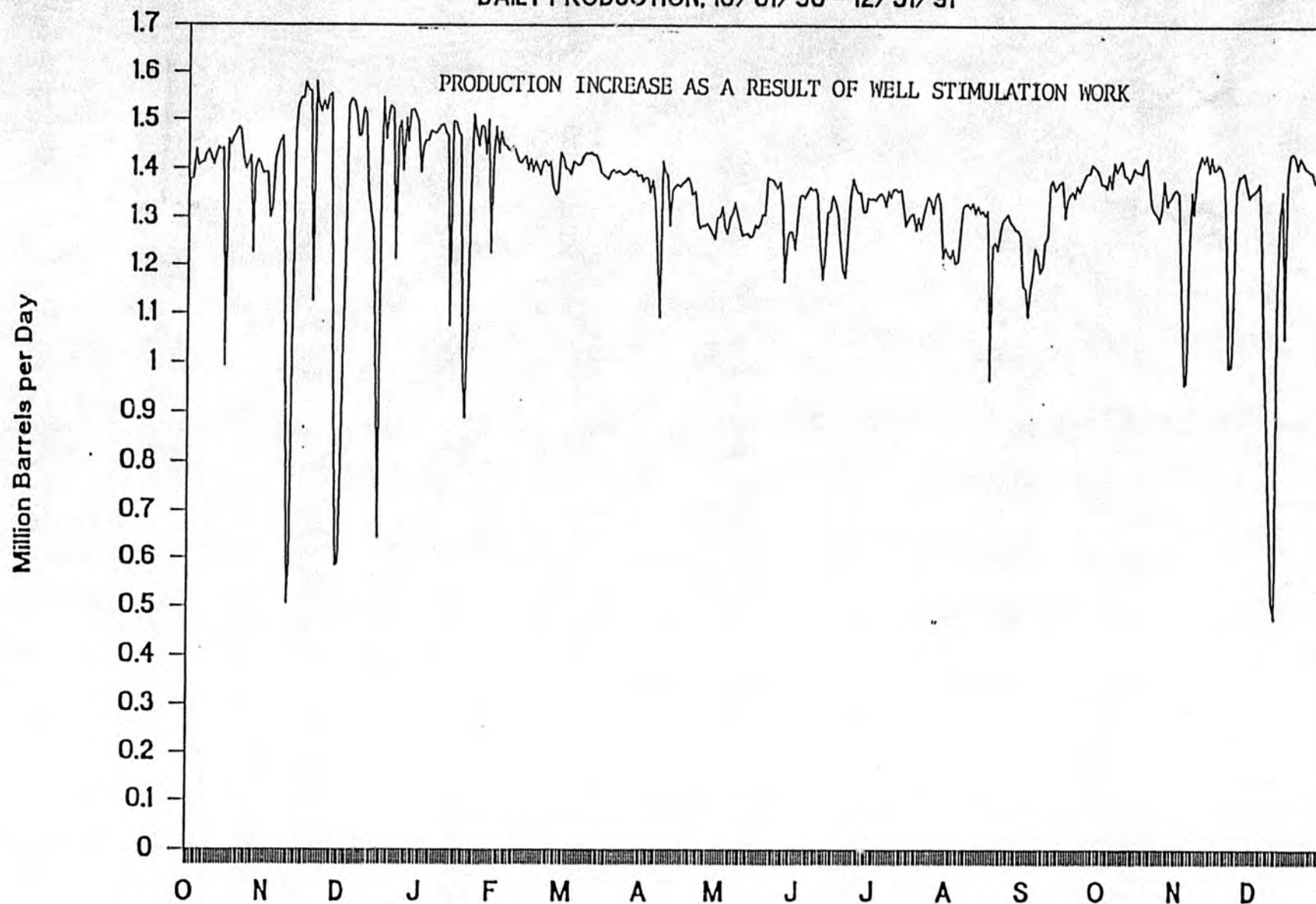


SCOMM

79:7

PRUDHOE BAY

DAILY PRODUCTION, 10/01/90 - 12/31/91



DIVISION OF OIL AND GAS
JANUARY 17, 1992

1/17/92

Prudhoe Bay Chronology

Date Specific Projects

- 1977--start up of production; implementation of a water flood assumed
- 1982--start up of Flow Station 3 enhanced oil recovery pilot project
- 1984--start up of full field water flood project
- 1986--start up of Central Gas Facility
- 1987--start up of large scale Prudhoe Bay Miscible Gas Project (PBMGP) EOR project
- 1988--start up of the West End/Eileen drillsites
- 1990--start up of GHX-1 project
- 1991--start up of the Hurl State/P Pad drillsite
- 1995--proposed start up of GHX-2 project and apex gas injection

