THE FEDERAL INSPECTOR
ALASKA NATURAL GAS TRANSPORTATION SYSTEM
ROOM 2413, POST OFFICE BUILDING
1200 PENNSYLVANIA AVENUE
WASHINGTON, D.C. 20044

OCT 20 1981

Honorable John Dingell
House of Representatives
Washington, D. C. 20515

Dear Mr. Dingell:

At your request, my staff has prepared the attached analyses (which supersede the draft packages dated October 15 and 16, 1981) on the cost-of-service and other factors related to the Alaska Natural Gas Transportation System using your staff's assumptions and the sponsor's cost figures. I am always pleased to be of assistance, but in this case, you should be aware of certain limitations of this work.

As you know, determining cost-of-service is not one of the Office of the Federal Inspector's (OFI) responsibilities. However, one of OFI's employees is familiar with the computer model developed by the FERC to perform cost-of-service analyses. Using the input assumptions specified by your staff, we have used the model to perform cost-of-service analyses and developed the attached summaries of the results. We have also performed other calculations specified by your staff such as internal rates of return, consumer indifference, and effects of pre-billing which utilize the results of the cost-of-service analyses. Thus, our assistance was basically technical support. Because OFI is not staffed appropriately, we made no attempt to analyze the assumptions specified by your staff; our efforts have been directed to assuring that the model accurately analyzes the scenarios requested.

There are two packages attached. The package dated October 18, 1981 is based upon the cost estimates which have been filed by the sponsors. The package dated October 19, 1981 is based upon revised cost estimates and adjustments in the way costs are allocated which have not yet been formally filed. A comparison of the two estimates, including the Center Point allowances requested by the sponsors, is shown below:

1980 dollars in billions, including Center Point

	October 18, 1981 Package	October 19, 1981 Package
Conditioning Plant	3.3	3.6
Alaska Pipeline	10.6	10.8
Canada	5.8	5.8
U.S. Eastern Leg	1.9	1.9
U.S. Western Leg	0.9	0.9
TOTAL	22.5	23.0

At the request of your staff, we have provided copies of these analyses to other House and Senate staff who have a continuing interest in the Alaska Natural Gas Transportation System. Due to the impending resignation of the only member of our staff with a detailed understanding of the cost-of-service model, OFI will no longer be able to provide support in this area. We will, of course, attempt to answer any questions you may have after reviewing the attached explanations of the analyses, summaries of the results, and graphs.

Sincerely yours,

John T. Rhett

John T. Rhett
Federal Inspector

Enclosures

COST OF SERVICE

FOR THE

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

October 19, 1981

(This package is an updated version of a study dated October 18, 1981 and contains new capital cost estimates provided by Northwest Alaskan)

Alaska Natural Gas Transportation System

Cost of Service Analysis

BRIEFING BOOK

Table of Contents

COST OF SERVICE ANALYSIS

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

I. Management Summary

This briefing book contains several types of analyses related to the cost of service, or cost to consumers, of the Alaska Natural Gas Transportation System (ANGTS) as calculated in a computerized model called MARKV developed at the Federal Energy Regulatory Commission (FERC) in 1978. They include capital costs, unit delivered costs to consumers, rates of return for project owners, consumer indifference between gas and oil, billing commencement, and sensitivity to interest rates. Also included are a narrative of how cost of service is determined and the meaning and impact of various input assumptions to the models used to perform the calculations.

Specifically, two basic capital cost scenarios are used in the analysis. One is referred to as the "base" case which is the estimate filed by the project sponsor, Northwest Alaskan Pipeline Company (NWA) as their base estimate in 1980. The second is referred to as the "overrun" case, which is the base estimate with an allowance for additional costs expected by the project sponsor (commonly termed "Center Point").

Several key input assumptions and results from the analyses performed are summarized in the following tables. The first table shows the analysis based on inputs assumed by NWA which were used for calibrating the model used this analysis, with key comparisons with the NWA results. The second table shows similar results, as well as other additional results, for an alternative set of input assumptions which are the basis for the majority of the analyses included in this briefing book.

Some key items shown include:

1) 1980 dollar direct capital cost estimates
2) Assumed interest rate for debt
3) Assumed construction escalation factor
4) Assumed general inflation factor
5) Total project rate base, with dollars escalated to year of construction and including finance charges called AFUDC
6) Total unit delivered cost of gas, including wellhead price, conditioning plant and pipeline system unit cost of service, in nominal and 1980 dollars
7) Twenty year average unit delivered cost of gas in 1980 dollars
8) Profitability analysis for sponsors and gas producers
9) Real oil escalation rates equivalent to gas, projected over twenty years
10) Monthly average increase to residential customers from pre-billing charges from the conditioning plant, Alaska pipeline, or Canadian segment

Following these summary tables, two graphs are shown. One is the unit cost of gas delivered to consumers over time compared to increasing oil prices in 1980 dollars. The second is a graph of consumer indifference between oil and gas. Both graphs assume project financing as proposed by the sponsors.

Detail descriptions, inputs, results, and graphs of each of the areas listed above are also included in the various sections of this briefing book.

TABLE I

Calibration with Northwest Alaskan

1980 $ Direct Capital Costs (US$ billion)	
Alaska Plant	$ 3.3
Alaska Pipeline	10.6
Canada	5.8
US Eastern Leg	1.9
US Western Leg	0.9
Total	$22.5

Interest Rate on Debt	14% U.S., 15% Canada
Construction Escalation Rate	11% U.S., 12% Canada
General Inflation Rate	11%

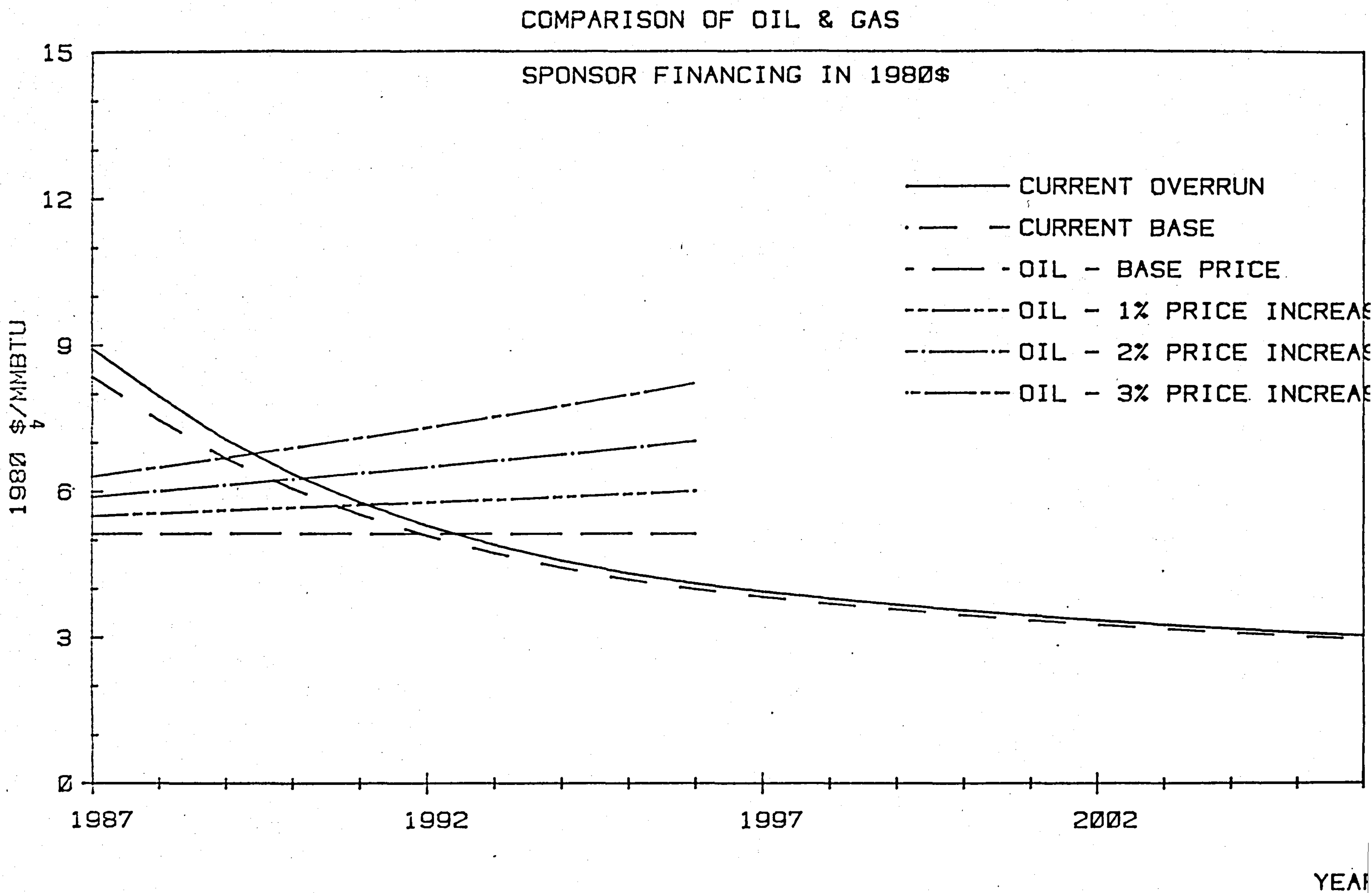
Results:	Northwest Alaskan		MARKV model
Total Rate Base (US$ million)			
Alaska Plant	$ 7373		$ 7436
Alaska Pipeline	25277		24886
Canada	15975		16187
US Eastern Leg	3514		3599
US Western Leg	1805		1821
Total	$ 53934	(0.01%)	$ 53929
Unit Delivered Cost of Gas Twenty year average 1980 $	$ 4.390	(0.04%)	$ 4.388

TABLE II
Basic Cases for Analysis

Significant assumptions held constant include:
Interest Rate on Debt - 11%, Construction Escalation - 8%, General Inflation - 8%

Scenario:	Current Filing		Current Filing with Center Point	
Financing:	Sponsor's	75/25	Sponsor's	75/25
1980 Dollar Capital Costs (US$ Billion)				
Alaska Plant	$ 3.3		$ 3.6	
Alaska Pipeline	8.5		10.8	
Canada	5.2		5.8	
US Eastern Leg	1.7		1.9	
US Western Leg	0.9		0.9	
Total	$19.6		$23.0	
Rate Base as of 1/1/87 including AFUDC (US$ Billion)				
Alaska Plant	$ 6.3	$ 6.3	$ 6.8	$ 6.7
Alaska Pipeline	18.2	17.0	21.7	20.9
Canada	10.0	10.0	11.2	11.2
US Eastern Leg	2.8	2.8	3.1	3.1
US Western Leg	1.5	1.5	1.5	1.5
Total	$38.8	$38.0	$44.3	$43.4
Delivered Costs - NGPA wellhead				
First year nominal $/mmbtu	$14.87	$13.70	$15.90	$15.04
First year 1980 $/mmbtu	8.35	7.69	8.93	8.44
Twenty year average 1980 $/mmbtu	4.49	4.23	4.67	4.48
Profitability Analysis				
Equity Investment for Plant and Pipeline in Alaska at Initial Operations - (1980 $ million)	$7020	$3483	$7540	$5883
AK Sponsors - Internal Rate of Return	25.1%	36.9%	25.0%	35.9%
Alaska Sponsors - Net Present Value of Profit Above 19% (nom $ million)	$2485	$1710	$2331	$1801
Producers - Internal Rate of Return	48.2%	75.1%	48.0%	72.5%
Producers - Net Present Value of Profit Above 19% (nom $ million)	$11283	$10951	$11217	$10989
Consumer Indifference - real oil price escalation rate equivalent to ANGTS gas at 70% of world oil price	1.99%	1.58%	2.27%	1.98%
Average increase to residential customer's monthly bill:				
Min Bill Plant	$0.29	$0.29	$0.31	$0.31
Min Bill Alaska Pipeline	0.63	0.68	0.83	0.85
Min Bill Canada	0.41	0.41	0.45	0.45
Total COS Plant	$0.43	$0.42	$0.46	0.45
Total COS Alaska Pipeline	1.40	1.14	1.55	1.37
Total COS Canada	0.68	0.68	0.75	0.75

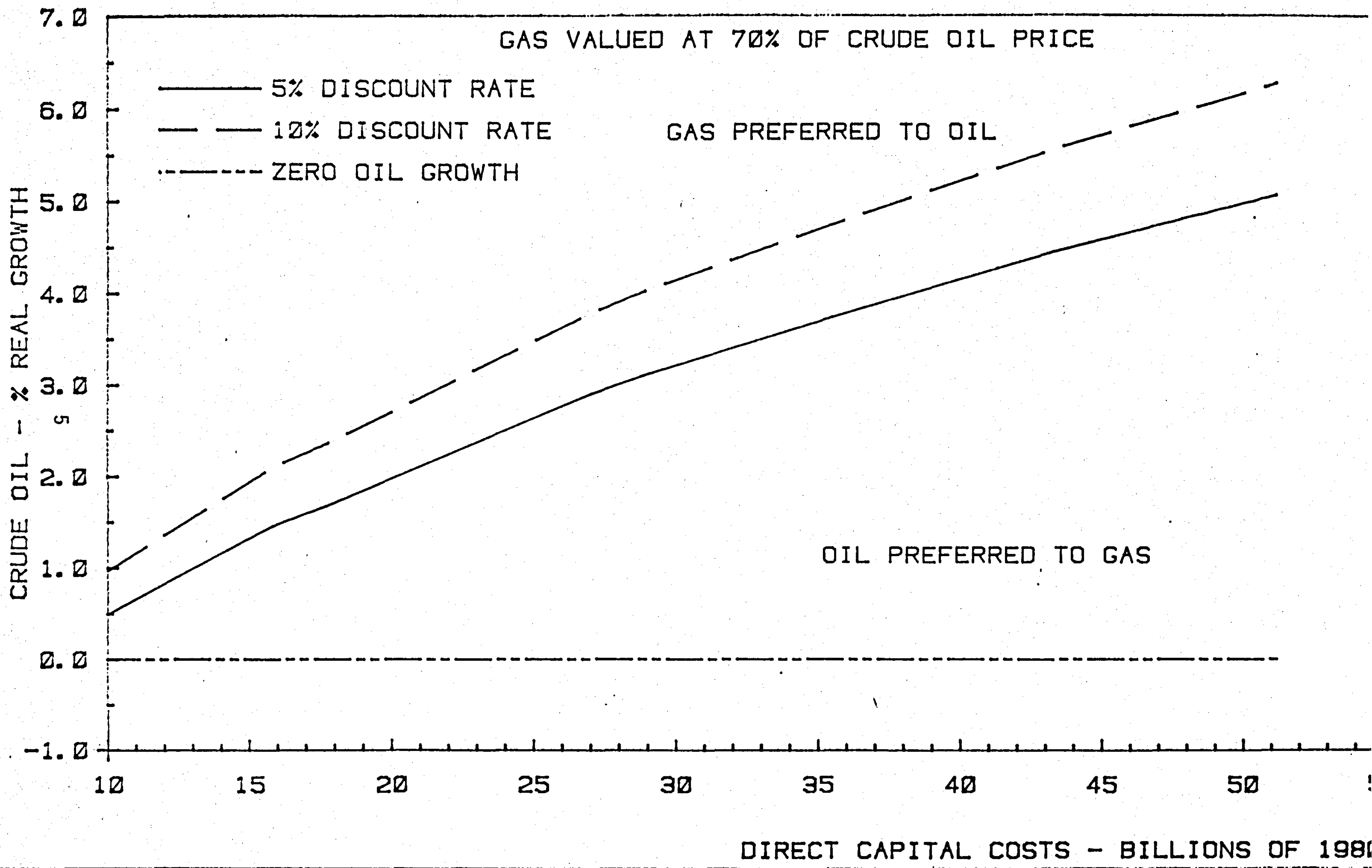
DELIVERED UNIT COST



4

CONSUMER INDIFFERENCE

SPONSOR FINANCING



II. Calibration of Model

To help assure the accuracy of this analysis, an independent analysis and comparison of the cost of service for the project has been made using a computerized model developed independent of the project sponsors. The preliminary results of this analysis are presented below. A further calibration with a refinement of input assumptions was also done, and the results are also summarized below.

The cost of service, or unit cost of natural gas delivered to customers in the lower 48 states from Alaska, is primarily based on tariff regulations of the Federal Energy Regulatory Commission (FERC) in the United States, and the National Energy Board (NEB) in Canada.

Capital costs, assumptions about various financial and economic parameters, and the volume throughput determine what consumers must pay for a unit of natural gas delivered in the lower 48 states.

The model which was calibrated with the sponsor's model was developed at the FERC in 1978, has been enhanced since then, and is now called MARKV. This model and the project sponsors' model are compared using two sets of input assumptions. For Case I of the initial comparison, low assumptions for inflation, interest rates, and capital cost are used. For Case II, slightly higher assumptions for these parameters are used. All other parameters are kept constant. The values for these two cases are as follows:

	Case I - Low	Case II - High
1980 dollar constant direct capital costs	$19.1 billion	$22.5 billion
Interest Rates	8% U.S. 9% Canada	14% U.S. 15% Canada
Construction Escalation	7% U.S. 8% Canada	11% U.S. 12% Canada
General Inflation	5%	11%

Based on these assumptions, the following total project costs, referred to as rate base, which is expressed in dollars escalated to the year of construction and which include the financing charges, are:

	Case I - Low	Case II - High
Project Sponsors Model	$ 35.4	$ 50.5
MARKV Model	$ 35.3	$ 51.0

The amounts to be pre-committed for financing are substantially less than these figures. First, approximately $3.0 billion dollars for the pre-build segments of the project have already been financed. Second, these figures include the equity portion of the construction finance charges, which are not dollars which must be financed. (These finance charges, called an Allowance for Funds Used During Construction (AFUDC), are included in the rate base because they determine the total cost of service.) And third, these figures also include a one-time accounting adjustment to the equity invested in the project as specified by the Incentive Rate of Return mechanism.

The resultant unit costs for delivered gas to U.S. consumers for the two cases examined in the initial calibration are summarized below:

First year delivered cost
(in escalated $/mmbtu)

	Case I - Low Sponsors	Case I - Low MARKV	Case II - High Sponsors	Case II - High MARKV
Wellhead	$ 2.83	$ 2.83	$ 4.30	$ 4.30
Conditioning Plant	1.08	1.12	1.65	1.71
Transportation	8.00	8.34	12.56	13.30
TOTAL	$11.91	$12.29	$18.51	$19.31
	(3.2% difference)		(4.3% difference)	
Twenty year average[1/] (1980 $/mmbtu)	$ 5.36	$ 5.07	$ 4.47	$ 4.37
	(5.7% difference)		(2.2% difference)	

An additional calibration effort was also performed to try and match input assumptions more closely. Significant changes occurred in the timing of debt and equity usage during construction and in the treatment of committment fees and underwriting fees for debt. This calibration was only performed for the high case of assumptions described above.

The results of this second calibration effort are shown below:

	Northwest Alaskan		FERC model
Total Rate Base (US$ million)			
Alaska Plant	$ 7373		$ 7436
Alaska Pipeline	25277		24886
Canada	15975		16187
US Eastern Leg	3514		3599
US Western Leg	1805		1821
Total	$53934	(0.01%)	$53929
Unit Delivered Cost of Gas Twenty year average 1980 dollars	$ 4.390	(0.04%)	$4.388

[1/] The twenty year constant dollar average for the low assumptions case is actually higher than the high assumption case because a lower inflation rate is used to convert escalated dollars to constant dollars. The sponsors have shown an upper range figure of $5.67/mmbtu which is based on lower inflation rates than the cases shown here.

III. Narrative Description of Cost of Service Model

1. Introduction

The term "cost of service" applies to the type of transportation tariff that will be utilized on the Alaska Natural Gas Transporation System. This type of tariff is regulated by the Federal government, and the rates charged to the transporters of gas through the pipeline are calculated based on the investment cost of the project and the rate of return granted to the pipeline owners by the Federal Energy Regulatory Commission (FERC) in the United States and the National Energy Board (NEB) in Canada.

A computerized model of this tariff was developed in 1978 to approximate and project various financial statistics associated with the project through its operational life. The key number is called "total cost of service" or "revenue requirement" for each project segment. All of the revenue requirements for each project segment are then added together, along with a cost allowance for fuel consumed in the system's compressor stations, and then divided by the amount of natural gas delivered to the lower 48 states to determine the unit cost of transportation through the system.

This unit cost, usually expressed as dollars per million btu ($/mmbtu), is added to the wellhead price as set by the Natural Gas Policy Act of 1978 to determine the total cost of gas to consumers. This total consumer unit cost can then be compared to equivalent btu costs for alternative energy sources, such as Canadian gas or world oil, on a nominal or constant dollar basis.

This narrative of the MARKV cost of service model briefly describes the cost estimate inputs, the financial input assumptions, the components of cost of service, calculations of unit delivered costs, the comparison of Alaskan gas to alternative energy sources, and the results from the project sponsor's model and MARKV.

2. Cost Estimates

Generally, there are three types of cost estimates for regulated pipeline projects. The first is the base, constant dollar direct capital costs for the installation of the pipeline and related facilities. These estimates typically include direct labor costs, material costs, indirect costs, and a contingency allowance.

The second type of cost estimate is referred to as escalated dollars. This estimate is developed by applying an escalation, or inflation, factor to the constant dollar estimate described above. The factors are compounded from the base year and applied to the direct costs expected to be spent in that year.

