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NATURAL GAS CONDITIONING AND PIPELINE DESIGN

A Technical Primer for Non-Technicians,
With Special Reference to Hydrocarbons from Prudhoe Bay
and the Alaska Highway Gas Pipeline

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Department of Natural Resources

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INTRODUCTION

The State of Alaska faces a variety of questions related to the proposed Alaska Highway Gas Pipeline which combine highly technical engineering considerations with important public policy issues. These questions include:

— location, design, and ownership of the gas conditioning plant,
— choice of fuel for North Slope operations, and
— pressure and diameter specifications of the pipeline itself.

Some grasp of the engineering jargon and basic principles is essential if Alaska's elected officials and agency staff are to identify the State's priorities correctly: What issues really affect the State's interests, and to what extent? Which, if any, of the other parties --- the producers, gas shippers, and federal authorities --- are likely to share the State's interests in each of these questions, and to what extent? How much can Alaskans depend on others, therefore, to look after the State's interests? How formidable is opposition likely to be to the State's position, and what burdens would the State's demands impose on others? Overall then, where should the State realistically direct its efforts?

This report, in itself, will not answer those questions; it should, however, make State decision-making a bit easier. We have tried to distinguish scientific facts from matters of differing engineering judgment, and both from differences of economic interest; and to present the range of opinions fairly. Our goals have been to develop a primer on gas conditioning and pipeline transportation that is relevant to Alaskans, speaks to non-technicians, yet is precise and complete enough to survive the scrutiny of experts.

Special thanks goes to Harold R. Galloway and James L. Shanks, Jr. of Exxon, D. J. Pritchard of Sohio, W. S. Dickinson of Arco, A. J. Green of Westcoast Transmission, Robert M. Maynard of the State of Alaska's Department of Law, and Robert H. Loeffler of Morrison & Foerster, the State's Washington counsel.

I. THE BASICS OF PIPELINE DESIGN

A. HYDROCARBON CHARACTERISTICS

1. Chemistry

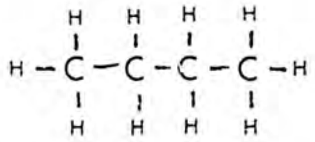
The crude oil and natural gas produced from Alaska's Prudhoe Bay reservoir are mixtures of hydrocarbons (compounds of carbon and hydrogen), plus impurities like water and carbon dioxide. The most fundamental classification of hydrocarbon compounds is in terms of the number of carbon atoms in each molecule.

TABLE 1

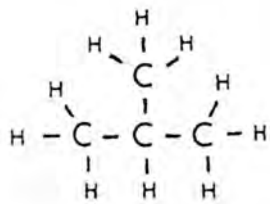
Reservoir Fluid	Compound	Chemical Formula	Abbreviation	Commercial Product
natural gas	methane	CH_4	C_1	dry gas
natural gas	ethane	C_2H_6	C_2	natural gas liquids (NGLs) or condensate
natural gas	propane	C_3H_8	C_3	natural gas liquids (NGLs) or condensate
natural gas	butane	C_4H_{10}	C_4	natural gas liquids (NGLs) or condensate
natural gas / crude oil	pentane	C_5H_{12}	C_5	natural gasolines, naphtha, or pentanes-plus
crude oil	hexane	C_6H_{14}	C_6	natural gasolines, naphtha, or pentanes-plus
crude oil	heptane	C_7H_{16}	C_7	natural gasolines, naphtha, or pentanes-plus
crude oil	octane	C_8H_{18}	C_8	natural gasolines, naphtha, or pentanes-plus / oils, waxes, tars
crude oil	-	-	-	oils, waxes, tars
crude oil	-	-	-	oils, waxes, tars
crude oil	etc.	C_nH_m	C_n	oils, waxes, tars

Hydrocarbons containing more than three atoms of carbon in each molecule have several different configurations. These forms or "isomers" often have different physical characteristics. For example, Table 2 shows that "normal" butane [n-butane] can remain in a liquid state in the TAPS oil pipeline at higher temperatures than can the branched isomer "iso" butane [i-butane].

FIGURE A: NORMAL AND ISO-BUTANE



"normal" (n) butane



"iso" (i) butane

2. Heating values

The heating value of each hydrocarbon reflects, in part, the number of carbon atoms that will oxidize as the fuel is burned. Table 2 shows the heating values of light hydrocarbons and their isomers, both in liquid and vapor states. Normally, heating values are expressed in gross BTU's[1], also called the higher heating value. The expected heating value of gas that will be shipped through the Alaska Highway gas pipeline (or Alaska Natural Gas Transportation System [ANGTS]), for example, is invariably expressed in gross terms.

The lower heating value, measured in net BTU's, serves a very limited function, primarily in describing the fuel requirements for various types of machinery and processes. Net BTU's for hydrocarbon vapors have beer used by some parties involved in the design of the North Slope gas conditioning plant; Table 2, therefore, includes net measurements for hydrocarbon vapors.

The difference between gross and net BTU's is highly technical. The reader need only remember that (1) unless specifically designated as net BTU's, one can assume that all heating value data represent gross measurements; and (2) like apples and oranges, the two should never be confused or mixed in heating value calculations.

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1) A British Thermal Unit (BTU) represents the amount of heat required to raise the temperature of one pound of water by one degree F.

TABLE 2

HYDROCARBON	VAPOR HEATING VALUE		LIQUID HEATING VALUE
	BTU/scf* gross	BTU/scf net	BTU/barrel** gross
Methane	1010	909	2,512,818
Ethane	1769	1618	2,771,916
Propane	2518	2316	3,824,730
i-butane	3253	3001	4,158,924
n-butane	3262	3010	4,325,538
i-pentane	4000	3698	4,569,180
n-pentane	4010	3708	4,624,284

Source: Natural Gas Processors and Suppliers Association, Engineering Data Book, 1979.

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* A Standard Cubic Foot (scf or cf) is the amount of gas that would fill a cubic foot of space at 60 degrees F. and standard atmospheric pressure. The following abbreviations are often used to represent large volumes:

Mcf = thousand cubic feet
MMcf = million cubic feet
bcf = billion cubic feet
Tcf = trillion cubic feet

** One barrel = 42 U.S. gallons.

3. Phase characteristics

The more carbon atoms a molecule contains, the heavier it is. The heaviness of a particular hydrocarbon will influence whether it exists in a vapor or liquid phase at various combinations of temperatures and pressures. Table 3 shows the boiling points of light hydrocarbons. At temperatures below the boiling point, a hydrocarbon is a liquid; above, it is a vapor.

TABLE 3

SUBSTANCE	MOLECULAR WEIGHT	BOILING POINT (F.) [at atmospheric pressure]
C_1	16.043	-258.69
C_2	30.070	-127.48
C_3	44.097	- 43.67
$i\text{-}C_4$	58.124	+ 10.90
$n\text{-}C_4$	58.124	+ 31.10
$i\text{-}C_5$	72.151	+ 82.12
$n\text{-}C_5$	72.151	+ 96.92
$n\text{-}C_6$	86.178	+155.72
$n\text{-}C_7$	100.205	+209.17
$n\text{-}C_8$	114.232	+258.22
CO_2	44.010	-109.30

Source: Natural Gas Processors and Suppliers Association, Engineering Data Book, 1979.

Oil is now injected into the Trans Alaska oil pipeline (TAPS) at a temperature of 142 degrees F. At times, the oil may experience pressures enroute as low as normal atmospheric conditions. Under these circumstances, Table 3 shows that hexanes (C_6) and all heavier hydrocarbons would always remain in a liquid phase during shipment through TAPS. Mixtures of heavy hydrocarbons also have the ability to carry small quantities of C_5 and even C_4 without vapor formation. On the other hand, mixtures of the lightest hydrocarbons (C_1, C_2, and C_3) remain in the vapor phase even in a chilled gas pipeline, and can likewise absorb some C_4 and possibly C_5 without condensation.

The question of how much of these intermediate hydrocarbons (C_4 and C_5) will be carried as vapors by ANGTS, shipped as liquids in TAPS or in a third "gas-liquids" pipeline, used for fuel on the North Slope, or routed to some other purpose, remains open. Resolution of this issue depends upon a whole array of decisions, including pressure and temperature specifications for operation of both the gas and oil pipelines, the amount of CO_2 permitted in the gas pipeline, the choice of gas conditioning process, the kinds and amounts of fuel used in the field and for pipeline pumps and compressors, and oil and gas production rates. This report examines each of those factors, their relationships, and the ultimate effect such decisions may have on the kinds and amounts of hydrocarbons transported.

B. GAS VERSUS LIQUIDS PIPELINES

Pipelines carrying hydrocarbons in a liquid phase (such as the TAPS oil line and a proposed gas liquids line) use pumps to move these materials. Pipelines designed for gaseous hydrocarbons, such as the proposed Alaskan Northwest pipeline, use compressors. The difference is subtle, but important.

In liquids, the individual molecules are packed tightly together and, for all practical purposes, cannot be compressed into a smaller volume. Instead, as more molecules are pumped into a pipe, they shove the mass of hydrocarbons in front of them into the next pump station, like a train of boxcars pushed from behind. Naturally, the greater the distance (and the greater the rise in elevation) between pump stations, the greater is the horsepower required.

Gaseous hydrocarbons, like all vapors, are compressible. Each compressor station on a gas pipeline draws vapor into its inlet at a relatively low pressure (called the suction pressure), compresses it into a smaller volume, and expels it at a higher pressure, known as the discharge pressure. As the gas expands between the outlet of one compressor station and the inlet of the next, pressure again falls, and this pressure drop or differential causes the gas to flow through the pipe. It is the discharge or operating pressure, being the greatest pressure experienced by the pipeline, that is limited by the strength of the steel pipe.

C. PRESSURE SPECIFICATIONS

Pressure drop is usually measured as a ratio to distance, psi per mile.[2] Being the stimulus for gas movement through a pipeline, it is therefore one of several factors that determine how much gas can be transported each day. Throughput is determined by the following components:

(1) Discharge pressure, (2) Suction pressure, and (3) Compressor Station spacing determine the pressure drop, and thereby the SPEED of flow, while

(4) Pipeline diameter determines the AMOUNT of gas that can be shipped through a pipeline at any given speed.

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2) Pressure is measured in pounds per square inch (psi). Objects at sea level are subjected to an atmospheric pressure of about 14.7 psi (which results from the weight of several miles of air resting on the earth's surface). Instruments designed to measure artificially induced pressures like those inside gas pipelines, record or guage pressures in excess of this ever-present atmospheric pressure (psig). Absolute pressure measurements include the 14.7 psi exerted by the atmosphere (psia). Hence, 1680 psig is the same as 1694.7 psia.

Of these four variables, a pipeline's diameter and the maximum discharge pressure that it can accomodate (that is, the pipeline's operating pressure) are the only ones that cannot be altered once the pipe is laid. The other two can, in theory, be modified to accomodate changes in throughput: Throughput can be increased either by adding more compressor stations or by increasing the suction power of existing compressors.

There are, of course, practical and economic constraints on the number of compressor stations that can be added. Likewise, the suction power of compressors experiences a marked drop-off in efficiency beyond a given range of compression ratios.

The compression ratio is the ratio between a compressor's discharge pressure and its suction pressure. Compression ratios are generally in the vicinity of 1.2 to 1.3. Table 4 shows the suction pressures corresponding to a compression ratio of 1.25 at four operating pressure levels heretofore considered for the Alaskan and Canadian sections of the Alaska Highway Gas Pipeline.

TABLE 4

Operating pressure	Efficient Delivery Pressure
1680 psig	1350 psig
1440 psig	1150 psig
1260 psig	1010 psig
1080 psig	860 psig

The National Energy Board (NEB) has approved construction of a 1080 psig 56 inch diameter pipeline in Canada. Though some contention still exists on the matter, the Federal Energy Regulatory Commission (FERC) has approved the design proposed by the pipeline sponsor, Northwest Alaskan, with an operating pressure of 1260 psig for a 48 inch pipeline in Alaska. EXXON and the State of Alaska have advocated higher operating pressures, such as 1680 psig (or even 2160 psig for a 42 inch diameter pipe). ARCO at one time proposed a compromise pressure of 1440 psig.

The controversy over the pipeline's operating pressure and diameter stems, in part, from a recognition that manipulating discharge and suction pressures or even building more compressor stations after the pipe is laid are not necessarily the most economic or practical responses to future changes in throughput. For these reasons, designers must choose pipeline diameter and wall thickness specifications and compressor station locations that reflect a realistic judgment of likely throughputs over the life of the facility. FERC and Northwest concluded that a 1260 psig 48" diameter pipeline is the most efficient and economic compromise for the volume of gas expected from the main Prudhoe Bay reservoir (about 2.0 bcf/day). However, they agree that at a throughput somewhere between 2.6 and 2.9 bcf per day, a 1680 psig line would make more sense. ["Report of the Alaskan Delegate on the System Design Inquiry", FERC, May 17, 1979; p. 27.]

Unfortunately, the additional volumes of North Slope gas likely to become available during the expected 20 or 25 years of gas pipeline operations are both uncertain and controversial. No one can know with confidence whether the 1260 psig system ultimately will prove to be the best choice.

A related issue that must be addressed during engineering design is the need for <u>crack arrestors</u>. Even if a pipeline's wall thickness is sufficient to withstand its own INTERNAL gas pressures, pipeline designers have to safeguard against the effects of catastrophic EXTERNAL forces --- such as a misguided bulldozer or a saboteur's bomb.

Obviously, localized damage cannot be prevented entirely. In a large diameter, high pressure gas pipeline (unlike TAPS), however, even a small injury to the pipe can result in a fracture that spreads explosively up and down the system, perhaps destroying pipe for tens of miles. Girdling the pipe at regular intervals with sturdy metal crack arrestors is one solution.

Virtually everyone agrees that a 1680 psig, 48 inch diameter pipeline must be equipped with crack arrestors. Opinions, however, vary with respect to a 1260 psig system. Since crack arrestors are a significant expense, no conclusive judgment about the relative economic advantages of a 1260 psig system can be reached in the absence of a decision on the need for crack arrestors.

Probably the biggest source of controversy with respect to the selection of an operating pressure for the Alaska Highway Gas Pipeline centers, however, on the ability of higher pressure pipelines to carry heavier hydrocarbons without risking two-phase flow.

D. HAZARDS OF TWO-PHASE FLOW

Long-distance pipelines must be designed to carry hydrocarbons either in a vapor phase (like the Northwest pipeline) or in a liquid phase (like TAPS and the proposed gas liquids line). Transporting vapors and liquids together in one stream results in a condition called two-phase flow. The dangers of two-phase flow are as follows:

(1) General problems of two-phase flow. A pump or compressor is designed to operate on material of a certain density. Encountering bubbles of vapor in a stream that should be totally liquid is a little like swinging a bat at a baseball and missing; while coming across droplets or, worse yet, big "slugs" of liquid in a stream that should be all vapor is like being hit with a barrage of snowballs. Either event can be rather jarring to the system.

(2) "Surge" and "slug" problems of two-phase flow. If droplets of liquids condense in the vapor stream, they tend to settle and accumulate in low spots along the pipeline, constricting the room available for vapor flow. As the amount of trapped liquid grows, pressure builds --- eventually forcing the liquid up and over the next hump. Large slugs of dense liquids are, therefore, accompanied by an uneven or surging flow of fluids. Extreme surging conditions can cause severe damage when a slug enters a compressor station.

It should be noted that some pipelines are intentionally operated in two-phase flow conditions, while gathering "wet" (unconditioned) gas in the field, or bringing gas from offshore wells to shore-based facilities. Usually, however, these pipelines are quite short and undersized; no pumps or compressors that could be damaged by surging slugs are located along the way. In fact, some offshore pipelines for which slug formation cannot be avoided empty onshore into several miles of convoluted pipeline called slug catchers. Here the tremendous force of the slugs is dissipated, and the liquid itself is "scrubbed" out of the gas, prior to entering pumping, processing, or compressing facilities.

Designers and operators of long-distance gas pipelines, like the ANGTS which has several compressor stations and many ups and downs enroute, can take a variety of actions to reduce the hazards of two-phase flow. They can:

* Avoid building an oversized line. One way to prevent the accumulation of liquids at low points along the line is to ensure that vapors flow at a high speed. This means choosing a pipeline diameter appropriate to the expected throughput, maintaining a high pressure drop, or both. If a system is designed to carry an average of 3.0 bcf/day and only 2.0 bcf/day is available for shipment, pressure drop would have to be reduced in order to ensure a steady flow of the smaller volume of gas. The result is a slower movement of gas and, hence, a greater danger of slug formation and surging.

* Equip the line with drains. Valves to drain off accumulated liquids can be inserted in low spots along the pipeline.

* Ensure against sloppy pipeline operations. If drains are installed, they must be used properly. If adequate drainage is impractical, the line should receive more frequent "pigging" (insertion of a solid object, or pig, which pushes accumulated liquids out ahead of it). If throughput is raised or lowered, changes in the input and output pressures must be synchronized. If the line is shut down temporarily, special care must be taken when operations resume to prevent the passage of entrained liquids that may have formed during the outage. For these reasons, no matter how free of droplets the sales gas may be when it enters the pipeline, sloppy operations can result in dangerous two-phase flow conditions.

None of the above precautions are of much use in long-distance pipelines, however, unless pipeline operators also:

* <u>Restrict the volume of heavy hydrocarbons</u>. Pipelines must transport only hydrocarbon mixtures that pose no threat of condensation at any combination of temperatures and pressures likely to be encountered under either normal or abnormal conditions. Determining the optimum mixture is rather complicated, as the next chapter shows.

II. GAS COMPOSITION DECISIONS

A. INTRODUCTION

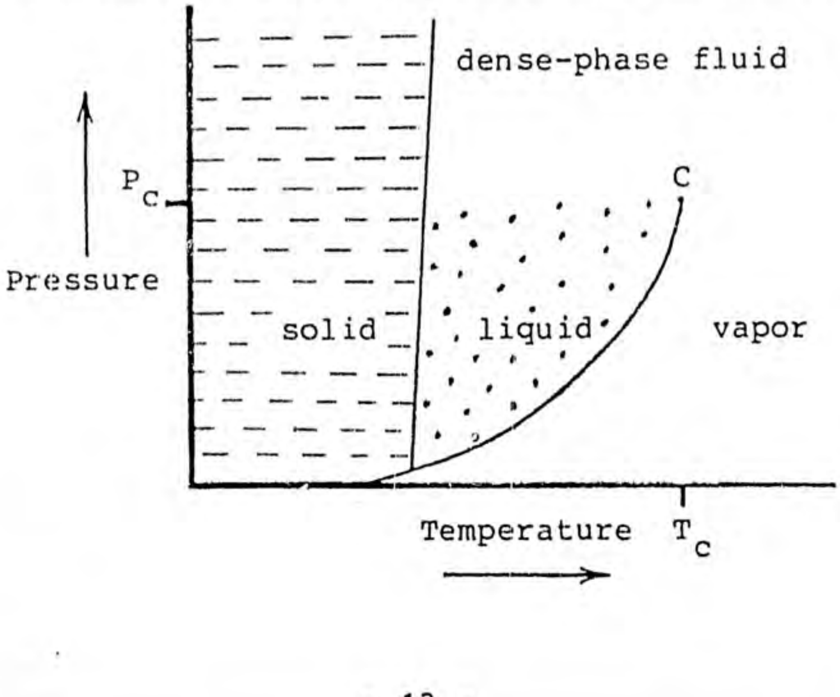
In designing a gas transportation system, everything seems to affect and be affected by everything else. We have seen, for example, that decisions about pipeline diameter, operating pressure, suction pressure, and compressor station spacing are all interdependent. Further, these specifications cannot be set intelligently except with reference to some volume or range of volumes for expected throughput. The same holds true with respect to determining the optimum chemical composition of <u>pipeline quality gas</u>; that is, the relative amounts of methane, ethane, propane, butane, heavier hydrocarbons, carbon-dioxide, water, and sulphur compounds in the gas delivered to the pipeline.

Temperature and pressure are the two factors that determine whether any particular hydrocarbon or mixture of hydrocarbons will be present in a vapor or in a liquid phase. Thus, pipeline designers must choose a balanced combination of pressure, temperature, and composition specifications that will ensure safe operations and avoid two-phase flow.

B. PHASE DIAGRAMS

Almost everyone is familiar with "bottle gas" -- pressurized containers of propane and butane used to fuel appliances in isolated homes, mobile homes, and recreational vehicles, and for camping stoves and lanterns. The propane or butane exists as a liquid inside the containers, but vaporizes upon release. Heavier hydrocarbons like gasoline and diesel fuel are liquids at atmospheric pressures and temperatures but vaporize when heat is added. These are all examples of phase changes. Each hydrocarbon has its own phase diagram, like that of Figure B, which shows how changes in pressure and temperature affect its physical characteristics.

FIGURE B: PHASE DIAGRAM OF A PURE SUBSTANCE



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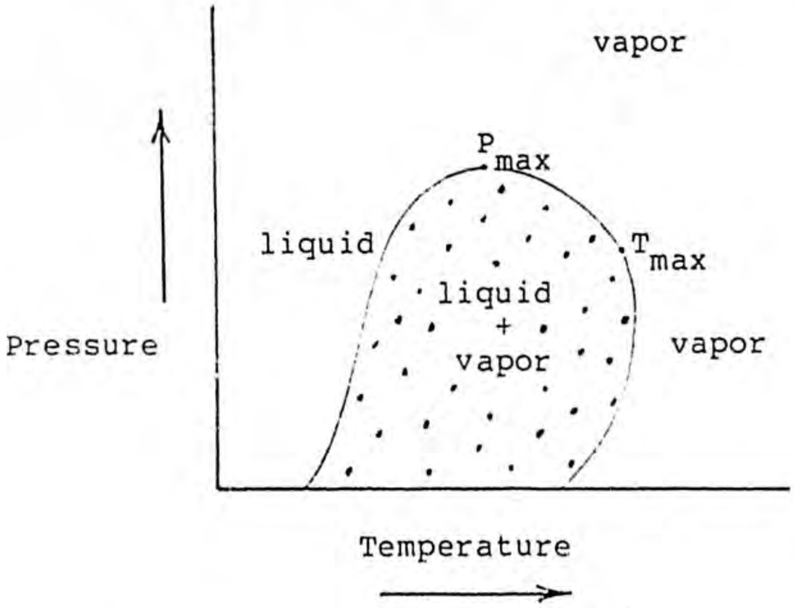
Notice first, that four phases are shown: solid, liquid, vapor, and something called dense-phase fluid. Unlike the other phases, it is hard to pinpoint where the dense phase fluid starts and ends; but we do know that it occurs only at extremely high pressures. It is also difficult to describe: A dense-phase fluid is dense like a liquid, but compressible like a vapor. And unlike solids, liquids, and vapors, which we all encounter in our daily lives, dense-phase fluids exist only deep inside the earth and within artificially created environments like natural gas pipelines.

While this high pressure phase is technically a creature unto itself, for our purposes there is no practical distinction between such fluids and vapors, and we shall generally use the word vapor for both.

Point C in Figure B is called the critical point. For any pure substance, no liquid can exist at pressures above the critical pressure (P_c) --- no matter how far the temperature drops. Likewise, no liquid can exist at temperatures beyond the critical temperature (T_c) --- again, no matter how much pressure is exerted.

Unfortunately phase diagrams of hydrocarbon MIXTURES, like that of Figure C, are more complicated to read and understand than are the diagrams of pure substances. For volumes containing only a single hydrocarbon type, two phases will coexist only at pressure-temperature combinations represented by the thin line separating liquid and vapor phases. But for hydrocarbon mixtures, the net effect of all the individual phase diagrams is a tongue-shaped region or phase-envelope in which both gas and liquid states are present. To avoid two-phase flow in pipelines, therefore, any combination of temperature and pressure falling inside the phase envelope must be avoided. Liquids pipelines must operate to the left of the phase envelope, while gas pipelines must function above or to the right of it.

FIGURE C: PHASE DIAGRAM OF A MIXTURE



The temperature and pressure combinations that delineate the right and upper boundaries of the phase envelope are called <u>dewpoints</u>, marking the conditions at which droplets first begin to appear in a vapor as the temperature or pressure falls. The combinations along the left side of the phase envelope are called <u>bubblepoints</u>, marking the conditions at which bubbles of vapor first appear in a liquid. TAPS engineers, therefore, worry about bubblepoints, while ANGTS engineers fret over dewpoints. The next chapter will examine how engineers use phase diagrams to determine what mixtures of light hydrocarbons can be handled safely in ANGTS.

THE RELATIONSHIP BETWEEN GAS COMPOSITION AND UPSET CONDITIONS

While the choice of operating (or discharge) pressure has thus far dominated the discussion of two-phase flow, the operating pressure in itself does not limit the allowable range of gas mixtures. Likewise, the temperature at which gas is discharged from each compressor station is not the limiting factor. Instead, project engineers concern themselves with the combination of pressure and temperature conditions that would occur in a system upset.

As the term implies, upset conditions are those that occur when the system malfunctions. Engineers study upset conditions in order to forecast the most troubling combination of temperature and pressure (from the standpoint of two-phase flow) that vapors moving through the gas pipeline are likely to encounter. Since ANGTS will be designed to carry light hydrocarbons in a high pressure vapor phase (more precisely, a dense-phase fluid), upset conditions denote the LOWEST expected combinations of temperature and pressure.

How are upset conditions determined? First, the normal operating window of pressures and temperatures must be calculated. This represents the range of conditions likely to occur, assuming that the system is functioning properly. The lowest pressure experienced under these normal conditions is the suction pressure, which occurs at the entrance to each compressor station.

Calculating the lowest temperature likely to occur under normal operating conditions is more difficult. It depends, in part, upon the temperature at which gas is ejected from the compressor stations. Interestingly, the Canadian pipeline segments south of Whitehorse have an advantage on this point. Compressor stations in Alaska must discharge gas with a temperature no higher than 32 degrees F., in order to prevent melting of permafrost through which the buried pipeline is laid. However, south of Whitehorse permafrost is a relatively minor problem and discharge temperatures, therefore, can be higher.

The lowest limit of acceptable gas temperatures is a function of the pipe's ductility and other physical characteristics. In the present preliminary design, this lower limit is -10 degrees F. Minimum normal operating temperatures are, in turn, determined mainly by the Joule-Thompson cooling effect: a gas naturally falls in temperature as it expands between its discharge from one compressor and its delivery to the next. The lowest operating temperature also depends upon what ground or air temperatures the designers expect to occur along the pipeline route. As long as the pipeline in Alaska is buried, the temperature it encounters will stay around 10 degrees F. throughout the year. If any section of the pipeline is constructed above ground, however, the cold Arctic winters become a real concern.

Once pipeline designers determine the normal operating window of temperatures and pressures, they can forecast the effects of specific malfunctions. Calculation of the resulting upset conditions reflects the designer's judgment as to WHICH malfunctions must be accomodated. Generally, upset conditions that have been discussed with respect to the Alaska gas pipeline reflect an assumption that the worst case would be one in which a single compressor station is totally shut down for repairs. But the implications of this assumption depend also on WHICH station is out of service. Moreover, the worst conditions under which the system will operate are also a function of how much the pipeline's designers and operators are prepared to reduce throughput in case of an upset: Will they simply route the

the gas past the ailing station without increasing the suction capability downstream? Or will the next station be forced to work harder in an attempt to keep throughput from falling too severely? Again, determining how much the operator can manipulate suction pressure at the downstream station depends upon the minimum stress temperature of the steel pipe (-10 degrees F, as we mentioned previously), the mechanical limitations of the machinery, and the dewpoint characteristics of the gas itself.

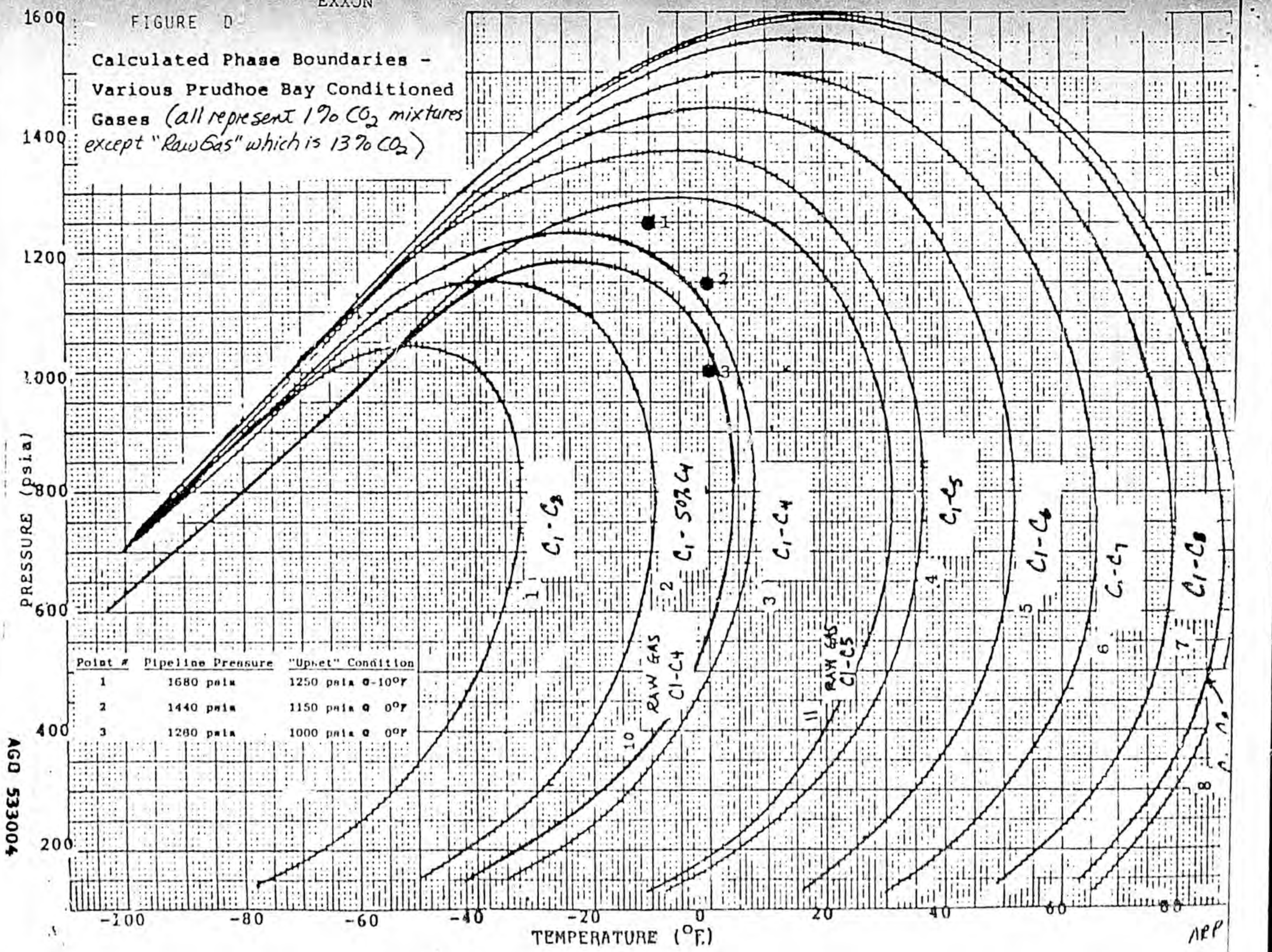
Figure D plots the temperatures and pressures of assumed upset conditions for the several pipeline operating pressures under consideration, and illustrates how close these points come to the two-phase flow conditions of various North Slope hydrocarbon mixtures. While an understanding of the basic physical principles reviewed here is important, no one can precisely assess the system's upset temperatures and pressures except in conjunction with detailed engineering and contingency plans. This explains why different parties have projected different upset conditions for ANGTS.

Figure D shows, for example, why upset conditions for the Canadian pipeline sections are of no real concern with respect to choice of gas composition. Even though the Canadian pipeline will function at a lower operating pressure (1080 psig, with a corresponding upset pressure of about 860 psig), it will have a significantly higher upset temperature (around 30 to 40 degrees F.) because the lack of permafrost south of Whitehorse permits higher compressor discharge temperatures. If one plots the intersection of 860 psig and 35 degrees F., it is evident that the design of the <u>Alaska</u> portion of the pipeline will be what limits the volume of intermediate hydrocarbons shipped through the entire system.

EXXON

FIGURE D

Calculated Phase Boundaries - Various Prudhoe Bay Conditioned Gases (all represent 1% CO_2 mixtures except "Raw Gas" which is 13% CO_2)



Point #	Pipeline Pressure	"Upset" Condition
1	1680 psia	1250 psia @ -10°F
2	1440 psia	1150 psia @ 0°F
3	1260 psia	1000 psia @ 0°F

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EXXON

VARIOUS PRUDHOE BAY CONDITIONED GAS COMPOSITIONS
(Mole Percent)

Component	Unconditioned Separator Off-Gas	(1) C_1-C_3	(2) $C_1-50\%C_4$	(3) C_1-C_4	(4) C_1-C_5	(5) C_1-C_6	(6) C_1-C_7	(7) C_1-C_8	(8) C_1-C_8	(9) C_1-C_9	(10) Off-Gas C_1-C_4
N_2	0.484	0.564	0.559	0.554	0.551	0.550	0.549	0.549	0.549	0.549	0.488
CO_2	12.659	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	12.773
C_1	74.706	87.053	86.296	85.554	84.964	84.818	84.742	84.695	84.679	84.676	75.382
C_2	6.428	7.491	7.426	7.362	7.311	7.299	7.292	7.288	7.287	7.287	6.486
C_3	3.340	3.892	3.859	3.826	3.799	3.793	3.789	3.787	3.786	3.786	3.370
$i-C_4$	0.450	--	0.260	0.515	0.512	0.511	0.511	0.510	0.510	0.510	0.454
$n-C_4$	1.038	—	0.600	1.189	1.181	1.179	1.178	1.177	1.177	1.177	1.04
$i-C_5$	0.217	—	--	—	0.247	0.247	0.246	0.246	0.246	0.246	--
$n-C_5$	0.383	—	—	--	0.435	0.435	0.434	0.434	0.434	0.434	--
C_6	0.148	--	—	--	--	0.168	0.168	0.168	0.168	0.168	—
C_7	0.081	—	—	--	--	--	0.091	0.092	0.092	0.092	--
C_8	0.047	—	--	--	--	—	—	0.054	0.054	0.054	--
C_9	0.016	--	—	--	--	—	—	--	0.018	0.018	--
C_{10}	0.003	--	—	--	--	--	—	--	—	0.003	--
Molecular Wt.	22.7	18.5	18.8	19.2	19.5	19.7	19.8	19.8	19.8	19.9	22.2
Heating Value (Btu/cf*)	1027	1095	1113	1131	1150	1156	1160	1163	1164	1164	996

*Gross, Wet, Actual @ 60°F., 14.73 psia

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Alaska state officials thus far have argued that decisions regarding pipeline design and gas composition should not preclude shipment of intermediate hydrocarbons such as butanes. (This position will be discussed in more detail later.) However, when the time comes to develop firm contingency plans for upset conditions, the State's interest in shipping intermediate hydrocarbons through the gas pipeline may well be surpassed by its likely --- and conflicting --- interest in maintaining high throughput levels: As the preceding discussion shows, in the event of upset, maintenance of throughput depends on an ability to reduce the suction pressure at the next compressor station, which in turn is partly limited by the proportion of intermediate hydrocarbons in the gas stream.

D. CARBON DIOXIDE CONTENT

Produced gas from the field (sometimes called raw gas) contains about 13 percent carbon dioxide (CO_2). Whether that amount is allowed to remain in the pipeline quality gas, or is removed via conditioning[3] down to a 1 percent or 3 percent level, depends on several factors:

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3) Some parties with an interest in ANGTS have used the words "gas conditioning" and "gas processing" interchangeably; and in many Lower 48 producing areas, the boundary between the two stages of natural gas treatment is hard to define. With respect to Prudhoe Bay natural gas, these two phrases have distinct regulatory definitions, which may result in very real differences in the price the law allows gas producers to receive. As a result, the producers are easily aggrieved by any "misuse" of the two terms. We will make no attempt here at a rigorous distinction between gas processing and conditioning; the reader should simply be aware of the sensitivity of this matter.

1. The effect of carbon dioxide on hydrocarbon dewpoint. Figure D shows that a 13 percent CO_2 mixture enables the introduction of greater quantities of heavy hydrocarbons than would be safe with a 1 percent CO_2 mixture, but the effect is really rather small. Instead, the choice of CO_2 concentration must be made on other grounds.

2. The effect of carbon dioxide on pipeline corrosion. Under certain conditions, carbon dioxide will combine with water to form carbonic acid. If present in the sales gas stream, carbonic acid will corrode the steel walls of the pipeline. The question, then, is how various concentrations of CO_2 affect the risk that carbonic acid will seriously damage the pipeline during the twenty-plus years of gas shipments.

The producers collectively argue that carbonic acid corrosion in the Alaskan section of the gas pipeline is a false issue, in part, because it takes two to tango. Carbon dioxide in any concentration cannot turn into carbonic acid except in the presence of "free" water (water that condenses out of the vapor phase). Since enough water must be removed to meet WATER dewpoint specifications of -35 degrees F. for the section of pipeline in Alaska, no problem should ensue unless the temperature within the pipeline falls below that point; but the HYDROCARBON dewpoint specification will have to be much higher --- somewhere around 0 degrees F. in order to maximize shipment of intermediate hydrocarbons. Thus, before carbonic acid formation could pose a serious threat to the pipeline, hydrocarbons present in two-phase flow conditions would already have made the system inoperative.

Northwest Pipeline Company counters the producers' arguments with a different concern from its own standpoint as pipeline operator. While the sales gas containing more than 1 percent CO_2 may indeed ENTER the pipeline at Prudhoe Bay in a dehydrated condition that poses no threat of corrosion, the pipeline operator must ensure that the gas REMAINS corrosion-free throughout the several thousand miles of its journey. Apparently, some water is expected to contaminate the sales gas not only as a result of upset conditions, but even during hydro-testing associated with pipeline start-up. Whether Northwest's demand for a 1 percent CO_2 specification, therefore, is reasonable, has not yet been decided by FERC.

Because of permafrost problems in Alaska, the temperature of the gas must be held below the freezing point of water. Hence, if any water drops out in Alaska, it will likely do so in the form of ice or more precisely, hydrates, which are like ice crystals but encapsulate molecules of light hydrocarbons or sulphur compounds within their structures. At the planned operating temperatures for the Alaska pipeline segment, free water will form hydrates at temperatures as high as 60 degrees F. But ice and hydrates, unlike water, cannot combine with CO_2 to form an acid. Instead of gradual corrosion, the presence of solids will present a more immediate problem: blockage of the pipeline and its valves.

The Canadian section of the pipeline poses, perhaps, an even more fundamental concern. Canadian regulators have given preliminary approval to a water dewpoint specification for gas added to pipeline sections south of Whitehorse that is less stringent than specifications proposed for the

Alaska section. This difference, however, does not indicate any malfeasance by Canadian pipeline owners and regulators, but rather a difference in judgment about what constitutes acceptable risks in the face of added costs for prevention.

3. <u>The effect of carbon-dioxide on downstream gas systems</u>. Purchasers of Prudhoe Bay gas have argued that a high CO_2 content would adversely affect their interests in several ways.

In its July 1979 comments to FERC, the Natural Gas Pipeline Company of America states that a gas of 13 percent CO_2 would create corrosion problems within its own pipeline system, because that system's low-CO_2 gas from other sources has a relatively high water content. In addition, if Alaska gas contained excessive amounts of CO_2, it would have to be mixed with large quantitites of gas from elsewhere in order to ensure consistent burning characteristics.

Northern Natural Gas Company in its letter to the Alaskan Gas Project Office of FERC (dated December 7, 1978), advocates even more stringent CO_2 standards. It claims that its purchased volumes of Alaska gas will first be stored as LNG and, as such, cannot tolerate a CO_2 content that exceeds about 200 parts per million (ppm). But as the State of Alaska observed in its reply comment of June 1979, all pipeline gas must undergo CO_2 removal at the LNG plant site. The State concluded, therefore, that Northern's concern should not influence the choice of CO_2 specifications for North Slope gas.

The valid point raised by Northern, however, was that most LNG facilities are now designed to treat pipeline gas whose CO_2 content does not exceed 1 percent. Hence, the additional expense that shippers must bear to treat 3 percent CO_2 gas must be taken into account in assessing the conditioning and transportation costs for Prudhoe Bay gas.

4. <u>The effect of carbon dioxide on project economics</u>. One other area of concern has entered the debate on CO_2 specifications --- overall project economics. How would different CO_2 levels affect the cost of conditioning versus the cost of pipeline transportation?

The Ralph M. Parsons Company (in its February 1979 CO_2 specification study[4]) estimates that by relaxing the CO_2 removal process to yield a sales gas of 3 percent CO_2 instead of 1 percent, the conditioning plant construction costs could be pared down by about 7 percent. If no CO_2 removal facilities were built (yielding a sales gas of 13 percent CO_2), construction costs would be about half as much. Fuel requirements for the scaled-down conditioning plant would decrease by 8 percent in the 3 percent CO_2 case, and would drop by about one-third in the 13 percent case.

TABLE 5

COSTS OF CONDITIONING	1% CO_2 (base case)	3% CO_2	13% CO_2
Construction cost	100%	93%	54%
Fuel requirements	100%	92%	66%

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4) The Ralph M. Parsons' studies of conditioning processes and facilities were financed jointly by the North Slope producers and a half dozen likely gas shippers (interstate gas transmission companies). It was conducted about two years ago and, necessarily, had to adopt some working assumptions in spite of the many unknowns. Consequently these assumptions and the study conclusions are not totally satsifactory to all of the sponsoring parties. The study is, however, the only in-depth analysis that presently exists; and it is, therefore, widely quoted.

Table 5 suggests that from the standpoint of conditioning costs and fuel requirements on the North Slope alone, the 13 percent CO_2 case is a clear winner. One must remember, however, that such high CO_2 levels would impose greater transportation costs, additional capital costs downstream (since CO_2 must be removed prior to customer distribution), and it threatens pipeline corrosion. The table also shows that a 3 percent CO_2 specification is preferable to one percent, but not overwhelmingly so.

On the other hand, Northwest Alaskan Pipeline Company in its February 1979 "CO_2 Transportation Study", shows that a 3 percent or 13 percent CO_2 specification would cost MORE than a 1 percent specification from the standpoint of pipeline transportation costs. (While the added volume of CO_2 contributes no additional heating value to the gas stream, it does require an increased investment in compression equipment and more fuel during pipeline operations.) But here too, the cost differences between the 1 and 3 percent CO_2 specifications are not very substantial.

In comparing how much money would be SAVED in the conditioning process by moving from a 1 percent CO_2 specification to 3 percent, versus how much additional money and fuel would be SPENT for pipeline transportation, even Northwest admits that the conditioning cost savings are of greater importance [p 5. of Northwest's "CO_2 Transportation Study"]. The difficulty for FERC will be in judging the significance of this net cost savings compared to the pipeline corrosion and downstream marketing problems previously discussed. FERC has, at least for the present, ruled that the cost of reducing CO_2 content below 3 percent, if required, is to be treated as a conditioning cost. Until the issue of conditioning cost allocation is finally decided, however, we cannot know whether it is the producers (and the State of Alaska) or the gas consumers who would benefit from an attempt to optimize total project costs.

E. VOLUMES OF GAS AND GAS LIQUIDS AVAILABLE FOR SHIPMENT

No intelligent discussion about sales gas composition can take place without some agreement as to what volumes and kinds of hydrocarbons will actually be AVAILABLE for shipment through the gas pipeline. Previous debate on the matter of gas composition has, in fact, been clouded by differing outlooks on gas availability. Worse yet, those discrepancies in underlying assumptions have largely been overlooked. Again, whether all the intermediate hydrocarbons will be ALLOWED to enter the gas pipeline for shipment is a complex question with which the rest of this report is concerned --- but that is all the more reason to make sure that hidden differences in assumptions about hydrocarbon availability are not ultimately responsible for disagreements on other matters.

This section will examine the three factors that determine how much and what kind of hydrocarbons are available for shipment through the gas pipeline: (1) reservoir production rates, (2) North Slope fuel requirements, and (3) the ability of the TAPS oil pipeline to carry intermediate hydrocarbons.

1. Reservoir production rates.

The field rules for the Prudhoe Bay reservoir currently limit raw gas production to 2.7 bcf per day, and it is expected that this rate can be maintained for 25 or more years. This rate, in turn, will yield about 2.0 bcf per day of conditioned gas. No one, of course, can guarantee that such offtake levels will indeed be physically possible, or that Alaska's Oil and Gas Conservation Commission will approve them throughout the life of the field, because the reservoir's production capabilities are based on predictions of FUTURE performance; but no one is now arguing seriously that any other figure makes more sense from the standpoint of today's planning needs.

2. Gas composition changes.

The expected hydrocarbon composition of that steady 2.7 bcf per day, however, IS expected to change through time. During the early years of gas sales, solution gas bubbling out of the crude oil will comprise the greater portion of total gas volume. But as crude oil production drops off, so will the volume of solution gas. The 2.7 bcf per day, instead, will increasingly consist of gas that comes directly out of the gas cap. Since gas cap gas is "leaner" in heavier hydrocarbons than the solution gas, the combined gas mixture, as well, will grow leaner through time.

ARCO [Dickinson letter to Tussing; January 3, 1980] estimates that by the 25th year of gas offtake, the natural gas liquids (NGL) content of the produced gas will have dropped by about 17 percent. Similarly, SOHIO [Pritchard letter to Barlow; January 23, 1980] estimates a drop-off in the ethane-propane NGL component of roughly 20 percent. The crucial issue is not, however, the absolute volumes of NGL's that must transit TAPS, but the PROPORTION of butanes in the oil stream, a ratio that promises to increase over time as oil production declines. It is nevertheless doubtful whether this trend is significant enough to merit any real consideration in system planning and design --- especially given the likelihood that during the 25 year operating period other gas reservoirs with different gas compositions will be tapped.

While the changing hydrocarbon content of PRUDHOE BAY natural gas may not be a major consideration in the design of ANGTS, system engineers do have to take into account the likelihood that gas produced from other, still undiscovered or undeveloped reservoirs on the North Slope may differ significantly in chemical composition. Prudhoe Bay gas is relatively sweet and wet (low in sulfur compounds and rich in NGL's), and has a relatively high CO_2 content. A conditioning plant designed to treat this raw gas stream, or a pipeline designed to carry it, would be uneconomic or even inoperable for gas from another reservoir which happened, for example, to be sour and dry, and contained little CO_2.

Under the present plan for ANGTS, the initial conditioning plant will be located on the North Slope and designed expressly to treat the volume and mixture of compounds the Prudhoe Bay reservoir is expected to produce. If new and different gas mixtures later came on stream from other reservoirs, the existing plant could be modified or new facilities added at the same place or elsewhere specifically to accommodate the new supply. In either case, the pipeline itself can be built to accommodate pipeline-quality (fully-conditioned) gas from any source in Arctic Alaska. If the conditioning plant were at Fairbanks or further downstream on the pipeline, however, system engineers would face the far more difficult task of designing both the pipeline and the conditioning plant to handle a stream of raw gas whose characteristics might change radically over time.

Thus, the possible need for ANGTS to handle different (and yet unknown) gas mixtures over its operating life is one reason why the gas producers, Northwest Alaskan, the prospective gas shippers, and FERC all seem to agree that the conditioning plant for Prudhoe Bay gas should be located on the North Slope, despite the belief of many Alaskans that construction and operating costs would be less, and local economic benefits greater, in an Interior Alaska location.

3. North Slope fuel requirements.

It takes a good deal of energy to produce, clean and condition, and transport oil and gas from the North Slope. This energy must be drawn out of the stream of produced hydrocarbons. There are three general categories of North Slope fuel uses: (1) FIELD FUEL, (2) TAPS FUEL, and (3) PLANT FUEL (for the gas conditioning plant).

(1) FIELD FUEL is needed for all of the activities relating to oil and gas PRODUCTION. In addition to actual oil production at the wells, energy is consumed in gathering the oil into facilities where the crude can be separated from the solution gas, dehydrated of its water content, and cleaned of its impurities. Field fuel is also consumed by the Prudhoe Bay electric generating plant. Produced gas in excess of fuel requirements is currently compressed to about 4000 psi for reinjection into the reservoir, pending the onset of gas sales. This function is performed in the Central Compressor Plant, which, likewise, requires a a good deal of energy.

Estimates of future field fuel requirements, such as those used in the Ralph M. Parsons Company report, must also provide for additional production activities, which will include more elaborate facilities for injecting back into the reservoir the produced water that is separated from the crude, and for the injection of source water from the Beaufort Sea in order to maintain reservoir pressure. (This is sometimes called waterflooding.) The "maximum" field fuel case used in the Parsons report takes all of these activities into account.

(2) TAPS FUEL is that which is needed to run the first four pump stations of the Trans-Alaska oil pipeline. While pump stations south of Station #4 provide for their own fuel

requirements by processing a portion of the crude oil into diesel fuel in individual topping plants, the TAPS owners decided that it would be cheaper to supply the more northerly pump stations with North Slope gas by means of a buried gas pipeline beside the oil line. Unlike the TAPS oil pipeline, the Alaska Highway gas pipeline will transport a mixture of hydrocarbons that can be used directly in its compressor stations, thus no provision has been made for supplying even its northern portions with a separate energy stream.

(3) PLANT FUEL is needed for all aspects of the gas conditioning process --- for (a) separating and fractionating propanes, butanes, and pentanes-plus from the lighter hydrocarbons; (b) for removing carbon dioxide from the remaining methane-ethane stream; and (c) for chilling and compressing the conditioned gas to meet the requirements for shipment through the gas pipeline. Sometimes PLANT FUEL is discussed more specifically as HEATER FUEL and TURBINE FUEL. The distinction is made because while heaters can run on a relatively low BTU fuel, turbines have more stringent requirements.

Where does all this fuel come from? Currently, the Field Fuel Gas Unit conditions a portion of the raw gas to provide energy for most ongoing field activities and for TAPS.[5] Since the TAPS fuel gas line experiences extremely cold temperatures enroute to the pump stations, the Field Fuel Gas Unit yields a gas stream with exceptionally stringent specifications --- a -40 degree F. hydrocarbon dewpoint and a -60 degree F. water dewpoint. When waterflooding begins, the Field Fuel Gas Unit can be expanded to

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5) The gathering centers in the western part of the field furnish their own fuel.

accomodate the new demand. Or, as the Parsons study antici-pates, additional FIELD FUEL requirements can be met by fuel generated at the conditioning plant. The Parsons study has chosen the latter technique in an attempt to optimize the entire system, disregarding ownership responsibilities. In so doing, an outlet is found for the ethane-rich CO_2 "waste" gas that is a by-product of the CO_2 removal process selected by Parsons. This stream is enriched with propane to provide a fuel suitable for field activities.[6]

Nevertheless, the producers make a point of emphasizing that they have several options for taking care of all their own fuel needs in the field and for TAPS, and they have not yet decided whether it would be in their interest to enter into an arrangement with the owner of the conditioning plant (whoever that may be) simply for the sake of overall project optimization. After all, their gas sales contracts commit for sale only the gas that is EXCESS to field and TAPS requirements. The producers further stress the poten-tial disadvantages of making their crude oil production, processing, and transportation facilities dependent upon a stream of by-products from the gas conditioning plant. This concern would probably be even greater if the conditioning plant were operated and controlled by another party, such as the state.