Ongoing Projects

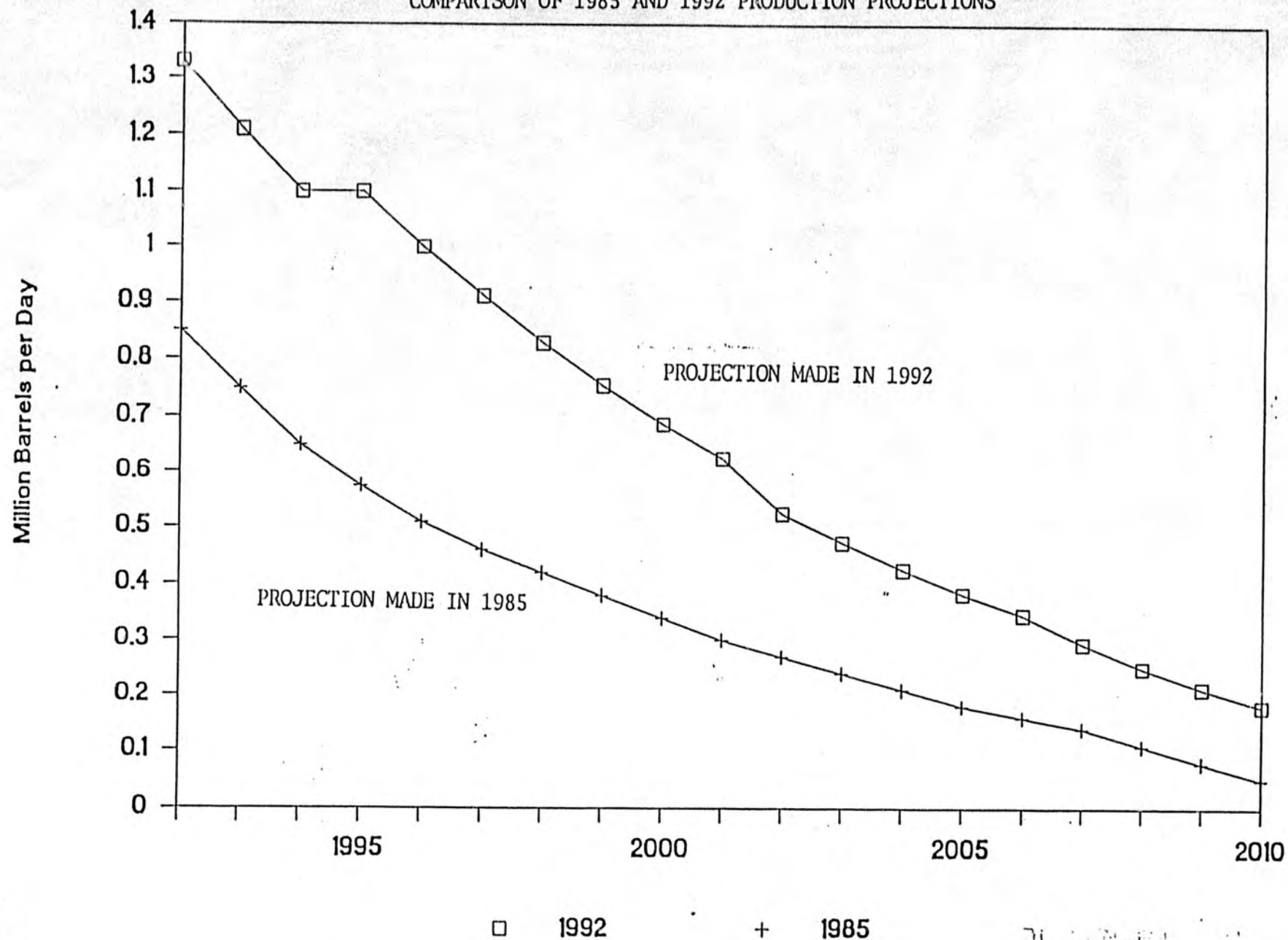
The following projects are not date specific:

1. infill drilling--well spacing has been reduced from the initial 320 acres per well to 160 or 80 acres per well depending on location in the field. Pilot projects are underway to evaluate the success of 40 acre well spacing. The ultimate well count in the field will likely double the original estimate.
2. peripheral drilling--wells are being drilled out to the edge of the oil accumulation to recover previously untapped oil reserves. During the early production years wells were not drilled in areas with less than 100 feet of oil pay.
3. gas cycling--although both the GHX 1 and 2 projects are major expansions of the gas cycling project, gas cycling has been occurring since field start up.
4. expansions in water handling facilities--as with gas handling facilities, if the produced water can not be processed due to a constraint in water processing capacity then oil/water production must be curtailed to avoid facilities overload.

Division of Oil and Gas
January 17, 1992

PRUDHOE BAY

COMPARISON OF 1985 AND 1992 PRODUCTION PROJECTIONS



DIVISION OF OIL AND GAS
JANUARY 17, 1992

(W)

Remaining Prudhoe Bay Oil Recovery
By Time Period

Time Period (years)	Oil Recovery (bbls)
1992-2000	3.26 billion
2001-2005	0.89
2006-2010	0.47
2011-2016	<u>0.23</u>
Total	4.85 billion

Remaining recovery after the year 2000-- 1.59 billion barrels

Remaining recovery after the year 2005-- 0.70 billion barrels

notes: Remaining oil recovery and timing estimates taken from
Division of Oil and Gas PBU production forecast.

Oil production for the period beyond the year 2010 assumes
that TAPS is still operational.

Division of Oil and Gas
January 17, 1992

STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

January 17, 1992

WALTER J. HICKEL, GOVERNOR

3001 PORCUPINE DRIVE
ANCHORAGE, ALASKA 99501-3192
PHONE: (907) 278-1433
TELECOPY: (907) 276-7542

The Honorable Mike Navarre
The Honorable Bill Hudson
Alaska State Representatives
P. O. Box V
Juneau, Alaska 99811

Dear Representatives Navarre and Hudson:

The Alaska Oil and Gas Conservation Commission welcomes the opportunity to appear before the joint session of the House Finance Committee and the House Oil and Gas Committee to discuss your concerns with Prudhoe Bay production management. Recently the commission concluded hearings on the expansion of the Prudhoe Bay Miscible Gas Project. Testimony offered by the unit operators included a full review and update of the past and current reservoir management plan for Prudhoe Bay. The commission has not yet issued an order in this matter.

While the commission could have approved the expansion of the Miscible Gas Project by administrative action without public hearing, we chose a process more open to public involvement out of respect for every Alaskan's right to be informed about the management of a resource that is vital to their interests. Our intent was to inform, not to confuse or to create controversy over gas sales or with Prudhoe Bay reservoir management. The hearings were not held to discuss gas sales nor to revisit the entire scope of management options for the Prudhoe oil reservoir. The commission will, however, hold such public hearings when gas sales are actually proposed or become more likely.

Turning our attention to the specific question you asked in your January 14 letter, we will address each in turn.

1. What effort has the AOGCC made to ensure that all feasible enhanced recovery techniques and other options

#1

(such as in-fill drilling) have been or will be undertaken by the producers?

Generally recognized enhanced recovery processes include: a) miscible gas displacement, b) surfactant flooding, c) enhanced waterflood techniques and d) thermal processes. The commission has reviewed each process for application in the Prudhoe Bay reservoir. Of these processes, miscible gas displacement is judged to be the most effective for Prudhoe Bay. Enhanced oil recovery processes are described in greater detail in Attachment A.

Other methods for improving oil recovery at Prudhoe Bay include infill drilling, high angle and horizontal drilling, well workovers, stimulations, fracture stimulations, water and gas influx control, redrills and coiled tubing work. These methods have been employed since initial production, and are generally recognized as contributing significantly to the sustained production rate from the reservoir. Development work during the next five years calls for 50 fracture treatments per year, 200 non-frac acid/chemical treatments per year, 200 nonrig workovers per year to control gas/water influx and profile modifications, 85 workovers per year to repair wells and 35 redrills per year, all providing a yearly rate benefit of 85 MBOPD.