The third type of estimate is referred to as the "rate base" or total project cost. This cost estimate uses the escalated costs developed by applying the escalation factors to the base estimate, and calculates the "allowance for funds used during construction" (AFUDC) determined by the financing plan used in the computer model of the tariff. This AFUDC amount is based on the amount of debt and equity used to finance the project, the interest rate on the debt, and the rate of return on equity allowed during construction. Once gas flows, the Incentive Rate of Return mechanism sets the rate of return for the remainder of the project life.

The following table compares the cost estimates used by the project sponsors with the resultant total costs from the MARKV cost of service model. The two rate base estimates are the basis for the unit cost summary shown in Section 6 of this paper. The two cases show the different results which are based on low and high assumptions for abnormal events (with or without the IROR center point), inflation (7-11%), and interest rates for debt (8-14%).

ANGTS Cost Estimate Summary
(in billions of U.S. dollars)

Project Segment	Project Sponsors 1980 US Dollars Low	Project Sponsors 1980 US Dollars High	Project Sponsors Total Rate Base Low	Project Sponsors Total Rate Base High	MARKV Total Rate Base Low	MARKV Total Rate Base High
Conditioning Plant	$ 3.0	3.3	$ 5.4	7.3	$ 5.4	7.4
Alaska	8.3	10.6	16.7	25.0	16.5	25.0
Canada	5.2	5.8	9.2	13.0	9.3	13.2
Lower 48 Legs	2.6	2.8	4.1	5.2	4.1	5.4
Subtotal	$19.1	22.5	$35.4	50.5	$35.3	51.0
Less Prebuild	(1.8)	(1.9)	(2.5)	(2.9)	(2.5)	(3.0)
TOTAL	$17.3	20.6	$32.9	47.6	$32.8	48.0

The slight differences in calculating total rate base between the sponsor's and MARKV models in this set of calibration runs can be attributed to slightly different approaches to debt and equity investment during construction.

3. Financial Input Assumptions

Each segment of the project is considered a separate entity within the model, and each sponsor consortium has its own set of financial input assumptions. These assumptions specify various parameters of the transportation tariff which will be used to determine the rates which consumers must pay. Also, various other inputs are required in the model. Some of these are the timing of expenditures, the duration of construction, the operation and maintenance cost, tax rates, and escalation rates during construction. These are listed as the first output report from the cost of service model for each project segment (See Section XII). A description of each of these inputs follows:

1) YRS OF CONSTRUCTION - the number of years of construction counting from year one of the model.

2) CONSTRUCT COST ESCALATION - the escalation factor to be used during construction; this parameter can vary year by year during construction.

3) DEBT CAPITAL RATIO - the percentage ratio of new money financing which is to be financed from debt; this ratio is specified year by year throughout construction.

4) INTEREST RATE ON DEBT - the interest rate to be paid on debt invested.

5) RETURN ON EQUITY - CONST - the rate of return on equity during the construction period.

6) RETURN ON EQUITY - OPERT - the rate of return on equity during the operation phase of the project.

7) BOOK LIFE OF PLANT - the depreciable life of the project to be used for determining depreciation; specified as number of years.

8) TAX LIFE OF PLANT - the tax life of the project as set under guidelines of the Internal Revenue Service; specified as number of years; or the tax depreciation schedule year by year.

9) STATE INC TAX RATE - the state income tax rate to be combined with the federal rate of 46%.

10) LEVELIZATION FACTOR - an adjustment factor greater than zero which changes the straight-line depreciation for rate purposes to an inverse accelerated depreciation schedule.

11) CAPITALIZATION RATIO - optional method of computing ad valorem, or property taxes, based partially on the capitalized value of income, and partially on the net value of the plant in service.

12) SH TERM DEBT RATIO - the percentage ratio of short term debt to the total debt invested.

13) SH TERM DEBT RETIRE YRS - the number of years during which the short term debt is repaid.

14) SH TERM DEBT START - the number of years after construction is completed in which short term debt repayments begin.

15) LN TERM DEBT RETIRE YRS - the number of years during which the long term debt is repaid.

16) LN TERM DEBT START - the number of years after construction is completed in which long term debt repayments begin.

17) AD VALOREM TAX RATE - the percentage rate of gross plant in service to be paid as ad valorem or property taxes.

18) ESC FOR AD VALOREM TAXES - escalation rate for ad valorem taxes.

19) OPER & MAIN COST - the constant dollar input value for operation and maintenance labor costs excluding fuel in the compressor stations.

20) OPER & MAIN ESCALATION - the percentage esclation factor to be applied on a compounded basis to the constant dollar O&M input.

21) COST OVERRUN FACTOR - a percentage factor which is applied to direct constant dollar construction costs for a given segment.

4. Components of Cost of Service

The basic cost of service model develops four financial reports based on the input assumptions provided. They are: 1) Pro Forma Balance Sheet, 2) Pro Forma Income Statement, 3) Pro Forma Cash Flow Statement, and 4) Pro Forma Tax Reconciliation. See Section XII for a sample of these reports.

The balance sheet shows the capital costs and associated results during construction when capital is invested, and during operations as the plant in service is depreciated.

The income statement shows all the components that make up the revenue requirements during operations for each year. Operation and maintenance expense is based on the constant dollar input value escalated each year. The annual depreciation expense is the initial rate base divided by the number of years for book depreciation. Other taxes are calculated by taking the tax rate times gross plant in service, unless an optional capitalization method is employed. Current and deferred income taxes are the total taxes based on the equity income for that year. Equity income is based on net plant, and provides for repayment of debt, interest due on outstanding debt, and a return on and of equity.

In summary:

Cost of service = Operation and Maintenance Expense
+ Depreciation Expense
+ Other taxes (ad valorem)
+ Deferred Income Taxes
+ Current Income Taxes
+ Equity Income

The cash flow statement shows the balances of debt and equity as they build up during construction, and as they are paid back during operations.

The tax reconciliation statement shows income taxes as calculated for the IRS, which should match the current income taxes shown on the income statement.

All values in the output reports are in nominal or escalated dollars except the constant dollar direct construction costs, line 9 on the balance sheet. Because depreciation decreases the total assets, or net plant, each year, the total revenue requirements decrease each year. This phenomenon is referred to as a "declining rate base" and is standard in project oriented cost of service tariffs.

5. Unit Cost Determination

The total revenue requirements for all segments of the ANGTS project are added together to determine the total project cost of service. Also, natural gas consumed in the compressor stations is considered as a separate fuel expense and is costed at the wellhead price according to the Natural Gas Policy Act of 1978 (NGPA). The total cost of service plus fuel costs is the total cost of transportation on an annual basis.

This total cost is then divided by the amount of natural gas delivered in the lower 48 states to provide the unit cost of transportation. The assumed or computed wellhead price according to NGPA is added to the unit cost of transportation to get the total unit cost of gas delivered to consumers. This unit cost is in nominal or escalated dollars, and is deflated to constant dollars by compounded escalation factors to calculate the twenty year average in constant dollars.

6. Unit Cost Summary

Based on the high and low assumptions used in the first calibration effort, the following table compares the unit costs from the MARKV model with the unit costs produced by the project sponsors' model:

First year delivered cost
(in escalated $/mmbtu)

	Case I - Low		Case II - High	
	Sponsors	MARKV	Sponsors	MARKV
Wellhead	$ 2.83	$ 2.83	$ 4.30	$ 4.30
Conditioning Plant	1.08	1.12	1.65	1.71
Transportation	8.00	8.34	12.56	13.30
TOTAL	$11.91	$12.29	$18.51	$19.31
	(3.2% difference)		(4.3% difference)	
Twenty year average[1/] (1980 $/mmbtu)	$ 5.36	$5.07	$ 4.47	$ 4.37
	(5.7% difference)		(2.2% difference)	

[1/] The twenty year constant dollar average for the low assumptions case is actually higher than the high assumption case because a lower inflation rate is used to convert escalated dollars to constant dollars. The project sponsors have shown an upper range figure of $5.67/mmbtu which is based on lower inflation rates than the cases shown here.

IV. Input Assumptions

Several input assumptions were held constant through all the analyses performed. Most of these assumptions came from Northwest Alaskan Pipeline Company through the calibration efforts shown in Section II. Other assumptions utilized were provided by other individuals making the request for the various analysis presented in this briefing book.

The key assumptions for each segment of the project are shown in the following table:

Input Assumption	Plant	Alaska	Eastern Leg	Western Leg	Canada
First year of operations	1987	1987	1987	1987	1987
Construction escalator	8%	8%	8%	8%	9%
General Inflation rate	8%	8%	8%	8%	9%
Interest Rate on Debt	11%	11%	11%	11%	12%
AFUDC Return on Equity	14%	14%	13%	13.5%	17.7%
Book Life of Project	25yrs	25yrs	25yrs	25yrs	25yrs
State/Prov Inc Tax Rate	9.5%	9.5%	5.2%	9.5%	13.3%
Federal Income Tax Rate	46%	46%	46%	46%	30%
Debt Life	20yrs	20yrs	20yrs	20yrs	20yrs
Ad Valorem Tax Rate	2%	2%	2%	2%	1%
Total COS Allocation	100%	100%	63.7%	70.6%	94.3%

Other overall input assumptions include:

- 75/25 debt-equity ratio is always the target, but achieved in two ways; the first is according to the yearly ratio proposed by project sponsors, and the second assumes a constant 75/25 ratio in each year for incremental direct costs.

- The NGPA wellhead price, including 10% severance tax, on 1/1/80 is $1.965 $/mmbtu.

- The volume delivered to the lower 48 states is 787 trillion btu's per year.

- The fuel usage in the conditioning plant is 22.1 trillion btu's per year, and for the entire pipeline system is 35.5 trillion btu's, and is priced at the wellhead priced assumed for that case.

- The exchange rate for Canadian to US dollars varies each year according the difference in assumed inflation rates.

- All 1980 dollars are expressed as of January 1, 1980.

- The Incentive Rate of Return mechanism applies to the Alaska Pipeline, the Canadian, and the US Eastern Leg segments, and the parameters are according to FERC Order 31.

- The ten year tax depreciation schedule from the Economic Recovery Tax Act of 1981 is used for all analyses.

- Normalized tax treatment is used for all US segments.

- Operation and maintenance costs are expressed in 1980 dollars, and escalated according to the general inflation rate.

- The general inflation rate is used for all determinations of 1980 dollars.

- Direct Capital Costs are based on the filing of project sponsors in 1980, as adjusted and refined in subsequent filings or information exchanges during the calibration of MARKV with the project sponsor's model.

V. Capital Cost Estimates

This section details the various capital cost estimates used in the various analyses contained in the remainder of this briefing book.

Two basic cost estimate scenarios were used to examine the impact of cost increases on various project parameters. These scenarios are:

1) Currently filed estimates of July 1, 1980 (Current Filed)

2) Currently filed estimates of July 1, 1980 including the sponsors' request for IROR Center Point (Current Filed with CP)

Two additional scenarios were analyzed which reflect the recommended adjustment to the Alaska pipeline direct capital costs and center point allowance contained in the draft Adger/Berman report for the FERC, and which reflect an additional 10% overrun for the entire project over and above the requested center point.

Two additional scenarios are also presented for completeness, but are not based on the same scope of project as is currently being considered. These relate to the ANGTS project as envisioned in 1977 in the President's Decision. At that time, the conditioning plant and pre-build segments of the current project were not included in the analysis, and are not included in the analysis of those scenarios shown herein. The two scenarios are:

1) The base filed estimate from March 1977 in 1980 dollars (Decision Filing)

2) The base filed estimate from March 1977 including the White House staff' expected overrun, equivalent to the requested center point of project sponsors (Decision with CP)

The sponsors' published estimate of $27 billion for the Alaska pipeline and conditioning plant in as spent dollars is comparable to the "Current Filed with CP" scenario evaluated in this study. The sponsors' estimate does not include the finance charges for equity investment. Also, their estimate is based on an assumption of 14% inflation per year during construction, whereas the analysis in this study assumes 8%.

Two financing assumptions were also analyzed. In one case, equity money for the Alaska pipeline and conditioning plant is spent first, and then debt is spent, and the debt captial ratio for the lower 48 segments is 70/30 instead of 75/25. This case is referred to as the sponsor's financing assumptions. The other case assumes an equal and constant expenditure of debt and equity funds in the ratio of 75/25 through all construction years.

In addition, eight cost estimate sensitivity studies were run for both financing plans. These sensitivity scenarios depict an actual cost performance of from a 50% underrun of filed costs to a 160% overrun of filed costs.

The following tables include the 1980 dollar base estimates, segment by segment, for the four cost estimate scenarios; those estimates in escalated dollars assuming an 8% inflation rate in the U.S. and 9% in Canada; and the total rate base resulting from adding the finance charges (AFUDC) assuming an 11% interest rate in the U.S. and 12% in Canada.

After the tables, several graphs present the capital cost estimates and total costs as they develop during the construction period.

These graphs include:

- Total Direct Capital Costs in 1980 dollars for

  V-1 Total ANGTS
  V-2 Conditioning Plant
  V-3 Alaska Pipeline
  V-4 Canada
  V-5 US Eastern Leg
  V-6 US Western Leg

- Total Capital Costs showing 1980 dollars, escalated to year of construction and including AFUDC, for the entire project assuming:

  V-7 Sponsor financing including center point
  V-8 Sponsor financing using filed costs
  V-9 75/25 financing including center point
  V-10 75/25 financing using filed costs

ANGTS Cost Estimate Summary
(in millions of U.S. dollars)

	Current Filing w Center Pt. plus 10%	Current Filing with Center Pt.	Adjust. Adger/ Berman	Current Filing	President's Decision with Center Pt.	President's Decision March 1977
1980 Constant Dollars						
Alaska Plant	3944	3585	3585	3331	--	--
Alaska Pipeline	11912	10829	9401	8525	3229	2786
Canada	6365	5786	5786	5213	4133	2635
US Eastern Leg	2098	1907	1907	1717	1313	1250
US Western Leg	990	900	900	900	704	636
Total	25309	23007	21572	19143	9379	7307
As Spent Dollars (Escalated)						
Alaska Plant	5573	5067	5067	4689	--	--
Alaska Pipeline	17474	15885	13758	12399	4817	4156
Canada	9768	8880	8880	7956	6429	4100
US Eastern Leg	2870	2609	2609	2344	2089	1988
US Western Leg	1448	1316	1316	1316	1238	994
Total	37133	33757	31639	28704	14573	11238
Rate Base including Finance Charges						
Alaska Plant	7451	6773	6773	6306	--	--
Alaska Pipeline	23835	21668	18916	18156	6289	5614
Canada	12295	11177	11177	10024	8352	5327
US Eastern Leg	3462	3147	3147	2872	2381	2283
US Western Leg	1697	1543	1543	1543	1425	1146
Total	48740	44308	41556	38901	18447	14370

75/25 Financing

ANGTS Cost Estimate Summary
(in millions of U.S. dollars)

	Current Filing w Center Pt. plus 10%	Current Filing with Center Pt.	Adjust. Adger/ Berman	Current Filing	President's Decision with Center Pt.	President's Decision March 1977
1980 Constant Dollars						
Alaska Plant	3944	3585	3585	3331	--	--
Alaska Pipeline	11912	10829	9401	8525	3229	2786
Canada	6365	5786	5786	5213	4133	2635
US Eastern Leg	2098	1907	1900	1717	1313	1250
US Western Leg	990	900	900	900	704	636
Total	25309	23007	21572	19143	9379	7307
As Spent Dollars (Escalated)						
Alaska Plant	5573	5067	5067	4689	--	--
Alaska Pipeline	17474	15885	13758	12399	4817	4156
Canada	9768	8880	8880	7956	6429	4100
US Eastern Leg	2870	2609	2609	2344	2089	1988
US Western Leg	1448	1316	1316	1316	1238	994
Total	37133	33757	31639	28704	14573	11238
Rate Base including Finance Charges						
Alaska Plant	7423	6748	6748	6280	--	--
Alaska Pipeline	22958	20871	18135	16959	6182	5491
Canada	12269	11154	11154	10024	8352	5327
US Eastern Leg	3399	3090	3090	2806	2370	2270
US Western Leg	1692	1538	1538	1538	1423	1144
Total	47741	43401	40665	37607	18327	14232

ANGTS Sensitivity Cost Estimate Summary (in millions of U.S. dollars)

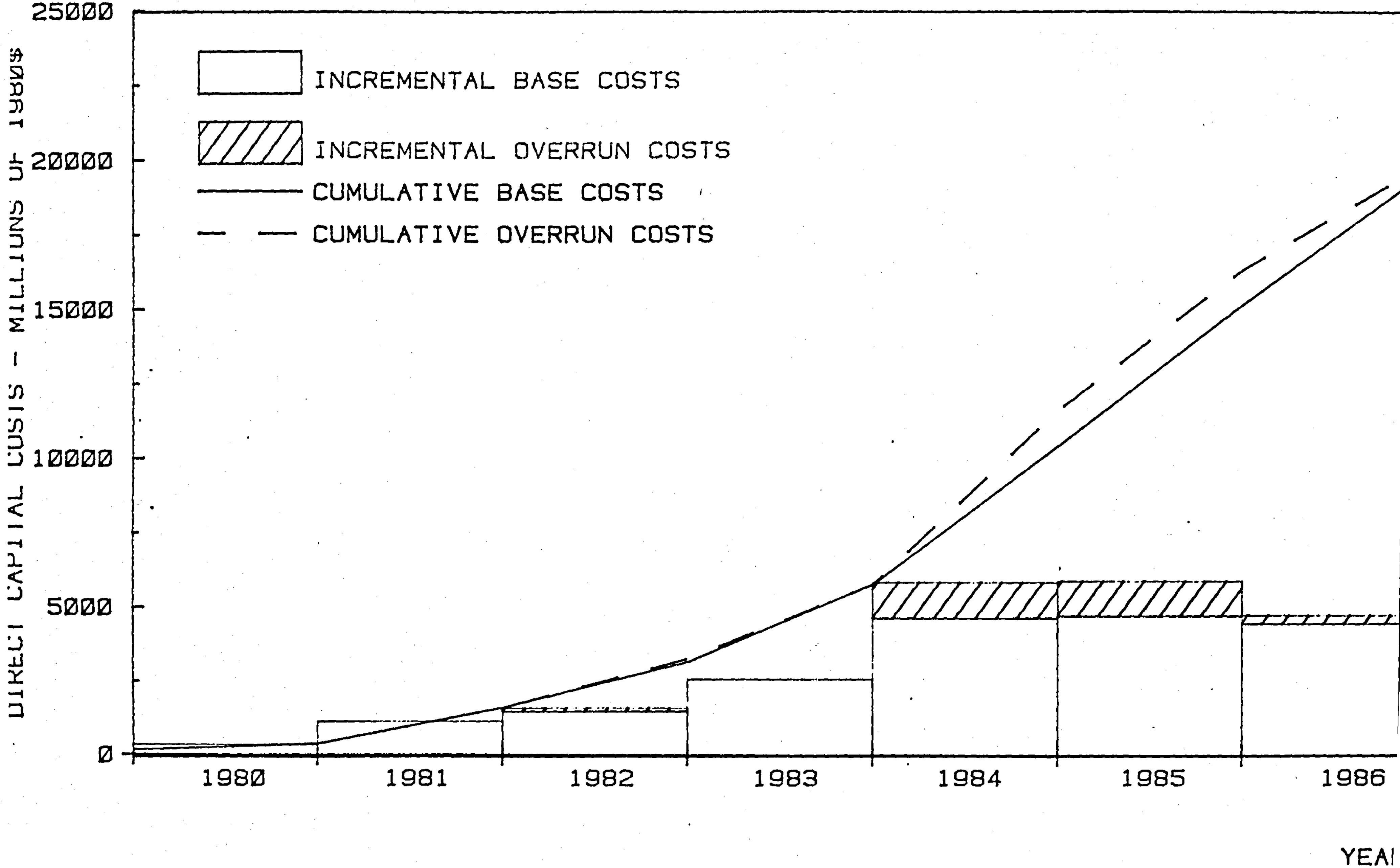
Percent Overrun or Underrun of Current Filing	-20%	-10%	40%	50%	-50%	80%	120%	160%
1980 Constant Dollars								
Alaska Plant	2665	2998	4663	4997	1666	5996	7328	8661
Alaska Pipeline	6820	7673	11935	12788	4263	15345	18755	22165
Canada	4170	4692	7298	7820	2607	9384	11469	13554
US Eastern Leg	1374	1545	2060	2232	859	3091	3777	4464
US Western Leg	720	810	990	1080	451	1620	1980	2340
Total	15749	17718	26946	28917	9846	35436	43309	51184
As Spent Dollars (Escalated)								
Alaska Plant	3751	4220	6565	7033	2344	8440	10316	12191
Alaska Pipeline	9970	11159	17359	18599	6200	22319	27279	32238
Canada	6365	7161	11139	11934	3979	14321	17503	20686
US Eastern Leg	1875	2110	2813	3048	1173	4220	5158	6096
US Western Leg	1052	1184	1447	1578	658	2368	2894	3421
Total	23013	25834	39323	42192	14354	51668	63150	74632
Rate Base including Finance Charges								
Alaska Plant	5044	5675	8828	9458	3153	11350	13872	16394
Alaska Pipeline	15294	16756	24073	25540	10430	29928	35782	41636
Canada	8034	9040	14061	15066	5021	18079	22096	26114
US Eastern Leg	2362	2615	3375	3629	1629	4871	5849	6826
US Western Leg	1234	1388	1697	1851	771	2776	3393	4010
Total	31968	35474	52034	55544	21004	67004	80992	94980

ANGTS Sensitivity Cost Estimate Summary
(in millions of U.S. dollars)

