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#21:31

United States Senate

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C. 20510

October 24, 1977

MEMORANDUM

TO: Members, Committee on Energy and Natural Resources

FROM: Henry M. Jackson, Chairman

RE: October 25 Hearing on the President's Recommendation to Designate the Alcan Pipeline Project for Approval

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On October 12 the Committee received testimony from Dr. Todd Doscher of the University of Southern California that production of natural gas from the Prudhoe Bay field could have a significant adverse effect upon the amount of oil that would be ultimately recovered.

In response to Dr. Doscher's testimony, the Committee has requested the State of Alaska and the three largest Prudhoe Bay producers to testify on his findings at tomorrow's hearing. Dr. Doscher will also testify.

Prior to the hearing I requested the staff to conduct a review of the studies available to the public on the Prudhoe Bay production potential. Four studies of the field were reviewed.

The first, which was done for Arctic Gas, was by DeGolyer-McNaughton. It estimated oil and gas production potential but showed no basis for those estimates.

The second, which was done for the Interior Department, was by Gruy Associates. It was a discounted cash flow analysis predicting the amount of production that would result from various oil and gas prices.

The third, which was done for the State of Alaska, was by Van Poollen and Associates. It used a computer to simulate the field's behavior to predict detailed reservoir behavior.

The fourth, which was done for Northwest Pipeline, Inc. (Alcan), was by Core Laboratories. It was also a computer simulation of the field's behavior.

The staff was assisted in its review by two members of the staff of the General Accounting Office. The GAO staff members who assisted the project are Dr. Tom Woods, a physicist with expertise in petroleum production forecatsing, and Mr. Bob Finney, a petroleum engineer from the GAO's Houston, Texas, field office. Their findings are enclosed for your use.

Questions concerning the hearing should be directed to George Dowd (ext. 4-2564) or to Betsy Moler (ext. 4-0611) of the Committee staff.

FINDINGS

1. We cannot evaluate Operators and D & M due to a paucity of information contained in the reports.

2. While we cannot describe the Operators and the D & M field simulations, we would conclude that of those we could, Gruy, Core and VanPoollen essentially simulate the operations of different fields although all 3 claim to utilize VanPoollen data. We find these anomalies in the following areas.

a. The water drives in all three simulations are significantly different with the VanPoollen simulation having the weakest aquifer and Gruy the strongest.

b. Both Gruy and Core only describe the Sadlerochit field and exclude considerations of hydrocarbons located elsewhere. VanPoollen posits a link between the gas cap in the Shublik formation.

c. Core indicates that for the same field parameters, the existance of an aquifer increases oil recoverability VanPoollen indicates the opposite, although the effect is small.

d. The production profiles on a yearly basis with and without aquifers are significantly different for Van Poollen and Core.

e. Similarly oil production profiles with gas sales show that the Sadlerochit field as simulated by VanPoollen does not agree with that as simulated by Core.

f. We have found the estimates of oil-in-place and gas-in-place to be inconsistent among the studies and in the case of the operator study, internally inconsistent.

g. We find no consistency, however, between the studies and the published API reserve figures as of 31 December 1976.

3. Despite these differences all 5 studies indicate either a maximum oil recovery of about 8.4 million barrels or 42.8 percent recovery of oil-in-place.

4. Production of gas from Sadlerochit requires gas cap production early on in the productive life. At 2.4 bcf a day, the capacity of the Alcan pipeline, this would require production of oil significantly above the current 1.2 million barrel a day capacity of the TAPS to avoid excessive gas cap production.

5. All studies agree without gas re-injection, and some type of water re-pressuring, there would be significant deterioration in the recovery of oil and gas.

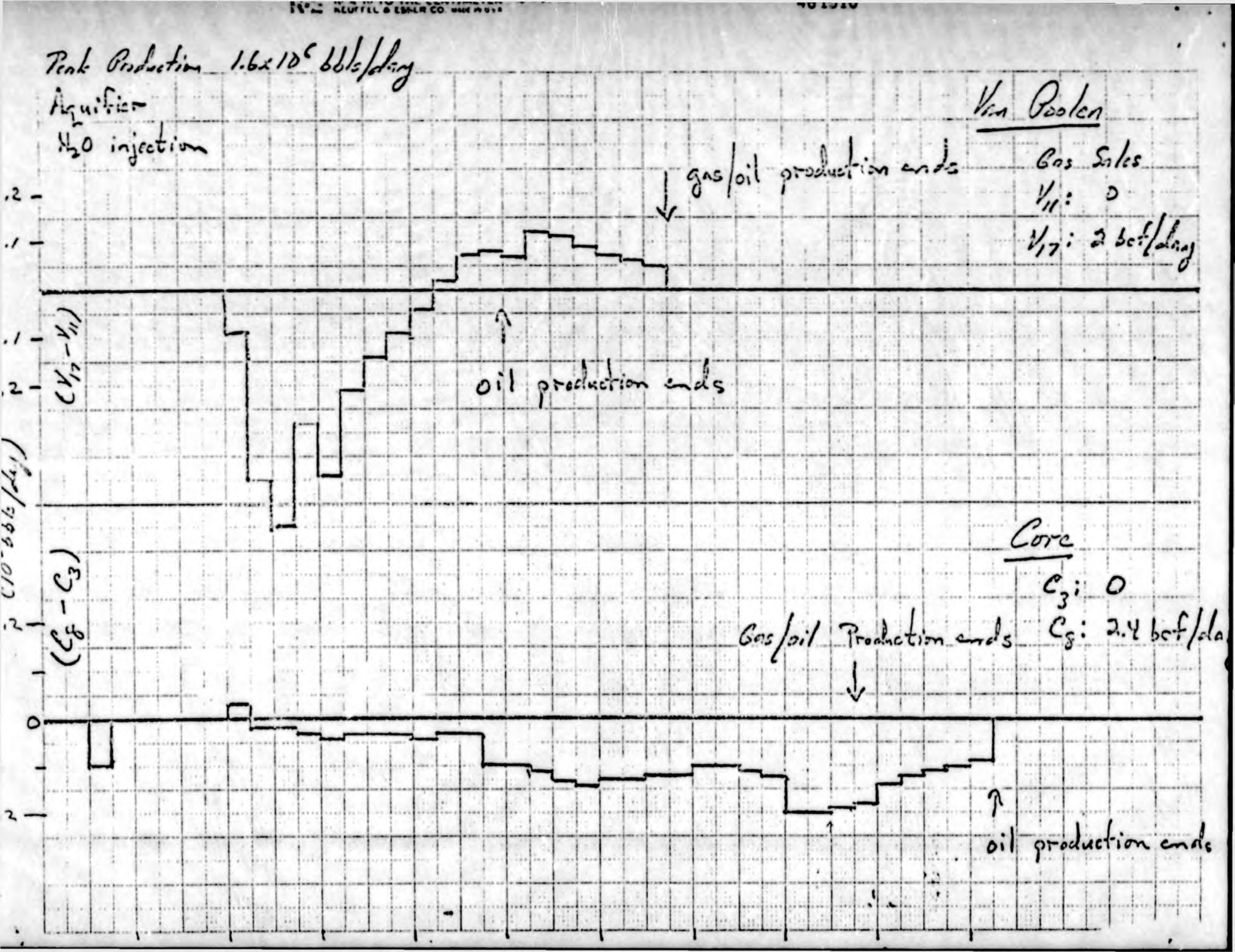
6. We find that none of the studies addressed natural gas liquids which at 1.45 gal/Mcf of gas and 2.4 bcf per day pipeline throughput results in almost 100,000 barrels a day of n.g.l.

7. We find that the production profiles in the Van Poollen and Core studies are markedly different. (Note: The attached graph shows the amount that oil production is likely to increase or decrease in a given year with 2.0 billion cubic feet of gas sales per day for Van Poollen and 2.4 bcf/d for Core.)

CONCLUSION

At this point we cannot ascertain the overall effect of gas production and sales on the ultimate recovery of oil from the Sadlerochit reservoir.

Thomas J. [illegible], Physicist, GAO
Robert E. [illegible], Petroleum Engineer, GAO



Peak Production 1.6x10^6 bbls/day
Aquifier
H2O injection
Van Poolen
Gas Sales
V11: 0
V17: 2 bcf/day
gas/oil production ends
oil production ends
(V17 - V11)
(10^6 bbls/day)
(C8 - C3)
Core
C3: 0
C8: 2.4 bcf/da
Gas/oil Production ends
oil production ends
.2
.1
.1
.2
.2
0
.2

STATE OF ALASKA
THE LEGISLATURE
LEGISLATIVE AFFAIRS AGENCY

POUCH Y · STATE CAPITOL
JUNEAU, ALASKA 99811
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October 19, 1977

The Honorable Henry M. Jackson, Chairman
Committee on Energy and Natural Resources
U.S. Senate
Washington, D.C.

Dear Senator Jackson:

Enclosed herewith is a copy of the report by Professors Doscher and Dougherty which you requested in your telegram of October 12th. Senator Chancy Croft, the legislator responsible for the contract under which this draft report was prepared, has authorized its release to you on the condition that it be considered an internal U.S. Senate document and that its use be restricted to senators and senate staff until 12:00 noon Alaska daylight time, October 20, 1977. This will provide Senator Croft time to distribute the report to the appropriate legislators here in Alaska. We trust this condition will not present you with any difficulties.

Please note that this is a draft, albeit a second one, and that it does not necessarily represent the views of the Alaska State Legislature or the Legislative Affairs Agency. We contemplate that the report will be prepared in final form later this month or early in November, and will make a copy available to you at that time.

Warmest regards,

Gregg

Gregg K. Erickson
Director of Research

Enclosure
cc: The Honorable Chancy Croft
GKE:dh

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(213) 654-2565

delivered on 11/25/77

At the time I was requested to appear before you on October 12, I informed you that my professional attention, and that of my colleague, Dr. Elmer Dougherty, Jr., was brought to bear on the Prudhoe Bay Oil Field because we were retained by the Legislative Affairs Agency of the State of Alaska to assess the operating plans that were submitted to the State's Division of Oil and Gas.

You are apparently here concerned with one of the conclusions which we reached in that study. We believe it is necessary for you to assess this one conclusion concerning gas sales within the total framework of our study.

Our overall conclusion is that studies prepared by the operators of the field, and those prepared on behalf of the Division of Oil and Gas as well as those prepared by still other groups have not been juxtaposed, scrutinized and challenged well enough for an unequivocal decision to be reached at this time as to what is the best operating plan for Prudhoe Bay. Certainly not to the extent as I and my colleague would have done had we been given the responsibility to do so.

Of course, a definition must be given to "the best" operating plan. The best may be variously defined as the best for maximizing the immediate flow of royalties and taxes to the state, or for maximizing the profitability of the operators, or for maximizing the recovery of crude oil, or a maximum flow of benefits to the people of Alaska.

Our studies explicitly used these two yardsticks for defining best: the maximum recovery of crude oil, and the maximum flow of benefits to the state. We were retained by the State of Alaska.

It is always a goal of the reservoir engineer to maximize the recovery of crude oil. At this time the need for attaining such a goal is intensified by the fact that our nation's access to supplies of crude oil is sorely limited and the limitation increases daily. The National Petroleum Council's prediction of future supplies of crude oil in the absence of Prudhoe Bay and new discoveries is shown in their Figure 5 of their December 1976 study. America's supplies will have dwindled to less than 1.5 million barrels a day by 1990, and even with Prudhoe Bay will be only 2. million barrels a day. Compare this with the 8 million or so we produced last year and the 20 million barrels we burned each and every day. It will be a stroke of sheer luck to be able to double this rate by successful exploration and enhanced recovery. A Prudhoe Bay discovered every other year would just keep our supplies constant if we could continue to import oil.

We must also look forward to severe limitations with the coming decade of our ability to import crude oil. The oil in the subsurface

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of the mid-East is limited too by nature, and production will surely peak within the decade ahead. Our basic yardstick therefore of assessing whether the proposed operating plans for Prudhoe Bay will maximize the recovery of crude oil is well justified. We concluded that the evidence for the claim that gas sales from Prudhoe Bay would not interfere with maximizing crude oil production is weak. We believe the evidence for reaching such a decision will not be available for several years during which time reservoir surveillance will provide the required data.

It is to be noted that the Prudhoe Bay field is so large that a mere 1 percent difference in recovery efficiency amounts to a volume of oil that is produced from some very large oil fields. So large, in fact, that less than a handful have been discovered in the United States since 1960. Whereas in former times one could be sanguine about sacrificing a percentage point in recovery efficiency for greater convenience, a smaller investment, or somewhat higher profitability, the same standards can no longer be applied.

Further, by conventional technology some twelve billion barrels of crude oil will not be recovered from Prudhoe Bay. It is folly to adopt an operating plan that doesn't consider the possible effect of such a plan on the potential implication of tertiary recovery processes that may succeed in capturing some of that twelve billion barrels of oil that will remain in the largest reservoir ever to have been discovered within the United States.

So much for our first yardstick.

Now for the second: the maximum flow of benefits to the State of Alaska. We concluded that this matter had not been given the attention it merits. We do not believe the sale of gas is in the best interests of the State or the nation; that is, the sale of gas now envisioned.

It will be impossible to sell more than two billion cubic feet of gas a day without seriously hurting the crude oil recovery even using the optimistic analysis of the operators therefor. It will be impossible to envision selling more than this short of the immediate implementation of a water flood that would balance withdrawals of gas and liquids. There are no plans for doing so. A daily sale of two billion cubic feet a day through a pipe line that might well represent an investment of 25 billion dollars, which we have observed in the literature, will require a transportation tariff of some $5 per thousand. This in itself, the transporation cost, is so much greater than current pipe line delivered costs for natural gas, and so much greater than those envisioned by any proponents of deregulation that the well head price of the gas itself will be pushed back to marginal values. The State will reap but a fraction of the value of the gas.

There is also a major question as to whether the gas will be marketable, on the proposed schedule, unless the price of all other gas supplies are raised to its equivalence.

The State would gain much more from their resources by ultimately converting a significant amount of the gas to lqiuid fuels, alcohols,

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and petrochemicals. The State could envision starting gas movements in the present crude oil line within fifteen to twenty years. The Prudhoe Bay reservoir is a short lived reservoir. Within eight years, oil production will start a precipitous decline, when our needs for additional liquid fuels will be verging on the desperate, and within fifteen years its potential will be less than 500,000 barrels a day.

The State could envision a long future of profitable and valuable utilization of its gas resources for over a century, particularly if such use is combined with utilization of its coal resources, should it not consent at this time to gas sales. The nation would be little the worse for not having the Prudhoe Bay gas available for immediate burning. It will amount to less than 5% of current consumption. An equivalent amount of gas could probably be made available from other sources, far cheaper and within the same time framework, if exploration and production of marginal sources were promoted by trivial increases in regulated prices. This would be true for a decade or two, but for longer periods of time you must address more fundamental issues.

I will close by bringing to your attention that it was more than Americans' know-how, more than their vim and vigor, more than their pursuit of free enterprise and freedoms that made America what it is. It was cheap and abundant sources of energy. Without the latter, America would not be America. We no longer have cheap and abundant sources of energy. We no longer have yesterday's potential. I implore you to take this into account when you deliberate on matters concerning the future of our nation.

TESTIMONY OF O. K. GILBRETH, JR.
DIRECTOR, DIVISION OF OIL AND GAS CONSERVATION
DEPARTMENT OF NATURAL RESOURCES, STATE OF ALASKA

BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C.
OCTOBER 25, 1977

MR. CHAIRMAN, OTHER DISTINGUISHED SENATORS, LADIES AND GENTLEMEN. MY NAME IS O.K. GILBRETH, JR. AND I AM DIRECTOR OF THE STATE OF ALASKA'S DIVISION OF OIL AND GAS CONSERVATION IN THE DEPARTMENT OF NATURAL RESOURCES AND CHAIRMAN OF ITS OIL AND GAS CONSERVATION COMMITTEE. WITH ME TODAY IS MR. HOYLE HAMILTON, OUR CHIEF PETROLEUM ENGINEER, WHO IS ALSO A MEMBER OF THE OIL AND GAS CONSERVATION COMMITTEE, DR. H. K. VAN POOLLEN, PRESIDENT OF H. K. VAN POOLLEN AND ASSOCIATES, WHO IS A CONSULTANT FOR THE STATE, AND ROBERT H. LOEFFLER, WHO HAS BEEN COUNSEL TO THE STATE IN THE GAS PIPELINE PROCEEDINGS.

MY PRIMARY RESPONSIBILITY AS DIRECTOR OF THE STATE DIVISION OF OIL AND GAS CONSERVATION IS TO REGULATE OIL AND GAS INDUSTRY OPERATIONS TO PREVENT THE PHYSICAL WASTE OF OIL AND GAS IN THE STATE AND TO PROTECT THE CORRELATIVE RIGHTS OF ALL INTERESTS IN AN OIL AND GAS FIELD. OUR GOAL IS TO REGULATE PRODUCTION IN A MANNER WHICH WILL INSURE THAT MAXIMUM RECOVERY OF HYDROCARBONS IS ACHIEVED AND PHYSICAL WASTE IS AVOIDED. AT THE OUTSET I WISH TO EMPHASIZE THAT WE DO NOT SET THE RATE OF PRODUCTION OF EITHER OIL OR NATURAL GAS SO LONG AS IT DOES NOT CREATE WASTE.

EARLIER THIS YEAR THE OPERATORS REQUESTED APPROVAL OF THE OIL AND GAS CONSERVATION COMMITTEE OF THEIR PLAN TO OPERATE THE PRUDHOE BAY FIELD. ON MAY 5, 1977, WE HELD A PUBLIC HEARING ON THIS PLAN, INCLUDING A REVIEW OF THE PROPER INITIAL RATES OF PRODUCTION. AS A RESULT OF THAT HEARING, CONSERVATION ORDER NO. 145 WAS ISSUED BY THE OIL AND GAS CONSERVATION COMMITTEE. THE ORDER CONTAINS MANY REQUIREMENTS TO SECURE DATA DURING START-UP AND THE INITIAL PRODUCTION PERIODS TO AID IN DETERMINING PROPER METHODS OF OPERATION OF THIS RESERVOIR. COPIES OF THE ORDER ARE ATTACHED TO MY PREPARED STATEMENT.

1. <u>THE PLAN OF OPERATIONS</u>: THE PROPOSED PLAN OF OPERATIONS PROVIDES INITIAL PRODUCTION RATES OF 0.6 MILLION BARRELS PER DAY FOR SIX MONTHS, 1.2 MILLION BARRELS PER DAY FOR APPROXIMATELY TWELVE MONTHS AND THEN A RATE OF APPROXIMATELY 1.5 TO 1.6 MILLION BARRELS A DAY UNTIL PRODUCTION DECLINE IS REACHED. THE PLAN PROVIDES FOR GAS PIPELINE DELIVERIES OF 2.0 BCF/D AS SOON AS GAS PIPELINE FACILITIES ARE AVAILABLE AND A CONDITIONING PLANT CAN BE APPROVED AND CONSTRUCTED. THE PLAN ALSO CONTEMPLATES SELECTIVE INJECTION OF <u>PRODUCED</u> WATER INTO THE PRUDHOE OIL POOL WHEN THOSE VOLUMES BECOME SIGNIFICANT. ALTHOUGH A FINAL COMMITTMENT IS NOT MADE, THE PLAN ANTICIPATES THAT WATER INJECTION FROM SOURCES OUTSIDE THE POOL WILL BE INITIATED WITHIN FIVE TO NINE YEARS AFTER THE START OF OIL PRODUCTION.

Order No. 145 tentatively approves offtake rates of 1.5 million b/d of oil and 2/7 bcf/d of gas (which will yield 2.0 bcf/d for sales) subject to revision as production and reservoir data are obtained and analyzed.

2. Possible Rates of Withdrawal: Our reports studied gas withdrawal rates of two (2) to five (5) billion cubic feet per day (i.e., gas sales of 1.5 to 3.75 Bcf/Day), correlated with oil production between 1.2 to 1.8 million barrels per day. We also studied oil recovery with no gas sales.

Our study shows us that the Prudhoe Bay Reservoir will be rate sensitve. By this we mean that the ultimate oil recovery from the reservoir would be affected by the net withdrawals from the reservoir and in some cases even by the rate of withdrawal. If oil, gas and water are removed without their reservoir volume being at least partially replaced, a reduction in oil recovery will result. If the reservoir voidage caused by production is replaced, then recoveries will be increased and can be maximized by the volume injected. Accordingly, we believe that fluids must be injected into the reservoir to supplement the natural recovery mechanism and that reservoir performance must be monitored closely and withdrawals controlled to achieve the maximum oil recovery. The level of gas sales will be determined by the volume of fluids injected.

If fluids are not returned to the reservoir, our study indicates that the greater the gas sales rates, the greater is the loss in ultimate oil recovery. If gas sales

ARE KEPT AT A CONSTANT RATE OF TWO BILLION CUBIC FEET PER DAY, THERE WILL BE AN INCREASE IN OIL RECOVERY WITH WATER INJECTION. AS A PRACTICAL MATTER, IT MAY NOT BE POSSIBLE TO INJECT ENOUGH FLUIDS TO PERMIT SUSTAINED SALES RATES VERY MUCH IN EXCESS OF TWO BILLION CUBIC FEET PER DAY. EARLY START OF WATER INJECTION WILL GIVE A SLIGHTLY HIGHER OIL RECOVERY THAN A DELAY OF SEVERAL YEARS, BUT THE ADVANTAGE IS SLIGHT.

3. SUCCESSFUL INJECTION PROGRAMS: ONCE THE PRUDHOE BAY RESERVOIR IS PRODUCING AT A NORMAL RATE, IT WILL BE NECESSARY TO HAVE AT LEAST TWO AND MAYBE MORE YEARS OF PRODUCTION TO ACHIEVE A DEGREE OF RELIABILITY IN FORECASTING THE BEST FUTURE METHOD OF OPERATION FOR THIS RESERVOIR.

MANY METHODS OF RECOVERY THEORETICALLY SHOW SOME PROMISE TO AID IN THE PRODUCTION OF SUBSTANTIAL AMOUNTS OF ADDITIONAL OIL. MANY OF THESE EXOTIC METHODS HOWEVER HAVE NOT YET BEEN PROVEN IN THE FIELD AND CURRENT ECONOMICS WILL NOT PERMIT THEIR USE. CERTAINLY WITH THE TREMENDOUS VOLUMES AVAILABLE AT PRUDHOE, NEITHER THE STATE NOR THE OPERATORS HAVE TO BE TOLD TO CONSIDER THESE POSSIBLITIES.

WE HAVE REQUIRED THAT OPERATORS SECURE VOLUMINOUS DATA WHICH WILL HELP DEFINE THE RESERVOIR PARAMETERS. AS IS OUR RIGHT AND OUR RESPONSIBILITY, WE WILL EXERCISE CONTINUING JURISDICTION OVER THE OPERATION OF THE FIELD AND WILL REQUIRE THAT THE METHOD ULTIMATELY CHOSEN BY THE OPERATORS BE ONE THAT WILL ACHIEVE THE GREATEST RECOVERIES FROM THE RESERVOIR

CONSISTENT WITH SOUND ENGINEERING AND OPERATING PRACTICES.

4. MOST APPROPRIATE PRODUCING PLAN: WATER INJECTION AS CONTEMPLATED BY THE OPERATORS OF THE PRUDHOE BAY FIELD HAS PROVED TO BE ONE OF THE MOST RELIABLE TECHNIQUES FOR MAXIMIZING OIL RECOVERY IN FIELDS ALL OVER THE WORLD. THIS DOES NOT MEAN THAT OTHER TECHNIQUES SHOULD BE RULED OUT EVEN THOUGH THEY MAY BE CURRENTLY UNECONOMIC OR NOT TECHNICALLY FEASIBLE AT THIS TIME. ONE SUCH TECHNIQUE, THE INJECTION OF CO_2, IS BEING CONSIDERED.

