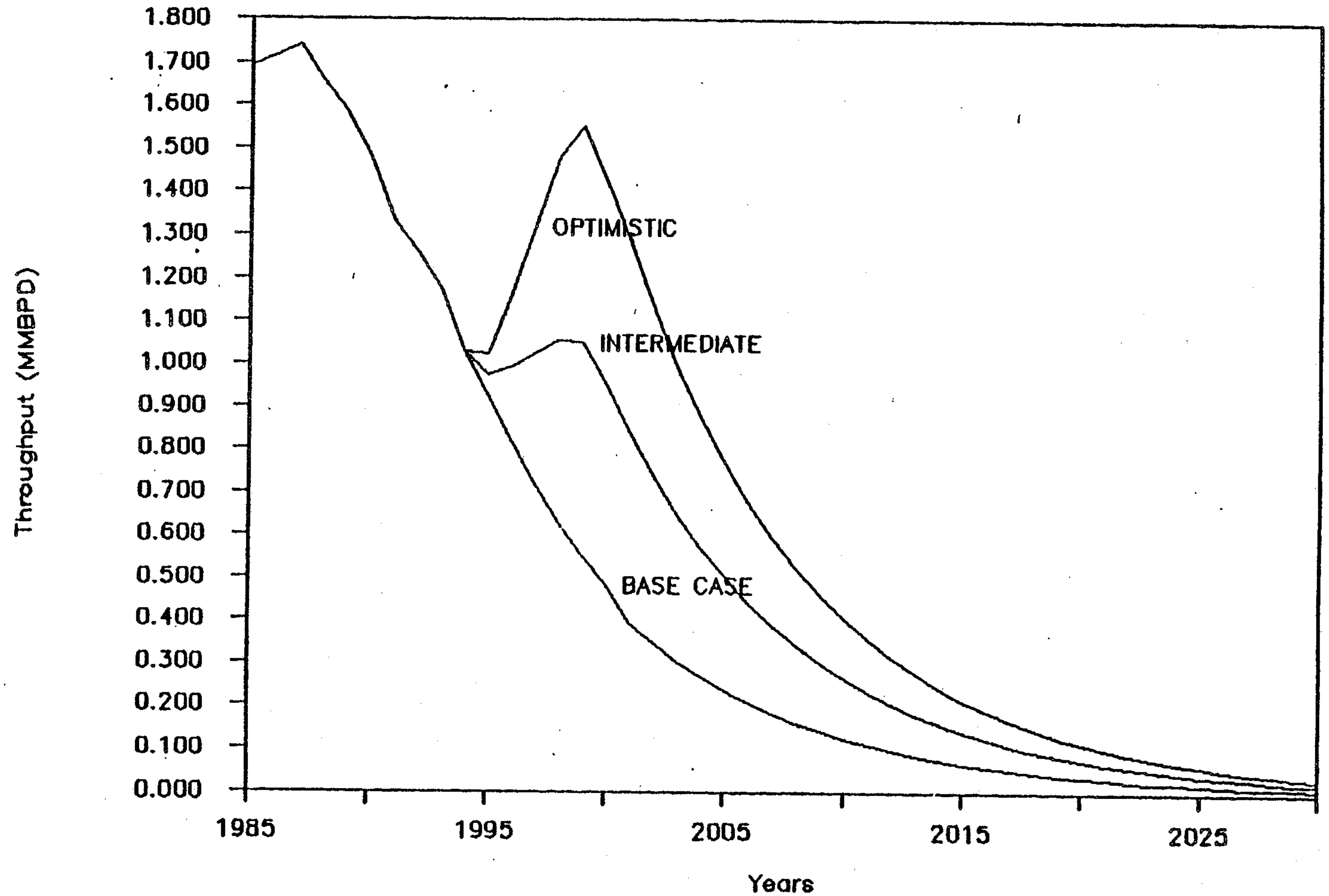
5. The TAPS will presumably remain as the only crude oil transportation system from the North Slope;

6. Substantial onshore and offshore leased acreage remains untested on the North Slope; and

7. Additional Federal and State lease sales are scheduled.

Trans-Alaska Pipeline System (throughput Scenario)

FIGURE 12



Source: Bureau of Land Management estimates, see the accompanying text for details.

These additional scenarios illustrate the potential effects on TAPS throughput of additional crude oil production from other areas on the North Slope. The throughput additions begin in 1995 and peak before the year 2000, with a subsequent 12-percent annual decline rate.

All three situations (figure 12) show rapidly declining throughput after the year 2000. This decline rate would be less if additional commercial discoveries are made on the North Slope or if technology changes to allow higher recovery rates from producing fields. The throughput scenarios highlight a potential problem for future North Slope production from areas like ANWR. The problem could arise from economic or technical minimum throughput requirements for TAPS. Once production drops to the TAPS minimum, all future petroleum production from fields in the latter stages of production and/or smaller less economic fields would be precluded without sufficient new discoveries that could withstand the cost of reactivating TAPS or building a new transportation system. Published information on the minimum throughput requirements for TAPS was not available, but figure 12 shows the importance of this issue for future North Slope production. For example, if the minimum throughput is 0.3 million barrels per day, then North Slope oil production would end in approximately the year 2003, 2009 or 2013 under the base, intermediate, and optimistic throughput scenarios. If the minimum throughput is much lower, such as 0.1 million barrels per day, the North Slope petroleum production would end in approximately the year 2012, 2018, or 2022. Both examples assume that no additional oil production from ANWR or other North Slope areas is added to TAPS throughput. Any additional petroleum production from these areas would ultimately change the throughput levels and the year in which TAPS throughput levels fall below an economic or technical minimum. Declining North Slope petroleum production and a minimum throughput level for TAPS could affect future ANWR development. These effects could range from shortening field production life and loss of a portion of recoverable resources to precluding ANWR resource development.

Tariffs for petroleum transportation through TAPS are a major component of total product transportation costs from ANWR to market. Future TAPS tariffs must be included in the DCF analysis for determination of the minimum economic field size for each prospect. Projecting future TAPS tariffs through the year 2030 required the following additional assumptions:

1. No major long-term capital expenditure is required to transport lower petroleum throughput levels after 2011;

2. Real annual capital investment will be similar to the capital expenditure levels projected in the settlement agreements for the period from 1985 to 1990, and all investment after 2011 will be considered as new property;

3. Real operating expenses per unit throughput will approximately equal the levels projected in the settlement agreements from 1985 to 2011;

4. Inflation, as measured by the consumer price index for urban consumers, will increase at an average annual rate of 6 percent from 2012 to 2030;

5. State and Federal income tax calculation procedures and rates will remain unchanged from 2012 to 2030;

6. State property tax base estimates will be extended through the year 2030 to account for the additional productive life of the pipeline;

7. No additional allowances will accrue for dismantlement, removal and restoration costs from 2012 to 2030; and

8. Intrastate deliveries of petroleum will equal approximately 1 percent of total net deliveries after the year 2011. Standard and nonstandard petroleum throughput levels will remain constant at 15 and 84 percent, respectively, from 2012 to 2030.

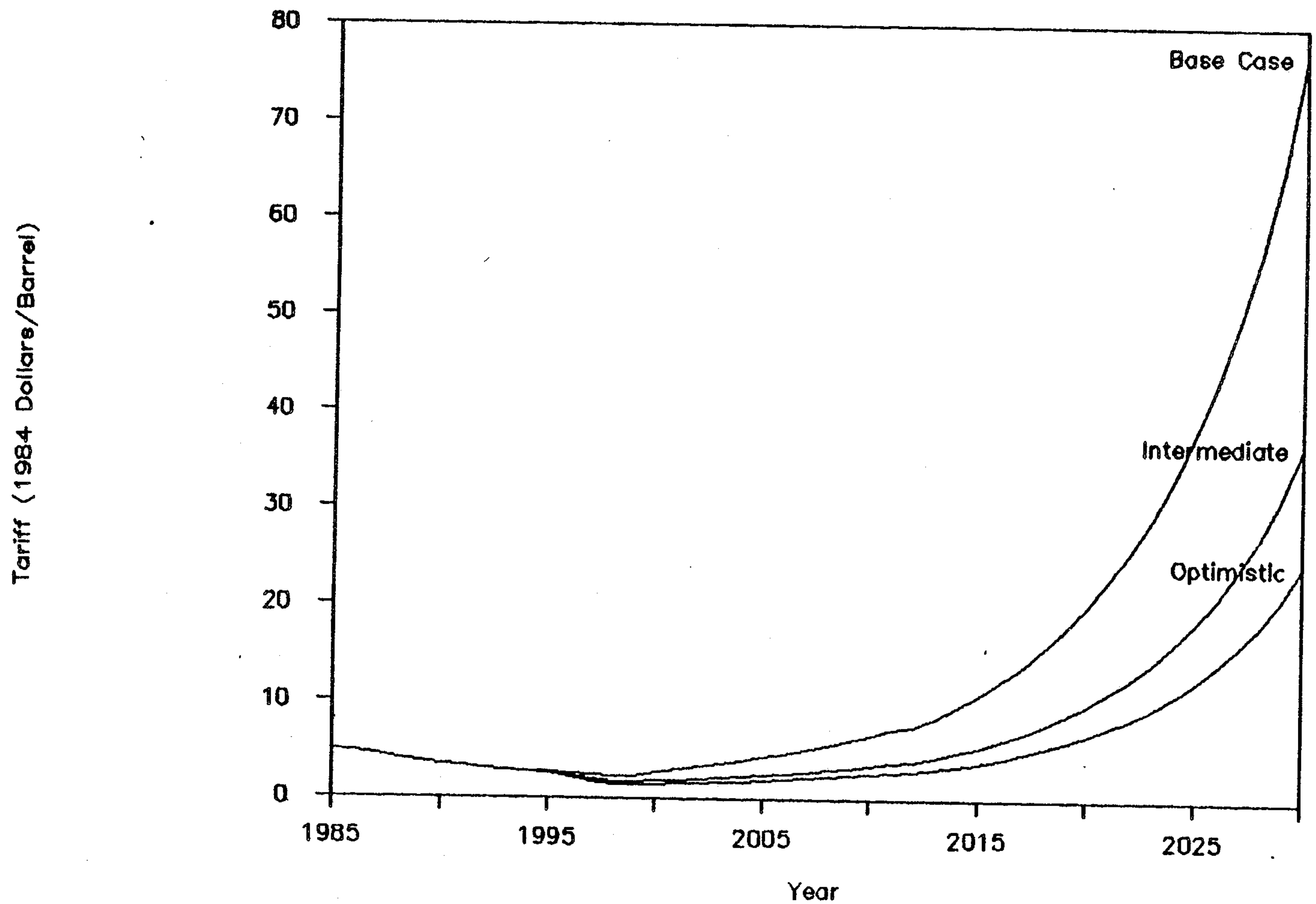
Projected TAPS tariff rates are shown in figure 13 on a constant 1984 dollar basis. Under all three scenarios the estimated tariff increases rapidly as TAPS throughput declines. The lower throughput levels projected for the base case result in substantially higher tariffs by the year 2030 than for the intermediate and optimistic cases. The effects of alternative TAPS tariff rates on minimum economic field size are discussed under "Minimum economic field size results and sensitivity analysis." It is conceivable that further TAPS tariff negotiations between interested parties would be required in latter years of TAPS operation to minimize tariff charges and recover as much North Slope hydrocarbons as is economically possible before terminating TAPS operations.