Percent Overrun or Underrun of Current Filing	-20%	-10%	40%	50%	-50%	80%	120%	160%
1980 Constant Dollars								
Alaska Plant	2665	2998	4663	4997	1666	5996	7328	8661
Alaska Pipeline	6820	7673	11935	12788	4263	15345	18755	22165
Canada	4170	4692	7298	7820	2607	9384	11469	13554
US Eastern Leg	1374	1545	2060	2232	859	3091	3777	4464
US Western Leg	720	810	990	1080	451	1620	1980	2340
Total	15749	17718	26946	28917	9846	35436	43309	51184
As Spent Dollars (Escalated)								
Alaska Plant	3751	4220	6565	7033	2344	8440	10316	12191
Alaska Pipeline	9920	11159	17359	18599	6200	22319	27279	32238
Canada	6365	7161	11139	11934	3979	14321	17503	20686
US Eastern Leg	1875	2110	2813	3048	1173	4220	5158	6096
US Western Leg	1052	1184	1447	1578	658	2368	2894	3421
Total	23013	25834	39323	42192	14354	51668	63150	74632
Rate Base including Finance Charges								
Alaska Plant	5024	5652	8792	9421	3140	11305	13817	16329
Alaska Pipeline	14044	15521	22908	24387	9319	28818	34728	40638
Canada	8018	9021	14033	15035	5011	18042	22051	26061
US Eastern Leg	2283	2543	3323	3584	1507	4872	5897	6922
US Western Leg	1230	1384	1692	1846	769	2768	3383	3999
Total	30599	34121	50748	54273	19746	65805	79876	93949

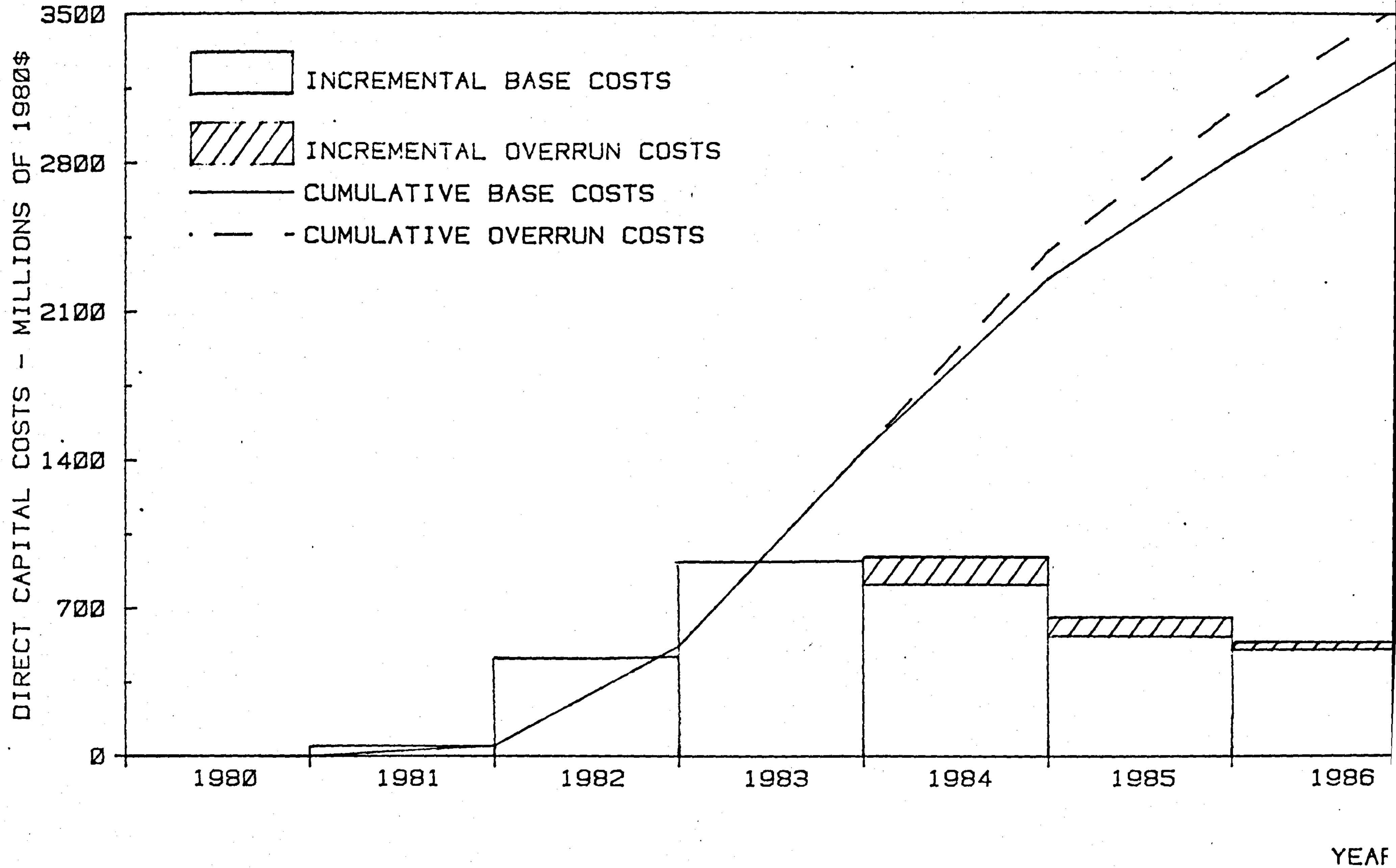
1980 DIRECT CAPITAL COSTS

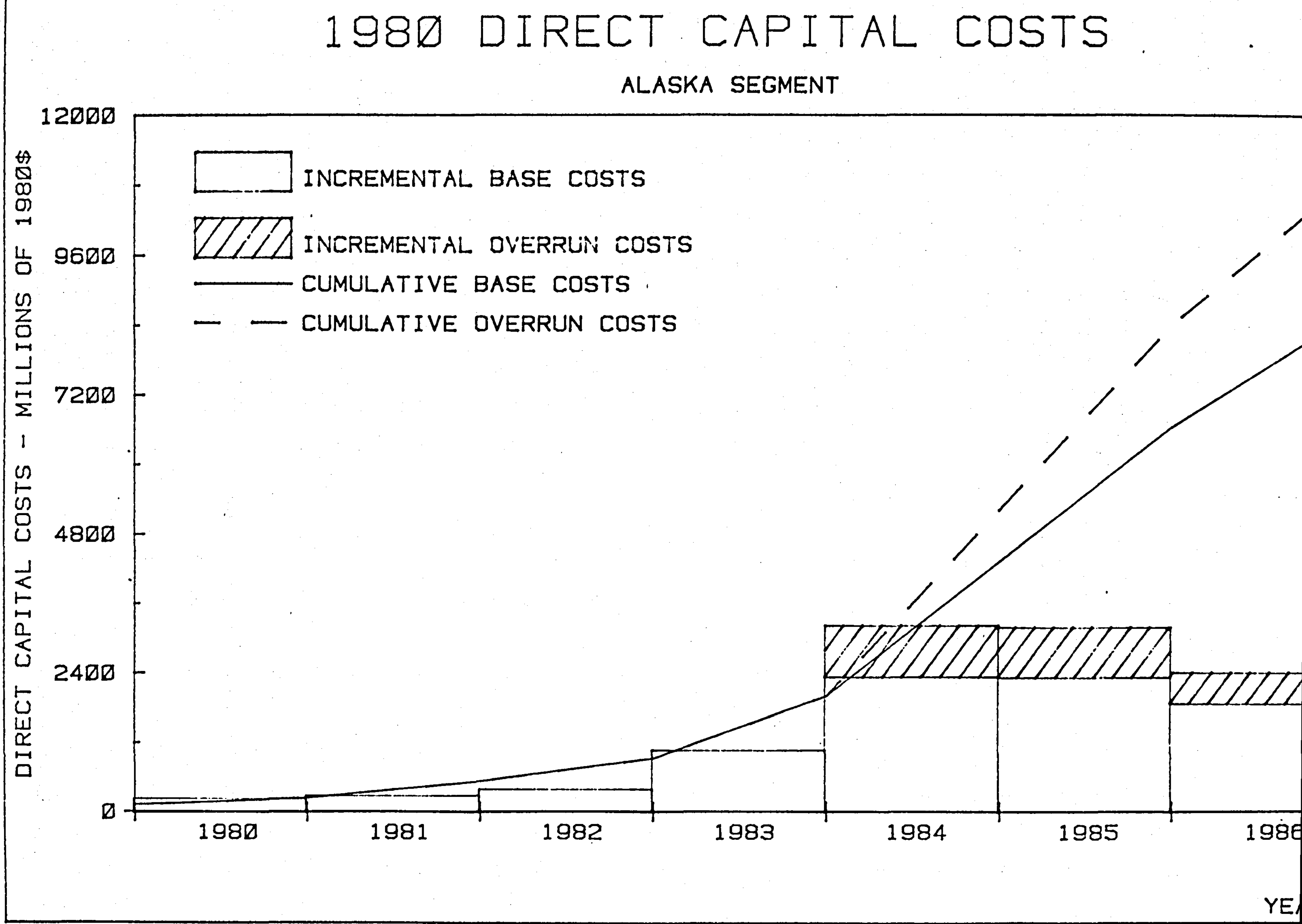
TOTAL SYSTEM



1980 DIRECT CAPITAL COSTS

CONDITIONING PLANT

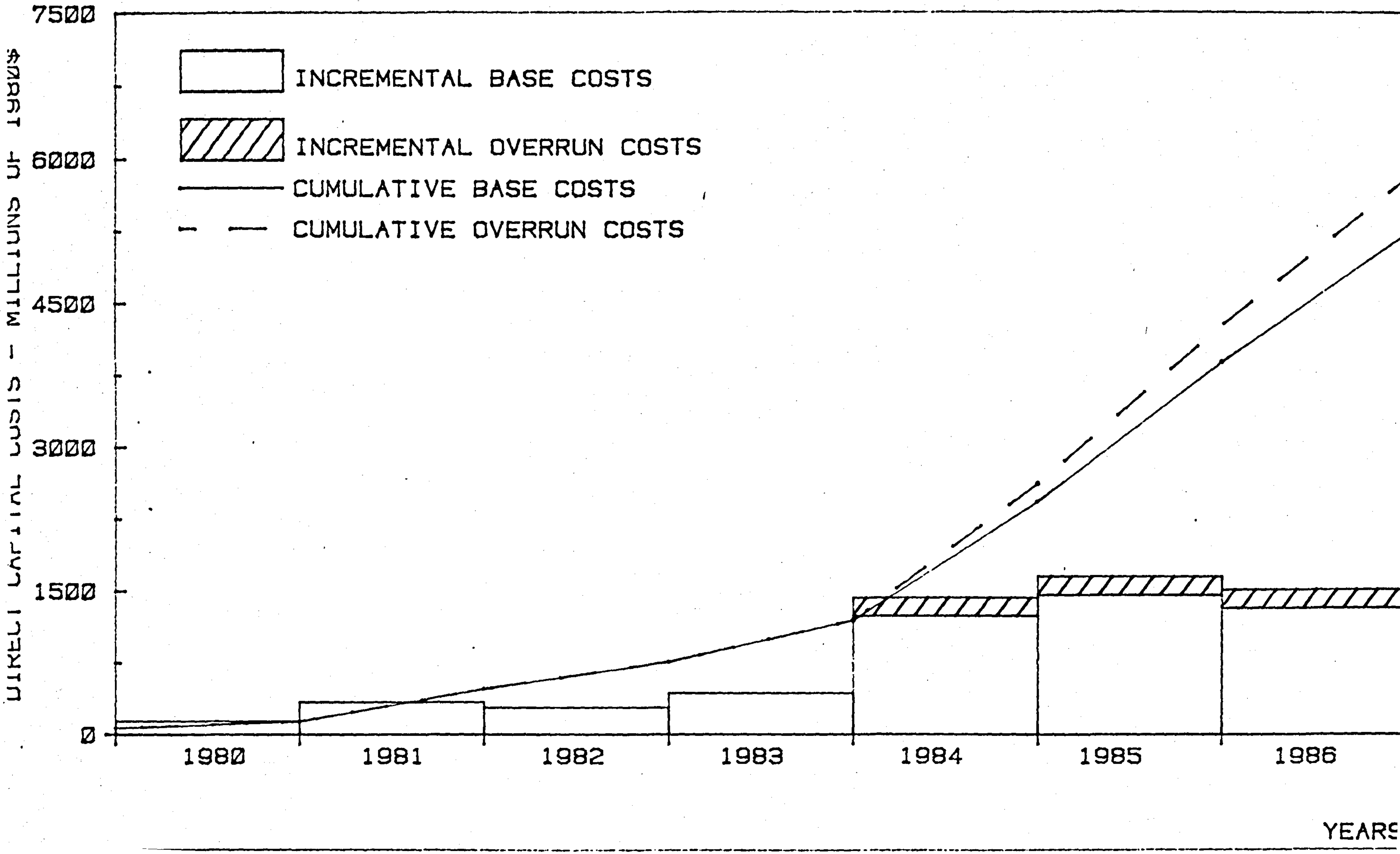




1980 DIRECT CAPITAL COSTS
ALASKA SEGMENT
INCREMENTAL BASE COSTS
INCREMENTAL OVERRUN COSTS
CUMULATIVE BASE COSTS
CUMULATIVE OVERRUN COSTS
DIRECT CAPITAL COSTS - MILLIONS OF 1980$
12000
9600
7200
4800
2400
0
1980
1981
1982
1983
1984
1985