OUR OPINION IS THAT PROCEEDING WITH THE APPROVED PLAN WILL NOT RESULT IN ANY IRREVERSIBLE DAMAGE TO OIL RECOVERY. DURING THE FIRST FIVE YEARS OF OPERATION, OR UNTIL THE APPROXIMATE TIME THAT A GAS LINE COULD BECOME OPERATIONAL, WE ESTIMATE THAT THE DECREASE IN RESERVOIR PRESSURE WOULD AMOUNT TO APPROXIMATELY TEN PERCENT OF THE ORIGINAL PRESSURE. BY THAT TIME WE WILL KNOW IF AND TO WHAT DEGREE THE DECLINE MUST BE ARRESTED, OR IF IT SHOULD BE REVERSED. IF, IN THE FUTURE, A BETTER METHOD OF OPERATION IS INDICATED, WE BELIEVE THAT THE MAXIMUM RECOVERIES STILL CAN BE ACHIEVED. MY PREPARED STATEMENT CITES AN ACTUAL EXAMPLE IN ALASKA WHERE WE HAVE FOLLOWED THIS COURSE AND ACHIEVED EXCELLENT RECOVERY. IN SHORT, WE DO NOT BELIEVE THAT A PRESSURE DECLINE OF THE MAGNITUDE WE HAVE DESCRIBED WOULD HAVE ANY LONG TERM DETRIMENTAL EFFECTS ON ULTIMATE OIL RECOVERY, AND WE CERTAINLY DO NOT AGREE WITH MR. DOSCHER THAT THERE WOULD BE LOSSES IN THE MAGNITUDE OF BILLIONS OF BARRELS.

5. <u>LIKELY RATE OF GAS PRODUCTION</u>: IF THE PLAN OF OPERATIONS AS PROPOSED BY THE OPERATORS IS FOLLOWED, WITH SIGNIFICANT WATER INJECTION, OUR WORK INDICATES THAT A GAS SALES RATE OF TWO BCF/D STARTING IN APPROXIMATELY FIVE YEARS COULD BE SUSTAINED OVER THE REMAINING LIFE OF THE FIELD.

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LET ME TURN TO MR. DOSCHER'S REPORT. IT IS IMPORTANT TO DISTINGUISH BETWEEN THE BASIC ENGINEERING CONCLUSIONS REACHED BY MR. DOSCHER IN HIS REPORT AND THE BROADER, MORE PHILOSOPHICAL AND POLICY PRONOUNCEMENTS CONTAINED IN HIS REPORT. BASICALLY, AS A PETROLEUM ENGINEER, I FIND LITTLE DISPUTE WITH MR. DOSCHER WHEN HE DESCRIBES WHAT IS STILL UNKNOWN AND MUST BE LEARNED AS OPERATIONS CONTINUE. OUR PLAN IS TO LEARN MORE AND ACT ACCORDINGLY. IT IS ON POLICY MATTERS WHERE I CANNOT AGREE WITH MR. DOSCHER'S APPROACHES, AND MY PREPARED STATEMENT GIVES A CLEAR EXAMPLE OF OUR DIFFERENCES.

I DISAGREE SHARPLY WITH MR. DOSCHER'S STATEMENT THAT THERE WILL BE A LOSS OF TWO TO FOUR BILLION BARRELS OF OIL IF THE PIPELINE IS APPROVED. MR. DOSCHER HAS NOT SUBSTANTIATED THIS FIGURE WITH ANY STUDIES AND HAS NOT FURNISHED TECHNICAL DATA ON WHICH THIS OPINION IS BASED. TO THE CONTRARY, OUR OWN STUDIES HAVE BEEN SUBSTANTIAL AND WE CAN REACH NO SUCH CONCLUSION BASED ON ANY INFORMATION AVAILABLE TO US, ASSUMING THAT A WATER INJECTION PROGRAM OF THE KIND PLANNED BY THE OPERATORS IS TIMELY IMPLEMENTED TO SUPPLEMENT RESERVOIR PRESSURE.

AS WE SEE IT, THE BASIC QUESTION IS WHETHER A PIPELINE DECISION SHOULD BE DEFERRED UNTIL MORE IS LEARNED ABOUT THE PERFORMANCE OF THE PRUDHOE BAY RESERVOIR. THE STATE OF ALASKA, BASED ON WHAT WE KNOW TODAY -- I.E., OUR OWN STUDIES, MR. DOSCHER'S TWO DRAFT REPORTS, THE MATERIAL PRESENTED TO US IN OUR REGULATORY CAPACITY, AND OUR OWN PROFESSIONAL JUDGMENT -- BELIEVES THERE IS NO SOUND TECHNICAL REASON TO DELAY, PROVIDED THAT THE OPERATORS ADOPT AND IMPLEMENT A SOURCE WATER INJECTION PROGRAM BY THE TIME GAS SALES START. IF THE OPERATORS DO NOT IMPLEMENT A SOURCE WATER INJECTION PROGRAM, THEN GAS SALES WILL HAVE TO BE LIMITED OR POSTPONED IN ORDER TO AVOID JEOPARDIZING ULTIMATE OIL RECOVERY.

WE AGREE THAT MORE INFORMATION ABOUT THE PERFORMANCE OF THE RESERVOIR IS DESIRABLE. BUT THE STATE'S PLAN ALLOWS FOR THE GATHERING OF THAT INFORMATION WITHOUT JEOPARDIZING THE EARLY CONSTRUCTION OF THE PIPELINE. IT DOES SO WITHOUT SUBSTANTIAL RISK TO THE ULTIMATE RECOVERY OF OIL FROM THE RESERVOIR, AND WITHOUT UNNECESSARY DELAY IN THE BRINGING OF A MAJOR NEW GAS SUPPLY TO LOWER FORTY-EIGHT USERS.

STATEMENT OF

E. G. HOULSTON
BP ALASKA, INC.

BEFORE THE

SENATE COMMITTEE ON

ENERGY AND NATURAL RESOURCES

OCTOBER 25, 1977

TESTIMONY OF E. G. HOULSTON
BP ALASKA/SOHIO

My name is George Houlston. I am the Manager of Reservoir Engineering for BP Alaska. BP Alaska operates in the Prudhoe Bay Field on behalf of The Standard Oil Company of Ohio.

I am here today in response to your request to take testimony concerning recommendations made before this Committee on October 12, by Dr. Todd Doscher. My statement today has been prepared to clarify BP/Sohio's position in regard to the points raised before this Committee.

Many studies on the Prudhoe Bay Field have been performed. Indeed, the claim has been made that this Field has been studied more than any other prior to production. In my opinion the most comprehensive review of the work performed on Prudhoe Bay Field was presented by the Working Interests and the Consultants to the State of Alaska, at the Conservation Hearing held in Anchorage on May 5 and 6. Those proceedings are a matter of public record.

The Prudhoe Bay Field is estimated to contain some 22.9 billion barrels of stock tank oil in place. By far the most significant portion of this in place oil, some 22.2 billion stock tank barrels, is to be found in the Sadlerochit formation. The other .7 billion stock tank barrels are located in the Sag River and Shublik formations which overlie the Sadlerochit. Major geologic faults appear to partition the reservoir between the Main Area of the Field and the West End or Eileen Area. The Field is thus subdivided by geologic formation and by area.

The Main Area Sadlerochit contains 21.4 billion stock tank barrels, and it is this accumulation which has been the subject of intensive study by the Working Interests in the Field and by other interested parties. It has been estimated that oil reserves of about 8.6 billion stock tank barrels will be recovered from the Main Area Sadlerochit. The estimated oil reserves for the entire field amounts to some 9.4 billion stock tank barrels. These include .5 billion stock tank barrels of condensate recovered from gas cap gas and .3 billion barrels from the Sag River and Shublik formations and the West End Sadlerochit.

Gas cap gas in place in the field amounts to 26.5 trillion cu.ft. at standard surface conditions. A further 17.1 trillion cu.ft. of gas is in place as solution gas. Some 26.5 trillion cu.ft. of hydrocarbon gas are considered to be recoverable and 300-400 million barrels of gas liquids. The heating equivalent of these reserves amounts to about 5 billion barrels of crude oil.

BP Alaska, acting on behalf of Sohio Petroleum, has viewed production from the field as a matter of maximizing total hydrocarbon recoveries. The studies we have conducted have been aimed towards formulating sound reservoir management policies consistent with that objective. Our studies have concentrated primarily on the Main Area Sadlerochit reservoir. The oil recoveries estimated in reservoir simulation calculations do not include the 800 million barrels of oil and condensate recoverable from other sources in the Field.

The studies we have conducted have included not only reservoir fluid flow considerations but also other factors which influence reservoir performance such as well density, surface facility operating conditions and capacities, gas lifting or pumping of oil wells, and the injection of gas and water. Ultimate hydrocarbon recovery is the outcome of collectively exercising these development options to varying degrees and at appropriate times throughout the life of the Field.

Based on current reservoir information and proven methods of recovery our studies have led us to a plan of operations which incorporates the following major elements:

(i) Production of oil at an average rate of 1.2 MMB/D increasing to 1.5 MMB/D when pipeline capacity is available.

(ii) The re-injection of gas produced in excess of that needed for fuel and sales.

(iii) The delivery of 2 BCF/D of sales gas as soon as a gas pipeline and a plant to condition the gas to specification can be completed. (Currently estimated to be some time during 1983).

(iv) The drilling of wells on 160-acre spacing or closer if necessitated by reservoir performance.

(v) The re-injection of produced water into the reservoir and the probable supplementing of such water with source water within seven years from the start of oil production (i.e., 1984 or earlier).

(vi) The installation of lower pressure gathering and separation systems and artificial lift facilities.

(vii) A very intensive program of reservoir surveillance and testing to compare forecasted against actual performance on a continuous basis.

By implementing this plan of operations it is anticipated that peak production rates from the Field could be sustained for seven or eight years and deliveries of gas could be held at 2 BCF/D for about 25 years. In all the cases we have studied, oil production declines when gas handling facilities can no longer cope with the gas produced with the oil. It should be possible to manage and operate the reservoir within the framework of this plan to achieve a recovery of about 40% of the original oil in place after 25 years and about 72% of the gas originally in place over 40 years.

After 25 years of oil production our simulation models indicate residual oil saturations in the original oil column which are mainly in the range of 25-45%. Earlier testimony given to this Committee to the effect that residual oil saturations in our simulatio runs were extremely low, approaching zero, can be categorically dismissed as without foundation and in complete contradiction to sworn testimony presented by BP Alaska to the Division of Oil and Gas Conservation, State of Alaska.

Scope may well exist for improving recoveries by applying methods of enhanced recovery, when such methods have been proven in the field. The plan of operations should not diminish the viability of any such prospective schemes. The Working Interests will remain continuously alert to all promising schemes for additional recovery.

In developing the present plan of operations, we investigated many variations in oil offtake, gas sales and water injection. In contrast to some opinions expressed, our studies have shown that the timing of gas sales at a rate of 2 BCF/D affects ultimate oil recovery only slightly. We estimate a possible loss of oil recovery on the order of 1% of the oil in place or just over 200 million barrels over 25 years of oil production. Over the same period, more than twelve times the heating equivalent of the 'lost' oil could be recovered through gas sales. We conclude that the rather sweeping quality judgment that the sale of gas is detrimental to ultimate oil recovery, is thoroughly misleading when considered out of the context of the level and timing of gas sales, the associated oil offtakes and all the other developments which are planned to promote recovery from the Field.

We have tested our plan of operations against oil offtakes of 1.2 to 1.8 MMB/D and gas sales of 2 BCF/D starting as soon as a gas line and conditioning plant can be completed. Again, from our studies we expect only slight variations in ultimate oil recoveries after 25 years of production.

At oil offtake rates of 1.5 MMB/D, we have studied the effects of gas sales at 2.5 BCF/D commencing as soon as a gas pipeline is available. This resulted in a lower oil recovery of about one and one-quarter per cent after 25 years. Using an earlier reservoir description we also investigated extreme cases of no gas sales and sales of 3.5 BCF/D. In the case of no gas sales, water was still injected though at a lower rate, and recovery obtained was about one and one-half per cent higher than with sales at 2 BCF/D. At gas sales of 3.5 BCF/D recovery fell by about 5% but this run was performed with the same water injection rate as the 2 BCF/D gas sales rate. A more successful outcome would have been possible but was not pursued. We have concluded that gas sales at 2 BCF/D should not cause concern in regard to ultimate oil recovery. At this stage, any proposal to sell gas at 2.5 BCF/D by 1983 we would approach with caution, and we would actually oppose any scheme to sell gas at 3 BCF/D as early as 1983.

It is recognized that the forecasting of reservoir performance with little or no production history in a field as large as Prudhoe Bay is subject to uncertainty. We have had to rely heavily on our reservoir simulation studies to predict detailed reservoir behavior. However, the experience that has been gained from operating other fields similar to Prudhoe Bay has been specially valuable in assessing the validity of our model predictions. We are confident that our near term assessment of Prudhoe Bay performance is a reasonable one.

Looking to the longer term, in many of the reservoir simulation model runs we have made, the differences in oil recovery arising between hypothetical reservoir management options do not become fully apparent until after about 15-20 years of oil production have taken place. There is every reason to expect, therefore, that there will be time and scope to adapt our plan of operations to ensure that hydrocarbon recoveries are maximized. The intensive reservoir surveillance and testing program which we will be undertaking will provide the control information necessary for those purposes.

The Working Interests in the Prudhoe Bay Field have acquired unusually detailed reservoir information prior to production. This has been very fully utilized and very considerable efforts have been devoted to studying the Field and developing the plan of operations. Although the results of the studies performed by the Working Interests are not the same in numerical detail, all the Working Interests have drawn similar conclusions in regard to how the Field should be produced.

Mr. Chairman, I submit that this consensus view is a sound technical basis to support the sale of Prudhoe Bay gas as soon as a pipeline and conditioning plant can be constructed.

BP ALASKA, INC.
SAN FRANCISCO, CALIFORNIA
October 25, 1977

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STATEMENT OF ATLANTIC RICHFIELD COMPANY

BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES, UNITED STATES SENATE

OCTOBER 25, 1977

My name is Howard Koch. I am a graduate of Northwestern University with a PhD. in chemical engineering. Since 1949 I have been employed by Atlantic Richfield Company and am currently Manager of Engineering of Atlantic Richfield Company's North American Producing Division. For the past eight years I have been heavily involved in Atlantic Richfield's efforts to explore and develop the Prudhoe Bay Field in Alaska and I have been responsible for and directed many studies of the reservoir and its performance.

As you know, Atlantic Richfield operates the eastern one-half of the Prudhoe Bay Field and BP Alaska, Inc., operates the western portion. As owner of approximately 1/5 of the crude oil and approximately 1/3 of the natural gas in the field, Atlantic Richfield is deeply concerned with maximizing ultimate recovery of all hydrocarbons producible from the field. We believe that all of the produced substances are extremely valuable and should be made available to U. S. consumers at the earliest practicable date consistent with good reservoir management. We further believe that our development plan which has been approved by the State of Alaska satisfies all of these prerequisites.

The Prudhoe Bay Field, discovered in 1968, is by far the largest oil and gas field producing in the United States.

Its recoverable hydrocarbon reserves have an energy equivalent of over 80 quadrillion BTU's. Because of the significance of this vast energy resource, the major working interest owners, the Alaska Division of Oil and Gas Conservation and others, have independently evaluated plans for production of this field.

Many reports have been written concerning the optimum development of the Prudhoe Bay Field. In October 1976, the working interest owners prepared and submitted a report entitled "Technical Considerations--Prudhoe Bay Unit Operating Plan, North Slope Alaska" to Mr. O. K. Gilbreth, Director, Division of Energy and Minerals Management--State of Alaska. 1/ This report contained a summary of the work conducted by Atlantic Richfield as well as BP Alaska, Inc.; Exxon, U.S.A.; and The Standard Oil Company (Ohio). The major conclusions in this report concerning plans for production of the Prudhoe Bay Field are consistent with the conclusions contained in H. K. Van Poollen studies conducted for the State of Alaska. Specifically, these reports concluded that the optimum producing plan for the Prudhoe Bay Field includes the early sale of natural gas.

We wish to outline for you today the major objectives we strived to achieve in developing our plans for producing the

1/ See Exhibit A - "Technical Considerations, Prudhoe Bay Unit Operating Plan - North Slope Alaska".

Prudhoe Bay Field and to comment upon Dr. Doscher's remarks before this committee. One of our key objectives is the development of both the oil and gas reserves as efficiently as possible.

The proved hydrocarbon reserves at Prudhoe Bay represent approximately 30% of the Nation's liquid reserves and 12% of the Nation's natural gas reserves. For this reason, another prime objective in the development of our operating plan for the field included conservation of the total energy resource. Therefore, as required by State Law and as directed by our own management, we plan to produce the reservoir in a manner consistent with sound engineering practices designed to achieve maximum economic recovery of oil and gas and to prevent waste.

State Law requires that the proposed plan of production protects correlative rights; i.e., that each working interest owner is afforded an opportunity to produce, without waste, its just and equitable share of the oil and gas. The working interest owners and the State have agreed that the production plan, including the early sale of gas from the field, will provide for this protection.

Finally, our plans for producing the field should be as flexible as possible so that we can react promptly to anomalies in reservoir behavior to assure efficient recovery of oil and gas from the field.

To achieve these aforementioned basic objectives, i.e., timely development, conservation of resources, protection of correlative rights and flexibility to adapt to observed performance, we have combined our reservoir studies with engineering judgement gained through worldwide experience, to formulate our present reservoir management plan.

We developed the production plan by studying the effects of alternative development plans, through the use of mathematical reservoir models. Through the use of these sophisticated reservoir engineering tools, it is possible to study various aspects of field performance including such things as oil and gas production rates, gas and water injection rates, infill drilling, tubular equipment selection, artificial lift alternatives, gathering system pressures and reservoir description. The evaluation of reservoir description and its effect on our operating plan decisions is perhaps the most powerful advantage to using these mathematical models.

A question has been raised concerning the reliability of a reservoir model in the absence of production history. Although it is true that the availability of production history can provide a useful check of a study and a basis for modification, Atlantic Richfield has a high degree of confidence in its reservoir model predictions, especially when these models are used to compare different methods of reservoir management. Two reasons exist for this high degree of confidence. First, because of the long period of time between discovery and commencement of deliveries to TAPS, the operators have drilled wells over a rather large area of the reservoir. As a result of this, we have secured unusually detailed reservoir descriptive information and have compiled specialized studies including geologic history, rock data, fluid sample data and log data. These data were used to determine in-place volumes of oil and gas as well as for the determination of reservoir performance. Rarely is such quality and quantity of reservoir data available prior to any sustained production from a field. A portion of these data pertaining to individual well performance, has been verified through the use of individual well models in matching actual drawdown and buildup tests performed in the field. Although a limited amount of data under sustained production is now available, actual well performance matches our predictions.

Second, confidence in our reservoir model predictions has been gained through sensitivity testing. In sensitivity testing our objective was to identify those reservoir parameters having the greatest effect on ultimate recovery and define those parameters to the fullest extent possible. Our application of this approach and the subsequent followup work, both field and laboratory, has given us an extra degree of confidence in our forecast of Prudhoe Bay performance. Although some adjustments may be made in the model as production history is accumulated, our current forecasts are adequate to demonstrate the viability of our current operating plan.

I would like to briefly outline the major elements as well as explain the expected general performance of the field under our operating plan. This plan anticipates crude oil deliveries to TAPS of 1.5 million BOPD when pipeline capacity is available.

Injection facilities were installed for the reinjection of all produced gas in excess of that needed for field and pipeline fuel to conserve gas for future sales and to comply with the State of Alaska's nonflaring order. Current gas injection capacity of 1.2 billion cubic feet per day (BCFD) will be expanded to handle up to 2.0 BCFD by mid-1979.

Gas pipeline deliveries of 2.0 BCFD can be commenced as soon as a gas transmission system can be completed. Testimony before the Congress concludes that the most likely date that gas can be delivered into a pipeline system will be 1983. Our reservoir model studies have shown us that the field can be managed so that gas deliveries at that time will be non-injurious to the reservoir.

Current water production volumes are very small and are being injected into the shallower Tertiary/Cretaceous sands. When this produced volume becomes significant it will be reinjected into the portions of the Sadlerochit reservoir exhibiting low natural depletion recovery. It is anticipated that this operation will commence in 1981. Through optimum redistribution of the produced water, the benefits of the natural water influx will be maximized. We plan to supplement this produced water injection with additional volumes of water from an outside source when our current estimates of recovery benefits can be verified along with the substantiation of its economic viability.

Some of the reservoir performance characteristics which were repeatedly revealed in our model studies are:

1. A small volume of natural water influx. This anticipated volume will be substantially less than that required to fully maintain reservoir pressure. Poor aquifer response is expected because we have noticed a degradation of rock properties in the aquifer.
2. Although all the natural recovery mechanisms (gravity drainage, gas cap expansion, solution gas drive and natural water influx) will be operating, the gravity drainage mechanism will be dominant and lead to

efficient fieldwide recoveries.

3. The expansion of the gas cap is dramatic in the first several years of production. It not only moves in a vertical direction at the rate of about 25 feet per year, but it also moves horizontally along the top of the formation and underneath continuous shale barriers. This horizontal movement can occur over several miles and is a result of the rather low formation dip (1 to 2 degrees). This gas cap expansion in the early years will expose a large percentage of the wells to a free gas saturation.
4. The expansion of the gas cap will result in a large volume of gas cap gas being produced through the oil wells. This means that a rather large volume of gas will be reinjected in the absence of a gas pipeline.
5. The advance of the gas-oil contact, to a large degree, controls the onset of oil production decline. Since the expansion of the gas cap is largely a function of oil zone withdrawals, we have seen in

our models that the timing of anticipated gas sales has little or no impact on the point of oil decline.

6. We do not anticipate any oil migration into the original gas cap as a result of gas cap shrinkage because of the substantial voidage accumulated by the oil rim prior to gas sales, and because of the smaller cap voidage rate in the early years of gas sales.

I would now like to specifically discuss some of our reservoir model results and how they have led to our plan of operation for the Prudhoe Bay Field. Although a considerable effort has been expended over the last eight years by my company in determining various aspects of producing the field, I would like to emphasize only two areas of interest: gas sales and source water injection.

There are two major considerations when evaluating the timing of gas sales. Those are:

Is there a market for the gas now? (The Prudhoe Bay natural gas and gas liquids reserves (to be discussed in detail hereafter) amount to 26 trillion cubic feet and 400 million barrels respectively, the energy equivalent of approximately 4.7 billion barrels of crude oil, or over 1/2 of the crude oil reserves.)

In the opinion of experts appearing before the Congress there is no doubt that there is a market for this gas now, and delivery should commence as soon as a gas pipeline system is completed.

The next consideration is: What effect does the timing of gas sales have on ultimate recovery of hydrocarbons? (If you will remember, conservation was one of our major objectives in determining the optimum plan of operation for the field.)

In evaluating the effects of gas sales timing on crude oil reserves, reservoir model studies were made with different timing assumptions for the commencement of gas sales. From the studies, we found that the ultimate crude oil recovery could increase in the order of 1% of the original oil-in-place if gas sales were deferred from 1982 to 1992 and if no additional measures were taken to offset the loss. This finding represents the maximum impact that gas sales timing could have on ultimate crude oil recovery. To focus on this potential 1% loss only would be a mistake, for it would disregard other hydrocarbons in the reservoir that are as valuable as oil.