Another issue concerning TAPS tariff effects on minimum economic field size needs to be addressed. So far all potential operators on the North Slope have been viewed on an equally competitive basis, without special consideration for any group or single operator. Nevertheless, if viewed as a large integrated company, the eight companies that are owners of TAPS have a comparative advantage over operators not affiliated with TAPS. This advantage arises from the incremental cost to transport oil through TAPS. To a vertically integrated TAPS owner, the incremental transportation cost is not the TAPS tariff (as it would be to a nonaffiliated North Slope producer), nor is it the incremental pipeline cost (as it would be to a vertically integrated monopolist). Instead, for a TAPS affiliate the transportation cost of an additional barrel of oil is between these incremental costs (Levin, 1983). The size of the cost advantage to a single TAPS affiliate depends on the difference between the tariff and the incremental pipeline cost as a whole and the TAPS affiliate's ownership share. Assume, for example, that the tariff is $6.00 per barrel, the incremental pipeline cost of transporting an additional 100 barrels through TAPS is $4.00 per barrel, and the hypothetical TAPS affiliate holds a 50 percent ownership in the pipeline. Then the owner's incremental cost for transporting the additional 100 barrels of crude oil is calculated as follows:

50% x 100 bbl x $4.00 Pipeline's incremental cost	= $200.00
50% x 100 bbl x $6.00 Tariff	= $300.00
Total cost for 100 barrels	= $500.00

Estiamted Trans-Alaska Pipeline System tariffs (in 1984 dollars) by throughput scenario

FIGURE 13



Source: Bureau of Land Management estimates, see the accompanying text for details.

In this example the owner's incremental cost is $5.00 per barrel, a savings of $1.00 per barrel over the transportation cost of $6.00 per barrel for an unaffiliated shipper. Lower TAPS transportation costs for vertically integrated TAPS owners translates into higher wellhead prices and higher revenues from production. Therefore, the minimum economic field size for a vertically integrated TAPS owner would probably be lower, if incremental pipeline costs are less than the TAPS tariff.

Valdez, Alaska, to Market

Marine transportation is required to ship the crude oil from Valdez to refineries on the West, Gulf or East Coast of the United States. Table 7 shows the marine transportation costs reported by North Slope producers to the Alaska Department of Revenue from July 1981 through 1984. For marine transportation to the West Coast costs ranged from $1.17 to $1.46 per barrel. In comparison for transportation to the Gulf Coast and beyond costs ranged from $4.16 to $4.70. The volume weighted average transportation cost from Valdez to all ports ranged from $2.76 to $3.14. The relative proportions of crude oil sold in the various market areas are assumed to remain the same. Therefore, future changes in the volume weighted average marine transportation cost would reflect cost changes in marine transportation charges and Trans Panama Pipeline tariffs, rather than the respective proportion of North Slope crude delivered to specific market areas.

Projecting marine transportation costs is difficult, because of the many variables involved. For example, different types and sizes of ships have quite different operation costs, and many sizes of ships transport North Slope oil. In 1983, the West Coast marine traffic from Valdez to Puget Sound, Los Angeles, and San Francisco used ships ranging in size from 16,191 deadweight tons (DWT) to 188,697 DWT (U.S. Department of Transportation Maritime Administration, 1984). Most ships were in the range 65,000 - 125,000 DWT. In contrast, the ships traveling from Valdez to Panama in 1983 ranged from 69,306 to 264,073 DWT with most of the ships at 120,000 DWT and greater. Generally smaller ships of 90,000 DWT or less transport North Slope crude from the eastern side of the Panama Canal for the Gulf Coast trade.

This analysis assumes that present marine transportation costs will decline to a level that provides the same real rate of return of 10 or 8 percent as the most likely or optimistic economically recoverable resource scenarios, respectively. The weighted average breakeven cost has been estimated (table 8) to be $2.32 per barrel, based on breakeven rates by destination, tanker size and by volumes of North Slope crude oil delivered to the primary markets on the West, Gulf and East coasts of the United States. Volume weighted average tanker freight rates are expected to decrease from $2.76 in 1984 to $2.55 or $2.51 per barrel under the most likely or optimistic economically recoverable resource scenario, and increase at the rate of inflation assumed for each scenario throughout the evaluation period.

Geologic Characteristics and Productivity

The geologic estimates used in the determination of minimum economic field size for specific prospects are shown in Chapter III. To simplify the

TABLE 8 - Estimated Volume Weighted Breakeven Costs
For Marine Freight Rates From Valdez to Market
(Dollars Per Barrel)

Transportation Route	Tanker Size Category			Tanker Size Weighted Breakeven Cost	East/West Deliveries (Percent)	Volume Weighted Breakeven Cost
Alaska-West Coast	100,000 or less	100,000 or more				
Percent Transported[1/]	49.30	50.70				
Breakeven Cost[2/]	1.00	.85				
Tanker Weighted Breakeven Cost	.49	.43		.92		
Volume Weighted Percent Delivered to the West Coast					46.8	
West Coast Volume/Tanker Weighted Breakeven Cost						.43
Alaska-Panama Canal	105,000 or less	105,000+ 192,500	192,500 or more			
Percent Transported[1/]	3.10	60.70	36.20			
Breakeven Cost[2/]	1.94	1.65	1.13			
Total Tanker Weighted Breakeven cost	.06	1.00	.41	1.47		
Volume Weighted Percent Delivered to the Gulf/East Coast					53.2	
Alaska-Panama Volume/Tanker Weighted Breakeven Cost						.78
Panama-Gulf/East Coast	55,000 or less	55,000-75,000	75,000 or more			
Percent Transported by Canal[1/]	3.00	1.20	.50			
Breakeven Cost[2/]	1.79	1.60	1.68			
Total Canal Weighted Breakeven Cost	.05	.02	.01			
Percent Transported by Pipeline[1/]	39.90	19.40	36.00			
Breakeven Cost[2/]	2.18	2.01	2.05			
Total Pipeline Weighted Breakeven Cost	.87	.39	.74			
Total Tanker Weighted Breakeven Cost	.92	.41	.75	2.08		
Volume Weighted Percent Delivered to the Gulf/East Coast					53.2	
Panama-Gulf/East Coast Volume/Tanker Weighted Breakeven Cost						1.11
Total Volume/Tanker Weighted Breakeven Cost						2.32

1/ United States Department of Transportation, Maritime Administration 1983. Alaska north slope crude oil loading summary. Unpublished Memorandum from the Director, Office of Policy and Plans to Associate Administrator for Policy and Administration, February 27, 1984.

2/ Personal communication with Fran Olson of the United States Department of Transportation on January 8, 1985.

presentation of the minimum economic field size results and sensitivity analysis report, two representative prospects were developed from actual data for the ANWR area. Prospects in western ANWR are typically located at moderate depths with lower recovery rates, so a representative drilling depth of 7,500 feet is assumed with a recovery rate of 25,000 barrels per acre. Fields in eastern ANWR occur at much greater depths with higher estimated recovery rates, so a representative drilling depth of 12,000 feet and recovery factor of 37,000 barrels per acre are assumed to be typical of these prospects. The two representative prospects are assumed to each require six delineation wells, and all production wells are drilled on a 160-acre spacing with 0.4 injection wells required per production well. Exploration and development scheduling follows the assumptions presented previously.