Of course, the PLANT FUEL requirements will have to be met by the owners of the conditioning plant. Parsons Company, in its proposed plant design, has selected what it

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6) No one knows exactly how much field and TAPS fuel will be needed in the future. Moreover, those requirments will vary almost daily. Parsons, therefore, calculated both a "maximum" and a "minimum" field fuel case. Most parties believe the "maximum" case data is the more relevant for planning.

considers to be the most economical CO_2 removal process, given the raw gas composition and the probable gas pipeline specifications. The process chosen by Parsons, however, results in a waste gas that also contains about half of the ethane that enters the plant.[7] Accordingly, Parsons recommends using the ethane-CO_2 by-product for fuel. Given the fact that SOMETHING has to be burned as fuel, this is not necessarily a bad thing --- unless there is some reason to view the ethane (and the propane that enriches it) as exceptionally valuable hydrocarbons for which a better use exists. There is little argument within Alaska that ethane would be the most desirable feedstock for a local petrochemical industry. It is still unclear, however, whether an ethane based petrochemical plant is economically feasible in Alaska, and even if it were, whether all of the ethane would, in fact, be required for such a facility. For example, the November 1979 study prepared by Bonner & Moore Associates for the State of Alaska indicates that only about one-fourth of the ethane is needed to feed a "world-scale" petrochemical plant, in which case, the CO_2 removal process chosen by Parsons Company in itself should cause no alarm.[8]

One other major point of controversy arises with respect to design of the CO_2 removal process and PLANT FUEL requirements. The ethane-rich CO_2 waste gas has a lower heating value (net BTU) of about 200 to 220 BTU per cubic foot. While this mixture may be adequate for use in

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7) The Parsons design absorbs CO_2 via a physical, rather than a chemical, process. This process is much like fractionation in that the components are separated by their different boiling points. Given that the boiling point of ethane is relatively close to that of CO_2 (see Table 3), some of the ethane necessarily will "flash" off with the CO_2.

8) Bonner and Moore Associates, Inc., Promotion and development of the Petrochemical Industry in Alaska (November 1, 1979). See also the author's critical review of the Bonner and Moore report, "Prudhoe Bay Natural Gas Liquids, the Alaska Highway Gas Pipeline, and Petrochemical Development in Alaska" (January 20, 1980).

the plant heaters, it must be enriched to meet the specifications of the local turbines and field equipment. The Parsons Company design raises the BTU content by propane "spiking" to achieve a net heating value of about 475 BTU/cf for local turbine fuel, and 825 BTU/cf to suit the design limitations of existing field equipment. The controversy lies in the fact that while propane can easily be shipped south in the gas pipeline, butanes are more troublesome. Therefore, wouldn't it make more sense to use butane rather than propane for spiking purposes?

Unfortunately, the answer is not so simple. Butane could create the same hazards in the fuel system that it poses in the Alaska Highway gas pipeline --- condensation at low temperatures. In addition, its burning characteristics are different from those of propane, because it packs a bigger wallop of combustible carbons in each molecule. While use of butane instead of propane is not entirely out of the question, those responsible for smooth operations on the North Slope naturally will look for system designs and fuel compositions that promote simplicity and reliability. Unless the State of Alaska can demonstrate a special interest in the propanes or butanes that differs markedly from that shared by the other gas owners, any second-guesses the State might make with respect to fuel enrichment decisions would probably be viewed by others as unduly meddlesome.

Table 6 provides a perspective on North Slope fuel consumption. Of the hydrocarbons in the raw gas stream, about 15 percent will be consumed as field fuel, by the TAPS pump stations, and during the conditioning process.

TABLE 6

NORTH SLOPE FUEL REQUIREMENTS[1]

	Produced Gas[2]	FFGU Outlet[3]	Conditioning Plant Inlet	Field Fuel[4]	Plant Fuel[5]	Available Hydrocarbons[6]
Billion BTU/day (gross)	2849	[95]	2754	[214]	[113]	2427
Million cf/day	2700	[100]	2603	[236]	[248]	2104
Average BTU/cf (gross)	1055	953	1058	906	456	1154

NOTES:

1. Source: Exxon, personal communication (February 1980). Exxon personnel calculated these data using the Parsons reports maximum field fuel case.

2. An offtake rate of 2.7 bcf/day is assumed, consistent with the Prudhoe Bay reservoir field rules set by the Alaska Oil and Gas Conservation Commission. Parsons assumed a 2.8 bcf/day offtake rate.

3. FFGU Outlet signifies the fuel products of the Field Fuel Gas Unit that are used in the northern pump stations of TAPS and for a variety of field activities. Heavier hydrocarbons removed during that process are routed (along with the rest of the produced gas) to the conditioning plant and its fractionators.

4. Field Fuel designates those North Slope energy requirements that exceed the output of the Field Fuel Gas Unit. The present capacity of the Field Fuel Gas Unit is 100 million cubic feet per day. Parsons assumes that this capacity will be utilized fully, but that additional field fuel needs will be met by products of the conditioning plant, rather than by an expansion of the FFGU.

5. Plant Fuel includes both turbine and heater fuel for the conditioning plant. 456 BTU per cubic foot, therefore, represents the weighted average of the heating values for the relatively high BTU turbine fuel, and the low BTU heater fuel.

6. Available Hydrocarbons are the final product streams available for shipment through the gas pipeline or blended into TAPS crude.

4. Shipping intermediate hydrocarbons through TAPS.

As mentioned earlier, the Alaska Highway Gas pipeline will have no problem carrying light hydrocarbons (C_1, C_2, and C_3) in a vapor phase, while the TAPS oil pipeline can easily handle heavy hydrocarbons (C_6+) in a liquid phase. The question, then, is whether both systems together can support shipment of all of the intermediate hydrocarbons (C_4 and C_5) without encountering the hazards of two-phase flow.

Referring once again to Figure D, the reader will note that upset conditions attendant to a 1260 psig system limit the amount of butanes that can be transported through the Alaska Highway Gas Pipeline. The phase diagrams show that while 50 percent of the available butanes might be handled safely, shipping all of the available butanes would not be possible. Nobody can precisely judge what will constitute a safe limit, of course, until the pipeline engineering and contingency plans are completed. But it is clear that all of the pentanes and something less than half of the butanes will have to find another means of transport, such as TAPS.

Right now, crude oil enters the TAPS oil pipeline on the North Slope at 140 degrees F. Table 3 (on page 4) shows that at 140 degrees F., C_6 is a liquid but that C_5 and lighter hydrocarbons would be present in a vapor phase[9]. What are the prospects for lowering the TAPS inlet temperature to enable it to accept all the pentanes and maybe even some of the butanes?

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9) The table, however, makes no provision for the fact that hydrocarbon MIXTURES can safely accomodate some small volume of light hydrocarbons which, as pure substances, would exist as vapors.

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Most parties agree that the inlet temperature of TAPS can not feasibly be reduced below about 110 to 112 degrees F. Three factors account for this limitation:

(1) Even if the inlet temperature were reduced, say, to 100 degrees F., the warm summer months combined with the heat naturally generated by the friction of flow would result in somewhat higher temperatures in certain parts of the pipeline. Thus the temperature threshold that limits the introduction of intermediate hydrocarbons into the crude cannot effectively be reduced beyond about 100 degrees [Pritchard letter to Barlow; January 23, 1980].

(2) On the other hand, if the TAPS inlet temperature is reduced, the heavy components of the crude oil ("waxes") will solidify more readily, slowing the flow and thereby reducing the daily throughput. At lower inlet temperatures, the line will have to be "pigged" more often to strip away the wax build-up. Moreover, if inlet temperature specifications were relaxed, TAPS would face a greater risk that wax solidification might cause real problems if the line experiences an extended shut-down during the winter cold.

(3) Even if both of the previous limitations were ignored, there are practical constraints on the amount of intermediate hydrocarbons that can be shipped through TAPS. In order to control air pollution in the Los Angeles basin, government regulations permit no landing of crude oil with vapor pressures higher than 11.1 psia at storage temperatures of, say, 100 degrees F. That is, crude must emit no vapors when subjected to pressures at or above 11.1 psia and to temperatures at or below 100 degrees. Since the lowest pressure at which TAPS operates is around the atmospheric pressure of 14.7 psia, rather than 11.1 psia, a TAPS bubble-point specification compatible with California's standard would have to be somewhat above 100 degrees.

Given all three constraints just discussed, most parties seem to believe that a reasonable minimum inlet temperature for TAPS is about 110 to 112 degrees F. At that temperature, both ARCO [Dickinson letter to Tussing; January 3, 1980] and the Ralph M. Parsons Company [September 1978 study report, Volume II, page 2-271] believe that essentially all of the available pentanes and butanes could be transported through TAPS, at peak crude oil throughput rates. SOHIO, however, suggests that only some of the butanes can be accomodated [Pritchard letter to Barlow; January 23, 1980].[10]

Nevertheless, assuming that the gas pipeline can safely handle at least 50 percent of the available butanes as previous discussed,[11] there appears to be little chance that butanes will be stranded on the North Slope --- at least in the early years of gas shipments. As oil production declines, however, the ability of TAPS to carry intermediate hydrocarbons will drop accordingly. This decline is expected to occur much faster than the offsetting feature of a progressively "leaner" raw gas stream mentioned earlier. For example, assuming (1) a 1985 start-up for the gas pipeline, (2) ARCO's oil production forecast [Dickinson letter to Tussing; January 3, 1980], and (3) the Parsons' phase diagrams [Volume II, pp. 2-287, 2-297, of the September 1978 conditioning study], all of the "available" pentanes and butanes could be shipped through TAPS initially, but the oil line could no longer accept ANY butanes by the seventh year of gas shipments.

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10) Before one focuses on the apparent disagreement, it must be remembered that all calculations to date have been rough and possibly based on different crude oil assays, or different decline rates for crude oil production. Sohio is scheduled to complete a more refined analysis of this matter in early 1980.

11) Most parties agree that it is realistic to assume that ANGTS can accommodate about 85 percent of the butanes available after removal of the various fuel streams in the Parsons' maximum field fuel case. The State believes, however, that if NO ethane or propane is burned on the Slope, and those hydrocarbons are instead shipped through the gas pipeline, only about 25 percent of the butanes could be accommodated in ANGTS.

Is there, then, any real cause for alarm? First, putting things in perspective, even in the early years of gas production when butane content is greatest, it will comprise less than 2 percent of the gaseous hydrocarbon volume (though about 5 percent of the total BTU content of the raw gas stream). Moreover, unless there is some reason to believe that the producers and their gas purchasers have less interest than the State in getting as many of the North Slope BTU's to market as possible, here too, it may be unreasonable for the State to make second-guesses on the best overall system design.

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September 21, 1979

The Honorable Thomas K. Williams
Commissioner
Alaska Department of Revenue

Re: Alaska Gas Pipeline Financing Authority

Dear Commissioner Williams:

At your request we have reviewed A.S. 44.55 (the "Act") establishing the Alaska Gas Pipeline Financing Authority (the "Authority") and certain amendments to the Act which have been suggested. Our review has centered on those provisions of the Act which relate to the approval of the financial and Alaska impact plan (the "Plan") and the authorization, approval and issuance of bonds. We have not commented on the contents of the Plan itself since these appear to relate to policy matters which (although they may affect the practicality of the issuance of bonds) do not directly affect the legal ability of the Authority to issue bonds. This letter and the attached memorandum (Attachment A) contain our initial analysis of the legislation.

In the brief time available we have not been able to prepare definitive language for some technical changes which we suggest relating to the purposes and provisions of bonds which may be issued. As to most matters discussed, however, we have drafted amendments which reflect our comments (See Attachment B - Draft Revisions).

We have approached this analysis for the standpoint of bond counsel, and accordingly, our recommendations may seem overly cautious. By this, we mean that in analyzing a particular problem we may recommend a legislative amendment even though we might conclude that the Authority would ultimately prevail in any legal challenge on the matter. We have approached our analysis in this manner so that, to the extent possible, the Authority may avoid litigation on its issuance of bonds and that it may be able to obtain an unqualified approving legal opinion on such bonds. It is much easier to make clarifying changes at this point than to later resolve questions which might otherwise arise.

This letter addresses the following subjects:

A. Purposes and Security for Bonds of the Authority.

B. Approval Process for the Plan and Bonds.

1. General

2. Refunding Bonds

3. Amendment of the Plan

4. Approval of the Plan

C. Lending of Credit.

D. Compliance with "on behalf of" Regulations.

E. Public Purpose.

F. Other Suggested Changes.

1. "Project Sponsor"

2. "Notes"

3. Interim Financing

4. Pledge to Bondholders

5. Other

The attached Supplemental Memorandum provides additional explanation of some of the matters summarized in this letter and discusses other matters which we have concluded do not require amendments to the Act.

A. Purposes and Security for Bonds of Authority

The Act, in its present form, does not clearly state the purposes for which bonds of the Authority may be issued. Section

44.55.090(a) presently authorizes the issuance of bonds only "for the purpose of purchasing or otherwise acquiring any obligation issued with respect to the project . . . and for the establishment of reserves to secure or pay bonds. . . ." We suggest that the existing provisions in § 44.55.090(a) be amplified to clarify and broaden the purposes for which bonds may be issued. See attached draft revisions § 44.55.090(a).

The manner in which an Authority financing is to be accomplished - the security arrangements and permissible covenants upon which an issue of bonds is based - is now stated in the Act in a sketchy manner. We understand that it is not known at this time what form the financing plan would take. Accordingly, it seems desirable to give the Authority powers which allow it to employ a wide range of financing techniques, in order that the ultimate selection of a financing plan (which the Legislature would pass on) will not be limited by lack of statutory authority. To this end, we recommend that the Act be revised to include the following: (1) a broad definition of project costs which may be financed; (2) clarification that interim and other financing of the project by the project's sponsor may be refinanced; (3) more detailed authority for the acquisition of property interests and the granting of security interests in such property; (4) authority for making loans to project sponsors, or other persons, in furtherance of the financing of the project; and (5) expanded powers to enter into trust arrangements.

Such provisions must be carefully drawn after a more detailed investigation into the background of the proposed financing than has been possible for us to accomplish in the time available to date. Accordingly, although we have begun work on such provisions, we would suggest that we be allowed a further period of time in which to prepare such provisions for consideration by the Authority.

B. <u>Approval Process for the Plan and Bonds</u>

1. <u>General</u>: The financial and Alaska Impact Plan required by A.S. 44.55.100 is in many respects an estimate or projection, rather than a set of legal restrictions. For example, two items which the Plan must contain are "projected debt service requirements of the bonds" and "the preliminary financing plan for the entire transmission system, as prepared for submission to the Federal Energy Regulatory Commission".

The language of A.S. 44.55.110, requiring that "no bonds or notes may be issued except in accordance with the approved plan", converts such estimates into legal limitations on the issuance of bonds. Converting estimates into limitations has major drawbacks.

First, some elements of the Plan are not suited to function as limitations. While it is desirable to have an estimate or projection of debt service, for example, almost all states have concluded that putting legal limitations on interest rates, which are governed by market forces, is unwise. Even if it were desirable to put a limitation on debt service, there should be some leeway between the estimate and the limitation. Second, some elements of the Plan are inherently preliminary and subject to change: for example, the "preliminary financial plan for the entire transmission system". If there is a deviation from this preliminary financial plan in some element not related to the issuance of the bonds, is the power to issue bonds impaired, because their issuance would not be "in accordance with the Plan"?

For the foregoing reasons we recommend the following revisions to the existing legislation: (1) provide that approval of the Plan and approval of bonds be contained in separate concurrent resolutions; (2) provide that approval of the bonds may contain such limitations as the legislature deems appropriate; (3) eliminate the requirement that bonds be issued and sold "in accordance with the Plan". See attached draft revisions - § 44.55.090(a) and 44.55.110.

2. <u>Refunding Bonds</u>: Refunding bonds are simply a type of Authority bonds. The approval process can be the same as for initial funding bonds, i.e., legislative approval by concurrent resolution. Revising A.S. 44.55.090(g) accordingly would permit elimination of confusing existing references to refunding bonds in A.S. 44.55.110, the approval section for the Plan.

We therefore recommend: (1) revising A.S. 44.55.090(g) (dealing with refunding bonds) to incorporate by reference the approval procedure for initial funding bonds; (2) eliminating references to approval of refunding bonds in A.S. 44.55.110. See attached draft revisions - § 44.55.090(g) and 44.55.110.

3. <u>Amendment of Plan</u>: The existing A.S. 44.55.110 implies that no amendments to the Plan may be approved after passage by the Authority of a resolution authorizing sale of the bonds. Such a restriction seems unwise, for two reasons. First, many potential changes in the Plan might be desirable, yet have no impact at all on the issuance of Authority bonds or the rights or interest of bondholders. Such changes should not be precluded. Second, this legislation cannot limit the right of a future legislature to make legislative changes. The only limitation on the actions of future legislatures which is triggered by the

issuance of bonds is the constitutional prohibition against impairment of contracts. An existing section of the legislation already addresses this concern (A.S. 44.55.140-"Pledge of the State.")

For the foregoing reasons, we therefore recommend that amendments to the Plan be permitted except to the extent prohibited by the "pledge" section, i.e., except to the extent amendments to the Plan would impair the rights of bondholders. See attached draft revisions - § 44.55.110.

4. Approval of the Plan: If the foregoing revisions are made A.S. 44.55.110, dealing with approval of the Plan, need only provide for approval of the Plan (or a conditional Plan) by concurrent resolution. The provision for disapproval by either house seems unnecessary, since both houses must approve the Plan before it can become effective. See attached draft revisions - § 44.55.110.

C. Lending of Credit

A.S. 37.10.085 prohibits the state from lending its credit or borrowing money for the use of a corporation. It is critically important to make clear that this statute does not apply to the Authority or its bonds. Our analysis of A.S. 37.10.085 is more fully set forth in the attached Supplemental Memorandum under "Lending of Credit." We strongly recommend addition to the Act of language excluding A.S. 37.10.085 from application to the Authority. See attached draft revisions - § 44.55.135.

D. Compliance with "on behalf of" Regulations

Under existing regulations of the Internal Revenue Service, it is probable that bonds issued by the Authority would not be regarded as being issued by the state or a political subdivision. Bonds of the Authority may nevertheless be tax-exempt if the Authority is held to be an entity acting "on behalf of" the state. See the attached Supplemental Memorandum for a more detailed analysis of this subject under The Authority as a "Constituted Authority". IRS regulations (§ 1.103-1) which are currently proposed, though not yet in effect, detail certain requirements which must be met in legislation such as the Act if the Authority is to be held to be issuing bonds "on behalf of" the state. Although these regulations could be changed at any time, it is desirable that the Act meet the requirements as they are now proposed. Accordingly, the addition of certain language to the Act relating to disposition of the earnings or property of the Authority is suggested. See attached draft revisions § 44.55.145 and 44.55.155.

E. Public Purpose

The state constitution (Art. IX, §6) prohibits the use of public money, property or credit except for a public purpose. It is thus essential that there be as little room as possible to question the public purpose for the proposed use of the proceeds of Authority borrowing to finance the project. The courts will usually give great weight to legislative findings of public purpose, but the existing legislative findings on which the Act is based are equivocal. It is important that they be changed to find that state financing of the project will, rather than may, promote an essential public purpose. A detailed examination of this issue is contained in the attached Supplemental Memorandum under "Public Purpose".

F. Other Suggested Changes

1. "Project Sponsor": Section 44.55.200(5) defines a "project sponsor" as "any partner of the Alaska Northwest Natural Gas Transportation Company, or its successors," thereby apparently excluding that company or its successors from the definition of "project sponsor." This seems to be an unintended result and the following language is suggested.

> "(5) 'Project sponsor' means the Alaska Northwest Natural Gas Transportation Company, or its partners or successors, or any other company, individual or association which owns an interest in the project or any part thereof."

2. "Notes": The Act sometime refers to "bonds" and, on other occasions, to "bonds or notes". This makes it uncertain as to whether or not the provisions of the Act which refer only to bonds relate to notes as well. Since the word "bonds" is defined to include notes (A.S. 44.55.200(5)), reference to notes in the body of the legislation should be excluded.

3. Interim Financing: It may be desirable to issue obligations for interim financing pending the issuance of bonds. We suggest that language be added to the definition of "bonds" (A.S. 44.55.200(2)) to make it clear that interim financing may be authorized by the Legislature as well as permanent financing. See attached draft revisions - A.S. 44.55.200(2).

4. Pledge to Bondholders: The "Pledge" section appears to adequately protect bondholders interests, except in two respects. First, the pledge in Section 44.55.140 should be a direct pledge to the holders of the bonds, not a pledge to agree with the holders of the bonds. It is not clear whether the mechanism

provided for such a later agreement by the Authority with the bondholders binds the State. Second, very large amounts of bonds are commonly issued in several series, only as funds are required and to permit the market to absorb the bonds over a period of time. In such cases, it is necessary to assure the purchasers of the initial series that there is no obstacle to the issuance of the subsequent series, so that financing can be completed. The "pledge" section should be amended to include a promise that power to issue bonds will not be withdrawn once an initial series has been sold. See attached draft revision - § 44.55.140.

5. Other: Various other minor textual changes are suggested in the attached draft revisions. Also, we suggest the language in A.S. 44.55.090(a) referring to § 103 of the Internal Revenue Code be deleted, as the code may change in such a way that the bonds would not literally meet this requirement.

SUMMARY AND CONCLUSION

In summary we recommend as follows:

1. Modification of A.S. 44.55.090 to clarify the purposes for which bonds may be issued, and to provide that bonds may be issued only after approval of the financial and Alaska Impact Plan and pursuant to a separate resolution specifically approving the bonds.

2. Additions to the Act to better assure that the Authority will have the statutory authority to issue and secure bonds in such manner and for such purposes as may be proposed to and approved by the Legislature.

3. Modification of A.S. 44.55.110 to clarify the plan approval process.

4. Modification of the legislative findings to support the conclusion that financing by the Authority is for a public purpose.

5. Other changes to clarify and correct various sections of the Act as set forth in the attached draft revisions.

We would appreciate the views of the Authority as to these suggested revisions. The next step would be to place the suggested amendments into formal bill format, which we would be happy to do at your request.

Very truly yours,

PRESTON, THORGRIMSON,
ELLIS, HOLMAN & FLETCHER

By: John R. Messenger By: David L. Beller By: Forrest W. Walls

ATTACHMENT A

Supplemental Memorandum

Alaska Gas Pipeline Financing Authority Legislation

LENDING OF CREDIT

A question might be raised as to whether the issuance of revenue bonds pursuant to the Act would conflict with the provisions of A.S. 37.10.085 relating to financial aid to corporations by the State or political subdivision of the State. A.S. 37.10.085 reads as follows:

> Sec. 37.10.085 FINANCIAL AID TO CORPORATIONS BY STATE OR POLITICAL SUBDIVISION.
>
> Neither the state nor a political subdivision of the state may
>
> (1) make a subscription to the capital stock of a corporation;
>
> (2) lend its credit for the use of a corporation; or
>
> (3) borrow money for the use of a corporation

Under this section, it could be argued that through the issuance of revenue bonds by the Authority for purposes of financing the Alaska Natural Gas Transportation System, the State or a political subdivision of the State would, in effect, be lending its credit or borrowing money for the use of a corporation.

In response it could first be argued that neither the State nor a political subdivision of the State is lending its credit or borrowing money when the Authority issues its bonds pursuant to the Act.1/ This argument would be based upon the characterization of the Authority's bonds and the restriction on their issuance in AS 44.55.090(b)

1/ It might also be argued that the project sponsor Alaska Northwest Natural Gas Transportation Company, is not a corporation but a partnership and therefore any lending of credit would not offend A.S. 37.10.085. We doubt that this argument would ultimately prevail since the partners themselves are corporations and any benefit provided by the financing would flow to such partners.

That subsection reads:

> (b) The bonds issued by the authority do not constitute an indebtedness or other liability of the state or of a political subdivision of the state, but are payable solely from the income and receipts or other money of the authority. The authority may not pledge the faith or credit of the state or of a political subdivision of the state to the payment of a bond, and the issuance of a bond by the authority may not directly or indirectly or contingently obligate the state or a political subdivision of the state in any manner, except as specifically provided in this chapter.

This subsection specifically provides that bonds issued by the Authority are not obligations of the State or a political subdivision of the State. In addition, this subsection prohibits the authority from pledging the credit of or obligating in any manner, the State or a political subdivision of the State. As such, because of the status of the Authority's bonds and the restrictions on their issuance, there is no way that the authority through issuing bonds could be lending the credit of the State or a political subdivision of the State.

Secondly, it could be argued that notwithstanding the question of whether the issuance of the Authority's bonds is lending the credit of or borrowing money by the State, such lending or borrowing would not be prohibited by AS 37.10.085 since the issuance of bonds serves a public purpose.

In Wright v. City of Palmer, 468 P.2d 326 (Alaska 1970) the court held that because "significant control and restrictions" were retained by a city over a private corporation, city bonds to finance property leased to the corporation did not violate AS 37.10.085. In that case, the City of Palmer proposed to issue $450,000 in general obligation bonds for the purpose of financing a 20 year improvement program providing for the purchase of a site and the construction of a manufacturing and processing facility within the City of Palmer. After the general obligation bonds were issued, the City entered into an agreement with Huskey Manufacturing Corporation, a manufacturer of low-cost housing, whereby the corporation agreed: to lease the building which was to be constructed for a period of 20 years; keep its raw materials within the City for tax purposes; employ not less than 80% of its workers from the Palmer area; provide training facilities for its employees; maintain on-the-job training programs under state and federal auspices; use the public utilities owned by the City as much as possible; and make available a paved parking lot adjacent to the building for public uses.

It was argued that the bond issue and the improvement program violated AS 37.10.085 in that the City of Palmer was lending its credit or borrowing money for the use of a private corporation when it leased the facility, financed by general obligation bonds, to Huskey Manufacturing Corporation for its business operations.

The court found otherwise, holding that the significant restrictions and controls by City of Palmer insured a public purpose, thereby preventing a violation of AS 37.10.085. The court, in effect, let the determination of whether the lending of credit or the borrowing of money was for the use of a private corporation, turn on the question of whether there was a public purpose.

In the course of the opinion the court in Wright stated:

> Since significant restrictions and controls are retained by the City of Palmer over Huskey Manufacturing Corporation's operations, the bond issue in question is not violative of AS 37.10.085. These controls and restrictions were imposed upon the corporation to insure the effectuation of the public purpose objective of this bond issue. We think that the question of whether the public credit is being pledged for a private purpose is also comprehended under the broader question of whether a public purpose is served by the bond issue and plan for its expenditure, which is discussed below. (468 P.2d at 329)

Thus, Wright stands for the proposition that a lending of credit or a borrowing of money for the use of a private corporation does not exist when the State or a political subdivision of the State establishes significant restrictions and controls in the financing program to insure a public purpose and there is, in fact, a public purpose. This authority is pertinent in our situation since the legislature here, as did the City of Palmer in Wright, established significant restrictions and controls to insure a public purpose. We discussed above the public purpose set out in the Act.

Thus, it could be concluded that any lending of credit or borrowing of money would not be "for the use of a private corporation" within the meaning of AS 37.10.085 since a public purpose is present and insured by specific controls.

Therefore, because of the nature of the Authority, the restrictions of A.S. 44.55.090, other controls to establish a public purpose and in light of our later discussion of the public purpose concept, a court might hold that the issuance of revenue bonds under A.S. 44.55 for the Alaska Natural Gas Transportation System would not be a violation of A.S. 37.10.085. Specific legislation should, however, be enacted to avoid any question.

Accordingly, we propose the following amendment to the Act:

Sec. 44.55.135 OPERATION OF AS 37.10.085 EXCEPTED.

The authority shall not be considered to be the state or a political subdivision of the state for the purposes of AS 37.10.085.2/

THE AUTHORITY AS A "CONSTITUTED AUTHORITY"

It is, of course, appropriate to insure, to the extent possible, that the Act is structured in such a way that if bonds are issued by the Authority they will be considered tax exempt under Section 103 of the Internal Revenue Code as obligations issued by a state or political subdivision of the state.3/

Sec. 103(a) of the Internal Revenue Code provides:

"§103 INTEREST ON CERTAIN GOVERNMENT OBLIGATIONS

(a) General rule. Gross income does not include interest on

(1) The obligations of a State, a Territory, or a possession of the United States, or any political subdivision of any of the foregoing, or of the District of Columbia; . . . ."

2/ Similar amendments of this kind can be found in other Alaska authority statutes. See A.S. 44.61.190 and A.S. 18.26.250.

3/ The main obstacle to tax exempt status of Authority bonds requires an amendment to Sec. 103(c) of the Internal Revenue Code relating to Industrial Development Bond restrictions (the "two county rule") and cannot be cured by amendments to the Authority Statutes.

Although Section 103(a) expressly provides that interest on obligations of a state, a territory, a possession, or a political subdivision thereof are exempt from tax, Treas. Reg. §1.103-1 and Rev. Ruls. 54-106, 57-187 and 63-20 have construed the language of Section 103(a) as also including obligations issued "on behalf of" a state or political subdivision of a state.

Since the Authority is probably not "the State" or a political subdivision of the State, as defined by the Internal Revenue Service (IRS) (because it does not have the requisite sovereign powers), its obligations will be tax exempt only if it meets certain conditions imposed by the IRS.

Until recently, those conditions were set forth solely in Treas. Reg. §1.103-1 and amplified in Rev. Rul. 57-187, 1957-1 C.B. 65, Rev. Rul. 60-248, 1960-2 C.B. 35; and Rev. Rul. 63-20, 1963-1 C.B. 24.

However, on February 2, 1976, the IRS published Proposed Regulation §1.103-1 (41 Fed. Reg. 4829-4831) which set forth new criteria for determining whether a particular obligation would be considered issued on behalf of a state or political subdivision of a state. This proposed regulation by its own terms would amend the existing Treas. Reg. §1.103-1 and would supercede all outstanding revenue rulings such as those mentioned above.

This proposed regulation applies to obligations issued on or after 180 days after final adoption or at the option of a state or political subdivision to obligations issued on or after February 2, 1976. Although this proposed regulation is not final, could be changed at any time, and applies only at the option of the state, it is probably prudent to follow it rather than relying on the existing regulation and revenue rulings since the proposed regulation may become final at any time, and it represents the most current public expression of IRS policy.

A major consideration under the proposed regulation is whether the issuer is a "constituted authority" empowered to issue obligations "on behalf of" the state or a political subdivision of the state. The proposed regulation sets out six requirements (§1.103-1(c)) for determining whether the actual issuer is a constituted authority. In simplified summary form these six requirements are:

1. The authority is specifically authorized pursuant to state law to issue obligations to accomplish a public purpose of the unit (state or political subdivision of the state). (§1.103-1(c)(2)(i))

2. The unit controls the governing board of the authority. (§1.103-1(c)(2)(ii))

3. The unit has either organizational control over the authority or supervisory control over the activities of the authority. (§1.103-1(c)(2)(iii))

4. Any net earnings of the authority (beyond that necessary for retirement of the indebtedness or to implement the public purpose of the unit) may not inure to the benefit of any person other than the unit. (§1.103-1(c)(2)(iv))

5. Upon dissolution of the authority, title to all property owned by the authority will vest in the unit. (§1.103-1(c)(2)(v))

6. The authority must be created and operated solely to accomplish the public purpose of the unit specified in the authority's statutory authorization. (§1.103-1(c)(2)(vi))

Although this list is a very simplified expression of the complex requirements set out in the proposed regulation, it nonetheless illustrates for purposes of discussion the criteria which will be used to judge whether the authority is a "constituted authority" empowered to issue obligations "on behalf of" the state.

With this criteria in mind, we have reviewed the Act including its provisions relating to membership, powers and purposes to determine whether the Authority would, in fact, qualify as a constituted authority under the proposed regulation. It is our view that the Authority meets the six requirements of Prop. Reg. §1.103-1(c) through either express provisions of the Act or through necessary implication under the Act. However, we believe that some amendments would be appropriate so that the six requirements would be met by express language in the Act to avoid any possible question that might arise.

To expressly meet requirement number 4 (§1.103-1(c)(2)(iv)), we suggest the following amending language:

> SEC. 44.55.145 EARNINGS OF THE AUTHORITY.
>
> The earnings of the authority in excess of the amount required for the retirement of indebtedness or the accomplishment of the purposes stated in this chapter may not inure to the benefit of any person other than the State.

To expressly meet requirement number 5 (§1.103-1(c)(2)(v)), we suggest addition of the following new section:

SEC. 44.55.155 DISPOSITION OF AUTHORITY PROPERTY UPON DISSOLUTION

Upon dissolution of the authority, title to all property owned by the authority will vest in the state.

In order to avoid any misunderstanding as to our views, we would like to emphasize two important limitations. First, our view as to whether the Authority is a constituted authority empowered to issue obligations of the state is based upon current interpretations of Section 103(a) by the Internal Revenue Service. Before the time that any bonds, if any, are issued by the Authority, these interpretations may change through the final adoption of regulations different from those now set out as Proposed Regulations §1.103-1 (41 Fed. Reg. 4829-4831).

Secondly, our views above should not be construed as a conclusion that obligations issued by the Authority pursuant to the Act would now be tax exempt obligations since even though such obligations would be issued by a constituted authority, those obligations must still meet the requirements relating to industrial development bonds under Section 103(b) of the Internal Revenue Code. As mentioned above, this issue requires specific Congressional action.

CONSTITUTIONAL ISSUES

We have reviewed the Act to determine what constitutional challenges might be raised against the Act including challenges that have been made to other state bonding authorities and municipal bonding programs. With one exception, we do not find any serious constitutional questions arising under the Alaska Constitution.

Independent Agency

For example, we do not believe that a serious question could be raised under Article III, §22 of the Alaska Constitution which prohibits the creation of an independent agency not within a principal department. We have reviewed the membership of the Authority, its placement within the Department of Revenue and the administration controls imposed under the Act and believe that it is sufficiently close to the facts and tests enunciated in DeArmond v. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962) and Walker v. Alaska

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State Mortgage Association, 416 P.2d 245 (Alaska 1966) to insure that the Act does not violate Article III, §22 of the Alaska Constitution.

Restriction on State Debt

Similarly, we do not think that the Act or the intended activities of the Authority would run afoul of Article IX, §8 and §9 of the Alaska Constitution which place specific restrictions (including an election requirement) on contracting debt by the State or a political subdivision of the State. Among other reasons, Article IX, §11 sufficiently insulates the Authority's issuance of revenue bonds from an attack under Article IX, §8 and 9. Specifically, Article IX, §11 provides:

> SEC. 11 EXCEPTIONS
>
> The restrictions on contracting debt do not apply to debt incurred through the issuance of revenue bonds by a public enterprise or public corporation of the State or a political subdivision, when the only security is the revenues of the enterprise or corporation.

Because of the restrictions of A.S. 44.55.090(b), we believe that the Article IX, §11 exceptions would apply to the Act, and the issuance of obligations by the Authority under the Act, thereby preventing a violation of Article IX, §8 and 9.

Public Purpose

Given the existing language of the Act, a constitutional question could be raised under Article IX, §6 of the Alaska Constitution which provides:

> SEC. 6 PUBLIC PURPOSE.
>
> No tax shall be levied, or appropriation of public money made, or public property transferred, nor shall the public credit be used, except for a public purpose.

An argument could be made that the issuance of bonds by the Authority would constitute a use of the public credit, and that such use for financing the Alaska Natural Gas Transportation System would not be a public purpose. Additionally, the same argument could be made with respect to any legislative appropriation or transfer of state property to the Authority if such appropriation or transfer were, in fact, made or contemplated.

In response to such a challenge, an argument could be made that the public credit is not being used since under A.S. 44.55.090 the bonds issued by the Authority are not an indebtedness of the State or a political subdivision of the State. Further, under A.S. 44.55.090, the Authority is prohibited from pledging the credit or obligating in any manner the State or a political subdivision of the State. Specifically, A.S. 44.55.090(b) provides:

> The bonds issued by the authority do not constitute an indebtedness or other liability of the state or of a political subdivision of the state, but are payable solely from the income and receipts or other money of the authority. The authority may not pledge the faith or credit of the state or of a political subdivision of the state to the payment of a bond, and the issuance of a bond by the authority may not directly or indirectly or contingently obligate the state or a political subdivision of the state in any manner, except as specifically provided in this chapter.

This argument would be supported by the decision in <u>DeArmond v. Alaska State Development Corporation</u>, 376 P.2d 717 (Alaska 1962). This case involved the Alaska State Development Corporation, which was an instrumentality established to develop, stimulate and advance the business prosperity and economic welfare of Alaksa and its citizens. The corporation was authorized to issue bonds for its stated purpose but the Act provided that the corporation could not pledge the credit or the taxing power of the state or its political subdivisions and that the state and its political subdivisions were not liable for the debts of the corporation.

Although the court in <u>DeArmond</u> found a public purpose, under the meaning of Article IX, §6, it also found that the issuance of the corporation's obligations did not amount to a use of the public credit because the statute prohibited the corporation from pledging the credit and taxing power of the state and provided that the corporation's obligations were backed only by the resources and credit of the corporation. In particular, the court stated:

> Class A and B negotiable certificates are to be sold to the public in order to accumulate funds with which to make development loans. These certificates are backed only by the resources and credit of the corporation. The act specifically prohibits the corporation from pledging the credit or the taxing power of the state. The form of revenue bond adopted by the board of directors of the corporation provides therein:

'This bond shall not be deemed to constitute a debt of the State of Alaska or a pledge of the faith and credit of the State of Alaska, but shall be payable solely from the special fund provided therefor from revenues of the Corporation. The issuance of this bond shall not directly or indirectly or contingently obligate the State of Alaska to levy or to pledge any form of taxation whatever therefor.'

No public funds are being transferred to the corporation other than the loans just mentioned. The funds realized from the sale of certificates will come from private sources. The credit of the state is not being pledged. Even though we have found that the corporation's activities will serve a public purpose, it is clear enough that its objectives must be accomplished without the use of public funds and state credit. No violation of the constitution has been shown. (376 P.2d at 722)

Thus, it could be argued, based upon the language in A.S. 44.55.090(b) and the finding in DeArmond, supra, that the issuance of bonds by the Authority would not be a use of the public credit in violation of Article IX, §6 of the Alaska Constitution.

Despite the availability of this argument, it is important to buttress by the Act the existence of a public purpose.

The legislature created the Authority in A.S. 44.55.010, which provides:

SEC. 44.55.010 CREATION OF AUTHORITY

There is created the Alaska Gas Pipeline Financing Authority. The authority is a public corporation of the state. It is an instrumentality of the state within the Department of Revenue, but has a legal existence independent of and separate from the state. <u>Exercise by the authority of the powers conferred by this chapter is an essential governmental function of the state</u>. (Emphasis added)

Upon the creation of the Authority, the legislature set out its findings relating to the passage of the Act in §1 ch. 90, SLA 1978. Among other findings of benefits to the State, the legislature found that the creation of the Authority served a public purpose. Those pertinent provisions are as follows:

Section 1. LEGISLATIVE FINDINGS. The legislature finds that

(1) if the state makes a final determination that production of natural gas from the Prudhoe Bay reservoir will be consistent with optimal recovery of oil and gas from the reservoir, and if the Congress of the United States and federal regulatory agencies take favorable action with respect to matters of Alaska natural gas policy, then timely construction of the Alaska Highway Natural Gas Pipeline Project will be in the best interest of the state and of the United States;

(2) state assistance to the financing of the project will promote an essential public purpose in assuring timely transportation to market of Prudhoe Bay natural gas;

(3) the project is essential to the development of the natural resources and the long-term economic growth of the state, and will directly and indirectly provide employment in the state;

(4) additional benefits to Alaska from the project include increased state and local tax revenues, enhanced availability of natural gas for Alaska communities, and stimulus and expansion of the private sector economy, including greater potential for development of in-state manufacturing, refining and processing facilities;

(5) construction of the project is a matter of statewide concern; there is no existing general law adequate for the purpose of assisting with financing of the project, as provided in this chapter;

(6) it is a public purpose of the State of Alaska to promote timely completion of the project through the creation of an instrumentality empowered to sell revenue bonds, the interest on which is exempt from federal income tax except when held by a substantial user or related person as these terms are defined in sec. 103 of the Internal Revenue Code of 1954 as amended, and to use the proceeds to purchase or otherwise acquire obligations issued with respect to the project.

. . . .

Thus, the legislature specifically found a public purpose in creating the Authority empowered to issue revenue bonds for financing the Alaska Natural Gas Transportation System. This public purpose was based upon its findings of state benefits and interests such as increased employment, additional revenues, general economic development, development of new business and industry and meeting energy needs.

Such purposes as increased economic development, additional employment, and encouraging development of new business and industry have been found, in previous cases, as constituting valid public purposes within the meaning of Article IX, §6 of the Alaska Constitution. Alaska State Development Corporation, 376 P.2d 717 (Alaska 1962), Walker v. Alaska State Mortgage Association, 416 P.2d 245 (Alaska 1966); Wright v. City of Palmer, 468 P.2d 326 (Alaska 1970).

The principles involved in a determination of whether a public purpose is present were set out in DeArmond, supra:

> At the outset we observe that the phrase 'public purpose' represents a concept which is not capable of precise definition. We believe that it would be a disservice to future generations for this court to attempt to define it. It is a concept which will change as changing conditions create changing public needs. Whether a public purpose is being served must be decided as each case arises and in light of the particular facts and circumstances of each case.
>
> In determining the question presented this court adopts for its guidance the general rule, supported by the great weight of authority, that where the legislature has found that a public purpose will be served by the expenditure or transfer of public funds or the use of the public credit, this court will not set aside the finding of the legislature unless it clearly appears that such finding is arbitrary and without any reasonable basis in fact. (376 P.2d at 721).

In the context of the Authority the legislature has specifically found a public purpose and this stated purpose has been found in other cases to be a valid public purpose. Additionally, such stated purpose should be controlling and will not be set aside unless it can clearly be shown that such finding is arbitrary and without any reasonable basis in fact.

Since the original Act was passed, however, the legislature has amended its findings to negate or to at least call into question its finding of a public purpose. §4, ch. 31, SLA 1949 amended section 1(2) ch. 90 SLA 1978 as follows:

(2) state assistance to the financing of the project may [WILL] promote an essential public purpose in assuring timely transportation to market of Prudhoe Bay natural gas. . . ."

In addition, like findings (financing the project may promote a public purpose) were made in Legislative Resolve No. 13 in 1979.

The legislature did not, however, amend its finding of public purpose in Section 1(6), ch. 90 SLA 1978 which reads as rollows:

(6) it is a public purpose of the State of Alaska to promote timely completion of the project through the creation of an instrumentality empowered to sell revenue bonds, the interest on which is exempt from federal income tax except when held by a substantial user or related person as these terms are defined in sec. 103 of the Internal Revenue Code of 1954 as amended, and to use the proceeds to purchase or otherwise acquire obligations issued with respect to the project;

Because of the legislative change of the word "will" (promote a public purpose) to "may" in section 1(2) and its conflict with the language in section 1(6) of ch. 90, SLA 1978, as well as like findings in Legislative Resolve No. 13, we think that the legislature may have neutralized the legal presumption which it previously had established. That being the case, a court might determine the question of a public purpose without such presumption.

In light of this uncertainty and lack of legislative presumption on the question of public purpose, litigation might well have to be instituted to establish the Act's public purpose before any bonds could be issued.

To avoid this uncertainty and avoid such litigation we suggest that an amendment be made to §1(2); ch. 90, SLA 1978 to bring it back into conformity with its original language.

It is appropriate for the legislature to make the determination of whether the Act promotes a public purpose, rather than leaving the determination to the courts. If the legislature has any doubts as to whether the actual implementation of Authority powers will promote a public purpose, it may not approve the financial impact plan or it may impose certain conditions to insure that a public purpose is actually accomplished.

ATTACHMENT B

Draft Revisions

Sec. 44.55.090. Bonds of the authority. (a) The authority may borrow money and issue revenue bonds, in one or more series, [THE INTEREST ON WHICH IS EXEMPT FROM FEDERAL INCOME TAX EXCEPT WHEN HELD BY A SUBSTANTIAL USER OR RELATED PERSON AS DEFINED IN § 103 OF THE INTERNAL REVENUE CODE OF 1954 AS AMENDED,] up to the principal amount of $1,000,000,000 inclusive of amounts required for [FUND] reserves, capitalized interest, and costs of issuance of the bonds [OR NOTES] and exclusive of refunding bonds. Bonds of the authority may be issued for the corporate purposes of the authority including (1) financing or refinancing part of the cost of the project, or part or all of the cost of any part of the project, (2) purchasing or otherwise acquiring any obligation issued with respect to the project in any form which is fixed and certain as to terms of repayment and (3) for the establishment of reserves to secure or to pay bonds [OR NOTES] or interest on bonds [OR NOTES] and all other costs of the authority incident to and necessary for issuance of bonds. [OR NOTES.] The principal of and interest on the bonds [ARE] of the authority shall be payable from the income and receipts or other money derived by the authority with respect to the project, except to the extent payable out of money attributable to the proceeds of the sale of the bonds or out of income from the [TEMPORARY] investment of those proceeds.

Bonds may be issued by the authority only after approval by the legislature by concurrent resolution of a financial and Alaska Impact Plan and only in accordance with a separate concurrent resolution of the legislature approving the issuance of such bonds. The resolution approving the bonds may contain such limitations or conditions to the issuance of bonds as the legislature deems appropriate.

(b) The bonds issued by the authority do not constitute an indebtedness or other liability of the state or of a political subdivision of the state, but are payable solely from the income and receipts or other money of the authority. The authority may not pledge the faith or credit of the state or of a political subdivision of the state to the payment of a bond, and the issuance of a bond by the authority may not directly or indirectly or contingently obligate the state or a political subdivision of the state in any manner, except as specifically provided in this chapter.

(c) Bonds shall be authorized by resolution of the authority and shall be dated and mature as the resolution provides. Bonds shall bear interest at the rate or rates, be in the denominations, be in the form, either coupon or registered, carry the registration privileges, be executed in the manner, be payable at such times, in the medium of payment, at the place or places, and be subject to the terms of redemption which the resolution provides.

(d) All bonds, regardless of form or character, are negotiable instruments for all the purposes of the Uniform Commercial Code.

(e) All bonds may be sold at public or private sale in the manner, for the price, and at the time or times which the authority determines.

(f) The authority may enter into financing agreements necessary or desirable to secure the bonds. Before the issuance of bonds, the authority shall make provision by agreement with the owner or user of the project for payment by the owner or user of amounts at least sufficient in the judgment of the authority to pay the principal of and interest on the bonds as they become due, and to establish or maintain [THE] reserves for payment, if any, as the authority considers necessary or desirable.

(g) Refunding [OBLIGATIONS] bonds may be sold or exchanged for outstanding [OBLIGATIONS] bonds issued under this chapter subject to legislative approval as required by this section. If sold, the proceeds may be applied, in addition to other authorized purposes, to the purchase, redemption or payment of the outstanding [OBLIGATIONS] bonds to be refunded. Pending the application of the proceeds of any refunding [OBLIGATIONS] bonds, with any other available funds, to the payment of the principal, [(]accrued interest and any redemption premium on the [OBLIGATIONS] bonds being refunded[,] (and if so provided or permitted in the authorization for issuance of the refunding [OBLIGATIONS] bonds, to the payment of any interest on the refunding [OBLIGATIONS] bonds and any expenses in connection with the refunding), the proceeds may be invested in direct obligations of, or obligations the principal of and the interest on which are unconditionally guaranteed by, the United States of America which mature or which will be subject to redemption, at the option of the holders of them, not later than the respective dates when the proceeds, together with the interest accruing on them, will be required for the purposes intended.

Draft Revisions

Sec. 44.55.110. LEGISLATIVE APPROVAL. [EITHER HOUSE OF THE LEGISLATURE MAY DISAPPROVE THE FINANCIAL AND ALASKA IMPACT PLAN OR AN AMENDED VERSION OF THE PLAN AND THE SALE OF REFUNDING BONDS BY A SIMPLE RESOLUTION. IF THE PLAN OR AN AMENDED VERSION OF THE PLAN OR THE SALE OF REFUNDING BONDS IS NOT APPROVED OR CONDITIONALLY APPROVED BY THE LEGISLATURE WITHIN 60 DAYS AFTER PRESENTATION TO THE LEGISLATURE, IT IS DISAPPROVED. THE LEGISLATURE MAY BY CONCURRENT RESOLUTION APPROVE THE PLAN OR AN AMENDED VERSION OF THE PLAN WITH] The legislature may approve the financial and Alaska impact plan by concurrent resolution. The approval may be subject to conditions concerning matters included in the plan or amended version of the plan, and the conditional approval becomes effective upon certification to the legislature by the authority that the authority has accepted the conditions and modified the plan in accordance. [NO BONDS OR NOTES MAY BE ISSUED OR SOLD UNTIL THE APPROVAL REQUIRED BY THIS SECTION HAS BEEN OBTAINED, AND NO BONDS OR NOTES MAY BE ISSUED OR SOLD EXCEPT IN ACCORDANCE WITH THE APPROVED PLAN.] The legislature must approve the plan, or an amended version of the plan within 60 days of its presentation to the legislature. Subject to the provisions of A.S. 44.55.140, later amendments to the plan may be adopted in the same manner as provided for initial approval by the legislature. After approval of the financial and Alaska impact plan, the legislature may approve the issuance of bonds as provided in A.S. 44.55.090.

[AMENDMENTS TO THE PLAN MAY BE SUBMITTED BEFORE THE PASSAGE BY THE AUTHORITY OF THE RESOLUTION AUTHORIZING THE SALE OF BONDS AND BECOME EFFECTIVE UPON APPROVAL BY THE LEGISLATURE BY CONCURRENT RESOLUTION.]

Draft New Section

Sec. 44.55.135. OPERATION OF A.S. 37.10.085. The authority shall not be considered to be the state or a political subdivision of the state for the purposes of A.S. 37.10.085.

Draft Revisions

Sec. 44.55.140. Pledge of the state. The state pledges to [AGREE WITH] the holders of bonds issued under this chapter that the state will not limit or withdraw the power of the authority to issue bonds approved by the legislature pursuant to A.S. 44.55.090 once an initial series thereof has been issued and will not limit or alter the rights and powers vested in the authority by this chapter to fulfill the terms of any contract made by the authority with those holders, or in any way impair the rights and remedies of those holders until the principal amount of the bonds, together with interest on them, with interest on unpaid installments of that interest, and all costs and expenses in connection with any action or proceeding by or on behalf of those holders, are fully met and discharged. The authority is authorized to include this pledge and agreement of the state in a contract with those holders.

Draft New Section

Sec. 44.55.145. EARNINGS OF THE AUTHORITY. The earnings of the authority in excess of the amount required for the retirement of indebtedness or the accomplishment of the purposes stated in this chapter may not inure to the benefit of any person other than the State.