To fully evaluate the effects of early gas sales, we must also consider natural gas liquid recovery. These natural gas liquids will be removed in the conditioning of the field gas to meet gas pipeline specifications. We estimate that approximately 400 million barrels of these natural gas liquids can be removed. The volume of these liquids that can be delivered to the consumer through TAPS, however, is dependent upon a number of variables including oil throughput rate. If gas is sold early in the life of the field while the oil pipeline is at capacity, more of these liquids can be transported with the oil. If, on the other hand, gas sales are delayed un'il a point of low oil throughput rate, some of these liquids will be reinjected into the reservoir and probably not recovered.

Permit me to summarize the conservation aspects of gas sales timing. Potential adverse effects on crude oil recovery amount to approximately 1% of the original oil-in-place if gas sales timing is varied from 1982 to 1992. By way of comparison, this is less than 1/20 of the loss estimated by Dr. Doscher. We believe that such a potential loss in recovery would be offset in actual field operations by varying the number and location of producing wells, the areal distribution of oil offtake rates and the locations and volumes of water injection, and further be offset by the shipment of natural gas liquids with crude oil in TAPS during the early stage of field production. We estimate that the loss in natural gas liquids would amount to approximately 125 million barrels for a delay in sales from 1982 to 1992, a loss not considered by Dr. Doscher in his review. With a three year deferral of gas sales as proposed by Dr. Doscher the loss in natural gas liquids could be about 45 million barrels.

Potential reduction in oil recovery from any reservoir due to the early sale of gas has been a subject of considerable discussions in the field of petroleum reservoir engineering. There is one general conclusion that can be drawn concerning this early gas sale: i.e., the withdrawal of associated gas can cause a reduction in oil recovery if nothing is done to replace the energy. Beyond that, however, no other conclusions should be drawn. This potential reduction can only be estimated through a thorough analysis of the drive mechanisms that are present in a particular reservoir. One excellent method in accomplishing this is through the use of mathematical reservoir models.

In our analysis, the effect of gas sales at Prudhoe Bay was small for the following reasons:

1. The dominant recovery mechanism is gravity drainage. Gas in such a drive mechanism does not act as an expulsive force to drive the oil out of the pore spaces. Instead, the gas merely expands to fill the empty pore spaces as the oil drains out.
2. Prudhoe Bay crude is both a low shrinkage and relatively low viscosity oil.
3. Even with the earliest anticipated gas sales date (1983) approximately 30% of the ultimate oil reserves will have been recovered.
4. The normal dangers of gas cap shrinkage will not be a problem at Prudhoe Bay, due to the expansion of the gas cap in the early years of production combined with a rather modest cap voidage rate immediately after sales commence.

It has been stated to this Committee that the producers have calculated small gas sale effects due to low residual oil saturations left behind the invading gas cap. In our studies, these residual saturations range from 20 to 30%. We submit not only that such saturations are reasonable, but we also believe that an analysis of gas sale effects is not strongly dependent upon these saturations.

Turning now to water injection for Prudhoe Bay, a much more complex problem. Gas sales effects are mainly related to pressure-volume relationships and can be easily evaluated with fluid properties and in-place volume considerations. An optimized waterflood, on the other hand, will require more study including the location of water injection wells and injection rates. These optimum volumes and locations can best be determined through the analysis of actual field production history.

Our current estimate of incremental waterflood recovery is about 4% of the original oil-in-place. This incremental recovery benefit was forecasted with an injection program assumed to commence in 1984 with daily injection of 2 million barrels of water. Preliminary design studies are currently underway so that implementation time can be substantially reduced once a decision is made to waterflood the reservoir.

Laboratory work has been done by our Research Department in evaluating carbon dioxide as a possible means of tertiary recovery for Prudhoe Bay. Essentially, we found that miscibility pressure is considerably in excess of initial reservoir pressure. Although some additional work has been done with liquid petroleum gas enrichment of the CO2 to lower miscibility pressures, reservoir characteristics of the Sadlerochit reservoir may limit its use to the shaly portions of the formation. Although no firm estimates of incremental recovery benefits have been made by my company, it is our opinion that these benefits would be smaller than those attributed to conventional water flooding. Since it appears that CO2 has some possibility for enhanced recovery in North Slope reservoirs, continuation of our studies is planned.

To summarize, Atlantic Richfield believes that the optimum production plan for the Prudhoe Bay Field includes early gas sales combined with a source water injection program. We have proposed and the State of Alaska has approved a gas sales rate of 2.0 BCFD beginning as soon as a gas transportation system is completed. We (and the State of Alaska) have found that gas deliveries of this volume will be non-injurious to the reservoir. Gas deliveries in excess of 2.0 BCFD must be approved by the State of Alaska. In addition, we feel that supplemental source water injection is certainly a means of increasing ultimate oil recovery. If our current estimates of incremental crude oil recovery benefits are substantiated along with the economic viability of the project, we anticipate that a source water injection program will be commenced as early as 1984. Accumulation of actual field production history will be invaluable in selecting the optimum volume as well as the optimum locations for this water. Again, approval of such an injection program will lie in the hands of the State of Alaska.

You have requested that we estimate the gas delivery rates over the life of the field. If gas pipeline deliveries are commenced in 1983, we believe that the field will be capable of delivering gas at a rate of at least 2.0 BCFD for approximately 25 years.

I appreciate having an opportunity to appear before your committee today. Thank you.

EXHIBIT A

TECHNICAL CONSIDERATIONS,
PRUDHOE BAY UNIT OPERATING PLAN
NORTH SLOPE ALASKA

BP ALASKA INC.
P. O. Box 4-1379
Anchorage, AK 99509

ATLANTIC RICHFIELD COMPANY
P. O. Box 360
Anchorage, AK 99510

October 20, 1976

Mr. O. K. Gilbreth, Jr., Director
Division of Energy and Minerals Management
Department of Natural Resources
3001 Porcupine Drive
Anchorage, AK 99504

Dear Mr. Gilbreth:

During the Prudhoe Bay Unit review with the State of Alaska, Department of Natural Resources on August 18, 1976, in Anchorage, a draft Unit Agreement was presented by the working interest owners for your early review. Included in the Unit Agreement was a recommended plan of operations which was discussed at the meeting with the understanding that further technical review of the basis for the recommended plan of operations would be provided. In response to your request, the attached report of comprehensive technical studies has been prepared by the field major interest owners, A.R.Co., BP, Exxon and Sohio. The "Technical Considerations, Prudhoe Bay Unit Operating Plan" report is submitted for your early review in advance of a formal application for Unit approval.

The recommended operating plan, which is supported by the attached report is, of course, based on the assumption that current unit negotiations are successful and that one oil rim participating area and one gas cap participating area are formed within the Permo-Triassic reservoir. In the unlikely event current unit negotiations are unsuccessful or modified significantly, revision to the recommended operating plan may be required.

The studies conducted by the major interest owners and described in the attached report have considered a range of possible production schedules, as well as a number of different reservoir management options. These studies include both subsurface and surface aspects of oil and gas production and have led to an overall reservoir management plan for the optimum development of the total energy resource in the Prudhoe Bay Field under unitized operations.

The recommended operating plan is geared to producing the Prudhoe Bay Field in a timely manner consistent with good conservation and engineering practices while protecting the correlative rights of individual owners in both the gas cap and oil rim participating areas. The State of Alaska can be assured that the working interest owners, joining together within the Unit, will fully utilize their expertise to manage the field to obtain maximum economic recovery of oil and gas.

Following your review of the attached report, we are available, at your convenience, to meet with you for further discussion of the recommended operating plan for the proposed Prudhoe Bay Unit.

Respectfully submitted,

BP ALASKA INC.	ATLANTIC RICHFIELD COMPANY
K R Keep	[illegible] for
Kenneth R. Keep	Howard A. Slack
Vice President & General Manager	Vice President & Resident Manager

/vaf

Attachment

TECHNICAL CONSIDERATIONS

PRUDHOE BAY UNIT OPERATING PLAN

NORTH SLOPE - ALASKA

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INTRODUCTION

On August 18, 1976, a draft of the proposed Prudhoe Bay Unit Agreement was presented to the Department of Natural Resources by the working interest owners. This was done in accordance with the Department's regulations which provide for submission of the draft form for preliminary consideration prior to agreement by the parties. Exhibit "E" of the proposed Agreement summarized a recommended plan of operations for the Unit. This report has been prepared by the major interest owners (A.R.Co., BP, Exxon, and Sohio) to provide the Department with the detailed technical basis for the recommended plan and will provide the operating plan data requested by the Department. The report is submitted for the Department's review in advance of a formal application for Unit approval. The subject Unit is currently being negotiated and the proposed plan is based on successfully concluding those negotiations.

This is a report of comprehensive technical studies which have been conducted independently over the past several years by the major working interest owners to develop long range operating plans. Major objectives considered in developing the operating plan for the Prudhoe Bay Field were (1) to achieve maximum economic recovery of oil and gas resources consistent with good conservation practices, (2) to develop energy resources as expeditiously as possible, and (3) to protect correlative rights. To fulfill these objectives, it is necessary to consider reservoir performance, efficient utilization of field facility and pipeline capacities, economic factors, and operational considerations such as mechanical feasibility and implementation schedules.

The recommended operating plan provides for the timely development of the total energy resource in the Prudhoe Bay Field consistent with good conservation and engineering practices and the recognition of the correlative rights of the owners in both the Gas Cap and Oil Rim participating areas in the proposed Unit. Over the life of the Field, these plans will undergo continual evaluation and will be modified as necessary, based on observed reservoir performance, to achieve the maximum economic recovery of oil and gas from the Prudhoe Bay Field.

OVERVIEW

Both short and long-term operating plans have been developed for the Prudhoe Bay Field. Short-term plans for oil and gas production from the Main Area Sadlerochit reservoir are as follows:

1. Oil production will begin in mid-1977 at a rate of 600 MB/D. The rate will increase to about 1.2 MMB/D by the end of 1977, assuming pipeline capacity is available.
2. Produced gas in excess of the quantity needed for local fuel requirements will be injected into the gas cap until a gas pipeline and gas conditioning plant are approved and constructed, currently estimated to be 4-1/2 to 5 years after start of oil production. Reinjection of produced gas will not adversely affect ultimate oil recovery.
3. Gas pipeline deliveries of 2.0 Bcf/D dry gas will begin as soon as a gas pipeline and gas conditioning plant are approved and constructed. The gas conditioning plant will be needed to bring the gas to pipeline quality including carbon dioxide removal, extraction of gas liquids for hydrocarbon dew point control, dehydration, and compression and cooling to pipeline pressure and temperature. Both the pipeline and conditioning plant require long lead times and large capital commitments. For example, preliminary estimates made several years ago indicate the gas conditioning plant will require 4-6 years for design, fabrication, and construction and will cost approximately $1 billion (1975 $). State approval of the gas offtake plan is needed now to insure that FPC certification, final design,

financing, and construction of the pipeline can proceed on schedule.

Main Area Sadlerochit reservoir performance characteristics expected with these planned offtake rates include (1) early expansion of the gas cap, (2) limited water influx from the aquifer, (3) coning of gas and water, (4) efficient natural gravity drainage depletion in areas with a thick oil column and good vertical permeability, (5) substantially less efficient natural depletion in areas where gravity drainage is ineffective, and (6) potential for improving performance in low natural recovery areas by selective injection of water.

To develop long range operating plans for the Prudhoe Bay Field, detailed reservoir studies have been conducted by the major interest owners (A.R.Co., BP, and Exxon) based on the substantial volume of Prudhoe Bay reservoir descriptive data which have been obtained and analyzed over the past seven years.

Sensitivity studies have also been made to insure that major operating plan decisions are practical over a reasonable range of reservoir properties. The results of these studies, combined with engineering judgment developed from experience in other fields have led to development of long-range reservoir management plans. Over the life of the field the plan will undergo continual evaluation, and, based on observed performance, will be modified as necessary to achieve the maximum economic recovery of oil and gas.

A long-range operating plan has been developed as follows:

Oil Offtake Rates

An increase in production to 1.5 to 1.6 MMB/D is planned when pipeline capacity is available. Field facilities designed for a sustained oil offtake rate of 1.5 to 1.6 MMB/D will be completed during 1978 and 1979.

It is anticipated that the 1.5 to 1.6 MMB/D average oil offtake rate can be maintained for approximately eight years by additional development drilling, resulting in efficient utilization of facility capacity. Such development of the field is expected to include 500 or more wells on 160-acre spacing within the 100-foot oil thickness contour. Production support can also be obtained through the installation of low pressure production and artificial lift systems or further infill drilling between some 160-acre spaced wells.

Studies of the sensitivity of reservoir performance to oil offtake rates in the range of 1.2 to 1.8 MMB/D indicate there is no significant effect of oil rate on the ultimate recovery of oil or gas. To sustain annual average offtake rates of 1.5 to 1.6 MMB/D, field facilities have been designed for a maximum capacity of 1.8 MMB/D. Consequently, some flexibility may exist to produce the field at higher rates when field and pipeline capacity are available.

Gas Offtake Rates

Gas pipeline deliveries of 2.0 Bcf/D are planned at the earliest date a pipeline can be approved and constructed, estimated to be 4-1/2 to 5 years after the start of oil production. Such gas deliveries are clearly a part of the optimum field operating plan. Studies have shown that the field can be operated so that planned gas deliveries will not affect ultimate oil recovery. The planned delivery rate of 2.0 Bcf/D is a conservative volume which can clearly be supported by the reservoir and initial gas pipeline deliveries of up to 2.5 Bcf/D may be justified, depending upon field performance data and availability of pipeline capacity.

Planned gas pipeline deliveries will substantially increase domestic energy supplies. For instance, through year 2000, pipeline deliveries of 2.0 Bcf/D, beginning 5 years after the start of oil production, add the energy equivalent of 2 billion barrels of oil to the nation's energy supply. In addition, such gas deliveries reduce fuel consumption, eliminate unnecessary costs for compression, injection, and "double production" of gas, and provide a measure of correlative rights protection for the Oil Rim and Gas Cap participating area owners.

Water Injection Plans

Produced water injection into the Sadlerochit reservoir is planned when the volumes become significant. Initially, water production will be minimal and disposal will be by injection into the shallow Cretaceous sands. When water production becomes significant, plans are to selectively inject into areas of the reservoir which experience low primary oil recovery to achieve maximum additional oil recovery benefits. Projections indicate that produced water injection will increase primary recovery by as much as 2% of the original oil-in-place (OOIP).

Initially, there will be field capacity to inject up to 200 MB/D of produced water and additional capacity will be provided as needed. Without source water injection, produced water rates could be as high as 500 MB/D with ultimate injection of some 4 billion barrels of water.

Produced water injection will be supplemented with the injection of extraneous source water when the additional recovery predictions of 3 to 7% of OOIP from such water injection are verified and the economic viability of the over $1 billion project is ascertained. Reservoir performance and testing data are particularly important to determine the proper water injection locations and volumes. Consequently, final commitment to source water injection cannot be made at this time, although it is planned and will be implemented if current predictions are verified.

In terms of additional oil recovery, the major benefit of water injection is improved sweep efficiency. Consequently, the timing of source water injection is not very critical to ultimate oil recovery. It is more important that the water be injected in the proper volumes and at the proper locations to obtain optimum field performance. If a source waterflood is initiated with insufficient production data, it could be improperly designed. For example, if there are areal differences in aquifer response (which is likely in a field with such a large areal extent), water could be injected into an area which may experience substantial local aquifer influx. The likelihood of such potential errors in both volume and location can be reduced with production history and test data.

A comprehensive reservoir surveillance and testing program will insure that necessary reservoir information is obtained at the earliest possible date. Although water injection plans cannot be finalized at this time, preliminary design studies are proceeding to reduce the lead time to approximately 3 years for implementation once the final decision to inject source water is made.

<u>Summary</u>

The operating plan described herein provides the flexibility necessary to adapt, as required, to information obtained from field performance to allow the maximum economic recovery of oil and gas. Studies indicate that it will be possible to manage the field to recover approximately 40%

of the original oil-in-place (OOIP) and 75% to 80% of the original gas-in-place (OGIP) in the Main Area Sadlerochit reservoir of the Prudhoe Bay Field.

RESERVOIR DESCRIPTION

Circumstances over the last seven years have permitted the working interest owners to secure unusually detailed reservoir descriptive information prior to the commencement of production. Highly specialized studies and analyses of geologic history, core data, fluid sample data, and log data have been made to determine in-place hydrocarbons for ownership determination and to refine estimates of reservoir parameters which influence reservoir performance. Production performance and test data will allow further refinement of the key data interpretations, particularly the vertical to horizontal permeability ratios, relative permeability, the effect of shale barriers, and the effectiveness of the aquifer.

The reservoir description presented in this section covers the range of data interpretations developed independently by the major interest owners. Generally, the individual interpretations of reservoir descriptions are in close agreement. There were differences in the manner in which individual companies translated the reservoir description into reservoir simulation models. While the performance predictions from the models are not identical, the studies lead to the same conclusions regarding major provisions of the field operating plan.

A. Geologic Structure and Lithologic Units

Figure 1 is a structure map on top of the Sadlerochit sand which was prepared by the Proposed Prudhoe Bay Unit Geological Subcommittee. Limits of the hydrocarbon accumulation in the Sadlerochit reservoir are defined by faults, truncation of the reservoir rock and the oil-water contact. Faulting provides the northern limit while the gentle south-dipping flank is relatively uncomplicated with the oil-water contact providing the limit. The east flank of the Sadlerochit reservoir is truncated by the Lower Cretaceous unconformity. Complex northwest-southeast trending fault systems establish the productive limits in the northwest portion of the Main Area. Immediately to the west of the Main Area is the Eileen Area which is fault bounded to the southwest with a generally northeast-dipping flank.

In the Main Area Sadlerochit, the gas-oil contact occurs at a subsea elevation of 8578 feet; while in the Eileen Area, two small gas caps are defined in separate fault blocks. The gas-oil contacts for the eastern and western fault blocks are at 8792 and 8770 feet subsea, respectively. The water-oil contact is an irregular surface and is slightly tilted, ranging from about 9050 feet subsea in the eastern portion of the Main Area to a subsea elevation of slightly above 8950 feet in the Eileen Area.

Figure 2 is a typical log from a well which completely penetrates the Sadlerochit formation. This log contains all of the Sadlerochit subdivisions defined by the Proposed Prudhoe Bay Unit Geological Subcommittee and exhibits the log characteristics which were used to make the subdivisions. Zone 1 represents a transition facies of interbedded sandstones and shales between the underlying marine shales and the overlying more massive fluvial sands. This zone is further subdivided, as shown, into Sub-Zones 1A and 1B. Sub-zone 1A is the more shaly of the two subdivisions as indicated on the Gamma Ray log response.

Zone 2 is a series of more massive sandstones interbedded with fairly significant shales. These shales become more massive and continuous offstructure and into the aquifer, as would be expected with the depositional source being from the north. The lithology is predominately sandstone with increasing amounts of conglomerate toward the top of the zone. The three major continuous shales within this zone, as shown on Figure 2, occur at or near the top of Zone 1, in the lower third of Zone 2, and in the upper half of Zone 2. Although no agreed nomenclature has been adopted, for purposes of this report these shales have been designated A, B, and C, respectively.

Zone 3 is a conglomeratic interval which is present over most of the field but thins to the west, south, and east until it eventually disappears beyond the productive limits of the field. This zone represents the highest energy level of the southward flowing streams and contains essentially no shale. Zone 3 is easily identified by its lower porosity reflected on the sonic log with its top and base defined by an 85 microsecond cut-off.

The uppermost subdivision of the Sadlerochit, Zone 4, is a more homogeneous sandstone facies with minor discontinuous shales or mudstones. It represents a lower energy fluvial environment. The final major shale (D), which appears to be continuous over a significant portion of the Sadlerochit productive area occurs at the base of Zone 4 or near the top of Zone 3. The top of the Sadlerochit is marked by an unconformity and is picked on a correlative Gamma Ray peak underlain normally by a pyritic streak evidenced by a low response on the resistivity logs and a high reading on the density log.

As will be shown later in the report, the geologic description, particularly the identification of extensive shales which are important to reservoir performance and the selection of reservoir management plans, and the lithologic zonation have been used extensively in Prudhoe Bay modeling studies.

B. In-Place Hydrocarbon Volumes

The hydrocarbon-in-place volumes for the Permo-Triassic reservoirs (Sag River, Shublik, and Sadlerochit formations) in the Main and Eileen (West End) Areas were determined through a joint technical study by the Proposed Prudhoe Bay Unit Reservoir Engineering Subcommittee. The results of this study are summarized in Figure 3. Oil rim and gas cap gas-in-place volumes for the Permo-Triassic are 31.2 billion reservoir barrels and 26.6 trillion standard cubic feet, respectively.

The Main Area Sadlerochit contains over 93% of the oil-in-place, with the Eileen Area Sadlerochit, the Sag River, and the Shublik totaling less than 7%. Reservoir simulation studies have concentrated primarily on the Main Area Sadlerochit because it represents such a large portion of the oil-in-place. It is likely that development of the Eileen Area Sadlerochit, the Sag River, and the Shublik will follow full development of the Main Area.

A heavy oil/tar zone occurs throughout the Main Area Sadlerochit just above the water and contains much poorer quality crude than the "light oil" column above it. This zone contains 1.9 billion reservoir barrels of hydrocarbons and represents about 6.5% of the Main Area Sadlerochit oil rim volume.

C. Reservoir Rock Properties

Core data were utilized extensively in development of the rock properties used in the reservoir models of the Main Area Sadlerochit formation. As indicated in Figure 4, 33 wells have been cored in the Main Area and 8 wells in the Eileen Area, for a total of over 9000 samples. Areal distribution of the data is good and will continue to improve as key wells are cored throughout the development drilling phase.

All core samples have undergone routine lab analysis for porosity using the summation of fluids technique. Horizontal and vertical permeabilities were measured using air and reservoir fluids. Special tests were also conducted on selected samples for determination of relative permeability and capillary pressure relationships.

1. Porosity

Relationships between core and log data were developed to extrapolate the core data fieldwide. Three porosity logs (sonic, neutron, and density) are available on each well, but the sonic log was found to be preferable for calculating porosity in the Sadlerochit. Porosity-transit time relationships were established for each lithology and fluid type. With the relationships established, average porosity was determined for the net pay in each lithology in each well on a foot-by-foot basis.

The Gamma Ray log was used to exclude all shale or non-pay intervals. Isoporosity maps were developed for each lithology. Each map indicated some degree of downstructure degradation in porosity, consistent with sediment deposition from a northern source. Figure 5 indicates the range of porosity for each lithology in the Main Area Sadlerochit.

2. Horizontal Permeability

Core data were also utilized to develop permeability-porosity relationships for zones exhibiting similar characteristics. The foot-by-foot permeabilities calculated from logs using the porosity-permeability relationships were averaged by zone and then zonal isopermeability maps were developed. Permeability data from pressure buildup tests were also considered.

Figure 5 indicates the range of permeability of each zone of the Main Area Sadlerochit. The permeability range varies from a high of greater than 1000 md in the conglomeratic Zone 3 to about 100 md in Zone 1. All zones exhibit varying degrees of downstructure permeability degradation.

3. Vertical Permeability

Effective vertical permeability in the reservoir cannot be obtained directly from the core data due to reductions caused by small discontinuous shales. These shales cannot be correlated from well-to-well and their areal extent cannot, therefore, be exactly defined. Since vertical permeability is expected to have a significant impact on recovery, considerable effort was devoted to its evaluation. A statistical analysis of shale frequency was made from logs, and the areal extent of the shales was estimated from studies of modern day braided streams. Based on the data developed in these studies, a 28,500 grid block 3-D model was used to estimate their effect on vertical flow. Major correlatable shales also have a significant effect on vertical permeability as will be discussed later.