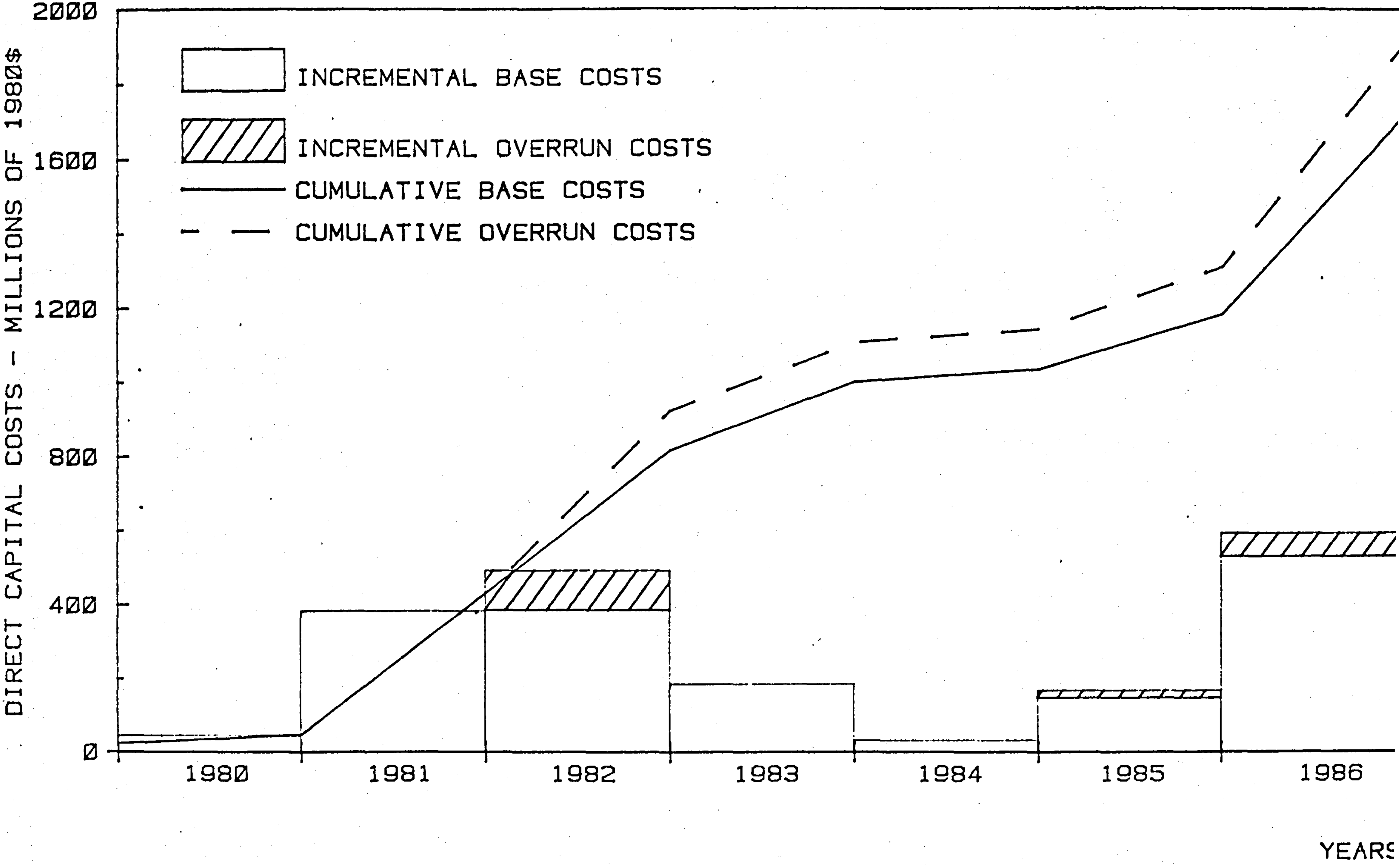
1980 DIRECT CAPITAL COSTS

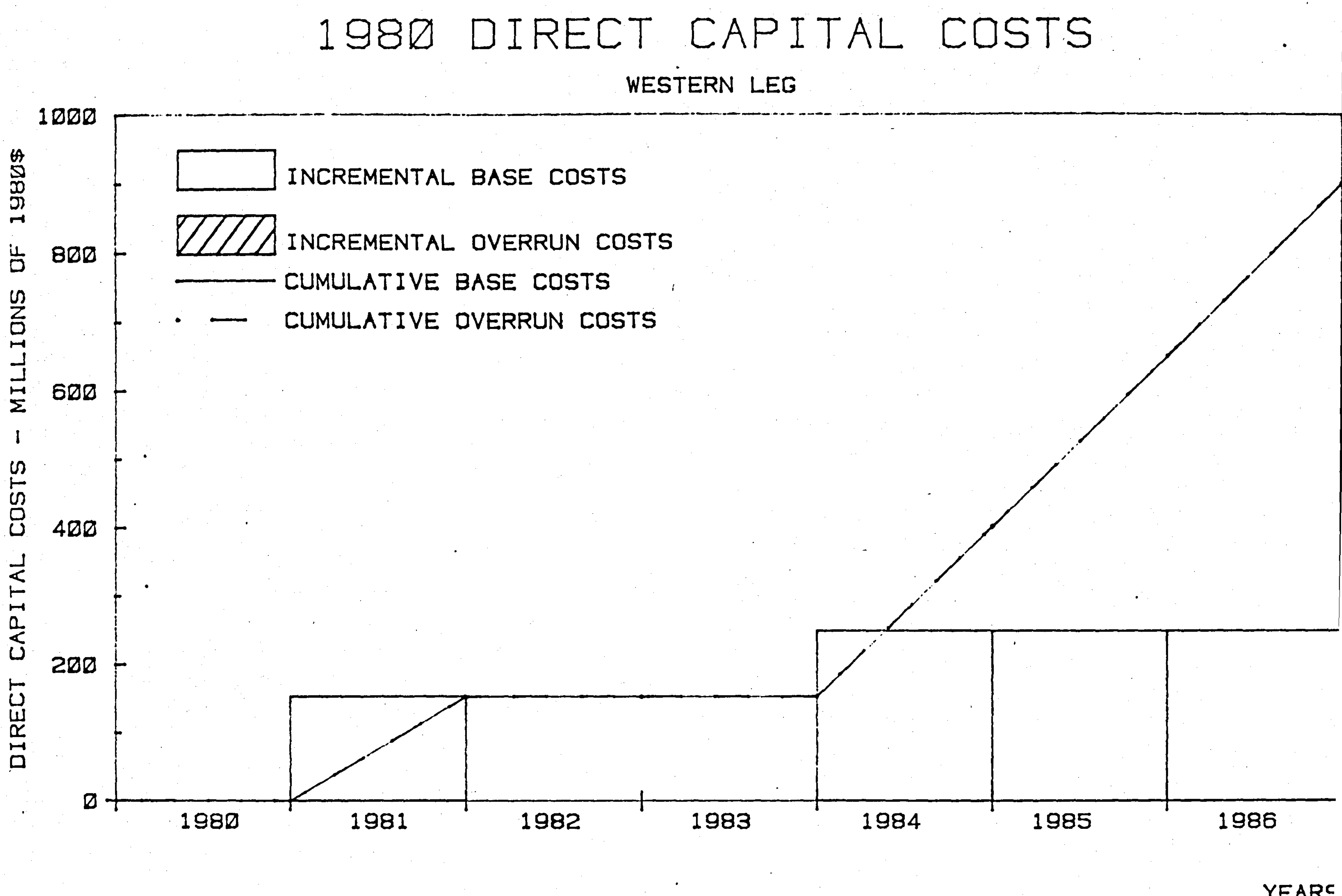
CANADIAN SEGMENT



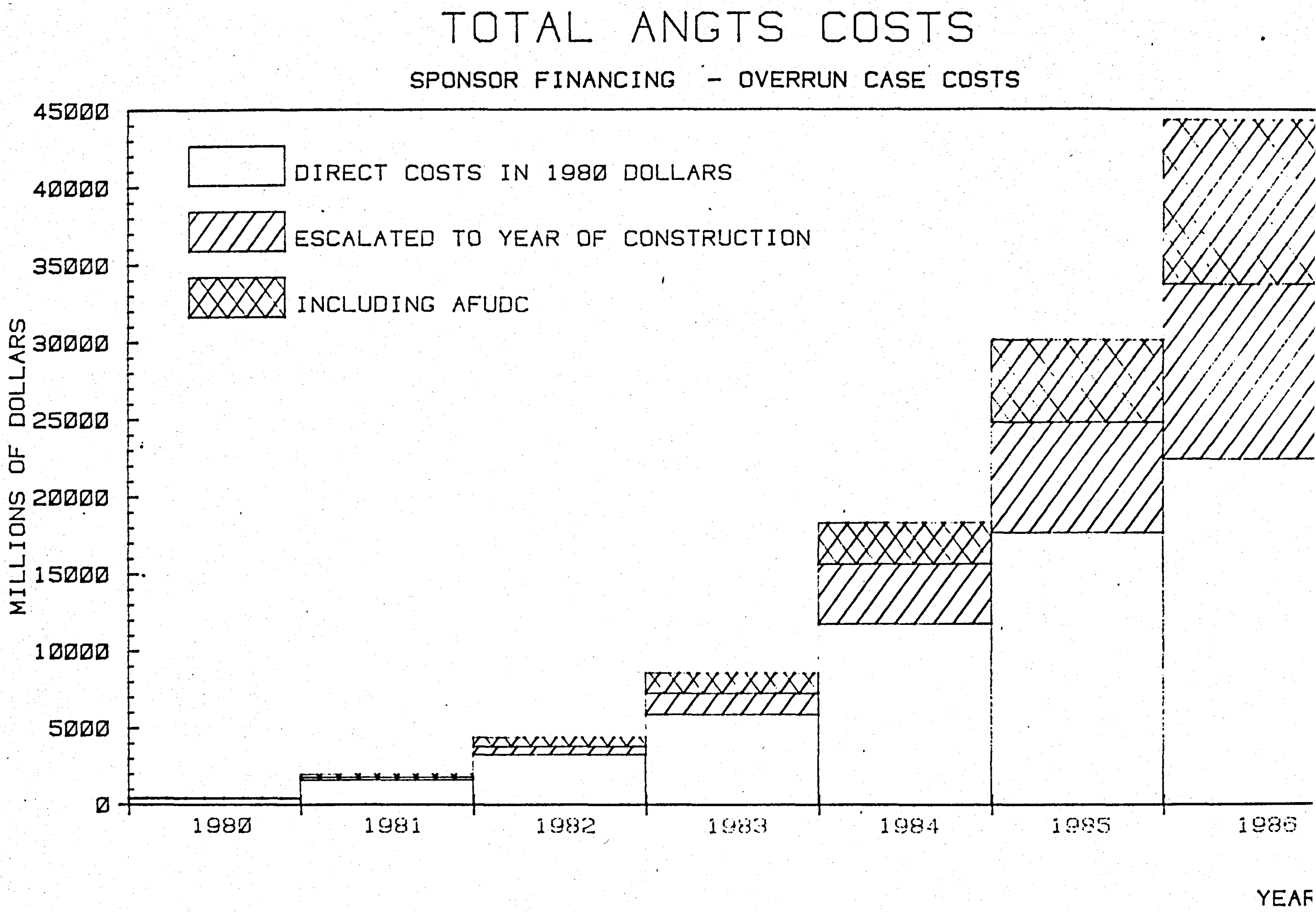
1980 DIRECT CAPITAL COSTS

EASTERN LEG

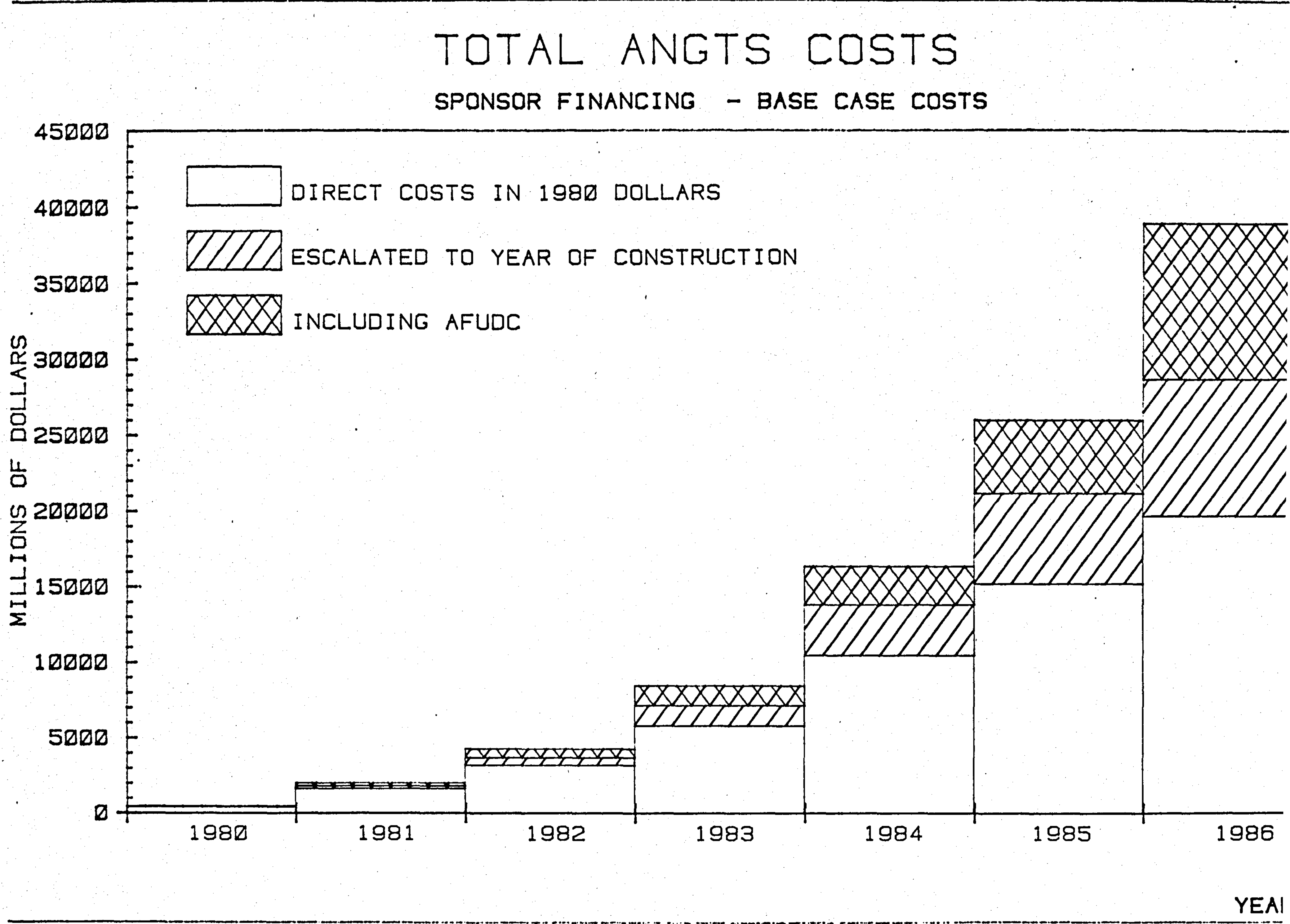




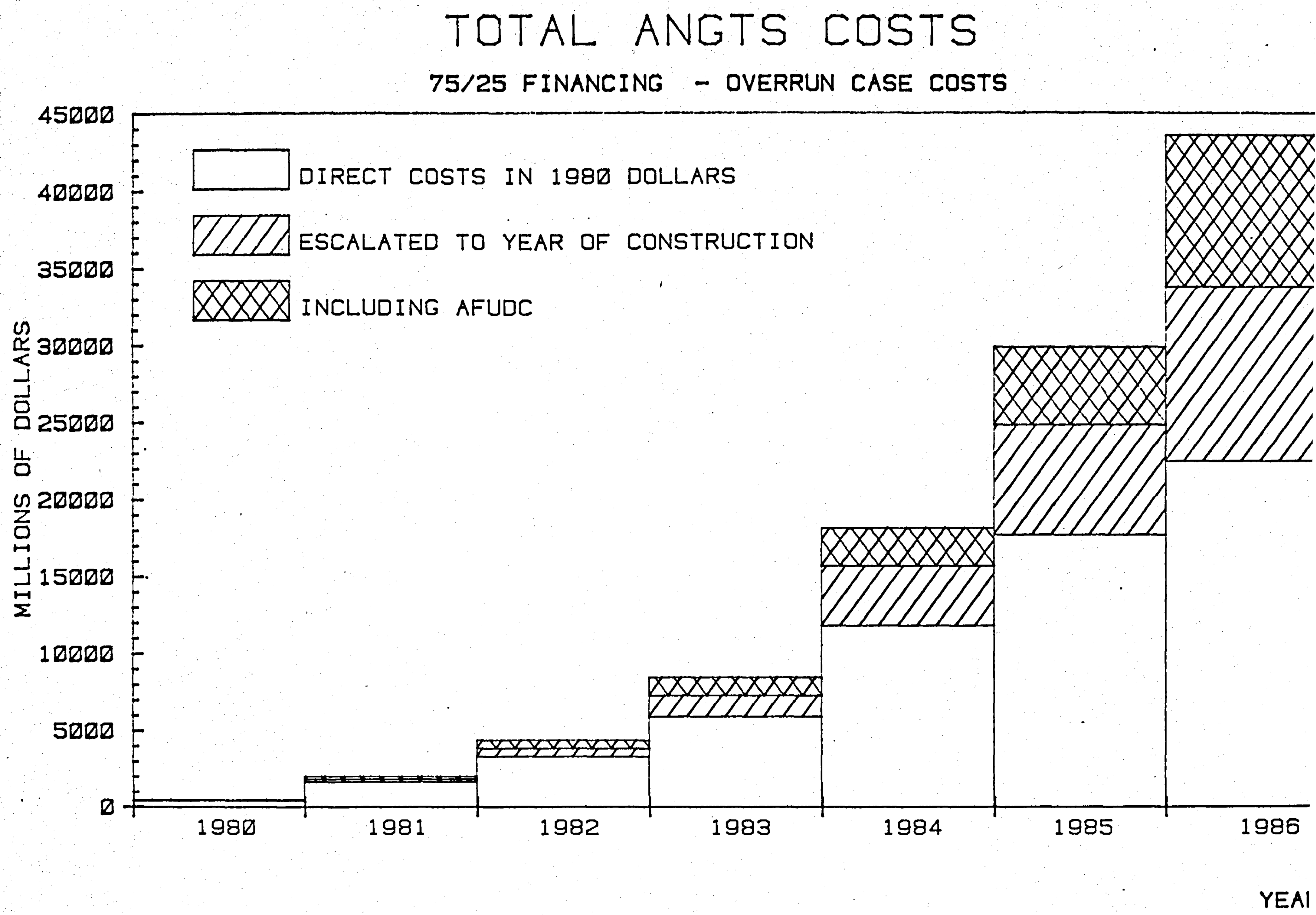
1980 DIRECT CAPITAL COSTS
WESTERN LEG
INCREMENTAL BASE COSTS
INCREMENTAL OVERRUN COSTS
CUMULATIVE BASE COSTS
CUMULATIVE OVERRUN COSTS
DIRECT CAPITAL COSTS - MILLIONS OF 1980$
1000
800
600
400
200
0
1980
1981
1982
1983
1984
1985
1986
YEARS

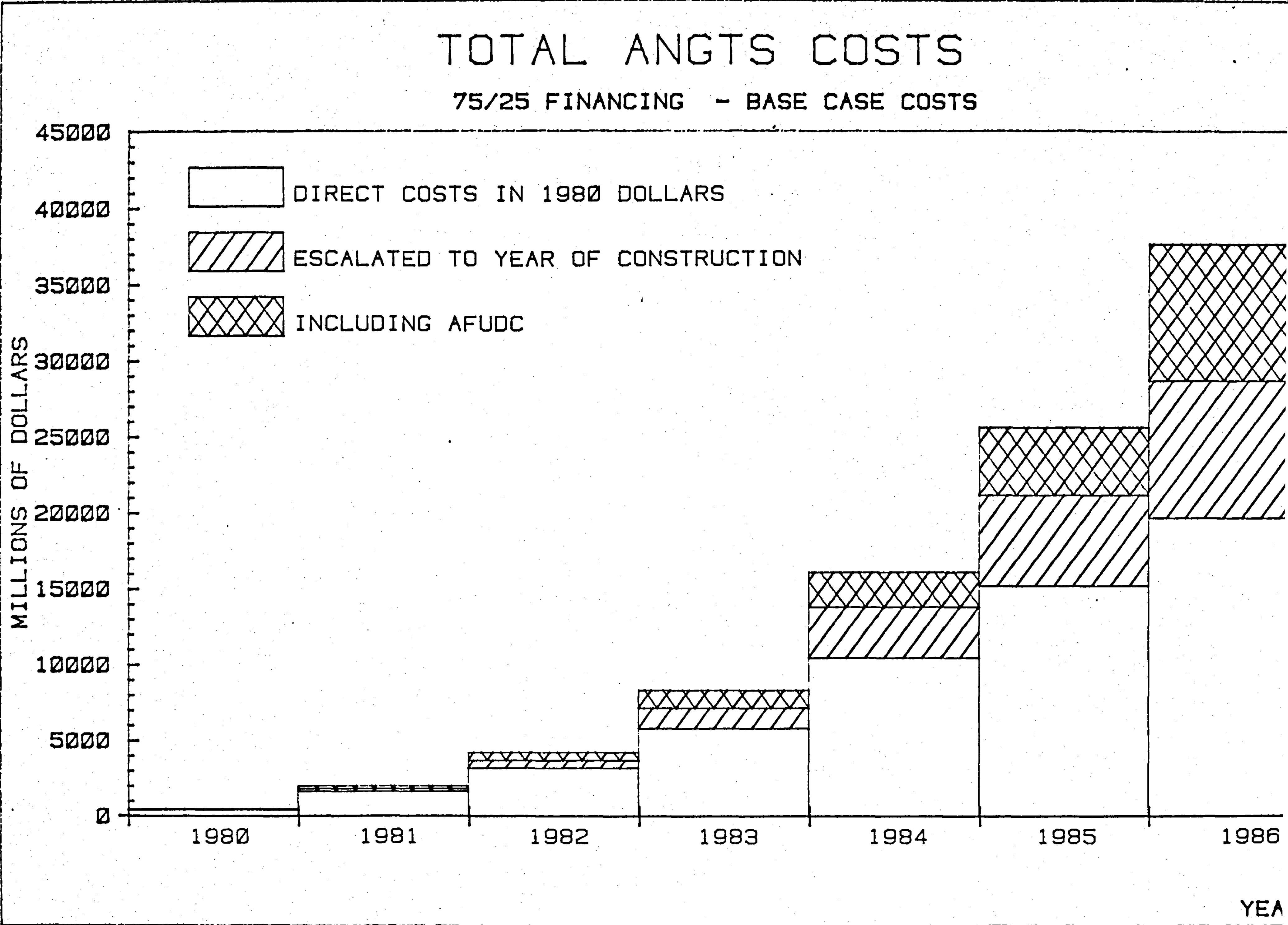


TOTAL ANGTS COSTS
SPONSOR FINANCING - OVERRUN CASE COSTS
DIRECT COSTS IN 1980 DOLLARS
ESCALATED TO YEAR OF CONSTRUCTION
INCLUDING AFUDC
MILLIONS OF DOLLARS
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
1980
1981
1982
1983
1984
1985
1986
YEAR



TOTAL ANGTS COSTS
SPONSOR FINANCING - BASE CASE COSTS
DIRECT COSTS IN 1980 DOLLARS
ESCALATED TO YEAR OF CONSTRUCTION
INCLUDING AFUDC
MILLIONS OF DOLLARS
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
1980
1981
1982
1983
1984
1985
1986
YEAI


TOTAL ANGTS COSTS
75/25 FINANCING - OVERRUN CASE COSTS
DIRECT COSTS IN 1980 DOLLARS
ESCALATED TO YEAR OF CONSTRUCTION
INCLUDING AFUDC
MILLIONS OF DOLLARS
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
1980
1981
1982
1983
1984
1985
1986
YEAI



TOTAL ANGTS COSTS
75/25 FINANCING - BASE CASE COSTS
DIRECT COSTS IN 1980 DOLLARS
ESCALATED TO YEAR OF CONSTRUCTION
INCLUDING AFUDC
MILLIONS OF DOLLARS
45000
40000
35000
30000
25000
20000
15000
10000
5000
0
1980
1981
1982
1983
1984
1985
1986
YEA

VI. Delivered Unit Costs

In addition to the capital cost analysis described in the previous section, and the resultant unit delivered costs, three wellhead pricing scenarios were also analyzed.

The first is based on the Natural Gas Policy Act of 1978 which results in a wellhead price of $1.97/mmbtu as of January 1, 1980. The second assumes that the wellhead price is equivalent to 100% of the 1981 world oil price ($5.13/mmbtu expressed in 1/1/80 dollars). The third assumes a wellhead price which is 70% of the equivalent 1981 world oil price ($3.59/mmbtu expressed in 1/1/80 dollars). All of these 1980 prices are projected through the life of the ANGTS project using an 8% escalation rate per year.

The following tables show the resultant first year unit delivered cost of gas to U.S. consumers in nominal and constant 1980 dollars, and the twenty year average in 1980 dollars. These values are shown for the three wellhead pricing scenarios, and for all the capital costs and the two financing scenarios described above.

Also included in this section are the following graphical presentations of these results:

- Comparison of gas with four projections of real oil prices

    VI-1 Sponsor financing in 1980 dollars
    VI-2 75/25 financing in 1980 dollars
    VI-3 Sponsor financing in nominal dollars
    VI-4 75/25 financing in nominal dollars

- Five capital cost scenarios

    VI-5 Sponsor financing in 1980 dollars
    VI-6 75/25 financing in 1980 dollars

- Comparison of three wellhead prices, assuming no real oil price growth

    VI-7 Sponsor financing in 1980 dollars
    VI-8 Sponsor financing in 1980 dollars

- First year and twenty year average costs as a function of capital costs

    VI-9 First year costs for both financing scenarios in nominal and 1980 dollars
    VI-10 Twenty year average costs for both financing scenarios

Sponsor Financing

Total Delivered Unit Costs
($/mmbtu)

	Current Filing w Center Pt. plus 10%	Current Filing with Center Pt.	Adjust. Adger/ Berman	Current Filing	President's Decision with Center Pt.	President's Decision March 1977
NGPA Wellhead Pricing						
First year nominal $	$17.07	$15.90	$15.18	$14.87	$ 8.86	$ 7.76
First year 1980 $	9.59	8.93	8.52	8.35	4.97	4.36
20 year ave 1980 $	4.90	4.67	4.53	4.49	3.31	3.08
70% Oil Equivalence Wellhead Pricing						
First year nominal $	$20.18	$19.00	$18.29	$17.97	$12.25	$11.15
First year 1980 $	11.33	10.67	10.27	10.09	6.88	6.26
20 year ave 1980 $	6.65	6.41	6.28	6.23	5.22	4.99
100% Oil Equivalence Wellhead Pricing						
First year nominal $	$23.12	$21.95	$21.23	$20.92	$15.31	$14.21
First year 1980 $	12.98	12.32	11.92	11.74	8.59	7.98
20 year ave 1980 $	8.30	8.07	7.93	7.88	6.93	6.70

Total Delivered Unit Costs
($/mmbtu)

	Current Filing w Center Pt. plus 10%	Current Filing with Center Pt.	Adjust. Adger/ Berman	Current Filing	President's Decision with Center Pt.	President's Decision March 1977
NGPA Wellhead Pricing						
First year nominal $	$16.13	$15.04	$14.32	$13.70	$ 8.72	$ 7.63
First year 1980 $	9.06	8.44	8.04	7.69	4.90	4.28
20 year ave 1980 $	4.69	4.48	4.34	4.23	3.28	3.05
70% Oil Equivalence Wellhead Pricing						
First year nominal $	$19.23	$18.14	$17.43	$16.80	$12.11	$11.02
First year 1980 $	10.80	10.19	9.79	9.44	6.80	6.19
20 year ave 1980 $	6.44	6.22	6.09	5.97	5.19	4.96
100% Oil Equivalence Wellhead Pricing						
First year nominal $	$22.18	$21.09	$20.37	$19.75	$15.18	$14.08
First year 1980 $	12.45	11.84	11.44	11.09	8.52	7.90
20 year ave 1980 $	8.09	7.88	7.74	8.62	6.91	6.68