Commission reservoir surveillance efforts insure that these processes will continue, and are applied as appropriate across the entire field. The commission works closely with the operators to insure that these operations are conducted expeditiously and in accordance with state regulations. Our permit turn around time is quite rapid relative to other agencies, and our petroleum field inspection program provides comprehensive follow up review of drilling and workover operations. We also interface with other agencies to ensure continued smooth operation of the field. As an example, our work with EPA has allowed rapid resolution of disposal problems with exploration and production wastes, including NORM waste and reserve pit close out.

It is important for the committee members to understand that good reservoir management is an evolutionary process. As knowledge is gained about the geology and productive mechanisms at work in the reservoir, development plans will

continue to evolve and improve. For example, initial plans for Prudhoe Bay called for 1.5 million barrels per day offtake, 2 Bcf per day gas handling capacity, nominal 160 acre well spacing, gas lift system, waterflooding, and gas sales five years after start up, with initial recoverable reserves estimated to be 9.6 billion barrels. Current plans call for full field 80 acre well spacing with some 40 acre development, gas handling capacity to 7.5 Bcf per day, miscible gas EOR, and NGL production, resulting in estimated total recoverable reserves of 12 billion barrels. Commission oversight will help ensure that this evolutionary process continues throughout the productive life of the reservoir.

2. What is the AOGCC's understanding of the relationship between potential gas sales, reservoir performance and total hydrocarbon recovery?

The relationship between gas sales, reservoir performance and total hydrocarbon recovery is dependent on a number of variables, primary among these are the timing of sales and proposed gas offtake rate. Basic economics, including the price of oil, price of gas, capital investment costs, available markets, taxes, tariffs, and the effect of government regulations also have direct bearing on the optimum depletion plan.

As we indicated in our letter to Representative Brown, formal effort to quantify the relationship between gas sales and hydrocarbon recovery is limited to the commission's reservoir modelling work done in the late 70's and early 80's. Our awareness of Prudhoe Bay reservoir dynamics today comes from monitoring oil production and field operations for over 14 years and from numerous discussions, both formal and informal, held with the producers during each year of that period.

Our information from these discussions tells us that gas sales are unlikely until sometime after the year 2005. Based upon this assumption, the commission has little concern that optimum recovery of both oil and gas would be obtained. If, on the other hand, gas sales occurred before that date, our attention would focus on the more rapid depletion of reservoir pressure and the possibility of

reduced oil recovery. Estimates have been made that with sales of one Bcf per day, the pressure in the Prudhoe Bay reservoir would decline about 50 psi per year, at two Bcf per day, it declines about 70 psi per year. Assuming these estimates are accurate, the commission would not be overly alarmed by this decline. Although it is more rapid than the current anticipated rate of 30 psi per year, we do not believe it would have a drastic affect on total oil recovery. Several factors mitigate our concern. First, gas sales will likely prolong the economic life of the field, allowing more oil to be produced over time. Secondly, while less gas would be available for cycling, the total pore volume of gas cycled over time may actually increase with longer field life. Thirdly, gas sales may actually increase the availability of enriching components for building the miscible injectant, allowing continued, or possibly expanded, use of the miscible gas displacement process. Finally, with gas sales of two Bcf per day, a 35 to 40 year supply of gas is available in Prudhoe Bay. Associated infrastructure would likely contribute to the continued and expanded development of other North Slope oil and gas fields.

The commission cautions, however, that further study should be undertaken to better confirm the relationship between gas sales and oil recovery when a definitive proposal is offered or appears more likely.

3. Given the AOGCC's statutory charge to prevent the waste of oil and gas resources, what specific, independent analysis has the commission performed concerning additional or alternative enhanced recovery projects? If an analysis was performed, what was the source of the base-data; how was it manipulated?

The commission's most extensive independent analysis was its three dimensional simulation study done in the late 70's and early 80's. This is the VanPoolen study referred to in Representative Brown's letter. The study exceeded three million dollars, but provided the framework for much of the development rules that govern Prudhoe Bay today. At the time, it was a precedent setting study for a conservation commission. Even today, we are not aware of any other studies by conservation commissions that compare to the

VanPoolen study, with the possible exception of some Canadian studies and an offshore California study.

Since then, our efforts have been focused on inhouse review of the operator's proposals using existing staff. The commission monitors production data, pressure data, and injection data, and uses this data to determine the effectiveness of voidage replacement. We monitor production decline, gas-oil and water-oil ratios, gas-oil contact movement, and cumulative production. We meet annually with the operators to review reservoir management plans and results of field performance monitoring studies required by the commission. We continually review field operations, including well workovers, stimulations, fracture treatments, and development drilling to ensure optimal reservoir development. We work informally with the operator to encourage expanded development, and have influenced increased gas handling capacity, apex gas injection, infill drilling, use of high angle and horizontal wellbores, and development of the West Eileen area.

Concerning the commission's work on enhanced recovery projects, our initial efforts using the 3-D study showed that waterflood would increase ultimate recovery. Based on this assessment, the commission encouraged the operators to begin waterflood early in the productive life of the field. Waterflood pilots began in 1979, with full scale waterflood implemented in 1984. By this time the operators had already applied for and received approval from the commission for a pilot miscible gas project in the Flow Station 3 area. Excellent results of this pilot project, and concurrent lab study and modeling, prompted the operators to apply for expansion of the miscible gas project to other areas of the field. The Prudhoe Bay MGP was approved by the commission in 1984, with start up in 1987 following installation of the Central Gas Facility. The MGP applications were reviewed by commission staff and its consultant, H. K. vanPoolen and Associates, Inc.. Our assessment considered the viability of other EOR options as described under question 1. We determined that the MGP was the best option for Prudhoe Bay EOR. Current estimates are that approximately 500 million barrels of additional oil will be recovered by miscible gas injection.

Today, we are again considering an expansion of the MGP. The commission considers this latest request to be the fifth increment of the project. The commission remains convinced that this EOR option remains the best alternative for Prudhoe Bay.

4. (paraphrasing) The question in your reply to Representative Brown, "How does one ensure that recovery of the overall resource is optimized, and a line is not drawn improperly between the recovery of gas vis-a-vis oil?" is the salient issue. The very purpose of the commission is to optimize and draw lines regarding hydrocarbon recovery, is it that the commission lacks authority, or has too broad a mandate or has insufficient resources/data to make such decisions? At some point in time these critical issues will have to be addressed. What is the commission doing to prepare for this eventuality?