Draft New Section

Sec. 44.55.155. DISPOSITION OF AUTHORITY PROPERTY UPON DISSOLUTION. Upon dissolution of the authority, title to all property owned by the authority will vest in the state.

Draft Revision

Sec. 44.55.200(2). "bonds" means bonds, notes, or other evidence of indebtedness of the authority, including bond anticipation notes or other obligations issued to provide interim financing for the project.

Draft Revision

Sec. 44.55.200(5). "project sponsor" means [ANY PARTNER OF] the Alaska Northwest Natural Gas Transportation Company, or its partners or [ITS] successors, [;] or any company, individual or association which owns an interest in the project or any part thereof;

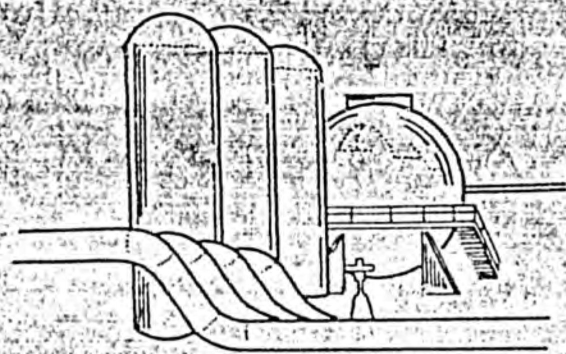
PLEASE NOTE: THE PRECEDING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

COMMUNITY INFORMATION CENTER

Special Report No. I

March 31, 1978

INSTATE ALTERNATIVES (EXTRA)



FAIRBANKS PETROCHEMICAL STUDY

by

Dr. John A. Kruse

Institute of Social and Economic Research

University of Alaska

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Special Report No. 1

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FOREWORD

This study was funded by a $37,000 appropriation from the Borough Assembly using a combination of federal anti-recession fiscal assistance funds and the Assembly budgetary reserve. Production and publication costs for this report were shared by the Community Information Center, the Environmental Services Department, and the Planning Department. A special thanks to Marsha Bauman and Heidi Sciore who drafted the figures and Cindy Lippincott who typed the report.

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Several individuals performed major roles in the execution of this study. Dr. Arlon Tussing, Dr. Louis York and Dr. Gordon Harrison were primarily responsible for the formulation of the petrochemical development scenario. Each was able to draw upon an impressive amount of personal knowledge and to assemble the required additional information within an extremely short period of time. Dr. Tussing in particular deserves a special note of thanks for his willingness to assume the time-consuming task of developing basic petrochemical scenarios when an unanticipated delay threatened the successful completion of the entire project.

Ms. Virgene Hanna performed magnificently as the project field director. As a result of her efforts, and the efforts of the 32 interviewers and coders she supervised, the field phase of the project was successfully completed ahead of schedule.

Ms. Sue Fison and the staff at the Borough Community Information office were able and willing to help throughout the study. I would also like to acknowledge the special efforts of Mrs. Donna Schuster in preparing the text and tables for the entire report. The final, but most important, acknowledgement is to the 436 Fairbanks residents who generously gave their time and opinions.

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Chapter One

INTRODUCTION

This report contains the results of work performed under Fairbanks North Star Borough Ordinance Number 7720II. The central objective of Ordinance Number 7720II is to assess the views of Fairbanks residents concerning petrochemical development in the Fairbanks North Star Borough. To achieve that objective, the Institute of Social and Economic Research at the University of Alaska initiated a study in January, 1978, which consisted of two major components. The first component involved the development of a comprehensive description of the most likely form of petrochemical development which could conceivably occur in the Fairbanks area. The description is based on a review of relevant technical and economic factors by a team of experts employed by the Institute. The second component of the ISER study consisted of a survey of Fairbanks residents which incorporated the petrochemical development description and met the rigorous sampling requirements necessary to insure that the results accurately reflect the views of all adults living in the Fairbanks North Star Borough.

The design of the petrochemical description and survey components of the study, in fact, reflects not only the overall study objective of assessing public attitudes concerning petrochemical development but also several specific sub-objectives. The results contained in this report can best be interpreted in the context of these sub-objectives so we have discussed each sub-objective in detail before the actual study findings are presented. Chapter One concludes with a brief summary of the results. Chapter Two presents the backup material that was used to generate the petrochemical description and Chapters Three through Seven contain a detailed discussion of the results of the survey. A description of the methods employed in conducting the survey and a copy of the questionnaire are included as Appendices A and B, respectively.

Sub-objective One: Presentation of a Description of Petrochemical Development

The topic of petrochemical development has appeared in over 20 articles in the Fairbanks Daily News-Miner in the past 2 months. While the public has been exposed to a vast amount of material on petrochemical development, the information has had the effect of increasing rather than diminishing the confusion which appears to surround public opinion on the issue. Even the most accurate reporting of statements and events cannot overcome the bewildering mix of facts, expert opinions and conjectures which broadly relate to the petrochemical industry. For this reason, it was felt that a simple polling of public opinion would do little to improve the information base used by the Borough

Assembly and Administration in the formulation of Borough policies regarding petrochemical development. The selected alternative approach has involved a substantial effort to clarify the meaning of petrochemical development as it pertains to the Fairbanks situation. While it is impossible to precisely project all the effects a petrochemical plant would have on the Fairbanks community, we have attempted to objectively review the set of technical, economic and environmental factors upon which public attitudes toward petrochemical development are based. This information has been presented to a scientifically selected sample of over 400 Fairbanks residents. We hope that the information will also become a focal point of discussion for the Fairbanks community as a whole. At the same time, we have designed the study in a way that will enable us to project what public attitudes would be regarding petrochemical developments which dramatically diverge from our own best estimates. Consequently, the results of this study should not become quickly outmoded as events transpire and new information is developed. Details about how the petrochemical development description was developed appear in Chapter Two. Public attitudes toward petrochemical development that are in part based on the petrochemical development description are discussed in Chapter Five.

Sub-objective Two: Assessment of Attitudes of the General Public Toward Petrochemical Development

It is important to remember that the petrochemical development description incorporated in the survey at best clarified the issue for two percent of the Fairbanks population. Even assuming that a successful community-wide information dissemination program is implemented, the majority of Fairbanks residents are likely to remain relatively uninformed about the changes that would be expected to result from a petrochemical development. If a referendum is conducted on the issue in the future, a substantial proportion of those voting may not have been exposed to a comprehensive description of the effects of the most likely petrochemical development in the Fairbanks area. It is, therefore, important to know the attitudes of potential voters who have not read or heard the petrochemical description. Because the survey sample accurately represents all Fairbanks residents, it is possible to meet this objective by asking a series of questions in the interview about petrochemical development before the petrochemical description is presented. In this way, the results of the survey reflect both the attitudes of the general public as well as the attitudes of a sample of the public that has been presented with detailed information about the most likely form of petrochemical development. Results reflecting the attitudes of the general public toward petrochemical development are presented in Chapter Four.

Sub-objective Three: Assessment of Expectations Concerning Petrochemical Development

Attitudes describe what people like or dislike about an object and are based on the basic values a person holds and the information they possess about the object. Although the petrochemical development description is designed to provide a uniform set of information, people are at liberty to disagree with this information and base their attitudes on information from other sources. In addition, the survey also assesses public attitudes before the petrochemical description is presented. In both instances, we need to know what information people are actually using as a basis for their attitudes. This information can best be described as a set of expectations about the changes that would result from petrochemical development in the Fairbanks area. The survey thus includes not only measures of public attitudes toward petrochemical development but also measures related to what people expect from a petrochemical devllopment. A discussion of general public expectations regarding petrochemical development can be found in Chapter Four. Results reflecting expectations which have been revised on the basis of the petrochemical development description appear in Chapter Five.

Sub-objective Four: Assessment of General Growth Attitudes and Expectations

Attitudes and expectations concerning petrochemical development cannot be divorced from the more general set of attitudes and expectations concerning growth and change in the Fairbanks area. The potential effects of petrochemical development must be compared with the expected course of changes that will result from other sources of economic growth such as agriculture, tourism and other industries. Of course, a general assessment of attitudes and expectations toward growth not only establishes the necessary comparative perspective but also provides a valable body of information in itself. The results of this assessment appear in Chapter Three.

Sub-objective Five: Assessment of Current Fairbanks Economic Conditions

The Fairbanks Petrochemical Study is primarily oriented toward the future but the survey presents an opportunity to collect valuable information about the present as well. Since economic conditions in Fairbanks affect almost every Borough policy, a current assessment is included as a sub-objective of the study. The survey focuses in particular on the current employment status of the population with additional questions on housing, moving plans, and past and expected major purchases. Together, the results of these questions will present a detailed picture of the current level of economic well-being in the Fairbanks community.

A major survey of the type performed in this study also yields a variety of information which is ancillary to the central objectives of the study but extremely valuable in other contexts. One such information byproduct is a detailed breakdown of the current demographic characteristics of the Fairbanks population. Another is a listing of key concerns people would like the Borough to know about. Information relevant to current economic conditions in Fairbanks and information not directly related to the central objectives of this study appear in Chapter Five.

Summary of Results

Survey results show that residents expect Fairbanks will continue to grow over the next ten years, but at a slower rate than that of the last several years. They believe that hunting and fishing opportunities and the quality of the air in Fairbanks have declined in recent years, and residents expect both community attributes to continue their decline at a moderate rate over the next ten years. Most other community attributes, such as the number of job opportunities, locally made products, new stores, and the amount of services provided by the Borough are only expected to increase slowly. Roughly a third of the Fairbanks population expect these attributes to remain at about current levels.

In responding to what specific changes they thought would occur over the next ten years in Fairbanks, most residents expected that undesirable[1] community attributes such as the amount of air pollution and population growth to increase more rapidly than such desirable attributes as the number of job opportunities and locally made products. However, when asked their overall expectations for change in Fairbanks, 76 percent of the population expected that Fairbanks would be just as good or a better place to live over the next ten years. The discrepancy is in part accounted for by the fact that slow increases in several desirable community attributes are considered more important than larger increases in some of the least desirable community attributes. Survey results also show that residents who are staying in Fairbanks primarily for economic reasons tend to expect the community to become a better place to live while those who are staying in Fairbanks primarily to take advantage of the surrounding wilderness environment tend to expect Fairbanks will become a worse place to live over the next ten years.

The results of the survey confirmed our expectation that few people agree about the direct effects of petrochemical development. While many residents believe that they are at least somewhat familiar with petrochemical development (69 percent), their expectations before being presented with our description of petrochemical development varied widely. For example, 26 percent of the population expects that a petrochemical facility would employ 100 or fewer persons, while 29 percent expect that over 500 persons would work at such a plant. Overall, most residents indicated that the primary effects of petrochemical development would be to create jobs, produce goods for local consumption and increase the amount of air pollution.

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[1]The desirability of community attributes was determined by the respondents themselves.

On balance, the same proportion of Fairbanks residents (29 percent) expect that a petrochemical plant would make Fairbanks a better place to live as expect it would make Fairbanks a worse place to live. Over a third of the population (35 percent) expected that petrochemical development would not affect their lives for the better or worse, and 7 percent simply did not know what to expect.

The description of petrochemical development presented to our survey respondents did have the desired effect of correcting much of the misinformation and reducing the confusion about petrochemical development. Several aspects of the description differed from general public conceptions about petrochemical development. First, the facility would cost more than residents would have expected and such a facility would add a substantial amount to the local tax base. Second, the construction of the plant would result in the employment of more people than most residents realized. Third, a petrochemical plant of the type most likely to be constructed in Fairbanks would not result in the smog initially expected by most residents. Finally, the plant would not result in many new products becoming available locally.

After being presented with the petrochemical development information, residents modified their expectations about resulting changes in 7 of the 14 major community attributes. They expected more rapid increases in the amount of taxable property, the quality of transportation links to Fairbanks, and in the amount of Borough services provided. In addition, they expected less rapid increases in the number of locally available products, the amount of air pollution, the number of new stores, and the number of jobs related to agriculture.

Respondents now expect that while there will be somewhat more growth with petrochemical development than without it, the growth will follow patterns similar to that expected to occur without the development.

Public attitudes on how such development will affect the quality of living in Fairbanks did not change substantially overall buy many individuals changed their attitudes after learning more about petrochemical development. The net result is that our informed sample of Fairbanks residents divided about equally (28 versus 26 percent) over whether petrochemical development would make Fairbanks a better versus worse place to live with 3 percent having no opinion. The remaining 43 percent of the sample did not expect petrochemical development to affect Fairbanks one way or the other. Nevertheless, most of the residents who did not expect petrochemical development to affect Fairbanks for better or worse tended to favor petrochemical development.

When asked whether the Borough should invite petrochemical companies to make proposals and if it should aid in developing information required by petrochemical companies, 67 percent of our respondents said yes. This question was asked after information was presented to the respondents on most likely effects of petrochemical development and thus reflects the attitude of an informed sample of the Fairbanks population.

It first appears strange that only 29 percent of the respondents expect that petrochemical development would make Fairbanks a better place to live, while 67 percent favor the Borough's promotion of petrochemical development. The 38 percent difference is explained by the petrochemical development leanings of those who think petrochemical development would not change Fairbanks for better or worse.

Support for petrochemical development can be assumed in two ways. If we count those who would just as soon have petrochemical development as not, there is considerable support. However, as mentioned above, this support does not accurately reflect the number of people who actually expect Fairbanks living conditions to improve as a result of petrochemical development. Alternatively, if we count those who expect to gain as being for development and those who expect to lose as being against, the levels of support and opposition for petrochemical development are equal. However, this approach ignores the preferences of 43 percent of the population who expect to neither gain or lose should petrochemical development occur.

The survey results do not directly establish what Borough policy should be, but they do furnish a basis on which Borough policy can be formulated. Since there is not a concensus supporting or opposing development, an equitable solution would require a tradeoff between the views of 26 percent of the population who expect petrochemical development will make Fairbanks a worse place to live and 43 percent of the population who don't expect to gain or lose as a result of petrochemical development, but who support it anyway.

Apart from the question of whether the Borough should support, oppose or remain neutral with regard to petrochemical development, survey respondents were asked for their views on several specific actions that could be taken to increase the economic feasibility of petrochemical development. The results indicate that most Fairbanks residents would like to encourage petrochemical development as long as it does not cost much to do so. The public believes that the Borough should pursue such inexpensive activities as inviting companies to make proposals and providing them with information. However, the majority of Fairbanks residents does not support such possible economic incentives as tax breaks, the sale of municipal revenue bonds to help finance development, or the sale of State royalty gas at less than full value. The lack of support for these incentives appears to reflect the fact that most residents do not expect petrochemical development to make Fairbanks a better place for them to live. Roughly, a third of the population does expect petrochemical development to make Fairbanks a better place to live, and we repeatedly find that about a third of the population support incentives which involve some sacrifices.

The following chapters take a much closer look at the survey results. The above summary is only intended to highlight the most important findings; the residents of Fairbanks provided a great deal more information than we have been able to cover here and we hope that the detailed discussion forming the main body of this report is more successful in capturing the rich fabric of attitudes and expectations regarding growth in general and petrochemical development in particular.

Chapter Two

A DESCRIPTION OF PETROCHEMICAL DEVELOPMENT

Petrochemicals are defined as chemicals derived from petroleum raw materials, including natural gas. They are the basic building blocks for thousands of products such as fertilizers, plastics, fibers, paints, solvents and many varieties of rubber. Whether a petrochemical industry can be located in Fairbanks and what type of petrochemical development would be best suited for Fairbanks are questions which involve dozens of facotrs. Among them are: the type of petroleum raw materials available, the cost of these raw materials, the cost of building and operating the plant, the availability of skilled labor, water, land, services for employees and adequate transportation facilities, the location of markets for petrochemicals, the location of other chemicals which can be used in a petrochemical plant, the cost of transporting both the inputs to and outputs from the plant, the price and demand for petrochemical products, the presence of environmental constraints, zoning regulations, property and income taxes as well as an equally extensive list for all alternative uses of the raw materials in Fairbanks and elsewhere. The above enumeration is probably no more, or less, extensive than that which might be given for any major industry. It should serve to make the point, however, that a description of petrochemical development must be based on many assumptions about factors whose characteristics are still uncertain. The price of North Slope natural gas is unknown. Even the content of the gas that will ultimately be in the Northwest gas pipeline is in question. At the same time, world production and consumption of petrochemicals are expected to change rapidly in the next decade.

It is easy to see why discussions about petrochemical development involve many confusing and often contradictory statements. It is also clear that it is impossible to describe the exact form of petrochemical development which might occur in Fairbanks or even to say at this point whether it is technically and economically feasible to construct such a plant in the Fairbanks area. We can, however, formulate a reasonably concrete description of the most likely technically feasible and economically conceivable facility. The range of projected effects can be considerably narrowed from that which applies to the petrochemical industry as a whole. For example, we are talking about a gas-based and not oil-based petrochemical plant. A description of the effects of oil-based petrochemical plants is appropriate for Kenai or Valdez, not Fairbanks. Another example of how the range of effects can be narrowed concerns the petrochemical products that can be expected from a plant located in Fairbanks. There are clear economic reasons why such a plant cannot produce final products such as tires and molded plastics. The remainder of this chapter is devoted to a brief discussion of the basic concepts that are relevant to petrochemical development in Fairbanks, followed by a technical description of the more likely forms of petrochemical development and concluding with the text of the petrochemical development description that was presented to our survey respondents.

BASIC CONCEPTS - Feedstock Sources.

We have assumed that the Northwest Alaskan (NWA) gas pipeline will carry only "dry" gas, i.e., a mixture of methane and ethane with only traces of propane, butane and heavier hydrocarbons, and that a separate gas liquids pipeline would be required to transport significant quantities of propane and butanes to or beyond Fairbanks. The small quantities of natural gasolines (pentanes plus) extracted from the natural gas stream can be transported either in such a liquids pipeline or mixed with the crude oil in the Alyeska oil pipeline.

While it is technically possible to move "wet" gas in the NWA natural gas pipeline, or to dissolve propane and butanes in the crude oil stream for movement in the oil pipelines, the authorities we have consulted regard these alternatives as unlikely economically. Thus we have assumed that three main possibilities exist for petrochemical feedstock sources in the Fairbanks area based upon natural gas production from Prudhoe Bay.

The first potential source of feedstocks is to remove some portion of the dry gas stream (methane and ethane) from the NWA pipeline at Fairbanks and to use these gases for petrochemical manufacturing in about the proportion in which they will be mixed in the processed gas stream from Prudhoe Bay. Any excess of either gas resulting from an imbalance of plant requirements relative to the proportion of gases in the gas supply would be returned to the NWA pipeline for shipment out of Alaska.

The second potential source of feedstocks is to process a part of the dry gas stream at Fairbanks, removing ethane for petrochemical manufacture and returning the methane to the NWA pipeline for shipment out of Alaska.

The third potential source of feedstocks is liquids from a processing plant at Prudhoe Bay, moved by a gas liquids pipeline from Prudhoe Bay to or beyond Fairbanks. This liquids stream could be composed of ethane, together with propane and butanes (perhaps with some natural gasolines) or alternatively all or most of the ethane could be retained in or returned to the gas stream in the NWA pipeline at the processing plant.

For the purpose of planning a petroleum complex, a fourth feedstock option is a combination of the preceding, using methane and ethane drawn from the NWA gas pipeline at Fairbanks with ethane, propane and butane from a gas liquids pipeline.

BASIC CONCEPTS - Transportation of Feedstocks.

The NWA gas pipeline will carry a mixture mainly of methane and ethane, so that this pipeline can be a source of either or both. Thus, it would not require a separate transportation facility to make either feedstock available to a petrochemical plant in Interior Alaska. Ethane, however, could also be moved to Fairbanks in a 440-mile gas liquids pipeline along with some or all of the heavier gas liquids. Moving all of the ethane, butane and propanes corresponding to 2.0 billion cubic feet per day of pipeline gas would probably require an 18-inch pipeline. If the ethane were retained in the gas pipeline, a 12-to 14-inch pipeline would be required to move all of the available propane and butanes. Moving only the volumes of ethane, propane and butane required to serve a world-scale olefins (ethylene-propylene-butylene) complex would require an 8-to 10-inch pipeline. It is very unlikely that it would become economic to move gas liquids separately on any smaller scale.

BASIC CONCEPTS - Transportation of Petrochemical Products.

Most petrochemical products from Interior Alaska could be shipped either in a product pipeline or by rail. The larger volumes of methanol envisioned previously, however, conceivably could be shipped in batches through the trans-Alaska oil pipeline to Valdez.

Assuming that its output is entirely liquids, the output of a world-scale ethylene facility could be served by an 8-inch pipeline to tidewater at Haines, Valdez, Whittier or Cook Inlet, and a broad-range olefins facility would require a 10-inch pipeline. If all the State's royalty gas were converted to methanol, the methanol alone would require a 12-inch pipeline; a 14-inch pipeline would be required to carry 55,000 barrels per day of methanol, together with the products of a world-scale olefins plant. The maximum scale products pipeline that can be envisioned is one which would carry methanol, olefins products plus all of the natural gas liquids produced with the Prudhoe Bay gas and not utilized in the field, for pumping or in chemical manufacturing; a 20-24-inch pipeline would be required for this purpose.

The alternative mode of transportation is the use of rail cars on the Alaska Railroad to Whittier or Seward. A world-scale ethylene plant (300,000-500,000 tons per year) would need 30-60 100-car unit trains per year, depending upon the product mix. An ethylene-propylene-butylene complex might require as many as 90 such trains. The methanol produced from all the State's royalty gas would require as many as one additional unit train per day. According to the Alaska Railroad, such additional volumes are all within the present capacity of the railroad to move without major capital improvements.

BASIC CONCEPTS - Petrochemicals from Methane.

The principal product from a petrochemical facility using methane from the NWA pipeline would be methanol. Other elementary methane derivatives which might be manufactured in such a facility are ammonia, acetylene, formaldehyde, urea and acrylonitrile. The volumes of any of these products that would be produced from processing the State's entire royalty gas stream (200 million cubic feet per day) would be very large in relation to existing North American consumption. The only methane product likely to be marketable in such quantities is fuel-grade methanol, the demand for which would be nearly unlimited at a price competitive with other clean-burning fuels in markets such as Southern California. Methanol could conceivably be used as boiler fuel or turbine fuel for electric power generation, or blended with motor gasoline or diesel oil in proportions up to 10 or 20 percent. Each million-cubic-feet-per-day facility would produce about 330,000 tons of methanol per year (5.5 mb/d). The State's royalty gas from Prudhoe Bay could conceivably support as many as ten such trains.

BASIC CONCEPTS - Petrochemicals from Ethane.

Ethane could be made available in Interior Alaska either from a gas processing plant extracting it from its mixture with methane in the NWA gas pipeline, or from a gas processing plant at Prudhoe Bay which would send the ethane, together with propane and butanes, through a gas liquids pipeline to or beyond Fairbanks. The principal use of ethane would be for manufacture of ethylene, which is the principal raw material for manufacture of polyethylene (high density and low density), ethyl alcohol and acetaldehyde, styrene (requires benzene), ethylene glycol and ethanolamine.

Any ethylene facility built in Interior Alaska would be of "world-scale," that is, of the most economical size assuming access to national and world markets. Such a plant would consume 13-21 mb/d of ethane and produce 300,000-500,000 tons per year of ethylene. Ethylene itself could be shipped by products pipeline or tank cars to tidewater for further processing elsewhere, or converted in the same plant to some of all of the products mentioned previously.

BASIC CONCEPTS - Petrochemicals from Propane and Butane.

Propane and butane extracted from the natural gas at a Prudhoe Bay processing plant might be transported to or beyond Fairbanks in a gas liquids pipeline, together with or apart from some or all of the ethane. The volumes of butane and propane corresponding to 2.0 bcf/d of pipeline gas (methane + ethane) are about 70mb/d and 10 mb/d respectively. A single world-scale propylene plant would utilize about 15mb/d of propane to produce about 130 million tons of propylene per year. Propylene might be further processed to isopropyl alcohol, acetone, cumene and polypropylene. Additional processing in Interior Alaska would be unlikely in the foreseeable future.

Butane can be cracked to butylene and further processed to n and t-butanol, methyl ethyl ketone, butadiene, butyl rubber, di- and tri-isobutane and polyisobutane. The size of a butane plant would be limited by feedstock availability rather than technology.

BASIC CONCEPTS - Further Processing.

Because of the severe capital and operating costs handicaps of operating in Interior Alaska compared to Lower 48 sites, the Far East or even tidewater locations in Alaska, it is unlikely that further processing beyond the products mentioned here to finished chemicals (pharmaceuticals, resins, paints, etc.) or plastic products would take place in Alaska. Comparatively high shipping costs for non-hydrocarbon raw materials would also make it unlikely that compounds involving halogens or sulphur would be produced locally.

The petrochemicals likely to be produced in an Interior Alaska plant would all tend to be liquids with relatively low vapor pressures or solids at ambient temperatures, relatively non-corrosive and without exceptional safety problems in handling.

Technical Descriptions

Technical descriptions of the types of petrochemical plants that conceivably could be located in the Fairbanks area were developed by three experts: Dr. Louis York, chief environmental scientist for Stearns-Roger, Dr. Arlon Tussing, professor of economics with ISER and Dr. Gordon Harrison, an economic consultant. Dr. York has had over 30 years experience in the fields of petroleum production, transportation, refining and in the assessment of the environmental effects of petroleum-related activities. He currently heads the environmental assessmental division of the world's largest petroleum engineering and construction firm. Dr. Tussing has been extensively involved in the economic analysis of energy developments and policies within Alaska. He has served as chief economist of the Senate's National Fuels and Energy Policy Study in 1974 and as a member of the Alaska Royalty Oil and Gas Development Advisory Board. Dr. Harrison has served as an economic consultant with the firm of Dames and Moore, developing projections of construction schedules and manpower requirements for such projects as the Atlantic Richfield Trans-Mountain pipeline project and for the Bureau of Land Management-Outer Continental Shelf Studies Program concerning offshore energy developments.

Initial project plans called for Dr. York, with the aid of engineers at Stearns-Roger, to develop estimates of the construction costs, direct employment and physical characteristics of one or more petrochemical facilities within a general range of facilities that was previously identified to be both technically feasible and economically conveivable. Dr. Harrison's project responsibility was to develop estimates of construction costs and manpower requirements for a gas liquids and a products pipeline. Estimates from both Dr. York and Dr. Harrison would be integrated by Dr. Tussing as a complete technical description to which he would add estimates of relevant indirect effects.

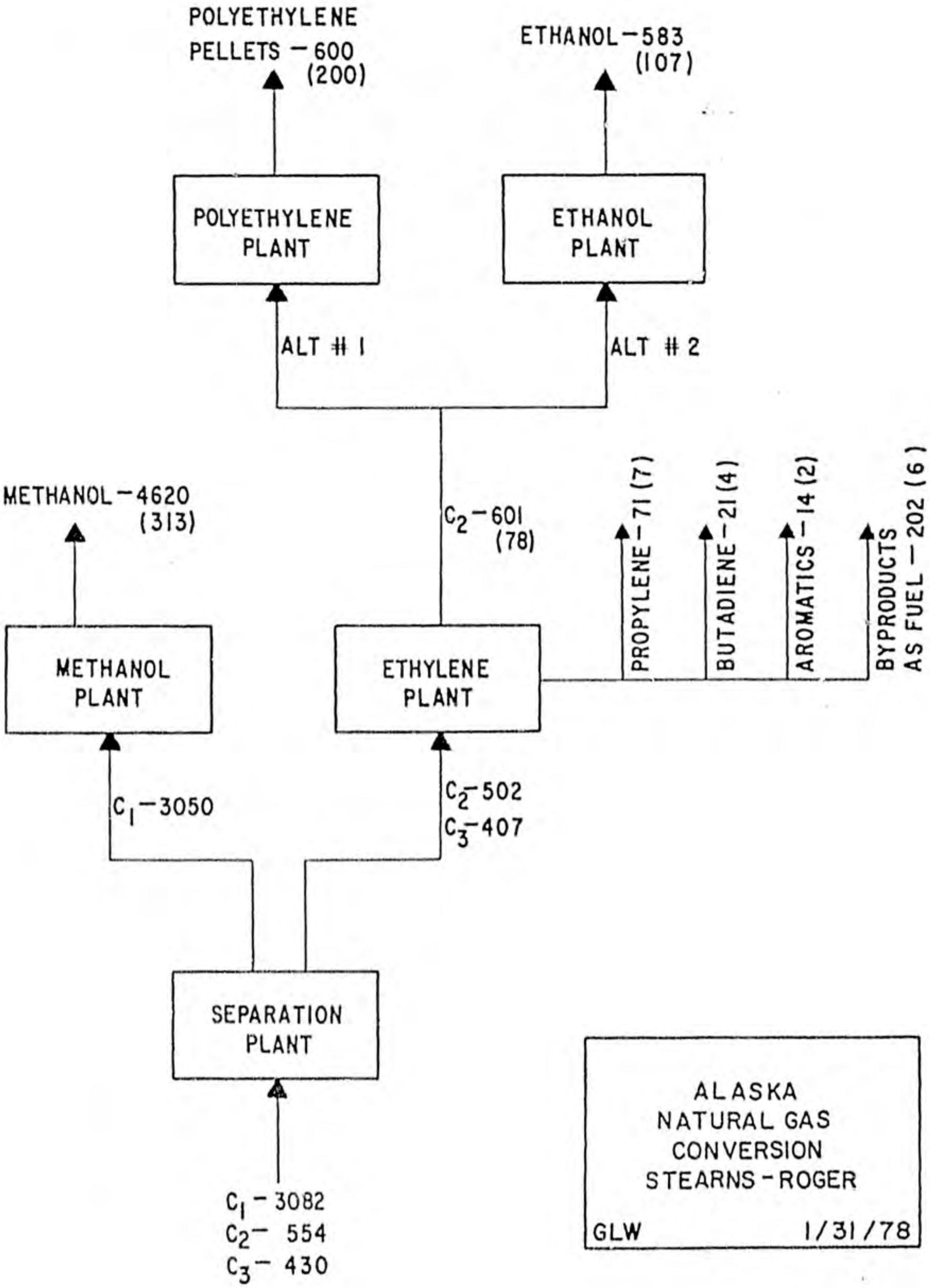
For reasons beyond his control, Dr. York was unable to provide Dr. Tussing with technical estimates on schedule. In order to maintain the extremely tight project schedule, Dr. Tussing proceeded to independently develop his own technical estimates. Thus, two sets of estimates were independently derived from this project. While the estimates are not entirely comparable, they are, in fact, quite similar. Dr. York assumes that all royalty gas will be removed at Fairbanks and processed through a separation plant to separate the methane from the ethane and a small amount of propane. The methane is assumed to be processed completely to methanol. The ethane and propane is assumed to be delivered to an ethylene plant, which then produces large amounts of ethylene and various quantities of other materials shown in Figure 2-1. The ethylene could be sold directly or could be converted to other products. York assumed two alternatives: conversion of all ethylene to polyethylene pellets or conversion of all ethylene to ethanol. The methanol and ethanol could be shipped as liquids in tank cars or by pipeline. The ethylene could be shipped as pressurized gas in cylinders or by pipeline. The polyethylene pellets are solid and could be shipped in closed hopper cars. A summary of the capital costs, process facilities, construction labor force requirements, operating costs and permanent labor force requirements under Dr. York's assumptions is given in Table 2-1.

Dr. Tussing developed four scenarios which range from the smallest to the largest technically feasible and economically conceivable facilities. In the first scenario, Dr. Tussing assumes that an ethylene plant would be constructed. Such a plant would be the simplest, lowest-cost world-scale petrochemical facility using North Slope feedstocks which is both technically feasible and economically plausible for Interior Alaska. Thirteen to twenty-one thousand barrels per day of ethane would be extracted from the gas stream (methane + ethane) in the Northwest Alaskan pipeline, and converted to 300-500 thousand tons per year of ethylene, which would be shipped to tidewater in special rail cars on the Alaska Railroad. No major roadbed or track improvements would be necessary to carry these volumes, but some additional railroad investment would be necessary for a spur track and terminal at the plant.

In the second scenario the State's entire royalty gas share (250 mmcf/d of methane and ethane) is used as feedstock for one 300-500 thousand ton per year ethylene plant as in the first scenario, or as feedstock to 10 facilities producing about 5.5 thousand barrels per day of fuel-gr de methanol. Both products would be transported to tidewater by means of a 12-inch products pipeline.

FIGURE 2-1

NOTES
1. FLOWS ARE GIVEN IN MM LB/YEAR
2. DOLLAR VALUE OF PRODUCTS IS GIVEN IN MM $/ YEAR -- SHOWN IN ( ).



ALASKA
NATURAL GAS
CONVERSION
STEARNS - ROGER
GLW 1/31/78

AGO 533079

TABLE 2-1

Alaska Natural Gas Conversion

Stearns-Roger
C-20763

	Separation Plant	Methanol Plant	Ethylene Plant	Polyethylene Plant	Ethanol Plant
Capital Expenditure, MM$	67	399	271	218	90
Typical Process	Expander	ICI Low Pressure	Lummus	Tubular LDPE	Veba-Chemie AG
Peak Construction Force	400	2,000	1,450	1,200	400
Operating Costs, MM$/Yr	4	57	24	10	4
Permanent Employees (excluding 50 overall plant support positions)	120	160	145	165	130
Operating Lines	1	3	1	2	1

NOTES

1. Plant cost based on 1978 dollars. Costs must be escalated to projected completion date. Costs assumed 200% of Lower 48.
2. Plant location assumed to be near the Fairbanks area. No camp facilities or special offsites included.
3. Construction force given as 120% of Gulf Coast requirements.
4. Operating costs include labor, maintenance, and utilities only.
5. All estimates are order of magnitude only.
6. Engineering design time: 18 mos.
   Construction time: 40 mos.
   Average const. force
   for first three plants: 2,160

The third scenario assumes that ethane, propane and butanes extracted from Prudhoe Bay natural gas on the North Slope are carried by an 8-inch gas liquids pipeline to the Fairbanks area, where they are used as feedstock for a world-scale olefins (ethylene, propylene and butylenes) steam-cracking facility. These olefins are further processed in the same complex into low- and high density polyethylene, ethyl alcohol, ethylene glycol, and (together with benzene purchased from the North Pole refinery) styrene monomer; acetone, propylene glycol, cumene, isopropyl alcohol and polypropylene; butanols, methyl ethyl ketone, butadiene, and isobutylenes). All these products (500-750 thousand tons per year) would be shipped to tidewater on the Alaska Railroad.

Finally, the fourth scenario describes the most extensive petrochemical development based upon Prudhoe Bay natural gas feedstocks which is technically feasible and economically plausible for Interior Alaska. It would use the State's entire royalty share of methane carried through the Northwest Alaskan gas pipeline, together with the entire stream of natural gas liquids produced from the gas processing plant on the North Slope, less the gas and liquids used as fuel in the field and as pump station fuel for the oil, gas and liquids pipeline. The liquids would be transported as far as Fairbanks in an 18-inch gas liquids pipeline. There would be a world-scale olefins complex as in scenario III, ten methanol trains as in scenario II, plus a 450,000 ton ammonia plant, a 500,000 ton urea plant, a 200,000 ton (37%) formaldehyde plant, and 50,000 ton ethanolamine and acrylonitrile facilities. Solids and liquids raising contamination problems would be transported by rail, while the remainder of the liquid products, plus the unutilized gas liquids, would be transported to tidewater in an 18-inch products pipeline.

Table 2-2 provides a summary of capital costs, construction estimates and permanent employment for the four scenarios developed by Dr. Tussing. A breakdown is also given by specific facility to permit a rough comparison to be made between Dr. York's and Dr. Tussing's estimates. The best comparison can be made between the first three columns of each table, thus including a separator, an ethylene and a methanol plant. The relevant figures are repeated in the first two columns of Table 2-3. Although derived independently, the estimates for required capital expenditures and permanent employment are not significantly different. Construction estimates do vary widely. Peak estimates will vary according to the timing of construction for each component of the plant, and Dr. York assumed all three plants would be built simultaneously while Dr. Tussing assumed that construction of the plants would be phased. It does appear, however, that a substantial difference between the estimates would remain even if common assumptions were made about the timing of the construction.

The scenario developed by Dr. York roughly corresponds to Dr. Tussing's second scenario. Dr. Tussing's third and fourth scenarios are considerably larger and more complex facilities. While Dr. Tussing has included them in the range of technically feasible and economically conceivable petrochemical developments, he cautions that it is extremely unlikely

TABLE 2-2

Alaska Natural Gas Conversion
Dr. Arlon Tussing

	Capital Expenditure MM$	Peak Construction Force	Construction Duration (months)	Total Man-months Construction	Average Monthly Construction Employment	Permanent Employees
Separation Plant	71	710	18	8,520	473	65
Ethylene Plant	284	710	18	8,520	473	160
Methanol Plant	381	736	30	6,200	207	200
Ethylene, Propylene, Butylene Complex	1,641	2,317	18	30,250	1,681	1,040
Methane Prod. Olefins Com. Ethanol, Amine, Acrylonitrile Facility	2,164	1,880	30	19,060	1,744	1,335
12-inch Product Pipeline	132	389	12	2,400	200	10
8-Inch Gas Liquids Pipeline	120	1,778	12	11,784	982	25
18-Inch Gas Liquids Pipeline	146	2,108	12	14,280	1,190	30
18-Inch Product Pipeline	146	330	12	2,640	220	12
RR Spur & Terminal	-	240	12	1,440	120	10
Scenario I	355	830	18	9,960	553	250
Scenario II	868	856	30	17,120	571	435
Scenario III	1,952	2,517	30	50,344	1,678	1,160
Scenario IV	2,908	3,462	30	69,240	2,308	1,642

TABLE 2-3

Comparison and Synthesis of Petrochemical Scenarios

	Dr. Tussing's Estimates	Dr. York's Estimates	Addition of Ethanol Plant	Final Estimates for Petrochemical Complex
Capital Expenditure (millions)	736	737	90	830
Peak Construct. Work Force	1,450	3,850	400	3,000
Ave. Construct. Work Force	680	2,160	216	1,500
Permanent Work Force	425	475	130	600

that economic conditions in the foreseeable future would be such as to justify processing North Slope natural gas beyond the most elementary products. Dr. Tussing suggested that it would be more realistic to rely only on scenarios I and II. A single question referring to the possibility of a much larger facility was, however, included in the survey.

To summarize the major scenarios developed by both Dr. Tussing and Dr. York, both assume that the methane and ethane from the Northwest gas pipeline will be separated and processed into methanol and ethylene. Furthermore, the permanent employment and capital cost estimates derived for each scenario are amazingly close. As a result, the integration of the two scenarios is relatively easy. Dr. York's scenario contains two alternative end products in the conversion of ethylene: ethanol or polyethylene. Both facilities are potential additions to Dr. Tussing's second scenario. It was felt that the best way to integrate scenarios was to add either the ethanol or the polyethylene processing facility to Dr. Tussing's second scenario. Ethanol was chosen as a product for the final scenario since the ethanol facility would be smaller than the polyethylene facility and the development of a smaller plant was considered more likely. The relevant figures for the ethanol plant appear as a third column in Table 2-3. Capital cost estimates for the basic facility agree closely, so there is little question about the assignment of a single best estimate for the complex as a whole (see Table 2-3). The same is true for the permanent workforce estimates. More judgment was involved in estimating average and peak construction employment. The final construction estimates, which appear in column four of Table 2-3, roughly correspond to the midpoint between the two estimates. Finally, it should be noted that Dr. Tussing's second scenario included a 12-inch products pipeline. To make the scenario easier to present to the public and since employment and capital costs for the products pipeline are minor compared to the petrochemical plant itself, cost and employment estimates were made only for the plant. The scenario did mention, however, that the petrochemicals would be transported by pipeline or rail.

The final scenario also mentions that few, if any, products would be available locally. This judgment is based on the fact that the local or even statewide market for petrochemical products is too small to warrant extensive processing of intermediate products for local distribution. Many such products would require the importation of chemicals to the Interior, thus adding substantial production costs. Final products that were available would be most profitably sold at just below current market prices. There was a strong concensus among the project staff that local products should not be listed among the likely benefits of a petrochemical facility located in the Fairbanks area.

The chemical processes involved in the final scenario clearly do not involve the pollutants that are associated with the oil-based petrochemical industry or with processes that require the addition of aromatic compounds or chemicals such as chlorine. The potential effect of water vapor emissions is more problematic. Providing stack emissions do not occur within about the first six hundred feet above the urban basin, it does not appear that a petrochemical plant would directly contribute to the ice fog which occurs at or near ground level. This judgment is based not only on a knowledge of the characteristics of petrochemical plant stack emissions but also on experience with similar emissions in the Fairbanks area.

The final area addressed in the petrochemical scenario is that of induced changes in employment and population. Traditionally applied employment multipliers are not appropriate for Fairbanks because much of the support sector employment increase generated by basic industry occurs in Anchorage. We assumed that the addition of five jobs in basic industry will result in one additional job in the support sector in the Fairbanks area. The projected population increase is based on the assumptions that two-thirds of the permanent jobs created will be filled by non-residents possessing the necessary skills and that the average family size of those moving to Fairbanks is 2.5. The exact number of indirect jobs created and the resultant population increase is, of course, impossible to predict. Under varying assumptions it is possible that both figures might be doubled. The important point is that the population will not increase by more than several percent nor will the number of permanent indirect jobs created be in any way comparable to that experienced during construction phase of the trans-Alaska pipeline.

Interviewers read the complete scenario to each respondent during the course of the interview. Respondents were also given a copy of the scenario and two diagrams (see Figures 2-2 and 2-3) to aid in remembering the points covered in the description. Following the presentation of the scenario, respondents were asked if they were confused about any statements or if they wished to hear parts of the scenario again. Interviewers were instructed to note which paragraphs were reread and to record any comments the respondent might make about the scenario. They were expressly forbidden to attempt to answer questions or respond to comments in any way other than to repeat information contained in the written scenario. Furthermore, interviewers were trained to read the scenario exactly as it was written. In this way, the information presented to each person interviewed was exactly the same. A copy of the information packet given to each respondent when the scenario was presented concludes this chapter.

FAIRBANKS PETROCHEMICAL STUDY

Interview Packet

SECTION B

PETROCHEMICAL DEVELOPMENT DESCRIPTION

1 We have found that not everyone expects petrochemical development to cause the same changes in the Fairbanks area. Some people believe the petrochemical plant would be very small and others feel it would be very large, for example. For this reason, it would be unfair of us to ask everyone simply if they favor petrochemical development. One person may favor petrochemical development because he thinks it will create many jobs and little air pollution. Another person may oppose petrochemical development because he thinks it will only employ outsiders and will result in poor air quality. Many more people may have no opinion because they don't know what to expect.

2 As a part of this study, we have asked several experts in the field of energy development to give us a description of the general type of petrochemical industry which could possibly locate in the Fairbanks area. The description includes how many people might be employed, what kinds of pollution might be produced and how much taxable property might be added in the Borough. I would like to take a few minutes to read the short description to you before proceeding with this interview.

GAS PIPELINE

3 As you know, the Prudhoe Bay field consists not only of the crude oil that is being transported in the trans-Alaska oil pipeline but also natural gas. Current plans call for all or a portion of the natural gas to be transported by pipeline down the oil pipeline corridor to Fairbanks and then along the Alaska highway through Canada to the lower 48 states.

PETRO-CHEMICAL PLANT

4 The State of Alaska owns a portion of the natural gas that is to be transported; it is referred to as State royalty gas. The State or even one of the private companies owning the gas may choose to sell some of the gas inside Alaska. Gas sold in Alaska might be used directly as fuel for homes and industry; most likely, however, it would be sold to a company which would make new products out of the gas. A petrochemical plant is basically a plant which uses natural gas or crude oil to make all sorts of new chemical products.

In the case of Fairbanks, the type of petrochemical plant we are talking about would use only natural gas, not the crude oil.

ECONOMIC FACTORS

5 A petrochemical plant is expensive to build anywhere, but in Fairbanks it would cost between 50 and 100 percent more to build. The transportation costs of shipping the products from Fairbanks to world markets would also be very high. The high construction and transportation costs for a Fairbanks plant make it uncertain if the plant could deliver its products to world markets at a price that is the same or lower than that of plants located elsewhere. In other words, it may not make economic sense to build a petrochemical plant in the Fairbanks area. On the other hand, if a plant were built in Alaska, Fairbanks would be one logical location.

6 For what we are talking about today, we don't have to worry about whether a petrochemical plant can be built in Fairbanks. We want to know what your opinions are about a petrochemical plant <u>if</u> it is built in the Fairbanks area.

7 How do the experts think a petrochemical plant would change Fairbanks anyway? Well, naturally, the experts don't all agree and there are many possible types of plants they can choose from. However, we did get several of them to agree on what they believe is the general type of plant that could be built in Fairbanks.

METHANE

8 Here is a diagram which shows you what's involved. Leaving Prudhoe are two lines, oil and gas. Both lines pass through the Fairbanks North Star Borough. Inside the Borough, State royalty gas is taken from the gas pipeline and separated into methane, the lightest gas, and a mixture of ethane and propane. From the separator plant, the methane is used primarily to make methanol which can be used as a fuel. The methanol and other methane-based products are shipped out of Fairbanks in a third pipeline and/or in special cars on the Alaska railroad. Just to give you an idea of scale, the methanol produced would more than double the supply in the United States.

ETHANE

PRODUCTS

9 The separated ethane, and a little propane, is converted primarily to ethylene which in turn is used to make ethanol, or polyethylene pellets and a mixture of other products. Neither the ethane or the ethane would be used to produce any finished chemical products such as paints, pantyhose or pharmaceuticals. While some products like ethylene glycol, the basic ingredient in anti-freeze, would be produced, our experts tell us that there is not much chance of their being marketed locally; and if they were, the price

would not differ greatly from what you pay now. The entire plant and surrounding lands might occupy one square mile.

CONSTRUCTION

10 Now on to what the petrochemical plant would mean to you, a Fairbanks resident. The plant would take about three years to construct, using an average of some 1,500 workers with a peak employment of perhaps twice that. Put another way, the local construction employment would be roughly two-thirds of the local employment during the construction of the oil pipeline. The first year of construction would probably involve local contractors and labor. Later stages of construction would require special skills not common in Fairbanks.

TAXABLE PROPERTY

11 I mentioned earlier that the plant would be expensive to build. That means that if it is built the plant will add a great deal to the total amount of taxable property in the North Star Borough. In fact, the plant would be worth between about 810 and 860 million dollars. That would represent about 40 percent of the value of all the property (including your home and everyone else's) in the Borough. If the plant paid property taxes at the current tax rate, it would pay 4 million a year to the Borough and increase total Borough revenues by about 15 percent.

RECAP

12 To recap our description so far, the plant would process the State royalty gas and ship the products by pipeline to Haines or the Cook Inlet. Few, if any, products would be available locally. The construction of the plant would require about two-thirds the number of workers locally as required by the construction of the oil pipeline. The plant itself would increase the amount of taxable Borough property by 40 percent.

PERMANENT JOBS

13 Besides local products, construction jobs, and tax revenues, we need to know something about permanent jobs created by the petrochemical plant. About 600 persons would work at the plant. Fifty of these jobs would be related to the overall management of the plant. The remaining 550 would be divided into shifts because the plant would have to operate 24 hours a day, year round. The plant jobs would either be filled by new residents or by existing Fairbanks residents who learn the necessary skills.

INDIRECT JOBS

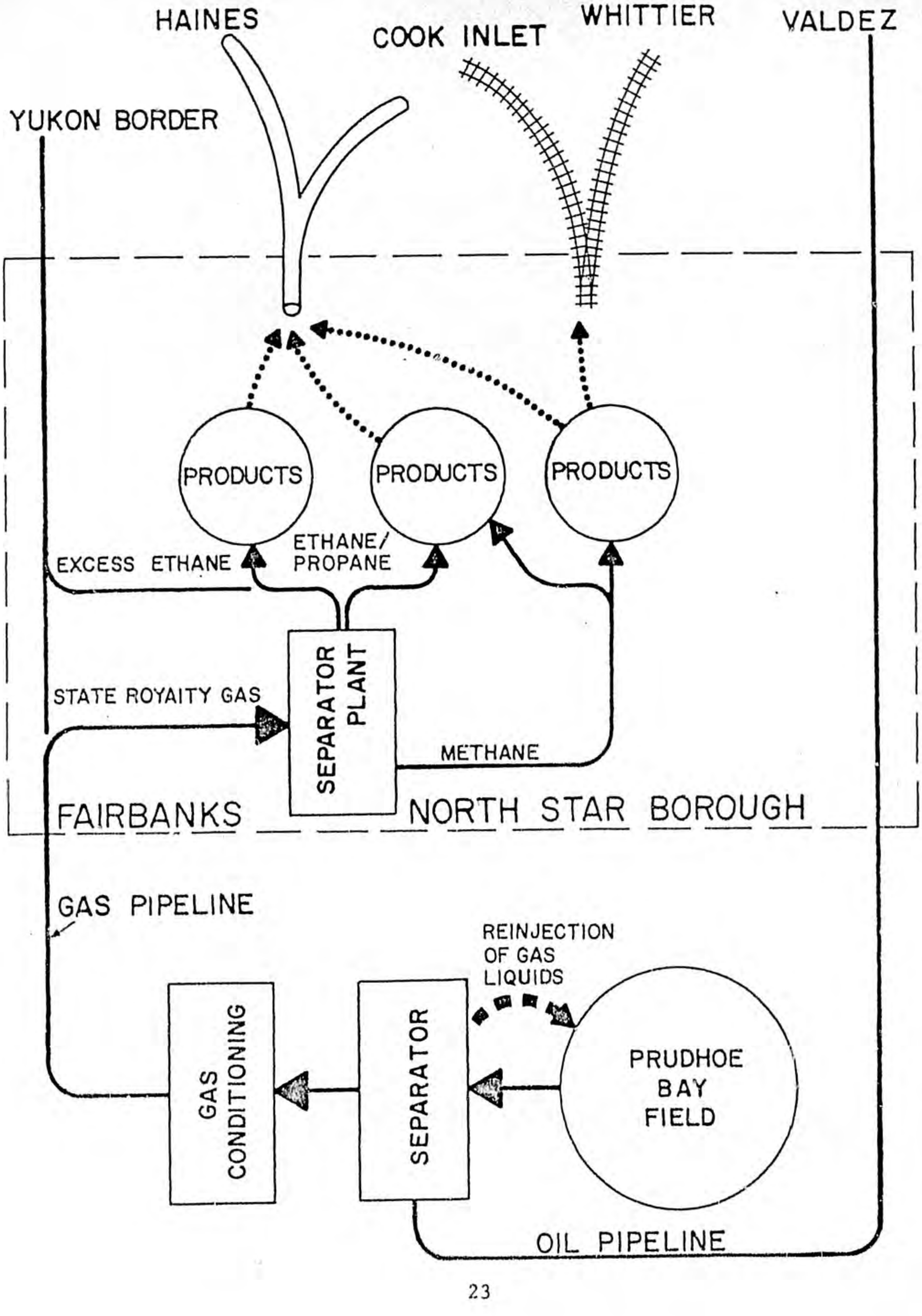
POPULATION

14 The plant would also indirectly result in roughly 100 new jobs ranging from sales clerks to hairdressers, depending on what new demands are placed on the community. All in all, the new jobs at the plant and in the community might bring 1,200 people to Fairbanks. The 1,200 represents about a 2 percent increase in population and would add their share of cars, housing, and ice fog and spend their share of dollars in the community.