MINIMUM ECONOMIC FIELD SIZE RESULTS AND SENSITIVITY ANALYSIS

A minimum economic field size estimate was determined for each specific prospect included in the derivation of economically recoverable resources (Draft LEIS, Chapter III). The results presented here are utilized to demonstrate the effects of variations in the level of selected input parameters on minimum economic field size (sensitivity analysis). Table 9 summarizes the input parameters and minimum economic field size results for the most likely and high (optimistic) economically recoverable resource scenarios for the two hypothetical representative prospects in eastern and western ANWR. Figure 14 shows a sample detailed print-out of the results obtained from the discounted cash flow model for the representative prospect in eastern ANWR, using the assumptions of the most likely scenario.

Under the most likely scenario, the minimum economic field sizes of the two representative prospects were 575 million barrels for eastern ANWR and 425 million barrels for western ANWR. The larger economic field size for the eastern prospect reflects the longer transportation distance (150 miles vs. 85 miles of pipeline), the deeper drilling depths, and the assumed greater productivity level of geologic formations. (The independent effects of each factor are discussed later.) Minimum economic field sizes were substantially reduced under the assumptions used for the optimistic (high) economically recoverable resource scenario. Higher oil price and lower cost, inflation, and rate-of-return assumptions resulted in estimated economic field sizes of 200 million and 150 million barrels for the representative prospects in eastern and western ANWR, respectively. Economic field sizes for the two representative prospects shown in table 9 under the optimistic scenario assumptions were approximately 35 percent of the estimated minimum economic field size requirements under the most likely scenario.

Figure 15 presents a crude oil price sensitivity analysis for the two representative prospects. Real market prices considered in this analysis ranged from $22.00 to $40.00 per barrel (1984 dollars) in the year 2000, with a constant 1-percent compound annual growth rate after the year 2000. The minimum economic field size for eastern and western ANWR were, respectively, 2,030 million and 1,390 million barrels for $22/barrel crude oil and 410 million and 330 million barrels for $40/barrel crude oil. At lower market prices the profit margin per unit of reserve is much less, so minimum economic field size increases rapidly as price declines. Therefore, the difference between the minimum economic field sizes in eastern and western ANWR increases

FIGURE 14

Sample print-out of the discounted cash flow analysis for minimum economic field size determination of the representative prospect in eastern ANWR under the most likely scenario

< < MINIMUM ECONOMIC FIELD SIZE DATA INPUTS > >

RCOVRABLE RESERVES	PEAK PROD (% OF RES)	DECLINE RATE (%)	EXPLRATON WELL COST	DVLOPMNT WELL COST	DVLOPMNT WELLS (#)	DELAY TO EXPLRATON	YEARS OF PRODUCTION	YR. PROD BEGINS	PROD ACREAGE	TRACT ACREAGE	ANN RENT/ ACRE	
386729528	0.091	0.12	21000000	6000000	139	1	26	9	15900	0	3	

OIL PRICE	TRANSPORT COST	OIL INFLATION	TRANSPORT INFLATION	GENERAL INFLATION	DRILLING INFLATION	ROYALTY RATE	NOM. DIS-CONT RATE	FED/STA TAX RATE	INVST TAX CRDT RATE	% RD IN DPR FR ITC	REAL COST/ PRICE YR.	PIPELINE COST(MM)
30.33	9.79	0.07	0.06	0.06	0.06	0.1667	0.166	0.5108	0.1	0.5	1984	1025

TANGIBLE EXP. COST	TANGIBLE DEV. COST	TANGIBLE FAC. COST	% INTANG DRIL AMORT	REAL FAC COST	FAC COST MULTIPLYR	COST OVERHEAD	PROD COST MULTIPLIER	OUTPUT HEADING --------NAME--------	TAPS TARIF RED FOR TP	Bbls REC. PER ACRE	TRANS COST MULTIPLIER
0.1	0.3	1	0.2	2268987533.	1	0	1	ANWR EAST MOST LIKEL	86.052	37000	1

FIGURE 14

(continued)

DETAILED RESULTS

HEADING: ANWR EAST MOST LIKELY RESERVES: 586729528

OUTPUT YEAR	PRODUCTION: TOTAL ANNUAL	PRODUCTION: AVERAGE DAILY	PRODUCTION: ANNUAL ROYALTY	PRODUCTION: NET ANNUAL	NOMINAL MARKET PRICE	1984 REAL MRKT PRICE	NOMINAL TRANSPORT COST	NOMINAL WELLHEAD PRICE	EXPLR WELLS	DEVEL WELLS	NOMINAL COST: EXPLR WELLS	NOMINAL COST: DEVEL WELLS	NOMINAL COST: FACILITY
1	0	0	0	0	32.45	30.62	13.19	19.27	0	0	0	0	0
2	0	0	0	0	34.72	30.90	13.77	20.96	1	0	23595600	0	0
3	0	0	0	0	37.16	31.20	14.53	22.63	2	0	50022672	0	0
4	0	0	0	0	39.76	31.49	15.24	24.52	2	0	53024032	0	0
5	0	0	0	0	42.54	31.79	15.77	26.77	2	0	56205474	0	0
6	0	0	0	0	45.52	32.09	16.32	29.20	0	20.85	0	177456741	804650545
7	0	0	0	0	48.70	32.39	16.95	31.76	0	27.8	0	250805527	852929578
8	0	0	0	0	52.11	32.70	17.94	34.18	0	27.8	0	265853859	904105353
9	10678477	29256	1780102	8898375	55.76	33.00	19.14	36.62	0	27.8	0	281805090	958351674
10	37374671	102396	6230358	31144313	59.66	33.32	20.44	39.22	0	20.85	0	224035047	0
11	53392387	146281	8900511	44491876	63.84	33.63	21.87	41.97	0	13.9	0	158318100	0
12	53392387	146281	8900511	44491876	68.31	33.95	23.39	44.92	0	0	0	0	0
13	53392387	146281	8900511	44491876	73.09	34.27	25.05	48.04	0	0	0	0	0
14	46985301	128727	7832450	39152851	78.21	34.59	26.84	51.36	0	0	0	0	0
15	41347065	113280	6892556	34454509	83.68	34.92	28.84	54.84	0	0	0	0	0
16	36385417	99686	6065449	30319968	89.54	35.25	30.97	58.57	0	0	0	0	0
17	32019167	87724	5337595	26681572	95.81	35.58	33.34	62.47					
18	28176867	77197	4697084	23479783	102.51	35.91	35.88	66.64					
19	24795643	67933	4133434	20662209	109.69	36.25	38.68	71.01					
20	21820166	59781	3637422	18182744	117.37	36.60	41.91	75.46					
21	19201746	52608	3200931	16000815	125.58	36.94	44.75	80.83					
22	16897536	46295	2816819	14080717	134.37	37.29	48.80	85.58					
23	14869832	40739	2478801	12391031	143.78	37.64	53.37	90.41					
24	13085452	35851	2181345	10904107	153.84	38.00	58.56	95.29					
25	11515198	31548	1919583	9595614	164.61	38.35	64.47	100.14					
26	10133374	27763	1689233	8444141	176.14	38.72	71.24	104.90					
27	8917369	24431	1486525	7430844	188.47	39.08	79.04	109.43					
28	7847285	21499	1308142	6539143	201.66	39.45	88.05	113.61					
29	6905611	18919	1151165	5754445	215.78	39.82	98.50	117.27					
30	6076937	16649	1013025	5063912	230.88	40.20	110.69	120.19					
31	5347705	14651	891462	4456243	247.04	40.58	124.93	122.11					
32	4705980	12893	784487	3921493	264.33	40.96	141.64	122.69					
33	4141263	11346	690348	3450914	282.84	41.35	161.38	121.45					
34	3644311	9984	607507	3036805	302.64	41.74	184.79	117.84					
35	0	0	0	0	0.00	0.00	0.00	0.00					
36	0	0	0	0	0.00	0.00	0.00	0.00					
37	0	0	0	0	0.00	0.00	0.00	0.00					
38	0	0	0	0	0.00	0.00	0.00	0.00					
39	0	0	0	0	0.00	0.00	0.00	0.00					
40	0	0	0	0	0.00	0.00	0.00	0.00					
TOTAL	573049533		95527357	477522175					7	139	182847779	1358274364	3520037150

FIGURE 14

(continued)