The question proposed by the commission in its reply to Representative Brown was merely hypothetical. Its purpose is to illustrate the type of information or assurance that must be presented to the commission in its consideration of gas sales. The issue of gas sales, however, does not appear imminent to the commission, but seems to be far enough into the future to allow reasoned and deliberative consideration of the question when the specifics of a gas sale proposal are known. The answer to this question today using only speculative data would likely be different than in the future when an actual proposal is presented.

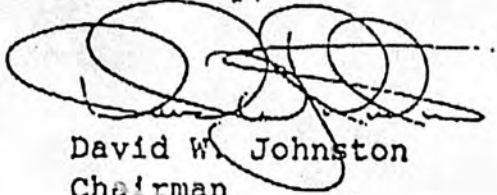
The commission believes it has the proper authority to consider the conservation issues surrounding gas sales, and are prepared to examine these issues when the time is appropriate. Further, we feel that we are the appropriate agency to make a determination in the matter of gas sales.

To prepare for this eventuality, the commission continues improving reservoir description and surveillance capabilities, field inspections, data storage and retrieval, communication and working relations with other state and federal agencies, and are rendering decisions in a more open forum. The commission maintains an effective working relationship with the operators, which is underpinned by our mutual desire to optimize recovery of oil and gas resources.

The commission is a small agency with limited resources. To continue improving in our conservation role we ask for your continued attention and support. As the commission identifies resource requirements, it will continue to request appropriate funding to meet those needs. Our desire is to more clearly define those state needs in forums such as the hearings now being held before the House Finance and Oil and Gas committees.

I hope our response to your questions has helped in your understanding of the issues involved. We will be pleased to answer any additional question you may have.

Sincerely,



David W. Johnston
Chairman

Attachment

cc. House Finance Committee members
House Oil and Gas Committee members
Representative Ben Grussendorf, House Speaker
Representative Max Gruenberg, House Majority Leader
Harold Heinze, DNR
Jim Eason, DNR

Attachment A

Enhanced Recovery Processes

Miscible gas displacement--This process includes two categories: lean gas (vaporizing) drive and enriched gas (condensing) drive. Both categories are utilized in Prudhoe Bay; vaporizing drive occurs in the gas cap and condensing drive occurs in the peripheral area of the field (i.e. PBMGP area). Vaporization occurs when lean gas comes in contact with residual hydrocarbons. The vaporized hydrocarbons are then produced with the gas. Condensing drive uses lean gas enriched with intermediate hydrocarbon components (butane, pentane, etc) to mobilize residual oil, which in turn is pushed toward the producing well by subsequent water injection.

Enhanced Waterflood (or mobility control process)--This process attempts to improve the sweep efficiency of conventional waterflood by various mobility enhancing additives. Three techniques were reviewed for Prudhoe Bay: carbonate waterflooding (CO₂), polymer waterflooding, and caustic waterflooding. However, since a favorable mobility ratio already exists between water and Sadlerochit crude, the use of mobility enhancing techniques would yield limited benefits. Each technique was determined to be less efficient than miscible gas displacement.

Surfactant flooding--This process uses a surfactant to reduce the oil-water interfacial tension, allowing more oil to be mobilized by subsequent waterflooding. Surfactant systems currently available are not effective over a large range of salinity or temperatures, thereby limiting application of this process in Prudhoe Bay which is flooded, in part, with low temperature Beaufort Sea water. Further, the manufacturing and delivery costs make this process uneconomical for Prudhoe Bay.

Thermal Processes--These processes improves recovery by reducing the oil viscosity and by expansion and distillation of the crude. The efficiency of thermal processes below 3000 feet is poor. The technology to use thermal recovery techniques in a reservoir as deep and as large as Prudhoe Bay is not available today.



Alaska State Legislature

HOUSE OF REPRESENTATIVES

Official Business

P.O. Box V
State Capitol
Juneau, Alaska 99811

January 14, 1992

David W. Johnston, Chairman
Alaska Oil & Gas Conservation Commission
3001 Porcupine Drive
Anchorage, AK. 99501

Dear Mr. Johnston,

The purpose of this letter is to confirm that the **House Finance Committee**, jointly with the **House Oil and Gas Committee**, will be holding an oversight hearing concerning Prudhoe Bay production management and forecasting issues on January 21, at 1:30 p.m. in Juneau and to ask for the Alaska Oil & Gas Conservation Commission's (AOGCC) assistance in obtaining a better understanding of the issues surrounding long-term projections of total hydrocarbon recovery from the Prudhoe Bay reservoir.

As you are well aware, recent proceedings before the Commission regarding the Prudhoe Bay Miscible Gas Expansion Project involve fundamental issues of long-term, total recovery of oil from the Prudhoe Bay reservoir. In recent correspondence with the AOGCC, a number of questions have been raised concerning the uncertain, although potentially adverse, impact that large scale gas sales could have on ultimate hydrocarbon recovery from Prudhoe Bay.

As you have stated (letter attached), large volume gas sales could impact the reservoir in three ways: field pressure would decline more rapidly, less gas would be available for cycling and the availability of miscible injectant could be affected. At this point, it appears that the state has only a limited understanding of the impact that large volume gas sales would have on the long-term, ultimate hydrocarbon recovery from Prudhoe Bay: "[f]ormal study of the relationship between potential gas sales and reservoir performance is limited to the simulations done with VanPoolen and Associates." As you appreciate, the VanPoolen modelling work is now largely outdated. As indicated by the Commission, the relationship between gas sales and oil recovery is complex and in need of further study.

#2

The uncertain impact gas sales could have on ultimate hydrocarbon recovery — and by implication the state's fiscal interests — is of significant concern. We would appreciate your help in obtaining a clearer understanding of the Commission's view of these concerns.