The range of Kv/Kh ratios used in the model studies is shown in Figure 5. Additional drilling, field testing, and reservoir performance data will be needed to verify this key parameter.

4. Correlatable Shales

Major shales, which are correlatable between wells, also occur within the Sadlerochit section (Figure 2). These shales were deposited in a bay environment as opposed to the braided stream environment of the minor, non-correlatable shales. Where possible, these shales were mapped and included in reservoir models as zero vertical permeability boundaries. For example, Figure 6 is a map showing the areal extent of the "D" shale over the Sadlerochit productive area.

These correlatable shales will have a significant effect on gas-oil and water-oil contact movement. In addition to their influence on gross fluid movement in the reservoir, these shales will dramatically affect the gas and water coning behavior of individual wells. Model studies show that continuous shales could provide injection control and thereby, improve waterflood performance in specific areas of the field. However, a complication could arise in that faults could allow communication across these shales.

D. Fluid Properties

Initial reservoir pressure in the Main Area ranges from 4335 psia at the gas-oil contact to about 4480 psia at the water-oil contact. Reservoir temperature varies both vertically and areally. At 8800 feet subsea, temperature varies from about 185°F in the northeast part of the field to 240°F in the Eileen Area. At these initial conditions, oil gravity in the "light oil" column of the Main Area averages about 27°API, varying from 30°API at the gas-oil contact to about 26°API at the top of the heavy oil/tar zone. The oil formation volume factor averages 1.36 RB/STB and varies from about 1.3 to 1.4 RB/STB while oil viscosity averages about 0.8 centipoise and varies from 0.5 to 1.2 centipoise. Solution gas-oil ratio averages about 750 SCF/STB, varying from about 650 to 900 SCF/STB between the gas-oil contact and the heavy oil/tar zone in the Main Area.

A gas cap gas condensate yield of about 35 barrels per million cubic feet of separator outlet gas is expected initially from the separator facilities located at the flow stations (gathering centers). In addition, it is expected that once gas sales begin, 10-15 barrels of gas liquids per million cubic feet of separator outlet gas will be extracted at the gas sales conditioning plant to make the gas acceptable for delivery into the gas pipeline.

Gas pipeline specifications are not currently known and final specifications may increase or decrease the volume of liquids which must be extracted from the gas to prevent condensation in the pipeline. Regardless of the final gas conditioning requirements, all liquids extracted will be used without waste; either to displace fuel gas or be transported through the oil pipeline.

Fluid properties of the heavy oil/tar interval are also important considerations. This interval, located just above the water throughout the Main Area, is distinctly different from the "light oil" column above it. An isopach of the zone (Figure 7) shows that the interval varies in thickness from 20 to 60 feet, being generally thinner in the southeastern third of the field. Well tests confined to this interval experienced only small amounts of fluid entry with oil gravities of less than 15°API. Analyses of cores from this zone indicate a low effective permeability to brine (approximately 1 millidarcy). Model studies indicate that the presence of the heavy oil/tar zone will offer some impedance to water influx although the effect on ultimate influx is expected to be relatively minor. The heavy oil/tar zone could have a more significant impact on peripheral water injection plans because of reduced injectivity. Reservoir performance and testing information will be necessary for final evaulation of the impact of the heavy oil/tar zone.

E. Aquifer Description

Figure 8 shows the aquifer properties, volume, and location of wells from which logs and core data were available. A total of 26 wells have been drilled in the Sadlerochit aquifer with core data obtained from 10 of these wells. Although the aquifer covers a large area, net sand thickness and quality appear to degrade rapidly moving away from the oil column. As shown by the inset of Figure 8 only about 35% of the aquifer volume is in rock with permeability of greater than 10 md.

The rapid degradation of rock properties in the Sadlerochit aquifer is expected to result in only limited water influx. Production history will provide necessary information to accurately quantify aquifer performance.

F. Saturation Functions

The range in the basic relative permeability curves used by the companies in their respective reservoir studies is shown in Figures 9 and 10. These curves are based on detailed laboratory analyses using several different techniques. Oil-water relative permeability data were obtained from waterflood tests run on core plugs and composite cores, some at reservoir conditions using reservoir fluids. Some oil-water relative permeability centrifuge tests were also run. Similar tests were used to obtain gas-oil relative permeability data.

Three-phase relative permeability values were determined from two-phase laboratory data by use of empirically derived probability models. In some of the simulation studies, history-dependent saturation functions developed from laboratory data have been used. Initial conditions in such models are established with drainage saturation functions and continue to use the drainage functions until there is a decrease in the non-wetting phase saturation. Once that occurs, hysteresis scanning curves are used to describe the transition to the imbibition functions.

Although extensive, sophisticated laboratory analyses have been conducted, final confirmation of relative permeability effects will depend upon data from field production performance and special well tests. Such information is needed for accurate assessment of water-oil displacement efficiency which is of critical importance in planning water injection programs.

RESERVOIR STUDIES

Extensive studies have been performed independently over the years by the owners in the Prudhoe Bay Field. The results of these studies represent a consensus assessment of the productive capabilities of the Main Area Sadlerochit reservoir and are supported by experience in producing similar types of fields throughout the world.

Reservoir performance studies have been integrated with downhole and surface facility considerations. Such factors affect production performance and ultimate reserves and are important aspects in the development of a sound, comprehensive plan of operation for the field.

The operational factors which have been considered are mechanically feasible for Prudhoe Bay operations and are typical considerations in the operation of other fields. Such factors include well density, field pressure systems, artificial lift, gas reinjection, facility capacity for handling produced water and gas, well workovers, and optimum water injection locations and volumes.

Costs of such operational factors are important in developing an operating plan to insure that it is economically feasible. Since the same production performance objectives might be accomplished with more than one of the operational alternatives, comparative costs are important to insure optimized operations. Lead times for the design, construction, and installation of field facilities are also important aspects of field management considered in developing the operating plan.

Where uncertainties exist, both in operational considerations and in the reservoir description, studies have been conducted to evaluate the sensitivity of ultimate oil and gas recovery for a reasonable range of uncertainty. The sensitivity studies have led to the development of a plan of operation which has the necessary flexibility to allow for a positive reaction to observed performance.

The following subsections describe the reservoir models used in the studies, the operating boundary conditions applied in the models and the general reservoir performance characteristics observed in the models.

A. Models

Major interest owners have compared and exchanged results of independent two-dimensional, three-phase cross-sectional model studies of the Main Area Sadlerochit. While results are not identical, the overall conclusions drawn regarding the field operating plan are the same. The fact that independent reservoir description and simulation efforts led to the same operating plan provides further confidence in the overall conclusions.

Two-dimensional, three-phase cross-sectional models were employed for the basic studies of long-range reservoir performance and the evaluation of overall reservoir management options, although the application of other models was necessary, particularly individual well models for studying coning and completion intervals. Cross-sectional models were selected because they adequately take into account: (1) the significant changes in rock properties which occur vertically and with position on structure, (2) vertical flow and gravity segregation which tends to dominate in a thick sand with fairly good vertical permeability, (3) gas cap expansion and water influx, and (4) the important influences of oil column thickness and fluid contact movement on the behavior of wells at different structural positions.

The cross-section models utilized by the three companies contained 14 or 15 vertical layers and 67 to 90 grid blocks horizontally. Separate studies were made with more finely gridded models to confirm that this grid definition reduced numerical error to within acceptable limits. Reservoir properties assigned were based on each company's interpretation of the basic reservoir data described previously and were within the ranges shown in the Reservoir Description section of this report. As might be expected with independent studies of this nature, there are many differences in the model descriptions. Despite these differences, the results and conclusions from the studies are very similar.

Numerous additional models have been utilized to compliment and verify the cross-sectional studies of the Sadlerochit reservoir. Two-dimensional areal models were used for aquifer sensitivity studies. Radial models describing typical wells have been utilized to study gas and water coning behavior and identify optimum completion intervals. Finely gridded two and three-dimensional model studies of portions of the reservoir have been made to confirm the large block models and evaluate displacement mechanisms in localized areas. Fieldwide three-dimensional, three-phase models have been used to analyze areal variations in reservoir performance and to confirm results of the cross-sectional models.

B. Operating Conditions

Well rates in the models were controlled by the productivity index of the completion interval as calculated from producing block thickness, rock permeability, and relative permeability values based on fluid saturations in the producing blocks. Damage ratios from

1.5 to 3.5 were based on interpretation of the production tests in the field. Well capacities considered the effects of wellbore hydraulics for the flow conditions predicted by the simulator and the planned tubular equipment. Artificial lift (both gas lift and pumping) was included when additional capacity was needed to sustain the target oil producing rate.

Completion intervals were chosen in conjunction with coning model studies. Generally, initial standoffs from the gas-oil contact were 150 to 200 feet while 50 to 100 feet standoff from the water-oil contact was maintained. Initial oil rates averaged about 10,000-12,000 B/D, but varied widely. Recompletions were allowed under various conditions, such as when an adequate production increase could be obtained, or when some present water-oil ratio (WOR), gas-oil ratio (GOR) or field facility capacity was reached.

The models considered approximately 500 wells developed on 160-acre spacing within the 100' oil thickness contour. In a number of cases, some infill 80-acre development wells are included.

Prior to gas sales, gas production volumes were limited to the injection capability of about 1.8 to 2.0 Bcf/D, plus field fuel requirements. During gas sales, gas production volumes included pipeline delivery volumes plus fuel, shrinkage and carbon dioxide (CO_2) removal. Because of these factors, a 2.0 Bcf/D pipeline delivery level requires production of 2.7 to 2.8 Bcf/D of raw gas.

A peak oil rate of 1.5 MMB/D and gas pipeline deliveries of 2.0 Bcf/D after 4-1/2 to 5 years of oil production were generally assumed, although higher oil and gas offtakes were evaluated. Water injection rate, timing, and location were varied in attempting to optimize the reservoir management plans studied.

C. General Reservoir Performance

Conclusions regarding reservoir performance characteristics, as defined by cross-sectional, coning, and other model studies, are:

1. Natural water influx is expected to be substantially less than required to fully maintain reservoir pressure. The modest contribution of the aquifer is due primarily to the degradation of rock properties that occurs with distance from the field.

   Sensitivity studies have been run to evaluate the effectiveness of the aquifer by assuming variations in the expected size, permeability, rock and water compressibility, and transmissibility across faults in the west area of the field. Over a reasonable range of values, water influx is relatively low.

2. The natural depletion mechanisms are gravity drainage, gas cap expansion, solution gas drive and water influx. The influence of gravity drainage is especially important in those areas with a thick oil column and good vertical permeability.

3. During early years of production, the gas cap expands rapidly, moving vertically into the oil rim at a rate of about 25 feet per year and advancing thousands of feet horizontally to override much of the oil zone at the top of the sand and under massive, continuous shale breaks. This early expansion of the gas cap eliminates concern that depletion of the gas cap during oil production might

result in a reduction in recoverable oil due to gas cap shrinkage.

4. Although completion intervals will be designed to take maximum advantage of shale protection and standoff distances from the original contacts, gas and water coning will eventually occur.

5. It is expected that significant volumes of gas cap gas will be produced through oil wells. If this gas is not delivered to a pipeline, it will be necessary to reinject an estimated 15-20 Tcf of gas into the gas cap. Although the return of such gas is not detrimental to reservoir performance, compression and injection of this volume of gas would require approximately 600-800 Bcf of fuel gas, or the energy equivalent of more than 100 MM barrels of oil. Moreover, the extraction of liquids required to condition the gas for pipeline delivery will provide for an additional 10 MM barrels per year of gas liquids.

6. The onset of oil production decline is largely controlled by the advance of the gas-oil contact. Increasing gas-oil ratios ultimately result in the gas handling capability being exceeded at which point oil production must be restricted. Since the advance of the gas-oil contact is related primarily to net oil zone withdrawals, gas sales timing does not significantly affect oil production decline. Source water injection does offer potential to delay oil decline by retarding advance of the gas-oil contact.

7. Model studies indicate that, taking into account the effect of coning, the 1.5 to 1.6 MMB/D oil rate can be sustained for about eight years.

8. The examination of a wide range of assumptions regarding oil and gas offtake rates leads to the conclusion that the reservoir can be managed to recover approximately 40% OOIP and 75% to 80% OGIP.

RESULTS OF RESERVOIR MODEL STUDIES

During the past several years of studying the Sadlerochit reservoir, each company has experienced an evolution in model development. Studies with early models considered a broad spectrum of reservoir management plans, while recent work has focused on the more reasonable alternatives. These studies have investigated the effects of varying both reservoir properties and operational factors on production peformance.

As discussed earlier in the report, there are uncertainties which relate to reservoir description, such as vertical-to-horizontal permeability ratio, shale continuity, and relative permeability which have an impact on ultimate recovery and on decisions relating to reservoir management options. Studies have been made to evaluate the potential impact of these factors on the plan of operation.

Factors related to field development and operations also affect production performance and ultimate recovery. For the Prudhoe Bay Field, such factors include the return of produced gas and water to the reservoir, source water injection, well density, gathering system pressures, artifical lift facilities, and the capacity of facilities for handling oil, water, and gas production. Simulation model studies have also been made to evaluate the effect of these operational factors on overall reservoir performance. Comparisions between cases have typically been made through changing one or two of the more significant factors at a time.

These sensitivity studies have made it possible to develop sound operating guidelines for the Prudhoe Bay Field which will provide necessary flexibility to modify the operational factors as reservoir properties are better understood. Such studies, combined with experience in other fields, result in confidence that optimum oil and gas recovery can be attained in the field even though the reservoir description may be different than the current interpretation. The considerable areal extent of the field will likely require that operations be optimized in a number of different ways to best suit local conditions. For instance, water injection may prove to be highly desirable in selective areas where natural depletion recovery is low, but much less desirable in areas with very efficient oil recovery through gravity drainage.

A. Recovery Estimates

The following paragraphs describe the estimated ultimate oil and gas recovery from the Main Area Sadlerochit reservoir at Prudhoe Bay under the oil and gas offtake conditions of a peak oil rate of 1.5 MMB/D and a gas pipeline delivery rate of 2.0 Bcf/D commencing 4-1/2 to 5 years after the start of oil production along with various water injection alternatives.

Due to the favorable reservoir rock properties which provide for good gravity drainage, the natural recovery mechanism (without return of produced water) at Prudhoe Bay will be efficient with oil recovery predicted by the companies ranging from 32% to 35% of OOIP. It is estimated that this oil recovery will be achieved over a period of 25 to 30 years. Ultimate gas recovery is expected to be in the range of 75% to 80% of total gas-in-place and will be recovered over a period of about 35 years.

Studies have indicated substantial benefits of injecting produced water into the Sadlerochit reservoir. Such water injection could involve rates as high as 500 MB/D and ultimate injection of up to 4 billion barrels. By selectively injecting this water to obtain maximum benefits, ultimate oil recovery may be increased as much as 2% OOIP. The range of recovery predicted by the companies for this plan is from 33% to 36% OOIP. The current operating plan calls for the injection of produced water into the Sadlerochit when volumes become significant.

Model studies indicate further potential for increasing ultimate oil recovery to a level of 39% to 40% OOIP by implementing a properly designed source water injection program within about five to nine years after the start of oil production. Selection of the optimum locations and volumes to be injected will be the key to the success of a source water injection program. Two or more years of production performance history and testing data will be necessary to select optimum locations and volumes and to confirm the additional recovery potential of 3 to 7% OOIP before the final decision is made to commit approximately one billion dollars for source water injection facilities. It will then take a minimum of three years to develop the final design, fabricate, and install the first stage of the source water injection system. As will be shown later, sensitivity studies indicate that ultimate oil recovery is not very sensitive to the timing of injection startup in the 5 to 9-year period. The studies indicate that it is possible to inject at higher rates and "catch up" with the later injection programs. Based on these projections, the current operating plan for the field includes source water injection programs to be implemented when performance and testing information confirm the need and allow selection of optimum locations and volumes of source water injection.

B. Sensitivity Studies

Numerous case studies were analyzed by the companies to evaluate the sensitivity of reservoir performance to operational factors which can be controlled, such as offtake rates, well density, and water injection. In evaluating the sensitivity of reservoir performance to these factors, potential variations in reservoir properties were also considered. Results of these sensitivity studies can be summarized as follows:

1. Oil Offtake Studies

Sensitivity studies to oil offtake rate in the range of 1.2 to 1.8 MMB/D indicate no significant effect of oil rate on the ultimate recovery of oil or gas.

2. Gas Offtake Studies

Model results have shown that the timing of 2.0 Bcf/D of gas pipeline deliveries does not significantly affect ultimate oil recovery under sound reservoir management plans. The sensitivity of oil recovery to the timing of gas offtake was investigated by delaying gas deliveries until 8-1/2 to 10 years after the start of oil production. Studies have shown that the minor potential reduction in ultimate oil recovery resulting from the earlier gas sales can be offset in the field by modifying one or more operating options, such as the number and location of wells, gathering system pressures, the volume and location of water injection, and the capacity of facilities for handling gas and water.

Assuming available pipeline capacity, increases in gas deliveries above 2.0 Bcf/D may be considered depending upon future reservoir studies and reservoir performance. Model studies have shown that the gas delivery rate can be increased from 2.0 Bcf/D to 2.5 Bcf/D without affecting ultimate oil recovery if appropriate modifications are made to the reservoir management plan. These studies were conducted without economic analysis and justification for gas sales rates above 2.0 Bcf/D will depend upon actual production performance and economic considerations.

3. Well Density Studies

The current operating plan anticipates approximately 500 wells on 160-acre spacing inside the 100-foot oil thickness contour line. Studies indicate potential for enhancing production performance by infill drilling between 160-acre spaced wells in selected parts of the reservoir, but such decisions will depend upon reservoir performance.

4. Water Injection - Rate and Timing

Water injection case studies indicate potential for increasing ultimate oil recovery to a level of 39% to 40% OOIP by implementing a well designed source water injection plan. As indicated previously, the earliest feasible implementation date for a source water injection project is approximately five years after the start of oil production. However, such timing may not provide adequate opportunity to analyze production performance. Therefore, studies have been made with water injection commencing seven to nine years after start of oil production. Results of these studies indicate ultimate oil recovery is not very sensitive to the timing of injection startup and that the later injection programs result in the same recovery if the rate of injection is increased.

The key to a successful source water injection program will be the selection of the optimum locations and volumes to be injected, which may vary from one area of the field to another, depending on local reservoir conditions. For instance, shale continuity, the effectiveness of injection into or below the heavy/oil tar zone, aquifer response, and natural depletion performance may influence desired injection locations. The major benefit in terms of additional oil recovery derived from water injection in the Sadlerochit reservoir is improved conformance or sweep efficiency. Additional recovery results primarily from water displacement in areas of the reservoir which experience inefficient recovery under the natural depletion process. Because of the complex and diverse nature of the field, selection of the optimum well locations will require field production performance and testing data.

Eight typical water injection sensitivity studies which demonstrate these effects are summarized in Figure 11. A single model (reservoir description) was used in these studies. All operational factors and offtake rates were held constant except for the indicated variations in the gas delivery and water injection programs. Produced water was returned to the reservoir in all cases. Cases 1 through 4 resulted in the recovery of approximately 39% OOIP with water injection timing varying from 5 to 9 years after beginning oil production. Injection rates for these four cases varied between 1.7 and 2.6 MMB/D. Cases 5 through 8 recovered approximately 40% OOIP with water injection timing varying from 5 to 7 years after beginning oil production. In Cases 5 through 8, injection rates varied between 2.0 and 3.5 MMB/D.

The difference in ultimate oil recovery among these cases is relatively small compared to the difference in the volumes of water injected. Increasing volumes of water injection yield diminishing benefits in terms of incremental oil recovery. Larger injection volumes also require more fuel, additional handling of produced water, and greater volumes of gas-lift gas. The results also indicate that the timing of gas pipeline deliveries does not significantly affect ultimate oil recovery.

The methods finally used in operating the Prudhoe Bay Field will depend on the overall economics which consider the optimum recovery of all hydrocarbons, fuel requirements, the relative cost for different operating procedures, and incremental benefits of the alternative secondary recovery programs.

The individual cases can be summarized as follows:

Cases Recovering 39% OOIP

Case 1:

The water injection program for this case involved startup after five years of oil production. The peak injection rate was 1.7 MMB/D with cumulative injection totaling 8.5 billion barrels through 20 years of oil production. Water was injected into areas which experience poor recovery under natural depletion and where shales can be utilized to control the water in the reservoir. Initially, source water was confined to the shaly areas in the lower one-half of the oil column and the natural gravity drainage mechanism was allowed to continue updip. After adequate gas invasion (7 years), injection was commenced updip behind the gas front in those areas where the "D" shale is continuous and can be utilized to confine the injection to Zone 4.

Case 2:

Source water injection was initiated after seven years of oil production in the same locations as in Case 1. By increasing the peak injection rate to 2.0 MMB/D, the same ultimate oil recovery was obtained as in the earlier water injection case. The source water injection locations utilized in Cases 1 and 2 are the most efficient that could be developed for the model. Even so, comparison with a natural depletion case with produced water injection indicates that for each incremental barrel of oil recovered, it is necessary to inject approximately 15 barrels of water.

Case 3:

In this case, source water injection was deferred until nine years after the start of oil production and the peak injection rate was increased to 2.5 MMB/D. Oil production had declined from the peak rate of 1.5 MMB/D prior to the start of source water injection. Although injection was concentrated in the shaly areas, some was injected in the flank in a peripheral pattern. While some rate acceleration benefits of water injection were sacrificed, the deferral of source water injection startup did not affect ultimate oil recovery.

Case 4:

Gas pipeline deliveries were initiated at 2.5 Bcf/D after five years of oil production. The water injection plan in the oil zone, which was started after seven years of oil production, was identical to the water injection plan in Case 2. In addition, water was injected into the gas cap beginning five years after the start of oil production. This case, with higher gas offtake rate, resulted in the same ultimate oil recovery as Case 2.

Cases Recovering 40% OOIP

Case 5:

Gas pipeline deliveries were deferred until 10 years after the start of oil production. Oil zone water injection was initiated after seven years of oil production at the same volumes and locations as in Case 2. Although the five-year delay in gas deliveries slightly improved ultimate oil recovery, Cases 6, 7 and 8 demonstrate that other water injection programs achieve the same oil recovery with gas deliveries commencing after 5 years of oil production. Moreover, as described previously, deferral of gas pipeline deliveries increases fuel requirements for reinjection and substantially decreases the total energy supply from the field during the early years.

Case 6:

This case reflects an early, large water injection program. Source water injection was initiated after five years of oil production at the peak rate of 3 MMB/D. Because the gas cap had not advanced sufficiently by this time, it was not feasible to inject updip in the oil zone above continuous shales. Such injection would have caused significant volumes of oil to be driven into the original gas cap. To avoid this, the water was injected into the gas cap, the shaly areas in the lower one-half of the oil column, and in the flank of the oil column in a peripheral pattern.

Case 7:

Water injection into the gas cap was initiated as in Case 6 after five years, but injection into the oil zone was deferred until seven years after the start of oil production to allow additional advance of the GOC so that a portion of the water could be injected updip in the oil column. The improved efficiency with this water injection plan offset the earlier start of water injection in Case 5. The importance of the location of injection is expected to be even more pronounced in the field where there are significant variations and complexities which cannot be considered in a simulation model.