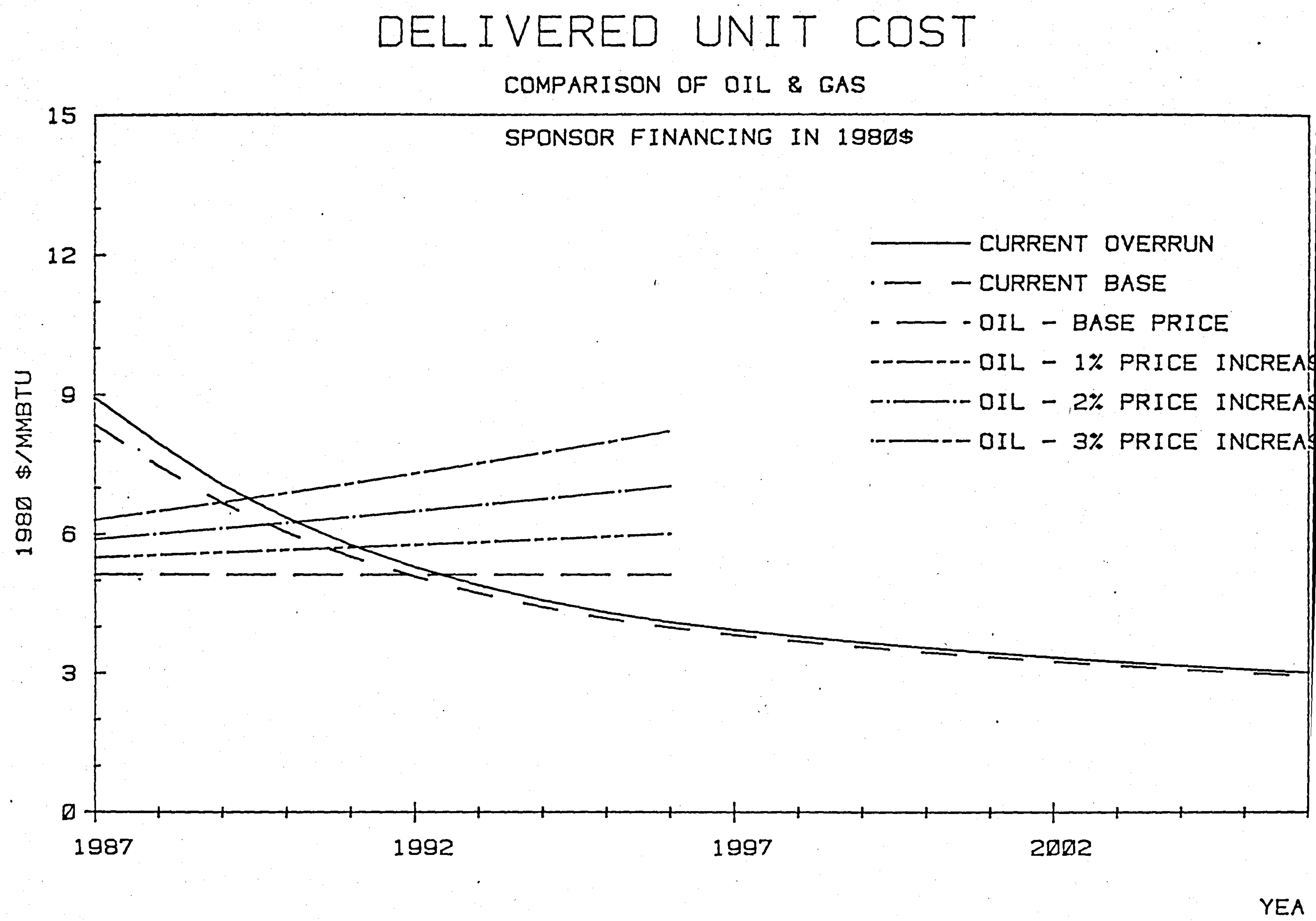
Total Delivered Unit Costs
($/mmbtu)

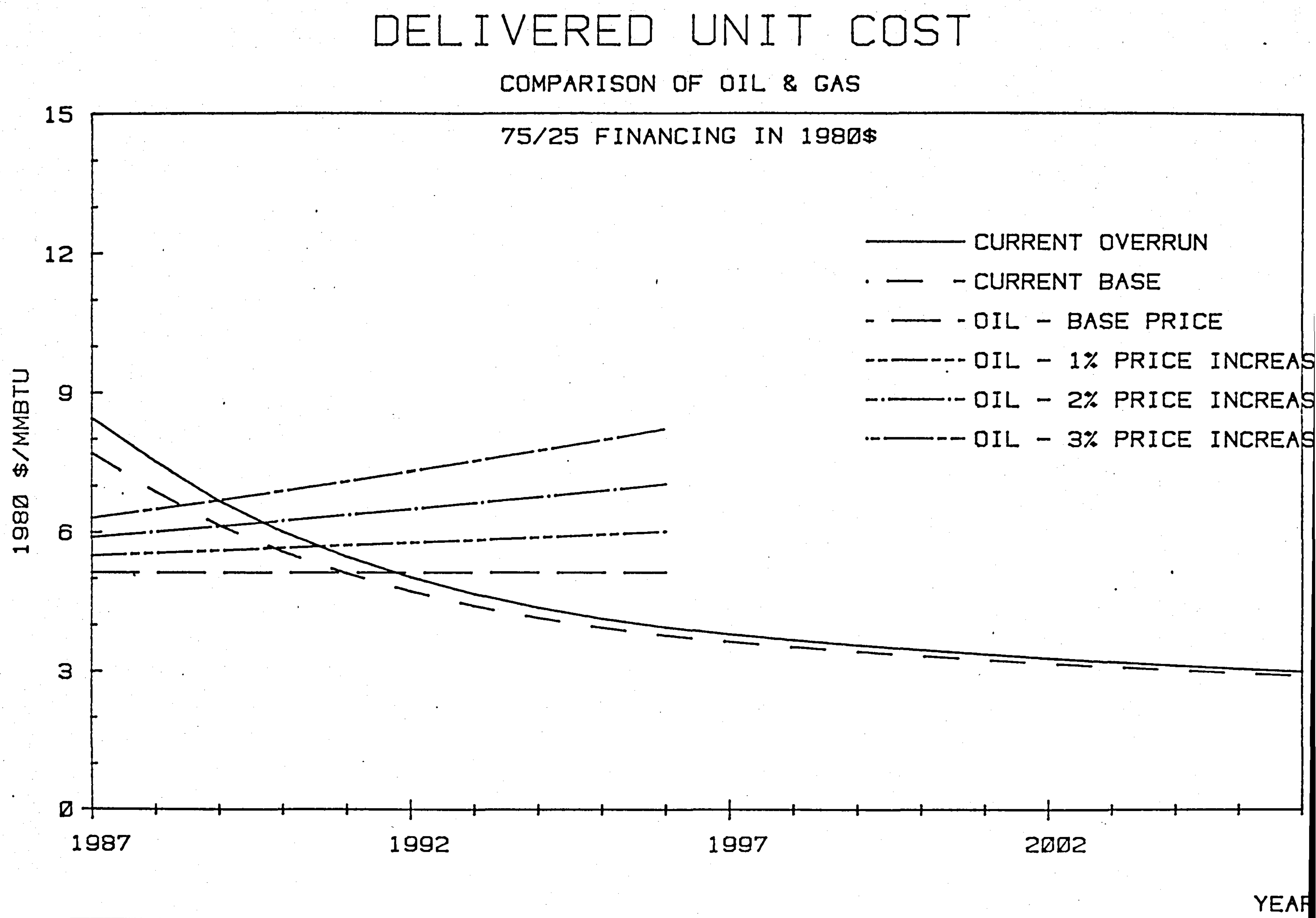
Percent Overrun or Underrun of Current Filing	-20%	-10%	40%	50%	-50%	80%	120%	160%
NGPA Wellhead Pricing								
First year nominal $	13.16	13.85	18.09	18.92	10.47	21.58	24.92	28.24
First year 1980 $	7.39	7.77	10.16	10.62	5.88	12.12	13.99	15.86
20 year average 1980 $	4.16	4.29	5.12	5.28	3.63	5.80	6.45	7.09
70% Oil Equivalence Wellhead Pricing								
First year nominal $	16.27	16.95	21.19	22.03	13.58	24.69	28.02	31.35
First year 1980 $	9.13	9.52	11.90	12.37	7.62	13.86	15.73	17.60
20 year average 1980 $	5.90	6.03	6.86	7.02	5.37	7.54	8.19	8.84
100% Oil Equivalence Wellhead Pricing								
First year nominal $	19.21	19.90	24.14	24.97	16.52	27.63	30.97	34.29
First year 1980 $	10.79	11.17	13.55	14.02	9.28	15.51	17.39	19.25
20 year average 1980 $	7.56	7.69	8.51	8.67	7.02	9.19	9.84	10.49

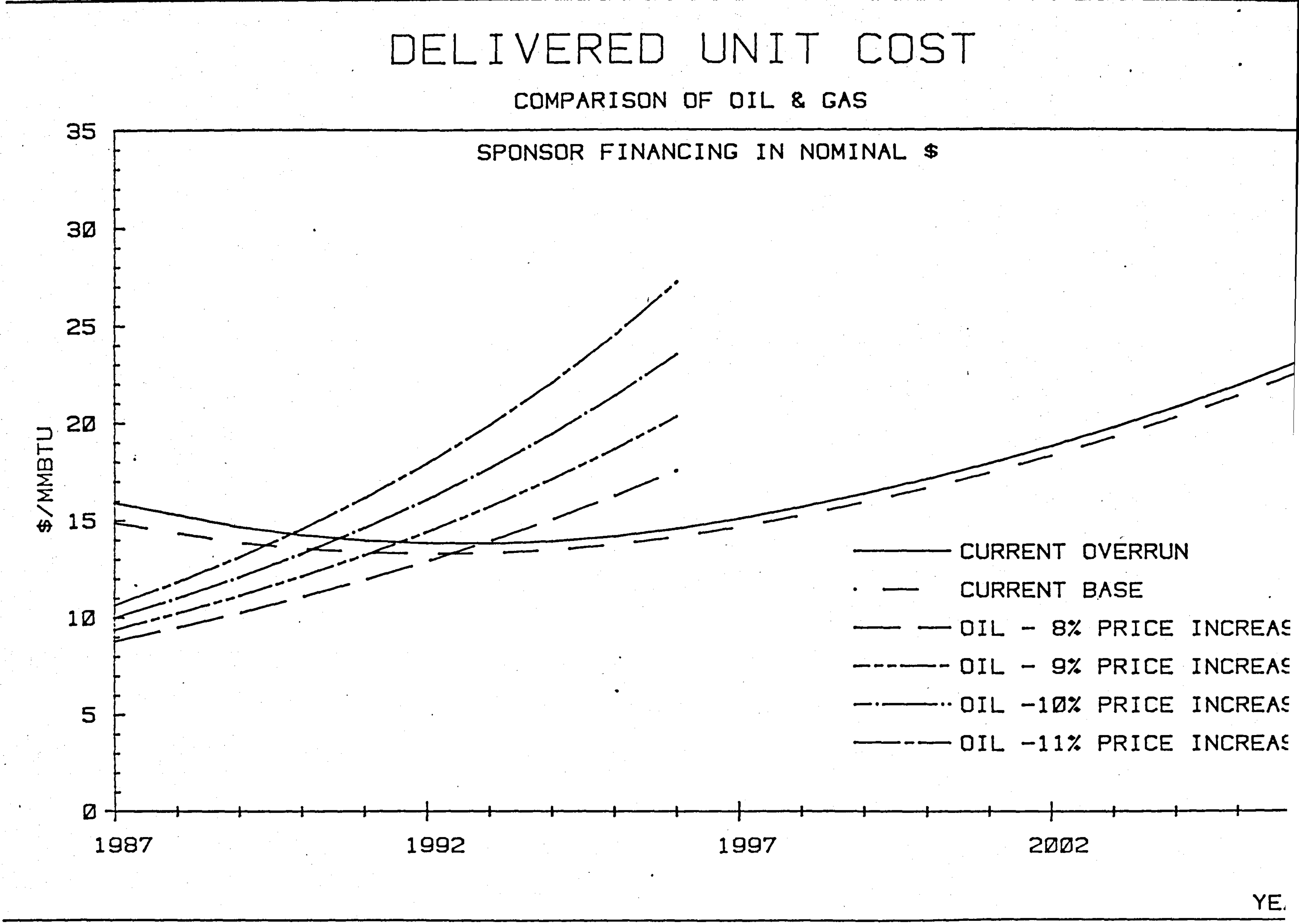
75/25 Financing

Total Delivered Unit Costs
($/mmbtu)

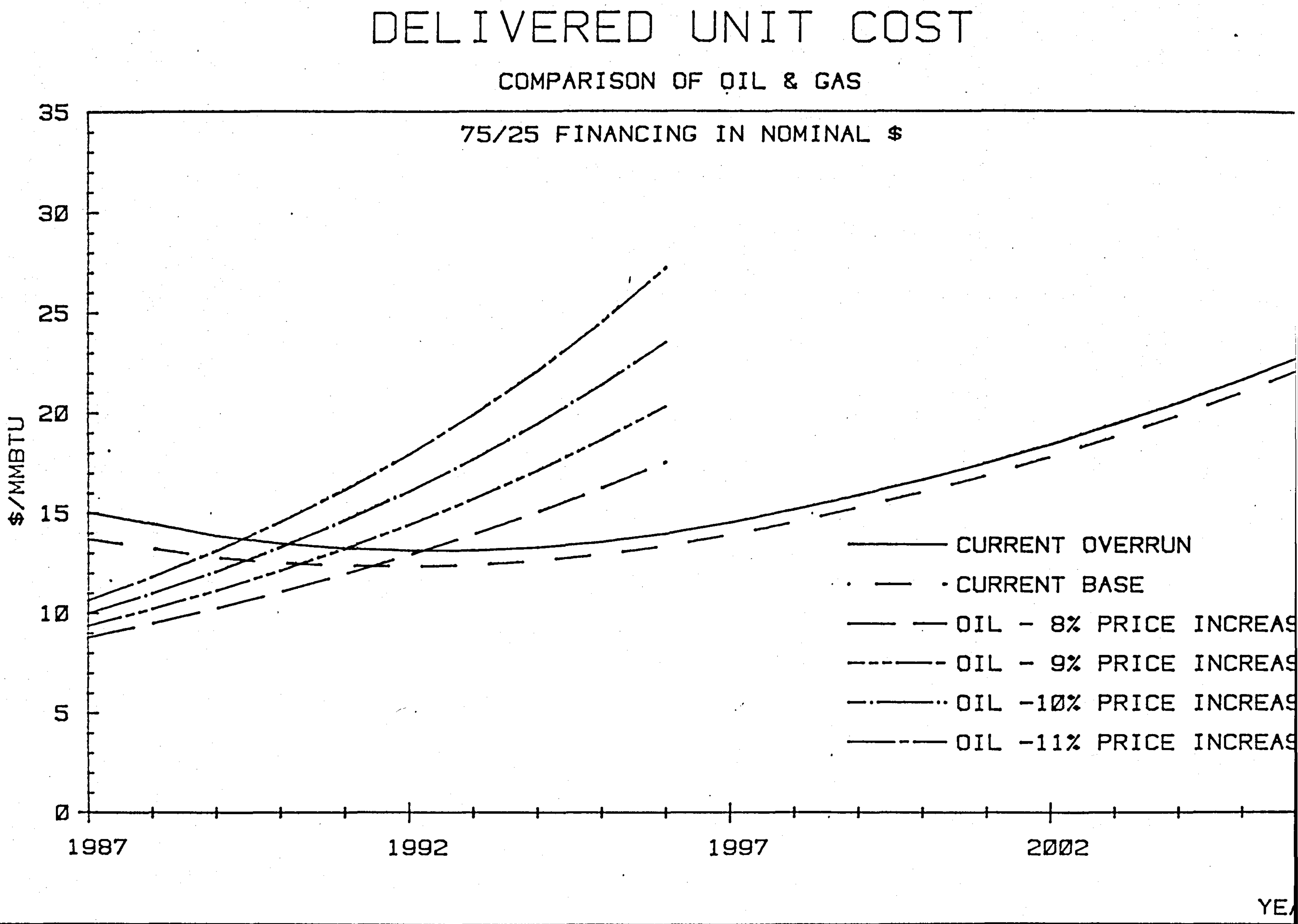
Percent Overrun or Underrun of Current Filing	-20%	-10%	40%	50%	-50%	80%	120%	160%
NGPA Wellhead Pricing								
First year nominal $	12.08	12.71	16.73	17.51	9.61	20.01	23.09	26.30
First year 1980 $	6.78	7.14	9.39	9.83	5.40	11.24	12.96	14.77
20 year average 1980 $	3.91	4.04	4.82	4.97	3.43	5.45	6.05	6.68
70% Oil Equivalence Wellhead Pricing								
First year nominal $	15.18	15.82	19.83	20.62	12.72	23.12	26.20	29.40
First year 1980 $	8.53	8.88	11.14	11.58	7.14	12.98	14.71	16.51
20 year average 1980 $	5.66	5.78	6.56	6.71	5.18	7.20	7.80	8.42
100% Oil Equivalence Wellhead Pricing								
First year nominal $	18.13	18.76	22.78	23.56	15.66	26.06	29.14	32.35
First year 1980 $	10.18	10.54	12.79	13.23	8.79	14.63	16.36	18.16
20 year average 1980 $	7.31	7.43	8.21	8.37	6.83	8.85	9.45	10.07


DELIVERED UNIT COST
COMPARISON OF OIL & GAS
SPONSOR FINANCING IN 1980$
15
12
9
6
3
0
1980 $/MMBTU
1987
1992
1997
2002
YEA
CURRENT OVERRUN
CURRENT BASE
OIL - BASE PRICE
OIL - 1% PRICE INCREAS
OIL - 2% PRICE INCREAS
OIL - 3% PRICE INCREAS


DELIVERED UNIT COST
COMPARISON OF OIL & GAS
75/25 FINANCING IN 1980$
CURRENT OVERRUN
CURRENT BASE
OIL - BASE PRICE
OIL - 1% PRICE INCREAS
OIL - 2% PRICE INCREAS
OIL - 3% PRICE INCREAS
1980 $/MMBTU
15
12
9
6
3
0
1987
1992
1997
2002
YEAR



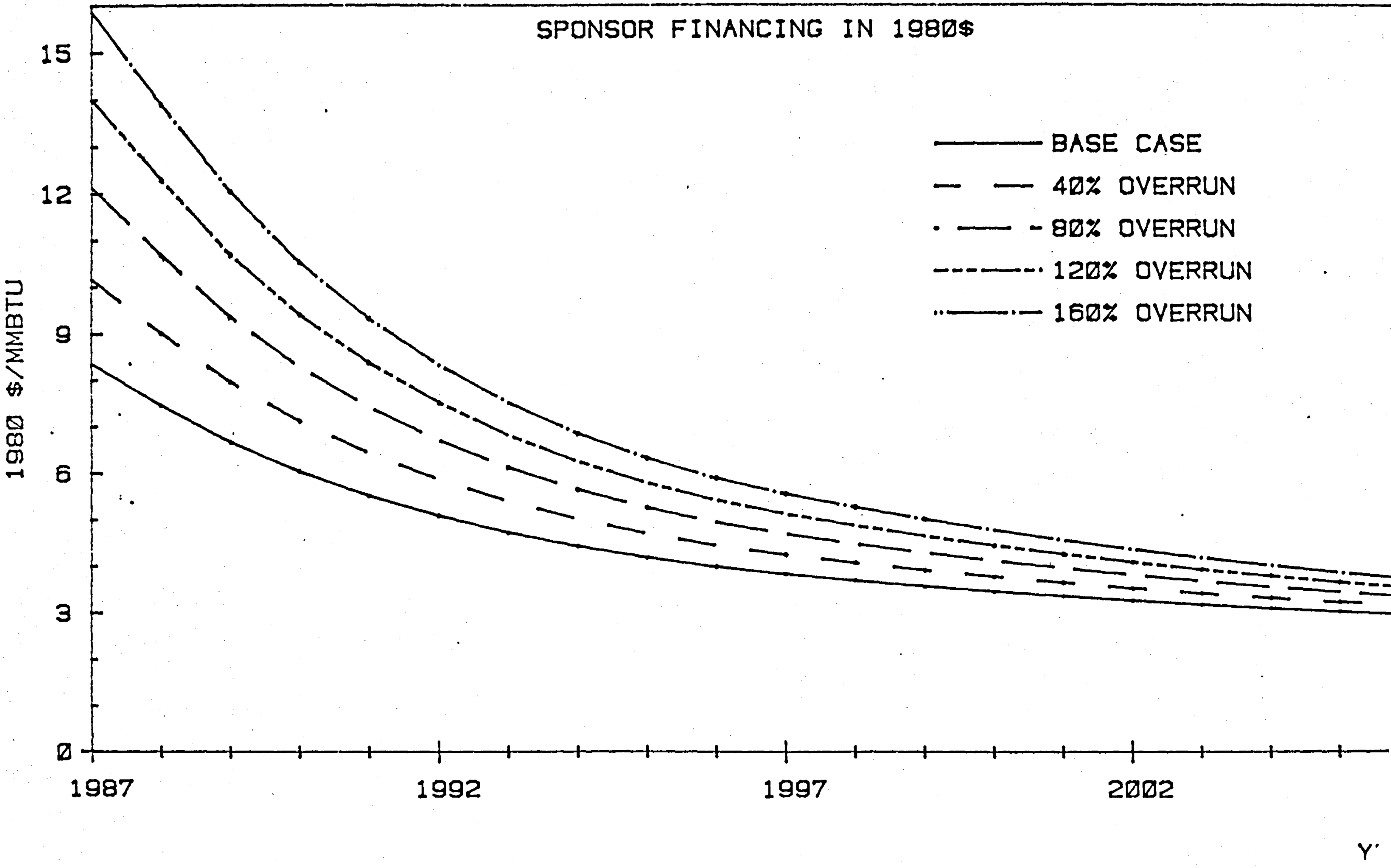
DELIVERED UNIT COST
COMPARISON OF OIL & GAS
SPONSOR FINANCING IN NOMINAL $
$/MMBTU
35
30
25
20
15
10
5
0
1987
1992
1997
2002
YE.
CURRENT OVERRUN
CURRENT BASE
OIL - 8% PRICE INCREAS
OIL - 9% PRICE INCREAS
OIL -10% PRICE INCREAS
OIL -11% PRICE INCREAS