15 ENVIRONMENT

The last part of our description concerns the effect of the plant on our air and water. The plant will use water, but probably they would use air rather than water where they need to cool a chemical process. As a result the plant would not use tremendous amounts of water or release hot water into nearby rivers. Gas-based petrochemical plants like the one we're talking about do not give off smelly or toxic fumes that oil-based petrochemical plants do. Gas-based plants do produce water vapor which could become ice fog in the winter. The water vapor problem and other factors make it desirable to locate the plant on higher ground, 600 feet or more above the urban area. The water vapor would then be released above the layer of air we breathe and drive around in. Since the higher layers of air do not mix with the lower layers on cold days, any ice fog produced by the plant would not be added to the ice fog layer in the urban area.

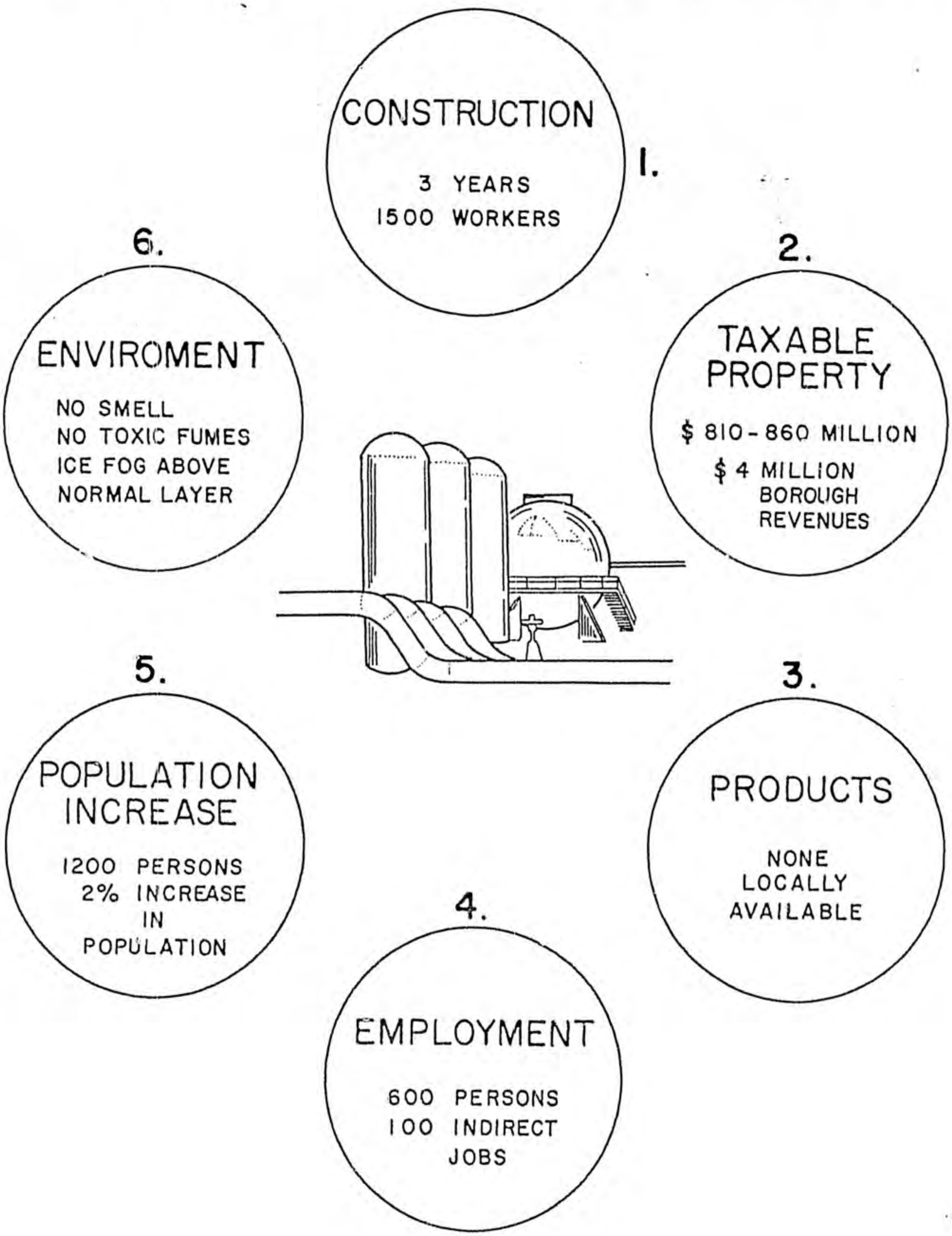
FIGURE 2-2



AGO 533089

FIGURE 2-3

EFFECTS OF PETROCHEMICAL DEVELOPMENT



State of Alaska

AGO 533091

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NEW YORK

November 20, 1979

The Honorable Avram Gross
Attorney General
State of Alaska
Juneau, Alaska

Dear General Gross:

This letter report will summarize our finds and recommendations on the issue of State financial support and participation in the proposed Alaskan Gas Pipeline.

Introduction

A discussion of State participation in the financing of the Alaskan Natural Gas Transportation System (ANGTS) should be first predicated on the conviction that a commitment of State resources to the project is desirable for the State of Alaska and its citizens. We believe there are solid demonstrable benefits to the State and its citizens to be derived from State participation. This opinion is not based on the proposition that without State participation the project will fail. Rather, it is based on the conviction that State financial participation will accelerate the project and that the State can and should achieve special leverage with respect to its own interests.

1. Jobs

An acceleration of the project creates jobs and economic activity now rather than later. To the current residents of Alaska today, jobs and economic activity have a concrete meaning.

2. Government Revenues (Royalty, severance tax, ad valorem taxes)

Based on a production level of 2 billion cubic feet of gas per day, governmental revenues should approach $500 million annually to the State by the time the line is open. On a discounted, present worth basis, dollars shifted from latter years to earlier years become more valuable. A delay of one year means permanently foregoing the largest part of the value of $500 million. This represents more than $1,200 per person in the State of Alaska.

3. Leverage at the Bargaining Table

The State will want to be a full fledged, participant in the resolution of a number of pipeline-related issues, including but not limited to the capture of the liquids stream to insure its highest and best use. By taking a constructive financial role, the State can arrive at the bargaining table in an advantageous manner. Without State financial participation, the State will still have a position, but a position whose strength depends largely upon regulation, controls and a certain negativism, which could have unfortunate side effects mentioned directly below.

4. Business Climate

The pipeline project is of such magnitude that the business community cannot avoid focusing on it and the State's role. Actions by the State will be scrutinized and conclusions, fortunately or unfortunately, magnified. At a time when State governments have all become extremely competitive relative to attracting jobs, it is important that the State of Alaska be conscious that its actions on the pipeline may affect the business community's perception of the overall business climate in Alaska. A policy which demonstrates a constructive policy toward business activity may be essential to a long term policy to broaden the economic base of the State.

5. <u>The United States Congress</u>

Historically, the United States Congress has played a larger role in the affairs of Alaska than in most other States. Being an active participant in this major project gives the State and its representatives in the Congress an opportunity to make friends and alliances which in the long run can pay dividends in areas entirely distinct from the pipeline itself. An inward-turning, perhaps isolationist policy, may not give the State it's maximum leverage in many other areas of State concern and interest.

For the reasons listed above, we conclude that it is in the best interests of the State to move the ANGTS project forward.

<u>Forms of State Participation</u>

This letter report will now address the way in which the State can most effectively move the project forward and simultaneously further the special interests of the State. Specifically, we will review four possible methods of State participation. We will recommend as a preferred approach State ownership in its entirety of the gas conditioning plant.

1. <u>State Ownership of Gas Conditioning Plant</u>

The first alternative and, in our opinion, the preferred alternative, is the ownership by the State of the gas conditioning plant (estimated cost of $2.8 billion). Gas conditioning is essential to the operation of the ANGTS project, and, yet, is a discrete project, which can be separately financed and operated. The risks of construction and ownership are modest. With respect to construction risks, a gas conditioning plant is not an item in the leading edge of technology; it is well within the normal range of construction technology. With respect to ownership risks, contractual arrangement can be made with producers and shippers so as to minimize the economic risks. These contractual arrangements would be in the form of take-or-pay contracts, or tolling fees which would guarantee operating costs, debt service and an agreed upon rate of return to the State. Under the most likely negotiations, the rate of return on the equity investment should match the pipeline's overall return (17 1/2%). The special economic benefit to the State is that the ownership of the plant will give the State considerable flexibility in capturing the value-added to liquids, and insuring its best use.

By carving out a special, distinct portion of the project for the State, the State will have greater negotiating leverage with respect to the pipeline than being a minority partner in the overall project.

As part of the arrangements with the producers, the State will negotiate an Option Agreement for five years for the purchase of a major portion of the liquids from the plant. This Option Agreement will enable the State to stimulate further economic development as circumstances permit.

From the point of view of the producers and shippers, the ownership by the State of the gas conditioning plant would relieve the overall pipeline project of considerable equity and debt financing, thereby releasing funds for the balance of the project.

The financing of the gas conditioning plant would not be a major problem. The plant would be financed by a maximum of 25% in equity and 75% in the form of non-recourse, tax-exempt debt. By non-recourse we mean the State would not be liable for the debt. The project itself, and contracts with producers and shippers would support the debt.

By shifting plant ownership to State hands, tax-exempt financing(1) would become likely. In addition, State ownership would mean that the

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(1) We would expect that Congressional approval would be required to satisfy the IRS in a project of this size.

plant would pay no income taxes. The change to tax-exempt status would substantially reduce conditioning costs. Inasmuch as conditioning costs are a major stumbling block in the financial plan of the producers and shippers, a reduction in such costs would be a welcome move by all parties.

It should be noted that the shift of ownership to State hands does not require in itself, that the conditioning costs be paid by producer or shipper, or by a combination of both. The resolution of this issue is separate from the issue of ownership. Similarly, the ownership of the plant by the State does not, in itself, resolve the issue of where the plant will be located (Prudhoe or Fairbanks). This, again, is a separate issue. However, the State's ownership position may result in a greater likelihood of compromise on these issues.

2. Other Alternatives for State Participation

a. The issuance of non-recourse, tax-exempt, revenue bonds, by the newly-created Alaska Gas Pipeline Financing Authority.

In June 1978, the Alaska State Legislature authorized up to \$1 billion in non-recourse revenue bond financing to be issued through a newly-created Alaska Gas Pipeline Financing Authority. The main purpose of this alternative was to tap new sources of financing the tax-exempt bond market.

The issuance of the proposed \$1 billion, non-recourse, tax-exempt, revenue bonds is, in our opinion, entirely feasible and will not adversely affect the credit of the State. This form of participation is of low risk to the State. This alternative is primarily a demonstration of the State's good will which is an important ingredient in setting the proper climate conducive to moving the project forward. This alternative does not, however, provide any special benefits to the State other than in helping to move the overall project forward, nor does it create any particular leverage for the State except that which is provided by general good will. This alternative is a minimal commitment and a minimal risk.

A change in the Federal tax code would be necessary to effect this alternative.

b. Insurance Fund

A third alternative for financial participation in the overall project would be to create an insurance fund jointly with the Federal government to cover part of the costs of possible overrun. Inasmuch as the overrun problem is the key financial problem for the private sector, the State might consider establishing an insurance fund jointly with the Federal government to give greater assurance as to project completion. The joint insurance fund would come into play only after the normal project contingency fund was exhausted. The joint insurance fund would purchase senior, secured bonds of the pipeline at market interest rates with relatively rapid amortization. The joint insurance would not require equal contributions of the State and the Federal government. It would be expected that the Federal government's share of the insurance fund might be three or four times that of the State. The insurance fund would receive a commitment fee from the insured until completion.

As an illustration, there might be created a special Alaska Gas Pipeline Insurance Fund in the amount of $2 billion, of which the State of Alaska's share would be $500 million. The Insurance Fund would be tapped only:

a) when the original financing, plus a 50% contingency reserve, is exhausted,

b) upon the further contribution by the private participants of 25% of additional overruns.

Using an Insurance Fund as a method of financial participation is relatively low risk for the State. Having the Federal government as a partner is an advantage. Such a contingent commitment is well within the financial capacity of the State. A Federal government insurance program has a great number of precedents, and has served critical functions in housing, banking and other projects which depend heavily on the private sector.

c. State Minority Participation in the Pipeline Itself

It has frequently been suggested that the State of Alaska participate directly in the financing of the overall pipeline project by purchasing a minority interest in the equity and/or debt of the pipeline itself. At times it has been suggested that because the State receives a 1/8th royalty share that it should purchase a 1/8th position in the pipeline. A 1/8th participation in the ownership and/or financing of the pipeline would mean that the State would assume the same risks and rewards as the producers and/or shippers. This alternative would not give the State any special benefit in return for a very large commitment. From the point of view of the producers and shippers, this 1/8th participation is not particularly needed and does not address the thorny question of overruns, which question will continue to plague the financibility of the project. Moreover, a 1/8th minority interest does not give the State very much leverage to achieve its particular ends in policy making and direction of ANGTS, nor in future economic development.

Summary

All four alternatives described above have merit because they demonstrate the State's good will toward the project, with favorable implications for the business climate in Alaska. All four approaches move the project forward. However, all the alternatives do not necessarily carry the same degree of risk or rewards for the State.

To summarize each alternative, the first alternative, the one we favor and recommend, the ownership by the State of the Gas Conditioning Plant, involves a substantial commitment by the State, but a low risk one. This alternative generates considerable economic benefits as well as special long term benefits for the State of Alaska and its citizens. The second alternative, that of issuance of non-recourse, tax-exempt revenue bonds, represents a minimal commitment and a minimal risk. The third alternative, that of a joint State Federal insurance fund, is relatively low risk and moves the project ahead importantly. However, it does not generate special benefits for the State of Alaska. The fourth alternative, that of a 1/8th participation in the overall project, is a major commitment with considerable risks and rather modest special benefits.

Next Step

In order to move a project of this magnitude ahead, it is strongly urged that an organization be established with Legislative authority to (a) prepare detailed feasibility studies, (b) negotiate necessary contracts with the producers and shippers, and (c) negotiate with the Federal government for the necessary approvals. The objective would be to prepare a plan and budget which can be submitted to the State Legislature for their approval.

It is particularly necessary to consolidate the State's effort into a small organization in order to negotiate seriously with producers and shippers. Producers and shippers will not seriously negotiate unless there is clear authority for such negotiations and a positive expression of intent by the Legislature.

Without attempting to impose any particular organization, it is suggested that a special Authority be established, an Executive Director and a small Board consisting of members of the Legislative houses and the Executive Branch be appointed. The Authority would be asked to submit to the State Legislature the final proposal for a commitment of State funds and borrowing authority by no later than January 5, 1981. Obviously, such commitment would be conditioned on the entire ANGTS project proceeding on a satisfactory basis.

Only minimal funds (estimated at $250,000) would be needed to bring the gas conditioning plant plan to the final Legislature approval stage. When the ANGTS project goes forward, the Authority could be expanded.

Attached is a report prepared by Purvin & Gertz addressing some of the technical issues involved in the construction and ownership of a gas conditioning plant.

Very truly yours,

Lazard Frères & Co.

PAL:g

Joint Gas Pipeline Committee
Alaska State Legislature

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POUCH V
JUNEAU, ALASKA 99811
(907) 465-3779

3/17/80

To: Members of the Joint Gas Pipeline Committee
From: Mary Halloran, MH Research Analyst

Re: Gas Conditioning Costs and Implications for State Revenues

At one point during the national negotiations over the Northwest gas pipeline project financing, it was suggested that the producers and/or the State might be penalized for not participating in project financing through federal manipulation of the gas wellhead price or the conditioning costs. The attached paper by Alexander Hoke of the House Research Agency analyzes the potential penalities to the State from different conditioning costs scenarios. The range between the "best" case and the "worst" case from the State's perspective is \$3.9 billion.

The analysis is based on 53¢/Mcf for all conditioning costs (24.9¢/Mcf for operating costs and 28.1¢/Mcf for capital costs), and a wellhead price of \$1.95/Mcf (1980 value). The field life is estimated to be forty years.

The cases and results are as follows:
<u>Case 1.</u> State and producers bear all conditioning costs, operating and capital, but <u>not</u> through a reduction in the wellhead value. No conditioning costs are passed through to consumers. State revenue = \$16.6 billion.
<u>Case 2.</u> State passes through all conditioning costs; but producers bear all conditioning costs, but not through a reduction in wellhead value. State revenue = \$18.8 billion.
<u>Case 3</u>. State bears all conditioning costs, but <u>not</u> through a reduction in wellhead value; producers pass through operating costs of conditioning, and bear capital costs but <u>not</u> through a reduction in wellhead value. State revenue = \$17.2 billion.
<u>Case 4.</u> State bears all conditioning costs, but <u>not</u> through a reduction in wellhead value; producers pass through all conditioning costs. State revenue = \$17.3 billion.
<u>Case 5</u>. All conditioning costs, both capital and operating, are deducted from the wellhead value for royalty purposes. State revenue = \$15.7 billion.
<u>Case 6</u>. Only operating conditioning costs are deducted from the wellhead value for royalty and severance tax purposes. State revenue = \$15.1 billion.
<u>Case 7</u>. All conditioning costs, both capital and operating, are deducted from the wellhead value for royalty and severance tax purposes. State revenue = \$14.9 billion.

HOUSE RESEARCH AGENCY
Pouch Y - State Capitol
Juneau, Alaska 99811
465-3991

MEMORANDUM March 10, 1980

TO: Representative Miles

FROM: Alexander Hoke Alexander Hoke

RE: Gas Conditioning Costs
Research Request No. 29

The following analysis is offered in response to your question regarding potential "penalties" to the State involving gas conditioning costs if the State does not participate in financing the Alaska Highway Gas Pipeline project. The Federal Energy Regulatory Commission's interpretation of the 1978 Natural Gas Policy Act lays the burden of gas conditioning costs on the producers of gas, which, in effect, precludes the State from being "penalized" with regard to conditioning costs. Our intent in this memorandum is to avoid speculating on the potential with which a "penalty" scenario may come to fruition, but rather direct our efforts to an analysis of the financial implications of a given "penalty" scenario should it occur.

Should the State of Alaska elect not to participate in gas pipeline financing, there appear to be two means by which the State could become the object of a "penalty" by the investors on the pipeline for its failure to bear a portion of the financial risk. The word "penalty" is used loosely here in reference to any disparity in treatment of the State relative to gas producers who participate in pipeline financing. Both "penalties" take the form of a differentiation in the wellhead price of gas produced at the North Slope.

Conditioning Cost Pass-Through for Pipeline Investors

The first means [and the most likely given the timbre of recent Federal Energy Regulatory Commission (FERC) ruling appeals by gas producers and potential sponsors of the Alaska Gas Pipeline] requires that FERC grant a financial hardship ruling which, in effect, permits those who participate in the financial risks of the pipeline to pass some or all of their share of the gas conditioning costs through to the gas purchasers. On the other hand, if the State chose not to participate financially in the pipeline, its share of conditioning costs would likely not be permitted to pass through to gas purchasers, resulting in an effectively lower wellhead value for the State relative to that for pipeline investors. For example, gas conditioning capital costs amortized over 30-year terms average 28.1¢ per MCF. The operating component of conditioning costs over the productive life of the field average about 24.9¢ per MCF. If sponsors of the gas pipeline were permitted to pass this total conditioning cost of 53¢ per MCF through to the gas purchasers, their effective wellhead price would be increased from $1.95/MCF to $2.48/MCF. The State, on the other hand, would not be permitted to pass through the conditioning costs, and consequently, its wellhead value for royalty and severance tax purposes would remain at $1.95/MCF (gas price ceiling fixed by 1978 Natural Gas Policy Act in 1980 dollars).

Conditioning Cost Deduction from Wellhead Price

The second method for differentiating the wellhead gas price on the basis of non-participation in gas pipeline financing involves a deduction of some, or all of the cost of gas conditioning from the wellhead price ceiling of $1.95/MCF. In this scenario, the State of Alaska, as a consequence of non-participation in gas pipeline financing, would be "penalized" by deducting up to 24.9¢/MCF for the operating component of conditioning costs (leaving a wellhead price of $1.70/MCF), or by deducting up to 28.1¢/MCF for capital conditioning costs (resulting in a $1.67/MCF wellhead price), or by deducting all gas conditioning costs (which results in an effective wellhead price of $1.42/MCF).

The "No-Penalty" Scenarios

Scenario number 1 of the attached table assumes that conditioning costs are neither deducted from the wellhead price of gas, nor permitted to be passed through to gas purchasers as a special federal allowance to offset the burdensome capital investment risks borne by those who participate in pipeline financing. The wellhead price of gas ($1.95) is the 1980-dollar value of the price ceiling fixed in the 1978 Natural Gas Policy Act. The 35.5% figure in the fifth column represents the fraction of total industry net cash flow on the attached computer run #1, constituted by the gas net cash flow component [39,706 ÷ (39,706 + 72,130) = 35.5%]. This percentage is used to calculate the figure for State income tax for gas production from the total State income tax listed on the computer printout.

In the last column, industry net cash flow from gas production is given as a comparitive measure of industry profits relative to total State revenue in the adjacent column. The total State revenue in this "no-penalty" scenario run is $16.6 billion.

Scenario #2 is shown on the attached table to indicate the level of increase in total revenue to the State that would accrue if the State participated in pipeline financing, and if FERC ruled that those bearing financial risk in the pipeline were permitted to pass conditioning costs (operating and capital) through to the gas purchasers. State revenues of $18.8 billion under this scenario significantly exceed the $16.6 billion revenues projected in the "no-penalty" scenario #1.

The "Penalty" Scenarios

Conditioning Cost Pass-Through:

Scenario #3 shows the effect of a pass-through of the operating costs of conditioning to gas purchasers allowed for gas producers only. Total State revenues = $17.2 billion.

Scenario #4 demonstrates the impact of permitting gas producers only the transfer of conditioning costs (operating and capital) to gas purchasers--compare to Scenario #2. Total State revenues = $17.3 billion.

Conditioning Cost Deduction from Wellhead Gas Price:

Scenario #5 shows the impact of deducting all conditioning costs (capital and operating) from the wellhead price of gas ($1.95/MCF) for royalty purposes only. Total State revenue = $15.7 billion.

Scenario #6 demonstrates the effect of deducting only the operating costs of conditioning from the wellhead price of gas for royalty and severance tax purposes. Total State revenue = $15.1 billion.

Scenario #7 represents the situation in which all conditioning costs (operating and capital) are deducted from the wellhead gas price for royalty and severance tax purposes. Total State revenue = $14.9 billion.

The Monetary Effect of Conditioning Cost Penalties

The most immediately apparent observation when comparing conditioning cost "penalty" scenarios 3 through 7 to the "no-penalty" scenario #1 are the differences in total State revenue. Scenarios 3 and 4 involving conditioning cost pass-through to gas purchasers result in higher revenues to the State than the $16.6 billion in the "no-penalty" scenario #1. This is primarily due to the increased State income tax revenue on higher profits earned by the producers when the conditioning costs are assumed by the purchasers of gas. On the other hand, scenarios 5, 6 and 7 have lower totals for State revenue than the "no-penalty" scenario #1, because deductions of gas conditioning costs from the wellhead price of gas directly affects royalty and severance tax revenue.

Conditioning Cost Pass-Through to Gas Purchasers:

Scenario #4 demonstrates the effect of an allowed pass-through of conditioning costs to gas purchasers by the gas producers (effectively raising their wellhead gas price to $2.48/MCF) while dissallowing the pass-through for the State of Alaska (which leaves the State's wellhead value at $1.95/MCF). Scenario #4 shows a total State revenue of $17.3 billion indicating a "penalty" from scenario #2 of $1.48 billion (18.779 - 17.302 = 1.48). Curiously, however, the total State revenue under this "penalty" situation is higher than the "no-penalty" scenario #1. In other words, even though the State may be "penalized" by not receiving the conditioning cost pass-through approval from FERC as a result of non-participation in gas pipeline financing, the State's total revenues would increase primarily due to higher income tax revenue on the producers' increased profits.

Conditioning Cost Deductions from Wellhead Gas Prices:

Scenarios 5, 6 and 7 show that total State revenues are significantly lower (than scenario #1) when operating and/or capital conditioning costs are deducted from the wellhead gas price of $1.95/MCF. In the worst case (scenario #7) average operating costs of 24.9¢/MCF and average capital costs of 28.1¢/MCF deducted from the $1.95/MCF wellhead price results in an effective wellhead price for State tax purposes of $1.42/MCF. When this deduction is applicable to royalties and severance taxes, the total State revenue is reduced to $14.9 billion compared to $16.6 billion when no deductions are made. The magnitude of the decrease in revenues from the "no-penalty" scenario #1 are somewhat attenuated when only the operating costs of conditioning are deducted from the wellhead price (scenario #6--total revenue = $15.1 billion), or when conditioning costs are deducted from the wellhead price for royalty purposes only (scenario #5--total revenue = $15.7 billion).

While the conditioning cost "penalties" described in scenarios 5, 6, and 7 are the most severe of those shown on the attached table, there is ample reason to suggest that the likelihood of their occurrance is remote. The Federal Energy Regulatory Commission Order #45, adopted August 24, 1979, addresses conditioning costs as the responsibility and burden of the producers of gas. Consequently, the fixed price ceiling set in the 1978 Natural Gas Policy Act could be defined as net of conditioning costs. In other words, the present price ceiling already excludes conditioning costs and further deductions from the ceiling price for conditioning cannot be justifed. Therefore, scenarios 5, 6 and 7 would seem inplausible short of a countermanding rule from FERC on conditioning costs.

AGO 533107

Methodology

Calculations made in preparing this analysis revolve around the use of the Eppenbach Producer Benefits computer model. As numerous assumptions have been made about production and price scheduling, debt financing (term, interest rates, amortization mode, etc.) federal tax rates, the proportion and timing of capital investments and many other environmental parameters of the model, discretionary interpretation of the precision of projected revenues is suggested. However, the relative magnitude of the projected State revenues are of greater policy significance, and we believe that the projections shown on the attached table fairly represent an accurate comparison of the relationship of one "penalty" scenario to another.

prepared by:
House Research Agenc

ALASKA REVENUE FROM NORTH SLOPE GAS PRODUCTION
(Millions of Dollars)

Conditioning Cost Penalty Scenario	Effective Wellhead Gas Price (per MCF)[1]	Royalty	Severance	Property Tax	Gas % of Total Net Cash Flow[2]	State Income Tax[3]	Total State Revenue	Gas Industr Net Cash Fl
1. Control Scenario no deviation	$1.95	$7,206	$5,044	$389	35.5%	$3,971	$16,610	$25,004
2. 30-year pass-through for State and producers of operating & capital costs	2.48	8,127	5,689	389	38.9%	4,574	18,779	28,897
3. 30-year pass-through of operating costs for producers only	1.95	7,206	5,044	389	38.6%	4,523	17,162	28,566
4. 30-year pass-through of operating & capital costs for producers only	1.95	7,206	5,044	389	39.4%	4,663	17,302	29,479
5. Operating & capital costs deducted (royalty)	1.42	6,104	5,154	389	36.3%	4,099	15,746	25,829
6. Operating costs deducted (royalty & severance)	1.70	6,285	4,399	389	36.0%	4,062	15,135	25,586
7. Operating & capital costs deducted (royalty & severance)	1.42	6,104	4,273	389	36.3%	4,099	14,865	25,829

[1] Effective wellhead price of gas for state tax purposes: 1980-dollar equivalent of the 1978 Natural Gas Policy Act gas price ceiling adjusted up or down by the following average conditioning costs: operating = 24.9¢/MCF capital = 28.1¢/MCF

[2] Gas component (percentage) of combined oil and gas net cash flows from attached computer runs.

[3] Multiply percentage in previous column times total state income tax from attached computer runs.

[4] Industry Net Gas Cash Flow from attached computer runs minus State and Federal Income tax multiplied by Gas % in previous column.

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

	* * * * * * OIL PRODUCTION * * * * * *						* * * * * * GAS PRODUCTION * * * * * *						
YEAR	PROD. RATE MMBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	PROD RATE MMMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	995.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	177.9	124.5	17.6	320.1	674.5	2,858.3
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	177.9	124.5	17.3	319.8	601.6	2,575.3
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	177.9	124.5	17.0	319.5	549.6	2,362.1
1988	1.000	748.3	512.9	62.9	0.4	1,324.1	2.000	177.9	124.5	16.5	319.0	495.3	2,138.6
1989	0.750	580.1	390.6	59.0	0.3	1,030.1	2.000	177.9	124.5	16.1	318.6	398.4	1,747.2
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	177.9	124.5	15.6	318.1	324.7	1,449.2
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	177.9	124.5	15.2	317.7	256.9	1,176.2
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	177.9	124.5	14.7	317.2	253.2	1,146.9
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	177.9	124.5	14.3	316.8	234.5	1,060.3
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	177.9	124.5	13.8	316.3	230.7	1,019.1
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	177.9	124.5	13.4	315.9	232.5	988.1
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	177.9	124.5	12.9	315.4	202.7	841.0
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	177.9	124.5	12.5	315.0	203.4	751.8
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	177.9	124.5	12.0	314.5	191.1	711.8
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	177.9	124.5	11.6	314.1	178.0	670.1
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	177.9	124.5	11.2	313.6	171.3	643.2
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	177.9	124.5	10.7	313.2	165.5	616.5
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	177.9	124.5	10.3	312.8	167.1	606.3
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	177.9	124.5	9.8	312.3	162.2	575.4
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	9.4	311.9	102.8	414.7
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.9	311.4	104.1	415.6
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.5	311.0	105.5	416.5
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.0	310.5	105.5	416.1
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.6	310.1	105.5	415.7
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.1	309.6	105.6	415.3
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.7	309.2	105.6	414.8
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.2	308.7	105.7	414.4
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.8	308.3	105.7	414.0
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.3	307.8	105.8	413.6
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.9	307.4	105.8	413.2
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.4	306.9	105.8	412.8
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.0	306.5	105.9	412.4
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.5	306.0	105.9	412.0
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.1	305.6	106.0	411.6
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.6	305.1	106.0	411.2
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.2	304.7	106.0	410.8
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.7	304.2	106.1	410.4
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.3	303.8	106.1	410.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.8	303.3	106.2	409.6
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.4	302.9	106.2	409.2
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	88.9	62.2	0.0	151.2	48.4	199.7
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,109	9	23,739	29,565T	7,206	5,044	389	12,640	11,186	47,559

CUMULATIVE TOTALS

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

YEAR 1-50	OIL PRODUCTION: WELLHEAD PRICE/BL	OIL PRODUCTION: GROSS INCOME	OIL PRODUCTION: STATE TAKE	OIL PRODUCTION: OPERAT COSTS	OIL PRODUCTION: CAPITAL COSTS	OIL PRODUCTION: NET OIL CASH FLOW	GAS PRODUCTION: WELLHEAD PRICE/MCF	GAS PRODUCTION: GROSS INCOME	GAS PRODUCTION: STATE TAKE	GAS PRODUCTION: OPERAT COSTS	GAS PRODUCTION: CAPITAL COSTS	GAS PRODUCTION: NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5054.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1700.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1548.0	320.1	192.0	104.9	930.9	674.5	1848.8	4313.9
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1548.0	319.8	212.0	104.7	911.4	601.6	1635.2	3815.4
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1548.0	319.5	219.0	95.2	914.3	549.6	1514.5	3534.0
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1548.0	319.0	193.0	93.1	942.8	495.3	1367.7	3191.3
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1548.0	318.6	192.0	91.1	946.2	398.4	1091.8	2547.7
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1548.0	318.1	192.0	87.6	950.2	324.7	881.6	2057.1
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1548.0	317.7	192.0	84.2	954.0	256.9	688.4	1606.3
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1548.0	317.2	192.0	82.3	956.4	253.2	677.9	1581.8
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1548.0	316.8	192.0	80.4	958.7	234.5	624.8	1457.8
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1548.0	316.3	192.0	78.5	961.1	230.7	613.8	1432.3
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1548.0	315.9	192.0	76.6	963.5	232.5	619.1	1444.7
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1548.0	315.4	192.0	74.6	965.8	202.7	534.2	1246.6
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1548.0	315.0	192.0	72.7	968.2	203.4	536.5	1251.9
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1548.0	314.5	192.0	70.8	970.5	191.1	501.3	1169.8
23	20.39	1255.5	177.9	99.0	236.3	752.2	1.95	1548.0	314.1	192.0	68.9	972.9	178.0	464.1	1083.0
24	20.80	1128.9	158.1	97.0	204.1	679.6	1.95	1548.0	313.6	192.0	67.0	975.3	171.3	445.0	1038.5
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1548.0	313.2	192.0	54.2	988.5	165.5	428.6	1000.2
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1548.0	312.8	192.0	37.1	1006.0	167.1	433.4	1011.3
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1548.0	312.3	192.0	20.6	1023.0	162.2	419.7	979.3
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1548.0	311.9	192.0	0.0	1044.1	102.8	214.1	499.7
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1548.0	311.4	192.0	0.0	1044.5	104.1	248.0	578.8
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	311.0	192.0	0.0	1045.0	105.5	281.8	657.6
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	310.5	192.0	0.0	1045.4	105.5	281.9	657.9
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	310.1	192.0	0.0	1045.9	105.5	282.1	658.2
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	309.6	192.0	0.0	1046.3	105.6	282.2	658.5
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	309.2	192.0	0.0	1046.8	105.6	282.3	658.8
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	308.7	192.0	0.0	1047.2	105.7	282.4	659.0
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	308.3	192.0	0.0	1047.7	105.7	282.5	659.3
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	307.8	192.0	0.0	1048.1	105.8	282.7	659.6
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	307.4	192.0	0.0	1048.6	105.8	282.8	659.9
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.9	192.0	0.0	1049.0	105.8	282.9	660.2
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.5	192.0	0.0	1049.5	105.9	283.0	660.5
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.0	192.0	0.0	1049.9	105.9	283.2	660.8
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.6	192.0	0.0	1050.4	106.0	283.3	661.0
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.1	192.0	0.0	1050.8	106.0	283.4	661.3
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	304.7	192.0	0.0	1051.3	106.0	283.5	661.6
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	304.2	192.0	0.0	1051.7	106.1	283.6	661.9
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.8	192.0	0.0	1052.2	106.1	283.8	662.2
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.3	192.0	0.0	1052.6	106.2	283.9	662.5
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	302.9	192.0	0.0	1053.1	106.2	284.0	662.7
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	774.0	151.2	96.0	0.0	526.7	48.4	143.4	334.8
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	23,772	4,050	8,654	72,130		62,696	12,640	8,335	2,094	39,706	11,186	30,225	70,425

AGO 533111

Item #2

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

YEAR	* * * OIL PRODUCTION * * * PROD RATE MMBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	* * * GAS PRODUCTION * * * PROD RATE MMMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	200.6	140.4	17.6	358.8	699.4	2,921.8
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	200.6	140.4	17.3	358.5	626.4	2,638.8
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	200.6	140.4	17.0	358.1	573.5	2,424.7
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	200.6	140.4	16.5	357.7	519.1	2,201.0
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	200.6	140.4	16.1	357.3	422.0	1,809.5
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	200.6	140.4	15.6	356.8	347.9	1,511.0
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	200.6	140.4	15.2	356.4	279.8	1,237.8
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	200.6	140.4	14.7	355.9	275.9	1,208.3
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	200.6	140.4	14.3	355.5	257.0	1,121.5
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	200.6	140.4	13.8	355.0	253.1	1,080.1
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	200.6	140.4	13.4	354.6	254.7	1,048.9
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	200.6	140.4	12.9	354.1	224.7	901.6
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	200.6	140.4	12.5	353.7	225.2	812.3
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	200.6	140.4	12.0	353.2	212.7	772.1
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	200.6	140.4	11.6	352.8	199.5	730.2
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	200.6	140.4	11.2	352.3	192.6	703.1
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	200.6	140.4	10.7	351.9	185.6	675.2
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	200.6	140.4	10.3	351.4	185.5	663.4
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	200.6	140.4	9.8	351.0	179.1	630.9
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	9.4	350.5	117.8	468.3
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.9	350.1	119.1	469.3
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.5	349.6	120.4	470.1
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	8.0	349.2	120.5	469.7
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	7.6	348.7	120.5	469.3
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	7.1	348.3	120.6	468.9
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	6.7	347.8	120.6	468.5
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	6.2	347.4	120.6	468.1
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	5.8	346.9	120.7	467.7
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	5.3	346.5	120.7	467.3
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.9	346.0	120.8	466.9
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.4	345.6	120.8	466.5
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	4.0	345.2	103.7	448.9
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	3.5	344.7	103.8	448.5
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	3.1	344.3	103.8	448.1
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	2.6	343.8	103.9	447.7
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	2.2	343.4	103.9	447.3
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	1.7	342.9	104.0	446.9
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	1.3	342.5	104.0	446.5
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	0.8	342.0	104.0	446.1
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	200.6	140.4	0.4	341.6	104.1	445.7
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	100.3	70.2	0.0	170.5	47.3	217.9
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
CUMULATIVE TOTALS	7,641T	13,570	9,042	1,109	9	23,732	23,565T	8,127	5,609	309	14,207	11,766	49,705

AGO 533112

INDUSTRY CASH FLOWS

(MILLIONS OF DOLLARS)

YEAR 1-50	* * * * * * OIL PRODUCTION * * * * * * WELLHEAD PRICE/OIL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	* * * * * * GAS PRODUCTION * * * * * * WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5054.3	1270.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1850.8	358.8	192.0	104.9	1195.0	699.4	1920.6	4481.4
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1850.6	358.5	212.0	104.7	1175.4	626.4	1706.9	3982.8
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1841.1	358.1	219.0	95.2	1168.7	573.5	1583.7	3695.4
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1839.0	357.7	193.0	93.1	1195.1	519.1	1436.3	3351.4
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1837.0	357.3	192.0	91.1	1196.6	422.0	1159.9	2706.4
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1833.5	356.8	192.0	87.6	1197.0	347.9	948.7	2213.6
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1830.1	356.4	192.0	84.2	1197.5	279.8	754.6	1760.7
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1828.2	355.9	192.0	82.3	1197.9	275.9	743.5	1735.0
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1826.3	355.5	192.0	80.4	1198.4	257.0	689.9	1609.8
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1824.4	355.0	192.0	78.5	1198.9	253.1	678.4	1583.1
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1822.5	354.6	192.0	76.6	1199.3	254.7	683.2	1594.3
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1820.5	354.1	192.0	74.6	1199.7	224.7	597.8	1394.9
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1818.6	353.7	192.0	72.7	1200.1	225.2	599.5	1399.0
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1816.7	353.2	192.0	70.8	1200.6	212.7	563.9	1315.7
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1814.8	352.8	192.0	68.9	1201.1	199.5	526.1	1227.7
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1812.9	352.3	192.0	67.0	1201.5	192.6	506.5	1182.0
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1800.1	351.9	192.0	54.2	1202.0	185.6	486.7	1135.6
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1783.0	351.4	192.0	37.1	1202.4	185.5	486.8	1135.8
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1766.5	351.0	192.0	20.6	1202.9	179.1	468.6	1093.4
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1745.9	350.5	192.0	0.0	1203.4	117.8	257.4	600.7
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1745.9	350.1	192.0	0.0	1203.8	119.1	291.3	679.8
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	349.6	192.0	0.0	1204.2	120.4	325.1	758.6
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	349.2	192.0	0.0	1204.7	120.5	325.2	758.9
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	348.7	192.0	0.0	1205.1	120.5	325.3	759.2
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	348.3	192.0	0.0	1205.6	120.6	325.5	759.5
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	347.8	192.0	0.0	1206.0	120.6	325.6	759.8
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	347.4	192.0	0.0	1206.5	120.6	325.7	760.0
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	346.9	192.0	0.0	1206.9	120.7	325.8	760.3
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	346.5	192.0	0.0	1207.4	120.7	325.9	760.6
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	346.0	192.0	0.0	1207.8	120.8	326.1	760.9
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1745.9	345.6	192.0	0.0	1208.3	120.8	326.2	761.2
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	345.2	192.0	0.0	1026.7	103.7	276.8	646.0
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	344.7	192.0	0.0	1027.2	103.8	277.0	646.3
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	344.3	192.0	0.0	1027.6	103.8	277.1	646.6
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	343.8	192.0	0.0	1028.1	103.9	277.2	646.9
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	343.4	192.0	0.0	1028.5	103.9	277.3	647.2
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	342.9	192.0	0.0	1029.0	104.0	277.5	647.5
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	342.5	192.0	0.0	1029.4	104.0	277.6	647.7
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	342.0	192.0	0.0	1029.9	104.0	277.7	648.0
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1563.9	341.6	192.0	0.0	1030.3	104.1	277.8	648.3
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	781.9	170.5	96.0	0.0	515.4	47.3	140.4	327.6
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	23,74[illegible]	4,050	8,654	72,130		70,427	14,207	8,335	2,094	45,871	11,766	31,900	74,335

AGO 533113

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

	* * * * * * OIL PRODUCTION * * * * * *						* * * * * * GAS PRODUCTION * * * * * *						
YEAR	PROD RATE MMBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	PROD RATE MMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	995.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	177.9	124.5	17.6	320.1	691.7	2,875.4
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	177.9	124.5	17.3	319.8	618.7	2,592.4
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	177.9	124.5	17.0	319.5	566.7	2,379.2
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	177.9	124.5	16.5	319.0	512.4	2,155.7
1989	0.760	530.1	330.6	59.0	0.3	1,030.1	2.000	177.9	124.5	16.1	318.6	415.5	1,764.4
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	177.9	124.5	15.6	318.1	341.8	1,466.3
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	177.9	124.5	15.2	317.7	274.0	1,193.3
1992	0.400	324.0	205.0	47.3	0.1	576.4	2.000	177.9	124.5	14.7	317.2	270.3	1,164.0
1993	0.350	283.2	176.3	43.2	0.1	508.3	2.000	177.9	124.5	14.3	316.8	251.6	1,077.4
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	177.9	124.5	13.8	316.3	247.8	1,036.2
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	177.9	124.5	13.4	315.9	249.6	1,005.2
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	177.9	124.5	12.9	315.4	219.8	858.1
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	177.9	124.5	12.5	315.0	220.5	768.9
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	177.9	124.5	12.0	314.5	208.2	728.9
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	177.9	124.5	11.6	314.1	195.1	687.2
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	177.9	124.5	11.2	313.6	188.4	660.3
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	177.9	124.5	10.7	313.2	182.6	633.6
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	177.9	124.5	10.3	312.8	184.2	623.4
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	177.9	124.5	9.8	312.3	179.3	592.5
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	9.4	311.9	119.9	431.8
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.9	311.4	121.3	432.7
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.5	311.0	122.6	433.6
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.0	310.5	122.6	433.2
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.6	310.1	122.7	432.8
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.1	309.6	122.7	432.4
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.7	309.2	122.7	432.0
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.2	308.7	122.8	431.5
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.8	308.3	122.8	431.1
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.3	307.8	122.9	430.7
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.9	307.4	122.9	430.3
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.4	306.9	122.9	429.9
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.0	306.5	105.9	412.4
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.5	306.0	105.9	412.0
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.1	305.6	106.0	411.6
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.6	305.1	106.0	411.2
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.2	304.7	106.0	410.8
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.7	304.2	106.1	410.4
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.3	303.8	106.1	410.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.8	303.3	106.2	409.6
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.4	302.9	106.2	409.2
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	88.9	62.2	0.0	151.2	48.4	199.7
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,109	9	23,732	29,565T	7,206	5,044	389	12,640	11,717	48,090

CUMULATIVE TOTALS

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

	* * * * * * OIL PRODUCTION * * * * * *						* * * * * * GAS PRODUCTION * * * * * *								TOTAL
YEAR 1-50	WELLHEAD PRICE/OIL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	533.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1730.0	320.1	192.0	104.9	1112.9	691.7	1898.2	4429.3
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1730.0	319.8	212.0	104.7	1093.4	618.7	1684.6	3930.9
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1730.0	319.5	219.0	95.2	1096.3	566.7	1564.0	3649.4
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1730.0	319.0	193.0	93.1	1124.8	512.4	1417.2	3306.8
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1730.0	318.6	192.0	91.1	1128.2	415.5	1141.3	2663.1
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1730.0	318.1	192.0	87.6	1132.2	341.8	931.0	2172.5
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1730.0	317.7	192.0	84.2	1136.0	274.0	737.9	1721.7
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1730.0	317.2	192.0	82.3	1138.4	270.3	727.4	1697.2
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1730.0	316.8	192.0	80.4	1140.7	251.6	674.2	1573.2
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1730.0	316.3	192.0	78.5	1143.1	247.8	663.3	1547.7
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1730.0	315.9	192.0	76.6	1145.5	249.6	668.6	1560.1
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1730.0	315.4	192.0	74.6	1147.8	219.8	583.7	1362.0
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1730.0	315.0	192.0	72.7	1150.2	220.5	586.0	1367.3
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1730.0	314.5	192.0	70.8	1152.5	208.2	550.8	1285.3
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1730.0	314.1	192.0	68.9	1154.9	195.1	513.6	1198.4
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1730.0	313.6	192.0	67.0	1157.3	188.4	494.5	1153.9
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1730.0	313.2	192.0	54.2	1170.5	182.6	478.1	1115.6
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1730.0	312.8	192.0	37.1	1188.0	184.2	482.9	1126.7
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1730.0	312.3	192.0	20.6	1205.0	179.3	469.1	1094.7
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1730.0	311.9	192.0	0.0	1226.1	119.9	263.6	615.1
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1730.0	311.4	192.0	0.0	1226.5	121.3	297.5	694.2
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	311.0	192.0	0.0	1227.0	122.6	331.3	773.1
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	310.5	192.0	0.0	1227.4	122.6	331.4	773.3
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	310.1	192.0	0.0	1227.9	122.7	331.5	773.6
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	309.6	192.0	0.0	1228.3	122.7	331.6	773.9
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	309.2	192.0	0.0	1228.8	122.7	331.8	774.2
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	308.7	192.0	0.0	1229.2	122.8	331.9	774.5
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	308.3	192.0	0.0	1229.7	122.8	332.0	774.8
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	307.8	192.0	0.0	1230.1	122.9	332.1	775.0
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	307.4	192.0	0.0	1230.6	122.9	332.3	775.3
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	306.9	192.0	0.0	1231.0	122.9	332.4	775.6
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.5	192.0	0.0	1049.5	105.9	283.0	660.5
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.0	192.0	0.0	1049.9	105.9	283.2	660.8
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.6	192.0	0.0	1050.4	106.0	283.3	661.0
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.1	192.0	0.0	1050.8	106.0	283.4	661.3
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	304.7	192.0	0.0	1051.3	106.0	283.5	661.6
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	304.2	192.0	0.0	1051.7	106.1	283.6	661.9
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.8	192.0	0.0	1052.2	106.1	283.8	662.2
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.3	192.0	0.0	1052.6	106.2	283.9	662.5
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	302.9	192.0	0.0	1053.1	106.2	284.0	662.7
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	774.0	151.2	96.0	0.0	526.7	48.4	143.4	334.8
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	23,732	4,050	8,654	72,130		68,338	12,640	8,335	2,094	45,348	11,717	31,758	74,003

CUMULATIVE TOTALS

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

	* * * * * * OIL PRODUCTION * * * * * *						* * * * * * GAS PRODUCTION * * * * * *					STATE	TOTAL
YEAR	PROD RATE MBBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	PROD RATE MMMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	INCOME TAX	STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	177.9	124.5	17.6	320.1	701.5	2,885.2
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	177.9	124.5	17.3	319.8	628.5	2,602.2
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	177.9	124.5	17.0	319.5	575.7	2,388.1
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	177.9	124.5	16.5	319.0	521.2	2,164.4
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	177.9	124.5	16.1	318.6	424.1	1,772.9
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	177.9	124.5	15.6	318.1	350.0	1,474.5
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	177.9	124.5	15.2	317.7	281.9	1,201.3
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	177.9	124.5	14.7	317.2	278.0	1,171.8
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	177.9	124.5	14.3	316.8	259.2	1,085.0
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	177.9	124.5	13.8	316.3	255.2	1,043.6
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	177.9	124.5	13.4	315.9	256.8	1,012.4
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	177.9	124.5	12.9	315.4	226.8	865.1
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	177.9	124.5	12.5	315.0	227.3	775.7
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	177.9	124.5	12.0	314.5	214.8	735.6
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	177.9	124.5	11.6	314.1	201.6	693.7
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	177.9	124.5	11.2	313.6	194.7	666.6
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	177.9	124.5	10.7	313.2	187.7	638.7
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	177.9	124.5	10.3	312.8	187.7	626.9
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	177.9	124.5	9.8	312.3	181.3	594.4
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	9.4	311.9	119.9	431.8
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.9	311.4	121.3	432.7
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.5	311.0	122.6	433.6
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	8.0	310.5	122.6	433.2
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.6	310.1	122.7	432.8
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	7.1	309.6	122.7	432.4
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.7	309.2	122.7	432.0
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	6.2	308.7	122.8	431.5
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.8	308.3	122.8	431.1
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	5.3	307.8	122.9	430.7
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.9	307.4	122.9	430.3
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.4	306.9	[illegible]	[illegible]
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	4.0	306.5	105.9	412.4
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.5	306.0	105.9	412.0
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	3.1	305.6	106.0	411.6
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.6	305.1	106.0	411.2
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	2.2	304.7	106.0	410.8
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.7	304.2	106.1	410.4
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	1.3	303.8	106.1	410.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.8	303.3	106.2	409.6
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	177.9	124.5	0.4	302.9	106.2	409.2
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	88.9	62.2	0.0	151.2	48.4	199.7
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
	7,641T	13,570	9,042	1,109	9	23,732	29,565T	7,206	5,044	389	12,640	11,852	48,226