With specific regard to the hearing on January 21st, it would be very helpful if the Commission would be prepared to comment on the following issues:

1. What effort has the AOGCC made to ensure that all feasible enhanced recovery techniques and other options (such as in-fill drilling) have been or will be undertaken by the producers?
2. What is the AOGCC's understanding of the relationship between potential gas sales, reservoir performance and total hydrocarbon recovery?
3. Given the AOGCC's statutory charge to prevent the waste of oil and gas resources, what specific, independent, analysis has the Commission performed concerning additional or alternative enhanced recovery projects? If an analysis was performed, what was the source of the base-data; how was it manipulated?
4. In your letter to Representative Brown, you closed by raising the most salient issues. "How does one", you asked, "ensure that recovery of the overall resource is optimized, and a line is not improperly drawn between the recovery of gas vis-a-vis oil?" To optimize and draw lines, regarding hydrocarbon recovery, appears to be the very purpose for which the Commission was established and entrusted with broad regulatory powers. Is it that the Commission views these powers as inadequate, their mandate as overly broad, or is it a matter of insufficient resources/data to make such decisions? At some point in time these critical issues will have to be addressed (and not just for Prudhoe Bay). What is the Commission doing to prepare for this eventuality?

Your response to these questions would be greatly appreciated. We look forward to a discussion of these issues on January 21.

Sincerely,



Representative Mike Navarre
Co-Chair, House Finance Committee



Representative Bill Hudson
Chair, House Oil & Gas Committee

cc: House Finance Committee members
House Oil & Gas Committee members
Jim Eason/Division of Oil and Gas
Bill Van Dyke/Division of Oil and Gas
Dave Johnston/Alaska Oil & Gas Conservation Commission
Representative Ben Grussendorf, House Speaker
Representative Max Gruenberg, House Majority Leader

STATE OF ALASKA

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

WALTER J. HICKEL, GOVERNOR

P.O. BOX 107034
ANCHORAGE, ALASKA 99510-7034
PHONE: (907) 762-2553

December 17, 1991

David W. Johnston, Chairman
Alaska Oil and Gas Conservation Commission
3001 Porcupine Drive
Anchorage, AK 99501

RE: Petition to Amend Conservation Order Number 195 Rule 2 and Request for Approval of Significant Expansion of the PBUMGP

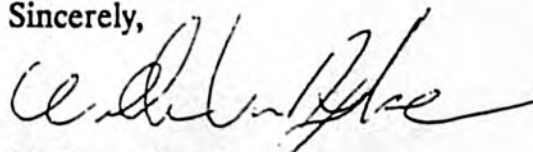
Dear Mr. Johnston:

The Alaska Oil and Gas Conservation Commission held a hearing on November 18, 19 and 20, 1991 in connection with the above referenced topics. The hearing was continued to December 20, 1991. In response to that hearing the Department submits the enclosed comments and suggested questions for the applicants. A brief statement of the overall rationale for some of the questions is also included. In this submittal we have not repeated any questions that were answered at the earlier proceedings. We have ask again the questions that we believe were not fully answered at the earlier sessions.

It is our understanding that the hearing will be reconvened at 9:00 am on Friday December 20, 1991 at the Commission's office. The Department will have a representative at the hearing to make an opening statement and to answer any questions the Commission may have at that time.

If you have any questions in the interim please contact me at the above address or phone me at 762-2550.

Sincerely,



William Van Dyke
Petroleum Manager

Overall Rational for Questions Asked by the Department of Natural Resources
December 17, 1991

The petition at hand requests the Commission's approval of an amendment to Conservation Order 195 Rule 2 and the Commission's concurrence that the expansion of the PBUMGP is a bona fide EOR project. New MI patterns will be added, infill MI patterns will be added, apex gas injection will be commenced and gas cycling volumes will be increased significantly. Taken in total, these projects represent a major change in reservoir management plans and strategies relative to those approved by the Commission in the mid 1980s.

Even without the implementation of these new projects and strategies, reservoir management strategies and facilities have evolved since the early field rules hearings. Water handling and gas handling facilities have been expanded, infill drilling is more prevalent, the GHX-1 project has resulted in increased gas cycling capability, condensate production and MI availability, and well stimulation and workover techniques have greatly improved. The waterflood, EOR project and the gas cycling strategy are all performing as good as or better than predicted and today's estimate of ultimate recovery is considerably above the original 9.6 billion barrels of oil. The operators have done an excellent job at implementing the plans and adapting to change and better information. No doubt the plans being proposed today will change to some degree in the future as new information becomes available. No one should expect that the plans presented in connection with this hearing are or should be the final word in reservoir management strategy. However, the factors and constraints that lead to the choices that were adopted should be understood before those choices are adopted or endorsed by the Commission.

It seems only appropriate that the Commission would want to review the reservoir management options that are available to the operators, study the alternatives that have been investigated to date and understand the degree of sensitivity that the major production and operation decisions have on ultimate recovery and timing of production. This hearing provides the ideal venue to investigate these issues and build a proper record to support the requests made by the applicants. The requests need to be considered in light of the potential effects and impacts on the entire reservoir. Although three distinct recovery mechanisms are operating--gravity drainage, waterflood/WAG MI and gas cap cycling--the field geology is such that fluid flow and pressure transients can not be constrained within exact areas. The record should be complete as to options studied, likely production cases investigated and sensitivities described.

There is no need to rush the decision making process. If necessary the Commission can

Page 2

December 17, 1991

Overall Rational

approve a reduction in the PBU reservoir pressure to 3500 psia and even order the implementation of the apex gas injection project while the long term plans are being carefully studied. Once the record with respect to production forecasts, WAG ratio schedules, MI composition schedules, gas utilization options, options for alternative EOR methods and the like is more complete the Commission can issue final rulings on the requests at hand. The Commission most likely will not have the manpower and fiscal resources available to it to independently track and evaluate the behavior of the Prudhoe Bay reservoir in future years. Having the operators present a complete status report and projection every five or so years has great merit and provides the Commission and other effected parties with an opportunity to evaluate the then in place production strategy. Long term relief and abandonment of Commission oversight of reservoir management practices should only be approved after full consideration by the Commission and only after a complete record is established.

The Department believes that the data have been collected and studies completed to show that all the likely production/operation options have been considered and that the proposal at hand is the "best" one available. The applicants and other owners at Prudhoe Bay should share this information with the Commission and include it in the hearing record. As an alternative the Commission could take pause in this hearing process to replicate the work that has been done by the owners. This option would no doubt take four or five years to complete given the appropriation and contracting constraints facing the Commission. A third option would be to have all the data reviewed by a third party and then have the third party present the results of that review to the Commission and include it in the record. Funding for the third party peer review could be negotiated between the Commission and the applicants. The applicants have described in qualitative terms what they propose to do. Before the Commission rules on the petition it should request a quantitative analysis of the proposed reservoir management strategy.