ROYALTY REVENUE	TAXABLE REVENUE	INTANG EXP WELL EXPENSE	INTANG DEV WELL EXPENSE	FACILITY EXPENSE	ANNUAL PRODUCTION EXPENSE	OVERHEAD EXPENSE	SEVERANCE TAX EXPENSE	CONSERVTON TAX EXPENSE	PROPERTY TAX EXPENSE	LEASE RENTAL EXPENSE
0	0	0	0	0	0	0	0	0	0	0
0	0	16988832	0	0	0	0	0	0	47191	0
0	0	36016324	0	0	0	0	0	0	148552	0
0	0	38177303	0	0	0	0	0	0	258593	0
0	0	40467941	0	0	0	0	0	0	377677	0
0	0	0	99375775	0	0	0	0	0	17544744	0
0	0	0	140451095	0	0	0	0	0	36519563	0
0	0	0	148878161	0	0	0	0	0	57005441	0
65184205	325842819	0	157810851	0	81887514	0	8283609	11123	79045640	0
244347388	1221443780	0	125459626	0	99450130	0	102243314	38930	81909958	0
373577513	1867439361	0	88658136	0	114382688	0	228761322	55615	84301482	0
399824967	1998645142	0	0	0	121245650	0	244834030	55615	85636256	0
427607349	2137523719	0	0	0	128520389	0	261846656	55615	86827717	0
402311263	2011073636	0	0	0	131855504	0	301661045	48941	87853863	0
377965792	1889375494	0	0	0	135808218	0	193292756	43068	88690566	0
353255602	1775851788				140362537	0	171021885	37900	89311400	
333440790	1666803899				145510406	0	149411598	33352	89687448	
312995668	1564602821				151250374	0	128720559	29350	89787101	
293509369	1467194706				157586597	0	108817710	25828	89575837	
274462832	1371984872				164528093	0	89617998	22728	89015988	
258745795	1293418544				172088187	0	72109496	20001	88066484	
241052440	1204972993				180284106	0	54868253	17601	86682582	
224110905	1120285644				189136679	0	39019021	15489	84815573	
207855080	1039026021				198670133	0	24867895	13630	82412465	
192232457	960931651				208911954	0	12875143	11995	79415648	
177201715	885795974				219892804	0	6755313	10555	75762528	
162668962	813149647				231646489	0	5944675	9289	71385138	
148621775	742930565				244209956	0	5231314	8174	66209715	
134998231	674829187				257623334	0	4603556	7193	60156255	
121753923	608623538				271929992	0	4051130	6330	53138026	
108858640	544162594				287176632	0	3564994	5570	45061046	
96249940	481134321				303413396	0	3137195	4902	35823531	
83845473	419126772				320693997	0	2760731.	4314	25315295	
71590329	357865755				339075870	0	2429444	3796	13417107	
0	0				0	0	0	0	0	
0	0				0	0	0	0	0	
0	0				0	0	0	0	0	
0	0				0	0	0	0	0	
0	0				0	0	0	0	0	
0	0				0	0	0	0	0	
6090268421	30444035245	131650401	760633644	0	4997141630	0	2230730641	596903	2021206409	0

FIGURE 14

(continued)

DEPREC. EXPENSE	AMORTIZED IDC EXPENSE	TAXABLE INCOME	FED/STA INCOME TAX	INVESTMNT TAX CREDIT	NET INCOME	--------NON-CASH------- PLUS DEPREC.	PLUS AMORTZATON	LESS INVESTMNT COSTS	CASH FLOW	NET PRESENT VALUE
0	0	0	0	0	0	0	0	0	0	0
336237	1415594	-10787855	-9596836	235956	-8955063	336237	1415594	2359560	-9562791	-7033760
1205971	4416655	-41787502	-21345056	500227	-19942219	1205971	4416655	5002267	-19321861	-12188585
2271799	7597778	-48305473	-24674435	530240	-23100797	2271799	7597778	5302403	-18533623	-10026887
3377815	9554175	-53777608	-27469602	562055	-25745951	3377815	9554175	5620547	-18434509	-8553401
11287484	14833601	-143041605	-73065652	5323702	-64652251	11287484	14833601	857887568	-896418733	-356713562
25025555	23355565	-225351778	-115109688	7524166	-102717924	25025555	23355565	928171236	-982508040	-335309810
39890674	32388847	-278163122	-142085723	7975616	-128101783	39890674	32388847	983861510	-1039683774	-304307645
557074294	37257949	-595528160	-304195784	360457868	69125492	557074294	37257949	1042893201	-379435465	-95246926
804477292	36008785	-28144256	-14376086	6721051	-7047118	804477292	36008785	67210514	766228445	164957766
770850607	30990952	549438560	280653216	4749543	273534886	770850607	30990952	47495430	1027881015	189783648
758359842	17841363	770672388	393659456	0	377012932	758359842	17841363	0	1153214137	182611176
741997282	7387439	910888622	465281908	0	445606714	741997282	7387439	0	1194991435	162286964
22883836	0	1466770447	749226344	0	717544103	22883836	0	0	740427939	86238877
9475338	0	1462065547	746823081	0	715242466	9475338	0	0	724717804	72392017
0	0	1375118066	702410308		672707758	0	0		672707758	57630134
0	0	1282161095	654927888		627233208	0	0		627233208	46084373
0		1194815437	610311725		584503712	0			584503712	36830988
0		1111188734	567595205		543593528	0			543593528	29376620
		1028800064	525511073		503288991				503288991	23326330
		961134376	490947439		470186937				470186937	18689643
		883120451	451097926		432022525				432022525	14727814
		807298883	412368269		394930613				394930613	11546601
		733061899	374448018		358613881				358613881	8992116
		659716912	336983399		322733513				322733513	6940333
		583374773	297987834		285386939				285386939	5263466
		504164057	257527000		246637057				246637057	3901193
		427271406	218250234		209021172				209021172	2835508
		352438849	180025764		172413085				172413085	2005714
		279498061	142767610		136730452				136730452	1364296
		208354351	106427403		101926949				101926949	872236
		138755297	70876206		67879091				67879091	498176
		70352435	35936024		34416411				34416411	216627
		2939539	1501517		1438023				1438023	7763
		0	0		0				0	0
		0	0		0				0	0
		0	0		0				0	0
		0	0		0				0	0
		0	0		0				0	0
		0	0		0				0	0
3748514025	223048704	16330512890	8341625984	394580424	8383467329	3748514025	223048704	3945804237	8409225822	0

TABLE 9 - Minimum Economic Field Size Results for a Representative Prospect in Eastern and Western ANWR

	Eastern ANWR		Western ANWR	
	Most Likely	Optimistic	Most Likely	Optimistic
	MODEL INPUTS			
Productive Acres	15,900	5,400	17,500	6,000
Petroleum Recovery (MBbl/Acre)	37	37	25	25
Prospect Depth (Feet)	12,000	12,000	7,500	7,500
Exploration & Delineation Wells	7	7	7	7
Exploration Well Cost (Millions 1984 Dollars)	147	110	105	79
Development Wells	139	47	154	53
Development Well Cost (Millions 1984 Dollars)	834	212	662	171
Facilities Cost (Millions 1984 Dollars)	2,269	1,068	1,941	985
Distance--ANWR to TAPS (Miles)	150	150	85	85
Transportation Cost--Year 2000 (1984 $/Bbl)	11.35	16.45	9.00	11.95
Oil Price in the Year 2000 (1984 $/Bbl)	33.00	40.00	33.00	40.00
Real Oil Price Growth Rate (Percent)	1.00	1.00	1.00	1.00
Inflation Rate (Percent)	6.00	3.50	6.00	3.50
Federal Royalty Rate (Percent)	16.67	12.50	16.67	12.50
Discount Rate (Percent)				
Real	10.00	8.00	10.00	8.00
Nominal	16.60	11.78	16.60	11.78
	ANALYSIS RESULTS			
Minimum Economic Field Size (MMB)1/	575	200	425	150
Peak Daily Production (1,000 Bbls)	146	50	109	37
Years of Production	26	24	25	23
Estimated Federal Revenues (Millions 1984 Dollars)2/	4,066	1,190	3,340	1,041
Estimated State Revenues (Millions 1984 Dollars)3/	2,139	832	1,489	616

Bbl, barrel; Bbls, Barrels; MBbl, thousand barrels; MMB, million barrels.