CUMULATIVE TOTALS

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

YEAR 1-50	WELLHEAD PRICE/OIL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	TOTAL NET CASH FLOW
	* * * * * * OIL PRODUCTION * * * * * *						* * * * * * GAS PRODUCTION * * * * * *								
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1834.9	320.1	192.0	104.9	1217.8	701.5	1926.8	4495.8
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1834.7	319.8	212.0	104.7	1198.1	628.5	1713.1	3997.3
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1825.2	319.5	219.0	95.2	1191.5	575.7	1589.9	3709.8
12	16.40	5987.1	1384.1	181.0	370.3	4111.7	1.95	1823.1	319.0	193.0	93.1	1217.9	521.2	1442.5	3365.8
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1821.1	318.6	192.0	91.1	1219.3	424.1	1166.1	2720.9
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1817.6	318.1	192.0	87.6	1219.8	350.0	954.9	2228.1
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1814.2	317.7	192.0	84.2	1220.2	281.9	760.7	1775.1
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1812.3	317.2	192.0	82.3	1220.7	278.0	749.7	1749.4
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1810.4	316.8	192.0	80.4	1221.1	259.2	696.1	1624.2
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1808.5	316.3	192.0	78.5	1221.6	255.2	684.6	1597.5
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1806.6	315.9	192.0	76.6	1222.1	256.8	689.4	1608.7
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1804.6	315.4	192.0	74.6	1222.4	226.8	604.0	1409.3
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1802.7	315.0	192.0	72.7	1222.9	227.3	605.7	1413.4
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1800.8	314.5	192.0	70.8	1223.3	214.8	570.0	1330.2
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1798.9	314.1	192.0	68.9	1223.8	201.6	532.3	1242.1
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1797.0	313.6	192.0	67.0	1224.3	194.7	512.7	1196.4
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1784.2	313.2	192.0	54.2	1224.7	187.7	492.8	1150.0
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1767.1	312.8	192.0	37.1	1225.1	187.7	492.9	1150.2
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1750.6	312.3	192.0	20.6	1225.6	181.3	474.7	1107.8
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1730.0	311.9	192.0	0.0	1226.1	119.9	263.6	615.1
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1730.0	311.4	192.0	0.0	1226.5	121.3	297.5	694.2
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	311.0	192.0	0.0	1227.0	122.6	331.3	773.1
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	310.5	192.0	0.0	1227.4	122.6	331.4	773.3
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	310.1	192.0	0.0	1227.9	122.7	331.5	773.6
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	309.6	192.0	0.0	1228.3	122.7	331.6	773.9
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	309.2	192.0	0.0	1228.8	122.7	331.8	774.2
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	308.7	192.0	0.0	1229.2	122.8	331.9	774.5
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	308.3	192.0	0.0	1229.7	122.8	332.0	774.8
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	307.8	192.0	0.0	1230.1	122.9	332.1	775.0
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	307.4	192.0	0.0	1230.6	122.9	332.3	775.3
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1730.0	306.9	192.0	0.0	1231.0	122.9	332.4	775.6
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.5	192.0	0.0	1049.5	105.9	283.0	660.5
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	306.0	192.0	0.0	1049.9	105.9	283.2	660.8
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.6	192.0	0.0	1050.4	106.0	283.3	661.0
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	305.1	192.0	0.0	1050.8	106.0	283.4	661.3
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	[illegible]	304.7	192.0	0.0	1051.3	106.0	283.5	661.6
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	[illegible]	304.2	192.0	0.0	1051.7	106.1	283.6	661.9
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.8	192.0	0.0	1052.2	106.1	283.8	662.2
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	303.3	192.0	0.0	1052.6	106.2	283.9	662.5
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1548.0	302.9	192.0	0.0	1053.1	106.2	284.0	662.7
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	774.0	151.2	96.0	0.0	526.7	48.4	143.4	334.8
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
CUMULATIVE TOTALS		108,567	23,737	4,050	8,654	72,130		69,782	12,640	8,335	2,094	46,793	11,852	32,151	74,919

AGO 533117

Run #5

ALASKA STATE REVENUES

(MILLIONS OF DOLLARS)

YEAR	* * * * * * OIL PRODUCTION * * * * * * PROD RATE MMBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	* * * * * * GAS PRODUCTION * * * * * * PROD RATE MMMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	0.9	0.9	539.7	2,338.5
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	2.5	2.5	544.1	2,365.9
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	4.3	4.3	548.0	2,391.9
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	142.0	128.1	6.7	276.9	678.9	2,819.5
1986	1.300	935.1	649.3	68.7	0.5	1,653.2	2.000	142.1	128.1	7.5	277.8	605.9	2,537.5
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	143.2	128.0	8.3	279.6	553.7	2,326.3
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	143.5	127.9	8.0	279.6	499.4	2,103.2
1989	0.700	580.1	390.6	59.0	0.3	1,030.1	2.000	143.8	127.9	7.8	279.6	402.4	1,712.2
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	144.2	127.9	7.6	279.8	328.6	1,414.7
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	144.6	127.8	7.4	279.9	260.8	1,142.3
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	144.9	127.8	7.2	279.9	257.0	1,113.4
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	145.1	127.8	6.9	279.9	238.3	1,027.2
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	145.3	127.8	6.7	279.9	234.4	986.4
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	145.6	127.7	6.5	279.9	236.2	955.8
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	145.8	127.7	6.3	279.9	206.4	809.1
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	146.1	127.7	6.1	279.9	207.0	720.3
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	146.3	127.7	5.9	279.9	194.6	680.7
1999	0.170	156.1	0.0	19.6	0.0	177.9	2.000	146.5	127.6	5.6	279.9	181.5	639.4
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	146.8	127.6	5.4	279.9	174.8	612.9
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	148.4	127.5	5.2	281.1	168.8	587.7
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	150.5	127.2	5.0	282.8	170.2	579.5
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	152.6	127.0	4.8	284.5	165.1	550.4
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	4.5	286.6	105.4	392.0
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	4.3	286.3	106.7	393.1
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	4.1	286.1	108.0	394.2
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.9	285.9	108.0	394.0
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.7	285.7	108.0	393.8
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.4	285.5	108.1	393.6
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.2	285.2	108.1	393.4
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	3.0	285.0	108.1	393.2
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	2.8	284.8	108.1	393.0
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	2.6	284.6	108.2	392.8
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	2.4	284.4	108.2	392.6
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	2.1	284.2	108.2	392.4
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.9	283.9	108.2	392.2
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.7	283.7	108.2	392.0
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.5	283.5	108.3	391.8
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.3	283.3	108.3	391.6
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	1.0	283.1	108.3	391.4
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	0.8	282.8	108.3	391.2
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	0.6	282.6	108.3	391.0
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	0.4	282.4	108.4	390.8
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	126.8	0.2	282.2	108.4	390.6
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	77.5	63.4	0.0	141.0	49.5	190.5
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
CUMULATIVE TOTALS	7,641T	13,570	9,042	1,109	9	23,732	29,565T	6,104	5,154	184	11,443	11,309	46,485

AGO 533118

Run #6

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

YEAR	* * * * * * OIL PRODUCTION * * * * * * PROD RATE MMBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	* * * * * * GAS PRODUCTION * * * * * * PROD RATE MMMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	3.0	3.0	539.5	2,340.4
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	7.5	7.5	543.6	2,370.5
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	12.1	12.1	547.3	2,399.0
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	155.1	108.6	17.6	281.4	676.7	2,821.7
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	155.1	108.6	17.3	281.1	603.7	2,538.8
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	155.1	108.6	17.0	280.8	551.7	2,325.5
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	155.1	108.6	16.5	280.4	497.5	2,102.0
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	155.1	108.6	16.1	279.9	400.6	1,710.7
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	155.1	108.6	15.6	279.5	326.8	1,412.6
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	155.1	108.6	15.2	279.0	259.1	1,139.7
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	155.1	108.6	14.7	278.6	255.3	1,110.4
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	155.1	108.6	14.3	278.1	236.6	1,023.8
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	155.1	108.6	13.8	277.7	232.9	982.6
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	155.1	108.6	13.4	277.2	234.6	951.6
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	155.1	108.6	12.9	276.8	204.9	804.4
1997	0.270	205.7	0.0	27.5	0.1	233.3	2.000	155.1	108.6	12.5	276.3	205.5	715.2
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	155.1	108.6	12.0	275.9	193.2	675.3
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	155.1	108.6	11.6	275.4	180.1	633.5
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	155.1	108.5	11.2	275.0	173.4	606.6
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	155.1	108.6	10.7	274.5	167.6	579.9
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	155.1	108.6	10.3	274.1	169.2	569.8
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	155.1	108.6	9.8	273.6	164.4	538.8
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	9.4	273.2	104.9	378.2
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	8.9	272.7	106.3	379.1
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	8.5	272.3	107.6	379.9
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	8.0	271.8	107.6	379.5
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	7.6	271.4	107.7	379.1
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	7.1	270.9	107.7	378.7
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	6.7	270.5	107.8	378.3
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	6.2	270.0	107.8	377.9
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	5.8	269.6	107.9	377.5
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	5.3	269.1	107.9	377.1
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.9	268.7	107.9	376.7
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.4	268.3	108.0	376.3
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.0	267.8	108.0	375.9
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.5	267.4	108.1	375.5
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.1	266.9	108.1	375.1
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.6	266.5	108.1	374.7
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.2	266.0	108.2	374.2
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.7	265.6	108.2	373.8
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.3	265.1	108.3	373.4
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.8	264.7	108.3	373.0
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.4	264.2	108.4	372.6
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	77.5	54.3	0.0	131.9	43.5	181.4
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
CUMULATIVE TOTALS	7,641T	13,570	9,042	1,109	9	23,732	29,565T	6,285	4,399	309	11,074	11,273	46,080

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

	* * * * * * OIL PRODUCTION * * * * * *						* * * * * * GAS PRODUCTION * * * * * *								TOTAL
YEAR 1-50	WELLHEAD PRICE/OIL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST. INC. TAX	FED. INC. TAX	NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	3.0	48.0	148.5	-199.6	539.5	1425.8	3326.8
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	7.5	54.0	172.8	-234.3	543.6	1431.7	3340.7
8	15.15	8296.8	1839.5	178.0	668.8	5610.5	1.95	0.0	12.1	60.0	235.1	-307.2	547.3	1426.7	3329.1
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1532.1	281.4	192.0	104.9	953.6	676.7	1855.0	4328.3
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1532.1	281.1	212.0	104.7	934.2	603.7	1641.3	3829.9
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1532.1	280.8	219.0	95.2	937.0	551.7	1520.7	3548.4
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1532.1	280.4	193.0	93.1	965.5	497.5	1373.9	3205.8
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1532.1	279.9	192.0	91.1	969.0	400.6	1098.0	2562.1
14	17.06	3612.8	806.3	139.0	354.2	2313.2	1.95	1532.1	279.5	192.0	87.6	972.9	326.8	887.8	2071.5
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1532.1	279.0	192.0	84.2	976.8	259.1	694.6	1620.7
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1532.1	278.6	192.0	82.3	979.1	255.3	604.1	1596.2
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1532.1	278.1	192.0	80.4	981.5	236.6	630.9	1472.2
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1532.1	277.7	192.0	78.5	983.9	232.9	620.0	1446.7
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1532.1	277.2	192.0	76.6	986.2	234.6	625.3	1459.1
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1532.1	276.8	192.0	74.6	988.6	204.9	540.4	1261.0
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1532.1	276.3	192.0	72.7	990.9	205.5	542.7	1266.3
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1532.1	275.9	192.0	70.8	993.3	193.2	507.5	1184.3
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1532.1	275.4	192.0	68.9	995.7	180.1	470.3	1097.4
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1532.1	275.0	192.0	67.0	998.0	173.4	451.2	1052.9
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1532.1	274.5	192.0	54.2	1011.3	167.6	434.8	1014.6
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1532.1	274.1	192.0	37.1	1028.8	169.2	439.6	1025.7
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1532.1	273.6	192.0	20.6	1045.8	164.4	425.9	993.8
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1532.1	273.2	192.0	0.0	1066.9	104.9	220.3	514.1
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1532.1	272.7	192.0	0.0	1067.3	106.3	254.2	593.2
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	272.3	192.0	0.0	1067.7	107.6	288.0	672.1
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	271.8	192.0	0.0	1068.2	107.6	288.1	672.3
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	271.4	192.0	0.0	1068.6	107.7	288.2	672.6
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	270.9	192.0	0.0	1069.1	107.7	288.4	672.9
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	270.5	192.0	0.0	1069.5	107.8	288.5	673.2
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	270.0	192.0	0.0	1070.0	107.8	288.6	673.5
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	269.6	192.0	0.0	1070.4	107.9	288.7	673.8
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	269.1	192.0	0.0	1070.9	107.9	288.8	674.0
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	268.7	192.0	0.0	1071.3	107.9	289.0	674.3
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	268.3	192.0	0.0	1071.8	108.0	289.1	674.6
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.8	192.0	0.0	1072.2	108.0	289.2	674.9
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.4	192.0	0.0	1072.7	108.1	289.3	675.2
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.9	192.0	0.0	1073.1	108.1	289.5	675.5
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.5	192.0	0.0	1073.6	108.1	289.6	675.7
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.0	192.0	0.0	1074.0	108.2	289.7	676.0
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.6	192.0	0.0	1074.5	108.2	289.8	676.3
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.1	192.0	0.0	1074.9	108.3	289.9	676.6
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.7	192.0	0.0	1075.4	108.3	290.1	676.9
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.2	192.0	0.0	1075.8	108.4	290.2	677.2
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	766.0	131.9	96.0	0.0	538.1	49.5	146.5	342.0
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
CUMULATIVE TOTALS		108,567	23,732	4,050	8,654	72,130		62,051	11,074	8,335	2,094	40,628	11,273	30,475	71,009

ALASKA STATE REVENUES
(MILLIONS OF DOLLARS)

Run #7

YEAR	* * * * * * OIL PRODUCTION * * * * * * PROD RATE MMBL/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	CONSERV. TAX	OIL TOTAL	* * * * * * GAS PRODUCTION * * * * * * PROD RATE MMCF/DAY	ROYALTY PAYMENT	SEVERANCE TAX	PROPERTY TAX	GAS TOTAL	STATE INCOME TAX	TOTAL STATE RETURN
1977	1.050	191.6	187.7	36.0	0.4	415.9	0.000	0.0	0.0	0.0	0.0	0.0	415.9
1978	1.425	390.0	382.2	37.9	0.6	810.9	0.000	0.0	0.0	0.0	0.0	197.2	1,008.2
1979	1.500	633.0	603.1	40.0	0.6	1,276.8	0.000	0.0	0.0	0.0	0.0	333.4	1,610.2
1980	1.500	958.1	759.8	41.7	0.6	1,760.4	0.000	0.0	0.0	0.0	0.0	528.6	2,289.1
1981	1.500	977.2	755.2	45.2	0.6	1,778.5	0.000	0.0	0.0	0.0	0.0	535.3	2,313.8
1982	1.500	996.8	750.1	50.1	0.6	1,797.8	0.000	0.0	0.0	0.9	0.9	539.7	2,338.5
1983	1.500	1,016.7	744.4	57.3	0.6	1,819.2	0.000	0.0	0.0	2.5	2.5	544.1	2,365.9
1984	1.500	1,037.1	737.5	64.1	0.6	1,839.5	0.000	0.0	0.0	4.3	4.3	548.0	2,391.9
1985	1.500	1,057.8	734.5	70.4	0.6	1,863.5	2.000	142.0	99.4	6.7	248.2	678.9	2,790.8
1986	1.300	935.1	649.3	68.7	0.5	1,653.8	2.000	142.1	99.4	7.5	249.1	605.9	2,508.9
1987	1.150	843.7	581.7	66.8	0.5	1,492.9	2.000	143.2	100.3	8.3	251.9	553.7	2,298.5
1988	1.000	748.3	512.3	62.9	0.4	1,324.1	2.000	143.5	100.4	8.0	252.1	499.4	2,075.6
1989	0.760	580.1	390.6	59.0	0.3	1,030.1	2.000	143.8	100.6	7.8	252.3	402.4	1,684.9
1990	0.580	451.6	299.3	55.0	0.2	806.3	2.000	144.2	100.9	7.6	252.8	328.6	1,387.8
1991	0.420	333.5	216.6	51.1	0.1	601.5	2.000	144.6	101.2	7.4	253.3	260.8	1,115.7
1992	0.400	324.0	205.0	47.2	0.1	576.4	2.000	144.9	101.4	7.2	253.5	257.0	1,087.0
1993	0.350	289.2	176.3	43.2	0.1	508.9	2.000	145.1	101.5	6.9	253.7	238.3	1,001.0
1994	0.330	278.1	154.3	39.3	0.1	472.0	2.000	145.3	101.7	6.7	253.9	234.4	960.4
1995	0.320	275.0	129.0	35.4	0.1	439.6	2.000	145.6	101.9	6.5	254.1	236.2	929.9
1996	0.250	219.2	71.9	31.4	0.1	322.7	2.000	145.8	102.1	6.3	254.3	206.4	783.4
1997	0.230	205.7	0.0	27.5	0.1	233.3	2.000	146.1	102.2	6.1	254.4	207.0	694.8
1998	0.200	182.4	0.0	23.6	0.0	206.1	2.000	146.3	102.4	5.9	254.6	194.6	655.4
1999	0.170	158.1	0.0	19.6	0.0	177.9	2.000	146.5	102.6	5.6	254.8	181.5	614.3
2000	0.150	142.3	0.0	15.7	0.0	158.1	2.000	146.8	102.7	5.4	255.0	174.8	588.0
2001	0.130	125.8	0.0	11.8	0.0	137.7	2.000	148.4	103.8	5.2	257.5	168.8	564.1
2002	0.120	118.4	0.0	7.8	0.0	126.4	2.000	150.5	105.3	5.0	260.9	170.2	557.5
2003	0.100	100.7	0.0	0.0	0.0	100.7	2.000	152.6	106.8	4.8	264.2	165.1	530.1
2004	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.5	268.4	105.4	373.8
2005	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.3	268.1	106.7	374.9
2006	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	4.1	267.9	108.0	376.0
2007	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.9	267.7	108.0	375.8
2008	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.7	267.5	108.0	375.6
2009	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.4	267.3	108.1	375.4
2010	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.2	267.0	108.1	375.2
2011	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	3.0	266.8	108.1	375.0
2012	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.8	266.6	108.1	374.8
2013	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.6	266.4	108.2	374.6
2014	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.4	266.2	108.2	374.4
2015	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	2.1	266.0	108.2	374.2
2016	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.9	265.7	108.2	374.0
2017	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.7	265.5	108.2	373.8
2018	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.5	265.3	108.3	373.6
2019	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.3	265.1	108.3	373.4
2020	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	1.0	264.9	108.3	373.2
2021	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.8	264.6	108.3	373.0
2022	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.6	264.4	108.3	372.8
2023	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.4	264.2	108.4	372.6
2024	0.000	0.0	0.0	0.0	0.0	0.0	2.000	155.1	108.6	0.2	264.0	108.4	372.4
2025	0.000	0.0	0.0	0.0	0.0	0.0	1.000	77.5	54.3	0.0	131.9	49.5	181.4
2026	0.000	0.0	0.0	0.0	0.0	0.0	0.000	0.0	0.0	0.0	0.0	0.0	0.0
CUMULATIVE TOTALS	7,641T	13,570	9,042	1,109	9	23,732	29,565T	6,104	4,273	184	10,561	11,309	45,603

INDUSTRY CASH FLOWS
(MILLIONS OF DOLLARS)

	* * * * * * OIL PRODUCTION * * * * * *						* * * * * * GAS PRODUCTION * * * * * *								TOTAL
YEAR 1-50	WELLHEAD PRICE/OIL	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET OIL CASH FLOW	WELLHEAD PRICE/MCF	GROSS INCOME	STATE TAKE	OPERAT COSTS	CAPITAL COSTS	NET GAS CASH FLOW	ST.INC. TAX	FED.INC. TAX	NET CASH FLOW
1	4.00	1533.0	415.9	103.0	122.6	891.4	1.95	0.0	0.0	26.0	0.0	-26.0	0.0	259.6	605.7
2	6.00	3120.7	810.9	140.0	161.9	2007.8	1.95	0.0	0.0	33.0	0.0	-33.0	197.2	533.2	1244.3
3	9.25	5064.3	1276.8	156.0	187.4	3444.0	1.95	0.0	0.0	32.0	0.0	-32.0	333.4	923.6	2155.0
4	14.00	7665.0	1760.4	163.0	290.6	5450.9	1.95	0.0	0.0	36.0	0.0	-36.0	528.6	1465.8	3420.3
5	14.28	7818.3	1778.5	171.0	369.0	5499.7	1.95	0.0	0.0	41.0	92.6	-133.6	535.3	1449.2	3381.5
6	14.56	7974.6	1797.8	173.0	511.9	5491.8	1.95	0.0	0.9	48.0	148.5	-197.5	539.7	1426.3	3328.2
7	14.85	8134.1	1819.2	174.0	590.3	5550.4	1.95	0.0	2.5	54.0	172.8	-229.3	544.1	1433.1	3343.9
8	15.15	8293.8	1839.5	178.0	668.8	5610.5	1.95	0.0	4.3	60.0	235.1	-299.5	548.0	1428.8	3334.0
9	15.45	8462.7	1863.5	230.0	462.7	5906.4	1.95	1522.9	248.2	192.0	104.9	977.6	678.9	1861.5	4343.5
10	15.76	7481.0	1653.8	210.0	476.3	5140.8	1.95	1522.9	249.1	212.0	104.7	957.0	605.9	1647.6	3844.4
11	16.08	6750.2	1492.9	195.0	378.3	4683.9	1.95	1523.8	251.9	219.0	95.2	957.6	553.7	1526.3	3561.5
12	16.40	5987.1	1324.1	181.0	370.3	4111.7	1.95	1523.9	252.1	193.0	93.1	985.6	499.4	1379.3	3218.5
13	16.73	4641.2	1030.1	157.0	362.3	3091.7	1.95	1524.1	252.3	192.0	91.1	988.6	402.4	1103.3	2574.5
14	17.06	3812.6	806.3	139.0	354.2	2313.2	1.95	1524.4	252.8	192.0	87.6	991.9	328.6	892.9	2083.5
15	17.40	2668.5	601.5	123.0	346.2	1597.6	1.95	1524.7	253.3	192.0	84.2	995.1	260.8	699.5	1632.3
16	17.75	2592.2	576.4	121.0	338.2	1556.5	1.95	1524.9	253.5	192.0	82.3	997.0	257.0	688.9	1607.5
17	18.11	2313.6	508.9	116.0	330.2	1358.4	1.95	1525.0	253.7	192.0	80.4	998.9	238.3	635.7	1483.3
18	18.47	2225.0	472.0	115.0	322.2	1315.8	1.95	1525.2	253.9	192.0	78.5	1000.8	234.4	624.6	1457.5
19	18.84	2200.7	439.6	114.0	314.1	1332.9	1.95	1525.4	254.1	192.0	76.6	1002.7	236.2	629.8	1469.5
20	19.21	1753.7	322.7	107.0	306.1	1017.8	1.95	1525.6	254.3	192.0	74.6	1004.6	206.4	544.8	1271.2
21	19.60	1645.7	233.3	105.0	283.6	1023.6	1.95	1525.7	254.4	192.0	72.7	1006.4	207.0	546.9	1276.1
22	19.99	1459.6	206.1	102.0	259.7	891.7	1.95	1525.9	254.6	192.0	70.8	1008.3	194.6	511.6	1193.8
23	20.39	1265.5	177.9	99.0	236.3	752.2	1.95	1526.1	254.8	192.0	68.9	1010.2	181.5	474.3	1106.7
24	20.80	1138.9	158.1	97.0	204.1	679.6	1.95	1526.2	255.0	192.0	67.0	1012.1	174.8	455.0	1061.8
25	21.21	1006.8	137.7	95.0	168.2	605.9	1.95	1527.3	257.5	192.0	54.2	1023.6	168.8	438.2	1022.4
26	21.64	947.9	126.4	94.0	121.7	605.8	1.95	1528.8	260.9	192.0	37.1	1038.7	170.2	442.3	1032.0
27	22.07	805.7	100.7	92.0	74.7	538.3	1.95	1530.3	264.2	192.0	20.6	1053.4	165.1	427.9	998.6
28	22.51	0.0	0.0	200.0	27.4	-227.4	1.95	1532.1	268.4	192.0	0.0	1071.7	105.4	221.6	517.2
29	22.96	0.0	0.0	100.0	13.5	-113.5	1.95	1532.1	268.1	192.0	0.0	1071.9	106.7	255.5	596.1
30	23.42	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.9	192.0	0.0	1072.1	108.0	289.2	674.8
31	23.89	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.7	192.0	0.0	1072.3	108.0	289.2	675.0
32	24.37	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.5	192.0	0.0	1072.5	108.0	289.3	675.1
33	24.86	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.3	192.0	0.0	1072.8	108.1	289.4	675.2
34	25.35	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	267.0	192.0	0.0	1073.0	108.1	289.4	675.4
35	25.86	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.8	192.0	0.0	1073.2	108.1	289.5	675.5
36	26.38	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.6	192.0	0.0	1073.4	108.1	289.5	675.7
37	26.91	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.4	192.0	0.0	1073.6	108.2	289.6	675.8
38	27.44	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.2	192.0	0.0	1073.9	108.2	289.7	675.9
39	27.99	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	266.0	192.0	0.0	1074.1	108.2	289.7	676.1
40	28.55	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.7	192.0	0.0	1074.3	108.2	289.8	676.2
41	29.12	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.5	192.0	0.0	1074.5	108.2	289.8	676.3
42	29.71	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.3	192.0	0.0	1074.7	108.3	289.9	676.5
43	30.30	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	265.1	192.0	0.0	1075.0	108.3	290.0	676.6
44	30.91	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.9	192.0	0.0	1075.2	108.3	290.0	676.8
45	31.53	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.6	192.0	0.0	1075.4	108.3	290.1	676.9
46	32.16	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.4	192.0	0.0	1075.6	108.3	290.1	677.0
47	32.80	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.2	192.0	0.0	1075.8	108.4	290.2	677.2
48	33.46	0.0	0.0	0.0	0.0	0.0	1.95	1532.1	264.0	192.0	0.0	1076.0	108.4	290.2	677.3
49	34.12	0.0	0.0	0.0	0.0	0.0	1.95	766.0	131.9	96.0	0.0	538.1	49.5	146.5	342.0
50	34.81	0.0	0.0	0.0	0.0	0.0	1.95	0.0	0.0	100.0	0.0	-100.0	0.0	0.0	-100.0
		108,567	23,732	4,050	8,654	72,130		61,924	10,561	8,335	2,094	41,014	11,309	30,580	71,254

CUMULATIVE TOTALS

STATE OF ALASKA

OIL AND GAS CONSERVATION COMMISSION

THREE DIMENSIONAL RESERVOIR STUDY SADLEROCHIT FORMATION PRUDHOE BAY FIELD

MARCH, 1980

THREE-DIMENSIONAL RESERVOIR STUDY

SADLEROCHIT FORMATION

PRUDHOE BAY FIELD

Prepared for

STATE OF ALASKA
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ACKNOWLEDGEMENT

This study was performed under contract for and in cooperation with the Alaska Oil and Gas Conservation Commission, State of Alaska. Data were made available by operators in the field for the purpose of this overall field-wide performance study.

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INTRODUCTION

This report describes the results of a three-dimensional (3-D) model study of the Sadlerochit Formation of the Prudhoe Bay Field. The objectives of the study were to determine the effect on ultimate oil recovery of:

1. A source water injection program.
2. Reservoir gas voidage of 2.7 billion cubic feet per day (2.0 billion cubic feet available for sales).

The available reservoir data included:

- Individual well completion data
- Production rate data
- Pressure data
- Core analyses
- Well logs

All data were originally released by the operators to the State of Alaska Oil and Gas Conservation Commission. The cutoff for most historical data was June 1979, however production figures were matched to August 1979. Using current volumetric data, the 1974 oil-in-place and gas-in-place volumes were updated as indicated in Table I. Next a three-dimensional, three-phase reservoir model was used to study the reservoir performance under various producing plans.

CONCLUSIONS

1. Oil recovery can be substantially increased by effective source water injection. For the cases studied, an average increased recovery of 1.5 billion barrels (1.1 to 1.9), representing an average difference in recovery of 7.4% of the stock tank oil-in-place (5.3% to 9.5%), may be attributed to source water injection.
2. Gas voidage of 2.7 billion cubic feet per day in the presence of source water injection should not materially affect ultimate oil recovery. Differences in recovery varied between 0.4% and 0.7% (0.08 to 0.14 billion barrels). These small variations are considered to be less than the average range of comparison sensitivity of the model.

3. Since all comparisons showed greater ultimate recovery with source water injection, it should be implemented as soon as feasible.
4. Ultimate oil recoveries range from 36% to 46% of the original-oil-in-place (O.O.I.P.). The low value was from a case without source water injection or optimized recompletions in the later field life. The high value was with source water injection and assumed no gas coning or adverse permeability variations.
5. While the boundary conditions were limited because of budget and time constraints they were sufficient to accomplish the basic study objectives.

RECOMMENDATIONS

Now that the State has a working 3-D model, additional studies should be made which include:

1. Different values of oil production rate, gas production rate and source water injection rate.
2. Updating the model using new production data, well data (logs, etc.) and pressures.
3. Monitoring field behavior.
4. Further study of the possible effects of gas coning/fingering and adverse permeability variations on ultimate recovery.
5. Fine-grid simulation to evaluate alternate injection patterns, shale effects, and well MER (maximum efficient rate).
6. Capillary pressure values in shaley areas.
7. The effects of lower producing bottom-hole pressures and different well densities.
8. The effects of source water injection into the gas cap.
9. The effect of increased gas recycling.

LIMITATION

Generally, accurate forecasting is limited to two or three times the actual production history. A data cutoff point of August 1, 1979 meant only 790 days of actual production history, or less than 2,000 days of effective prediction (five years). In the case of Prudhoe Bay, this effective prediction period may be longer because of the excellent nature of well data and density of wells. Even so, the ultimate recovery indicated for any group of comparative cases run may have a tolerance of as much as 5% of the O.O.I.P. (i.e., an indicated recovery of 40% might be as low as 35% or as high as 45%). The low range of production might be due to erroneous end values on relative permeability, coning and/or fingering effects, and adverse permeability variations. The high range might be due to better reservoir continuity, more favorable mobility and benefits of gas cycling. Nevertheless, the relative recoveries of the different processes should be valid (i.e., source water injection versus no source water injection and the relative effect of gas sales). Ultimate recovery estimates may vary as more history is gained and additional data become available from full field development. Conditions which might affect a change would affect comparative cases proportionately so that the conclusions remain valid.

The shale descriptions in the model are coarse, and a more detailed refinement is necessary for precise understanding of fingering and coning. Shale members in the eastern portion of the field sometimes occur more closely spaced than the vertical dimension of the grid blocks. This had to be accounted for mathematically as indicated on page 6.

BOUNDARY CONDITIONS

In-Place Volumes

In order to have a basis for comparing the cases, certain parameters were fixed. The original hydrocarbons in-place are 20.6 billion barrels of stock tank oil, 14.9 trillion standard cubic feet of solution gas and 23.4 trillion standard cubic feet of gas cap gas. The maximum field offtake rate was set at 1.5 million barrels of stock tank oil (STO) per day.

Ratios

Individual wells were allowed to produce at gas-oil ratios up to 100,000 cubic feet per barrel. This gas-oil ratio limit was not the major boundary condition as gas production limitation was prorated based on the actual maximum field gas handling capacity. It was assumed for all cases that 10% of the gas produced would be utilized as fuel for lease and pipeline operations. For the no-gas-sales cases, the remaining 90% of all produced gas was returned to the gas cap. The water-oil ratio limitation for individual wells was set at twenty barrels of water per barrel of stock tank oil, but was never reached because of the pronounced effect of three-phase relative permeability. In all cases, the field was shut-in when the total oil producing rate had declined to 100,000 barrels stock tank oil per day.

When applicable, gas voidage rates were set at 2.7 billion standard cubic feet of gas per day and started in mid-1985.

Productivity Index

Existing wells were assigned actual values for productivity index (PI). For a well with a full oil column this value ranged from less than 5 to over 100 with an average of 14.6 barrels per day per psi. For wells with less oil column a value of 3.65 was assigned to each "exposed" grid interval. All new wells were assigned this average value for each exposed layer.

Pressure

The minimum producing bottom-hole pressure for all wells was set at 2,000 psi. This was intended to simulate using artificial lift and a low pressure gathering system. There may be a possibility of reducing this to 1,500 psi which would improve ultimate recovery and could affect producing gas-oil ratios. Further work is needed in this regard.

Injection

In each case, all produced water was reinjected into peripheral water injection wells starting in mid-1981 and source water, where applicable, was initiated in mid-1984. While the number of produced water injection wells was increased as necessary to accommodate the produced water volume, all source water injection wells were activated in mid-1984. For the cases which had source water injection, it was limited to a maximum injection rate of two million barrels per day, or a maximum reservoir pressure of 3,950 psi.

Wells

Producing wells were located on 160-acre spacing and generally had multiple intervals exposed. Injection wells were also on 160-acre spacing located above the heavy oil-tar zone (HO-T) with single interval completions.

INPUT DATA

The volumetric determination of oil- and gas-in-place was updated from the 1974 report using data from wells logged through the end of 1978. The same approach was used as in the 1974 report and the comparisons are depicted in Table I.

HO-T Zone

The heavy oil-tar zone (HO-T) has been discussed in prior reports. Because of the high viscosity of the oil in this zone it will probably result in higher residual oil saturations and adversely affect the relative permeability to water.

In this study the HO-T zone was represented as having an average thickness of 50 ft ranging from 8,990 to 9,040 ft, a total oil-in-place volume of 1.9 billion barrels, a residual oil saturation of 40%, a reduced relative permeability to water by a factor of 10, and an increased oil viscosity by a factor of 10. The oil recovery from this interval is essentially zero.

Both operators conducted independent water injectivity tests which confirmed high injectivity into both the light oil and aquifer intervals but poor injectivity into the HO-T interval. It was determined that sufficient injection water could be passed through the HO-T interval to allow effective peripheral flooding from aquifer injection, barrier faults along the western field boundary precluded its use in that area. This, together with the more realistic response time of "in zone" injection, led us to place all water injection intervals above the HO-T zone.

Aquifer

Based on previous studies and field observation, the aquifer is only slightly effective. A 1.7 trillion barrel aquifer was used in this model.

Faults

The field has been cut by several vertical faults. Where these faults appear to be fluid barriers they were simulated in the model as a plane of zero horizontal transmissibility.

Shales

An extensive study by the operators gave an excellent description of shales. This study, together with work done by the A.O.G.C.C. geological staff aided in the simulation of the shales. The thickness of the grid blocks used in this study varied. All thicknesses were in excess of 30 ft while shales were found as closely spaced as 5 ft. The mathematics of the model dictate that all shales had to be moved to their respective grid block boundary (either up or down, whichever was closer). Hence, our grid block dimensions may have been too coarse to truly evaluate detailed fingering. We found that, in general, when shales were present, the vertical permeabilities of the shale should be reduced by a factor of 0.01 times the vertical permeability of the adjacent sands. In some instances, this was modified based on relative shale strengths in individual grid blocks and ranged from 0.02 for blocks with partial single shales to 0.003 for blocks with multiple shales. On the east side of the field where the shales are thicker and more extensive, a vertical permeability of zero was sometimes used.

For those blocks without measured shale values (either no well present or no log available), a contour method was devised for estimation of these data.

Permeability

The permeability within each grid block was determined from both pressure build-up curves and core analyses. Individual core plugs show that vertical permeability is about 0.5 times the horizontal permeability. On the basis of permeability variation, vertical permeability in the presence of thin shale lamanae is reduced. The vertical permeability value of 0.35 times the horizontal permeability was used throughout.

Pressure build-up curves were evaluated for both radial and spherical flow and shale breaks. Calculated values were corrected for saturation effects prior to introduction into the model.

A statistical approach was used to determine the values for the undrilled grids. Permeability values for wells having data were posted on a map. In areas of adequate representation of data derived from build-up tests, a ten point average was taken. This enabled assignment of permeability values to surrounding grid blocks. In areas where actual data were limited, one average value determined from the available data was used.

Relative Permeability

A thorough review and analysis of two-phase relative permeability data resulted in selecting the values shown in Figures 1 and 2.

Three-phase relative permeability was determined by the model using the Modified Stone's* Formula shown below:

$$k_{ro} = k_{ro_{cw}} \left[\left(\frac{k_{row}}{k_{ro_{cw}}} + k_{rw} \right) \left(\frac{k_{rog}}{k_{ro_{cw}}} + k_{rg} \right) - \left(k_{rw} + k_{rg} \right) \right]$$

where:

k_{ro} = relative permeability to oil in the presence of both gas and water

k_{row} = relative permeability to oil in the presence of water

k_{rw} = relative permeability to water

k_{rog} = relative permeability to oil in the presence of gas

*Dietrich, J.K., and Bonder, P.L., "Three-Phase Oil Relative Permeability Models," preprint of SPE 6044, presented at the 51st Annual Fall Meeting of SPE, October 3 - 6, 1976, New Orleans, LA.

k_{rg} = relative permeability of gas

$k_{ro_{cw}}$ = relative permeability to oil at connate water saturation

Water Compressibility

An average water compressibility value of 3.3×10^{-6} per psi was used.

Rock Compressibility

An average rock compressibility value of 3.4×10^{-6} per psi was used.

Pressure-Volume-Temperature (PVT)

The possibility exists that PVT properties may vary both vertically and horizontally. For the purpose of this study, only the vertical variation was considered and is shown in Figures 3, 4 and 5.

Individual Well Data

Perforated intervals and shale breaks were graphically compared. Productivity indices were determined for all existing wells and assigned to the appropriate intervals. New wells or recompletions were assigned a value of 3.65 barrels per day per psi for each grid-interval exposed.

Pressure Build-Up

A total of 249 pressure build-up tests was analyzed to determine reservoir pressure and permeability. These tests were distributed over 137 wells. The method used by the authors gave values that compared favorably with static pressure tests and with core measured permeability values.

RESERVOIR MODELING

The approach was to model the field with six layers generally in vertical communication. The modeling blocks were 160 acres throughout the oil-bearing portion of the field and were gradually increased to a maximum of 2,560 acres in the far corners of the aquifer and gas cap. This eventually resulted in a 52 x 23 x 6 model containing 4,858 active and 2,318 passive grid blocks as shown in Figure 6.

The objective was to match the 26 months of reservoir performance and to make reservoir and individual well forecasts under different sets of producing conditions.

Empirical functions for relative permeability, capillary pressure and vertical permeability were derived using fine- and coarse-grid cross sections to adjust for numerical dispersion effects.

Cross Sections

Two major cross sections were made, as indicated in Figure 7. The fine-grid cross sections are depicted on Exhibits A and B. The cells below shale breaks were assigned a partially segregated relative permeability curve.

Shales were represented as reductions in vertical permeability as described on page 6. Modifications in horizontal permeabilities had very little or no effect on trying to duplicate gas fingering. Eventually the right combination of values was found and the NS cross section was matched. This combination was then used in the EW section and a nearly instantaneous match was obtained.

Once a match was obtained on the fine-grid cross sections, a forecast was made for each cross section. Future well rates were assumed to be equal to the last rates. Some additional runs were performed with these fine-grid cross sections using water injection and gas sales. These forecasts then became the artificial history for the derivation of the model modifiers using coarse-grid cross sections.

The coarse-grid sections (indicated by the heavy lines on Exhibits A and B) have the same dimensions as were used in the oil column of the 3-D model (i.e., six layers and 160 acres). To obtain a match for the artificial history from the fine-grid sections, the following parameters were modified:

1. Cell to cell relative permeability
2. Individual well relative permeability to represent the limited perforated intervals, perforation standoff from fluid contacts and coning or fingering effects

3. Capillary pressure
4. Vertical permeability to represent shales.

The first two functions are shown in Figures 8 and 9. Functions and their modifications were deliberately kept simple to allow for a random use in the 3-D work.

Three Dimensional

The 3-D network was assigned all reservoir functions derived from the coarse-grid cross sections in addition to the general input data. Next, individual wells, or in some instances clusters of wells, were matched. Basically, the only modifications were in the change of assigned shales in areas of lesser control. In some instances, well relative permeabilities were modified.

After the 3-D history match was obtained, forecasts were made using a predicted drilling schedule which would allow for full field development attempting to use the same general guidelines used by the operators. The new wells were assigned similar relative permeability curves as the wells which were producing during the history match.

During the forecast, wells were recompleted as follows. When gas-oil ratio from a layer reached 100,000 cubic feet per barrel, that layer and all layers above it were shut-in. After all layers of a well were shut-in, that well was reviewed for recompletion by opening those layers having sufficient oil saturation for further production. Table II shows a schedule of this type of recompletion. A similar shut-in process was used for high water-oil ratios; however, this did not become a problem as wells were not shut-in because of water production.

INDIVIDUAL RUNS

Four major runs are described in this report and shown diagrammatically on Figure 10. With the exception of Case C, all cases were optimally recompleted in the later project life. It is conceivable that such optimization would provide some additional recovery for Case C. Even with significant improvement, however, the ultimate recovery for this case would still be too low to be an acceptable method of field exploitation.

All cases were normalized to a field abandonment producing rate of 100,000 barrels of oil per day. The variations in operating conditions would probably cause each case to have a different economic limit. Minor variations in the economic limits would not have a significant impact on ultimate recoveries. A much larger impact would result from the energy required to reinject gas that might otherwise be sold. This could exceed 100 million barrels of oil in equivalent BTU content.

The reader should refer to the section entitled Boundary Conditions for other common parameters to the following cases:

Case A - had no gas salès and no source water injection. Total oil recovery was 8.42 billion stock tank barrels representing 40.8% OOIP in 36.3 years.

Case B - had no gas sales with source water injection of 2 million barrels per day or less, governed by reservoir pressure. Total oil recovery was 9.51 billion stock tank barrels representing 46.1% OOIP in 37.5 years.

Case C - had gas sales of 2 billion cubic feet per day and no source water injection. Total oil recovery was 7.42 billion stock tank barrels representing 35.9% OOIP in 24.2 years.

Case D - had gas sales of 2 billion cubic feet per day and source water injection of 2 million barrels per day. Total oil recovery was 9.37 billion stock tank barrels representing 45.4% OOIP in 26.6 years.

The results of these four cases are plotted on Figures 11 through 22.

EFFECTS OF GAS CYCLING AND CONING

Some additional runs were made to evaluate the effect of added gas recycling capacity. Results are not yet conclusive and additional work is recommended.

The effect of gas coning was also evaluated. This was done by increasing the well gas-oil relative permeability ratio. Gas coning effects in the runs used in this study reduced recovery percentages from 3 to 6. While these are valid numbers, additional runs are necessary using adverse gas-oil relative permeability values and permeability variations to further determine the sensitivity to gas coning.

TABLE I

ORIGINAL HYDROCARBONS IN-PLACE
SADLEROCHIT FORMATION
PRUDHOE BAY FIELD

Zone	Stock Tank Oil Billion Barrels		Solution Gas Trillion Standard Cubic Feet		Gas Cap Gas Trillion Standard Cubic Feet		Gas Cap Condensate Stock Tank Oil Million Barrels	
Study Date	1974	1978	1974	1978	1974	1978	1974	1978
Upper	8.6	9.0	6.3	6.5	10.4	10.3	358	354
Middle	5.0	5.7	3.6	4.1	6.0	7.0	206	241
Lower	5.5	5.9	4.0	4.3	4.8	6.1	165	210
TOTALS	19.1	20.6	13.9	14.9	21.2	23.4	729	805

TABLE II

RECOMPLETION SCHEDULE FOR CASES A, B, C, D
PRUDHOE BAY FIELD

Days	Yrs	Case A	Case B	Case C	Case D
1,855	5	8 wells, *	8 wells, *	8 wells, *	8 wells, *
		8 wells, **	8 wells, **	8 wells, **	8 wells, **
2,220	6	152 wells, **	152 wells, **	152 wells, **	152 wells, **
		1 well, *	1 well, *	1 well, *	1 well, *
2,585	7	189 wells,**	189 wells,**	189 wells,**	189 wells,**
		1 well,*	1 well,*	1 well,*	1 well,*
2,950	[1]8	24 wells,**	10 wells,*	8 wells,*	11 wells,*
		9 wells,*			
3,315	9	392 wells,**	8 wells,*	12 wells,*	13 wells,*
		21 wells,*			
3,680	10	37 wells,**	19 well,*	14 wells,*	20 wells,*
		8 wells,*			
4,045	11	99 wells,**	22 wells,*	14 wells,*	38 wells,*
		11 wells,*			
4,410	12	20 wells,*	19 wells,*	19 wells,*	24 wells,*
4,775	13	11 wells,*	21 wells,*	5 wells,*	23 wells,*
5,140	14	9 wells,*	13 wells,*	20 wells,*	17 wells,*
5,505	15	5 wells,*	10 wells,*	6 wells,*	13 wells,*
		102 wells,**	102 wells,**	102 wells,**	331 wells,**
5,870	16	9 wells,*	4 wells,*	11 wells,*	2 wells,*
6,235	17	5 wells,*	11 wells,*	11 wells,*	12 wells,*
6,600	18	6 wells,*	7 wells,*	9 wells,*	12 wells,*
6,965	19	2 wells,*	5 wells,*	10 wells,*	5 wells,*
7,330	20	9 wells,*	9 wells,*	13 wells,*	8 wells,*
7,695	21	5 wells,*	6 wells,*	14 wells,*	11 wells,*
8,060	22	6 wells,*	6 wells,*	3 wells,*	17 wells,*
8,425	23	3 wells,*	11 wells,*	11 wells,*	15 wells,*
8,790	24	5 wells,*	2 wells,*		26 wells,*
9,155	25	1 well,*	5 wells,*		27 wells,*
9,520	26				34 wells,*
9,885	27		3 wells,*		38 wells,*
10,250	28	2 wells,*	13 wells,*		
10,615	29		3 wells,*		
10,980	30		2 wells,*		
11,345	31	1 well,*	5 wells,*		
11,710	32	2 wells,*	5 wells,*		
12,075	33	2 wells,*	3 wells,*		
12,440	34	1 well,*	3 wells,*		
12,805	35	1 well,*			

* Model automatically shuts in individual layers due to excessive GOR
** Recompletion of individual layers based on moveable oil

[1] Year 8 is the break for the specific cases of A-D. Some recompletions were made prior to that time.

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FIGURE 1

A.O.G.C.C.

Prudhoe Bay Field

Two Phase Relative Permeability

K_{ro} and K_{rw} vs S_w

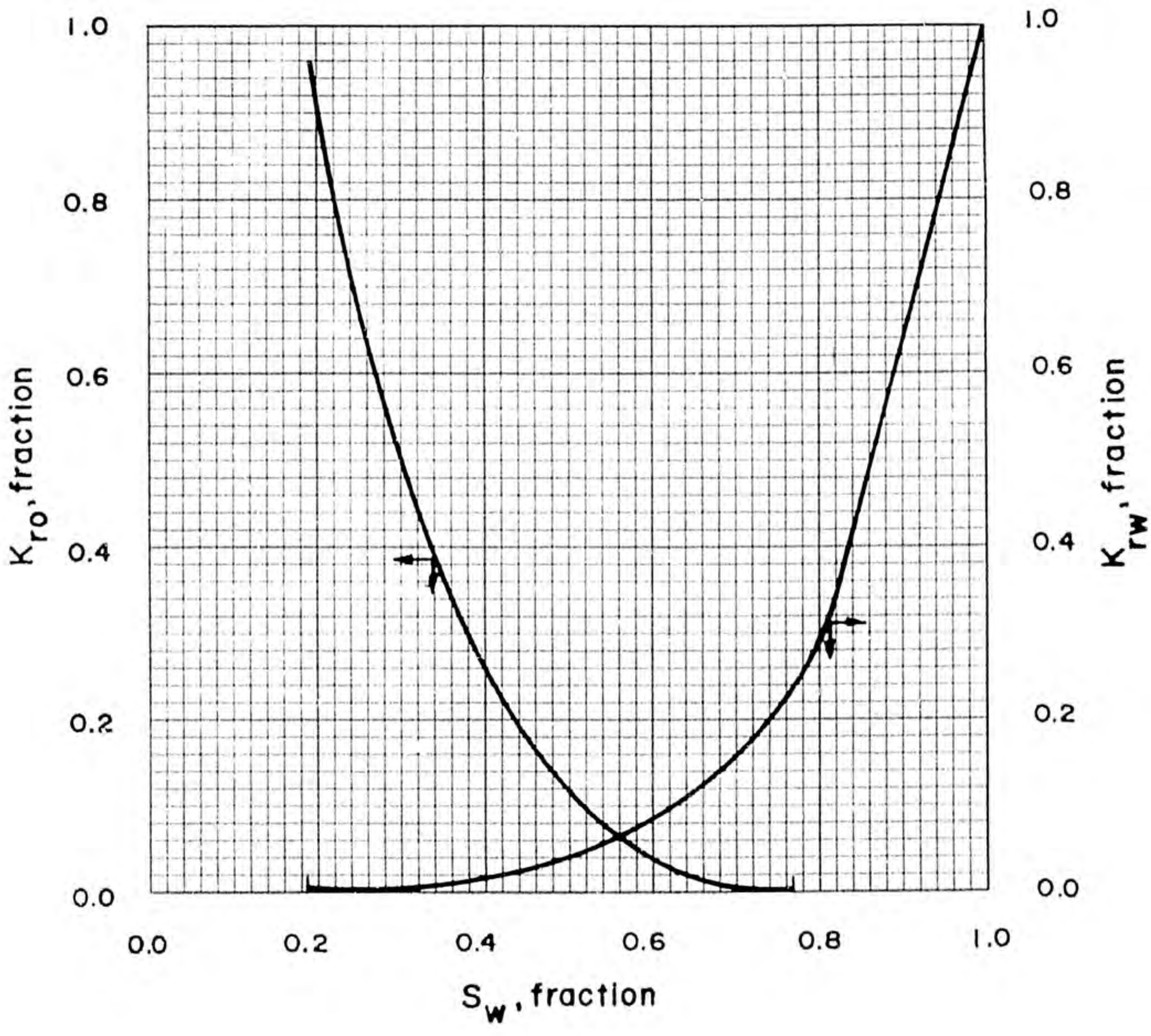

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FIGURE 2

A.O.G.C.C.