Conservation Orders apply to the specific field in question. The current operators at Prudhoe Bay have shown their ability to properly manage the field. However, there is no guarantee that the current operators will remain in place for the next 30 years. The Commission's approval criteria should include this possibility.

New Questions Submitted by the Department of Natural Resources
December 17, 1991

Listed below are new questions that were not part of the Department of Natural Resources submittal dated November 18, 1991.

1. What other methods of EOR have been investigated for the Sadlerochit reservoir? SPE papers 20220 and 20236 (Title pages attached) discuss the application of a polymer/surfactant EOR method. Has this process been investigated for Prudhoe Bay? Is it viable?
2. Has the use of a tapered MI slug been investigated? Will any tapered slugs be used at Prudhoe Bay?
3. SPE paper 24159 describes a new MI allocation method currently being used in the field. Will the overall life of the current EOR project or the overall ultimate recovery change as a result of using the new MI allocation method? Will this method also be used in the expansion and infill areas? What range of WAG ratios will result from the new method? Will the field rules be amended to reflect this change in operating strategy?
4. Exhibit B-61 shows an estimated production rate for the year 2000 and the year 2010 by recovery method. Is there a similar forecast for the year 2020? What happens after the year 2010? Between the year 1990 and the year 2000 production declines by over 60%. What is the cause of this rapid drop in oil production rate? Why is the rate of decline slower after the year 2000? Would a different reservoir management strategy lessen the decline rate during the next 10 years?
5. What are the benefits of accelerating the start up of apex gas injection?
6. What are the consequences of designing the MI slug with a 500 psi "safety factor" verses the proposed 250 psi differential? Would this be a cheap form of insurance against faster than expected pressure drops or unpredicted compositional changes? If a richer slug is needed to accommodate a larger pressure buffer, what decrease in volume of available MI would accompany this richer MI slug requirement?
7. If the MI slug loses miscibility while in the reservoir does the oil bank established up to that point still get displaced to a production well?
8. Do the existing production wells in the PBUMGP area have an MI cone around them from the coning down of MI in to the wells?
9. Exhibit B-38 indicates that the equation of state predicts the lean gas crude oil vaporization process quite well. Is there lab data available that shows how well the equation predicts miscibility? Have one or two or three dimensional laboratory model MI floods been compared to numerical models of the same?

SPE/DOE 20220

The Low-Tension Polymer Flood Approach to Cost-Effective Chemical EOR

B. Kalpakci* and T.G. Arf, BP Research; J.W. Barker,* BP Research Sunbury; A.S. Krupa, BP Research; J.C. Morgan,* BP Research Sunbury; and R.D. Neira, BP Research

*SPE Members

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This paper was prepared for presentation at the SPE/DOE Seventh Symposium on Enhanced Oil Recovery held in Tulsa, Oklahoma, April 22-25, 1990.

This paper was selected for presentation by an SPE Program Committee following review of information contained in an abstract submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the Society of Petroleum Engineers and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the Society of Petroleum Engineers, its officers, or members. Papers presented at SPE meetings are subject to publication review by Editorial Committees of the Society of Petroleum Engineers. Permission to copy is restricted to an abstract of not more than 300 words. Illustrations may not be copied. The abstract should contain conspicuous acknowledgment of where and by whom the paper is presented. Write Publications Manager, SPE, P.O. Box 833836, Richardson, TX 75083-3836. Telex, 730989 SPEDAL.

ABSTRACT

The Low Tension Polymer Flood approach addresses the two EOR problems of cost and control. Coinjection of low concentration surfactant and a biopolymer, followed by a further mobility control buffer, leads to much reduced overall chemical consumption, even in relatively high clay content rock. Though the optimum chemical injection period is more prolonged, the oil recovery timescale is not unduly prolonged. The LTPF process moves chemical flooding surfactant a long way toward being a simple, low-level waterflood additive process, attractive for field operations. It uses surfactant-polymer interactions as an advantage rather than coping with them as a problem.

The chemical system described is based on a scleroglucan biopolymer (500 - 750 ppm) plus surfactant mixture (3000 ppm total surfactant). No cosolvent is used. This system was developed specifically for use with high salinity injection water (seawater) in a high temperature reservoir. The essential phase behavior description is given, together with other physical parameters and detailed coreflood performance.

Finally, we discuss the computer simulation approach used to predict reservoir performance and the results obtained.

INTRODUCTION

Many surfactant-polymer field tests have been conducted over the past three decades. This activity stemmed from the promise of highly effective oil recovery by surfactants in a period of increasing oil prices. Results of these tests and critical reviews published on them identified the main parameters important to the technical success of a surfactant-polymer project.¹⁻¹⁵ One of the key findings is that preflushes to remove excessive salinity and hardness have been ineffective and chemical systems capable of being effective in the presence of both injection brine and formation water are needed.^{1-2,5-6}

A second important conclusion is that effective and timely oil recovery from surfactant-polymer field tests correlates well with maintaining good mobility control of both the surfactant slug and the polymer buffer^{3,4}. Further, as the pattern size increases so does the need for having a salinity tolerant system with favorable mobility control. However, this is not meant to suggest that other design parameters such as low interfacial tension and high injectivity are unimportant. Rather, we should focus on robustness and control as also being mandatory.

In this context, waterflood modification with viscous polymer alone is usually reported as being technically and economically successful in field operations addressing mobility control problems.^{7,8} However the process effectiveness is generally low. If successful, oil recoveries are in the range of 2-12% of the residual oil⁹.

Since the oil price fall of 1986, concerns over the risks, costs, ineffectiveness and test failures considered to be associated with chemical flooding have led to widespread abandonment of chemical EOR research by the scientific community. In addressing these concerns we decided to explore ways of combining the effectiveness of surfactants with the control of polymers. The properties of the combined system, which we refer to as Low Tension Polymer Flood (LTPF), can confer some significant advantages.

The aim of LTPF is to increase the oil recovery of a relatively ineffective but low chemical cost polymer flood by the addition of limited amounts of polymer compatible surfactants. The basic LTPF injection scheme described here involves the injection of up to 0.7 swept pore volume (PV) of LTPF with additives comprising about 3000 ppm surfactant(s) and 500-750 ppm polymer in a brine. This is followed by 0.5 PV of graded viscosity polymer buffer. However, optimum flood design, including presence or absence of a polymer preflush and length/level of chemical additions, depend on reservoir description. If operationally attainable, the salinity of the make-up water used for the polymer buffer may be made lower than that used during LTPF injection to take advantage of the salinity gradient effect. Thus LTPF is technically a bridge between the surfactant and polymer flooding processes.