Case 8:

In this case, source water injection was started after seven years and built to a peak rate of 3.5 MMB/D. Because this volume was larger than could be confined to only the more efficient areas, it was necessary to inject in the unconfined flank of the oil column and in the gas cap. In total, increasing the injection rate from 2.0 MMB/D in Case 2 to 3.5 MMB/D in Case 8 increased oil recovery by less than 1% OOIP. On an incremental basis, it was necessary to inject more than 35 barrels of water for each additional barrel of oil recovered. This demonstrates that the benefits derived from water injection diminish with increasing volumes because the additional water must be injected into areas of the reservoir which respond less favorably to water displacement.

In summary, these water injection sensitivities demonstrate that (1) ultimate oil recovery levels can be maintained with timing of source water injection varying from 5 to 9 years after the start of oil production with modifications to the water injection program, (2) injecting source water in the optimum locations and at the proper volumes may be more important than the timing of injection startup, (3) the benefits of source water injection diminish with increasing volumes of injection, and (4) adjustments to the water injection program is one method of compensating for potentially adverse effects of the timing or volume of gas pipeline deliveries ranging from 2.0 Bcf/D to 2.5 Bcf/D. These studies, as well as experience in other reservoirs, indicate that it is prudent to evaluate reservoir performance and the results of field testing before making final source water injection decisions.

RESERVOIR SURVEILLANCE AND TESTING PLANS

As discussed in the previous section on simulator study results, operating guidelines have been formulated with sufficient flexibility to accomodate variations in reservoir performance from that predicted. The key to optimizing the reservoir management plan and recognizing deviations from predicted performance is a thorough program of reservoir surveillance and testing. Surveillance activities will include monitoring pressures and gas-oil and oil-water contact movements, and observing the performance of individual wells.

In addition to the regulatory requirements for initial static pressures in all wells and regular pressure surveys in key wells, it is planned that pressures in the gas cap and aquifer will be monitored. Selected wells may also be completed prior to their connection to producing facilities to provide virtually continuous pressure observations within the oil column and gas cap during the early stages of production.

Cased hole neutron logs will likely provide the best indication of gas-oil contact movements, although other tools will be run to provide confirmation. A comprehensive cased-hole baseline logging program is currently being developed.

Water-oil contact movements will be monitored with pulsed-neutron baseline logs (e.g., TDT-K and carbon-oxygen logs) run in selected wells. The gamma ray log has also proven successful in locating water in certain instances and the gamma ray will be run routinely during the completion of each well. Open-hole logs will provide additional spot checks on contact movements for a number of years as development wells continue to be drilled in the field.

The information obtained from the pressure and contact surveys will be analyzed to evaluate such parameters as shale continuity, displacement efficiencies, and aquifer response.

Comprehensive well test procedures are planned, including measurements of productivity index (PI), gas-oil ratio (GOR), and water-oil ratio (WOR) and regular samples of both produced oil and separator gases.

Special interference, pulse, and vertical permeability tests will be conducted to provide information such as effective vertical permeability and the extent of communication across faults and shale intervals.

Production logging will be intensive shortly after startup to monitor the flow distribution of fluids entering the wells and to provide information regarding the continuity between sand members. For these purposes, flowmeters and possibly noise logs and/or radioactive tracers will be run. In problem wells, other surveys might also be necessary, e.g., flowing temperature, gradiomanometer, etc.

Within two years after the start of production, it is planned that water injectivity tests be performed in selected locations. The objectives of such tests would be to (1) determine the injectivity into various subzones under sustained injection conditions to determine the number and location of injection wells and (2) to determine from such tests whether water displacement characteristics in the reservoir confirm present laboratory information obtained from cores. It is considered impractical to make detailed plans for a large-scale waterflood without obtaining such vital information.

Reservoir simulation modeling will also be an integral part of the overall reservoir surveillance program. As production data are gathered, history matching will be utilized to update the models. Projections of future performance will allow continuing evaluation of various operating alternatives.

WATERFLOOD PLANNING

Once adequate reservoir performance information is available to allow evaluation of the desirability and optimum plan for a source water injection program, about three years are required to develop the final design, fabricate, and install the system. Although three years is a tight schedule to install the first increment of a source water injection system at Prudhoe Bay, it is achievable based on recent experience gained in installing production facilities. Production facilities for 1.2 MMB/D of oil will have been completed in approximately 3-1/2 years from the beginning of detail design work. During this period construction expertise has been gained and extensive support facilities have been constructed, all of which will be used in future Prudhoe Bay construction projects, including source water injection systems.

In order to keep construction lead time to a minimum, a detailed Waterflood Planning Study has been initiated which will provide necessary information concerning water source, water treating requirements, potential water freezing problems, environmental considerations, and equipment and material requirements. Based on Arctic construction experience and worldwide waterflood experience, technology exists to solve anticipated Prudhoe Bay waterflood problems, however, numerous optimization studies are necessary to assure the economic viability of the project.

One phase of the Waterflood Planning Study that has already received considerable effort is water treating requirements, including filtration, deaeration, and chemical treatment. The major intent of this preliminary study is to obtain water samples from the Arctic Ocean at Prudhoe Bay on a seasonal basis. In March and June, 1976, an extensive sampling program was conducted. The March sampling was taken during conditions of thick ice and minimum turbidity while the June sampling occurred during the time of maximum river run-off. The results of both of these sampling programs indicate the Arctic water to be of good quality. Dissolved solids and biological studies indicate rapid settling rates and essentially sterile conditions. Oxygen content of the water is low and deaeration may only be necessary during periods of rapid river run-off. Overall, results indicate that the Arctic Ocean can be used and is the most likely source of injection water.

The Cretaceous water sands which overlie the Sadlerochit reservoir at Prudhoe Bay have also been considered as a potential source. However, these sands are poorly consolidated and developing them as a water supply would likely require the drilling of a large number of wells, special sand control completion techniques, and the use of high-volume submersible pumps. While these early indications suggest that the Cretaceous may not provide an adequate long-term, high-volume supply of injection water, these sands may be useful as a source of injection water for localized areas.

Studies conducted over the past several years have indicated that source water injection is mechanically feasible at Prudhoe Bay. However, water injection rates, location, and total volumes appear to be as important to the overall success of a water injection project as the mechanical optimization requirements. Consequently, the reservoir and mechanical aspects of the project must be evaluated concurrently. The preliminary Waterflood Planning Study currently in progress should be completed in mid-1978 at which time more detailed design studies can begin. These studies will continue concurrent with the gathering and analysis of field performance history which is necessary before a final decision to inject source water can be made.

CONCLUSIONS

1. The proposed Prudhoe Bay Unit operating plan provides for sustained oil offtake rates of 1.5 to 1.6 MMB/D after 1978, assuming available oil pipeline capacity, and gas pipeline deliveries of 2.0 Bcf/D as soon as gas pipeline facilities and a conditioning plant can be approved and constructed (4-1/2 to 5 years after the start of oil production). This plan provides for expeditious and economic development of the total energy resource at Prudhoe Bay consistent with good oil and gas conservation practices. Approval of the gas offtake plan is needed now to insure that gas pipeline and conditioning plant projects can proceed on schedule.

2. The planned oil offtake rate is supported by sensitivity studies which indicate that in the range of 1.2 to 1.8 MMB/D, oil rate has no significant effect on the ultimate recovery of oil or gas.

3. The planned gas pipeline sales from Prudhoe Bay, when begun, will immediately increase current energy to the consumers and current income to the owners, eliminate fuel requirements and unnecessary costs for injecting produced gas, and provide for a measure of protection for the correlative rights of owners in the Oil Rim and Gas Cap participating areas of the proposed Prudhoe Bay Unit. With appropriate reservoir management, the planned gas offtake rates will have little or no effect on ultimate oil recovery.

A gas conditioning plant is required to remove carbon dioxide, extract excess gas liquids, dehydrate, and cool the gas to meet pipeline specifications. The final design of gas conditioning facilities will depend upon gas pipeline pressure and specifications. Gas liquids extracted during conditioning will either be blended with the crude and condensate for transportation through the oil pipeline or utilized as fuel.

4. Injection of produced water into certain areas of the Sadlerochit reservoir with poor natural depletion performance will be beneficial to ultimate oil recovery. The current plan is to selectively inject produced water into the Sadlerochit reservoir when water production volumes become significant.

5. Potential exists for additional oil recovery by the implementation of a well designed source water injection program. Within reasonable limits, the timing of source water injection startup is not as critical as injecting proper volumes of water at the optimum locations. Reservoir surveillance and testing information obtained during the first few years of production will provide information necessary to confirm the desirability and define the optimum plan for source water injection. Preliminary design studies currently underway will shorten the implementation time once final decisions can be made. Although final commitment cannot be made at this time, the current plan anticipates that source water injection will be initiated within five to nine years after the start of oil production.

6. Studies indicate that depending on overall economic considerations, oil recovery of about 40% OOIP (8.5 billion barrels) can be achieved from the Main Area Sadlerochit reservoir for a reasonable range of operating conditions and reservoir descriptions. These reserves do not include additional production from the Eileen Area, other Permo-Triassic formations or gas liquids. An expected ultimate gas recovery of approximately 75% of the total gas-in-place in the field results in dry gas reserves of about 26 trillion cubic feet (after removal of gas liquids and non-hydrocarbons).

FIGURE 1

STRUCTURE MAP
TOP OF SADLEROCHIT SAND

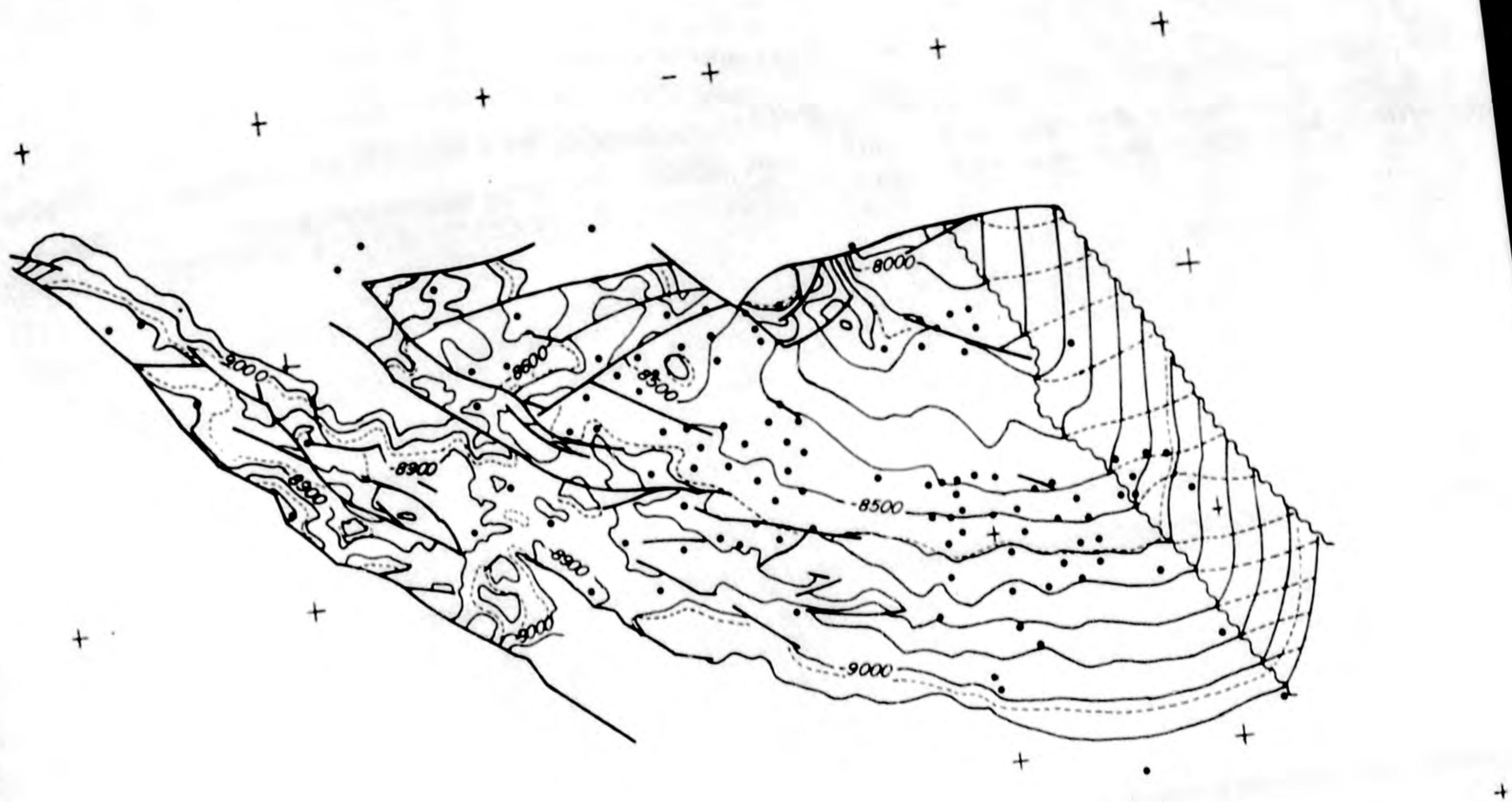


FIGURE 2

PRUDHOE BAY SADLEROCHIT FORMATION

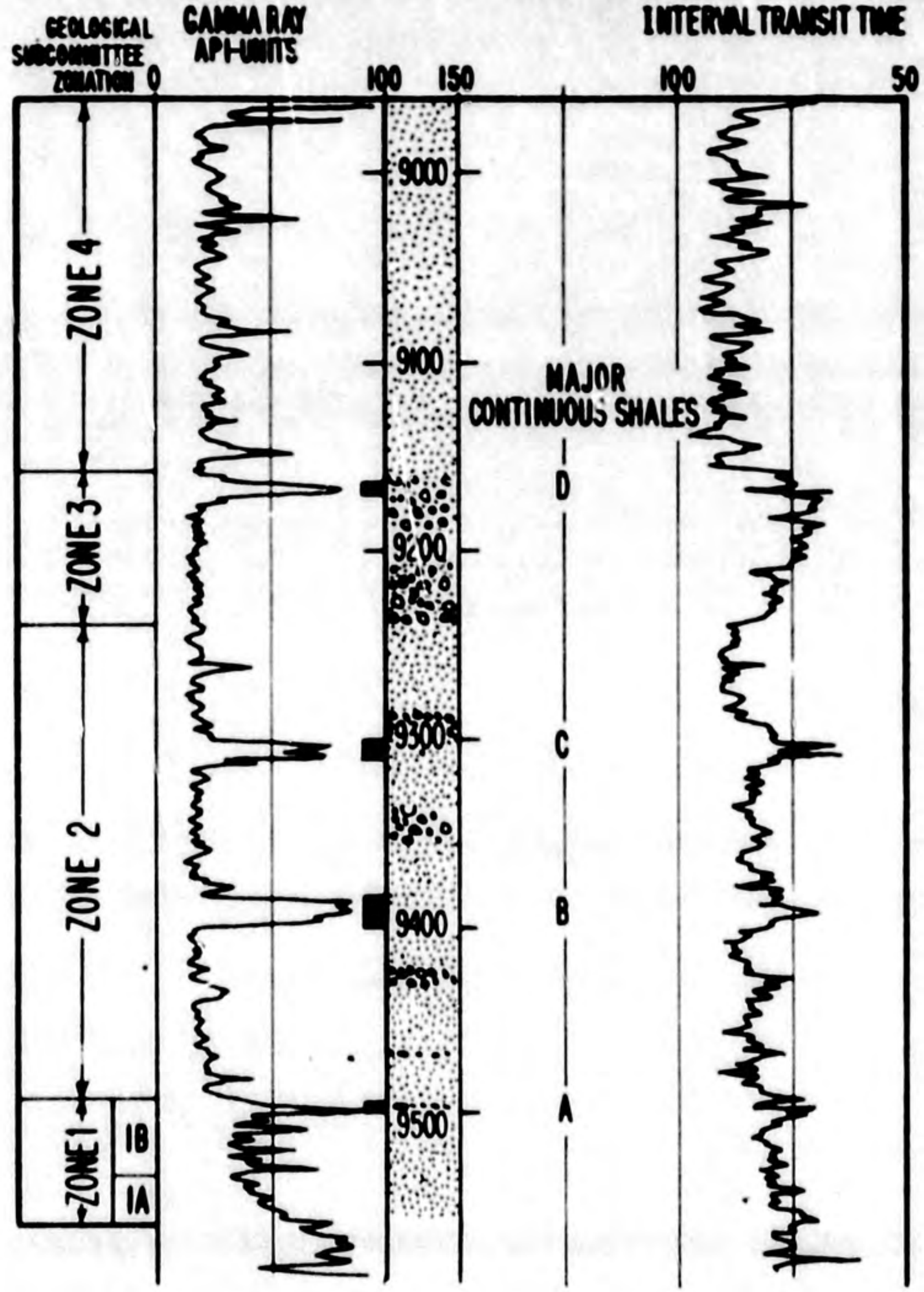


FIGURE 3

3955

PRUDHOE BAY FIELD

IN-PLACE HYDROCARBON VOLUMES

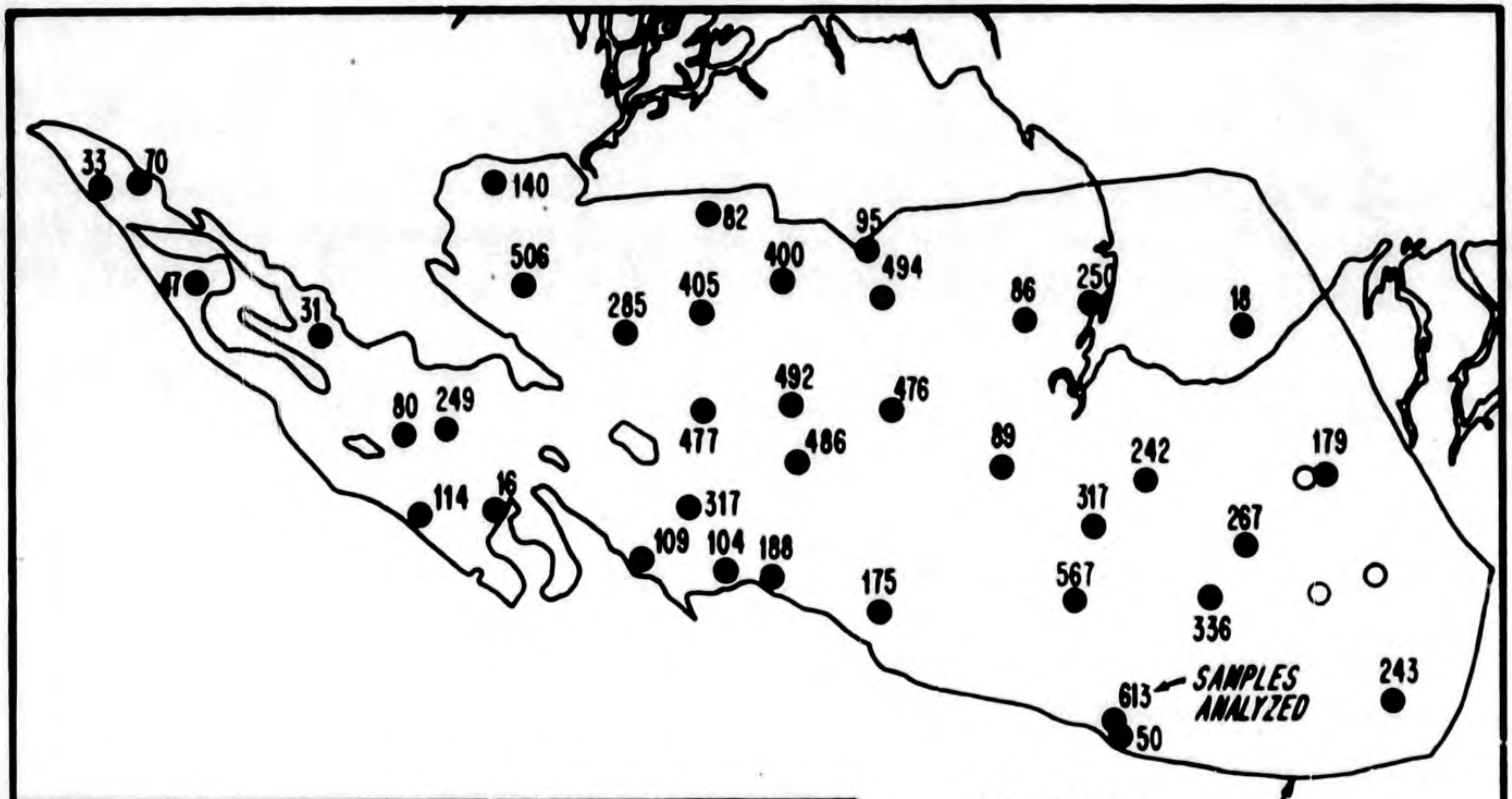
SAG RIVER, SHUBLIK & SADLEROCHIT FORMATIONS

	MAIN AREA			EILEEN AREA			TOTAL
	SAG	SHUB	SADL.	SAG	SHUB	SADL.	
GAS CAP (TSCF):	3.6	0.1	22.4	0.2	—	0.3	26.6
OIL ZONE (MMMRB):							
LIGHT OIL	0.8	0.1	27.2	0.1	<0.1	1.1	29.3
HEAVY OIL/TAR	—	—	1.9	—	—	—	1.9
TOTAL	0.8	0.1	29.1	0.1	<0.1	1.1	31.2