Prudhoe Bay Field

Two Phase Relative Permeability
K_{rg} and K_{rL} vs S_L

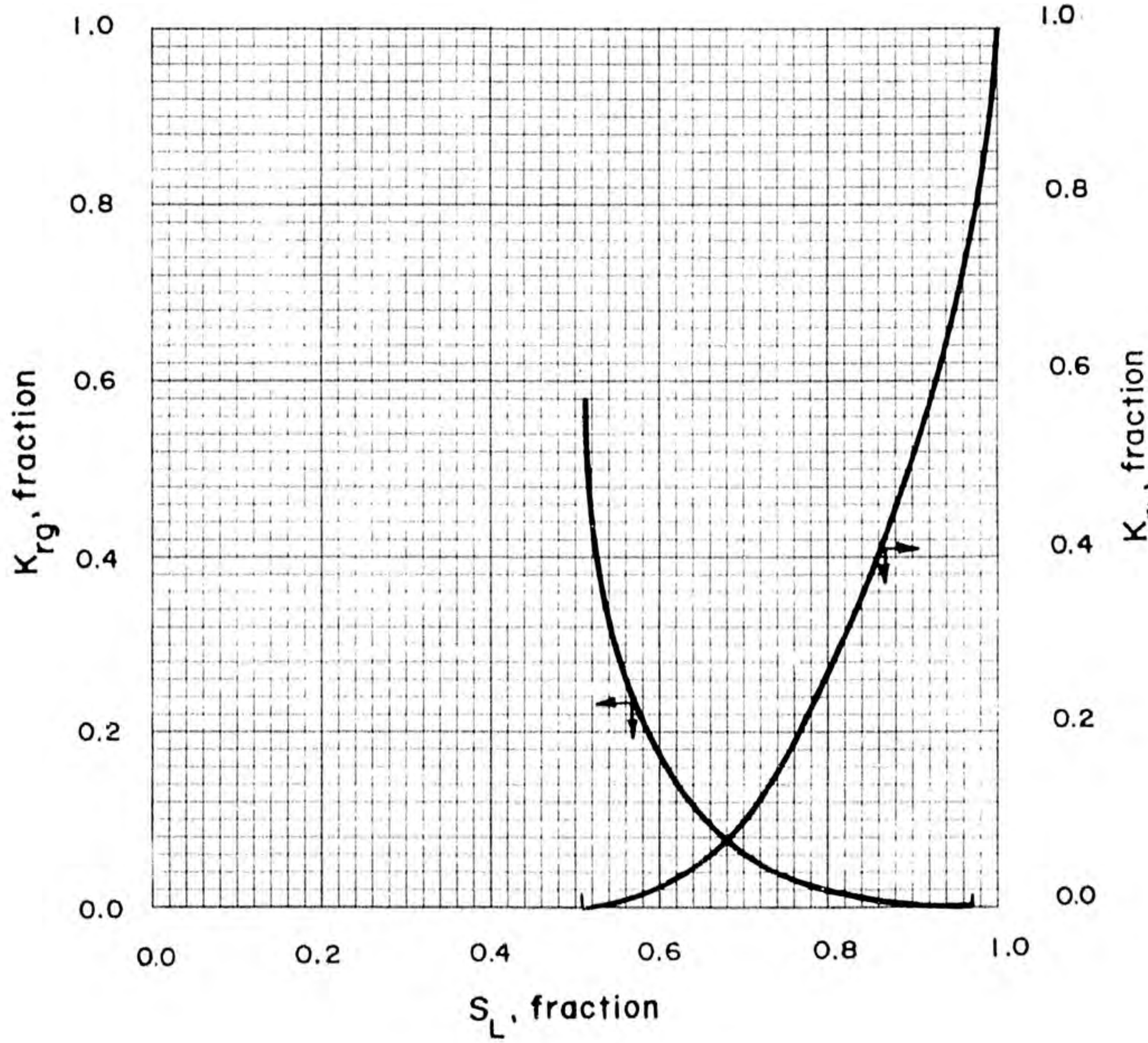

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FIGURE 3

A.O.G.C.C.

Prudhoe Bay Field

Oil PVT Table # 1
Oil Properties vs Pressure

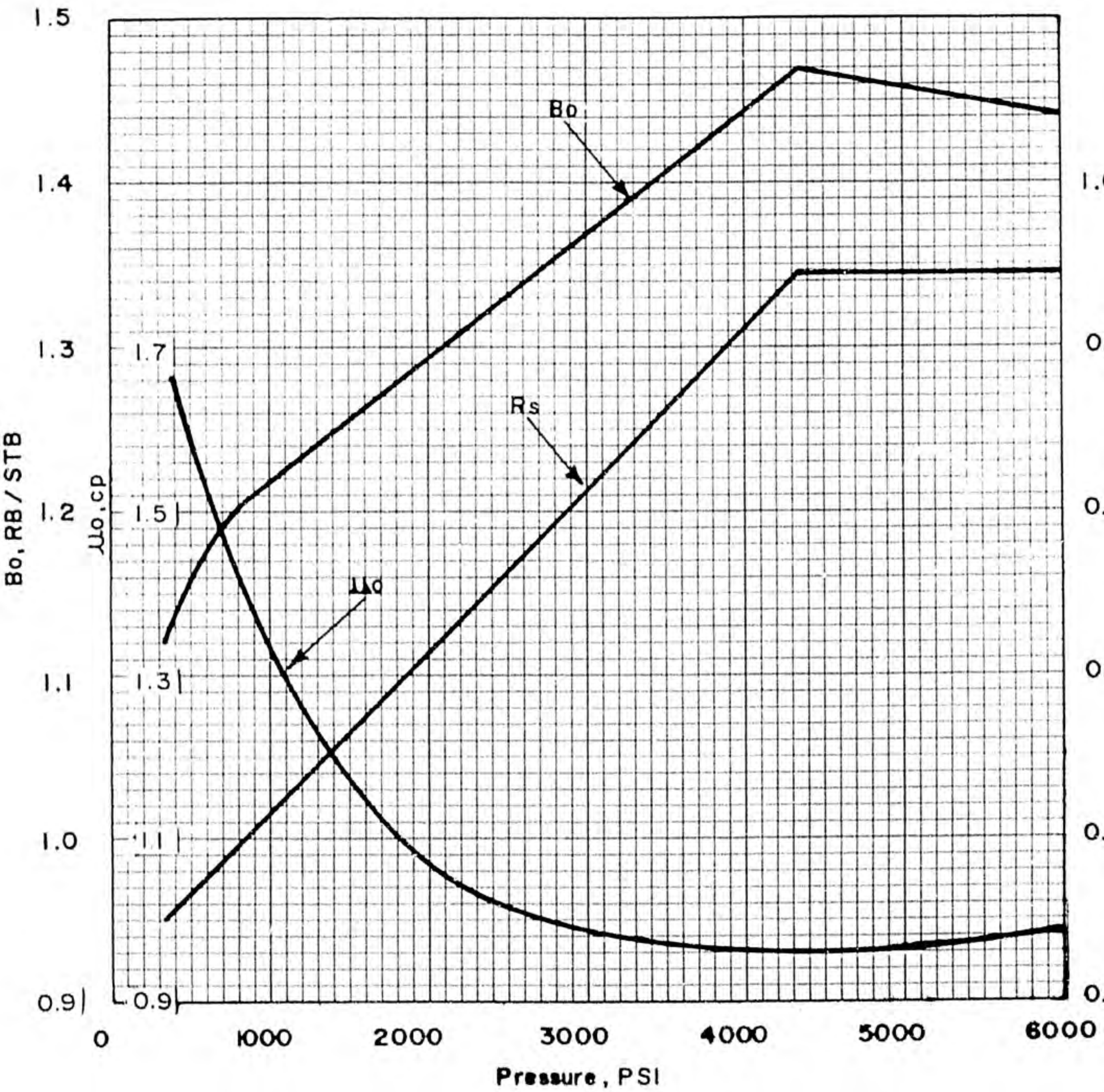

FIGURE 4
A.O.G.C.C.
Prudhoe Bay Field
Oil PVT Table #2
Oil Properties vs Pressure

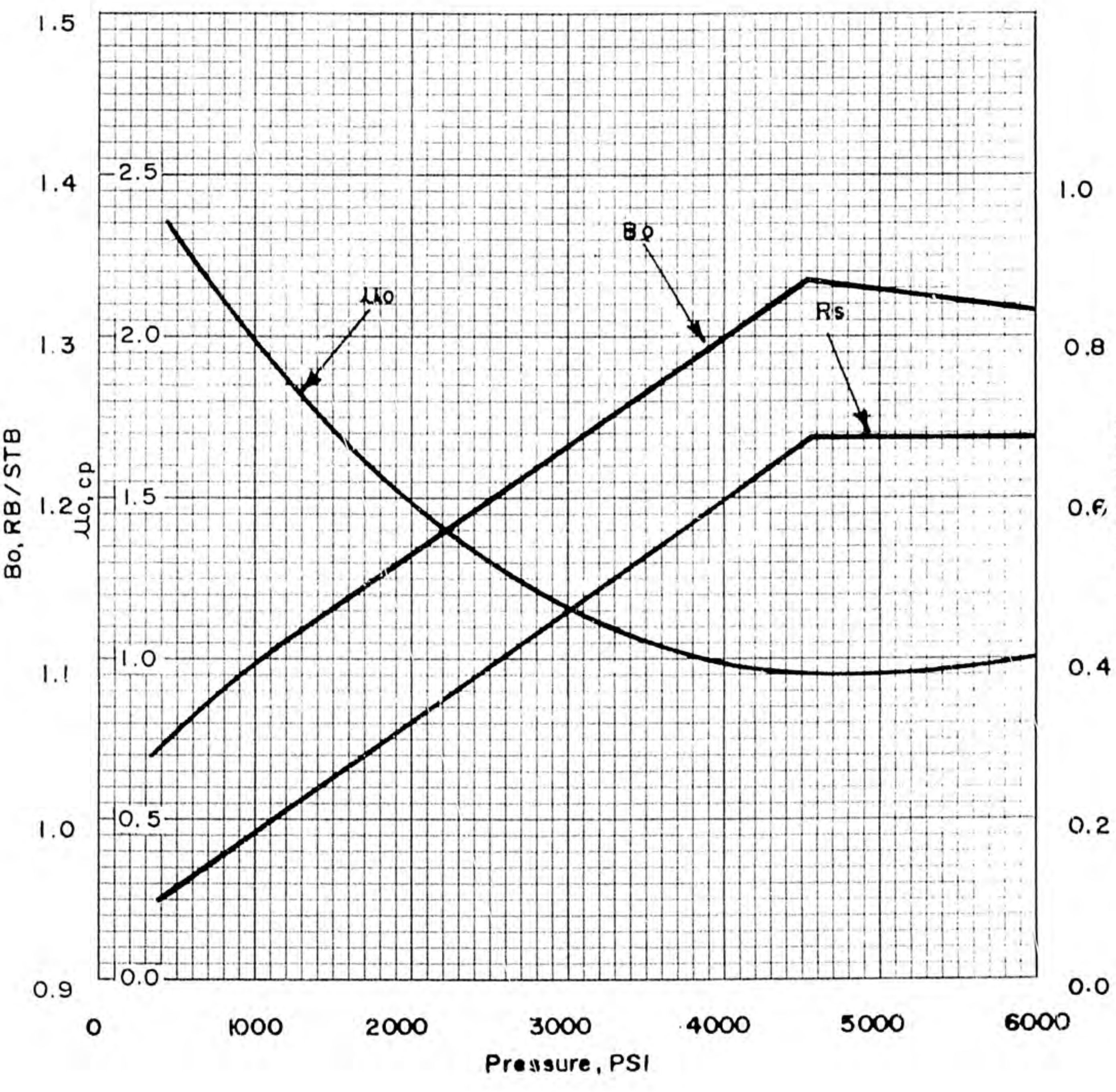

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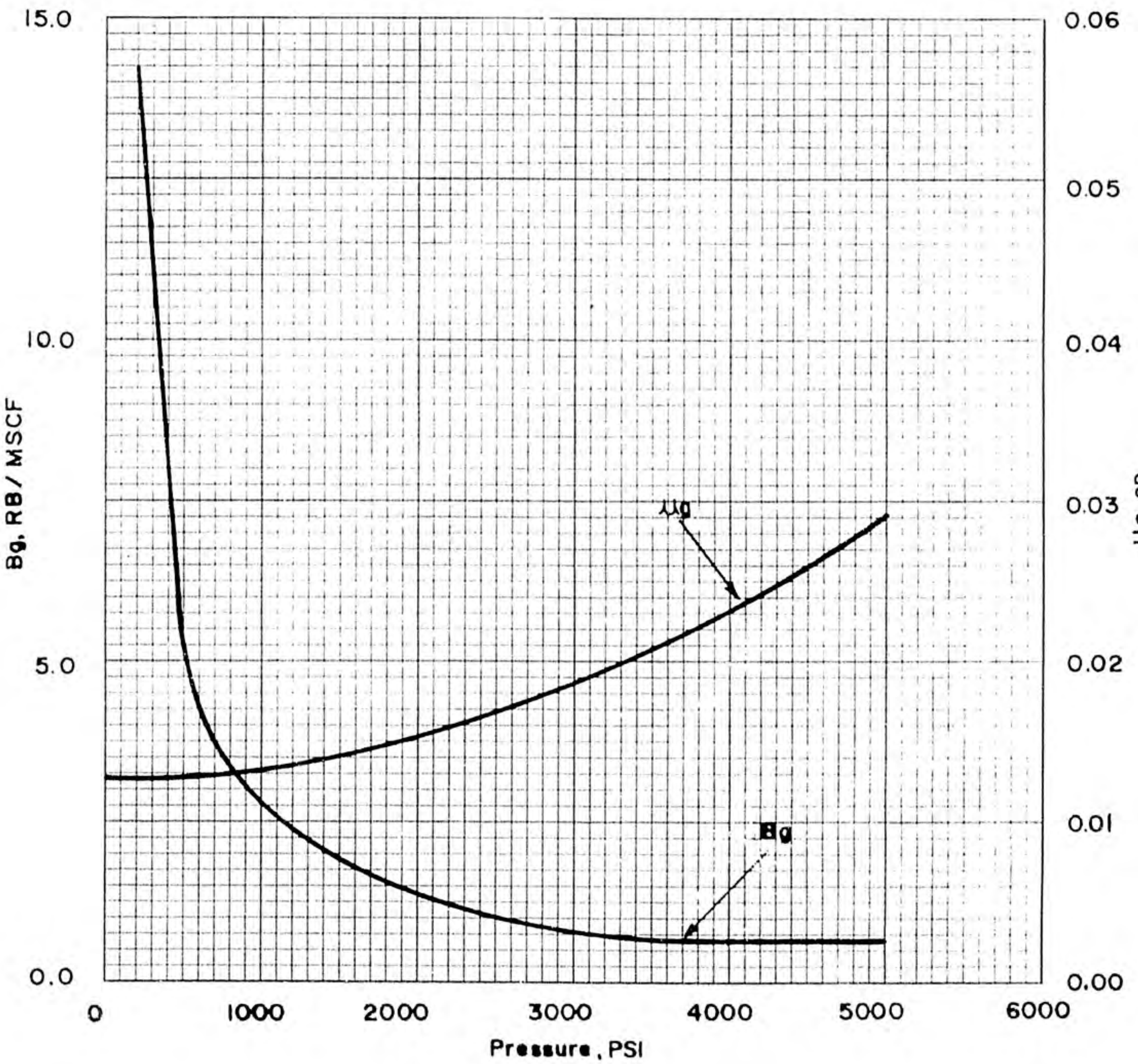
FIGURE 5

A.O.G.C.C.

Prudhoe Bay Field

Gas PVT Table # I
Gas Properties vs Pressure



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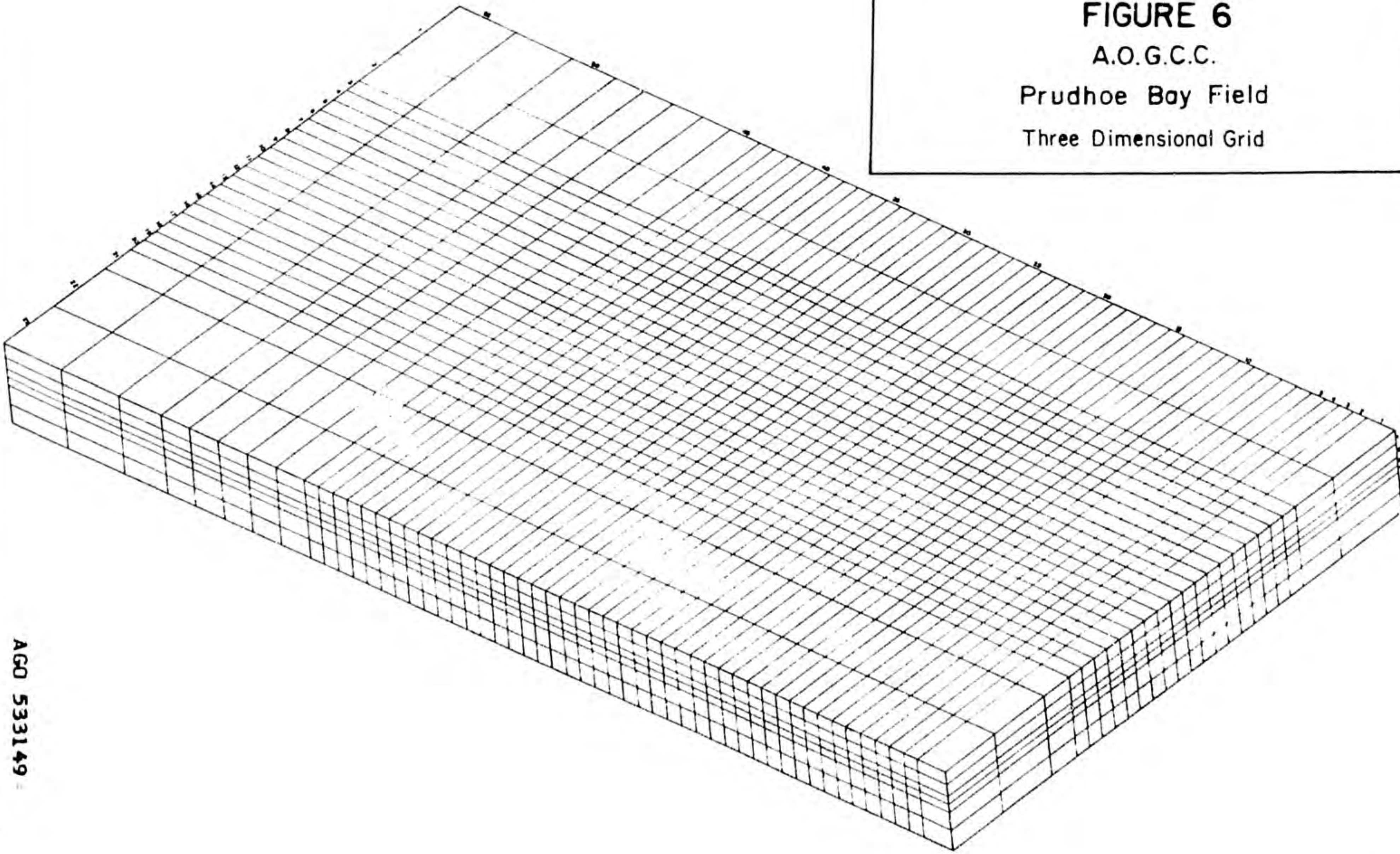


FIGURE 6

A.O.G.C.C.

Prudhoe Bay Field

Three Dimensional Grid

FIGURE 7

A.O.G.C.C.

Prudhoe Bay Field

Cross-Section Model Locations

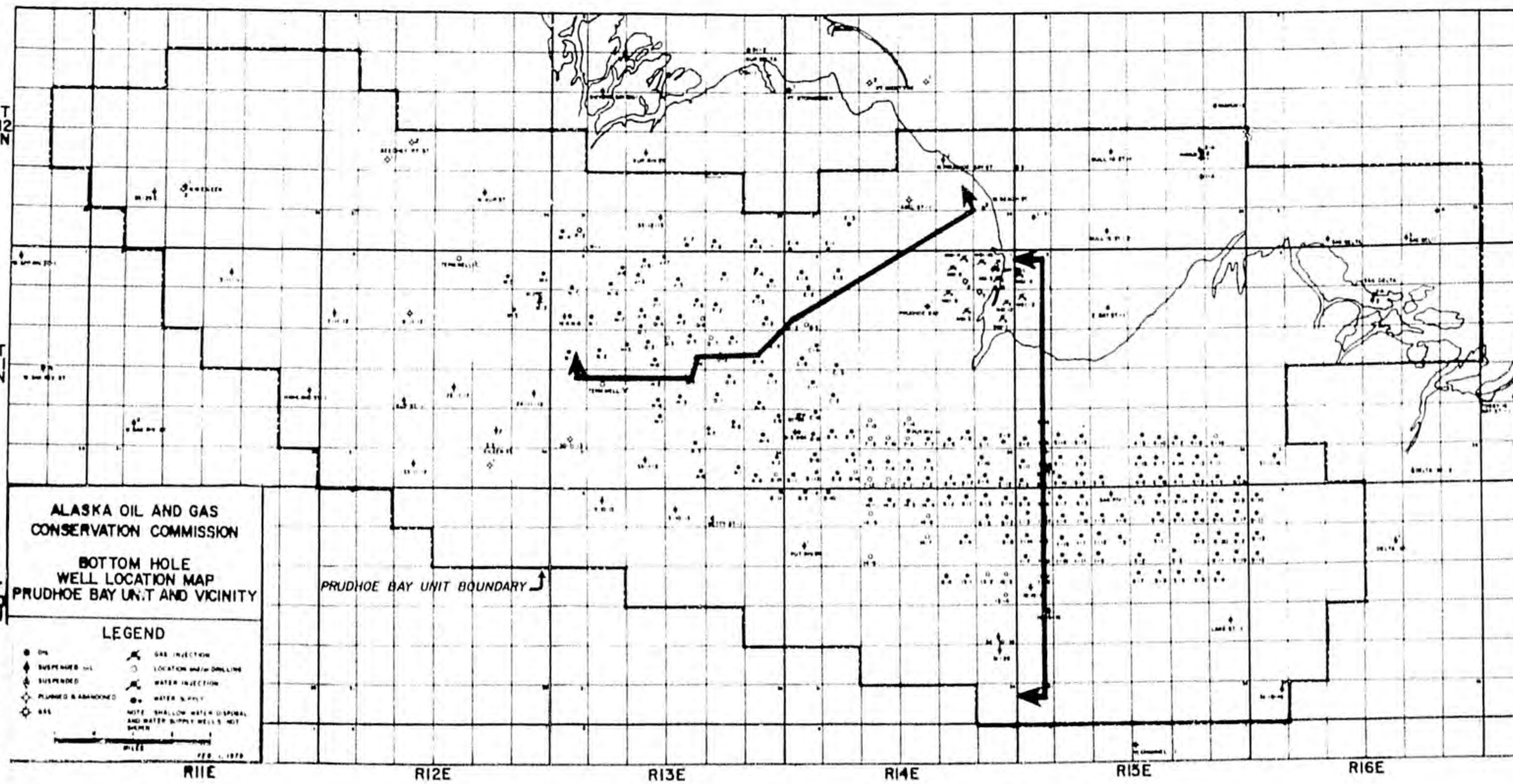


FIGURE 8

A.O.G.C.C.

Prudhoe Bay Field

Cell to Cell Relative Permeability

K_{rg} and K_{rL} vs S_L

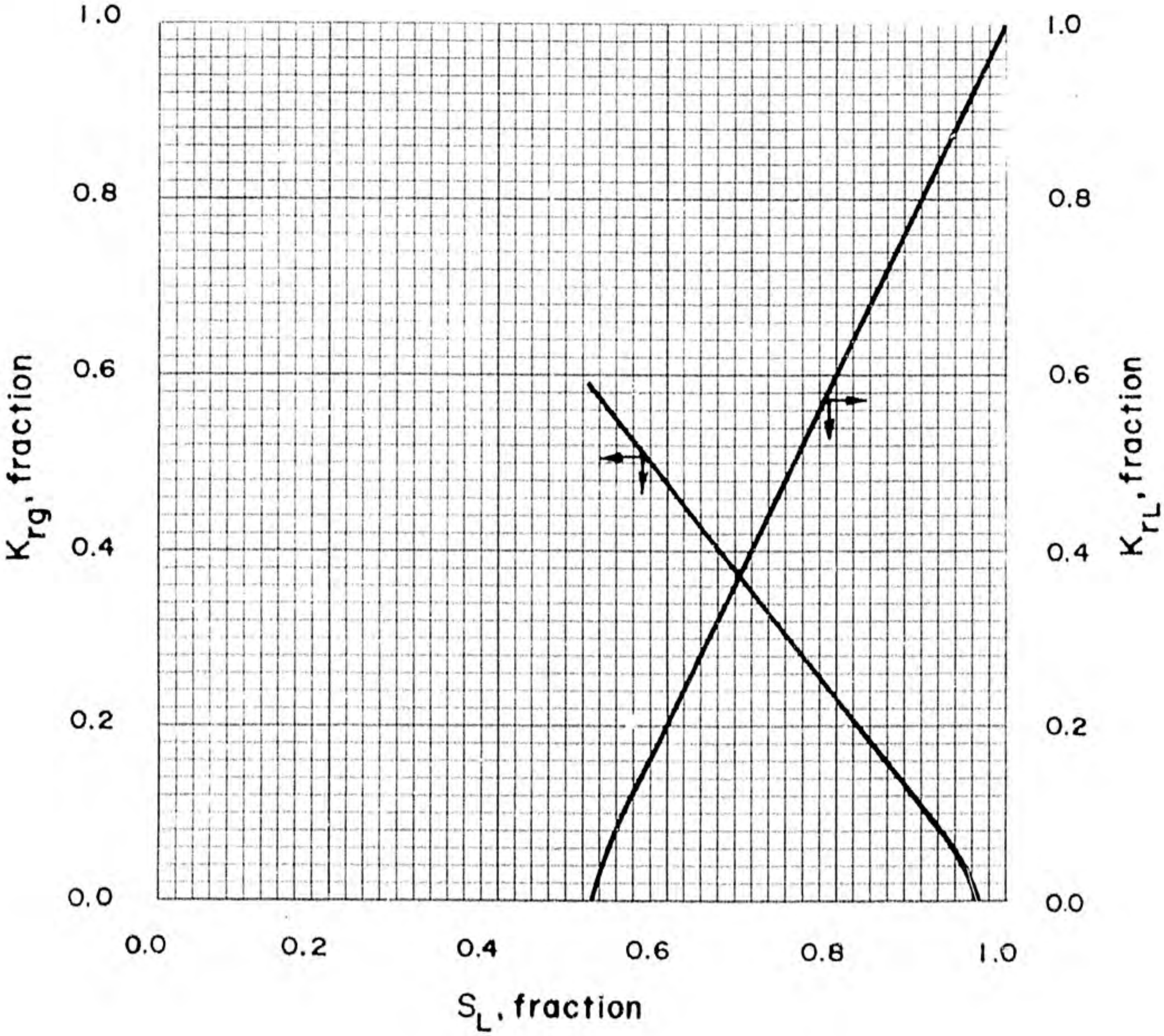


FIGURE 9

A.O.G.C.C.

Prudhoe Bay Field

Individual Well Relative Permeability

K_{rg} and K_{rL} vs S_L

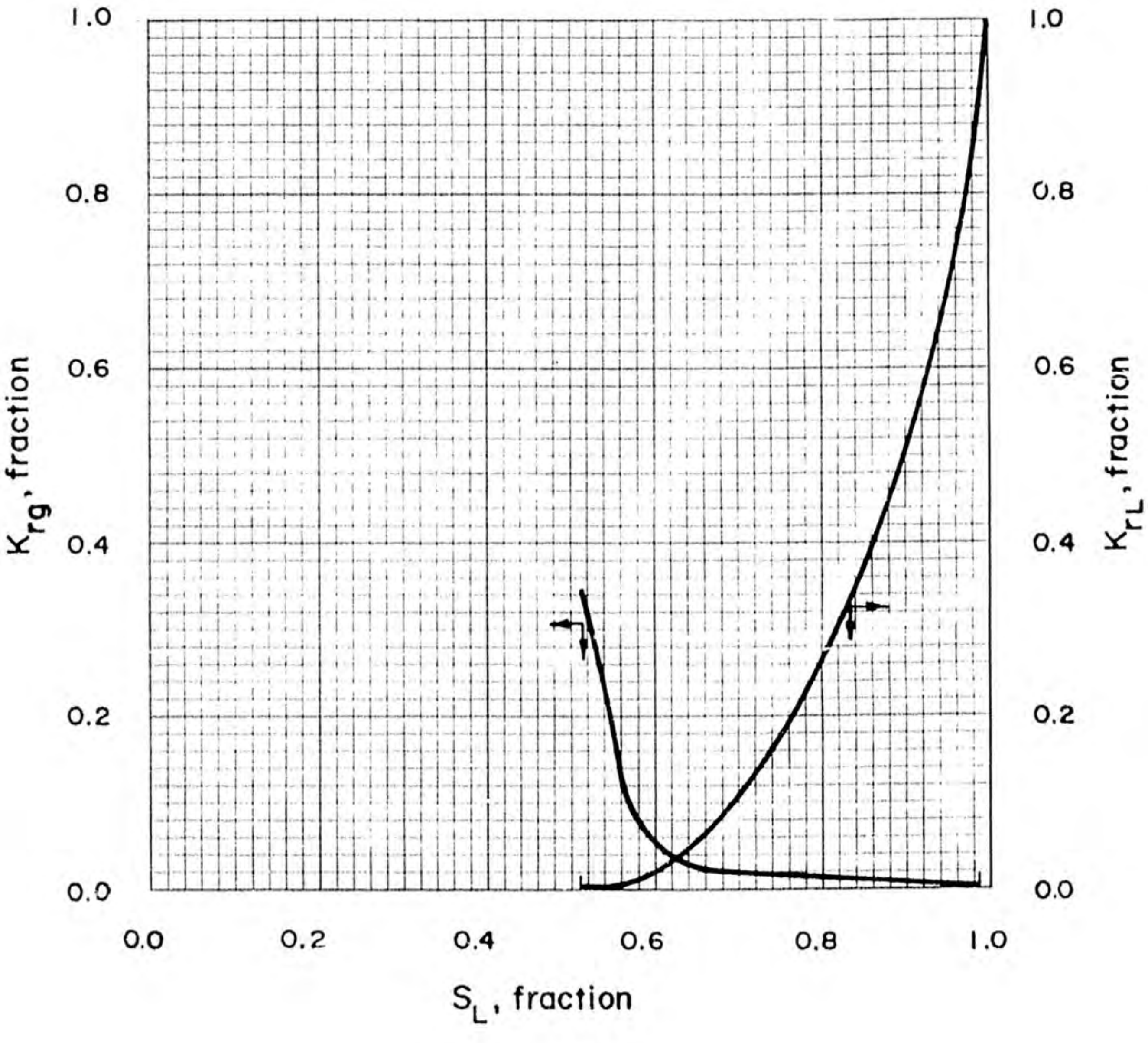
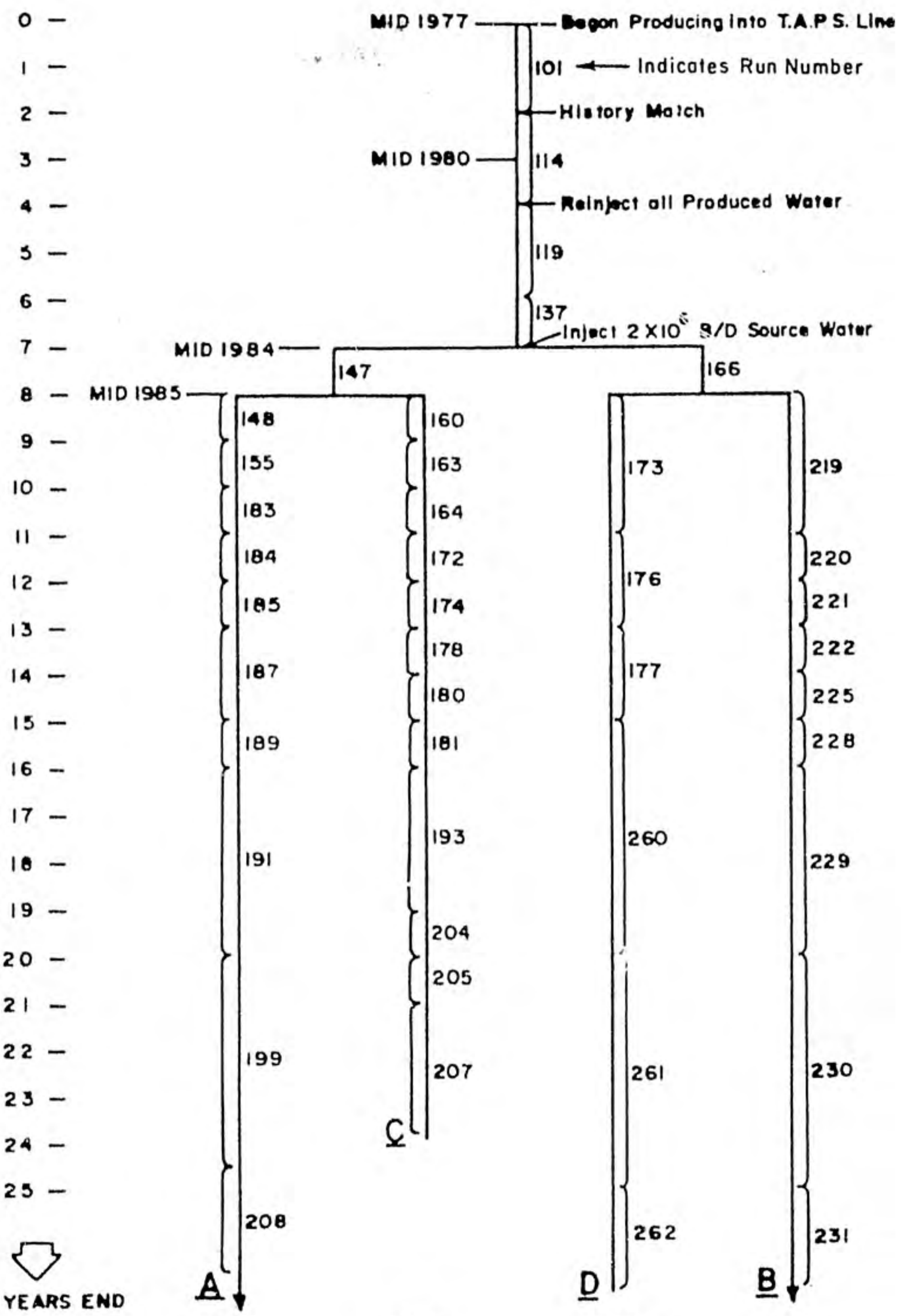


FIGURE 10

A.O.G.C.C.

Prudhoe Bay Field

Schematic Representation of Cases A, B, C and D



	A	C	D	B
Yr Run Ended	2012	2001	2005	2012
Yr Oil Rate Reaches 100,000 B/D	2013*	2001	2003	2014*

Extrapolation*

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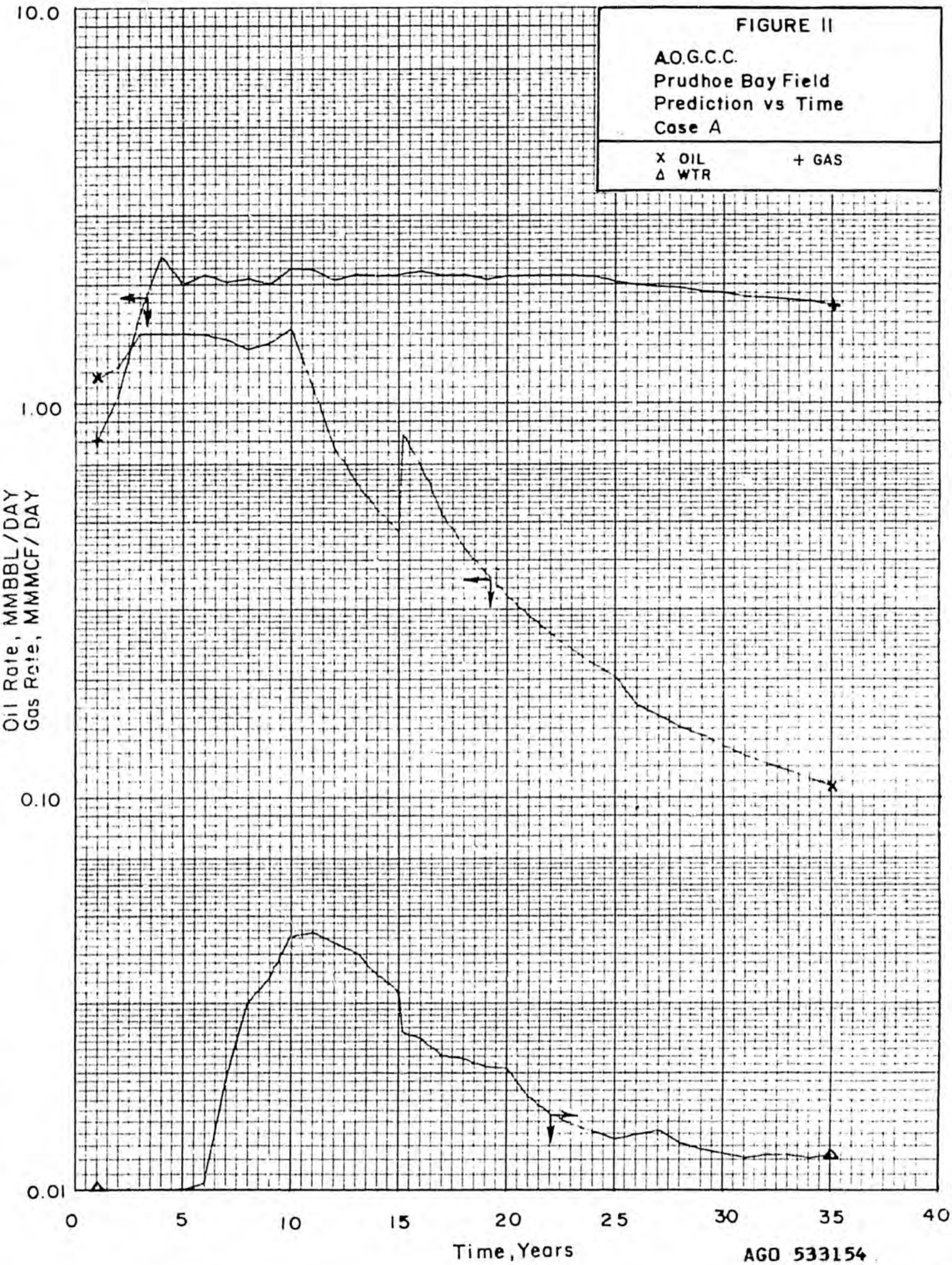
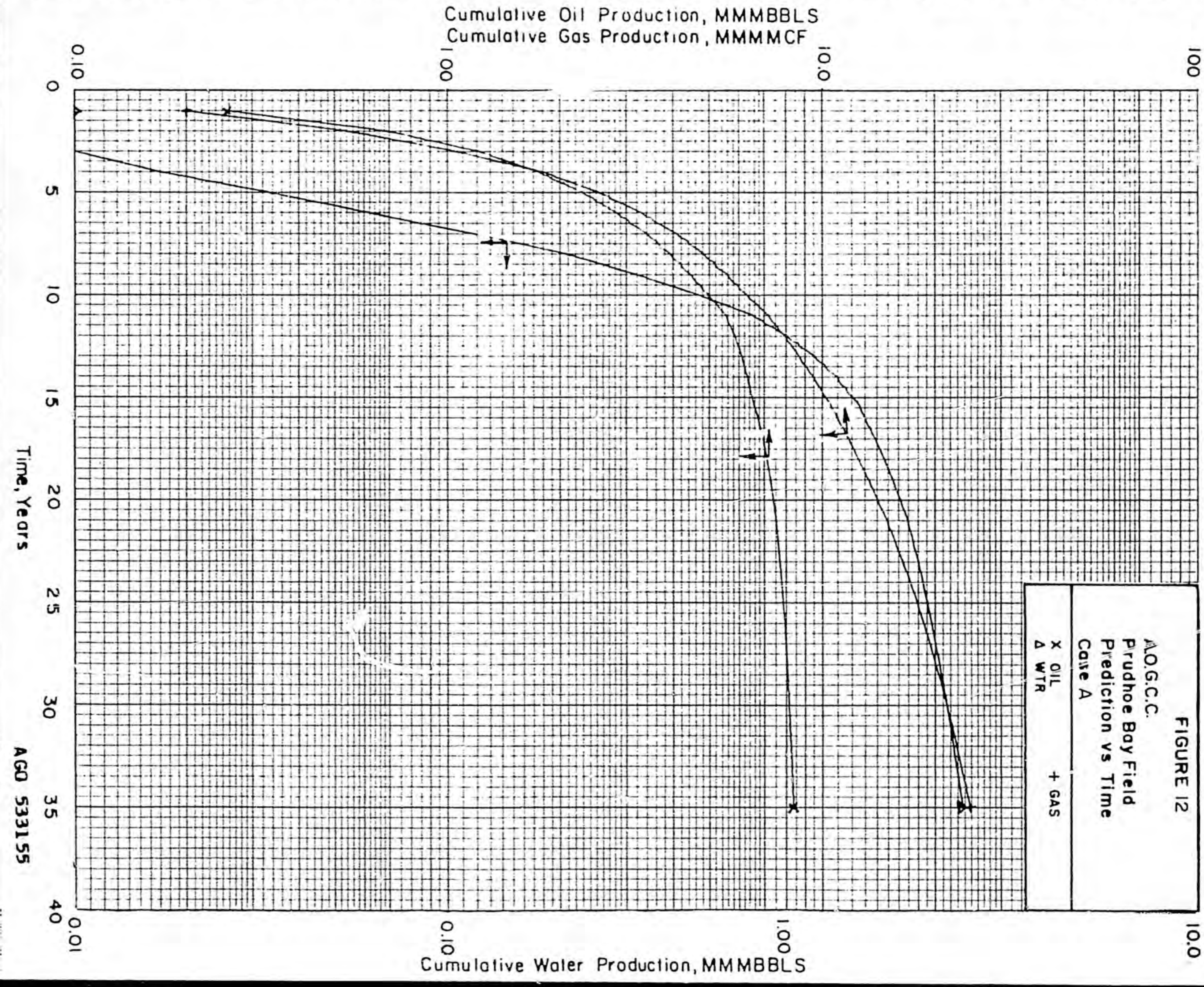


FIGURE II
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case A
X OIL
+ GAS
Δ WTR
10.0
1.00
0.10
0.01
100.
10.0
1.00
0.10
Oil Rate, MMBBL/DAY
Gas Rate, MMMCF/DAY
Water Rate, MMBBL/DAY
0
5
10
15
20
25
30
35
40
Time, Years

AGO 533154



Cumulative Oil Production, MMMBBLS
Cumulative Gas Production, MMMMCF
0.10
1.00
10.0
100
Time, Years
0
5
10
15
20
25
30
35
40
0.01
0.10
1.00
10.0
Cumulative Water Production, MMMBBLS
FIGURE 12
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case A
X OIL
Δ WTR
+ GAS

AGO 533155

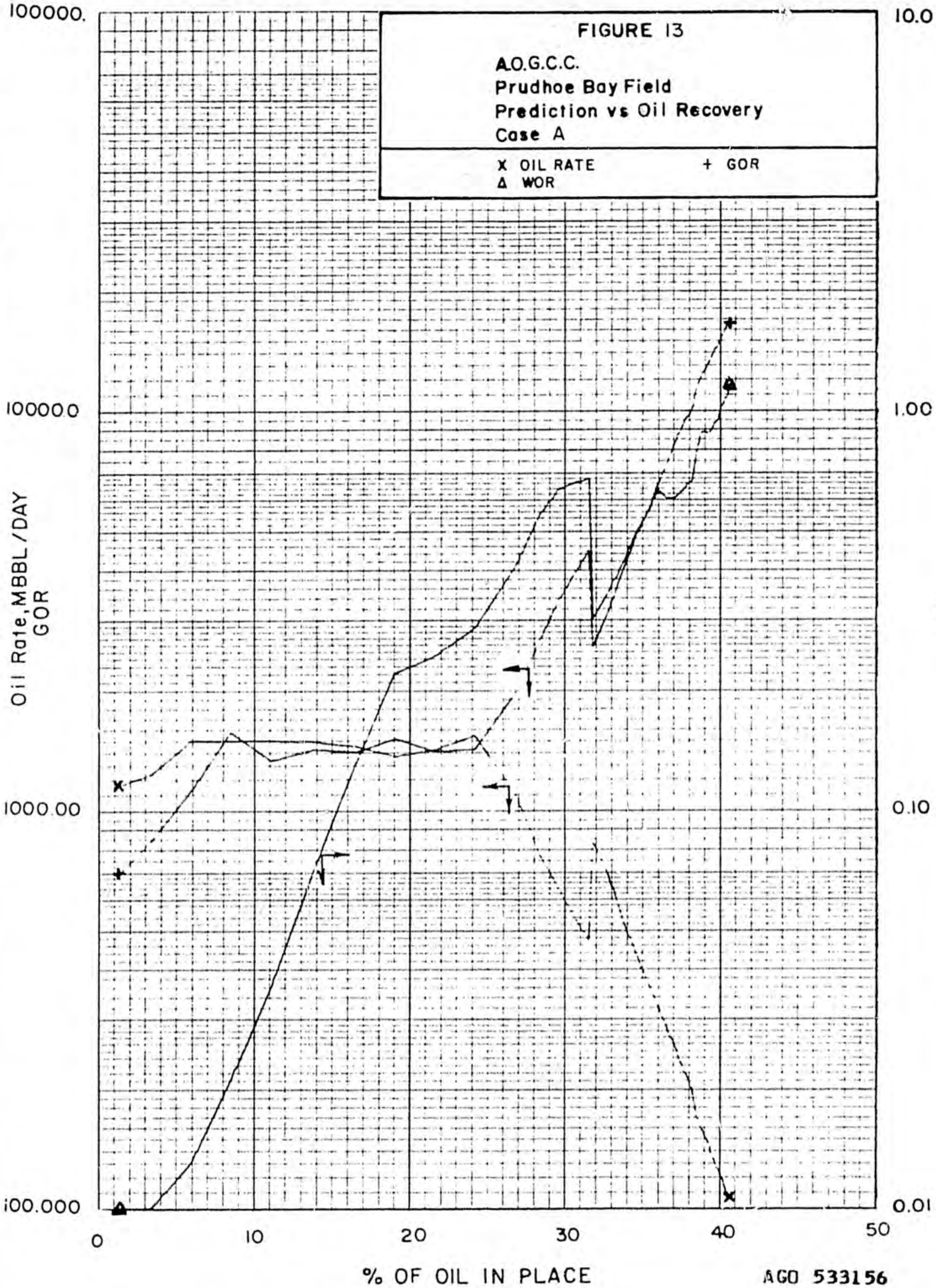


FIGURE 13
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case A
X OIL RATE
+ GOR
Δ WOR
100000.
10000.0
1000.00
100.000
10.0
1.00
0.10
0.01
0
10
20
30
40
50
Oil Rate, MBBL/DAY
GOR
WOR
% OF OIL IN PLACE

AGO 533156

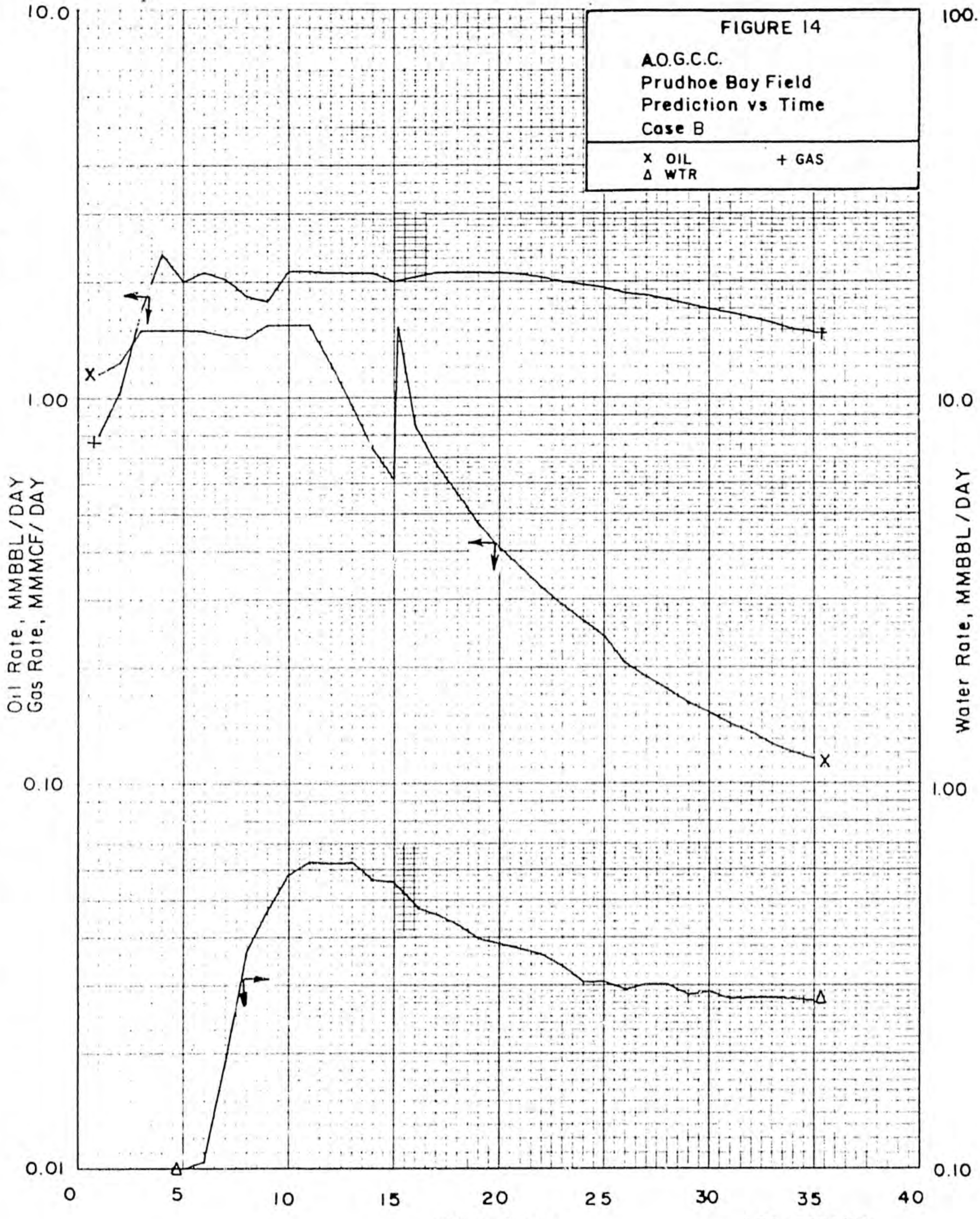


FIGURE 14
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case B
X OIL
+ GAS
Δ WTR
Oil Rate, MMBBL/DAY
Gas Rate, MMMCF/DAY
Water Rate, MMBBL/DAY
10.0
1.00
0.10
0.01
100.
10.0
1.00
0.10
0
5
10
15
20
25
30
35
40
Time, Years