References and Illustrations at end of paper.

SPE/DOE 20236

Co-Deployment of Surfactant/Polymer and Miscible Gas Enhanced Oil Recovery Processes: A Simulation Study

J.W. Barker, BP Research Centre

SPE Member

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ABSTRACT

A reservoir simulator capable of modelling both surfactant/polymer flooding and gas displacement processes (immiscible or miscible) is described. Novel extensions to existing phase behaviour and relative permeability models are used to represent interactions between the two processes. Results are presented quantifying the possibilities for combined chemical and miscible EOR.

1. INTRODUCTION

Waterflooding rarely recovers more than half the original oil in place in a reservoir. Miscible gas flooding and surfactant/polymer ("chemical") flooding are two enhanced oil recovery techniques that might be applied to recover a substantial fraction of the waterflood residual oil. Normally, these processes are regarded as alternatives, and one or the other (usually neither) may be selected depending on circumstances such as oil type, permeability, lithology, clay content, and gas availability.

The sweep efficiency of miscible gas floods is frequently limited by gravitational segregation, viscous fingering, and channelling of injected gas towards the production wells. Thus, substantial amounts of oil remain in the reservoir after such a flood, and this oil could still be a target for a chemical flood, which can have a high sweep efficiency. In particular, since the miscible gas will tend to rise to the upper layers of the reservoir, while the water-soluble chemicals will tend to underdrive the oil in most cases, there may be scope for the two processes to act almost independently.

Earlier work¹ has shown the benefits of using polymer in a surfactant flood for mobility control purposes. Recent research² has shown that polymer can interact with the surfactant to produce greater reductions in interfacial tension, and to maintain the activity of the surfactant down to very low concentrations. This observation has led to the development of a Low

References and figures at end of paper.

Tension Polymer Flood (LTPF) system, which can achieve high oil recovery efficiency at low chemical concentrations, which has low adsorption, and which can tolerate high temperatures, salinities, and a divalent ion concentrations.

Natural targets for the LTPF system are large reservoirs which have been developed by waterflooding. However, some of these reservoirs are already subject to miscible WAG flooding, so it is of interest to know whether the LTPF process could be applied successfully in these cases. To answer this question quantitatively requires examination of both EOR processes within the same simulation model.

In this paper, a reservoir simulator ("BPOPE") capable of modelling both processes is described. Novel extensions to existing phase behaviour and relative permeability models are used to represent the interactions between the two processes. Illustrative calculations are presented which quantify the possible oil recovery from a chemical flood applied in combination with miscible gas injection. Two different reservoir descriptions are used in the calculations. The results indicate that, in some cases, the potential for successful application of chemical flood is not significantly affected by prior miscible gas flood.

2. OVERVIEW OF THE BPOPE SIMULATION MODEL

BPOPE is a multi-phase, multi-component reservoir simulation model. It has been developed in-house at the BP Research Centre, Sunbury, UK, from an earlier version of the University of Texas chemical flood model, UT-CHEM³. Developments introduced at BP include reformulation of the basic equations (following Acsal⁴) to allow for compressibility, modelling temperature variations and their effects on phase behaviour, a model for the surfactant/polymer interaction, a general orthogonal curvilinear coordinate system, generalised boundary conditions, FCT (Flux Corrected Transport) algorithm for control of numerical dispersion, an efficient ICCG (Incomplete Cholesky Conjugate Gradient) solver for the pressure equation, and models for miscible and immiscible

December 17, 1991

List of Selected Questions from November 18, 1991 Department of Natural Resources
Submittal with Rational for Continuing with Those Lines of Questions

Original question is restated followed by a brief statement of the rational for the question.

I. Miscible Injection Project and MI Composition

3. What is the greatest pressure drop that a portion of a given MI slug is expected to see while it is in the reservoir? How is recovery effected if the pressure drop is greater than that projected? [NEW QUESTION FOLLOWS] What are the simulator predictions of the minimum and maximum reservoir pressures in each PBUMGP area during each year that MI is being injected?

RATIONAL This question is very important because the producers must guarantee that the MI will always remain miscible in the face of not knowing exactly what future pressure performance will be and what the pressure gradients in the reservoir will be. This is essential to a successful project because the MI designed NOW must remain miscible for up to 5 years (McGuire testimony, pp 259 line 20).

Furthermore, the producers offered testimony that they will design the MI composition for the lowest anticipated average pressure plus an additional 100 psi safety factor. For a given average reservoir pressure, there will be some parts of the reservoir at pressures higher than this average and some parts that are at lower pressures. How can the producers guarantee that their prediction of future reservoir pressure performance is accurate to +/- 250 psi? The consequences of falling below the miscibility are severe in terms of reduced displacement efficiency. Is the 250 psi really enough to guarantee miscibility at all times under all conditions?

7. How would gas sales of one billion cubic feet per day effect the availability of MI? How would gas sales of two billion cubic feet per day effect the availability of MI?

RATIONAL The producers answered that the effect is dependent on when gas sales began. So, rephrase the question to address the issue of liquid losses for a specific starting date and volume of gas sales; What would be the loss in ultimate liquid recovery if gas sales commenced in 1995, in 2000? At 1 bcf/d? At 2 bcf/d?

II. Fluid Properties and Gas Cap Properties

6. Under constant volume depletion conditions, i.e., a differential gas liberation process (as compared to constant overall composition conditions, i.e., a flash gas liberation process) what is the phase diagram for the gas cap gas at 4300 psia?--at 3600 psia?--at 3000 psia?

Under constant volume depletion conditions what portion of the retrograde liquids revaporize at some lower reservoir pressures? At what pressure does this revaporization begin? All else being equal, theory has it that more retrograde liquid is left in the gas cap at intermediate pressures relative to higher or lower pressures. Will this be true for the IPA? Is this retrograde phenomena exaggerated over time as the phase diagram for the gas cap gas is modified as the gas cap gas composition changes?

RATIONAL This question asks for routine phase behavior data for the gas cap gas. This is useful reservoir engineering data for understanding the behavior of the gas cap with changing pressure and temperature conditions over the producing life of the reservoir. How else is one to understand what is going on in the gas cap?