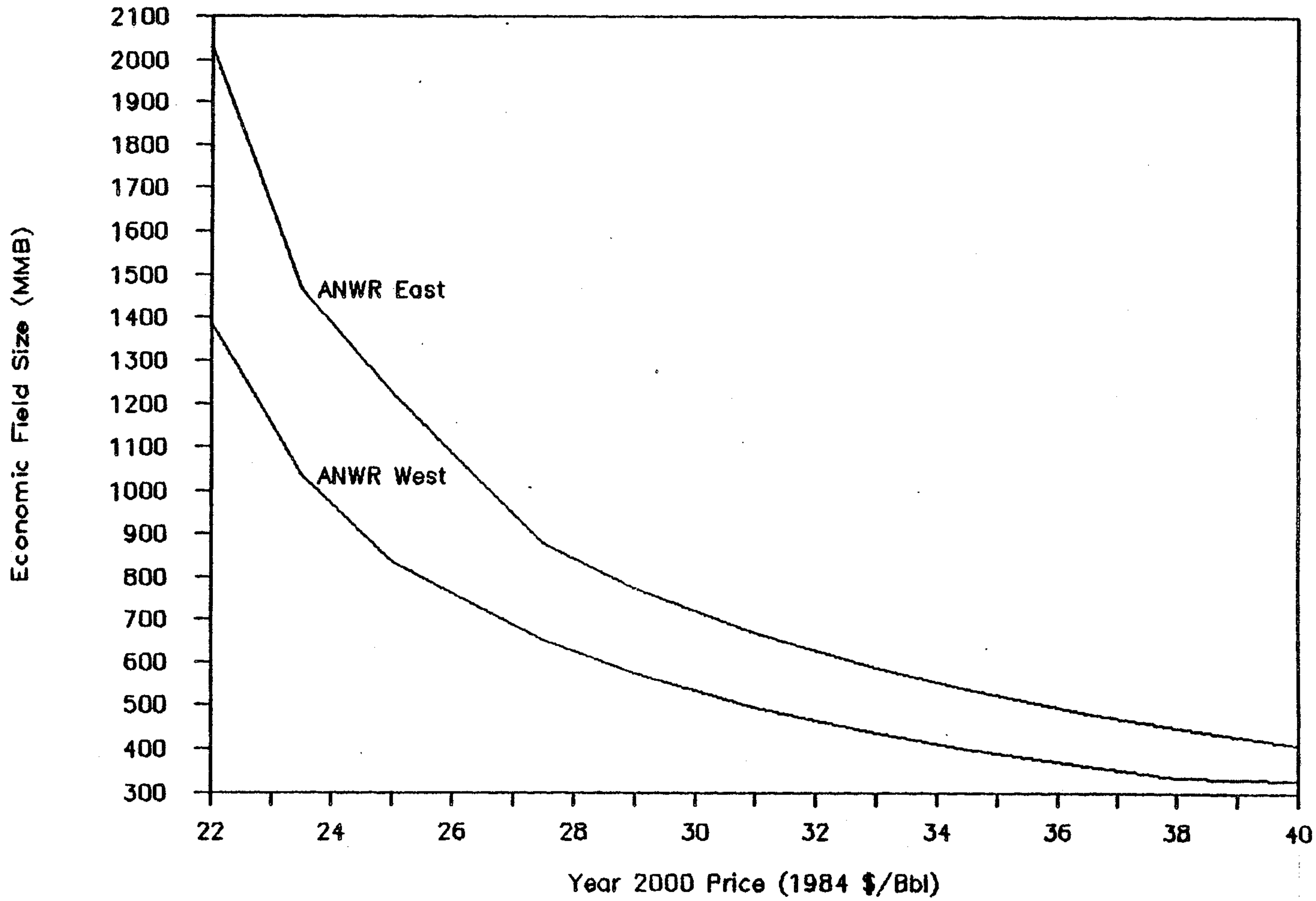
1/ Rounded to the nearest 25 million barrels.

2/ Includes Federal royalties and income tax with no disbursements to the State of Alaska.

3/ Includes State of Alaska property tax, severance tax, conservation tax and corporate income tax.

ANWR crude oil market price (Sensitivity Analysis)

FIGURE 15



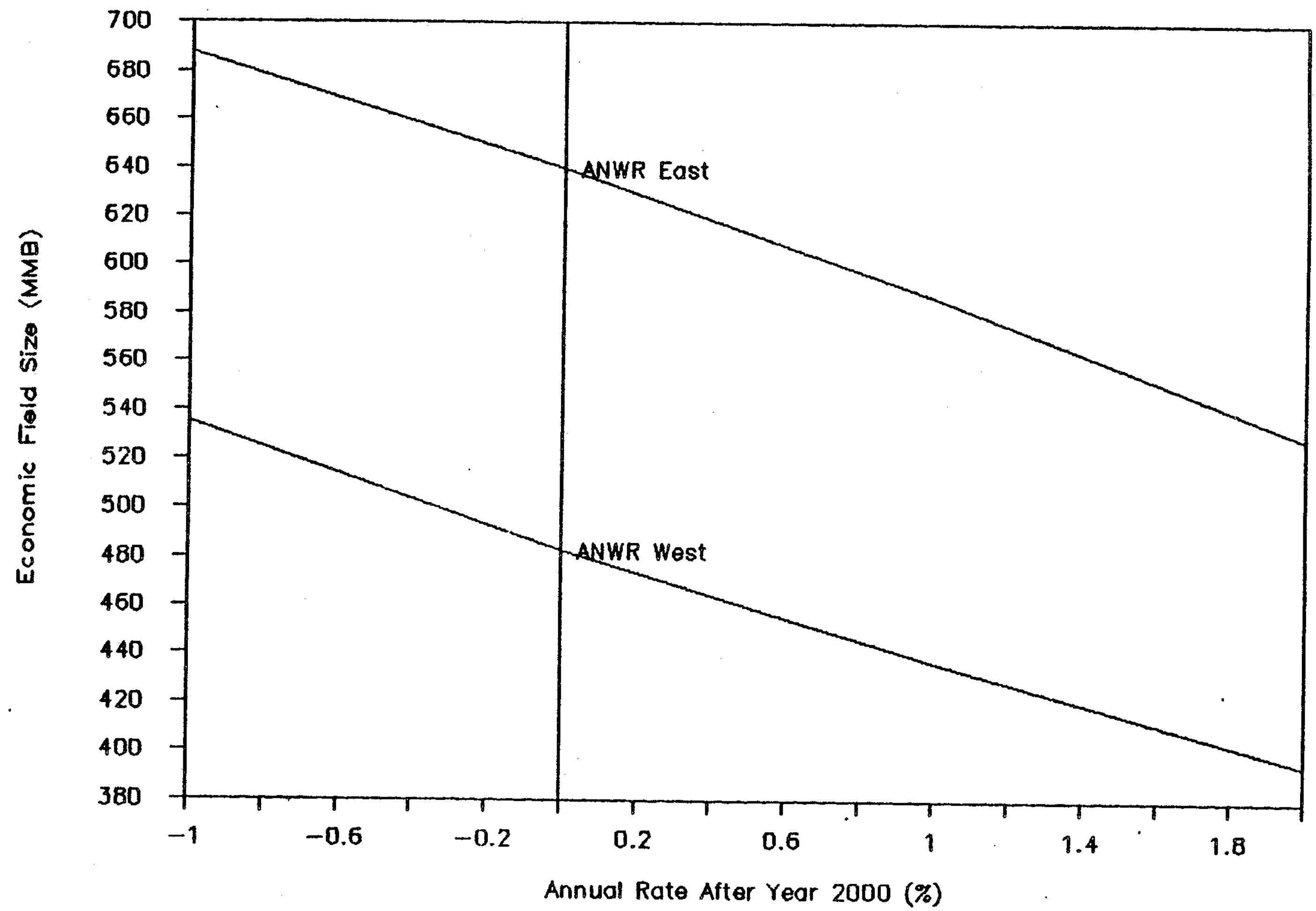
as price decreases or conversely, declines as crude prices increase (figure 15). This analysis illustrates that minimum economic field size is very sensitive to changes in crude oil market prices.

The sensitivity analysis for real oil price growth rate is shown in figure 16. Real oil price growth is ranged from a negative 1 percent to a positive 2 percent compound annual rate. Minimum economic field size estimates of 575 million and 425 million barrels, in eastern and western ANWR under the most likely scenario (1 percent compound annual real price growth), increase to 690 million and 540 million barrels, respectively, when real price growth is reduced to a negative 1-percent compound annual rate. In comparison, the minimum economic field size is reduced to approximately 90 percent of the most likely scenario in eastern and western ANWR when real prices increase at a compound annual rate of 2 percent. The sensitivity analysis presented in figure 16 is conducted over a relatively narrow range of possible growth rates, so the curves shown on the graph are nearly linear. If the range of potential real price growth rates is widened, then the graphs shown in figure 16 would appear more curvilinear which is typical of compound growth functions. That is, minimum economic field size estimates would increase more rapidly as the real oil price growth rate is reduced. Because minimum economic field size threshold for development is quite sensitive to future price changes, expectations as to future price certainly influence the level of economically recoverable resources in ANWR.

The estimated exploration, development, production and transportation costs represent the aggregate costs of exploiting potential crude oil resources of individual prospects in ANWR and delivering a salable product to market. However, the cost projections are based on data from several sources, and site-specific engineering cost analyses were not made. Acknowledging the uncertainty in the cost estimates, figure 17 illustrates the effect of cost variations on minimum economic field size estimates. The sensitivity curves shown in figure 17 were derived as a percent of exploration, development, production and transportation costs for the most likely scenario. If all costs could be reduced to 75 percent of the most likely case, the minimum economic field size for the representative prospects in eastern and western ANWR would be reduced from 575 million and 425 million barrels to approximately 350 million and 260 million barrels, respectively. Conversely, if the cost estimates in the most likely scenario are increased by 25 percent, the respective minimum economic field size for the two prospects would be approximately 1,060 million and 720 million barrels. Therefore, the minimum economic field size estimates are highly sensitive to uniform variations in total costs. The sensitivity of individual cost components, such as production costs, would be less than the combined effects of uniform variations in all costs. The upward slope of the sensitivity curves in figure 17 illustrates the concept of reduced profit margin per unit of recoverable resource. At higher cost levels the monetary return per unit of resource is less; thus larger quantities of recoverable resources are required to achieve an equivalent rate of return. The difference in sensitivity curves shown in figure 17 increases as total costs rise. This spread reflects greater total costs for eastern ANWR, the return per unit of reserve is less and the minimum economic field size must be proportionately larger than for western ANWR.