AGO 533157

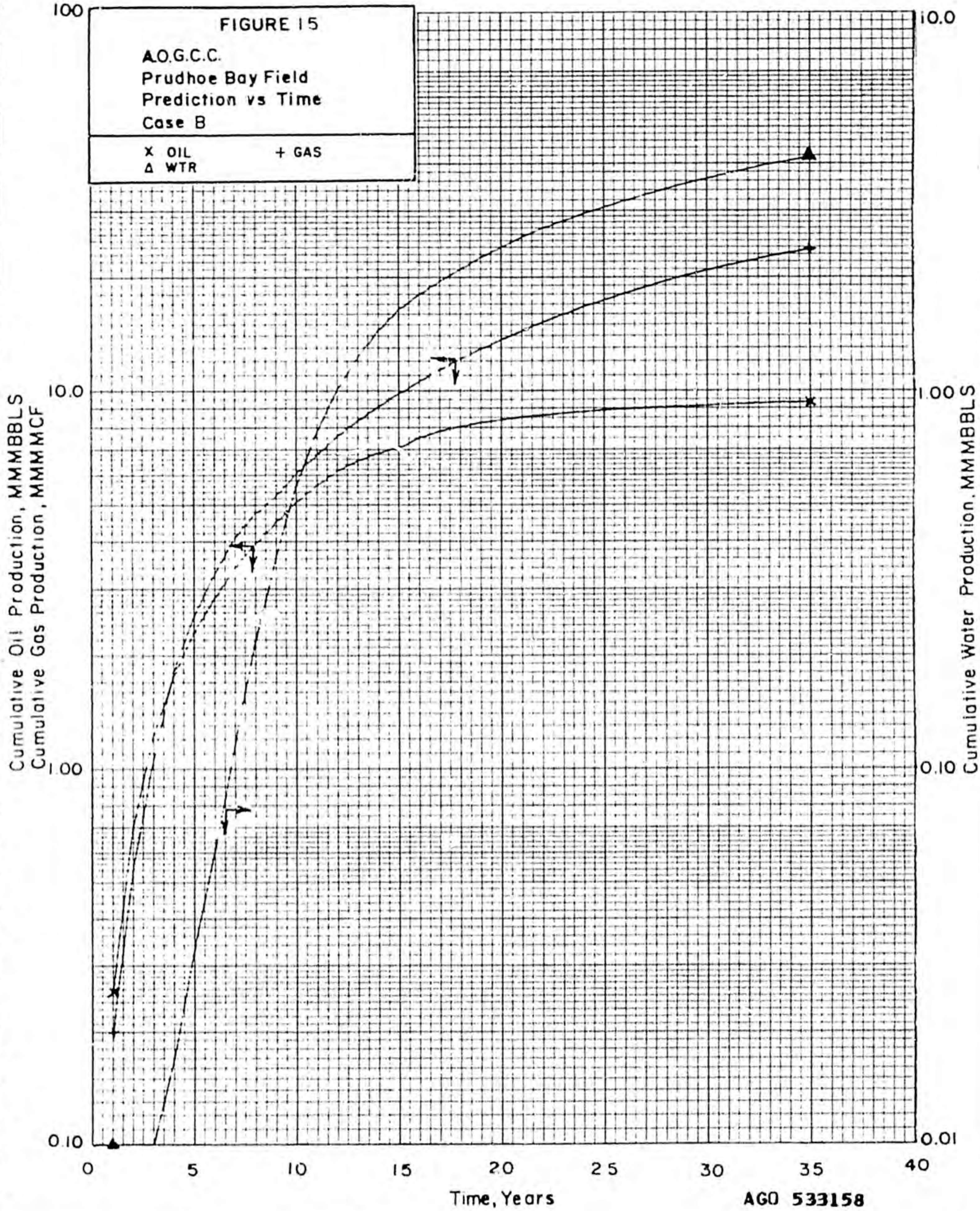


FIGURE 15
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case B
X OIL
+ GAS
Δ WTR
100
10.0
1.00
0.10
10.0
1.00 S
0.10
0.01
Cumulative Oil Production, MMMBBLS
Cumulative Gas Production, MMMMCF
Cumulative Water Production, MMMBBLS
0
5
10
15
20
25
30
35
40
Time, Years

AGO 533158

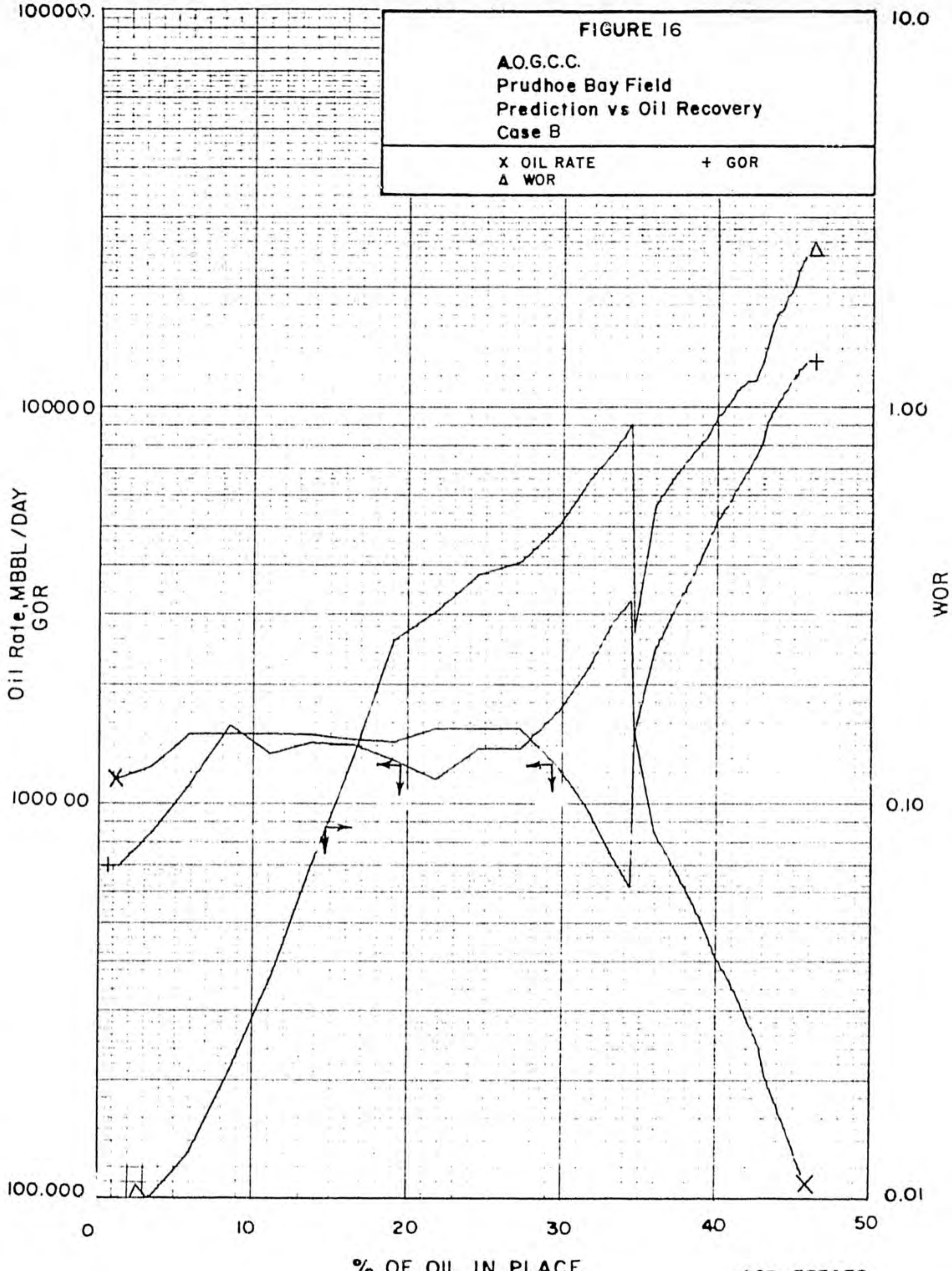


FIGURE 16
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case B
X OIL RATE
+ GOR
Δ WOR
100000.
10000 0
1000 00
100.000
10.0
1.00
0.10
0.01
Oil Rate, MBBL/DAY
GOR
WOR
0
10
20
30
40
50
% OF OIL IN PLACE

AGO 533159

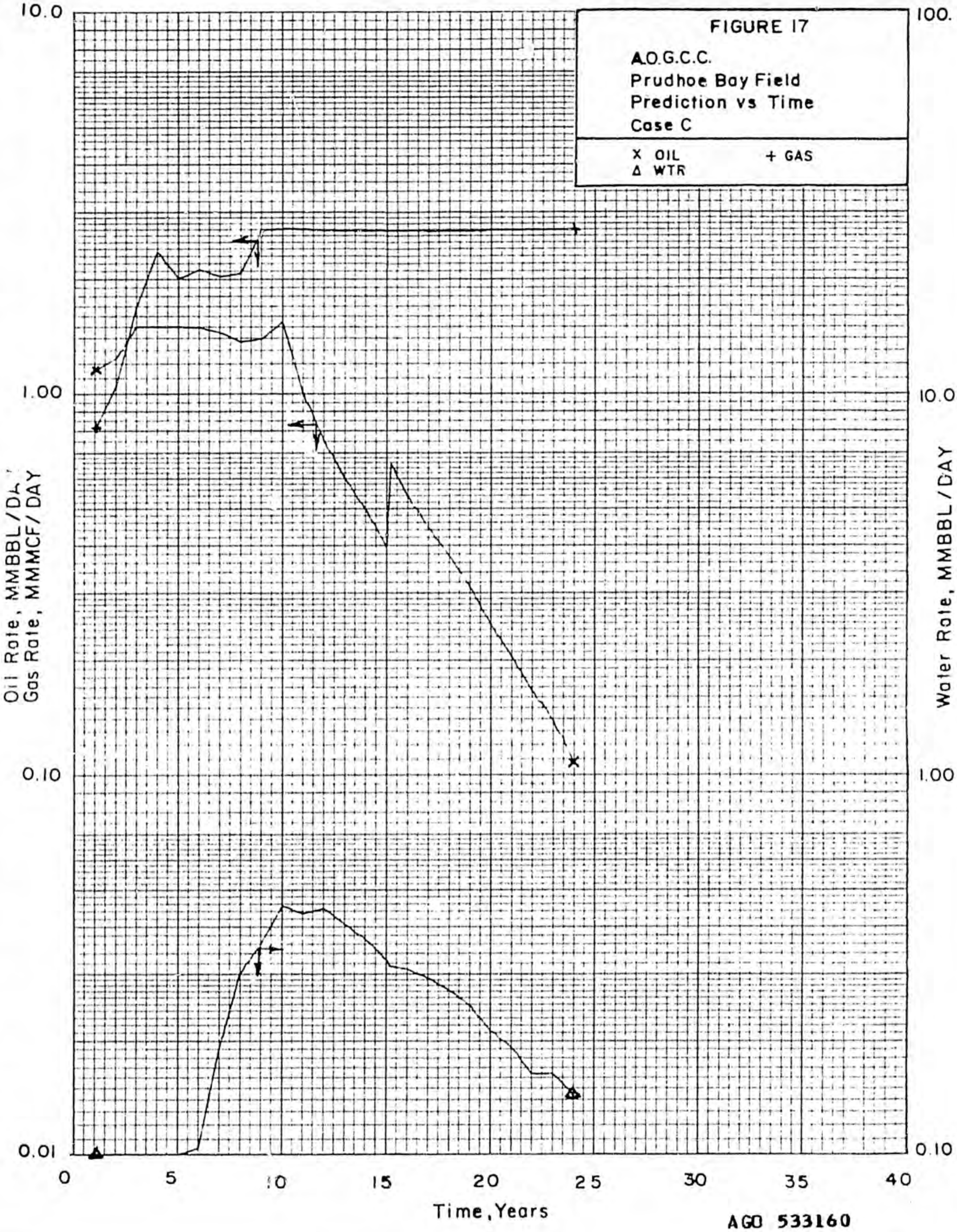


FIGURE 17
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case C
X OIL
+ GAS
Δ WTR
10.0
1.00
0.10
0.01
100.
10.0
1.00
0.10
Oil Rate, MMBBL/DAY
Gas Rate, MMMCF/DAY
Water Rate, MMBBL/DAY
0
5
10
15
20
25
30
35
40
Time, Years

AGO 533160

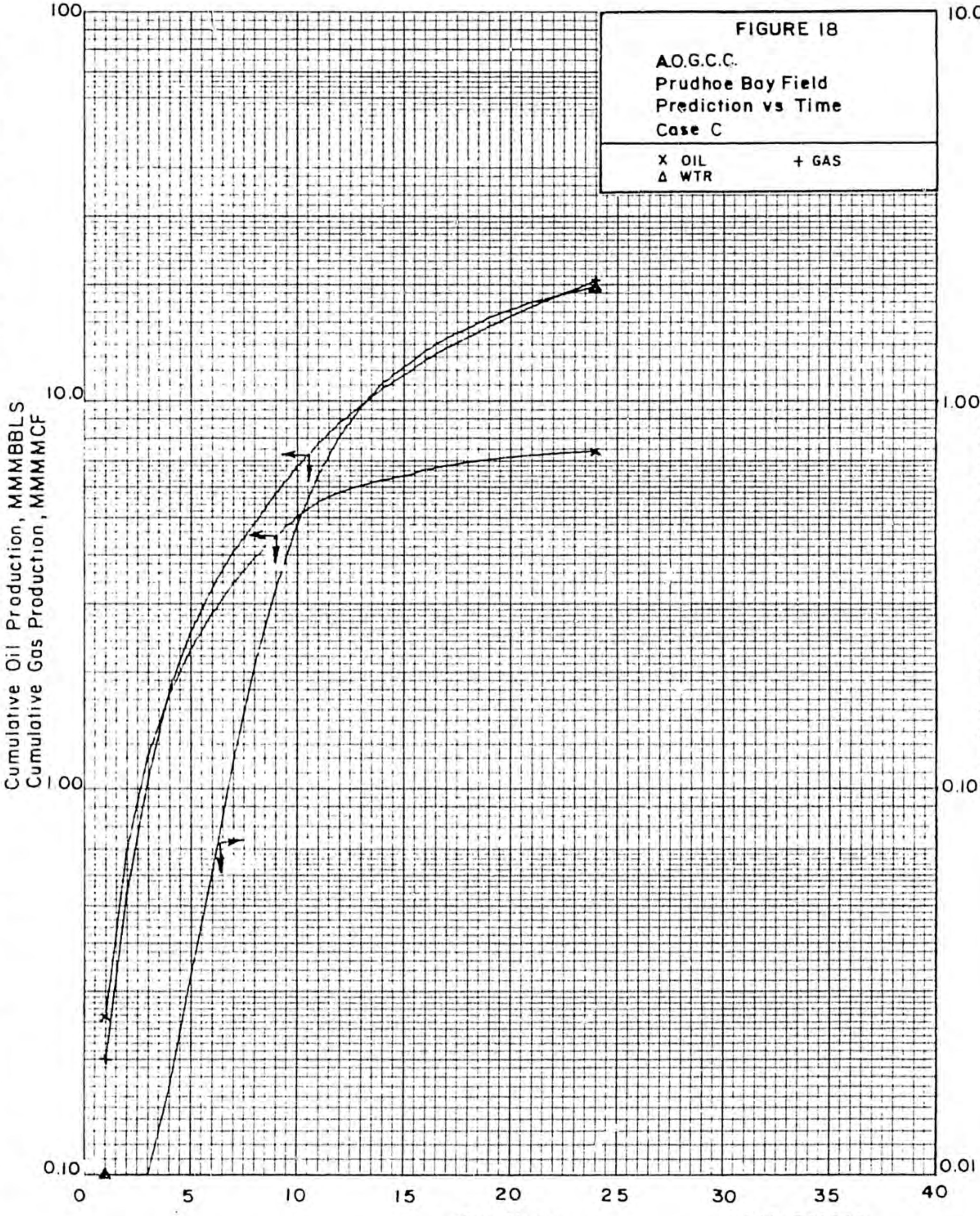


FIGURE 18
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case C
X OIL
+ GAS
Δ WTR
Cumulative Oil Production, MMMBBLS
Cumulative Gas Production, MMMMCF
Cumulative Water Production, MMMBBLS
100
10.0
1.00
0.10
10.0
1.00
0.10
0.01
0
5
10
15
20
25
30
35
40
Time, Years

AGO 533161

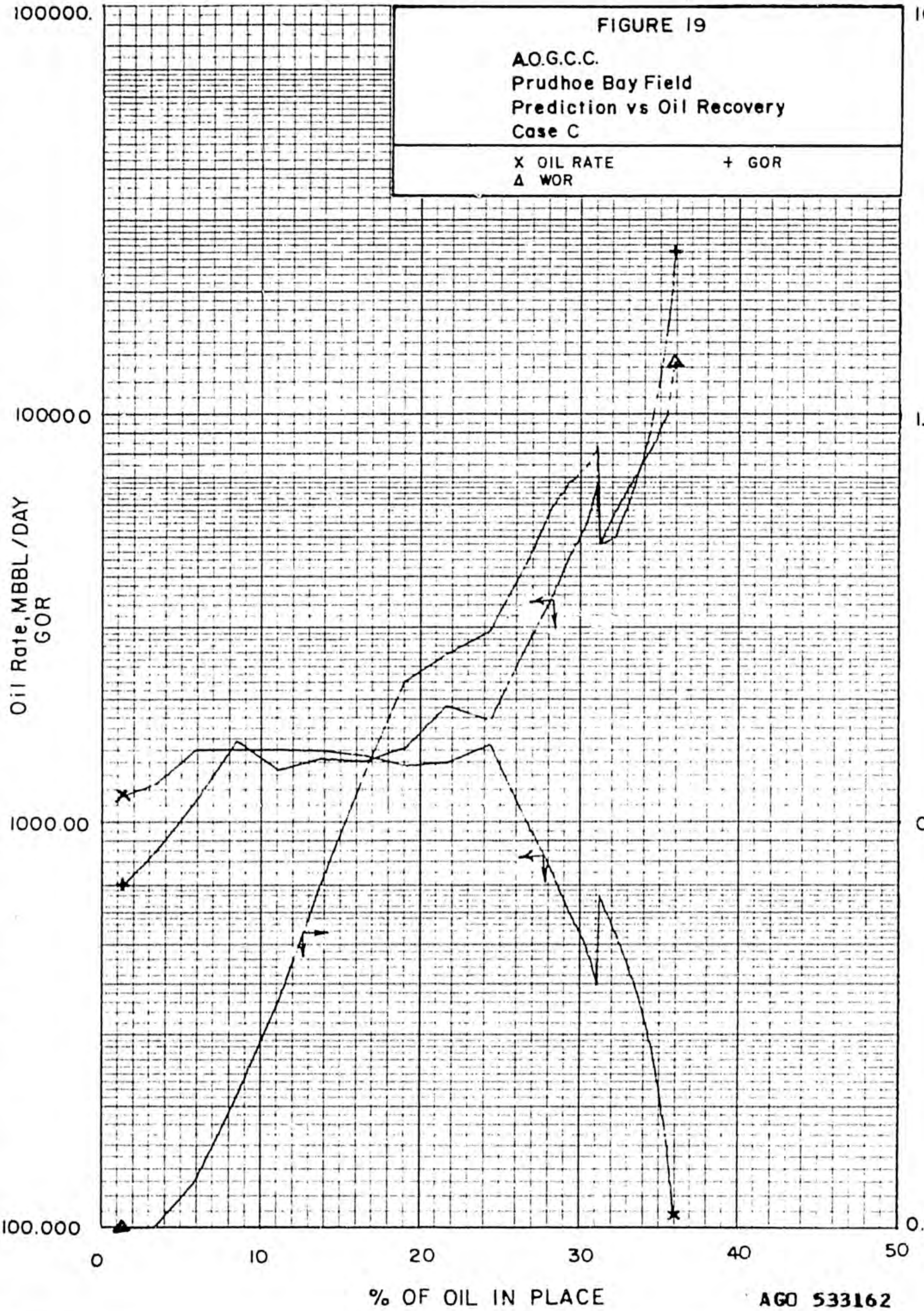
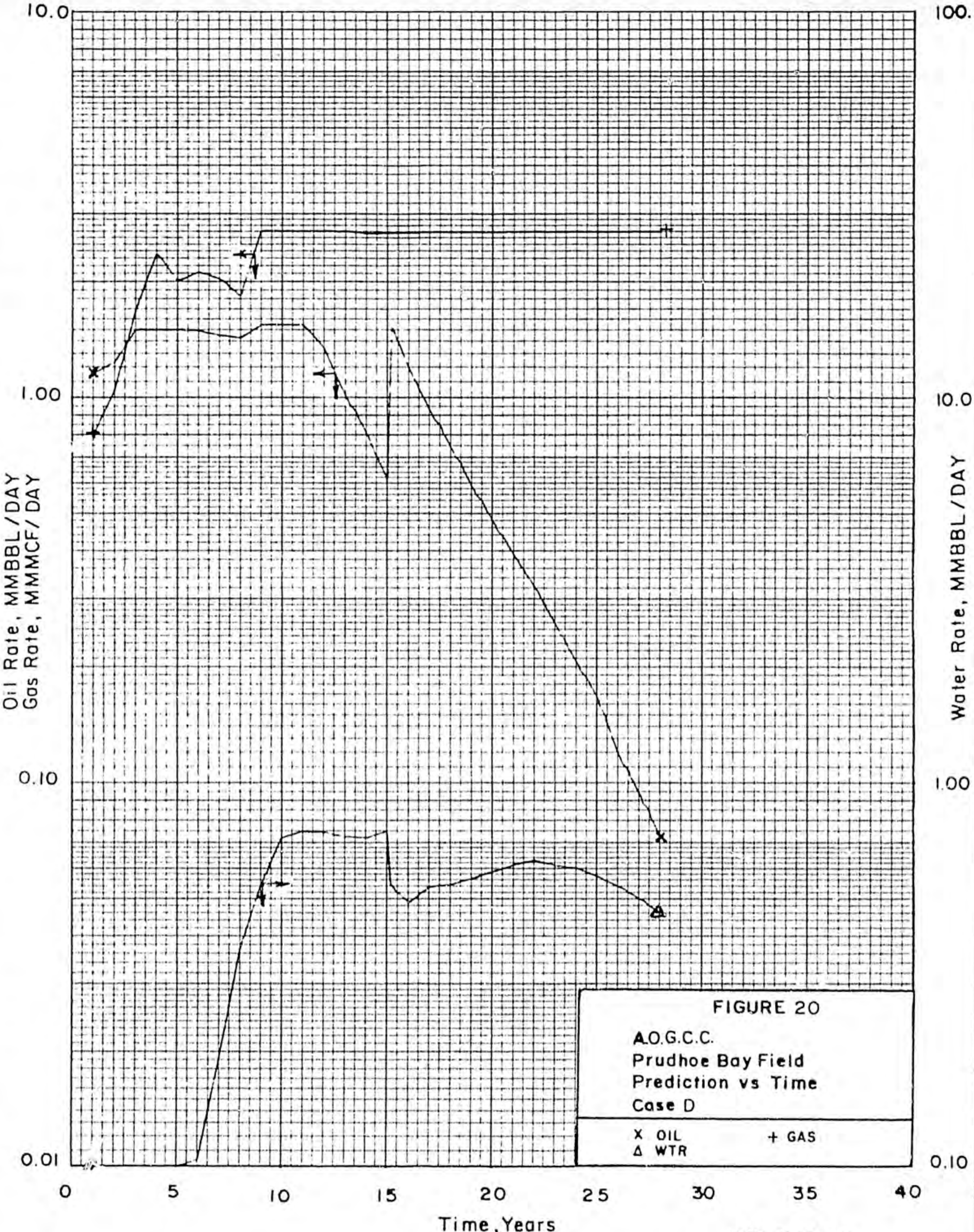


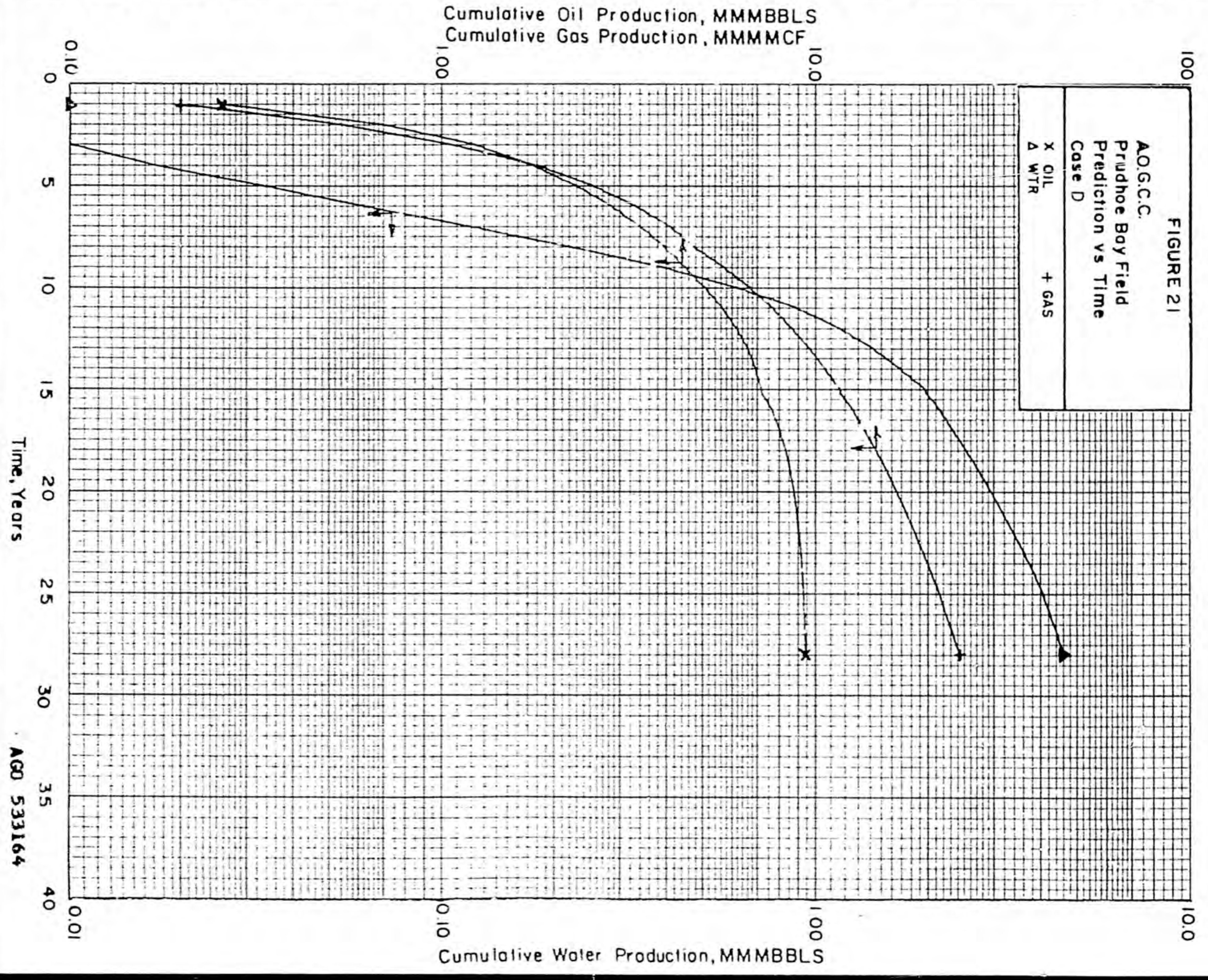
FIGURE 19
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case C
X OIL RATE
+ GOR
Δ WOR
100000.
10000.0
1000.00
100.000
10.0
1.00
0.10
0.01
Oil Rate, MBBL/DAY
GOR
WOR
0
10
20
30
40
50
% OF OIL IN PLACE

AGO 533162



10.0
1.00
0.10
0.01
100.
10.0
1.00
0.10
Oil Rate, MMBBL/DAY
Gas Rate, MMMCF/DAY
Water Rate, MMBBL/DAY
0
5
10
15
20
25
30
35
40
Time, Years
FIGURE 20
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case D
X OIL
+ GAS
Δ WTR

AGO 533163



Cumulative Oil Production, MMMBBLS
Cumulative Gas Production, MMMMCF
0.10
1.00
10.0
100
FIGURE 21
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Time
Case D
X OIL
+ GAS
Δ WTR
0
5
10
15
20
25
30
35
40
Time, Years
0.01
0.10
1.00
10.0
Cumulative Water Production, MMMBBLS
AGO 533164

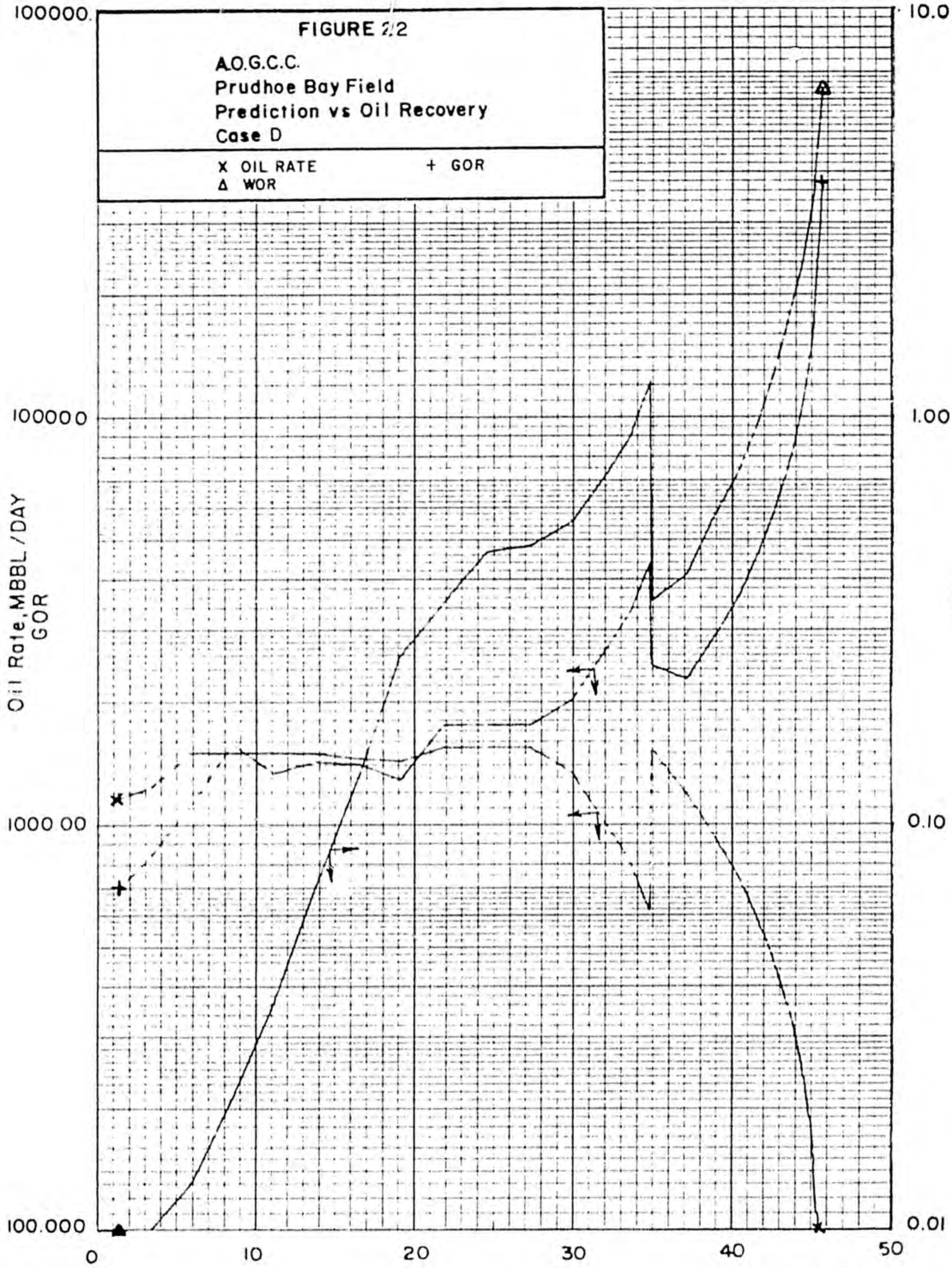
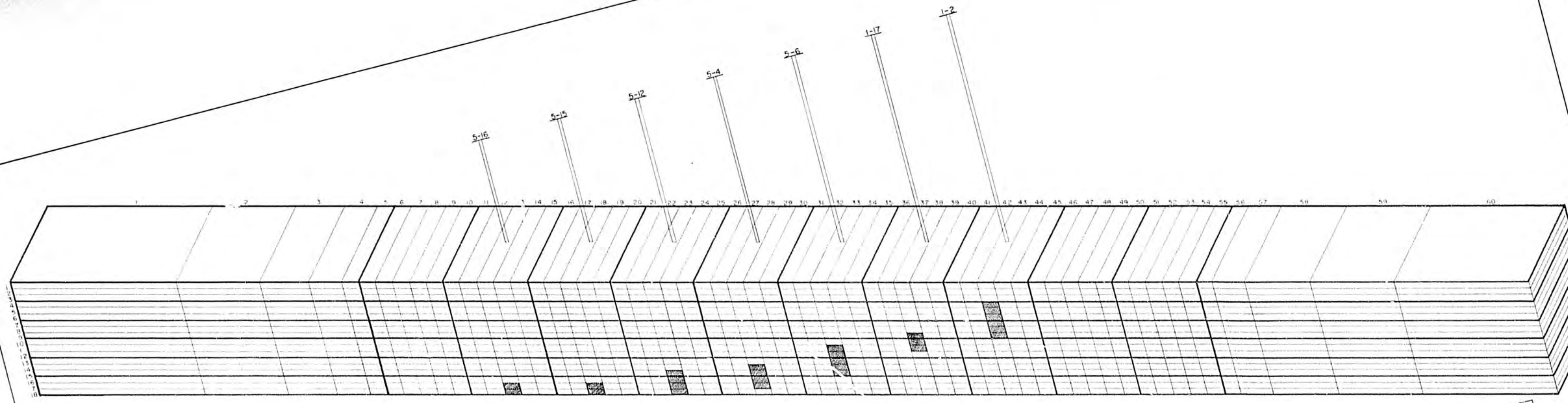


FIGURE 2.2
A.O.G.C.C.
Prudhoe Bay Field
Prediction vs Oil Recovery
Case D
X OIL RATE
+ GOR
Δ WOR
Oil Rate, MBBL/DAY
GOR
WOR
100000.
10000.0
1000.00
100.000
10.0
1.00
0.10
0.01
0
10
20
30
40
50
% OF OIL IN PLACE

AGO 533165



LEGEND

Well

Perforated Zone

EXHIBIT A

H.K. VAN POOLLEN AND ASSOCIATES, INC.

A.O.G.C.C.

PRUDHOE BAY FIELD

North-South Cross Section

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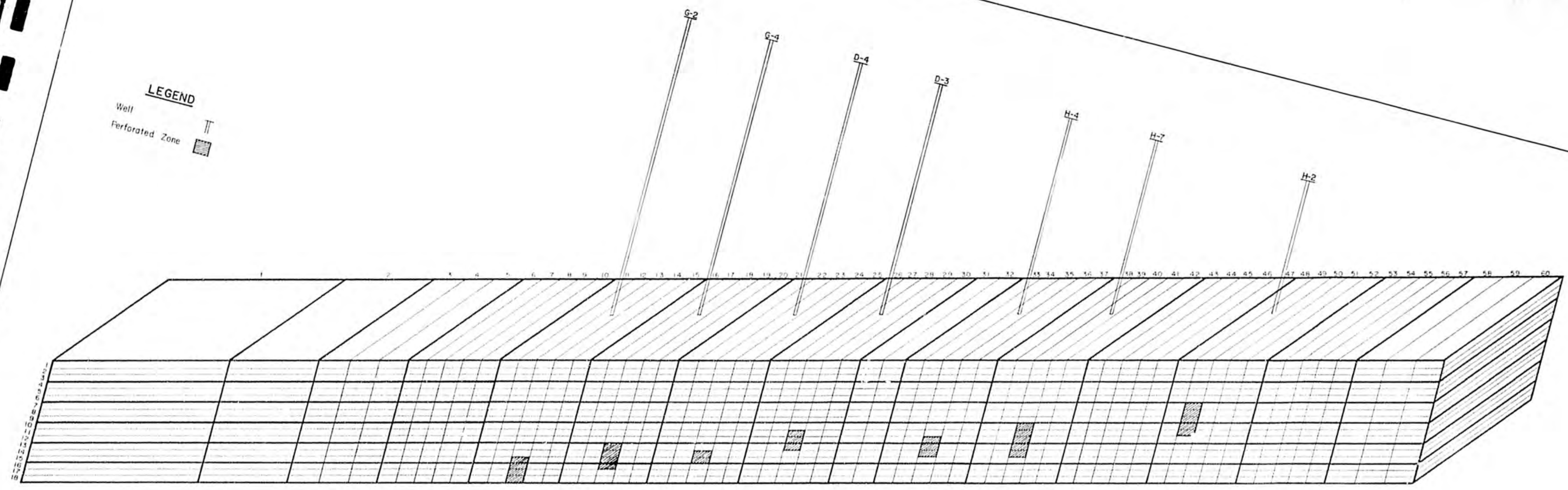

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EXHIBIT B
H.K. VAN POOLLEN AND ASSOCIATES, INC.
A.O.G.C.C.
PRUDHOE BAY FIELD
East-West Cross Section

AGO 533167

Oil & Gas new

Alaska State Legislature

Senate

JUNEAU, ALASKA

5/10/77

TO: Senator Rader
FR: Connie Barlow, Assistant
RE: Materials distributed at May 5 Royalty Board meeting

cc: Poland, Croft, Huber, Colletta
Malone, Osterback, Gruening

Don Wold, executive director of the Royalty Board supplied our office with materials relating to the Royalty Board meeting that took place on May 5, 6. I asked for a few extra copies to pass on to interested legislators. These are attached:

(1) Final Policies for Disposition of Royalty Oil & Gas

The Board adopted a set of 8 policies following testimony on 10 draft policies by Hammond, Rader, Osterback, and Silides.

(2) Statement of Governor Hammond on Royalty Oil Disposition

(Note: Osterback and Silides supplied written statements too.)

(3) "Criteria Document" (lead agency in preparation was DPDP)

Board hopes to use this document for determining the "net benefit" of the various refinery proposals; and in order to specify how the existing proposals need to be more detailed. (Phase I questions are to be incorporated in the final solicitation notice of May 15) Don Wold is looking for comments on this document by Board members, purchasers, and legislators.

SCHEDULE

The Board informally adopted a schedule for completing a large-volume refinery sale:

- May 15 - final solicitation of proposals (specific questions pulled out of "Criteria Document")
- Aug 1 - preliminary proposals due
- Nov 1 - final proposals due
- Dec 1 - final selection of proposal, negotiation begin
- Feb 1 - contract submitted for legislative approval.

POLICY STATEMENT MADE BY

The Alaska Royalty Oil and Gas
Development Advisory Board

May 5 & 6, 1977

1. The Royalty Oil and Gas Board shall recommend disposition of royalty oil and gas (through in-value taking, in-kind taking, sales, and sales conditions) in such a manner to maximize net benefits to the State. These net benefits include not only price, but also the various economic, social, and environmental ramifications, including employment, local training, Alaskan ownership, secondary effects, tax base, and many other factors.

2. The baseline price for any royalty oil or gas sale shall not be less than the price that would be received for that oil or gas if taken "in-value".

3. Preference will be given first to existing in-state facilities with no alternate sources of oil or gas, and second to those who will construct new in-state facilities or expand existing in-state facilities.

4. A portion of royalty oil will be withheld meet from long-term committment in order to anticipated future small local demands.

5. With the exception of small sales to public utilities, sales will be for specified volumes or proportions of production, constant throughout the year, rather than for flexible volume "options" to be called by the purchaser.

6. Sales of royalty oil and gas for in-state processing will attempt to insure that products for in-state use are priced at the lowest possible price, within the limits of the general net benefit policy and the pricing policy.

7. Products produced from royalty oil and exported from the State must be surplus to the State's domestic and industrial product needs.

8. In general royalty oil and gas will be disposed of in long-term contracts, rather than in "piece lots" as may be done by a private-sector trader or dealer.

PLEASE NOTE: THE FOLLOWING PAGES WERE TREATED AS A UNIT IN THE ORIGINAL DOCUMENT.

COMMENTS BY GOVERNOR JAY S. HAMMOND
ALASKA ROYALTY OIL AND GAS BOARD
MAY 5, 1977

MR. CHAIRMAN AND MEMBERS OF THE BOARD, I AM DELIGHTED TO TAKE THIS OPPORTUNITY TO DISCUSS PRESENT AND FUTURE POLICIES REGARDING DISPOSITION OF OUR ROYALTY SHARE OF ALASKA'S OIL AND NATURAL GAS. I FEEL AN OPEN PUBLIC DISCUSSION OF WHAT OUR POLICIES AS ALASKAN CITIZENS SHOULD BE IS ESPECIALLY GERMANE AT THIS TIME, AS THE BOARD ENTERS INTO CONSIDERATION OF HOW TO DERIVE MAXIMUM BENEFIT OF OUR ROYALTY SHARE OF PRUDHOE BAY OIL. ANY SALE OF THIS OIL WILL INDEED BE A MAJOR ACTION BY THE PEOPLE OF ALASKA, INVOLVING IN ALL LIKELIHOOD MORE THAN A BILLION BARRELS OF OIL AND POSSIBLY UPWARDS OF $10 BILLION. THE PEOPLE OF ALASKA ARE INDEED FORTUNATE THAT A GROUP SUCH AS YOURSELF HAS AGREED TO LEND YOUR CONSIDERABLE WISDOM AND EXPERTISE TO THIS SUBJECT, IN SOME CASES WITHOUT COMPENSATION WHATSOEVER. I CERTAINLY COMMEND THE PUBLIC MEMBERS OF THIS BOARD FOR THEIR DEDICATION TO THE PEOPLE OF ALASKA IN THESE IMPORTANT TIMES.

I HOPE WE CAN HAVE A USEFUL DISCUSSION TODAY REGARDING THE PRINCIPLES WHEREBY WE CAN, IN THE NAME OF THE PEOPLE OF ALASKA, BEST USE THIS GREAT AMOUNT OF MINERAL WEALTH THAT IS OURS BY VIRTUE OF THE ROYALTY PROVISIONS OF THE PRUDHOE BAY LEASES. I FEEL THAT THE PRINCIPLES THE BOARD AND THE LEGISLATURE ESTABLISH NOW, WITH THE HELP OF THE PEOPLE OF THE STATE, SHOULD APPLY TO ALL FORESEEABLE FUTURE USE OF ROYALTY OIL AND GAS. THEREFORE, IT IS EXTREMELY CRITICAL THAT WE DEFINE REALLY WHAT WE WANT TO GAIN FROM ANY DISPOSITION OF THIS OIL AND GAS.

THE ALASKA PUBLIC FORUMS THAT I HAVE ATTENDED THROUGHOUT THE STATE HAVE, AS I AM SURE YOU ARE AWARE, ADDRESSED THIS VERY PROBLEM. MY PARTICIPATION IN THE FORUM HAS GIVEN ME SOME DEFINITE IMPRESSIONS REGARDING WHAT THE PEOPLE OF THE STATE WANT DONE WITH ROYALTY OIL AND GAS. THE PEOPLE'S UNDERLYING GOALS SEEM TO BE TO ENCOURAGE IN-STATE USE, AND WHATEVER POSITIVE DEVELOPMENTAL SPINOFFS MAY OCCUR FROM IT, SHORT OF SELLING AT CUT-RATE PRICES.

THE PEOPLE, IT IS OBVIOUS TO ME, WANT TO ENCOURAGE HEALTHY INDUSTRY, AND DECIDEDLY DO NOT WISH TO ENCOURAGE INDUSTRY THAT MUST BE SUBSIDIZED FROM OUR NONRENEWABLE RESOURCE WEALTH (IN THE FORM OF REDUCED PRICE FOR ROYALTY OIL AND GAS). THEREFORE, I SUGGEST THAT THE BOARD NOT CONSIDER ANY SALES OF ROYALTY OIL AND GAS AT BELOW THE PRICE THE STATE WOULD GET WERE IT TO TAKE THE OIL OR GAS IN VALUE. THIS SHOULD BE THE BOTTOM LINE.

THIS, THEN, SHOULD BE OUR "BOTTOM LINE" REGARDING PRICING. BUT WHAT SHOULD THAT "BOTTOM LINE" BE REGARDING IN-STATE USE OF THE ROYALTY OIL AND GAS? I THINK BOTH THE STATUTE AND THE PEOPLE ARE VERY CLEAR ON THIS POINT: IN-STATE USES THAT PROVIDE A HEALTHY NET BENEFIT TO THE STATE AS A WHOLE SHOULD BE UNABASHEDLY ENCOURAGED. THOSE THAT PROVIDE A NET LOSS SHOULD NOT BE AIDED WITH OUR ROYALTY OIL AND GAS. IT IS BECOMING CLEAR THAT OUR ROYALTY OIL AND GAS PROVIDE NOT ONLY A VERY VALUABLE LIQUID ASSET, BUT ALSO AN EXTREMELY VALUABLE LEVER WHICH, IF WE ACT INTELLIGENTLY, WE MAY USE TO ENCOURAGE THE TYPES OF INDUSTRY WE ALL WANT IN THE STATE. THESE ARE THE INDUSTRIES THAT EMPLOY RESIDENT ALASKANS, THAT ARE CLEAN AND NOT POLLUTING, THAT RETURN TO THE PEOPLE OF THE STATE MORE IN TAXES AND OTHER BENEFITS THAN THEY TAKE FROM US IN INCREASED PUBLIC SERVICES, STATE PAYROLLS, CRIME, SOCIAL PROBLEMS, ETC.

THERE CERTAINLY ARE INDUSTRIES THAT WILL PROVIDE A CLEAR NET BENEFIT TO ALASKANS, WHEN ALL ECONOMIC, SOCIAL, ENVIRONMENTAL, AND OTHER FACTORS ARE TAKEN INTO ACCOUNT, AND THESE ARE THE INDUSTRIES THAT WE SHOULD USE OUR ROYALTY OIL AND GAS TO ENCOURAGE.

I THINK THAT THE APPROACH BEFORE YOU IS A GOOD ONE. AS I UNDERSTAND IT, THIS APPROACH WOULD ASK ALL POTENTIAL PURCHASERS OF OUR PRUDHOE BAY OIL IN THIS CASE TO ANSWER A LONG SERIES OF TOUGH QUESTIONS. IN THEIR AGGREGATE, THESE ANSWERS WILL ALLOW US TO CALCULATE WHICH, IF ANY, OF THESE FIRMS IS OFFERING THE "DEAL" THAT IS IN THE BEST NET BENEFIT OF THE PEOPLE OF THE STATE, CONSIDERING ALL THESE FACTORS. I FEEL THAT THESE QUESTIONS SHOULD BE ASKED SPECIFICALLY, THAT THE ANSWERS CAN BE GIVEN WITHOUT PUTTING TOO MUCH EXTRA STRESS ON THE APPLICANTS, AND THAT THE DECISION CAN BE MADE PUBLICLY AND EXPEDITIOUSLY ONCE THE ANSWERS ARE IN. I HOPE THAT THE BOARD ADOPTS THIS APPROACH AND USES IT TO NEGOTIATE A SALE THAT IS CLEARLY IN THE NET BEST INTERESTS OF THE PEOPLE OF ALASKA.

I HAVE BEEN REPEATEDLY ASKED "DO YOU FAVOR A REFINERY IN ALASKA?" MY ANSWER HAS ALWAYS BEEN, YES I DO FAVOR A REFINERY IN ALASKA AS LONG AS IT PAYS ITS OWN WAY ON A NET BASIS, AND IS ENVIRONMENTALLY SOUND. I THINK THAT IF THE BOARD APPROACHES THESE POTENTIAL OIL PURCHASERS THROUGH THE METHOD OUTLINED ABOVE, WE WILL ALL KNOW VERY CLEARLY WHICH PROPOSALS WILL PAY THEIR OWN WAY AND ARE ENVIRONMENTALLY SOUND. I AM EQUALLY SURE THAT THE FACILITY WE ENCOURAGE THROUGH COMMITMENT OF OUR ROYALTY OIL WILL BE A VERY WELCOME CORPORATE CITIZEN OF THE STATE OF ALASKA.

I HAVE ALWAYS FELT THAT A MAJOR PART OF ANY ROYALTY OIL OR GAS CONTRACT SHOULD BE THE BENEFITS THAT ALASKAN CITIZENS GAIN IN THE FORM OF LOWER PRICES FOR HEATING FUEL, GASOLINE, AIRCRAFT FUEL, WATERCRAFT FUEL, AND OTHER PETROLEUM PRODUCTS. IT HAS ALWAYS SEEMED TO ME A SINGULAR TRAVESTY THAT THE NATION'S MOST ENERGY-RICH STATE SHOULD PAY TWO-WAY TRANSPORTATION FOR OUR FUELS AND PETROLEUM PRODUCTS. I HAVE HEARD SEVERAL INTRIGUING SUGGESTIONS AS TO HOW IN-STATE PRODUCT PRICE MAY BE AFFECTED BY ROYALTY OIL AND GAS SALES, BUT DO NOT KNOW WHAT THE BEST ANSWER IS AT THIS POINT. I HAVE INSTRUCTED COMMISSIONER LERESCHE, AND WOULD HOPE THAT THE BOARD CONCURS, TO SEEK AN APPROPRIATE BENEFICIAL SOLUTION TO IN-STATE PRODUCT PRICES AS PART OF A LARGE SALE OF PRUDHOE OIL. I HOPE THAT THIS DOES NOT INVOLVE THE STATE ASSUMING ROLES, SUCH AS DISTRIBUTOR, WHICH MORE PROPERLY BELONG IN THE PRIVATE

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SECTOR, BUT WOULD HOPE THE BOARD CONSIDERS ALL SUGGESTIONS FOR SOLUTIONS TO THIS IN-STATE PRICE PROBLEM.

I MENTIONED BEFORE THAT OUR ROYALTY OIL IS A LEVER FOR ACHIEVING THE KIND OF GROWTH WE WANT IN ALASKA. AS A COROLLARY TO THIS, IT WOULD SEEM APPROPRIATE TO ME TO RESERVE THIS LEVER FOR USE WHERE IT DOES THE MOST GOOD. IN GENERAL, I WOULD EXPECT PERSPECTIVE PURCHASERS OF ROYALTY OIL AND GAS TO EXHAUST POSSIBILITIES OF PURCHASING OIL OR GAS FROM THE OTHER PRODUCERS, BEFORE THEY APPROACH THE STATE FOR OUR ONE-EIGHTH SHARE. IF WE DO NOT GRANT CUT-RATE PRICES, WHICH I THINK WE SHOULD NOT, THERE IS NO REASON FOR PERSPECTIVE PURCHASERS TO PREFER US TO OTHER PRODUCERS, AND I FEEL WE SHOULD RESERVE OUR ROYALTY PORTION FOR USE WHEN OTHER ALTERNATIVES ARE NOT AVAILABLE. I THINK IT ALSO FOLLOWS

FROM THIS THAT EXISTING FACILITIES IN-STATE, WITH EXISTING SUPPLY CONTRACTS, SHOULD NOT GENERALLY BE PURCHASERS OF OUR ROYALTY OIL AND GAS, UNLESS, OF COURSE, THEY EXPAND IN SUCH A WAY THAT MEETS THE NET BENEFIT CRITERIA WE HAVE ALREADY DISCUSSED. OF COURSE, PUBLIC UTILITIES ARE AN EXCEPTION TO THIS.

PUBLIC UTILITIES ARE NONPROFIT INSTRUMENTS OF THE CITIZENS OF ALASKA, AND THEREFORE SHOULD RECEIVE SOME MANNER OF SPECIAL TREATMENT FROM THE ROYALTY OIL AND GAS BOARD. I PERSONALLY FEEL, HOWEVER, THAT THIS SPECIAL TREATMENT SHOULD NOT INCLUDE SPECIAL CUT-RATE PRICING WHICH WOULD MERELY BE A SUBSIDIZATION OF CONSUMERS IN ONE AREA OF THE STATE AT THE EXPENSE OF THE POCKETBOOKS OF ALL ALASKANS. THERE ARE WAYS AROUND THIS WHICH THE LEGISLATURE MIGHT EXPLORE,

INCLUDING ENERGY TAX CREDITS FOR ALL CITIZENS, DISCOUNTED BY THE AMOUNT OF LOCAL SUBSIDY TO PUBLIC UTILITIES THROUGH CUT-RATE ROYALTY OIL AND GAS PRICING, BUT UNTIL THESE ARE INSTITUTED, WE SHOULD GIVE NO SELECT GROUP OF ALASKANS SPECIAL TREATMENT OVER ALL OTHERS.