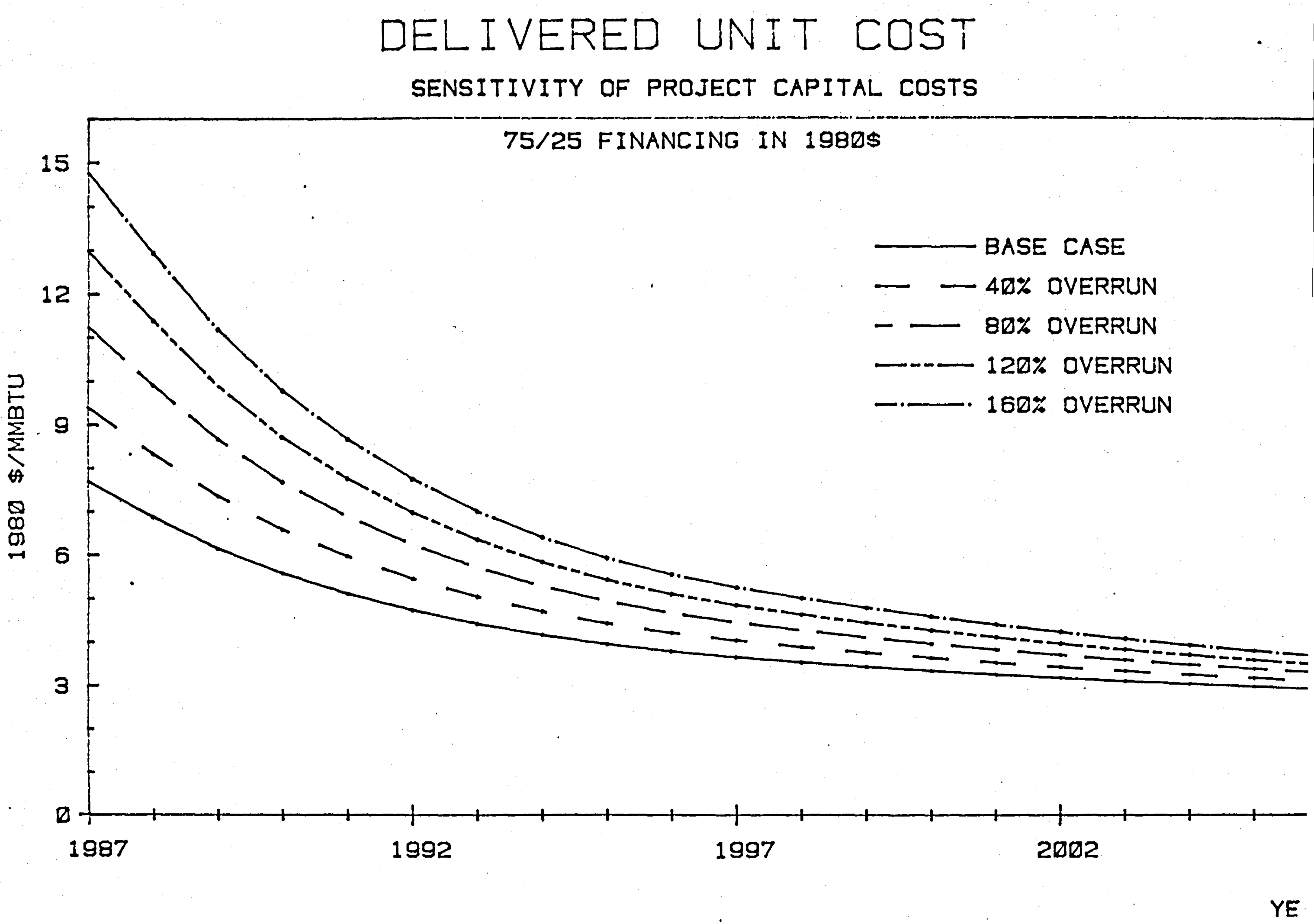


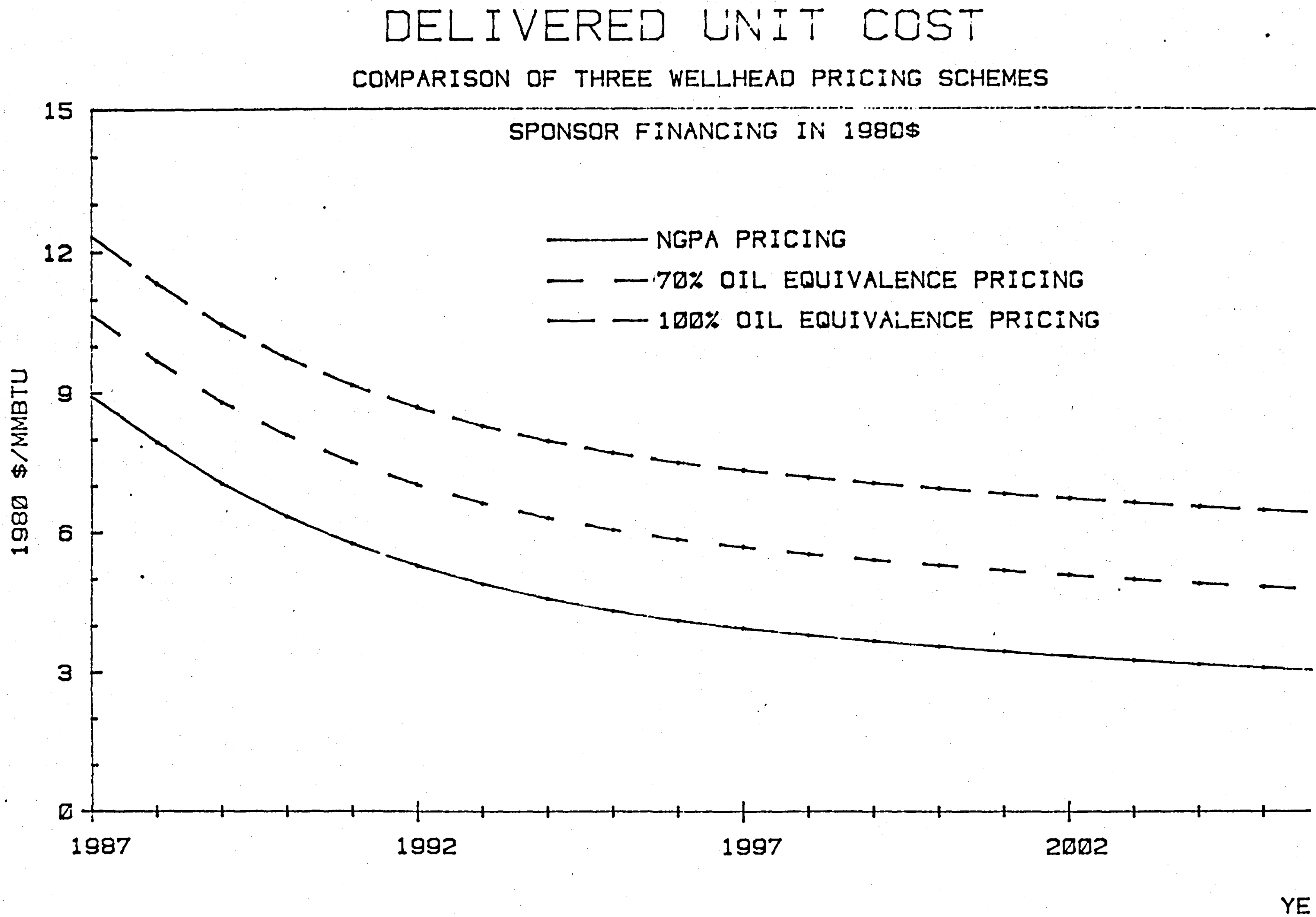
DELIVERED UNIT COST
COMPARISON OF OIL & GAS
75/25 FINANCING IN NOMINAL $
$/MMBTU
35
30
25
20
15
10
5
0
1987
1992
1997
2002
YE
CURRENT OVERRUN
CURRENT BASE
OIL - 8% PRICE INCREAS
OIL - 9% PRICE INCREAS
OIL -10% PRICE INCREAS
OIL -11% PRICE INCREAS

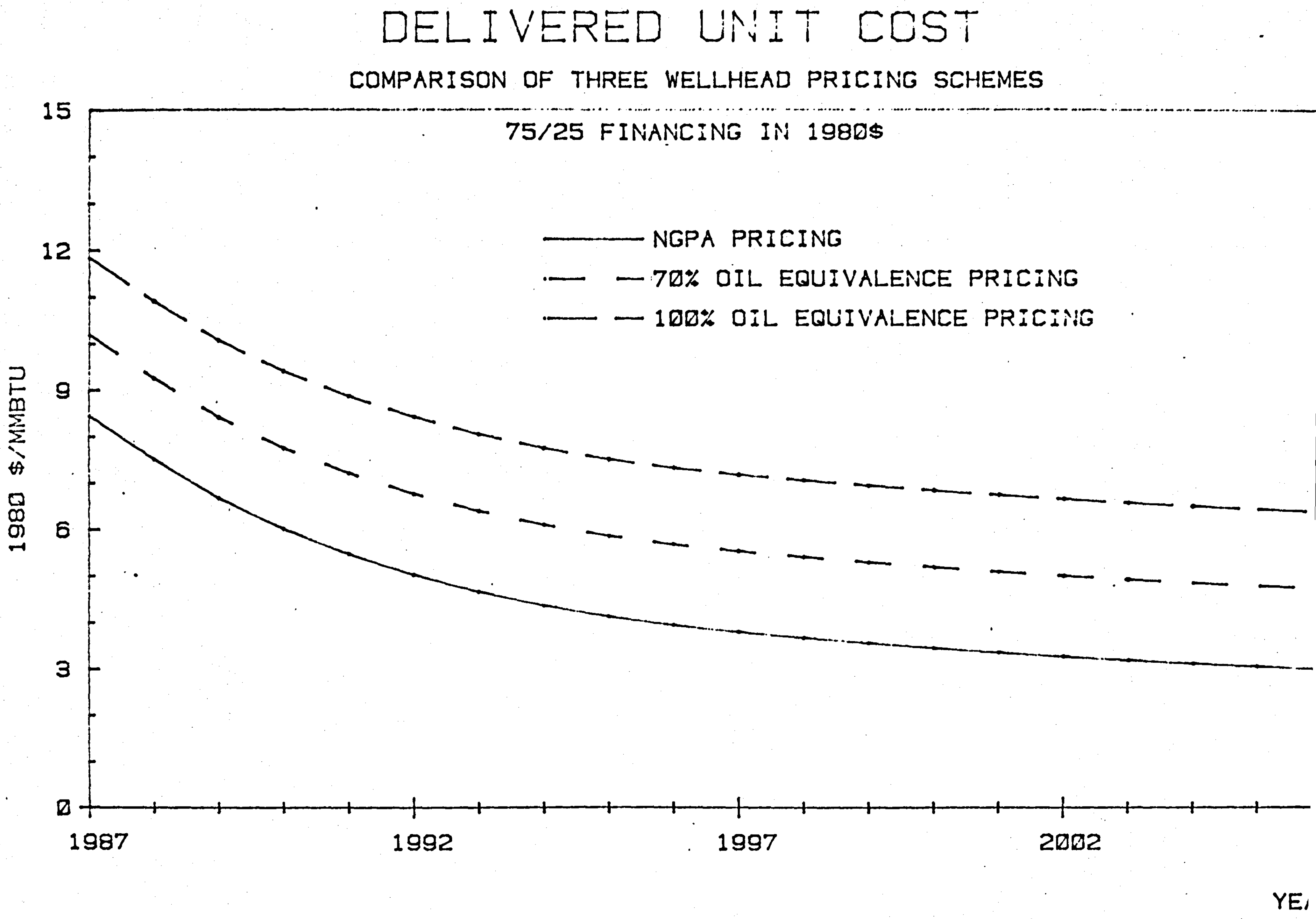
DELIVERED UNIT COST

SENSITIVITY OF PROJECT CAPITAL COSTS



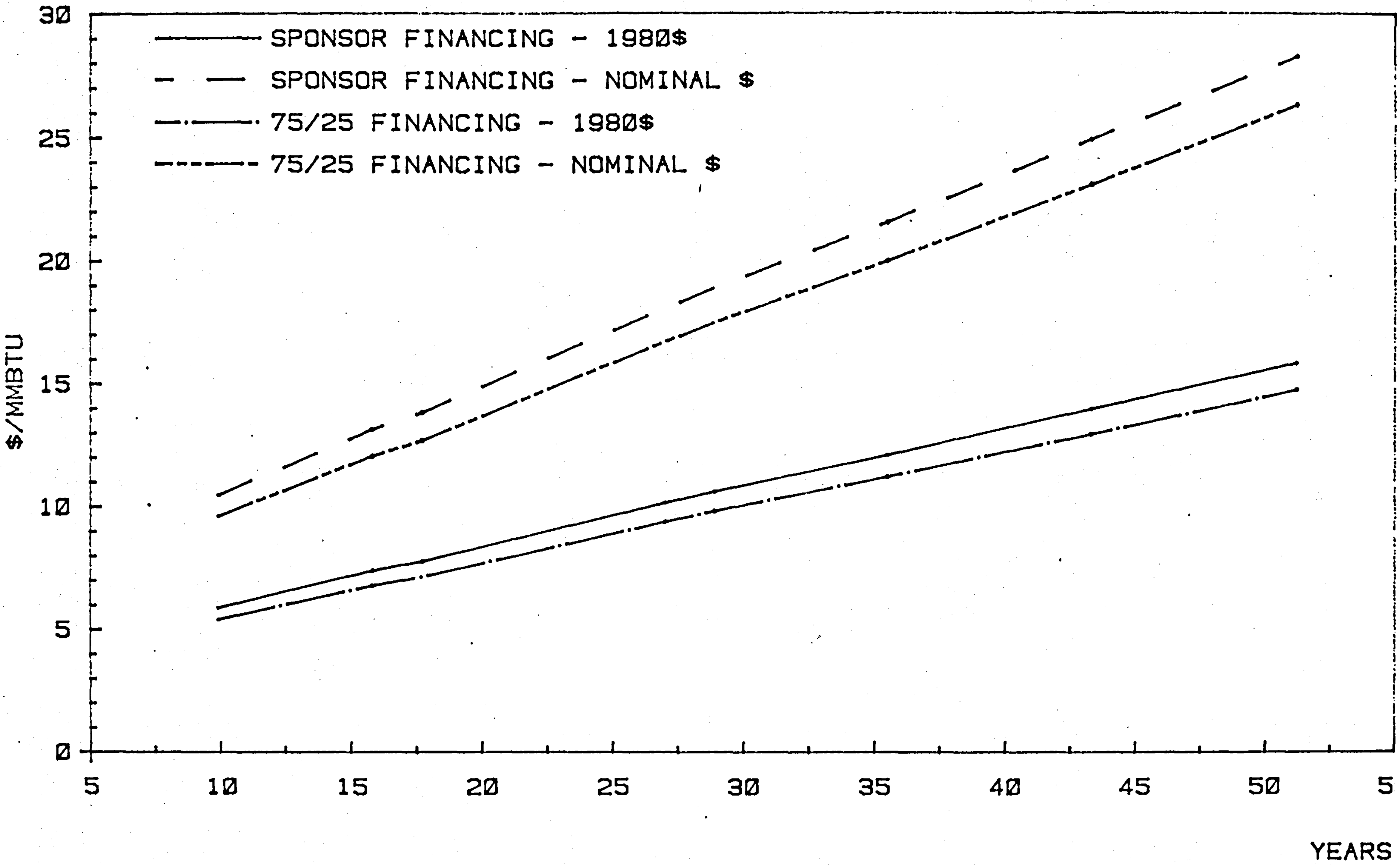

DELIVERED UNIT COST
SENSITIVITY OF PROJECT CAPITAL COSTS
75/25 FINANCING IN 1980$
BASE CASE
40% OVERRUN
80% OVERRUN
120% OVERRUN
160% OVERRUN
1980 $/MMBTU
15
12
9
6
3
0
1987
1992
1997
2002
YE


DELIVERED UNIT COST
COMPARISON OF THREE WELLHEAD PRICING SCHEMES
SPONSOR FINANCING IN 1980$
NGPA PRICING
70% OIL EQUIVALENCE PRICING
100% OIL EQUIVALENCE PRICING
1980 $/MMBTU
15
12
9
6
3
0
1987
1992
1997
2002
YE

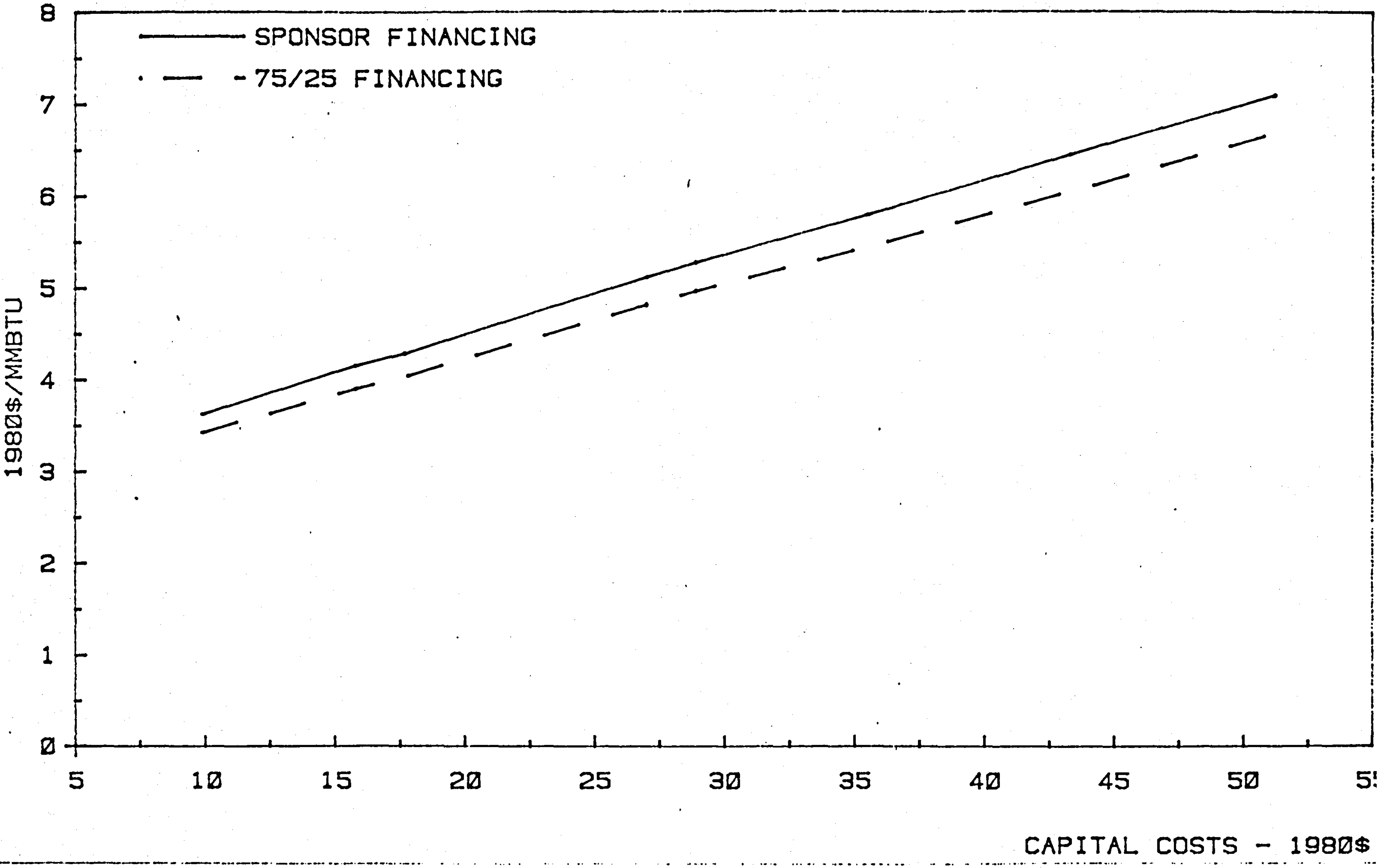


DELIVERED UNIT COST
COMPARISON OF THREE WELLHEAD PRICING SCHEMES
75/25 FINANCING IN 1980$
NGPA PRICING
70% OIL EQUIVALENCE PRICING
100% OIL EQUIVALENCE PRICING
1980 $/MMBTU
15
12
9
6
3
0
1987
1992
1997
2002

ANGTS FIRST YEAR COSTS



TWENTY YEAR AVERAGE COST



VII. Profitability Analysis

During the construction of the ANGTS, project sponsors will be investing equity money while borrowing debt money from lending institutions to finance the direct construction costs of the project. During the operation of the pipeline, the sponsors will be allowed to earn a rate of return on their investment. The cost of service model generates these cash flows, both into and out the project, which can be analyzed under different assumptions.

By analyzing the cash flows generated by the model, the internal rate of return for the project can be calculated. This is determined by finding the discount rate which makes the net present value of the cash flow, both in and out of the project, equal to zero.

This parameter, however, does not capture the magnitude of the return received by project sponsors. Therefore, another parameter is calculated which shows the magnitude of additional return received by a sponsor over and above a 19% discount rate, which is the multiplicative combination of a 10% real rate of return with 8% inflation.

Both the internal rate of return and net present value calculations are performed for both the project sponsors for the conditioning plant and Alaska pipeline, and the producers who intend to share ownership of the two Alaskan segments, in addition to receiving cash flow from gas sales. It is assumed that there are no costs associated with producing the gas. Cash flow to producers generated by gas sales are converted to an after tax return based on the three assumptions about wellhead pricing discussed in Section VI.

Also, these parameters are calculated assuming that the producers own either 30% (according the May, 1981 financing agreement) or 100% of the Alaskan pipeline and conditioning plant.

The following tables present these parameters for the two financing scenarios and all the capital cost scenarios described in Section V.