FIGURE 4

PRUDHOE BAY FIELD
CORE DATA & ANALYSIS
SADLEROCHIT RESERVOIR

3945-A



	EILEEN AREA		MAIN AREA	
	WELLS	SAMPLES	WELLS	SAMPLES
● CORE DATA ANALYZED	8	640	30	8488
○ WELLS RECENTLY CORED			3	

FIGURE 5

PRUDHOE BAY
SADLEROCHIT FORMATION

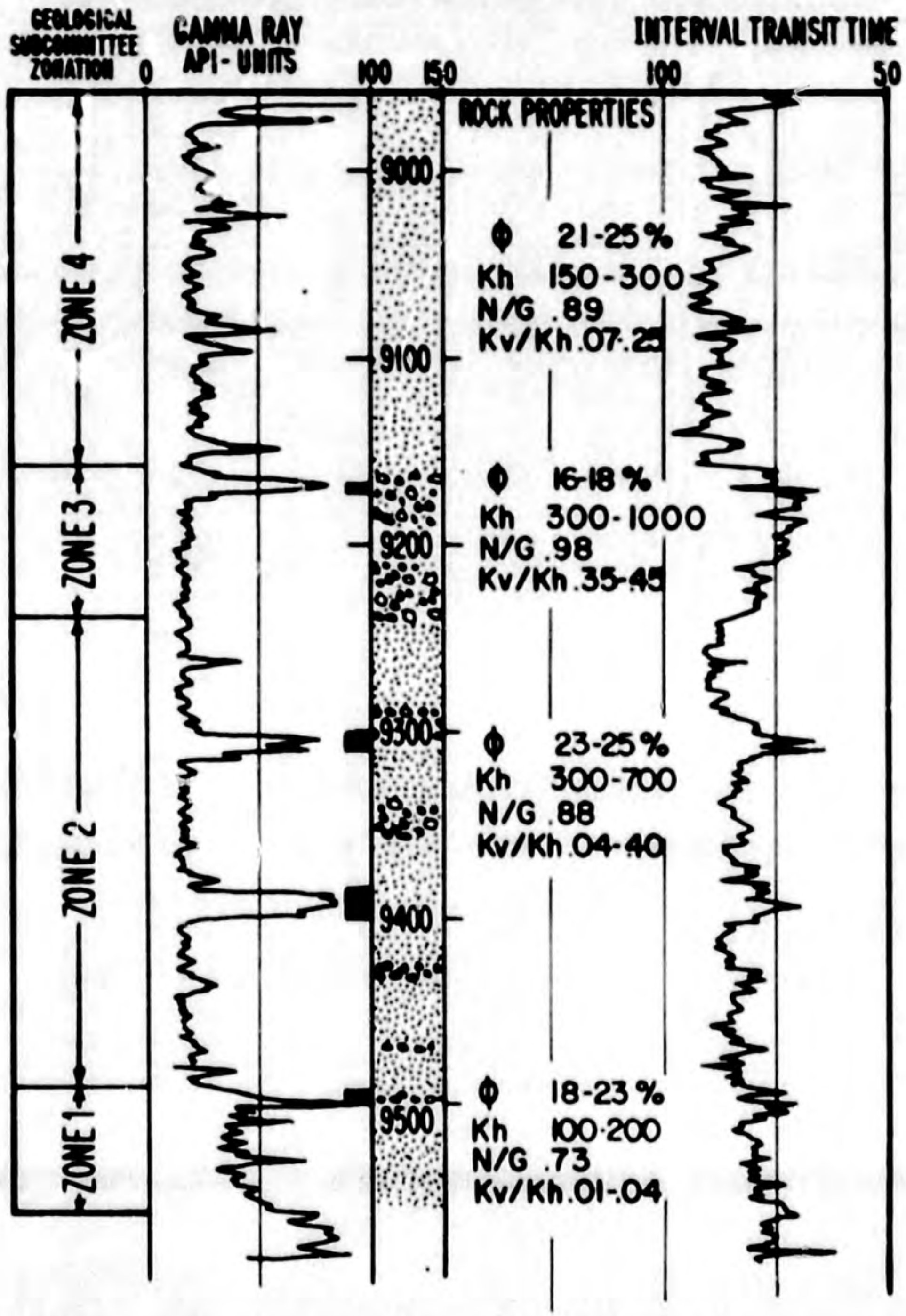


FIGURE 6
PRUDHOE BAY AREA

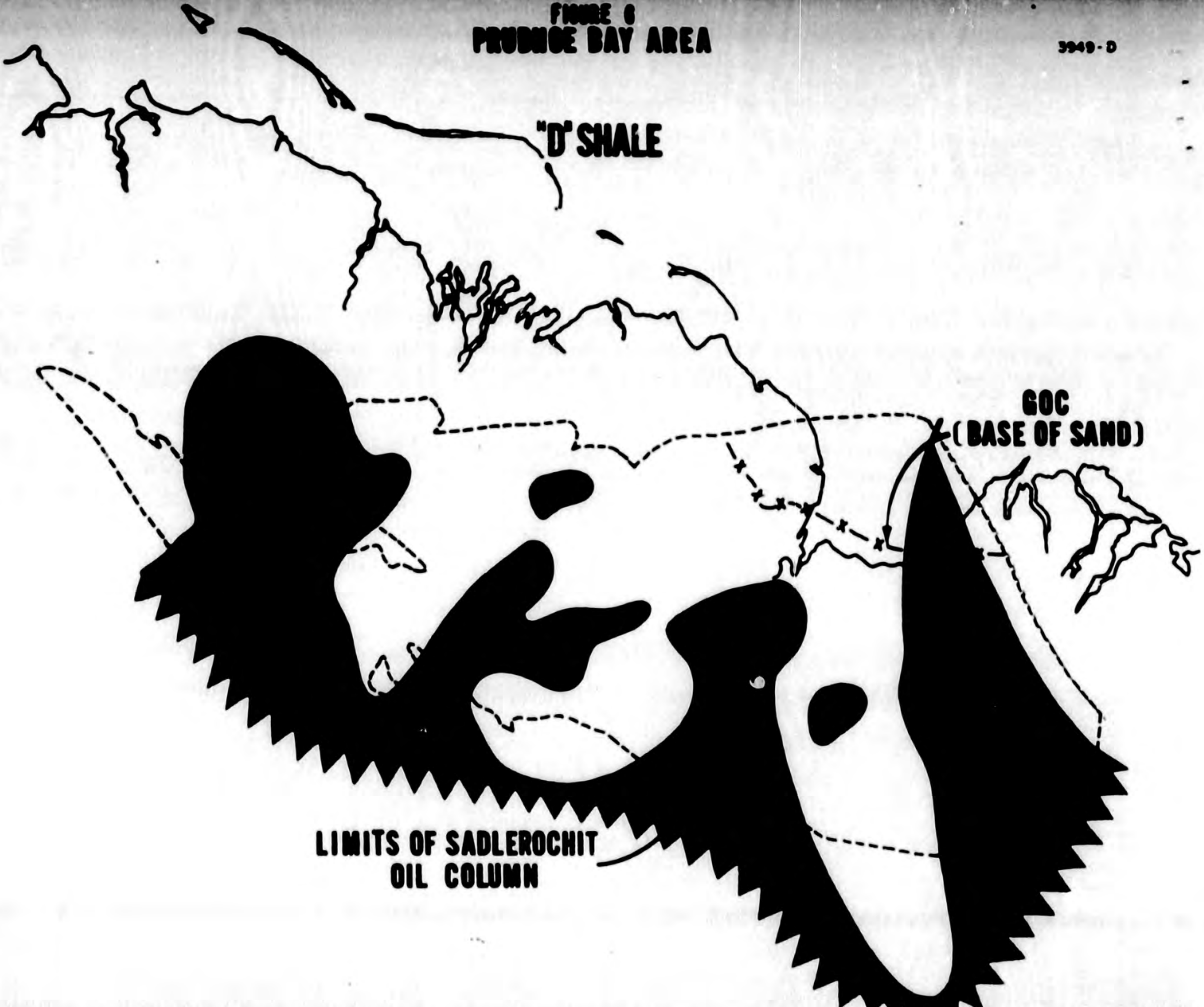


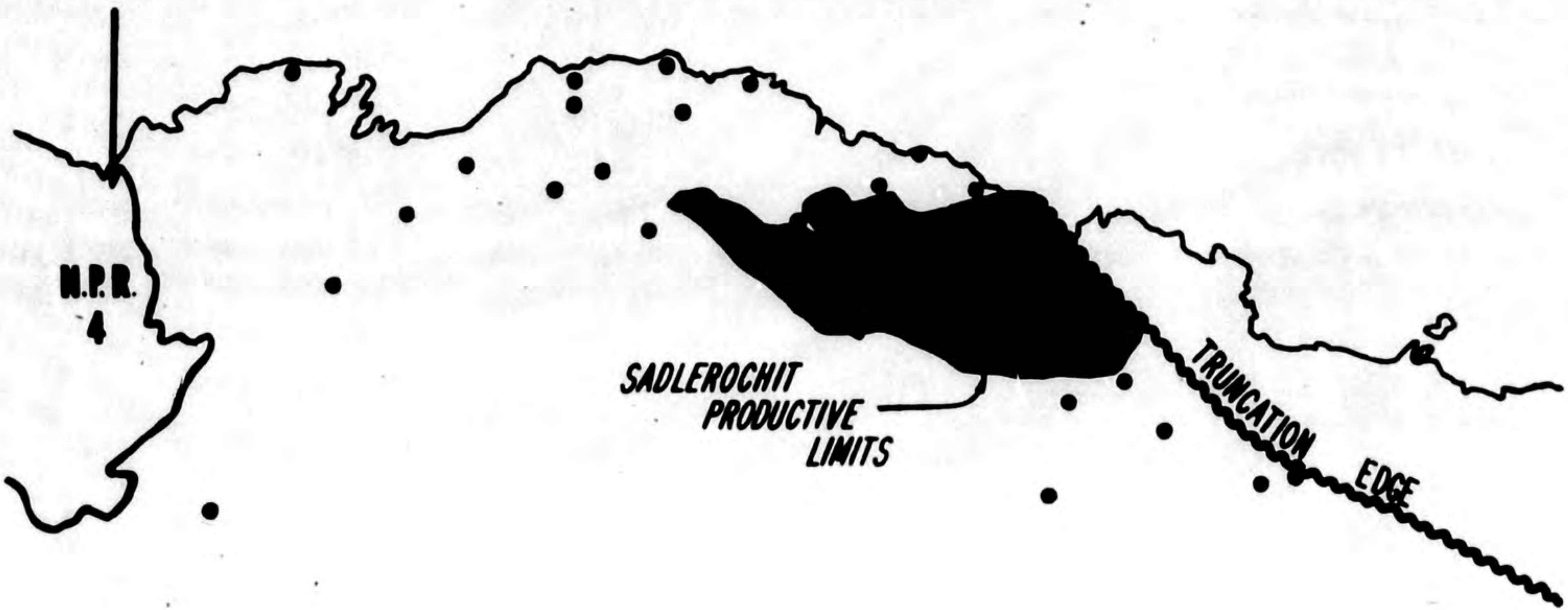
FIGURE 7

HEAVY OIL - TAR ISOPACH

C.I.= 20

FIGURE 8

PRUDHOE BAY FIELD
AQUIFER DESCRIPTION
SADLEROCHIT RESERVOIR



DIST. FROM OWC (mi)	AVG. PROPERTIES Φ (%)	K (md)	AQUIFER VOL. (Billion RB)
1.	20.6	225	36
5	18.1	80	163
10	15.3	25	308
15	13.5	12	400
25	11.4	5	705
50	9.1	2	1150

0 5 10 15
Scale in Miles

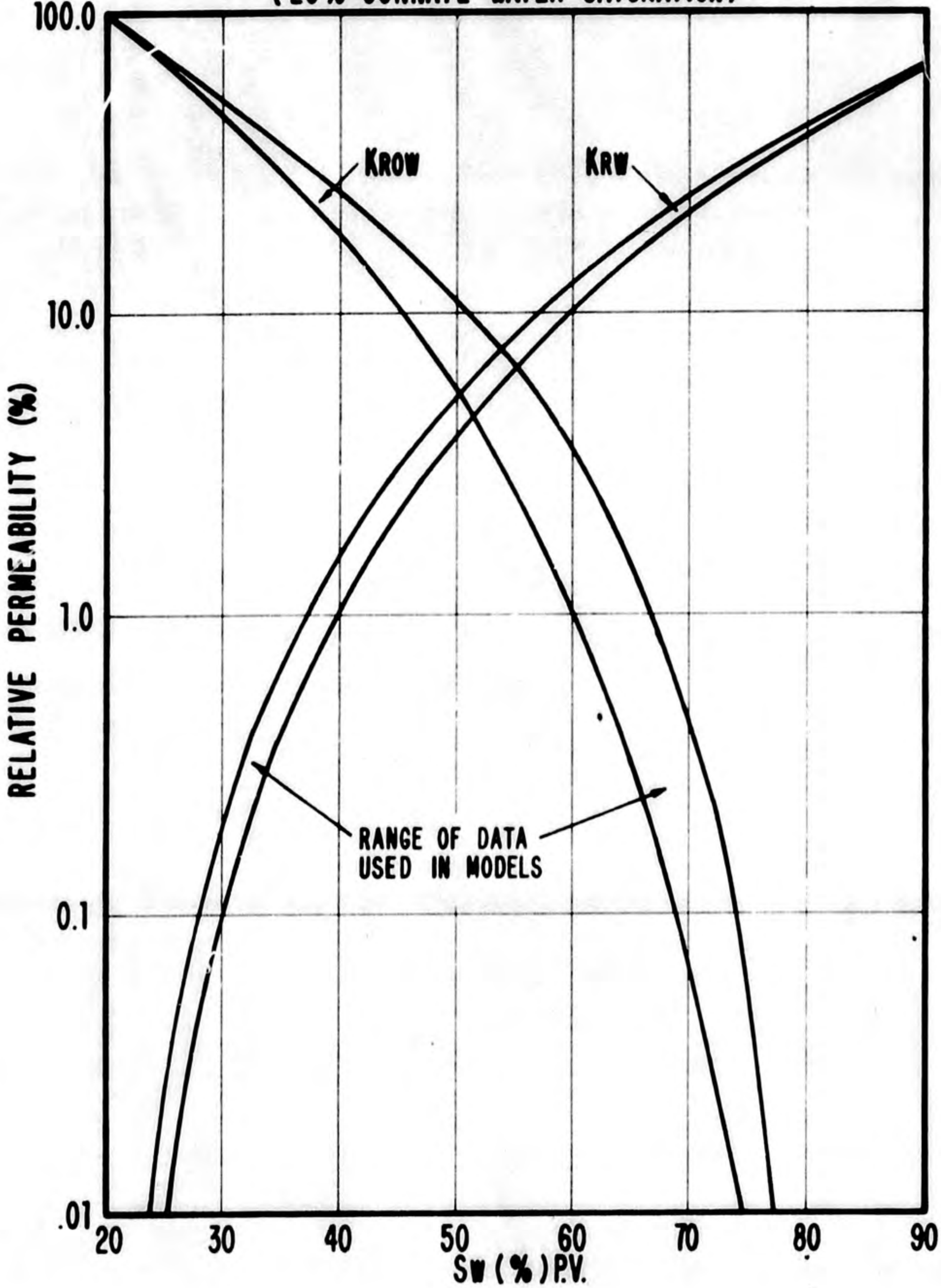
FIGURE 9

SADLEROCHIT WATER - OIL IMBIBITION

RELATIVE PERMEABILITY

(20% CONNATE WATER SATURATION)

3952



3953

FIGURE 10

SADLEROCHIT GAS - OIL DRAINAGE RELATIVE PERMEABILITY

(20% CONNATE WATER SATURATION)

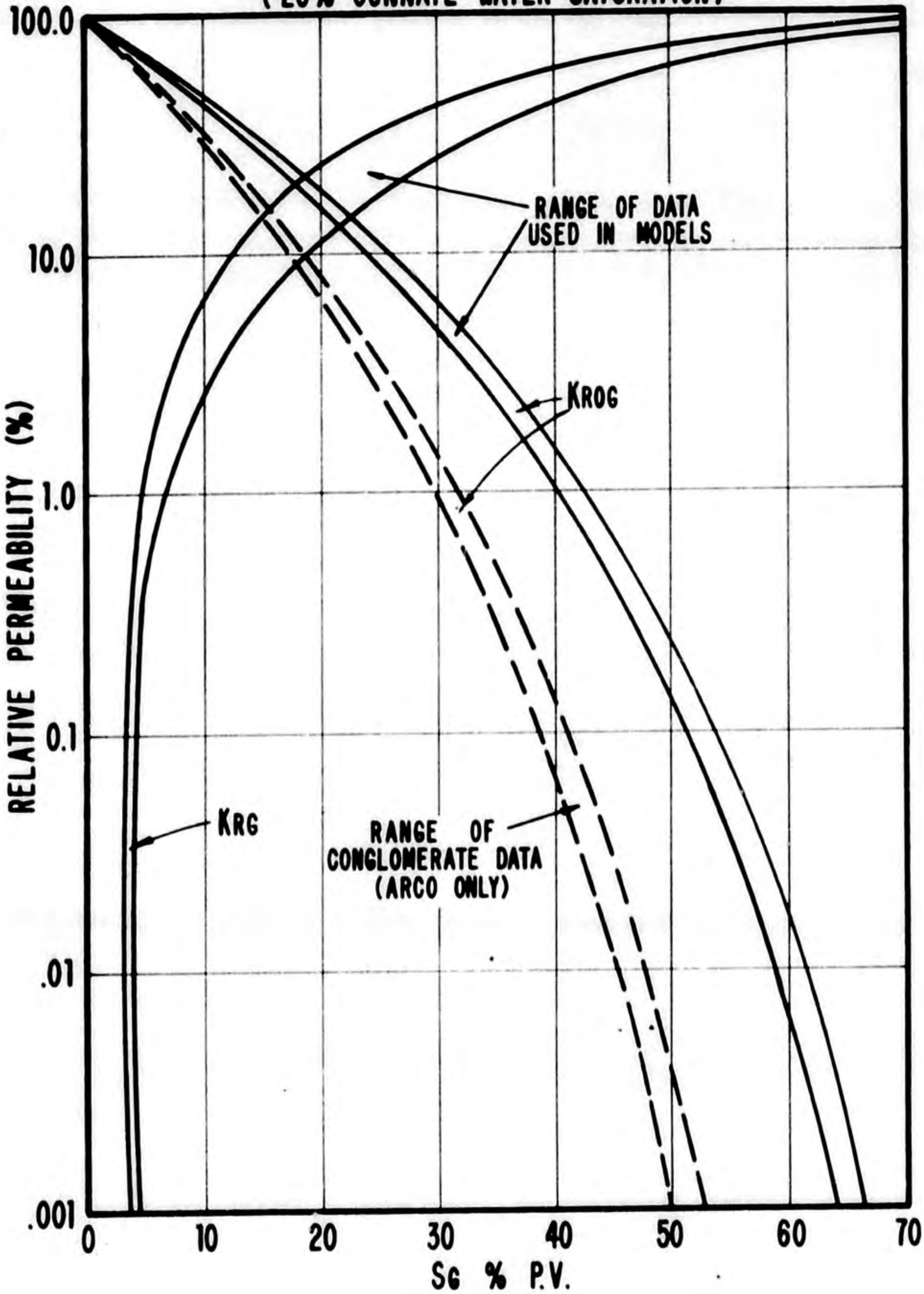


FIGURE 11

WATER INJECTION CASE STUDIES
MAIN AREA SADLEROCHIT RESERVOIR
PRUDHOE BAY FIELD, NORTH SLOPE, ALASKA

	Water Injection Program			Gas Pipeline Deliveries	
Case No.	Startup (Yrs. of Prod'n)	Peak Rate (MMB/D)	Total Injection thru 20 years (MMMB)	Start (Yrs. of Prod'n)	Rate (Bcf/D)
	CASE STUDIES RECOVERING APPROXIMATELY 39% OOIP:				
1.	5	1.7	8.5	5	2.0
2.	7	2.0	8.6	5	2.0
3.	9	2.5	10.0	5	2.0
4.	7/5	2.6	11.8	5	2.5
	CASE STUDIES RECOVERING APPROXIMATELY 40% OOIP:				
5.	7	2.0	8.6	10	2.5
6.	5	3.0	12.4	5	2.0
7.	7/5	3.0	12.2	5	2.0
8.	7	3.5	15.6	5	2.0

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DIRECT TESTIMONY BEFORE THE
SENATE COMMITTEE ON ENERGY
AND NATURAL RESOURCES
OCTOBER 25, 1977

Mr. Chairman, Committee Members, I am Dr. Terry Koonce, Alaska Operations Manager for the Western Division of Exxon Company, U.S.A. Prior to assignments in Exxon's Production Department, I spent 10 years with Exxon's production research affiliate. For more than half of this time I was directly involved in and managed reservoir research and engineering studies for Exxon's worldwide operating affiliates. I appreciate the opportunity to appear before this Committee and to testify on a subject so vital to the Nation's energy supply.

Introduction

Exxon believes strongly that it is in the common best interest of the Nation and all concerned, including the producers, to maximize recovery of both oil and gas at Prudhoe Bay and elsewhere. We firmly believe that the plan of operation developed for the Prudhoe Bay Field is sound and that the estimated oil recovery of 40 percent will be achieved.

Exxon's experience in other fields supports this relatively high recovery efficiency. While we do not operate the Prudhoe Bay Field, we have a substantial working interest in the oil and gas and are assisting the operators with the technical skills necessary to maintain an operating plan that maximizes recovery.

Data Base

Exxon participated in drilling the discovery well in 1968; since that time, massive amounts of data have been collected and thoroughly analyzed to develop the best possible description of the Prudhoe Bay Field. Exxon, in conjunction with its research affiliate, has independently analyzed rock and fluid properties. Reservoir rock properties have been determined from more than 10,000 samples from over 40 wells and confirmed by approximately 50 production pressure tests. Fluid distribution in the reservoir is based on the rock samples and over 70,000 feet of well logs from 175 wells. Fluid properties have been derived from over 40 samples of the oil and gas in the reservoir. Displacement efficiencies have been determined from extensive lab tests, many of which were conducted at reservoir temperature and pressure conditions using actual reservoir rock and fluids.

Using this data base, we have been actively involved in conducting independent reservoir performance studies necessary for development of a field operating plan. We have taken into account comparisons with other producing fields and have employed proven reservoir engineering technology, including the use of the most advanced models and simulator techniques available. Exxon alone has devoted about 50 man-years and 700 hours of computing time to Prudhoe Bay reservoir studies.

Operating Plan

Our studies support the operating plan for the Prudhoe Bay Field which includes:

First, an annual average oil offtake rate of 1.5 million barrels per day when oil pipeline capacity is available. Our studies have shown essentially the same oil recovery for oil offtake rates ranging from 1.2 to 1.8 million barrels per day. At the planned offtake rate, oil production is projected to decline after 1987 at a normal rate of about 14 percent per year.

Second, the plan includes gas pipeline deliveries of 2.0 billion cubic feet per day as soon as a gas transmission system can be completed. It is estimated that this gas delivery can be sustained for 20 to 25 years before declining.

Third, low pressure and artificial lift systems are planned when needed to maintain productive capacity, and

Fourth, injection of produced water into the reservoir is planned as soon as those volumes become significant, now estimated to be within 2 to 4 years. Additionally, injection of water from a source external to the reservoir can begin within about 7 years when additional oil recovery benefits are confirmed and the optimum injection locations and volumes are determined. This timing is adequate to achieve maximum benefits of waterflooding.

The detailed studies supporting this plan were presented to the State of Alaska Division of Oil and Gas Conservation and their consultant during the course of technical meetings requested by the Division in 1975 and 1976 and were summarized at the public pool rules hearing in Anchorage on May 5 and 6, 1977.

Surveillance

We are confident that the approved operating plan has sufficient flexibility to accommodate variations in reservoir performance from that predicted. The key to recognizing these variations and optimizing the operating plan is a thorough program of reservoir surveillance and testing. Such surveillance activities include monitoring pressures, gas-oil contact movement, oil-water contact movement, and individual well performance. These activities have been approved by the State of Alaska Division of Oil and Gas Conservation and are incorporated in the field rules.

Tertiary Recovery

In the course of our reservoir performance studies, the possible application of tertiary recovery programs has also been considered. Exxon maintains a considerable research effort devoted to developing viable tertiary recovery techniques, but we know of no such techniques that would be applicable at Prudhoe Bay on a fieldwide basis. The industry has many field tests of tertiary processes underway in more mature fields in the lower 48. As such research and development continues, we will examine the potential use of tertiary recovery methods in the Prudhoe Bay Field.

Doscher Testimony

I would like to comment briefly now on Dr. Doscher's testimony. In June and July of this year, reservoir engineers from Exxon, as well as BP and ARCO, met twice with Dr. Doscher. The purpose of the meetings was to allow him to review the studies which served as the basis for the operating plan approved by the State of Alaska. At the close of those discussions, Dr. Doscher took no exception to the approved operating plan for the field, which includes gas sales. We are not aware of any independent analyses that he had conducted at that time or has conducted since that time. Consequently, we do not understand how, based on existing studies, he could have reached the conclusions he stated before this Committee on October 12.

As we previously testified before the State of Alaska, our studies show that there is sufficient operational flexibility to make gas sales of 2.0 billion cubic feet per day without adversely affecting ultimate oil recovery.

Simulation studies conducted independently by the field operators and numerous consultants for the State of Alaska, the Department of Interior, and gas pipeline applicants also support the preferred plan of operation for the field including early gas sales.

It is unfortunate that confusion has arisen in the proceedings of this Committee in spite of such overwhelming evidence. In Exxon's view the Committee should move forward in its consideration of the gas pipeline with confidence that Prudhoe Bay gas can be produced without adversely affecting oil recovery.