ANWR real oil price growth (Sensitivity Analysis)

FIGURE 16



ANWR collective costs (Sensitivity Analysis)

FIGURE 17

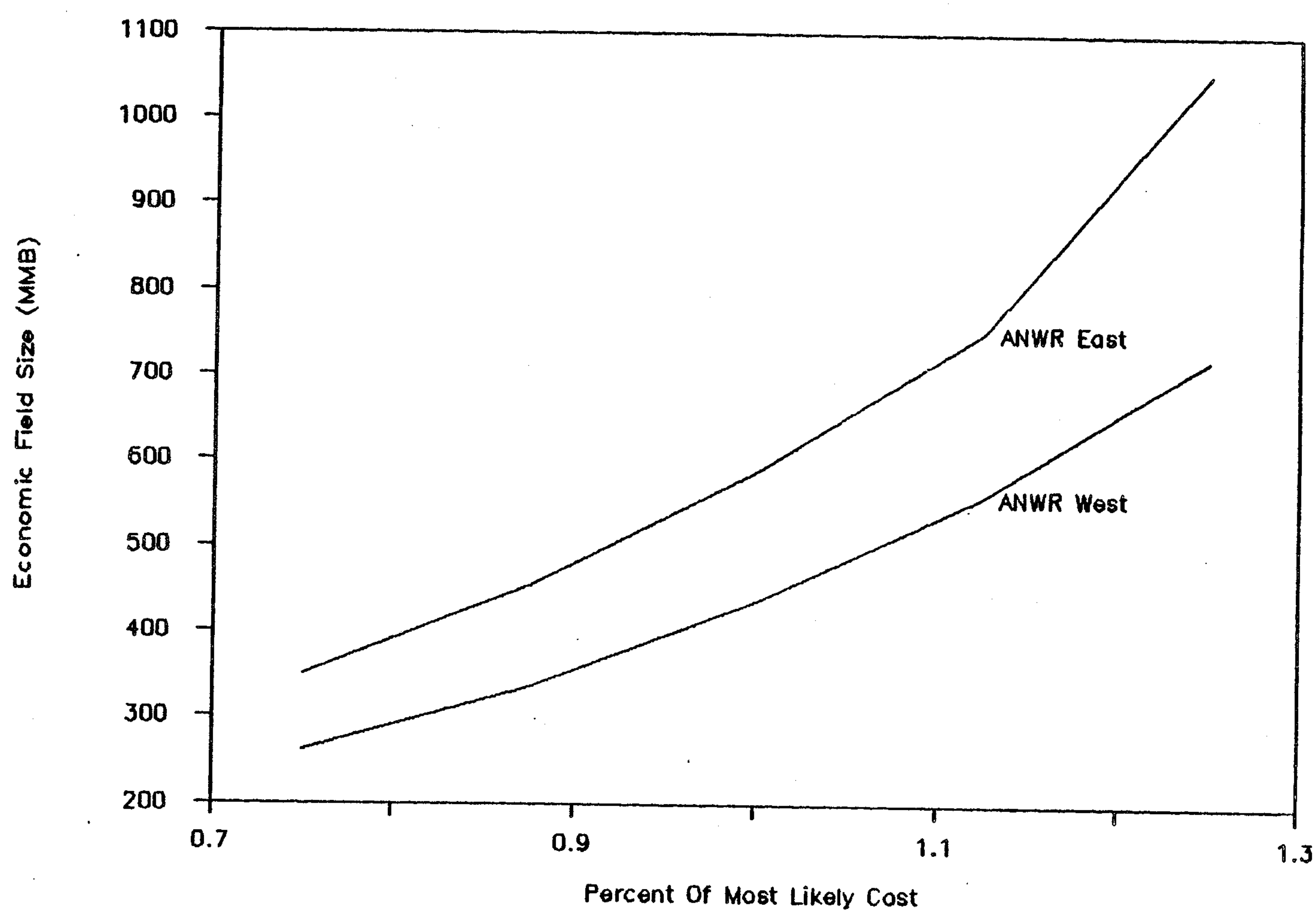


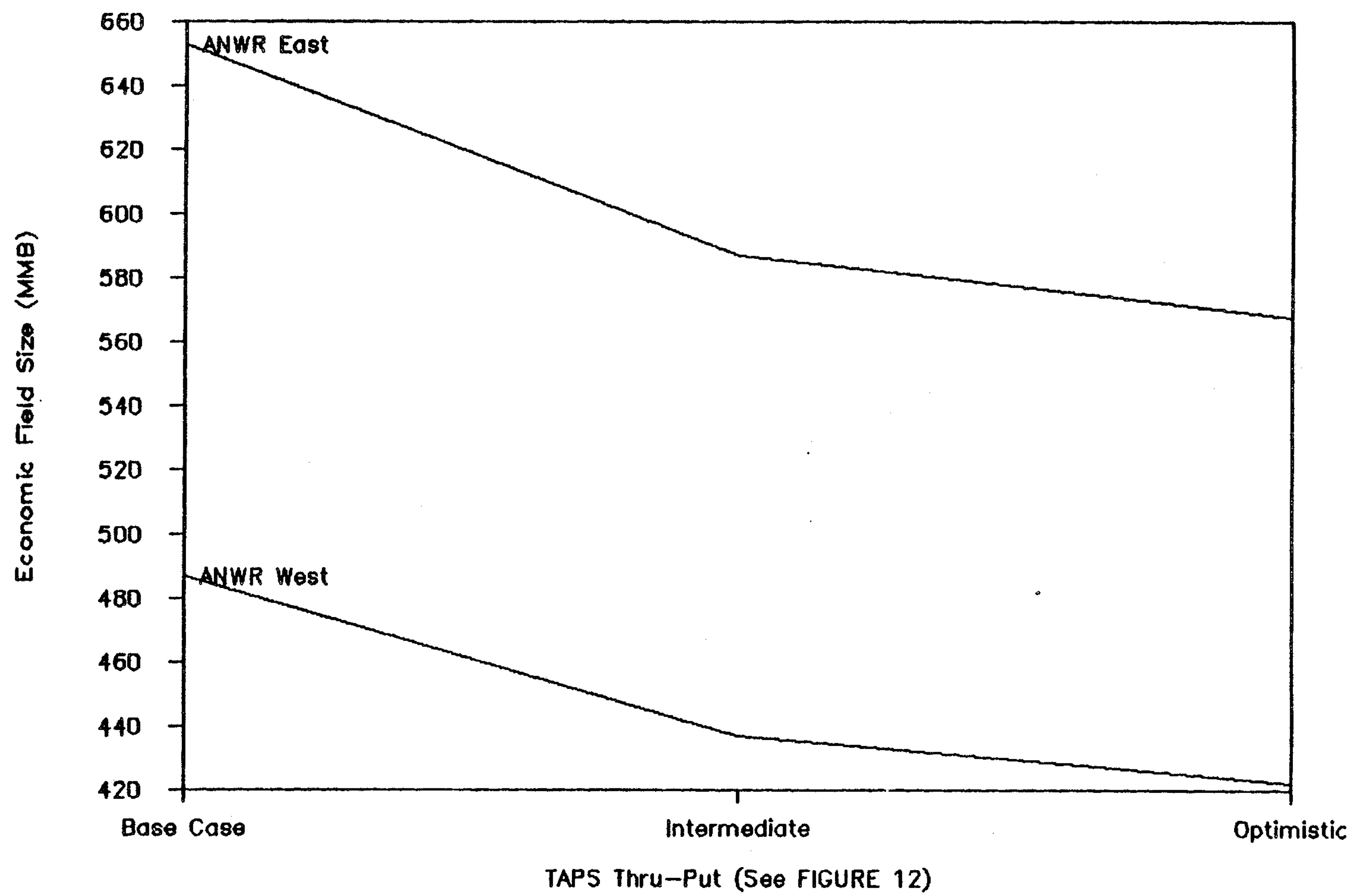
Figure 13 showed alternative TAPS tariff rates according to variations in the level of projected TAPS throughput. Most of the difference in tariff rates occurred after the year 2005, with the largest variation in the year 2030. The effects of the three alternative tariff streams or minimum economic field size are shown in figure 18. Minimum economic field sizes in eastern and western ANWR were 650 million and 490 million barrels under the base case (low) TAPS throughput scenario to 570 million and 420 million barrels under the optimistic (high) TAPS throughput scenario. The minimum economic threshold for development is only moderately affected by the three alternative throughput levels. These results can be explained by the time frame over which future TAPS tariff increases occur. The greatest tariff increases would occur in the final years of field production, and the discounting process assigns less weight to future values than to near-term values. Therefore, higher tariffs in the terminal years of production scarcely affect net present value; field production life is reduced from approximately 26 years for the optimistic (high) TAPS throughput scenario to 22 years the for base case (low) throughput scenario. The alternative TAPS tariff levels only have a moderate effect on minimum economic field size estimates; but higher tariffs do have serious implications on efficient resource development. Excessively high TAPS tariff levels would probably terminate production for economic reasons and could result in larger quantities of crude oil being left in place than would have otherwise been recovered with existing technology.