After the tables of results, a graph shows how the rates of return decrease as project capital costs increase. This is due to the operation of the Incentive Rate of Return mechanism for project sponsors. For producers, this mechanism also operates on their share of ownership in the project, but more importantly, as the producers invest more capital in the project, their combined rate of return decreases when mixed in with the "infinite" rate of return associated with the "free" gas.

Profitability Analysis

	Current Filing w Center Pt. plus 10%	Current Filing with Center Pt.	Adjust. Adger/ Berman	Current Filing	President's Decision with Center Pt.	President's Decision March 1977
Internal Rate of Return (nominal %)						
Alaska Sponsors	25.0	25.0	24.6	25.1	25.0	26.2
Producers:						
30% Equity owned NGPA wellhead	46.8	48.0	48.5	48.2	72.8	74.8
30% Equity owned 70% oil wellhead	57.8	59.4	60.2	59.6	92.8	94.9
30% Equity owned 100% oil wellhead	64.3	66.2	67.0	66.4	104.0	106.2
100% Equity owned NGPA wellhead	34.9	35.6	35.7	35.6	49.1	50.8
100% Equity owned 70% oil wellhead	41.3	42.3	42.7	42.4	62.2	64.1
100% Equity owned 100% oil wellhead	45.3	46.5	47.0	46.7	70.1	72.1

75/25 Financing

Profitability Analysis

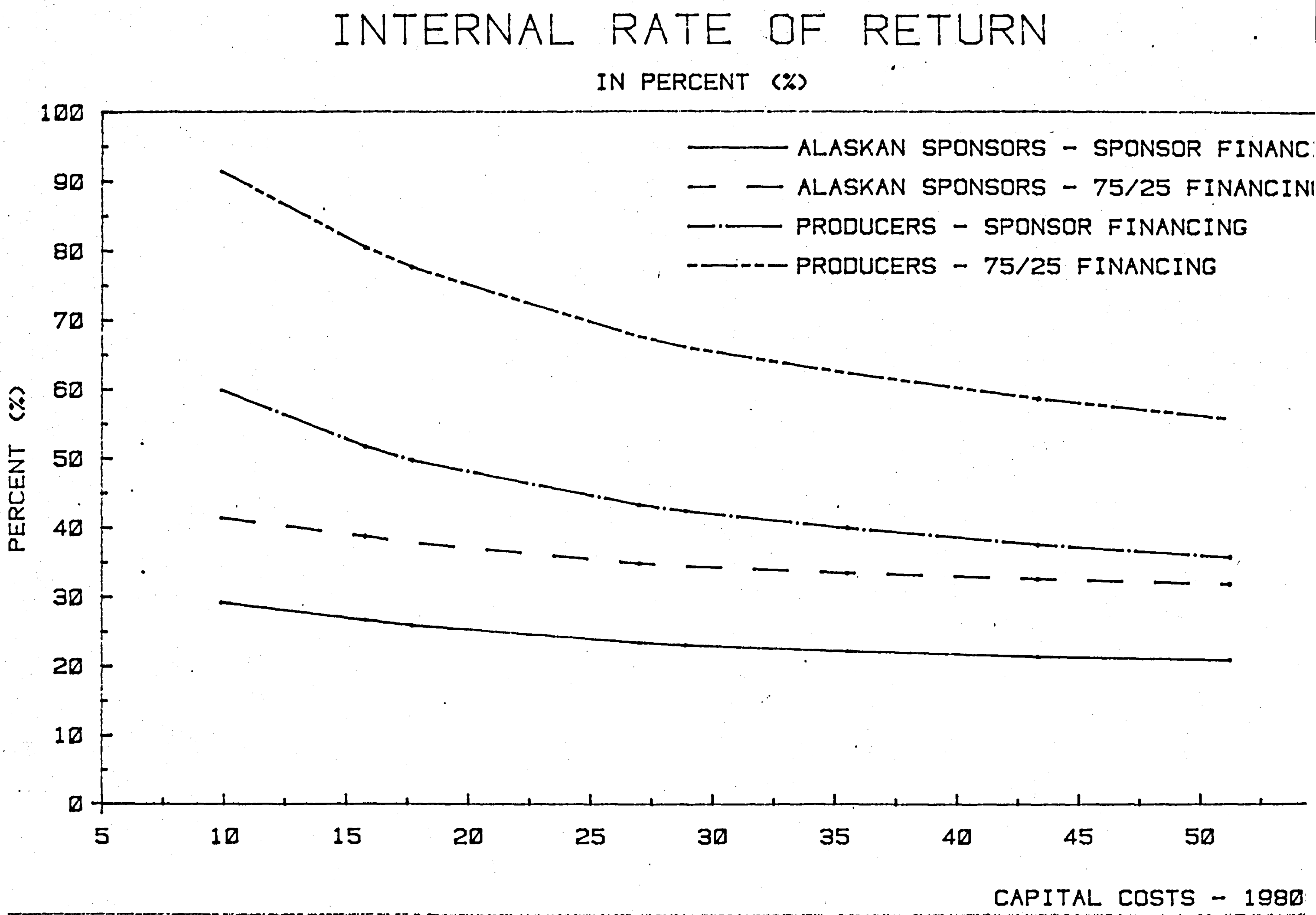
	Current Filing w Center Pt. plus 10%	Current Filing with Center Pt.	Adjust. Adger/ Berman	Current Filing	75/25 Financing: President's Decision with Center Pt.	75/25 Financing: President's Decision March 1977
Alaska Sponsors	35.9	35.9	35.6	36.9	26.8	27.9
Producers:						
30% Equity owned NGPA wellhead	70.5	72.5	73.9	75.1	79.8	81.2
30% Equity owned 70% oil wellhead	88.2	90.7	92.4	93.5	100.9	102.2
30% Equity owned 100% oil wellhead	98.4	101.3	103.9	104.0	112.5	113.9
100% Equity owned NGPA wellhead	51.4	5256	53.3	54.6	54.1	55.5
100% Equity owned 70% oil wellhead	61.7	63.4	64.5	65.8	68.7	70.1
100% Equity owned 100% oil wellhead	68.3	70.2	71.6	72.8	77.3	78.8

Profitability Analysis

Percent Overrun or Underrun of Current Filing	-20%	-10%	40%	50%	-50%	80%	120%	160%
Alaska Sponsors	26.7	25.9	23.4	23.0	29.2	22.2	21.4	20.9
Producers:								
30% Equity owned NGPA wellhead	51.8	49.8	43.3	42.4	59.9	40.0	37.6	35.8
30% Equity owned 70% oil wellhead	64.1	61.7	53.6	52.4	74.1	49.4	46.4	44.0
30% Equity owned 100% oil wellhead	71.3	68.7	59.7	58.4	82.2	55.1	51.6	49.0
100% Equity owned NGPA wellhead	38.2	36.8	32.3	31.7	43.7	30.1	28.6	27.4
100% Equity owned 70% oil wellhead	45.6	43.9	38.2	37.4	52.6	35.4	33.4	31.9
100% Equity owned 100% oil wellhead	50.2	48.3	42.0	41.1	58.0	38.8	36.5	34.8

Profitability Analysis

Percent Overrun or Underrun of Current Filing	-20%	-10%	40%	50%	-50%	80%	120%	160%
Alaska Sponsors	38.8	37.9	34.8	34.4	41.4	33.5	32.6	31.9
Producers:								
30% Equity owned NGPA wellhead	80.5	77.7	67.6	66.1	91.4	62.4	58.7	55.8
30% Equity owned 70% oil wellhead	99.9	96.5	84.2	82.3	112.4	77.7	72.9	69.1
30% Equity owned 100% oil wellhead	110.8	107.2	93.8	91.8	123.9	86.7	81.3	77.1
100% Equity owned NGPA wellhead	58.5	56.4	49.5	48.6	67.1	46.2	43.9	42.1
100% Equity owned 70% oil wellhead	70.7	68.1	59.3	58.0	81.7	54.9	51.8	49.4
100% Equity owned 100% oil wellhead	78.2	75.3	65.4	64.0	90.5	60.5	56.9	54.1



INTERNAL RATE OF RETURN
IN PERCENT (%)
ALASKAN SPONSORS - SPONSOR FINANC
ALASKAN SPONSORS - 75/25 FINANCIN
PRODUCERS - SPONSOR FINANCING
PRODUCERS - 75/25 FINANCING
PERCENT (%)
100
90
80
70
60
50
40
30
20
10
0
5
10
15
20
25
30
35
40
45
50
CAPITAL COSTS - 1980

VIII. Consumer Indifference

The ANGTS tariff declines over time because of the decreasing rate base due to the depreciation of the facilities. This means that in 1980 dollars, the unit delivered cost of Alaskan gas begins high and decreases during the operating life of the project. This declining cost is difficult to compare with alternative energy sources which are expected to increase over time.

Therefore, a methodology was developed which attempts to equate the declining cost of Alaskan gas with the projected increasing cost of world oil. This method tries to find the real oil price escalation rate that has an equivalent present value cost to consumers as the present value of the ANGTS gas. At this oil price growth rate, consumers would be "indifferent" between oil and gas, assuming that a consumer can easily switch from one fuel to the other.

If a series of these indifference points were determined, under varying assumptions about ANGTS direct capital costs, a curve would result which indicates how oil growth rates compare with assumptions about ANGTS capital costs. Multiple curves can also be developed depending on assumptions about the btu-equivalent value of gas, and what is the correct real discount rate to use to determine present values.

The following tables present the results from this methodology for both financing scenarios, all the capital cost assumptions, and two real discount rates.

Two graphs (VIII-1 and VIII-2) are included which present the indifference curves using the two financing scenarios described in Section V. On each graph, two curves are drawn which result from discount rates of 5% and 10%. For these graphs, 70% equivalence between oil and gas is assumed.

Also included are two graphs (VIII-3 and VIII-4) which show the declining ANGTS cost and the increasing oil price curves in 1980 dollars which are equivalent at 70% parity and assuming a 5% discount rate.

	Consumer Indifference Values				Sponsor Financing	
	Current Filing w Center Pt. plus 10%	Current Filing with Center Pt.	Adjust. Adger/ Berman	Current Filing	President's Decision with Center Pt.	President's Decision March 1977
NGPA Wellhead Pricing						
ANGTS 1980 $ Unit Costs						
Present Value at 5%	48.96	46.42	44.94	44.44	31.79	29.34
at 10%	26.89	25.41	24.54	24.24	16.88	15.47
Real Oil Escalation Equivalent to ANGTS PV						
- 5% discount rate	2.61	2.27	2.06	1.99	-0.16	-0.68
- 10% discount rate	3.45	3.06	2.82	2.73	0.18	-0.44
70% Equivalent of World Oil Wellhead Pricing						
ANGTS 1980 $ Unit Costs						
Present Value at 5%	64.78	62.25	60.77	60.26	49.08	46.63
at 10%	34.88	33.40	32.53	32.23	25.61	24.19
Real Oil Escalation Equivalent to ANGTS PV						
- 5% discount rate	4.47	4.11	3.96	3.91	2.62	2.30
- 10% discount rate	5.22	4.93	4.75	4.69	3.11	2.71
100% Equivalent of World Oil Wellhead Pricing						
ANGTS 1980 $ Unit Costs						
Present Value at 5%	79.78	77.25	75.77	75.26	64.66	62.21
at 10%	42.45	40.97	40.11	39.81	33.48	32.06
Real Oil Escalation Equivalent to ANGTS PV						
- 5% discount rate	5.65	5.45	5.33	5.29	4.35	4.11
- 10% discount rate	6.51	6.31	6.17	6.11	4.95	4.65

Consumer Indifference Values

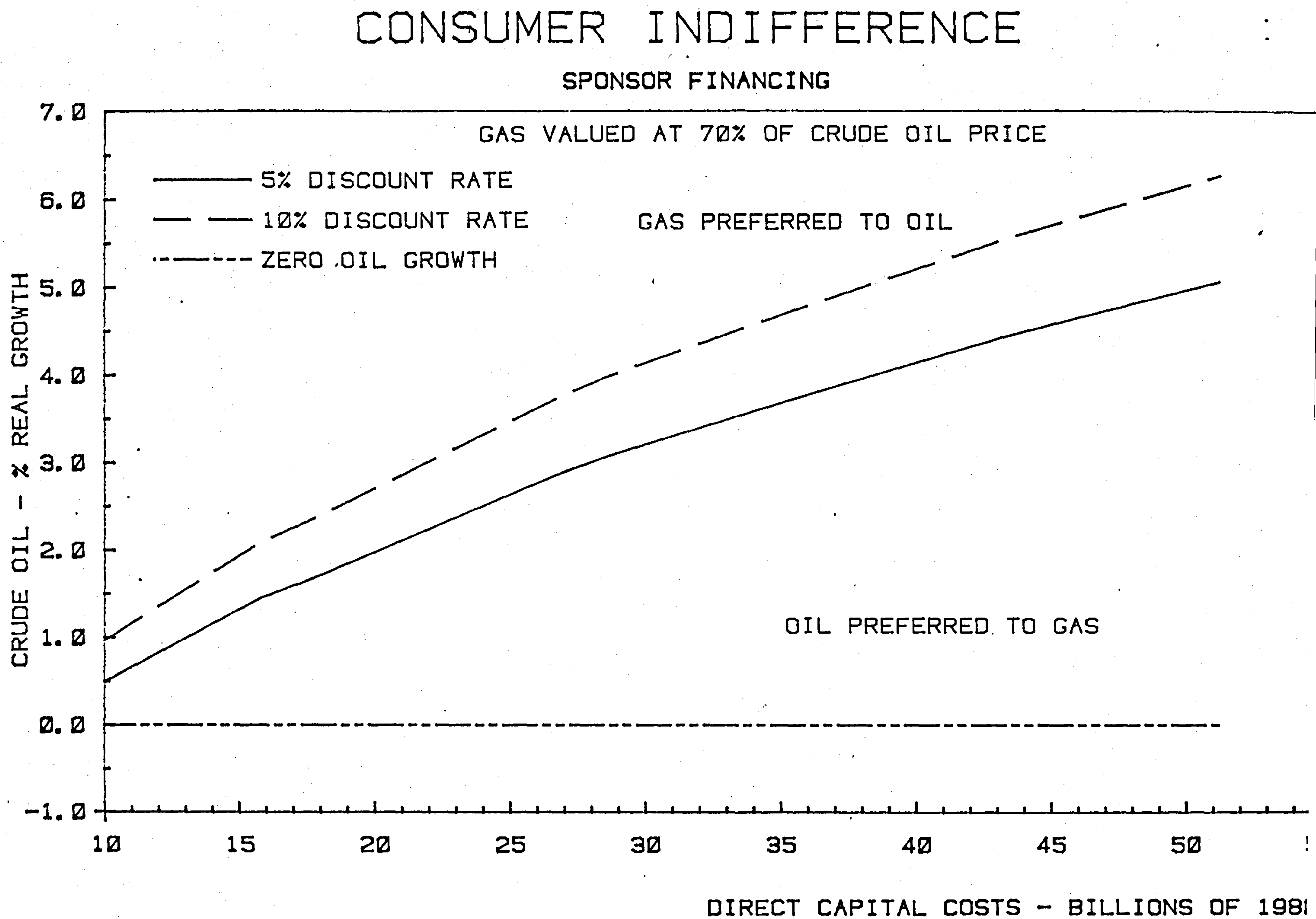
	Current Filing w Center Pt. plus 10%	Current Filing with Center Pt.	Adjust. Adger/ Berman	Current Filing	President's Decision with Center Pt.	President's Decision March 1977
NGPA Wellhead Pricing						
ANGTS 1980 $ Unit Costs						
Present Value at 5%	46.68	44.36	42.88	41.62	31.50	29.05
at 10%	25.56	24.21	23.34	22.61	16.71	15.29
Real Oil Escalation Equivalent to ANGTS PV						
- 5% discount rate	2.31	1.98	1.77	1.58	-0.22	-0.75
- 10% discount rate	3.10	2.72	2.46	2.24	0.11	-0.52
70% Equivalent of World Oil Wellhead Pricing						
ANGTS 1980 $ Unit Costs						
Present Value at 5%	62.51	60.18	58.71	57.45	48.79	46.33
at 10%	33.56	32.20	31.33	30.60	25.44	24.02
Real Oil Escalation Equivalent to ANGTS PV						
- 5% discount rate	4.14	3.90	3.75	3.61	2.58	2.26
- 10% discount rate	4.96	4.68	4.50	4.33	3.07	2.67
100% Equivalent of World Oil Wellhead Pricing						
ANGTS 1980 $ Unit Costs						
Present Value at 5%	77.51	75.18	73.70	72.45	64.37	61.92
at 10%	41.13	39.77	38.91	38.17	33.31	31.89
Real Oil Escalation Equivalent to ANGTS PV						
- 5% discount rate	5.47	5.28	5.16	5.05	4.32	4.08
- 10% discount rate	6.33	6.11	5.96	5.83	4.91	4.61

Consumer Indifference Values

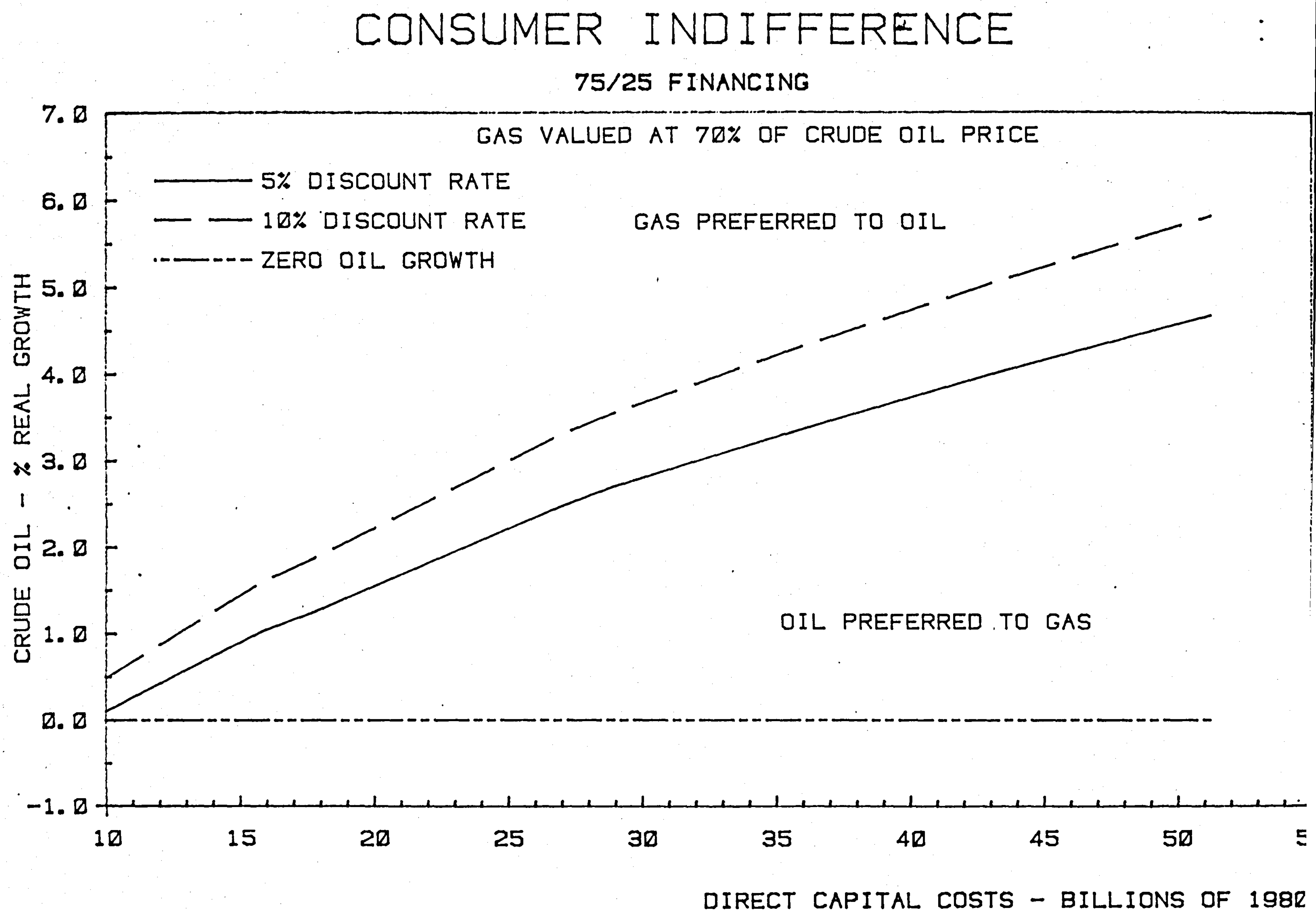
Percent Overrun or Underrun of Current Filing	-20%	-10%	40%	50%	-50%	80%	120%	160%
NGPA Wellhead Pricing								
ANGTS 1980 $ Unit Costs in Present Value at 5%	40.85	42.31	51.25	53.01	35.12	58.62	65.67	72.69
at 10%	22.15	23.00	28.23	29.26	18.80	32.54	36.66	40.77
Real Oil Escalation Equivalent to ANGTS PV								
- 5% discount rate	1.46	1.68	2.90	3.11	0.48	3.74	4.45	5.07
- 10% discount rate	2.10	2.36	3.78	4.03	0.95	4.75	5.56	6.28
70% Equivalent of World Oil Wellhead Pricing								
ANGTS 1980 $ Unit Costs in Present Value at 5%	56.68	58.13	67.08	68.84	50.95	74.45	81.50	88.52
at 10%	30.14	30.99	36.22	37.25	26.79	40.53	44.65	48.76
Real Oil Escalation Equivalent to ANGTS PV								
- 5% discount rate	3.53	3.69	4.58	4.74	2.86	5.22	5.78	6.28
- 10% discount rate	4.23	4.42	5.48	5.67	3.42	6.24	6.88	7.47
100% Equivalent of World Oil Wellhead Pricing								
ANGTS 1980 $ Unit Costs in Present Value at 5%	71.68	73.13	82.08	83.84	65.95	89.45	96.49	103.52
at 10%	37.71	38.57	43.79	44.82	34.36	48.10	52.22	56.33
Real Oil Escalation Equivalent to ANGTS PV								
- 5% discount rate	4.99	5.11	5.82	5.95	4.47	6.35	6.81	7.24
- 10% discount rate	5.75	5.90	6.75	6.91	5.12	7.38	7.92	8.42