I DO FEEL, THOUGH, THAT PUBLIC UTILITIES SHOULD HAVE FIRST CALL ON ROYALTY OIL AND GAS AT THE GOING PRICE, AND THEREFORE THAT SOME REASONABLE PROPORTION SHOULD BE HELD FROM ANY LARGE-SCALE SALE OF PRUDHOE BAY ROYALTY OIL. IN ADDITION, I FEEL IT APPROPRIATE THAT MAXIMUM FLEXIBILITY IN VOLUME BE ALLOWED TO PUBLIC UTILITIES, WHEN SUCH FLEXIBLE VOLUME SALES ARE SMALL ENOUGH TO NOT DISRUPT THE ENTIRE ROYALTY OIL OR GAS PICTURE.

IN SUMMARY, OUR ROYALTY OIL AND GAS IS NOT ONLY A HUGE FINANCIAL ASSET, BUT ALSO A VERY SIGNIFICANT SOCIAL LEVER, WHEREBY WE MAY ENCOURAGE THAT HEALTHY TYPE OF ALASKAN INDUSTRY THAT SERVES TO THE BENEFIT OF US ALL, AND THAT WHICH ALL ALASKANS WELCOME INTO OUR STATE.

I VERY MUCH APPRECIATE THE OPPORTUNITY TO SHARE MY THOUGHTS WITH YOU THIS MORNING, AND HOPE WE CAN USE THE REST OF MY TIME TO DISCUSS IN DETAIL THE POINTS I HAVE MENTIONED OR ANY OTHER MATTERS YOU WOULD LIKE TO BRING UP.

THANK YOU VERY MUCH.

ALASKA ROYALTY OIL AND GAS
In-State Use - A Developers Guide

DRAFT

Prepared For:
Alaska Royalty Oil and Gas Development Advisory Board

INTRODUCTION

This guide includes the following components:

A. State Information Needs - Phase I Preliminary Submittal

B. State Information Needs - Phase II Pre-Proposal Submittal

C. Preliminary Siting Criteria

D. State Evaluation Factors

E. State Permitting Requirements

The purpose of the guide is to provide a means for improving the flow of information between the State and a prospective developer, in order to generate a mutually acceptable proposal for in-state facilities making use of Alaska's non-renewable resources. This is not a formal Request for Proposal, nor does it in any way supercede applicable State and local leasing, permitting or regulatory requirements. It is intended solely to:

1. ensure that the State receives, on a timely basis, the necessary information to evaluate a potential development;

2. provide a prospective bidder with information on how the State will be evaluating a project as well as some of the requirements and criteria that a developer will be expected to meet.

A. State Information Needs - Phase I Preliminary Submittal

The preliminary list includes basic types of information that a developer should provide the State in order to initiate the evaluation process. The State will utilize this information to perform a preliminary analysis of the proposed project. The State will make this evaluation available to the developer along with any additional questions and/or concerns.

B. State Information Needs - Phase II Pre-Proposal Submittal

Following the Phase I evaluation, a more detailed analysis of the potential project will be undertaken by the State. A prospective developer will be expected to provide a more specific set of information to satisfy the Phase II evaluation. After satisfactory completion of this phase, efforts can be geared to finalizing a mutually acceptable proposal package and, subsequently, a formal contract.

C. Preliminary Siting Criteria

In order to assist a developer in preparing a description of the proposed facility and locating potential acceptable sites, a preliminary set of State siting criteria is included in the guide.

D. State Evaluation Factors

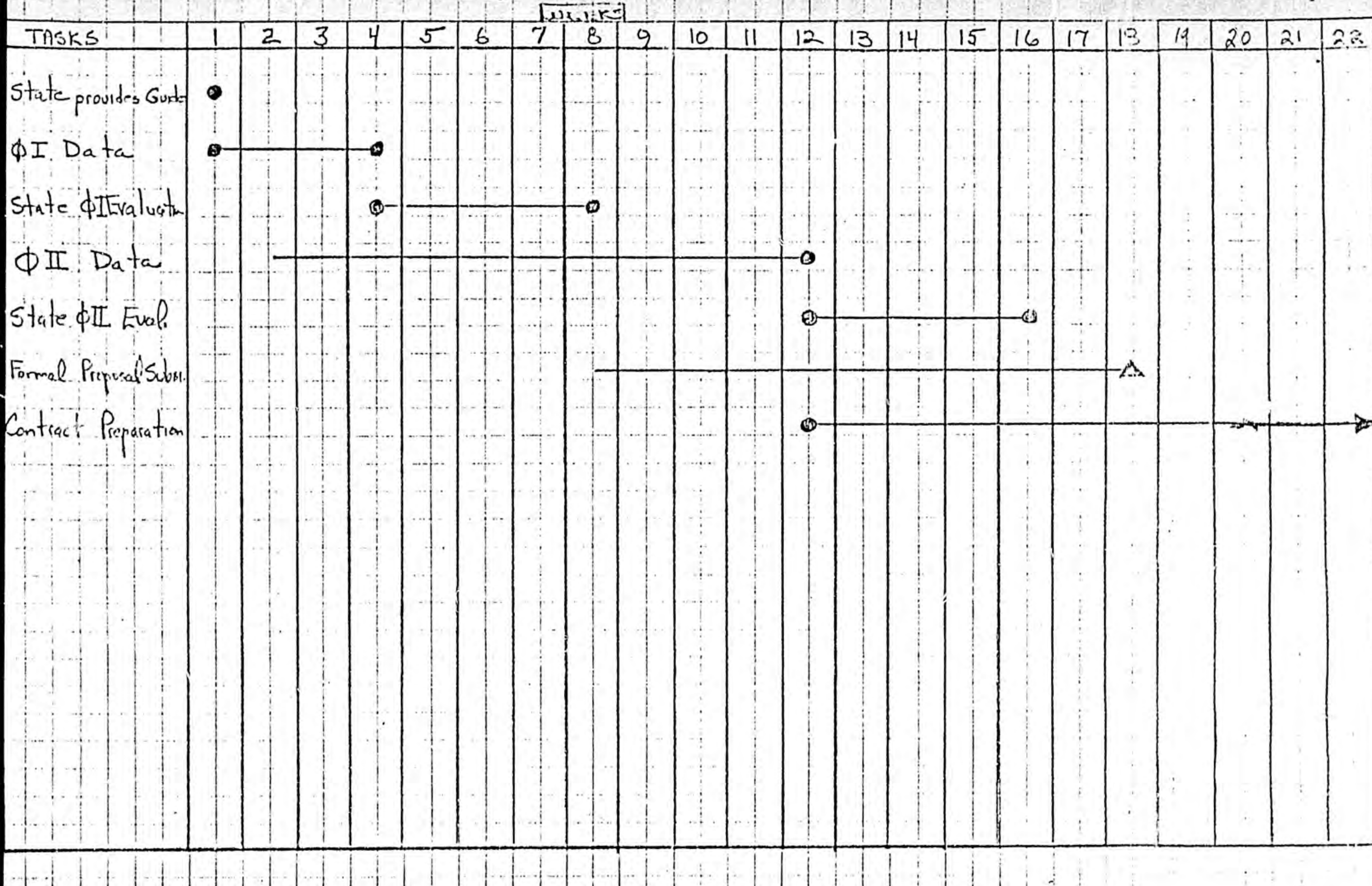
The State will perform a formal two phase evaluation process. The particular areas of State concern, examples of evaluation factors and agency evaluation responsibilities are described in this internal document. This information should assist developers in understanding how their inputs will be utilized by the State, and the key factors of concern to the State. A more formalized comprehensive interagency project evaluation procedure is now in the process of being developed.

E. State Permitting Requirements

A draft inventory of State permits is included to assist the prospective developer in understanding the scope of required actions necessary prior to development activities. The applications for the appropriate State permits are not a part of the above information flow and evaluation process. If a proposal is accepted, formal applications must be submitted.

A working committee of key State personnel has been established to assist in the information exchange/evaluation process. This group will be available to respond to particular questions, clarify the procedures, provide available data (environmental standards and regulations, site-specific land uses, critical habitat areas, local socioeconomic characteristics, to name just a few), as well as to expedite State evaluation of a proposed project. Following is a tentative timing schedule of activities.

TIME TABLE



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INFORMATION NEEDS - DEVELOPER RESPONSIBILITIES

A. Phase I - Preliminary Submittal

B. Phase II - Pre-Proposal Submittal

A. INFORMATION NEEDS - DEVELOPER RESPONSIBILITY

PHASE I - PRELIMINARY SUBMITTAL

PHYSICAL CHARACTERISTICS

- General project description - site and logistical support requirements; type, pattern and timing of activities; project phasing; life of facility; product mix/volume;

- Site development concept; potential locations (general rationale) (see: Preliminary Siting Criteria)

- Power needs; raw material needs; access needs and transportation activities; construction material needs - General

- Water utilization requirements

- Technology scale-up requirements

ECONOMIC/FINANCIAL CHARACTERISTICS

- Estimated direct revenues to State and locality (source and timing)

- Financing and ownership schemes

- Labor demands - skills, full-time/part-time/seasonal, short-term/long-term

- Approaches to local and statewide hiring and training

- Preliminary estimates of availability and price of products and/or by-products for local and state-wide use

- Approaches/alternatives for sharing in the responsibility to: provide additional needed public facilities and services; provide in-state service industries; compensate or offset potential negative environmental, economic and fiscal impacts to State and locality

- General information on contribution to local and State economy

- Estimates of type and quantity of inputs demanded by industry

- Expected contributions of State and/or locality - land, infrastructure, tax incentives, below-market-price raw materials, etc.

ENVIRONMENTAL CHARACTERISTICS

- General environmental implications and conflicts expected

- Projected discharges and emissions

- Overview of mitigation strategies/alternatives - spills contingency, air pollution control, site protection, solid waste and waste water disposal, toxic and hazardous substance control, erosion control, etc.

MISC.

- Data collection and study plans and schedule

- Public participation schemes

- Plans for joint government (State and Local) and developer planning and study efforts

B. INFORMATION NEEDS - DEVELOPER RESPONSIBILITY

PHASE II - Proposal Submittal

PHYSICAL CHARACTERISTICS

- Alternative site locations and designs and recommended site and design (with rationale and statement of why recommended site and design are superior)

- Project description (from design to close-down) - specific site and logistical support requirements; operational (including expansion or contraction) plans; product mix/ volume; site development plans; provisions for protective or buffer zones

- Readjusted (if necessary) power needs; raw material needs; access needs, transportation loads, density and frequency of transportation activities, types of vehicles and/or vessels; communications requirements; construction material utilization plan and potential sources

- Water consumption and utilization plans; potential sources/ conflicts

- Specific technology scale-up requirements

- Convertibility of facilities for other uses (bulk storage, industrial park); potential concurrent uses of facilities (general cargo area, recreational facilities); conversion schemes

- Prior site and construction material negotiations with local landowners/government

ECONOMIC/FINANCIAL CHARACTERISTICS

- Direct revenues to State and locality (timing and sources)

- Updated financing and ownership plans; opportunities for local equity participation

- Updated labor demands - skills, job classifications, full-time/part-time/seasonal, short-term/long-term

- Local and state-wide hiring and training (management and high skills) plans (including phasing and construction/ operation separation)

- Refined estimates of availability and price of products and by-products; marketing schemes and/or commitments

- Prior negotiations with suppliers, distributors, transport services, unions

- Commitments for sharing in the responsibility to: (1) provide additional needed public services and facilities; (2) provide in-state service industries; (3) compensate or offset potential negative environmental, economic and fiscal impacts to the State and locality; (4) provide adequate monitoring, surveillance and quality control programs

- Specific expected State and/or local contributions--land, tax incentives, below-market-price raw materials, low-cost power, etc.

ENVIRONMENTAL CHARACTERISTICS

- Volume and timing of all discharges and emissions

- Degree of dredging required (if any) and proposed disposal plans and locations

- Probable primary and secondary impacts; probable adverse effects which cannot be avoided; anticipated irretrievable commitment of resources

- Mitigation strategies - spills contingency; air pollution control; site protection; solid waste and waste water management; revegetation, reclamation and/or restoration schemes; erosion control; stream protection; etc.

- Visual impacts; potential noise and dust problems

- Adequacy (at recommended site) of soils and local geology for solid waste and sewage disposal

- Recycling and conversion schemes; energy conservation and alternative energy use strategies

MISC.

- Monitoring, surveillance and quality control strategies

- Estimates of energy efficiency of project

- Data collection and analysis plans and schedule - base line data; environmental and engineering studies; technology assessment; risk analysis; EIS preparation

- Perceived or expected external constraining factors - Federal permits, NEPA, political opposition, land claims, etc.

- Cost breakdown including: estimated capital/construction/ operating costs; training programs; public participation; studies; etc.

- Initial schedule for public inputs (on proposal and potential sites)

- Non-resident employee orientation program plans

C. PRELIMINARY SITING CRITERIA

C. PRELIMINARY SITING CRITERIA

The following preliminary siting criteria can be utilized to assist a prospective developer in: (1) locating potential sites; (2) responding to the information needs of the State:

1. Compatibility - Ensure that facility sites are compatible with existing and projected land and water uses;

2. Consolidation - Utilize existing sites and facilities that are capable of handling anticipated demand while meeting the other siting criteria;

3. Traffic - Avoid siting facilities where the most likely vehicular and/or vessel route(s) would interfere with: community activities; population centers; fishing and/or harbor operations;

4. Access - Facilities should be sited such that access to navigable waterways and recreational areas shall not be foreclosed;

5. Safety - Site fuel, crude oil and LNG storage and transfer areas: downwind from populated areas to reduce the hazard of fire and explosion to human population; at elevations sufficiently above mean sea level to escape the highest tsunami run-up;

6. Pipelines - Align pipeline routes away from active faults, areas of subsidence, glacial surge;

7. Resource Protection - Site facilities so that areas of particular historic, agricultural, scenic, recreational and unique environmental, wildlife habitat, and cultural values will be protected;

8. Site Preparation - Avoid sites where extensive site clearing, dredging and construction in productive wetlands, estuaries, deltas or other sensitive areas would be required;

9. Environmental Management - Site facilities in areas of least biological productivity, diversity and uniqueness and where effluents, emissions and spills can be controlled or contained easily;

10. Air Quality - Site facilities where the probability of chronic air quality problems would be low;

11. Water Quality/Supply - Site facilities where the probability of water quality degradation would be low and where the existing water supply would not be adversely affected;

12. Local Preference - Locate facilities where local preferences are supportive of such development.

D. Examples of State Evaluation Factors

ECONOMIC CONSIDERATIONS

AREA OF CONCERN

Impact on governmental resources and responsibilities

EVALUATION FACTORS (Examples)

- net governmental fiscal balance over time--local and state-wide (particularly revenue shortfalls)
- change in quality and quantity (per capita) of public services or goods
- long-term convertability of facilities for public or private use; potentials for concurrent use

AGENCY RESPONSIBILITY

Department of Revenue, Department of Community and Regional Affairs, Division of Budget and Management, Department of Public Works, Department of Highways

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AREA OF CONCERN

Direct contribution to local and state-wide private economy (includes changes resulting from the development itself and activities accompanying it due to expanded markets)

EVALUATION FACTORS (Examples)

- change in real per capita income and product (due to project and attendent service facility expansions)
- short- and long-run price impacts (e.g. short-run shortages of private goods or facilities; long-run private economies of scale, increased competition, changes in transportation costs)

AGENCY RESPONSIBILITY

Department of Commerce and Economic Development, Department of Revenue

ECONOMIC CONSIDERATIONS

AREA OF CONCERN

Employment

EVALUATION FACTORS (Examples)

- change in local and regional (% and #) employed, unemployed, under-employed Alaskans
- type, level and salaries of jobs
- time characteristics of jobs and their distribution (short- vs. long-term)
- level of training and Alaska hire commitment (amount of labor imported)
- degree to which manpower training dovetails with timing of employment requirements

AGENCY RESPONSIBILITY

Department of Labor, Department of Commerce and Economic Development, Department of Community and Regional Affairs

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AREA OF CONCERN

Distributional aspects and implications of the development

EVALUATION FACTORS (Examples)

- distribution of income and jobs associated with the project among groups (in-state vs. out-of-state; local vs. state-wide, current residents vs. in-migrants; Native/non-Native; income classes; sectors of the economy)
- opportunities for local (participation--investment)
- ownership of assets (in-state vs. out-of-state)
- changes in land value and ownership

AGENCY RESPONSIBILITY

Department of Community and Regional Affairs, Department of Revenue, Department of Labor, Department of Commerce and Economic Development

ECONOMIC CONSIDERATIONS

AREA OF CONCERN

Indirect or spinoff economic activities (the primary project's impact on future economic developments)

EVALUATION FACTORS (Examples)

- the possibility of related developments (either producing inputs for the production process of the primary industry or utilizing outputs of the primary industry)
- size and impact of such development (measured in ways similar to economic impact of primary industry)

AGENCY RESPONSIBILITY

Department of Commerce and Economic Development, Department of Community and Regional Affairs, Department of Revenue

SOCIAL

AREA OF CONCERN

Lifestyle changes and social conflicts

EVALUATION FACTORS (Examples)

- the potential for value conflicts between local residents and expected in-migrants
- potential for cross-cultural conflicts between local residents and expected in-migrants
- conflict with subsistence use of wildlife
- growth management capability
- degree of local control and self-determination
- impact on quality of rural lifestyle or village lifestyle amenities
- public sentiment (local and state-wide)

AGENCY RESPONSIBILITY

Department of Community and Regional Affairs, Department of Health and Social Services, Department of Education, Department of Fish and Game

COMPATIBILITY WITH PLANS, PROGRAMS AND POLICIES

AREA OF CONCERN

Natural resources and land use alternatives

EVALUATION FACTORS (Examples)

- impact on forest sustained yield
- impact on fishery resources/areas of high biologic-commercial productivity
- impact on mineral extraction (including oil and gas)
- impact on available water supply
- impact on agricultural potentials
- impact on fish and wildlife habitats/populations
- impact on recreational potentials
- impact on wilderness, historic, scenic and sensitive environmental areas
- construction material demands

AGENCY RESPONSIBILITY

Department of Natural Resources, Department of Fish & Game, Department of Environmental Conservation, Department of Commerce and Economic Development

AREA OF CONCERN

Safety and Health

EVALUATION FACTORS (Examples)

- air, water and noise pollution (degree of localization; impact on human settlements, environmentally sensitive areas, highly scenic areas)
- dust, spills, thermal discharges (same as above)
- safeguards for transport and storage of toxic and hazardous substances
- drainage pattern impacts
- adequacy of soils and local geology for solid waste and sewage disposal
- compliance with State, local, and Federal environmental standards and criteria

AGENCY RESPONSIBILITY

Department of Environmental Conservation, Department of Fish and Game, Department of Natural Resources, Department of Health and Social Services

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AREA OF CONCERN

Environmental Management

EVALUATION FACTORS (Examples)

- monitoring, surveillance and quality control strategies
- development time frame (to build up environmental protection capabilities)
- degree of commitment of irretrievable resources and/or irreversible consequences
- environmental data sufficiency
- degree of internalization of environmental costs

AGENCY RESPONSIBILITY

Department of Environmental Conservation, Department of Fish and Game

TECHNICAL CONSIDERATIONS

AREA OF CONCERN

Construction feasibility/probability of construction delays/cost overrun potentials

EVALUATION FACTORS (Examples)

. technology requirements

. data base/engineering studies sufficiency

. infringement on high hazard areas

. legal and/or regulatory constraints

. degree of consolidation/concentration of facilities

. external constraints (political, economic, logistic)

. expansion potentials

. energy efficiency of project/energy conservation measures

. use of alternative energy sources

AGENCY RESPONSIBILITY

All departments

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Permits Issued by
the Department of Environmental Conservation

1. Waste Water Disposal Permit

A person conducting any operation which results in the disposal of solid or liquid waste material into the waters or onto the lands of the State must procure a permit from the Department of Environmental Conservation before disposing of the waste material. The permit must be obtained for direct disposal and for disposal into publicly operated sewerage systems. The permit does not apply to persons discharging only domestic sewage into the sewerage system.

Procedure: Permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor. See Department of Environmental Conservation "Contacts List" in appendix.

Requirements: The Department may require the submission of plans for sewage and industrial waste disposal or treatment or both for publicly or privately owned or operated industrial establishments, community, public or private property subdivision or development.

Authority for Permit:
* AS 46.03.100. Waste disposal permit.
* AS 46.03.090. Plans for pollution disposal.
* AS 46.03.110 and 720. Waste disposal permit procedure.
* 18. AAC. 72.030. Pretreatment.

Criteria for Issuance: AAC Title 18, Chapter 70 and 72.

2. Solid Waste Disposal Permit

No person may establish, modify or operate a solid waste disposal facility without a permit, except the following:

1) a single family or duplex residence on which solid waste is generated and disposed of, on-premises;

2) a farm on which solid waste generated from the operation of that farm is disposed; and

3) incinerator facilities having a total rated capacity of less than 200 pounds of solid waste per hour.

Procedure: Permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for appropriate forms. Application for permit shall contain:

1) completed permit application forms;

2) detailed plans and specifications for facility;

3) certification of compliance with local ordinances and zoning requirements;

4) a report detailing the proposed methods for operation, population of area to be served, characteristics, quantity and source of material to be processed; and

5) 60 days public notice and public hearing.

Requirements: Detailed plans and specifications for the facility are required, as outlined above.

Authority for Permit:
* AS 46.03.020. Powers of the department.
* AS 46.03.100. Waste disposal permit.

Criteria for Issuance: AAC Title 18, Chapter 60, Solid Waste Management.

AGO 533200

3. Air Emissions Permit

A permit is required to operate a facility capable of emitting quantities of pollutants injurious to human health or welfare, animal or plant life or property.

Procudure: Applicant should contact the Department of Environmental Conservation Regional Supervisor.

Requirements: No person may construct or modify a facility requiring a permit to operate until detailed plans and specifications are submitted to the Department and approved.

Authority for Permit:
* AS 46.03.010. Declaration of policy.
* AS 46.03.140. Emission control requirements.
* AS 46.03.150. Classification and reporting.
* AS 46.03.160. Additional contaminant control measures.
* AS 46.03.170. Variances.
* 18 AAC 50.120. Permit to operate.

Citeria for Issuance:
* 18 AAC 50.020. Ambient Air Quality Standards.
* 18 AAC 50.030. Open Burning.
* 18 AAC 50.040. Incinerators.
* 18 AAC 50.050. Industrial Processes and Fuel Burning Equipment.
* 18 AAC 50.120. Permit to operate.

4. Pesticides Permit

No person may, without a permit issued by the Department, apply or cause to be applied any pesticide or broadcast chemical.

Procedure: The permit applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for the appropriate form.

Requirements: An application for a permit to use pesticides shall include information relating to the name of the pest to be controlled, the type of formulation to be used, and percentage of active ingredients, the quantity of active ingredients to be applied per unit area, and other information.

Authority for Permit:
* AS 46.03.320. Authority.
* AAC Title 18, Chaper 90. Pesticide and Broadcast Chemical Control.

Criteria for Issuance:
* AAC Title 18, Chapter 90. Pesticide and Broadcast Chemical Control.

5. Surface Oiling Permit

No person may discharge, cause to be discharged, or permit the discharge of oil, asphalt, bitumen or a residuary product of petroleum onto the lands of the State unless that person has been granted a surface oiling permit.

Procedure: Applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor for the appropriate form.

Requirements: An application for a surface oiling permit shall be made on forms prescribed by the Department and shall contain information considered necessary to the Department.

Authority for Permit:
* 18 AAC 75.010. Surface Oiling Permit.
* AS 46.03.020. Powers of the Department.
* AS 46.03.740. Oil pollution.

Criteria for Issuance:
* AAC Title 18, Chapter 75.

AGO 533203

6. Open Burning Permit

Open burning for disposal of oils, oily waters, asphalts and tars and similar wasted materials is prohibited unless conducted under a permit from the Department.

Procedure: Applicant should contact the Department of Environmental Conservation Regional Environmental Supervisor.

Requirements: Emission data may be required prior to grant of the permit.

Authority for Permit:
* AS 46.3.020. Powers of the Department.
* 18 AAC 50.030. Open Burning.
* 18 AAC 50.120. Permit to Operate.

Criteria for Issuance:
* 18 AAC 50.020. Ambient Air Quality Standards.

Permits Issued by
the Department of Fish and Game

7. Anadromous Fish Protection Permit

If a person or governmental agency desires to construct a hydraulic project, or use, divert, obstruct, pollute, or change the natural flow or bed of a specified river, lake or stream, or use wheeled, tracked, or excavating equipment or log-dragging equipment in the bed of the specified river, lake, or stream, the person or governmental agency shall notify the Department of Fish and Game before the beginning of the construction or use.

Procedure: Permit applicant should contact the Department of Fish and Game Regional Habitat Supervisor for his region. See Department of Fish and Game "Contacts List" in appendix.

Requirements: If the Commissioner of the Department of Fish and Game determines to do so, he shall require the person or government agency to submit to him full plans and specifications for the proper protection of fish and game in connection with the construction or work, or in connection with the use, and the approximate date the construction or work or use will begin, and shall require the person to obtain written approval from him as to the sufficiency of the plans and specifications before the proposed construction or use is begun.

Authority for Permit:
* AS 16.05.870. Protection of Fish and Game.
* 5 AAC 95.010. Waters important to Anadromous Fish.

Copies of the List of Waters Important to Anadromous Fish or of information contained therein may be obtained by writing the Lieutenant Governor or the Department of Fish and Game, Habitat Protection Section, Subport Building, Juneau, Alaska, 99801, or may be obtained from ADF&G Regional Habitat Supervisors.

8. Critical Habitat Areas Permit

Before the use, lease or other disposal of land under private ownership or State jurisdiction and control, within State Fish and Game critical habitat areas, the person or responsible State department or agency shall notify the Department of Fish and Game.

Procedure: The responsible person should contact the Department of Fish and Game Regional Habitat Supervisor for his region.

Requirements: If the Board of Fish and Game so determines, it shall instruct the Commissioner to require the person or governmental agency to submit full plans for the anticipated use, full plans and specifications of proposed construction work, complete plans and specifications for the proper protection of fish and game, and the approximate date when the construction work is to commence, and shall require the person or governmental agency to obtain the written approval of the Commissioner as to the sufficiency of the plans and specifications before construction is commenced.

Authority for Permit:
* AS 16.20.250. Multiple land use.
* AS 16.20.260. Submission of plans and specifications.

Criteria for Issuance:
Determination of Board of Fish and Game.

9. State Game Refuge Land Use Permit

Where the use, lease or disposal of real property in State game refuges is under the control or jurisdiction of the State, whether through Federal permit or State ownership, the responsible State department or agency shall notify the Department of Fish and Game before initiating any use, lease or disposal of real property.

Procedure: The responsible State department or agency should contact the Commissioner of the Department of Fish and Game.

Requirements: If the Commissioner so determines, he may require the person or governmental agency to submit full plans and specifications for the anticipated use, full plans and specifications of proposed construction work, complete plans and specifications for the proper protection of fish and game, and the approximate date when the construction work is to commence, and shall require the person or agency to obtain written approval of the Commissioner as to the sufficiency of the plans and specifications before construction is commenced.

Authority for Permit:
* AS 16.20.050. Multiple land use.
* AS 16.20.060. Submission of plans and specifications.

Criteria for Issuance:
Determination of the Commissioner.

10. Encroachment Permit

An encroachment may be constructed, placed, changed or maintained across or along a highway but only in accordance with regulations adopted by the Department. No encroachment may be constructed, placed, maintained or changed until it is duly authorized by a written permit issued by the Department of Highways.

Procudure: Applicant should contact the Department of Highways District Engineer for his region. See Department of Highways "Contact List" in appendix.

Requirements: During routine maintenance patrol, road and weather condition inspection, or at regular intervals as deemed necessary, maintenance personnel shall inspect right-of-way for encroachments. When an encroachment is found, District Right-of-Way will make a recommendation to the District Engineer as to whether the encroachment should be permitted or removed.

Authority for Permit:
* AS 19.25.200. Encroachment permits.

Criteria for Issuance: State of Alaska Department of Highways Standard Operating Procedure, S.O.P. #0000-14.

11. Utility Permit

An electric transmission, telephone, or telegraph line, pole line, railway, ditch, sewer, water, heat, or gas main, flume, or other structure which by law may be constructed, placed or maintained across or along a highway by a person or political subdivision may be maintained or constructed only in accordance with regulations prescribed by the Department. No utility project of this nature may be undertaken until it is authorized by a written permit issued by the Department.

Procedure: Applicant should contact the Department of Highways District Engineer in his region.

Requirements: Plans are required.

Authority for Permit:
* AS 19.25.010. Use of right-of-ways for utilities.
* 17 AAC 15.010. Application for utility permit.
* 17 AAC 15.020. Utility Permit.

Criteria for Issuance: See Alaska Administrative Code 17 AAC 15.010-020.

12. Driveway Permit

Before starting the construction of driveways or performing any work upon the right-of-way, the property owner shall first apply for and obtain a revocable permit from the Department of Highways.

Procedure: Applicant should contact the Department of Highways District Engineer for his region.

Requirements: Applicant must perform all work in accordance with permit.

Authority for Permit:
* 17 AAC 10.020. Driveways and Road Approaches.
* AS 19.05.020. Regulations.

Criteria for Issuance:
* 17 AAC 10.020. Driveways and Road Approaches.

Driveway Regulations can be obtained at Department of Highways District Offices.

13. Overweight - Oversize Permit

The Department of Highways, with respect to highways under its jurisdiction, may:

1) establish limitations on weight and load of vehicles;

2) issue special written permits authorizing the operation of overweight vehicles; and

3) prohibit the operation or impose restrictions on vehicular use of highways during certain seasons of the year.

Procedure: Applicant should contact the Department of Highways District Office for application form 14-156.

Requirements: Permits may be issued for operation of oversize-overweight vehicles when:

1) Application has been made in writing, good cause has been shown and all pertinent requirements are met;

2) The applicant has completely described his load and vehicle route and time of travel;

3) The applicant has certified that the load cannot "reasonably" be dismantled or disassembled to meet the legal load and size requirements. Disassembly may be required by the District Engineer to assure the safety of the traveling public or the highways and its appurtenances;

4) The applicant has affirmed that the vehicle or vehicles meet all requirements of the Alaska Department of Commerce and the Transportation Commission; and

5) The proposed move will not be detrimental to the public safety or damage the roadway structure or bridges as determined under State requirements.

Authority for Permit:

* AS 19.10.060. Regulation of weight and load of vehicles and use of highways during certain seasons.
* AS 28.05.020. Authority for Commissioner of Highways to adopt regulations.
* 17 AAC 25.010. Penalty and Exclusion.
* 17 AAC 25.020. Width of Vehicles.
* 17 AAC 25.030. Height and Length of Vehicles and Loads.

Criteria for Issuance: * 17 AAC 25.010-030.

Alaska Oversize and Overweight Permit Movements State of Alaska, Department of Highways, Maintenance Division, P. O. Box 1467, Juneau, Alaska, 99802.

Parks, Recreation and Public Use - Special Land Use Permits

14. Investigation and Collection Permits

A person qualified under 11 AAC 16.040 may apply to the director upon an application form provided by him for a permit to investigate or collect historic, prehistoric or archaeological resources of the State.

Procedure: Applicant should contact the Department of Natural Resources District Office. See "Contacts List" in appendix.

Requirements: Person must qualify as having some experience in anthropology or field archaeology.

Authority for Permit:
* AS 41.20.040. Division within Department of Natural Resources.
* AS 41.35.050. Regulations.
* AS 41.35.080. Permits.
* 11 AAC 16.030. Investigation and Collection Permits.

Criteria for Issuance:
* 11 AAC 16.040. Qualified Person.

15. State Park Incompatible Use Permit

Incompatible uses (e.g., mineral exploration, cutting of timber) of public lands within a State park are allowable only with a permit. Permits will be issued where it is determined that the ecology of the area will not be damaged and public use values will be protected.

Procedure: Applicant should contact the Department of Natural Resources District Office.

Requirements: Contact District Office.

Authority for Permit:
* AS 41.20.020. Duties of Department of Natural Resources.
* AS 41.20.040. Division within Department of Natural Resources.
* 11 AAC 18.010. State Park Incompatible Uses.

Criteria for Issuance:
* 11 AAC 18.010. State Park Incompatible Uses.

16. Access Routes Permit

A permit is required to gain an access route across State park land or water to privately owned property wholly or partially within a State park.

Procedure: Contact the Department of Natural Resources District Office.

Requirements: Permittee must construct access route according to specifications provided by the director.

Authority for Permit:
* AS 41.20.020. Duties of the Department of Natural Resources.
* AS 41.20.040. Division within the Department of Natural Resources.
* 11 AAC 18.020. Access Routes.

Criteria for Issuance: Determined by Director of Parks and Recreation.

AGO 533215

17. Drilling Permits

A person wishing to drill or deepen any well for oil and gas must first submit an application accompanied with a fee of $100.00, and then obtain permit.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division. See "Contacts List" in appendix.

Requirements: $100.00 fee. A survey plat must accompany the application showing the precise location of the drilling activity.

Authority for Permit:
* AC 31.05.090. Permits and fees to drill wells.
* 11 AAC 22.005. Permit to Drill or Deepen.

Criteria for Issuance:
* 11 AAC 22.005. Permit to Drill or Deepen.

18. Drilling Deviation Permit

A permit is required before a well operator may intentionally deviate from the vertical, except for the purposes of straightening the hole, side-tracking junk, or correcting mechanical difficulties.

Procedure: Contact the Department of Natural Resources - Minerals and Energy Division.

Requirements: Application for permit shall include:

1) surface and proposed producing interval locations in terms of distances from lease and section boundaries;

2) reason for deviation;

3) list of affected operators and a showing that each has been furnished a copy of the application by certified mail, or a showing that the applicant is the only affected operator; and

4) neat and accurate plat of lease and all affected operators and the surface and proposed producing interval locations as well.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.050. Deviation.

Criteria for Issuance:
* 11 AAC 22.050. Deviation.

19. Well Spacing Permit

A person must apply for and receive an exception to the well spacing regulations before deviation from the regulations is allowed.

Procedure: Permit applicant should contact the Department of Natural Resources Minerals and Energy Division.

Requirements: An application must indicate the affected operators, and include a plat of the proposed action.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.055. Well Spacing.

Criteria for Issuance:
* 11 AAC 22.055. Well Spacing.

20. Notice of Abandonment

Before beginning work on any well, notice of intention to abandon must be filed, and approval must be given.

Procedure: Person should contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Notice must show the reason for abandonment and must be accompanied by a detailed statement of proposed work including such information as kind, location, size of plugs, and plans for mudding, etc.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.100. Notice.

Criteria for Issuance:
* 11 AAC 22.100. Notice.

21. Plugging Procedure

To deviate from the plugging procedure set up in the regulations, approval upon application must be obtained.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Follow procedures outlined in 11 AAC 22.110., Plugging Procedures.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.110. Plugging Procedure.

Criteria for Issuance:
* 11 AAC 22.110. Plugging Procedure.

22. Well Marker

In order to waive well marker requirements, the surface owner must request and receive approval.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and Duties of the Department.
* 11 AAC 22.120. Well Marker.

23. Water Wells

Written authority for a well to be used as a fresh water well must be applied for and approved.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.140. Water Wells.

24. Temporary Abandonment

Approval is required if a well is to be temporarily abandoned.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: If approved, a plug must be placed at the top and bottom of the well casing in such a manner as to prevent the intrusion of any foreign matter into the well. The well shall be left full of mud.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.150. Temporary Abandonment.

25. Location Cleanup

Time extension must be obtained for the well operator to deviate from the cleanup regulations.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.170. Location Cleanup.

26. Multiple Completion of Wells

No well may be put into multiple production without approval.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Approval will require evidence of adequate and complete separation as ascertained by pressure or circulation tests.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.210. Multiple Completion of Wells.

27. Commingling of Production

An order approving commingling in the same well bore of production from two or more wells must be obtained before such practice is permitted.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Proposing operator must certify that contact has been made with the affected parties and no opposition is furnished to committee within 15 days.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.215. Commingling of Production.

28. <u>Earthen Reservoirs</u>

Permission must be obtained to store oil in earthen pits.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact Minerals and Energy Division.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.220. Earthen Reservoirs.

29. Disposal of Brine and Other Wastes

Permission is required for the disposal of salt water.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: It must be shown that the disposal of salt water will not contaminate fresh water or endanger other natural resources.

Authority for Permit:
* AS 31.05.030. Powers and duties of the Department.
* 11 AAC 22.250. Disposal of Brine and Other Wastes.

Note: The items listed under the above heading involve the need for administrative approvals and orders from the Oil and Gas Conservation Committee. These approvals on various well operations are, in effect, permits to do various types of work once a well is completed or to abandon a well. However, the forms and procedures do not bear the title permit.

Oil and Gas - Plan of Operations

30. Additional Recovery Methods

A permit is required for any method of pressure maintenance or methods of additional recovery used other than primary recovery techniques.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Application must contain a plat showing the unit, lease or group of leases within the proposal project, along with other related information.

Authority for Permit:
* AS 31.05.020. Waste Prohibited.
* 11 AAC 22.400. Application.

31. Development Work

No development work shall be done on coal deposits on State lands without the advance approval of the State geologist.

Procedure: Contact the Department of Natural Resources - Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Division.

Authority for Permit:
* AS 27.20.005. Purposes.
* AS 27.20.010. Rules and Regulations.
* 11 AAC 46.010. Advance Approval.

32. Right-of-Way or Easement Permit

The Division of Lands Director may issue permits for roads, trails, ditches, pipelines, drill sites, log storage, telephone and transmission lines or similar uses or improvements.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Plats are required, as well as an application fee.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.075. Leasing procedures.
* AS 38.05.330. Permits.
* 11 AAC 58.200. Right-of-Way or Easement Permit.

33. Special Land Use Permit

The Director of the Division of Lands may issue special land use permits on such terms and conditions as he deems to be in the interests of Alaska.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Provide information as to the nature of the proposed activity.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.075. Leasing procedures.
* 11 AAC 58.210. Special Land Use Permit.

34. Tidelands Permit

The Director of the Division of Lands may issue permits for the improvement or use of State-owned tidelands, or for personal use of materials. The first preference in the granting of such permits will be granted to the upland owner over other nonpreference applicants for the use of tideland and contiguous submerged land seaward of the upland property.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: A $20.00 filing fee is required. Upon receipt of the application, the Director shall, within 60 days, express his approval or disapproval, and shall state his reasons. Each upland owner may protest the issuance of the permit. No permits shall be issued that will deny the upland owner reasonable access to tide waters during the course of or completion of the work.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.320. Occupied tidelands and submerged lands.
* 11 AAC 62.710. Tidelands Permits.

Criteria for Issuance:
* 11 AAC 62.720. Application for Tideland Permits.

35. Tideland Right-of-Way and/or Easement Permits

Permits may be issued by the Division of Lands Director for secondary roads, trails, ditches, pipelines, telephone transmission lines, log storage, oil well drilling sites, and production facilities for the purposes of recovering minerals from adjacent lands under valid lease and other similar uses or improvements. First preference shall be granted to the upland owner.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: An applicant must furnish the name and address of the upland owner.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.320. Occupied Tidelands and submerged lands.
* 11 AAC 62.810. Tidelands Right-of-Way and/or Easement Permits.

Criteria for Issuance:
* 11 AAC 62.810. Tideland Right-of-Way and/or Easement Permits.

36. Limited Personal Use Permit

Permits may be granted for a limited quantity of materials for personal use, and such materials shall not be sold. The director shall, in each permit, specify the quantity of material allowed but in no event shall the quantity exceed 100 cubic yards. The permits are for temporary use only.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authorities and duties of the Commissioner.
* AS 38.05.320. Occupied Tidelands and submerged lands.
* 11 AAC 62.820. Limited Personal Use Permit.

37. Permit to Appropriate Water

Any person who desires to appropriate otherwise unappropriated waters of the State shall make application for a permit to appropriate water.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: An application for a permit to appropriate water shall include:

1) location of source from which water is to be appropriated;

2) place where the appropriated water will be of beneficial use;

3) quantity of water to be appropriated;

4) proposed use of water to be appropriated; and

5) description of the proposed means of diversion.

Authority for Permit:
* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.050. Application for Permit to Appropriate.

38. Dam Construction

An application for a permit to appropriate water must include plans and specifications for any dam that may be built.

Procedure: Applicant must contact the nearest District Office of the Department of Natural Resources.

Requirements: Plans are required. If necessary, the Director may request that the applicant obtain an independent appraisal of the plans and specifications from a qualified engineer acceptable to the Director.

Authority for Permit:
* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.060. Dam Construction.

39. Application for Preferred Use

The holder of a preferred use status may make an application for a permit to appropriate either unappropriated or previously unappropriated waters or both.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: A $20.00 filing fee is required. The applicant must provide the names and addresses of all holders of existing water rights, permits to appropriate or certificates of appropriation whose rights to water would be reduced, or in times of water scarcity, could be reduced by the diversion of water to the preferred use. Also required are certified copies of executed agreements between the holder of preferred use status and all other persons names as required to provide compensation for loss of previously appropriated water, or certified copies of any court orders which direct the amount and manner of compensation paid.

Authority for Permit:
* AS 46.15.040. Right to appropriate.
* AS 46.15.060. Existing rights.
* AS 46.15.070. Notices; objections.
* AS 46.15.135. Determination of existing rights.
* AS 46.15.180. Crimes.
* 11 AAC 72.160. Application for Preferred Use.

40. Use of Timber and Materials

Gravel, sand, and rock used by a purchaser in connection with a sale of timber may be acquired under a special permit issued in connection with the timber sale.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authorities and duties of the Commissioner.
* AS 38.05.110. Sale of timber and materials.
* AS 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.185. Use of Timber and Materials.

41. Authorization for Transportation Facilities

Timber purchasers must obtain a permit for use of tidelands under State jurisdiction which are necessary for dumping, sorting, storage and rafting of timber cut from State sales.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Location and design of roads or access will be approved by the Director prior to construction.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.110. Sale of timber and materials.
* As 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.205. Authorization for Transportation Facilities.

42. Special Material Use Permit

The Director may issue special material use permits for periods not to exceed one year upon such terms and conditions as he deems to be in the interest of the State.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.115. Limitations and conditions of sale.
* AS 38.05.120. Disposal procedure.
* 11 AAC 76.540. Special Material Use Permit.

43. Noncompetitive Procedures

Applications for noncompetitive leases on permits for a mineral may be filed on any noncompetitive lands opened for leasing of that mineral.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.135. Generally.
* AS 38.05.145. Leasing Procedure.

44. Coal Prospecting Permit

A permit is required for prospecting or exploration work necessary to determine the existence of coal deposits in an unclaimed and undeveloped area. The permit is for a period of two years, and not to exceed 5,120 acres.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.035. Powers and duties of the Director.
* AS 38.05.145. Leasing procedure.
* AS 38.05.150. Coal.
* 11 AAC 84.115. Prospecting Permits Operations.

45. Sodium Leasing Method

Prospecting permits for lands not known to contain valuable deposits of sodium are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 30.05.145. Leasing procedure.
* 11 AAC 84.400. Sodium Leasing Method.

46. Potassium Leasing Method

Prospecting permits authorized for lands not known to contain valuable deposits of potassium compounds are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.145. Leasing procedure.
* 11 AAC 84.600. Potassium Leasing Method.

47. Geothermal Resources Leasing Method

Prospecting permits authorized for lands which have not been classified as geothermal resources areas are issued noncompetitively.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.145. Leasing procedure.
* 11 AAC 84.700. Geothermal Resources Leasing Method.

Land and Waters - Offshore Permits

48. Tide and Submerged Lands

The exclusive right to prospect for deposits of minerals in or on tide and submerged lands may be granted by the Director of the Division of Lands.

Prodecure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Applicant must meet qualifications outlined in AS 38.05.190.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.250. Tide and submerged lands.
* 11 AAC 86.500; 510; 530; and 540. Permit Applications, Acceptable Permit Work, Conversion of an Offshore Prospecting Permit to a Mining Lease, and Lease Rental.

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49. Surface Use Permits

A permit is required for millsite and tailings removal.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: A reasonable rate or fee schedule shall be charged for such use.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.255. Surface use.
* 11 AAC 86.600. Millsites.

50. Burning Permit

A burning permit is required during the fire season for the burning of any materials in the area designated by the Department of Natural Resources.

Procedure: Applicant should contact the nearest District Office of the Department of Natural Resources.

Requirements: The applicant shall provide information as to the type, location, size and person in charge of the burning; the area and material to be burned; and the number of persons controlling the burn. Prior to the issuance of the permit, an inspection may be required of the area to be burned.

Authority for Permit:
* AS 41.15.050. Fire Season.
* 11 AAC 92.010. Permit.

51. Operations on State Land Requiring Permits

A permit is required for the following activities on State lands: 1) activity requiring; a) the use of explosives; b) the use of hydraulic prospecting or mining equipment and/or methods; c) drilling to a depth in excess of 300 feet; and (2) activity which the Director of the Division of Lands determines may result in harm to lands having special scenic, historic, archaeological, scientific, biological, recreational or special resource value.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit:
* AS 38.05.020. Authority and duties of the Commissioner.
* AS 38.05.035. Powers and duties of the Director.
* 11 AAC 96.010. Operations Requiring permits.

52. <u>Subleases of State Land</u>

A permit is required from the Director of the Division of Lands prior to the sublease or assignment of any portion of State-leased land.

<u>Procedure</u>: Contact the nearest District Office of the Department of Natural Resources.

<u>Requirements</u>: Contact the District Office.

<u>Authority for Permit</u>:
* AS 38.05.095. Subleases.

53. Right-of-Way Permits

The Director of the Division of Lands may issue permits, right-of-ways or easements on State land for secondary roads, trails, ditches, transmission lines and distribution pipelines, field-gathering lines, telephone and transmission lines, log storage, oil well drilling sites, and production facilities for the purposes of recovering minerals from adjacent lands under valid lease, and other similar uses or improvements for the limited use or timber or materials.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permits
* AS 38.05.330. Permits.

54. Abandonment of or Reduction or Impairment of Service of Pipeline by Leasee Carrier.

No leasee may abandon or reduce or impair service of any portion of a pipeline that is on State land or subject to lease without first receiving a certificate from the Commissioner that the action is in accordance with the terms of the lease.

Procedure: Contact the Department of Natural Resources Minerals and Energy Division.

Requirements: Contact the Minerals and Energy Divison.

Authority for Permit:
* AS 38.35.030. Abandonment of, or reduction or impairment of, service of pipeline by leasee carrier.

55. Applications for Right-of-Way Leases and Certificates

Persons desiring to own a pipeline which is proposed to be located in whole or in part on State land shall apply for a noncompetitive right-of-way lease of this land and a certificate that the construction, operation, transportation, service, or sale is in accordance with the lease.

Procedure: Contact the nearest District Office of the Department of Natural Resources.

Requirements: Contact the District Office.

Authority for Permit
* AS 38.35.050. Applications for right-of-way leases and certificates.

56. Preservation of Archaeological Resources

If the State archaeologist determines that archaeological sites or remains will be adversely affected by public construction, the project cannot commence until the State archaeologist performs necessary investigations.

Procedure: Contact the Division of Parks and Recreation.

Requirements: Contact the Division of Parks and Recreation.

Authority for Permit:
* AS 41.35.070. Perservation of historic, prehistoric, and archaeological resources threatened by construction.

Department of Environmental Conservation Contacts List

Central Office
Department of Environmental
Conservation
Pouch O
Juneau, Alaska 99811

Northern Regional Office

Doug Lowery
Regional Environmental Supervisor
Department of Environmental
Conservation
P. O. Box 1601
675 Seventh Avenue
Fairbanks, Alaska 99707

Phone: 452-1714

Southcentral Regional Office

Kyle Cherry
Regional Environmental Supervisor
Department of Environmental
Conservation
Rm. 1206, MacKay Building
338 Denali Street
Anchorage, Alaska 99501

Phone: 274-5527

Prince William Sound Regional Office

Randy Bayliss
Regional Environmental Supervisor
Department of Environmental
Conservation
Pouch E
Valdez, Alaska 99686

Phone: 835-4698

Southeast Regional Office

Deena Henkins
Regional Environmental Supervisor
Department of Environmental
Conservation
Pouch OA (Mayflower Building, Dougla
Juneau, Alaska 99811

Phone: 364-2165

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Department of Fish and Game Contacts List

Region I

Rick Reed
Regional Supervisor
Habitat Protection Section
Department of Fish and Game
210 Ferry Way
Juneau, Alaska 99801

Phone: 586-6630

Region II

Tom Trent
Habitat Protection Section
Department of Fish and Game
333 Raspberry Road
Anchorage, Alaska 99502

Phone: 344-0541

Region III

J. Scott Grundy
Regional Supervisor
Habitat Protection Section
Department of Fish and Game
1300 College Road
Fairbanks, Alaska 99701

Phone: 452-1531

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Department of Highways Contacts List

District Engineers

Southeastern - Region III

Wallace K. Williams
Southeastern District Engineer
Department of Highways
6860 Glacier Highway
P. O. Box 3-1000
Juneau, Alaska 99802

Phone: 789-0841

Central - Region I

Jack M. Spake
Central District Engineer
Department of Highways
5700 Tudor Road
P. O. Box 6750
Anchorage, Alaska 99502

Phone: 337-1511

Interior - Region II

H. Woodrow Johansen
Interior District Engineer
Department of Highways
2301 Peger Road
Fairbanks, Alaska 99701

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Southcentral - Region V

Rowe D. Redick
Southcentral District Engineer
Department of Highways
P. O. Box 507
Valdez, Alaska 99686

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Western - Region IV

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Nome, Alaska 99762

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Department of Highways Contacts List

Overweight-Oversize Permit Contacts

Central - Region I

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Southeastern - Region III

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Juneau, Alaska 99802

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Western - Region IV

Ron Davena
Department of Highways
P. O. Box 220
Nome, Alaska 99762

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Southcentral - Region V

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Valdez, Alaska 99686

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Department of Natural Resources Contact List

Southeast Land District Office

Henry Lee Hall
Division of Lands
Department of Natural Resources
Pouch M
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Southcentral Land District Office

Lawrence A. Dutton
Division of Lands
Department of Natural Resources
323 East Fourth Avenue
Anchorage, Alaska 99501

Phone: 279-5577

Northcentral Land District Office

William Copeland
Department of Natural Resources
State Office Building
Room 116
Fairbanks, Alaska 99701

Phone: 479-2243

Department of Natural Resources Minerals and Energy Division

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323 East Fourth Avenue
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Phone: 274-8542

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