Conclusions

In conclusion, the approved operating plan for the Prudhoe Bay Field meets the major objectives we feel are important.

First, it provides for the timely development of the total Prudhoe Bay energy resource, both oil and gas. The earliest possible development of Prudhoe Bay gas is extremely important since it represents 12 percent of proven domestic gas reserves. The Department of Interior and Federal Power Commission have stated that Prudhoe Bay gas is competitive with alternative energy sources and its development has a positive net national economic benefit.

Second, the reservoir will be managed to achieve the maximum recovery of both oil and gas, consistent with sound engineering practices.

Third, the plan provides the flexibility necessary to respond to actual reservoir performance so as to maintain efficient recovery of oil and gas from the field.

In view of the critical need for domestic energy supplies, Exxon believes the prompt and efficient development of Prudhoe Bay oil and gas resources is in the common best interest of the producers, the State of Alaska, and the Nation.

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STATEMENT OF

E. G. HOULSTON
BP ALASKA, INC.

BEFORE THE

SENATE COMMITTEE ON

ENERGY AND NATURAL RESOURCES

OCTOBER 25, 1977

TESTIMONY OF E. G. HOULSTON
BP ALASKA/SOHIO

My name is George Houlston. I am the Manager of Reservoir Engineering for BP Alaska. BP Alaska operates in the Prudhoe Bay Field on behalf of The Standard Oil Company of Ohio.

I am here today in response to your request to take testimony concerning recommendations made before this Committee on October 12, by Dr. Todd Doscher. My statement today has been prepared to clarify BP/Sohio's position in regard to the points raised before this Committee.

Many studies on the Prudhoe Bay Field have been performed. Indeed, the claim has been made that this Field has been studied more than any other prior to production. In my opinion the most comprehensive review of the work performed on Prudhoe Bay Field was presented by the Working Interests and the Consultants to the State of Alaska, at the Conservation Hearing held in Anchorage on May 5 and 6. Those proceedings are a matter of public record.

The Prudhoe Bay Field is estimated to contain some 22.9 billion barrels of stock tank oil in place. By far the most significant portion of this in place oil, some 22.2 billion stock tank barrels, is to be found in the Sadlerochit formation. The other .7 billion stock tank barrels are located in the Sag River and Shublik formations which overlie the Sadlerochit. Major geologic faults appear to partition the reservoir between the Main Area of the Field and the West End or Eileen Area. The Field is thus subdivided by geologic formation and by area.

The Main Area Sadlerochit contains 21.4 billion stock tank barrels, and it is this accumulation which has been the subject of intensive study by the Working Interests in the Field and by other interested parties. It has been estimated that oil reserves of about 8.6 billion stock tank barrels will be recovered from the Main Area Sadlerochit. The estimated oil reserves for the entire field amounts to some 9.4 billion stock tank barrels. These include .5 billion stock tank barrels of condensate recovered from gas cap gas and .3 billion barrels from the Sag River and Shublik formations and the West End Sadlerochit.

Gas cap gas in place in the field amounts to 26.5 trillion cu.ft. at standard surface conditions. A further 17.1 trillion cu.ft. of gas is in place as solution gas. Some 26.5 trillion cu.ft. of hydrocarbon gas are considered to be recoverable and 300-400 million barrels of gas liquids. The heating equivalent of these reserves amounts to about 5 billion barrels of crude oil.

BP Alaska, acting on behalf of Sohio Petroleum, has viewed production from the field as a matter of maximizing total hydrocarbon recoveries. The studies we have conducted have been aimed towards formulating sound reservoir management policies consistent with that objective. Our studies have concentrated primarily on the Main Area Sadlerochit reservoir. The oil recoveries estimated in reservoir simulation calculations do not include the 800 million barrels of oil and condensate recoverable from other sources in the Field.

The studies we have conducted have included not only reservoir fluid flow considerations but also other factors which influence reservoir performance such as well density, surface facility operating conditions and capacities, gas lifting or pumping of oil wells, and the injection of gas and water. Ultimate hydrocarbon recovery is the outcome of collectively exercising these development options to varying degrees and at appropriate times throughout the life of the Field.

Based on current reservoir information and proven methods of recovery our studies have led us to a plan of operations which incorporates the following major elements:

(i) Production of oil at an average rate of 1.2 MMB/D increasing to 1.5 MMB/D when pipeline capacity is available.

(ii) The re-injection of gas produced in excess of that needed for fuel and sales.

(iii) The delivery of 2 BCF/D of sales gas as soon as a gas pipeline and a plant to condition the gas to specification can be completed. (Currently estimated to be some time during 1983).

(iv) The drilling of wells on 160-acre spacing or closer if necessitated by reservoir performance.

(v) The re-injection of produced water into the reservoir and the probable supplementing of such water with source water within seven years from the start of oil production (i.e., 1984 or earlier).

(vi) The installation of lower pressure gathering and separation systems and artificial lift facilities.

(vii) A very intensive program of reservoir surveillance and testing to compare forecasted against actual performance on a continuous basis.

By implementing this plan of operations it is anticipated that peak production rates from the Field could be sustained for seven or eight years and deliveries of gas could be held at 2 BCF/D for about 25 years. In all the cases we have studied, oil production declines when gas handling facilities can no longer cope with the gas produced with the oil. It should be possible to manage and operate the reservoir within the framework of this plan to achieve a recovery of about 40% of the original oil in place after 25 years and about 72% of the gas originally in place over 40 years.

After 25 years of oil production our simulation models indicate residual oil saturations in the original oil column which are mainly in the range of 25-45%. Earlier testimony given to this Committee to the effect that residual oil saturations in our simulatio runs were extremely low, approaching zero, can be categorically dismissed as without foundation and in complete contradiction to sworn testimony presented by BP Alaska to the Division of Oil and Gas Conservation, State of Alaska.

Scope may well exist for improving recoveries by applying methods of enhanced recovery, when such methods have been proven in the field. The plan of operations should not diminish the viability of any such prospective schemes. The Working Interests will remain continuously alert to all promising schemes for additional recovery.

In developing the present plan of operations, we investigated many variations in oil offtake, gas sales and water injection. In contrast to some opinions expressed, our studies have shown that the timing of gas sales at a rate of 2 BCF/D affects ultimate oil recovery only slightly. We estimate a possible loss of oil recovery on the order of 1% of the oil in place or just over 200 million barrels over 25 years of oil production. Over the same period, more than twelve times the heating equivalent of the 'lost' oil could be recovered through gas sales. We conclude that the rather sweeping quality judgment that the sale of gas is detrimental to ultimate oil recovery, is thoroughly misleading when considered out of the context of the level and timing of gas sales, the associated oil offtakes and all the other developments which are planned to promote recovery from the Field.

We have tested our plan of operations against oil offtakes of 1.2 to 1.8 MMB/D and gas sales of 2 BCF/D starting as soon as a gas line and conditioning plant can be completed. Again, from our studies we expect only slight variations in ultimate oil recoveries after 25 years of production.

At oil offtake rates of 1.5 MMB/D, we have studied the effects of gas sales at 2.5 BCF/D commencing as soon as a gas pipeline is available. This resulted in a lower oil recovery of about one and one-quarter per cent after 25 years. Using an earlier reservoir description we also investigated extreme cases of no gas sales and sales of 3.5 BCF/D. In the case of no gas sales, water was still injected though at a lower rate, and recovery obtained was about one and one-half per cent higher than with sales at 2 BCF/D. At gas sales of 3.5 BCF/D recovery fell by about 5% but this run was performed with the same water injection rate as the 2 BCF/D gas sales rate. A more successful outcome would have been possible but was not pursued. We have concluded that gas sales at 2 BCF/D should not cause concern in regard to ultimate oil recovery. At this stage, any proposal to sell gas at 2.5 BCF/D by 1983 we would approach with caution, and we would actually oppose any scheme to sell gas at 3 BCF/D as early as 1983.

It is recognized that the forecasting of reservoir performance with little or no production history in a field as large as Prudhoe Bay is subject to uncertainty. We have had to rely heavily on our reservoir simulation studies to predict detailed reservoir behavior. However, the experience that has been gained from operating other fields similar to Prudhoe Bay has been specially valuable in assessing the validity of our model predictions. We are confident that our near term assessment of Prudhoe Bay performance is a reasonable one.

Looking to the longer term, in many of the reservoir simulation model runs we have made, the differences in oil recovery arising between hypothetical reservoir management options do not become fully apparent until after about 15-20 years of oil production have taken place. There is every reason to expect, therefore, that there will be time and scope to adapt our plan of operations to ensure that hydrocarbon recoveries are maximized. The intensive reservoir surveillance and testing program which we will be undertaking will provide the control information necessary for those purposes.

The Working Interests in the Prudhoe Bay Field have acquired unusually detailed reservoir information prior to production. This has been very fully utilized and very considerable efforts have been devoted to studying the Field and developing the plan of operations. Although the results of the studies performed by the Working Interests are not the same in numerical detail, all the Working Interests have drawn similar conclusions in regard to how the Field should be produced.

Mr. Chairman, I submit that this consensus view is a sound technical basis to support the sale of Prudhoe Bay gas as soon as a pipeline and conditioning plant can be constructed.

BP ALASKA, INC.
SAN FRANCISCO, CALIFORNIA
October 25, 1977

TESTIMONY OF O. K. GILBRETH, JR.
DIRECTOR, DIVISION OF OIL AND GAS CONSERVATION
DEPARTMENT OF NATURAL RESOURCES, STATE OF ALASKA

BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
WASHINGTON, D.C.
OCTOBER 25, 1977

Mr. Chairman, other distinguished Senators, Ladies and Gentlemen. My name is O. K. Gilbreth, Jr. and I am Director of the State of Alaska'a Division of Oil and Gas Conservation in the Department of Natural Resources and Chairman of its Oil and Gas Conservation Committee. Our office is located at 3001 Porcupine Drive, Anchorage, Alaska 99501. With me today is Mr. Hoyle Hamilton, our Chief Petroleum Engineer, who is also a member of the Oil and Gas Conservation Committee, Dr. H. K. van Poollen, President of H. K. van Poollen and Associates who is a consultant for the State, and Robert H. Loeffler, who has been counsel to the State in the gas pipeline proceedings.

My primary responsibility as Director of the State Division of Oil and Gas Conservation is to regulate oil and gas industry operations to prevent the physical waste of oil and gas in the State and to protect the correlative rights of all interests in an oil and gas field. Our goal is to regulate production in a manner which will insure that maximum recovery of hydrocarbons is achieved and physical waste is avoided.

I presented testimony to the Federal Power Commission during its hearing on the Alaska gas pipeline similar to the testimony I am presenting here today. I also accompanied the State's Commissioner of Natural Resources when he presented testimony on the subject of production rates from the Prudhoe Bay Field before the Senate Interior and Insular Affairs Committee in February, 1976.

First, I will address briefly a history of the field and the State's preparation for exercising its regulatory responsibilities with respect to the field, next I will respond to the five questions your Committee addressed to us, and finally I will comment upon several points made by Professor Todd Doscher in his testimony to this Committee and in his report for the State of Alaska's Legislative Affairs Agency.

After the Prudhoe Bay Field was discovered, our assessment of the reservoir content, size, configuration and fluid properties suggested to us that the reservoir probably would be rate sensitive and that the rate of gas withdrawal might affect oil recovery. For that reason, in 1972 we recommended to the legislature that the State undertake an independent reservoir study of the Prudhoe Oil Pool using reservoir models to simulate the reservoir performance of the Pool. Funds were appropriated for that purpose and the State hired the firm of H. K. van Poollen and Associates of Littleton, Colorado to assist in this analysis. The van Poollen firm was selected because it is one of the foremost firms in the Nation specializing in petroleum engineering and reservoir simulation.

Generally, State personnel did the geological and mapping work and some of the basic reservoir engineering. The van Poollen organization performed a large part of the reservoir analysis and made the simulation runs which predict reservoir performance. Our Chief Petroleum Engineer, Mr. Hamilton, has supervised this work and maintained overall control of the project since inception. During the five years of this study, the State has spent approximately one-half million dollars in addition to several thousand manhours on accumulating and analyzing the reservoir data.

Because of the vast size of the Prudhoe Bay Field, it was realized early in the development of the field that it would be very difficult to protect correlative rights in the reservoir under conventional operations. Consequently the parties holding interests in the field joined to form a unit, as authorized by State law, so that the reservoir could be operated in an efficient and economical manner. In essence, this is achieved by operating the field as a single large lease with two operators, Atlantic Richfield Company and BP Alaska, Inc. The unit agreement, to which the State is a party by virtue of its status as an owner of a royalty interest in the field, was approved and signed by the State in May of this year and became effective retroactively to April 1. In agreeing to the Unit Agreement the State was acting in its proprietary capacity as lessor of the field and as owner of a royalty interest in the field.

Earlier this year the operators also requested approval of the Oil and Gas Conservation Committee of their plan to operate the Prudhoe Bay Field. On May 5, 1977, a public hearing was held by the Alaska Oil and Gas Conservation Committee to determine the acceptability of the operators' plans, to determine the proper initial rates of production for the reservoir and to adopt field rules regarding operation of the Prudhoe Oil Pool. As a result of that hearing Conservation Order No. 145 was issued by the Oil and Gas Conservation Committee. A copy of that order is attached to this testimony as Exhibit 1. The order contains many requirements to secure data during start-up and the initial production periods to aid in determining proper methods of operation of this reservoir.

The order requires that the operators obtain many bottom hole pressures in the early years of production and the securing of other data to aid in the surveillance of the gas/oil and water/oil contact movements. These requirements are designed to ensure that adequate information is obtained during the early life of this reservoir and to permit future operations to be undertaken in a manner to achieve the greatest ultimate recoveries.

Large volume production from this field started on June 20, 1977, but due to problems at Pump Station 8 the anticipated rates of production have not yet been realized. Data are already being gathered however to aid in matching computer predictions to actual field performance data.

With this as a background, we turn to the five questions that we understand the Committee would like to have addressed in our presentation.

1. <u>Existing reports and data pertaining to producers plans for operating the field.</u>

In October of 1976 the operators filed with the State their proposed plan of operations. Basically they plan to develop the reservoir on 160-acre spacing with initial production rates of 0.6 million barrels per day for six months, 1.2 million barrels per day for approximately twelve months and then increasing the rate to approximately 1.5 to 1.6 million barrels a day until production decline is reached. The plan provides for gas pipeline deliveries of 2.0 Bcf/D as soon as gas pipeline facilities are available and a conditioning plant can be approved and constructed. The plan also contemplates selective injection of <u>produced</u> water into the Prudhoe Oil Pool when those volumes become significant. Although a final committment cannot be made yet because of the need to gain operating experience with this Pool, the plan anticipates that water injection from sources outside the Pool will be initiated within five to nine years after the start of oil production.

Our study shows us that the Prudhoe Bay reservoir will be rate sensitive. By this we mean that the ultimate oil recovery from the reservoir would be affected by the net withdrawals from the reservoir and in some cases even by the rate of withdrawal. If oil, gas and water are removed without their reservoir volume being at least partially replaced, a reduction in oil recovery will result. If the reservoir voidage caused by production is replaced, then recoveries will be increased and can be maximized by the volume injected. Accordingly, we believe that fluids must be injected into the reservoir to supplement the natural recovery mechanism and that reservoir performance must be monitored closely and withdrawals controlled to achieve the maximum oil recovery. It is therefore obvious that if gas is to be sold, fluids or gases must be injected into the reservoir. The level of gas sales will be determined by the volume of fluids injected. In this respect, our studies do not differ significantly from those of the operators.

Our reservoir study -- commonly referred to as the van Poollen Report -- which leads to these conclusions was not undertaken for the purpose of dictating to the operators how the field must be operated. Rather, it was done to provide us with a guide to evaluating the operators proposal to manage the field.

The van Poollen Report was supplied to the Federal Power Commission and to all parties, including the competing pipeline applicants, in the Federal Power Commission Alaska gas pipeline proceeding.

2. <u>The possible effects of gas withdrawal at rates between 1.5 and 2.6 million cubic feet per day correlated with oil production between 1.2 and 2.0 million barrels per day.</u>

After the operators filed the proposed operating plan, the State utilized it to update Alaska's model of the Prudhoe reservoir and made several additional computer runs. These additional runs may be found in a February 1977 supplement to our reservoir study titled "Prediction of Reservoir Fluid Recovery Sadlerochit Formation Prudhoe Bay Field, Supplement A." By using the later data, we were able to make more definitive runs than had been made before. Our reports studied gas withdrawal rates of two (2) to five (5) billion cubic feet per day (i.e., gas sales of 1.5 - 3.75 Bcf/Day), correlated with oil production between 1.2 to 1.8 million barrels per day. We also studied oil recovery with no gas sales.

We looked at the effect of gas production and sales on ultimate oil recovery from the reservoir. Our analyses showed that if fluids are not returned to the reservoir to replace the voidage, ultimate oil recovery is reduced. In this case, the greater the gas sales rates, the greater is the loss in ultimate oil recovery.

We also looked at the effects of water injection in the event of gas sales. If gas sales are kept at a constant rate of 2 billion cubic feet per day, there will be an increase in oil recovery with water injection. Early start of water injection will give a slightly higher oil recovery than a delay of several years but the advantage is slight. Our cases included some in which no gas sales were made and water was injected. These cases showed oil recovery about the same as would result from gas sales with larger volumes of water injection.

These analyses show that gas production rates in excess of 2.7 billion cubic feet per day, which would give gas sales rates in excess of 2 billion cubic feet per day, would cause a significant reduction in ultimate oil recovery unless very large volumes of fluids are returned to the reservoir. As a practical matter, it may not be possible to inject enough fluids to permit sustained sales rates very much in excess of 2 billion cubic feet per day.

3. <u>An evaluation of a successful injection program, utilizing water or carbon dioxide, instead of natural gas produced from the field</u>.

Once the Prudhoe Bay reservoir is producing at a normal rate it will be necessary to have at least two and maybe more years of production to achieve a degree of reliability in forecasting the best future method of operation for this reservoir. Mr. Doscher has suggested that carbon dioxide be considered as an injection fluid in this field for enhanced recovery. No one knows at this time, including Mr. Doscher, what the best recovery mechanism will be. It is just as possible that the best recovery methods will incorporate either water, enriched gas, solvents, fire, steam, chemicals or inert gases or some combination of these.

It should be noted that many of these methods of recovery show some promise to aid in the production of substantial amounts of additional oil. Many of these exotic methods however have not yet been proven in the field and current economics will not permit their use. Some are at the technological and economic edge of the state of the art. As the price of oil is increased, they become more attractive and possible. Certainly with the tremendous volumes available at Prudhoe, neither the State nor the operators have to be told to consider these possibilities.

We are convinced that some fluids must be injected into the reservoir. However, until enough production history is available to validate the reservoir simulation programs, we do not believe it is possible for anyone to say what the ultimate method of operation of the reservoir should be. We have required that operators secure voluminous data which will help define the reservoir parameters. As is our right and our responsibility, we will exercise continuing jurisdiction over the operation of the field and will require that the method ultimately chosen by the operators be one that will achieve that greatest recoveries from the reservoir consistent with sound engineering and operating practices.

4. <u>What type of producing plan appears to be most appropriate to insure the maximum production of both oil and gas over the expected life of the field</u>.

Water injection as contemplated by the operators of the Prudhoe Bay Field has proved to be one of the most reliable techniques for maximizing oil recovery in fields all over the world. This does not mean that other techniques should be ruled out even though they may be currently uneconomic or not technically feasible at this time. One such technique, the injection of CO_2, is being considered. The produced gas in the Prudhoe Bay Field does contain approximately twelve percent CO_2 which could be removed and injected into the reservoir. We have not ruled out any recovery techniques yet, nor have we foreclosed use of alternative techniques by our authorization of an initial operating plan.

Our opinion is that proceeding as we have will not result in any irreversible damage to recoveries. During the first five years of operation, or until the approximate time that a gas line could become operational, we estimate that the decrease in reservoir pressure would amount to approximately ten percent of the original pressure. By that time we will know if and to what degree the decline must be arrested or if it should be reversed.

If, in the future, a better method of operation is indicated we believe that the maximum recoveries still can be achieved. We believe the free gas saturation to be established by permitting the reservoir pressure to drop will be beneficial to a water or gas injection project. If some other type of project is undertaken and the free gas saturation is not needed, it can be eliminated simply by rebuilding reservoir pressure by injection. This has been done many times in other fields. As a matter of fact, our own Swanson River Field in Alaska, which is a very large field by conventional standards, has an extremely efficient recovery and it was operated in this manner. The

field produced for some period of time before a miscible gas injection project was initiated. The recoveries have far exceeded most expectations.

In short, we do not believe that a pressure decline of the magnitude we have described would have any long term detrimental effects on ultimate oil recovery and we certainly do not agree with Mr. Doscher that there would be losses in the magnitude of billions of barrels.

5. <u>What the likely rate of gas production will be for each year over the expected life of the field</u>.

If the plan of operations as proposed by the operators is followed, with significant water injection, our work indicates that a gas sales rate of two Bcf/D starting in approximately five years could be sustained over the remaining life of the field.

In summary, Mr. Chairman, let me say that the State of Alaska is aware of the many unknowns in producing this reservoir and of many possibilities in the mode of operations. We have made a completely independent and comprehensive study of this reservoir. We have concluded that the present proposal of production rates of 2.7 billion cubic feet per day which will provide about two billion cubic feet of gas for sale will not be detrimental to recoveries if satisfactory fluid volumes are injected in a reasonable time. This depends on the plans of the operators. It is our intent to maintain a close surveillance of the reservoir performance and require operations that will achieve the greatest recoveries.

Now I would like to comment on certain aspects of Mr. Doscher's testimony. To begin with, it is important to distinguish between the basic engineering conclusions reached by Mr. Doscher in his report and the broader more philosophical and policy pronouncements contained in his report. Basically, as a petroleum engineer, I find little dispute with Mr. Doscher when he describes what is still unknown and must be learned, as operations continue. Our plan is to learn more and act accordingly. It is on policy matters where I cannot agree with Mr. Doscher's approaches. For example, Mr. Doscher says: "No operating plan should be approved or committed to by the State at this time which does more than assure the minimum orderly development of the field to attain crude oil production at the rate required for successful operation of the Aleyska Pipe Line." I see two problems with that statement. First is the assumption that our approval of an operating plan was, or should be, motivated by a desire to ensure successful operation of the Alyeska Pipeline. Our approval of a plan is based on conservation of hydrocarbons in the reservoir. If successful operation of the Alyeska line needed 1.5 million barrels/day and the reservoir could only produce at 1.0 million without loss of ultimate recovery, then we would be legally required to limit production to 1.0. Happily, this is not the case.

The second problem with Mr. Doscher's statement is that it implies that the State has committed to more than is necessary. That is not the case. Conservation Order No. 145 clearly indicates the Conservation Committee is concerned about production rates of the reservoir, will retain continuing jurisdiction, and will review and require adjustments in the operating plans if additional information indicates adjustments are appropriate. I believe what Mr. Doscher would have had the Conservation Committee do is remain totally silent on the question of gas production. While that certainly was possible, I believe such course would have been irresponsible in light of the National concern and interest in the question. We choose instead to share our knowledge on this point and to make the clear decision to proceed in a manner consistent with good conservation practices.

I disagree sharply with Mr. Doscher's statement that there will be a loss of two billion barrels of oil if the pipeline is approved. Mr. Doscher has not substantiated this figure with any studies and has not furnished technical data on which this opinion is based. To the contrary, our own studies have been substantial and we can reach no such conclusion based on any information available to us assuming that a water injection program is implemented to maintain field pressure.