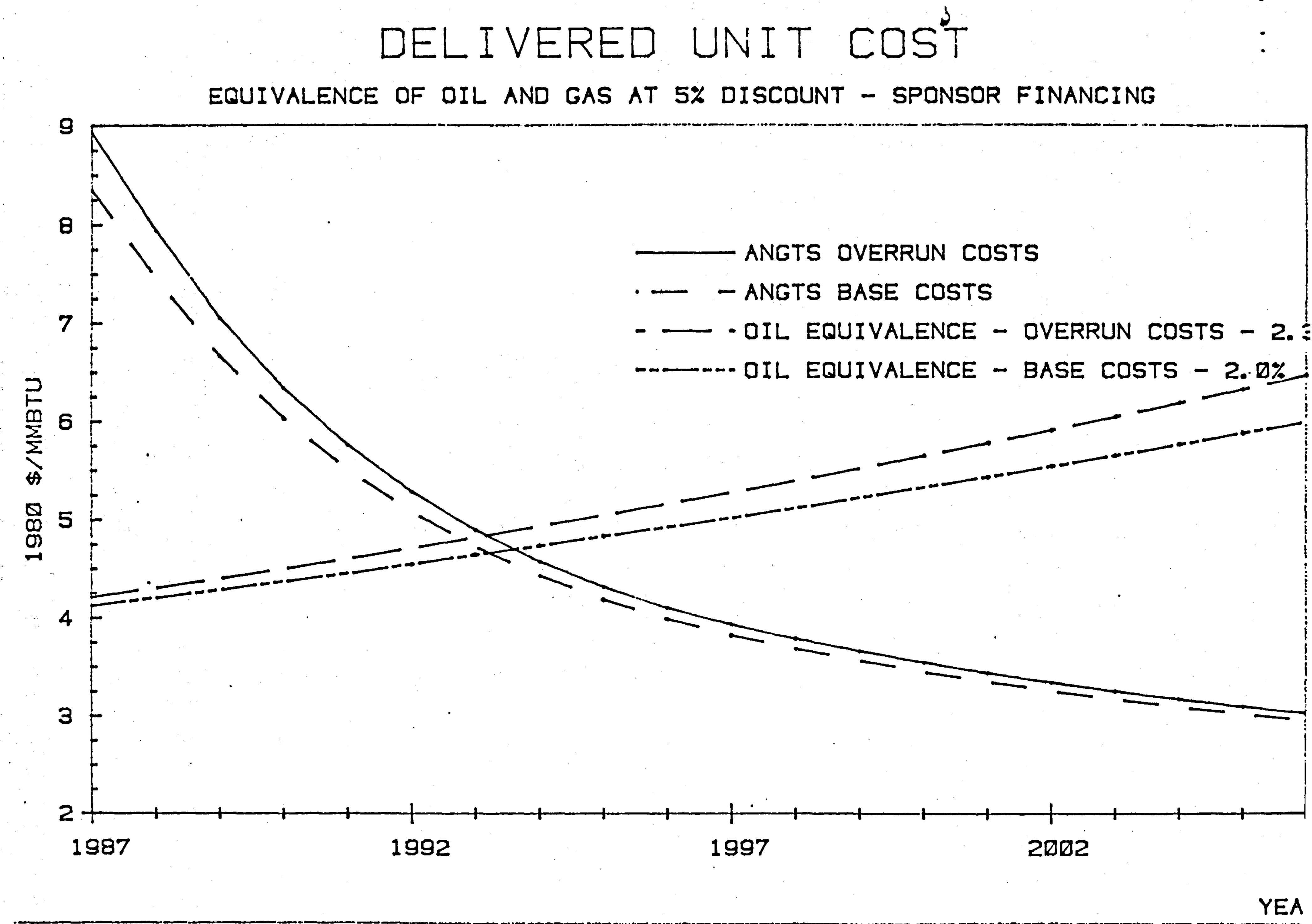
Consumer Indifference Values

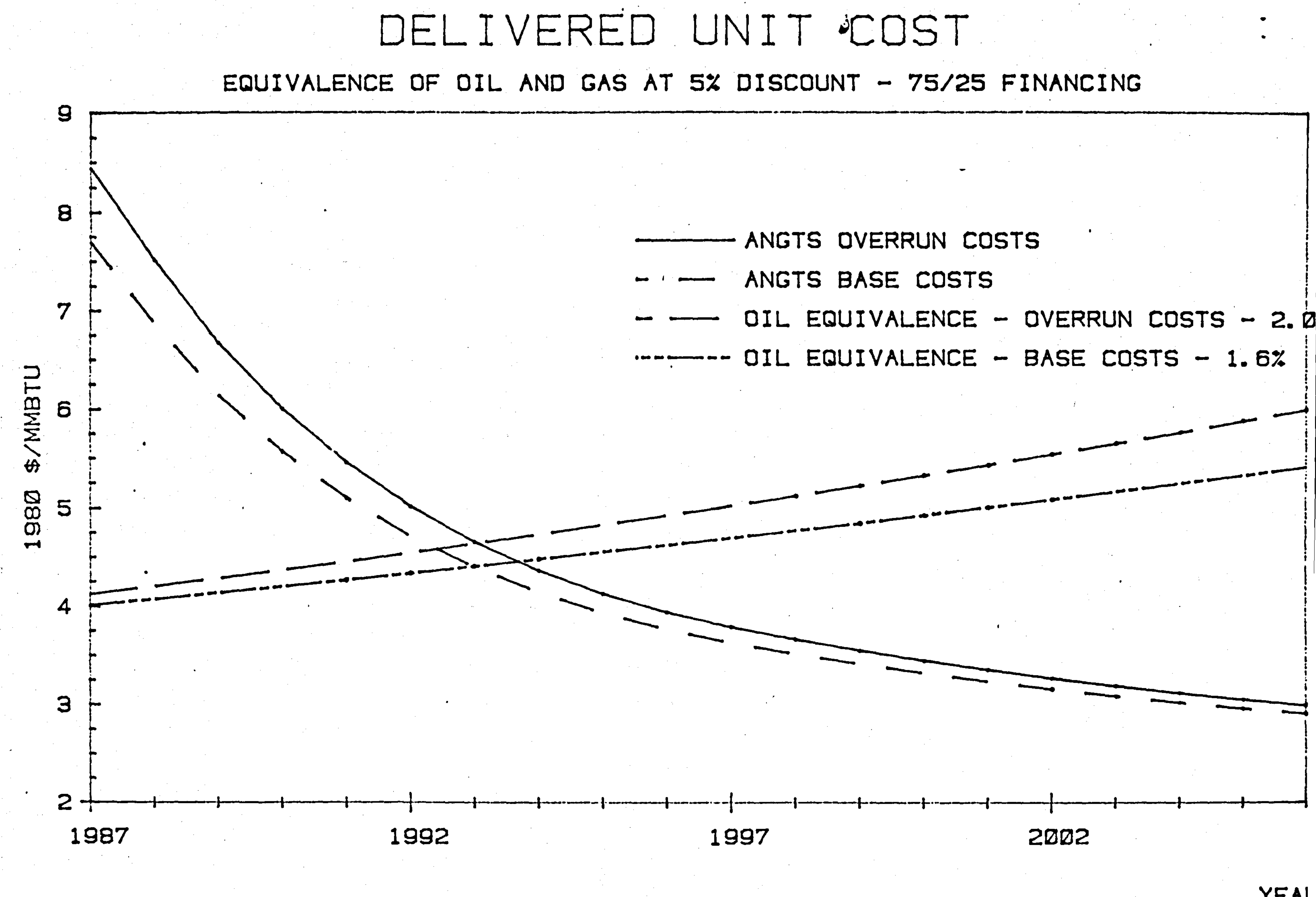
Percent Overrun or Underrun of Current Filing	-20%	-10%	40%	50%	-50%	80%	120%	160%
NGPA Wellhead Pricing								
ANGTS 1980 $ Unit Costs in Present Value at 5%	38.23	39.57	48.00	49.65	33.03	54.90	61.39	68.14
at 10%	20.62	21.42	26.34	27.30	17.58	30.37	34.16	38.11
Real Oil Escalation Equivalent to ANGTS PV								
- 5% discount rate	1.03	1.25	2.48	2.70	0.09	3.33	4.03	4.68
- 10% discount rate	1.60	1.87	3.30	3.55	0.47	4.28	5.08	5.82
70% Equivalent of World Oil Wellhead Pricing								
ANGTS 1980 $ Unit Costs in Present Value at 5%	54.05	55.40	63.83	65.48	48.85	70.72	77.22	83.97
at 10%	28.61	29.41	34.33	35.29	25.58	38.36	42.15	46.10
Real Oil Escalation Equivalent to ANGTS PV								
- 5% discount rate	3.23	3.39	4.27	4.43	2.59	4.91	5.45	5.96
- 10% discount rate	3.87	4.06	5.12	5.30	3.10	5.86	6.50	7.09
100% Equivalent of World Oil Wellhead Pricing								
ANGTS 1980 $ Unit Costs in Present Value at 5%	69.05	70.40	78.83	80.48	63.85	85.72	92.22	98.97
at 10%	36.19	36.98	41.90	42.86	33.15	45.93	49.73	53.97
Real Oil Escalation Equivalent to ANGTS PV								
- 5% discount rate	4.76	4.88	5.57	5.70	4.27	6.06	6.53	6.96
- 10% discount rate	5.47	5.62	6.46	6.61	4.88	7.07	7.60	8.14



CONSUMER INDIFFERENCE
SPONSOR FINANCING
GAS VALUED AT 70% OF CRUDE OIL PRICE
5% DISCOUNT RATE
10% DISCOUNT RATE
ZERO OIL GROWTH
GAS PREFERRED TO OIL
OIL PREFERRED TO GAS
CRUDE OIL - % REAL GROWTH
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
-1.0
10
15
20
25
30
35
40
45
50
DIRECT CAPITAL COSTS - BILLIONS OF 1981


CONSUMER INDIFFERENCE
75/25 FINANCING
GAS VALUED AT 70% OF CRUDE OIL PRICE
5% DISCOUNT RATE
10% DISCOUNT RATE
ZERO OIL GROWTH
GAS PREFERRED TO OIL
OIL PREFERRED TO GAS
CRUDE OIL - % REAL GROWTH
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
-1.0
10
15
20
25
30
35
40
45
50
DIRECT CAPITAL COSTS - BILLIONS OF 1980


DELIVERED UNIT COST
EQUIVALENCE OF OIL AND GAS AT 5% DISCOUNT - SPONSOR FINANCING
ANGTS OVERRUN COSTS
ANGTS BASE COSTS
OIL EQUIVALENCE - OVERRUN COSTS - 2.
OIL EQUIVALENCE - BASE COSTS - 2.0%
1980 $/MMBTU
9
8
7
6
5
4
3
2
1987
1992
1997
2002
YEA


DELIVERED UNIT COST
EQUIVALENCE OF OIL AND GAS AT 5% DISCOUNT - 75/25 FINANCING
ANGTS OVERRUN COSTS
ANGTS BASE COSTS
OIL EQUIVALENCE - OVERRUN COSTS - 2.0
OIL EQUIVALENCE - BASE COSTS - 1.6%
1980 $/MMBTU
9
8
7
6
5
4
3
2
1987
1992
1997
2002
YEA

IX. Billing Commencement

One of the waivers requested by the project sponsors provides for "pre-billing" of consumers for segments of the project that have been completed but no Alaskan gas is flowing because another project segment is not yet complete. This section attempts to calculate the impact on the average residential customer if this waiver provision is approved.

First, two cost allowances of three project segments are examined--the "minimum bill" and "full cost of service" for the conditioning plant, Alaska pipeline, and the Canadian segment. The minimum bill consists of operation and maintenance expense, ad valorem taxes, debt expense, and debt repayment. The full cost of service includes these items plus return on and of equity, and federal and state income taxes.

For the two calibration cases described in Section II, the following table summarizes the results:

	Low Assumptions		High Assumptions	
1980 Dollar Estimate	$ 19.1 B		$ 22.5 B	
Interest Rate	8%		14%	
Construction Escalation Rate	7%		11%	
General Inflation Rate	5%		11%	
ANGTS Costs in millions of 1987 dollars:				
Alaska Plant (min. bill)				
Oper & Main	$ 92.45		$ 140.35	
Ad Valorem Tax	107.12		148.97	
Interest	257.91		652.02	
Debt Repayment	165.33		238.84	
Subtotal	622.81		1180.18	
1980 Dollars		432.0		539.5
Alaska Pipeline (min. bill)				
Oper & Main	$ 55.44		$ 84.08	
Ad Valorem Tax	330.91		500.48	
Interest	659.67		2036.41	
Debt Repayment	422.86		745.94	
Subtotal	1468.88		3366.91	
1980 Dollars		1018.7		1539.3
Canada (Full Cost of Service)				
Canadian dollars	$2350.85		$ 4052.95	
U.S. dollars	1880.2		3249.7	
1980 Dollars		1304.0		1389.0
23.5% Share of ANGTS costs (residential sales to total sales)				
Alaska Plant	$ 101.5		$ 126.8	
Alaska Pipeline	239.4		361.7	
Canada	306.4		326.4	
80.5% U.S. customers affected by Alaskan gas (in millions)	34.9		34.9	
Monthly average increase in customer's bill (1980 $)				
Alaska Plant	$ 0.24		$ 0.30	
Alaska Pipeline	0.57		0.86	
Canada	0.73		0.78	

For the "Current Filing" and "Current Filing with Center Point" cost estimates, using the assumptions shown in Table II of Section I which are different from those used in the calibration analysis, the following table summarizes the monthly average increase in a residential customer's bill. Both financing scenarios are shown, as well as the "minimum bill" and "full cost of service" impacts for the three key segments of the project.

Scenario:	Current Filing		Current Filing with Center Point	
Financing:	Sponsor's	75/25	Sponsor's	75/25
Average increase to residential customer's monthly bill:				
Min Bill Plant	\$0.29	\$0.29	\$0.31	\$0.31
Min Bill Alaska Pipeline	0.63	0.68	0.83	0.85
Min Bill Canada	0.41	0.41	0.45	0.45
Total COS Plant	\$0.43	\$0.42	\$0.46	0.45
Total COS Alaska Pipeline	1.40	1.14	1.55	1.37
Total COS Canada	0.68	0.68	0.75	0.75

X. Interest Rate and Inflation Rate Sensitivity

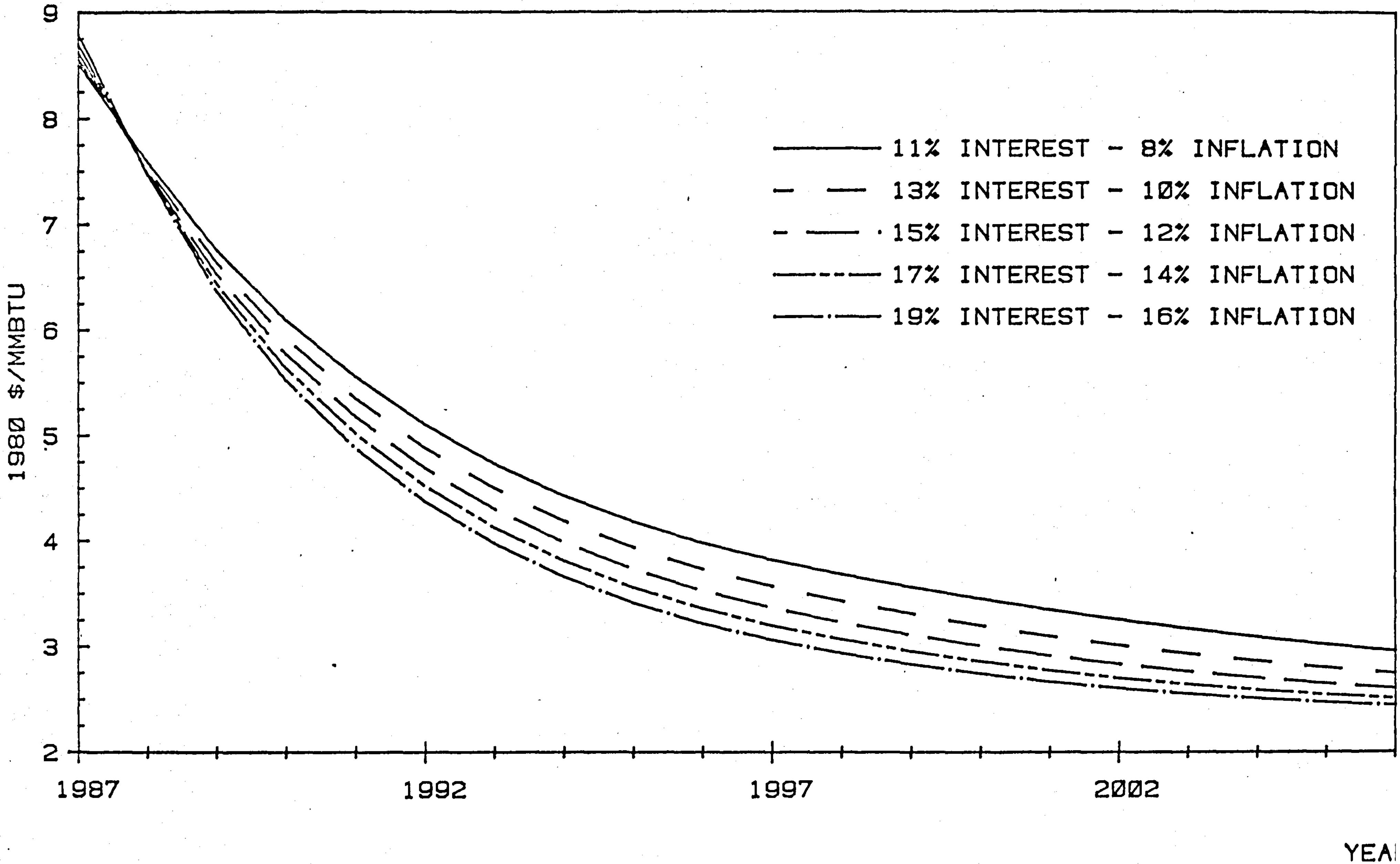
With varying interest rates and corresponding inflation rates possible over the life of the project, a sensitivity study was performed varying only those rates for all segments of the project to determine their impact. The base case for this analysis is the "Current Filing including Center Point" as filed in 1980 without the recent cost estimate update used in the other analysis is this study. Also, the project sponsor's financing assumptions were used.

The following table presents key results from this sensitivity study, and the following graph shows several curves of delivered unit costs for the various interest and inflation rates.

Interest Rate	11%	13%	15%	17%	19%
Inflation Rate	8%	10%	12%	14%	16%
Direct Capital Cost (US $ Billion)	$22.5	$22.5	$22.5	$22.5	$22.5
Total Rate Base (US $ Billion)	$43.4	$48.3	$53.7	$59.7	$66.3
First Year Delivered nominal $/mmbtu	$15.15	$17.48	$20.16	$23.23	$26.75
Twenty Year Average 1980 $/mmbtu	$ 4.51	$ 4.31	$ 4.15	$ 4.02	$ 3.92

DELIVERED UNIT COST

COMPARISON OF INTEREST AND INFLATION RATES



XI. Comparison of Effect of New Tax Law

This section presents the effect of the new tax depreciation schedule allowed in the Economic Recovery Tax Act of 1981. The assumptions for this case correspond to sponsor's financing and current filing with center point based on the sponsor's filing of 1980, without the recent updated capital cost estimates used in the other studies in this briefing book.

	Old Tax Law		New Tax Law	
1980 Dollar Capital Costs (US$ Billion)	$22.5		$22.5	
Rate Base including AFUDC (US$ Billion)	$43.4		$43.4	
Two Key Years Total Cost of Service (millions of US dollars)	1994	1997	1994	1997
Alaska Plant	710.4	667.0	598.9	591.6
Alaska Pipeline	3306.6	2884.6	2770.4	2521.9
Canada	1816.9	1696.8	1848.9	1696.8
Eastern Leg	303.3	271.0	262.4	249.0
Western Leg	158.1	141.5	129.7	123.0
TOTAL	6295.3	5660.9	5610.3	5182.3

Note: These two years are compared because 1994 corresponds to the cross-over year between accelerated and straight-line depreciation under the new tax law, and 1997 corresponds to the cross-over year under the old law.

	Old Tax Law	New Tax Law
Delivered Unit Costs - NGPA wellhead		
First Year Nominal $/mmbtu	$ 15.16	$ 15.15
First Year 1980 $/mmbtu	8.51	8.51
Twenty year average 1980 $/mmbtu	4.65	4.51
Consumer Indifference		
Real oil price escalation rate equivalent to ANGTS, assuming market value of gas equal to 70% of world oil price	-0.74%	-1.14%
Profitability Analysis		
Alaska Sponsors - Internal ROR	14.7%	15.5%
Producers - Internal ROR	36.4%	37.0%