Federal royalty assessment on potential crude oil production from ANWR is under the discretion of the U.S. Department of the Interior within the bounds of applicable Federal law. The resulting latitude in establishing Federal royalty rates would directly influence the threshold for economic development. Figure 19 presents the minimum economic field size estimates for the two prospects at various royalty rates. The sensitivity curves depicted are nearly linear because a fixed royalty rate, set as a percent of production, collects a constant share of total revenue. Minimum economic field sizes of the two prospects in eastern and western ANWR ranged from 550 million and 410 million barrels at a fixed 12.5 percent Federal royalty rate to 620 million and 460 million barrels, respectively, at a fixed 20.0 percent royalty rate. In this analysis royalty rates increased 60 percent (from 12.5 percent to 20 percent), but the minimum economic field size requirements increased only 13 percent. Federal royalty rate effects on the minimum threshold for development are only moderately sensitive as compared to oil prices or total costs. However, lower Federal royalty rates could increase the level of total economically recoverable resources by lowering the minimum economic threshold for development.

Crude oil recovery from potential prospects in ANWR directly affects the minimum economic threshold for development, as figure 20 illustrates for the two representative prospects. As the barrels-per-acre recovery rate increases, the minimum economic field size decreases. This reflects the reduced requirement for development wells and associated facilities and the greater productivity per well. Conversely, if the recovery per acre declines, more wells and facilities are required to produce the same amount of oil so the minimum economic threshold for development must increase. The projected productive potential of prospects in ANWR significantly affects the estimate of total economically recoverable resources.

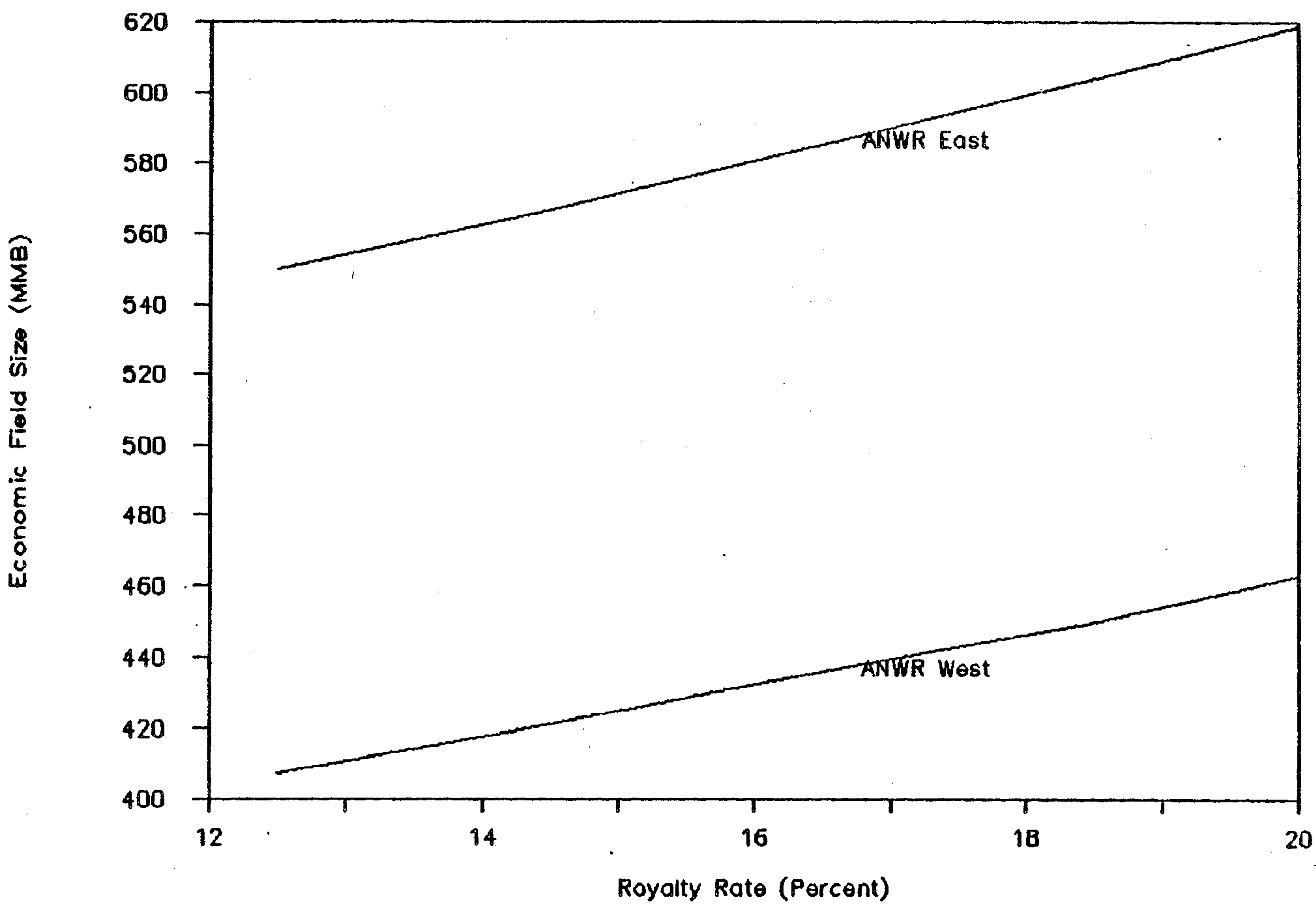
TAPS tariff by throughput level (Sensitivity Analysis)

FIGURE 18



ANWR royalty rate (Sensitivity Analysis)

FIGURE 19



ANWR crude oil recovery (Sensitivity Analysis)

FIGURE 20

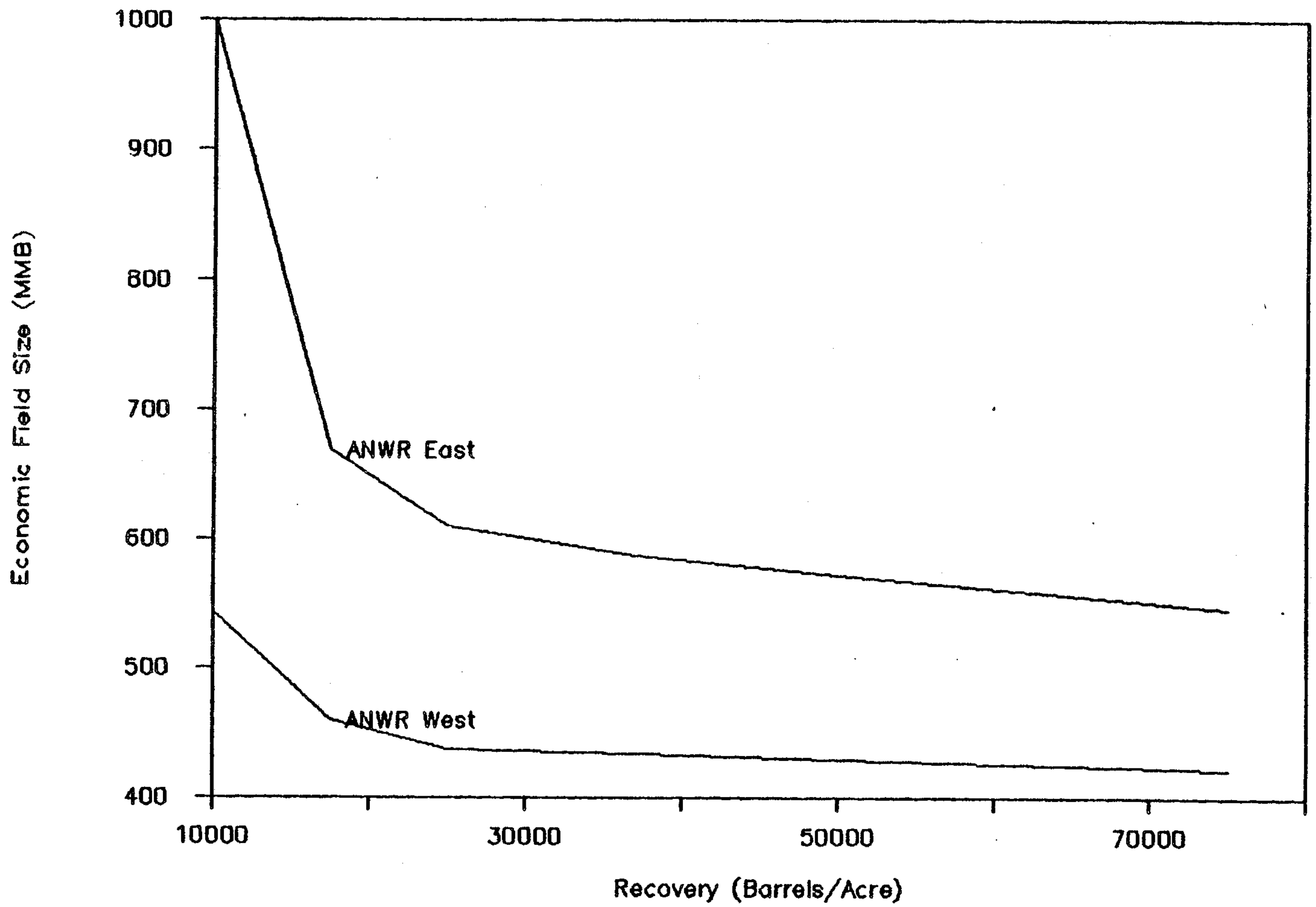
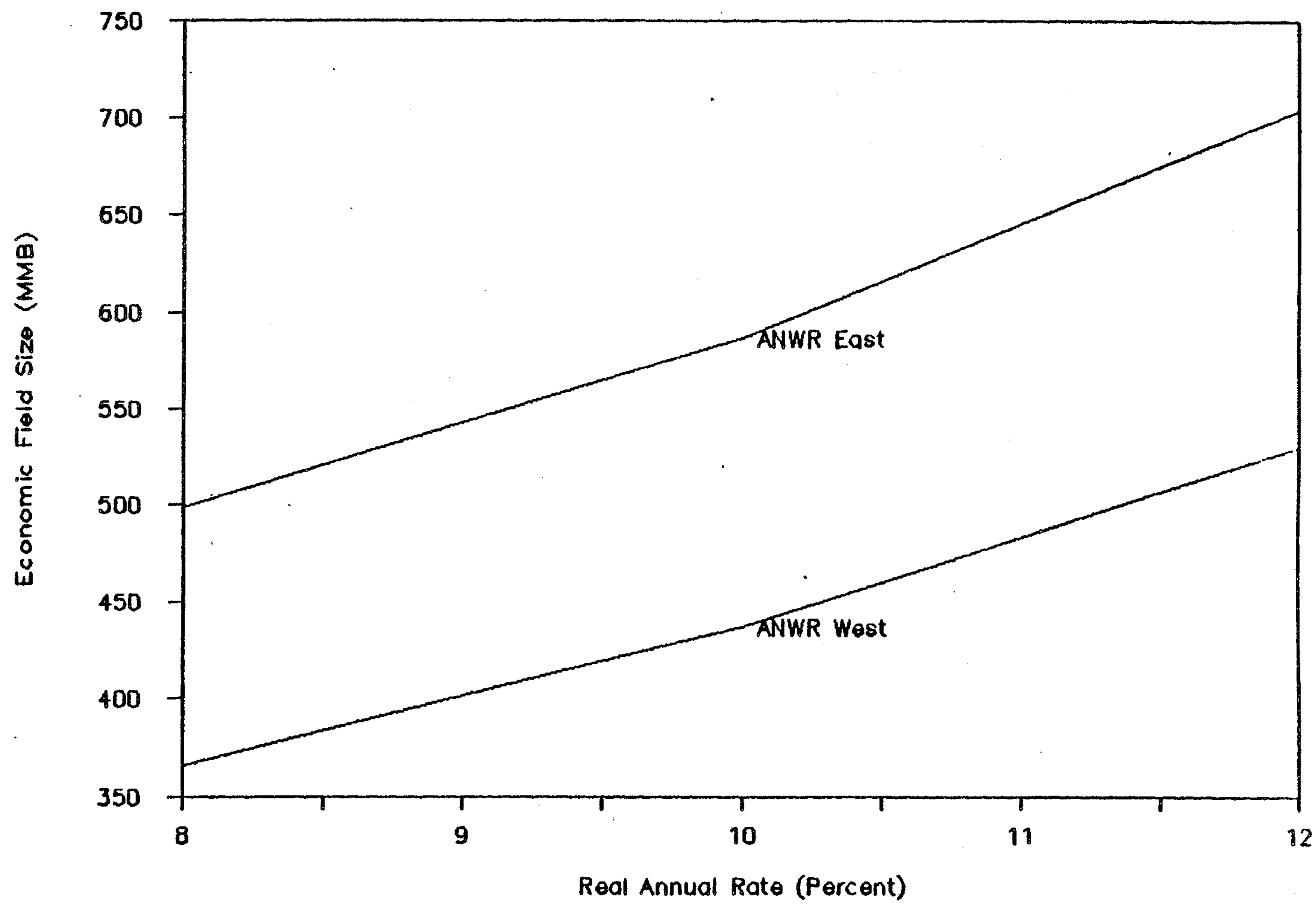