As we see it, the basic question is whether a pipeline decision should be deferred until more is learned about the performance of the Prudhoe Bay Reservoir. The State of Alaska, based on what we know today -- i.e., our own studies, Mr. Doscher's two draft reports and testimony here, the material presented to it in its regulatory capacity, and its own professional judgment -- believes there is no sound technical reason to delay provided that the operators adopt and implement a source water injection program by the time gas sales start. If the operators do not implement a source water injection program, then gas sales will have to be limited or postponed in order to avoid jeopardizing ultimate oil recovery.

We agree that more information about the performance of the reservoir is desirable. But the State's plan allows for the gathering of that information without jeopardizing the early construction of the pipeline. It does so without substantial risk to the ultimate recovery of oil from the reservoir, and without unnecessary delay in the bringing of a major new gas supply to lower forty-eight users.

State of Alaska
Exhibit No. 1

STATE OF ALASKA
Department of Natural Resources
Division of Oil and Gas Conservation

Alaska Oil and Gas Conservation Committee
3001 Porcupine Drive
Anchorage, Alaska 99501

Re: The request of Atlantic Richfield Company and BP Alaska Inc. to present testimony to determine new pool rules and amend existing rules for the Prudhoe Oil Pool.	)	Conservation Order No. 145 Prudhoe Bay Field Prudhoe Oil Pool June 1, 1977

IT APPEARING THAT:

1. The referenced companies applied by letter received March 30, 1977, for a hearing to adopt new or amend existing pool rules.

2. Notice of public hearing was published in the Anchorage Daily News on April 2, 1977.

3. A public hearing was held in the Ramada Inn, Anchorage, Alaska on May 5 and 6, 1977.

4. The hearing record was continued until the close of business on May 16, 1977. Additional data was received.

FINDINGS:

1. Rules pertaining to the Prudhoe Oil Pool have been included in Conservation Order Nos. 98-B, 130, and 137.

2. Administrative approvals 98-B.3, 98-B.6, 98-B.7, and 98-B.8 written pursuant to Conservation Order No. 98-B, Rule 8 are currently in effect.

3. Waivers pertaining to blowout prevention practices written pursuant to Conservation Order No. 137, Rule 2 are currently in effect.

4. The applicants propose to raise and lower the vertical pool limits of the Prudhoe Oil Pool to include the "Put River Sandstone" and Ivishak Shale respectively.

5. No drill stem tests or production tests have been conducted in the "Put River Sandstone" or the Ivishak Shale.

6. No analysis of fluid from the "Put River Sandstone" or the Ivishak Shale are presently available to the Committee.

7. The areal extent of the Prudhoe Oil Pool as defined on March 12, 1971, in Conservation Order No. 98-B, is considerably larger than the area now proven to be productive by the drilling of additional wells since that time.

8. Most producing wells in the Prudhoe Oil Pool are deviated holes to minimize the number of drilling pads.

9. The applicants propose to eliminate reference to acreage spacing requirements but request that at least 2000 feet be maintained between the pay opened in the well bore in all wells in the Prudhoe Oil Pool.

10. The applicants propose that a distance of 1000 feet be maintained between the pay opened in any well and the boundary of the Prudhoe Oil Pool.

11. Data from the early production performance is needed for the proper regulation and operation of the reservoir.

12. Performance must be accurately observed and quickly analyzed for a timely assessment of reservoir behavior.

13. Performance during the first two years will be used to design the water flooding projects and will be vital in formulating and implementing future operating plans.

14. A reservoir surveillance program can provide for monitoring both reservoir and production data.

15. Monthly production tests will monitor changes in well productivity, gas-oil and oil-water ratios, and provide basic data for reservoir performance studies.

16. The reservoir is complex with many discontinuous interbedded shales.

17. The reservoir is underlain by a heavy oil or tar zone of varying thickness.

18. Some areas of the reservoir contain many faults.

19. The reservoir pressure data will provide information on well flow efficiency, reservoir permeability, reservoir discontinuities, and the need for a pressure maintenance program.

20. The use of specialized transient pressure testing techniques such as pulse testing, vertical permeability tests, and interference tests may prove useful.

21. Specific wells may be selected which are located outside the main area of the Sadlerochit oil column to monitor the pressure in the gas cap, the aquifer, the Eileen area, and the Sag River gas cap.

22. The applicants have agreed to a common datum plane of 8800 feet subsea for all pressure surveys.

23. Changes in the gas-oil fluid contact movement in the reservoir with response to production would provide information on shale continuity, effective vertical permeability, displacement efficiency of oil by gas and define areas of poor natural recovery.

24. Preliminary studies indicate that early run open hole or cased hole neutron logs may provide a suitable base log for monitoring the movement of the gas-oil contact by comparison with a later cased hole neutron log run in the same well.

25. Open hole neutron logs have already been run on the majority of wells.

26. Cased hole neutron logs have already been run in a number of wells and will continue to be run in selected wells until this technique is confirmed.

27. Monitoring the movement of the oil-water contact should help to determine the extent of water influx from the aquifer, identify areas of peripheral water influx and allow determination of the water displacement efficiency.

28. Monitoring the oil-water contact should provide information to help define locations where water injection would be beneficial.

29. A program is now in progress to evaluate the capability of monitoring the oil-water contact with one of three different methods, such as the Thermal Decay Tools (T.D.T.) or the Neutron Lifetime Log (N.L.L.), the Carbon-Oxygen Log and the Gamma Ray Log.

30. The capability of these methods to monitor the changing oil-water contact has not been demonstrated as yet.

31. The contribution of each of the various perforated intervals in each producing well may be determined through downhole spinner flow meter surveys.

32. A reliable assessment of the rate of the production from the various lithologic subdivisions within the reservoir will assist in the determination of the effectiveness of the well completions to drain the reservoir.

33. Numerous computer reservoir simulation model studies of the Sadlerochit Formation have been made by the State and the working interest owners. In these studies the offtake rates of oil and gas and the injection rates of gas and water have been varied.

34. The Trans-Alaska Pipeline will have an initial capacity of 1.2 million barrels per day and should be ready to accept oil near mid 1977.

35. The applicants have submitted a Plan of Operations which includes proposed average annual offtake rates of 1.5 million barrels per day for oil plus condensate production and 2.7 billion cubic feet per day for gas.

36. Production facilities to support an average oil offtake of 1.2 million barrels per day will be installed by the last quarter of 1977. Additions are planned during 1978 and 1979 to support an average oil offtake rate of 1.5 million barrels per day plus condensate production, when pipeline capacity is available.

37. Gas sales in large volumes from the Prudhoe Bay Field will not be possible until a gas conditioning plant and a large gas sales pipeline are constructed.

38. The completion of a large gas sales pipeline and plant to condition gas is estimated at approximately five years from start of oil production.

39. Until a large gas sales pipeline is available, all produced gas, except that used as fuel in the field and small local gas sales, will be reinjected into the gas cap.

40. Gas will be used to supply the operating requirements of the Prudhoe Bay Field, the first four pump stations of the Trans-Alaska Pipeline and other minor local fuel needs.

41. To meet pipeline sale quality it will be necessary to remove carbon dioxide from the gas.

42. Water production will be minimal initially and will be disposed of by injection into sands of Cretaceous age.

43. When water production becomes significant, the applicants plan to file a secondary recovery application for the injection of this water into the Prudhoe Oil Pool.

44. Injection of produced water into the Prudhoe Oil Pool could begin within two years after start of oil production.

45. The applicants will proceed with design and implementation studies concurrently with injectivity tests and reservoir data gathering to shorten the implementation time for a source water injection system.

46. The Sadlerochit Formation aquifer exhibits the best reservoir qualities near the Prudhoe Bay Field area and progressively deteriorates away from the field.

CONCLUSIONS:

1. To avoid confusion it would be desirable to consolidate the outstanding Pool rules effecting the Prudhoe Oil Pool into one order. Conservation Orders Nos. 98-B, 130, and Rule 2 of Conservation Order No. 137 should be canceled and the relevant portions included in Conservation Order No. 145.

2. Administrative Approvals 98-B.3, 98-B.6, 98-B.7, and 98-B.8 should remain in effect and will be applicable until stable production from the field is attained or until the time period stipulated expires.

3. Waivers pertaining to blowout preventers written pursuant to Conservation Order No. 137, Rule 2 should remain in effect.

4. There are insufficient data to justify raising or lowering the vertical limits of the Prudhoe Oil Pool, as proposed by the applicants, to correspond with the vertical limits of the Prudhoe Bay (Permo-Triassic) Reservoir as described in the Prudhoe Bay Unit Agreement.

5. The areal extent of the Prudhoe Oil Pool should be identical to the initial participating area of the Prudhoe Bay Unit which is described as the Prudhoe Bay (Permo-Triassic) Reservoir in the Unit Agreement.

6. A rule eliminating acreage spacing in the Prudhoe Oil Pool should facilitate present and future additional recovery operations and enable the unit operators to develop the productive capacity to meet the planned throughput of the Trans-Alaska Pipeline.

7. A distance of 2000 feet between the pay opened in the well bore in all wells in the Prudhoe Oil Pool should maintain an adequate drainage area, not unnecessarily restrict bottomhole target locations and protect correlative rights and prevent waste.

8. A distance of 1000 feet between the pay opened in any well and the boundary of the Prudhoe Oil Pool will protect correlative rights.

9. To gather the data necessary for proper regulation and operation of the reservoir, a rigorous surveillance program of reservoir performance should be accurately observed and assessed especially during the first two years of operation. The surveillance program should also provide guidelines for a long term key well surveillance program.

10. A surveillance program should include monitoring the reservoir pressures, gas-oil and oil-water contact movements, production tests, gas-oil and water-oil ratios, and productivity profiles of individual wells.

11. A gas-oil contact movement monitoring program, based on a comparison of open hole neutron base logs to be later compared with neutron logs run in the same wells should be attempted.

12. The data obtained during the first two years could lead to a key well program of periodic surveys that may adequately monitor the gas-oil contact movements.

13. Monitoring the movement of the oil-water contact is desirable to evaluate the water influx in the reservoir and the applicability of water injection systems. Three methods are potentially applicable as means of monitoring the movement of the oil-water contact. These methods are the Thermal Decay Tools or the Neutron Lifetime Log, the Carbon-Oxygen Log and the Gamma Ray Log. The program to evaluate the relative capability of these

logs should be continued and should any method be demonstrated capable of adequately monitoring the changing water saturations in the reservoir, a key well program should be set up.

14. Downhole spinner flow meter surveys to determine well productivity profiles should help determine the effectiveness of completions and provide information on reservoir drainage.

    To provide the necessary productivity profile data a base line survey should be run on each well with later follow up surveys on each well.

15. The injection of produced water into the sands of Cretaceous age will not contaminate fresh water sources or endanger other natural resources.

16. Studies of the aquifer have indicated that it probably will not offer much pressure support.

17. Reservoir studies have shown that both produced water injection and source water injection into the Prudhoe Oil Pool should increase oil recovery.

18. Reservoir studies have shown that large scale source water injection will probably be necessary to maximize oil recovery.

19. The planned reinjection of gas into the Sadlerochit gas cap prior to large gas sales will help to maintain reservoir pressure and will not adversely affect ultimate recovery.

20. The Plan of Operations proposed by the applicants which include average annual offtake rates of 1.5 million barrels per day for oil plus condensate production and 2.7 billion cubic feet per day for gas are consistent with sound conservation practices based on currently available data.

21. After field and local fuel requirements and the removal of carbon dioxide and liquids from the produced gas, it is estimated that a gas production rate of 2.7 billion standard cubic feet per day will yield 2.0 billion standard cubic feet per day of pipeline quality gas.

22. Production history will be needed to locate water injection wells and to refine reservoir model studies.

23. The offtake rates approved by the Committee at this time must be established without the benefit of production history. Therefore, these offtake rates may be changed as production data and additional reservoir data are obtained and analyzed.

NOW, THEREFORE, IT IS ORDERED THAT the rules hereinafter set forth apply to the following described area referred to in this order as the affected area:

UMIAT MERIDIAN		
T. 10N.,	R. 12E.,	Sections 1, 2, 3, 4, 10, 11, 12
T. 10N.,	R. 13E.,	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 24
T. 10N.,	R. 14E.,	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 36
T. 10N.,	R. 15E.,	all
T. 10N.,	R. 16E.,	5, 6, 7, 8, 17, 18, 19, 20, 29, 30, 31
T. 11N.,	R. 11E.,	1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 24, 25
T. 11N.,	R. 12E.,	all
T. 11N.,	R. 13E.,	all
T. 11N.,	R. 14E.,	all
T. 11N.,	R. 15E.,	all
T. 11N.,	R. 16E.,	30, 31, 32
T. 12N.,	R. 11E.,	15, 16, 17, 18, 19, 20, 21, 22, 25, 26, 27, 28, 29, 30, 32, 33, 34, 35, 36
T. 12N.,	R. 12E.,	23, 24, 25, 26, 27, 28, 33, 34, 35, 36
T. 12N.,	R. 13E.,	19, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 14E.,	25, 26, 27, 28, 29, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 15E.,	27, 28, 29, 30, 31, 32, 33, 34

Rule 1 Pool Definition

The Prudhoe Oil Pool is defined as the accumulations of oil that are common to and which correlate with the accumulations found in the Atlantic Richfield - Humble Prudhoe Bay State No. 1 well between the depths of 8,110 and 8,680 feet.

Rule 2 Well Spacing

In the affected area, no pay shall be opened in a well closer than 2000 feet to any pay opened in another well in the Prudhoe Oil Pool or be nearer than 1000 feet to the boundary of the affected area.

Rule 3 Casing and Cementing Requirements

(a) Casing and cementing programs shall provide adequate protection of all fresh waters and productive formations and protection from any pressure that may be encountered, including external freezeback within the permafrost.

(b) For proper anchorage and to prevent an uncontrolled flow, a conductor casing shall be set at least 75 feet below the surface and sufficient cement shall be used to fill the annulus behind the pipe to the surface.

(c) For proper anchorage, to prevent uncontrolled flow and to protect the well from the effects of permafrost thaw, a string of surface casing shall be set at least 500 feet below the base of the permafrost section but not below 2,700 feet unless a greater depth is approved by the Committee upon showing that no potentially productive pay exists above the proposed casing setting depth, and sufficient cement shall be used to fill the annulus behind the pipe to the surface.

The surface casing shall have minimum post-yield strain properties of 0.9% in tension and 1.26% in compression.

(d) If the surface casing does not meet the strain requirements in (c) above, the integrity of the well shall be protected from the effects of permafrost thaw by running an inner string of casing also set at least 500 feet below the base of the permafrost section and properly cemented except that the two casing strings shall not be bonded together within the permafrost section. This inner string of casing shall not be utilized as production casing.

(e) Other means for maintaining the integrity of the well from the effects of permafrost thaw may be approved by the Committee upon application.

(f) Production casing shall be landed through the completion zone and cement shall cover and extend to at least 500 feet above each hydrocarbon-bearing formation which is potentially productive. In the alternative, the casing string may be set and adequately cemented at at an intermediate point and a liner landed through the completion zone. If such a liner is run, the casing and liner shall overlap by at least 100 feet and the annular space behind the liner shall be filled with cement to at least 100 feet above the casing shoe, or the top of the liner shall be squeezed with sufficient cement to provide at least 100 feet of cement between the liner and casing. Cement must cover and extend at least 500 feet above each hydrocarbon-bearing formation which is potentially productive.

(g) Casing and liner, after being cemented, shall be satisfactorily tested to not less than 50% of minimum internal yield pressure or 1,500 pounds per square inch, whichever is less.

(h) No well shall be produced through the annulus between the tubing and the casing unless a cement sheath extends from the top of the pay to the shoe of the next shallower casing string.

Rule 4 Blowout Prevention Equipment and Practice

(a) The use of blowout prevention equipment shall be in accordance with good established practice and all equipment shall be in good operating condition at all times.

All blowout prevention equipment shall be adequately protected to ensure reliable operation under the existing weather conditions. All blowout prevention equipment shall be checked for satisfactory operation during each trip.

(b) Before drilling below the conductor string, each well shall have installed at least one remotely controlled annular type blowout preventer and flow diverter system. The annular preventer installed on the conductor casing shall be utilized to permit the diversion of hydrocarbons and other fluids. This low pressure, high capacity diverter system shall be installed to provide at least the equivalent of a 6-inch line with at least two lines venting in different directions to insure downwind diversion and shall be designed to avoid freeze-up. These lines shall be equipped with full-opening butterfly type valves or other valves approved by the Committee. A schematic diagram, list of equipment, and operational procedure for the diverter system shall be submitted with the application Permit to Drill or Deepen (Form 10-401) for approval. The above requirements may be waived for subsequent wells drilled from a multiple drill site.

(c) Before drilling below the surface casing all wells shall have three remotely controlled blowout preventers, including one equipped with pipe rams, one with blind rams and one annular type. The blowout preventers and associated equipment shall have 3000 psi working pressure and 6000 psi test pressure.

(d) Before drilling into the Prudhoe Oil Pool, the blowout preventers and associated equipment required in (c) above shall have 5000 psi working pressure rating and 10,000 psi test pressure rating.

(e) The associated equipment shall include a drilling spool with minimum three-inch side outlets (if not on the blowout preventer body), a minimum three-inch choke manifold, or equivalent, and a fill-up line. The drilling string will contain full-opening valves above and immediately below the kelly during all circulating operations with the kelly. Two emergency valves with rotary subs for all connections in use will be conveniently located on the drilling floor. One valve will be an inside blowout preventer of the spring-loaded type. The second valve will be of the manually-operated ball type, or any other type which will perform the same function.

(f) All ram-type blowout preventers, kelly valves, emergency valves and choke manifolds shall be tested to required working pressure when installed or changed and at least once each week therafter. Annular preventers shall be tested to 50% recommended working pressure when installed and once each week thereafter. Test results shall be recorded on written daily records kept at the well.

Rule 5 Automatic Shut-in Equipment

Upon completion, each well shall be equipped with a suitable safety valve installed below the base of the permafrost which will automatically shut in the well if an uncontrolled flow occurs.

Rule 6 Pressure Surveys

(a) Prior to initial sustained well production, a static bottomhole pressure survey shall be taken on each well.

(b) Between 90 and 100 days after commencement of sustained pool production, the applicants shall perform an initial key well bottomhole transient pressure survey on one specific well on each producing pad or drill site. Another survey of the same type shall be conducted each 90 days thereafter.

(c) Within the first six months following the initial sustained well production, the applicants shall conduct a transient pressure survey on each well.

(d) A semi-annual transient pressure survey shall be conducted on one well in each governmental section from which oil is being produced. This is in addition to the pressure surveys conducted in (b) and (c) above.

(e) A long-term key well pressure survey will be formulated and implemented in approximately two years from the start of production based upon evaluation of data submitted under (a), (b), (c), and (d) above.

(f) Data from the above mentioned surveys shall be filed with the Committee by the fifteenth day of the month following the month in which each survey is taken. Form No. 10-412, Reservoir Pressure Report, shall be utilized for all surveys with attachments for complete additional data. Data submitted shall include but is not limited to rate, pressure, time, depths, temperature, and other well conditions necessary for complete analysis for each survey being conducted. The pool pressure datum plane shall be 8800 feet subsea. Bottomhole transient pressures obtained by a 24 hour buildup or multiple flow rate test will be acceptable.

(g) Results and data from any special reservoir pressure monitoring techniques, tests or surveys shall also be submitted as prescribed in (f) above.

(h) By administrative order the Committee shall specify additional pressure surveys if the survey program designated in this rule is found to be inadequate.

Rule 7 Gas-Oil Ratio Tests

Between 90 and 120 days after substantial production starts and each six months thereafter a gas-oil ratio test shall be taken on each producing well. The test shall be of at least 12 hours duration and shall be made at the producing rate at which the operator ordinarily produces the well. The test results shall be reported on gas-oil ratio test form P-9 within fifteen days after completion of the survey. The Committee shall be notified at least five days prior to each test.

Rule 8 Gas Venting or Flaring

The venting or flaring of gas is prohibited except as may be authorized by the Committee in cases of emergency or operational necessity.

Rule 9 Gas-Oil Contact Monitoring

Open hole and cased hole neutron logs shall be run in selected wells to confirm gas-oil contact movement unless this technique is proved unworkable or an alternative approach is recommended and accepted by the Committee.

The wells selected for this neutron log survey together with a summary of the survey analyses shall be submitted to the Committee by January 1, 1978, and each six months thereafter. The Committee may also specify additional wells to be surveyed should they decide the survey program being followed is inadequate.

The cased hole neutron logs run shall be filed with the Committee by the fifteenth day of the month following the month in which the logs were run.

Other methods of monitoring the gas-oil contact movement may be approved if they show to be more effective.

A long term key well gas-oil contact movement monitoring program may be formulated and implemented in approximately two years from start of production if a workable technique is found.

Rule 10 Oil-Water Contact Monitoring

(a) A report on the evaluation program to determine the oil-water contact monitoring capability of the Thermal Decay Tools or the Neutron Lifetime Log, the Carbon-Oxygen Log and the Gamma Ray Log shall be submitted to the Committee by January 1, 1978.

(b) If the capability of monitoring the change in oil-water contact movement can be demonstrated by one or more of these methods, a key well program shall be set up by the applicants subject to the approval of the Committee.

Rule 11 Productivity Profiles

(a) A spinner flow meter survey shall be run in each well during the first six months the well is on production.

(b) A follow up survey shall be performed on a rotating basis so that a new production profile is obtained on each well periodically. Nonscheduled surveys shall be run in wells which experience an abrupt change in water cut, gas-oil ratio, or productivity.

(c) The complete spinner survey data and results shall be recorded and filed with the Committee by the 15th day of the month following the month in which each survey is taken.

(d) By administrative order the Committee shall specify additional surveys should they determine the surveys submitted under (a), (b) and (c) above are inadequate.

Rule 12 Changing the Affected Area

By administrative approval the Committee may adjust the description of the affected area to conform to future changes in the initial participating area.

Rule 13 Orders Cancelled

Conservation Orders Nos. 98-B, 130, and Rule 2 of Conservation Order No. 137 are hereby cancelled. Portions of Conservation Orders Nos. 98-B and 137 are made part of this order and the hearing records of these orders are also made part of the hearing record of this order.

Rule 14 Approvals Redesignated

Administrative Approvals made pursuant to CO 98-B, Rule 8 and the waivers made pursuant to Conservation Order No. 137, Rule 2 remain in effect and will now be authorized by this order.

Rule 15 Pool Off-Take Rates

The maximum annual average oil offtake rate is 1.5 million barrels per day plus condensate production. The maximum annual average gas offtake rate is 2.7 billion standard cubic feet per day, which contemplates an annual average gas pipeline delivery sales rate of 2.0 billion standard cubic feet per day of pipeline quality gas when treating and transportation facilities are available. Daily offtake rates in excess of these amounts are permitted only as required to sustain these annual average rates. The annual average offtake rates as specified shall not be exceeded without the prior written approval of the Committee.

Annual average offtake rates mean the daily average rate calculated by dividing the total volume produced in a calendar year by the number of days in the year. However, in the first calendar year that large gas offtake rates are initiated, following the completion of a large gas sales pipeline, the annual average offtake rate for gas shall be determined by dividing the total volume of gas produced in that calendar year by the number of days remaining in the year following initial delivery to the large gas sales pipeline.

DONE at Anchorage, Alaska, and dated June 1, 1977.

Thomas R. Marshall, Jr., Executive Secretary
Alaska Oil and Gas Conservation Committee

Concurrence:

Hoyle H. Hamilton, Chairman
Alaska Oil and Gas Conservation Committee

Lonnie C. Smith, Member
Alaska Oil and Gas Conservation Committee