Figure 21 presents the minimum economic field size estimates for the two representative prospects, at selected minimum rates of return (discount rates). If investors will accept lower real rates of return, such as 8 percent, instead of the 10 percent rate in the most likely case, then the minimum economic field size for eastern and western ANWR is reduced from 575 million and 425 million barrels to 500 million and 370 million barrels, respectively. Conversely, if the investor requires a higher rate of return than the 10 percent assumed for the most likely case the minimum economic field size will increase and the estimate of total economically recoverable resources in ANWR will probably decrease. The curves demonstrate that minimum economic field size is sensitive to the investor's minimum acceptable rate of return.

Projected inflation rates also affect minimum economic field size (figure 22). For this analysis inflation rates were held constant throughout the evaluation horizon. In this type of discounted cash flow analysis inflation primarily affects the value of cash costs and tax deductions that do not rise with inflation (decline in real terms as a result of inflation). These factors include depreciation and amortization expenses and investment tax credits. High rates of inflation reduce the real value of these tax items and subsequently increases the minimum level of reserves required for an economic field. Minimum economic field size of the representative prospects is only moderately sensitive to variations in the rate of inflation.

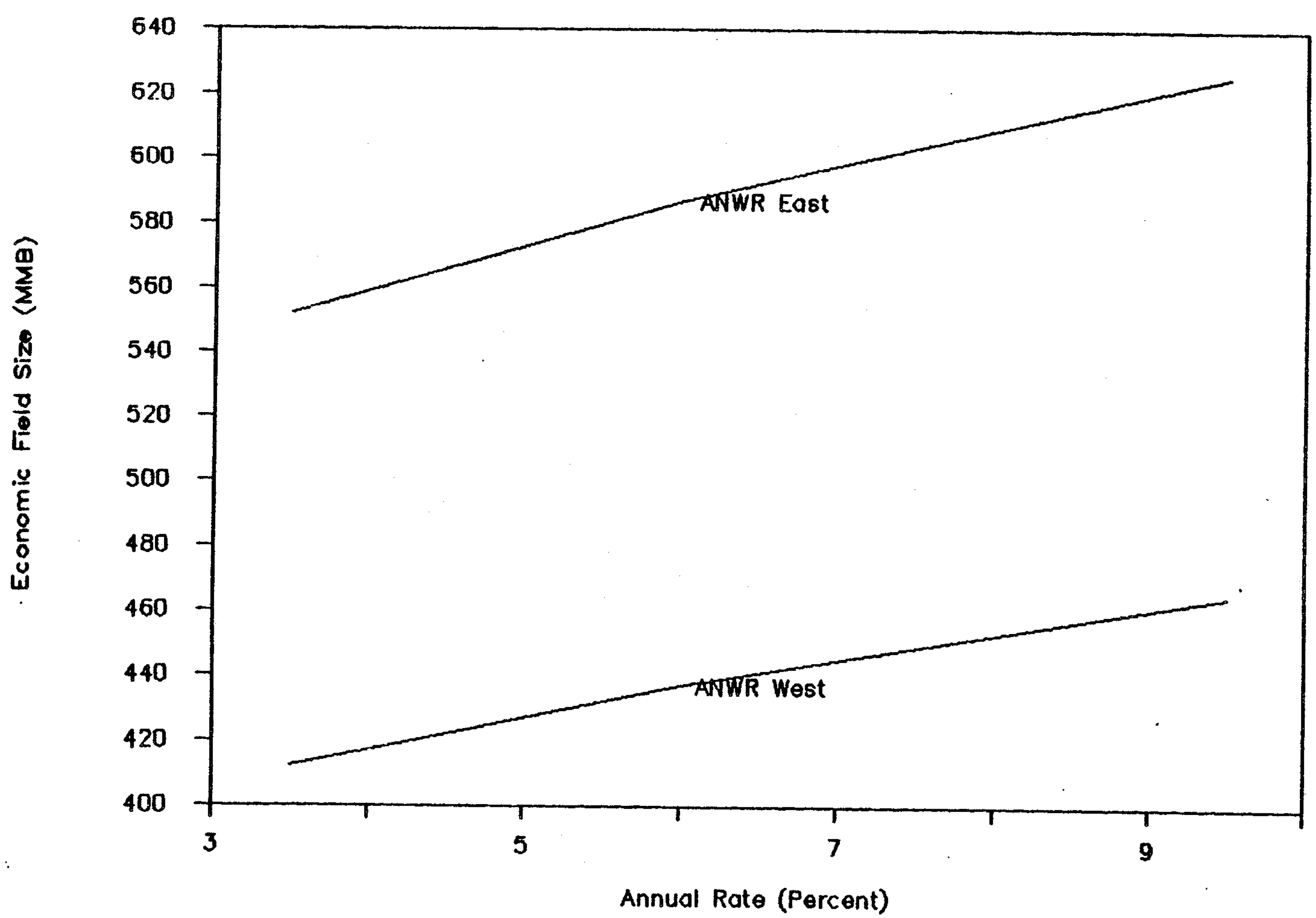
ANWR discount rate (Sensitivity Analysis)

FIGURE 21



ANWR inflation rate (Sensitivity Analysis)

FIGURE 22



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GLOSSARY

Netback Price: The value of crude oil at the wellhead, which is the market selling price less the transportation costs to deliver the oil to market.

Nominal Dollar Values: Nominal dollar represent monetary values that are affected by inflation. Nominal dollars relate to real dollar (measured at a specific point in time) by the difference in dollar values due to changes in purchasing power of the dollar (inflation or deflation). Synonymous terms are inflated or current dollar values.

Real Dollar Values: Real dollar values represent the purchasing power of the dollar for a specific reference point in time. Constant dollars are synonymous with real dollars.