5. What is the current composition of the residual "black" oil saturation in the gas cap?--has it changed since 1977? What is the saturation of this fluid? How did the saturation get that low? What is the composition of the retrograde liquid that drops out of the gas in the gas cap? Will it change over time? Will the combined black oil and retrograde liquid saturation in the gas cap ever be high enough to allow the combined liquids to flow?

RATIONAL This question was not asked in its entirety. It needs to be reasked in order to understand why there is residual black oil in the gas cap and why the saturation value is currently so low. That is, why is the residual oil saturation so low. The point of the question in part was to demonstrate that the gravity drainage mechanism can be extremely efficient.

III. Reservoir Depletion Options and Alternatives

1. What are the basic assumptions contained in the base case that was used to evaluate the proposed reservoir depletion option over time, i.e., assumptions such as-- oil, CGF liquids and gas production rates, residue gas and MI injection rates, water injection rate, pressure behavior, injection and production well count, work over requirements, capital investment in new or modified unit facilities, off unit (or transfer between the IPA and Lisburne) gas and MI sales, sharing of IPA production facilities with other participating areas in or out of the unit, project life?

RATIONAL Rephrase the question to ask for the producer's simulator predictions for various possible depletion scenarios; for the following depletion cases and on a year by year basis what were the predicted well counts, oil production rates, GOR's WOR's, MI injection rates residue gas injection rates, condensate and CGF liquid rates, and average reservoir pressures?

1. the currently proposed plan,
2. the case of 2 bcf/d gas sales starting in 2000,
3. the case of stopping gas cycling immediately,

4. the case of stopping MI injection immediately (waterflood only in the MI areas)

If these cases were made available, the AOGCC and ADNR would have some basis for discussions of the producers' assumptions that went into these predictions as well as a fall for four different depletion alternatives and why the proposed plan before the AOGCC is the "best" plan.

3. Have the operators investigated using flue gas for reinjection? From a future gas sales perspective would it help to inject the CO₂ or flue gas or N₂ just in the apex wells and continue some injection of residue gas at the existing gas injection pad?

RATIONAL This was part of Question #3, but was not answered by the producers. They only addressed injection of N₂ or CO₂ throughout the gas cap.

4. Would ultimate liquid recovery benefit from increased availability of MI or residue gas? Is the MI recovery processes in the IPA rate sensitive or time sensitive?

RATIONAL The AOGCC eliminated this question. The question is important because it addresses two issues of the currently proposed depletion plan that the AOGCC is about to rule on: 1) what would be the priority between producing blendable CGF liquids versus manufacturing MI; 2) rate sensitivity is a fundamental question in any enhanced recovery process.

7. Is the gravity drainage recovery process enhanced, unaffected or slowed down by continued gas cycling? Will the gravity drainage process continue throughout the production life of the reservoir? What is the expected final residual oil saturation in the gravity drainage area?

RATIONAL The producers answered the question by saying that the gravity drainage is enhanced by the gas cycling due to the ability to produce high GOR wells. However, since it is the gas cycling (in part) that contributes to the high GOR's and if cycling were not done, the GOR's would generally be lower. Also, the higher gas saturations due to gas cycling slows down the gravity drainage by relative permeability effects.

We would like to rephrase this question to the following: Would the oil recovery from the oil zone in the gravity drainage area be the same if gas cycling operations were not being conducted? The point being to determine whether the black oil (not condensate) recovery in the gravity drainage area would be the same whether gas cycling was being conducted or not.

10. Would there be an increase in ultimate recovery of liquids from the gas cap by diverting all the available gas (including the MI) to the apex wells for reinjection? Or would this just accelerate the recovery process in the gas cap? Is there an urgency to recover liquids from

) the gas cap sooner verses later? Do the liquids recovered from just the gas cap have to be blended with black oil in order to be shipped down TAPS? Would the amount of gas liquids be large enough to support the operation of TAPS by themselves?

RATIONAL The first part of this question was not asked by the AOGCC. Since the Commission is charged with the prevention of waste and the question deals with an increase in ultimate recovery under a particular development option, the question seems appropriate in trying to understand the impacts of cycling the gas cap at the apex.

11. With respect to the potential for future off-unit gas sales, would cycling gas for longer periods of time at lower pressures result in the same liquid recovery as cycling gas for a shorter period of time at a higher pressure? What type of a gas cycling/EOR/gas sales/liquid recovery plan extends the life of TAPS the longest? Has the TAPS availability issued been studied?

RATIONAL This question was eliminated by the Commission. Without TAPS the oil production will have to be shut in. Waste may be created by not optimizing recovery prior to this shut in. DNR wishes to resubmit this question in the following form: Would cycling gas for longer periods of time at lower pressures result in the same liquid recovery as cycling gas for a shorter period of time at a higher pressure? What type of a gas cycling/EOR/gas sales in either 1995 or 2000/liquid recovery plan extends the life of TAPS the longest? Has the TAPS availability issue been studied?

STATE OF ALASKA

JAY S. HAMMOND, GOVERNOR

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DEPARTMENT OF LAW

OFFICE OF THE ATTORNEY GENERAL

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February 14, 1977

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RE: ECONOMIC WASTE UNDER
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Dear Hoyle:

You have asked if AS 31.05 permits the Conservation Committee to consider "economic waste" as well as physical waste. It is my conclusion that the Conservation Committee is allowed to consider economic factors in its establishment of conservation practices but that the term "economic waste" must be defined and the question related to a specific regulatory decision before a more meaningful legal opinion is possible.

I.

Brief History of Conservation Regulation

It will be helpful to an understanding of AS 31.05 to review briefly the history of oil and gas conservation regulation by states.* This is appropriate and useful because Alaska's conservation statute contains many of the same clauses and provisions found in the IOCC model statute and/or other state conservation statutes.

*/ This review is taken principally from S. McDonald, Petroleum Conservation in the United States: An Economic Analysis (1971); see also, Interstate Oil Compact Commission, A Study of Conservation of Oil and Gas in the United States (1964).

Initial conservation legislation was designed to prevent damage to other resources caused by oil and gas production and to eliminate certain obvious and easily preventable losses of natural gas. These initial conservation statutes usually established regulations applicable to individual wells (rather than whole reservoirs) and prohibited specific practices or conversely required certain specific practices, such as for example, requiring the proper casing and plugging of wells to prevent interchange of fluids among reservoir or the contamination of ground water supplies, or to prevent natural gas leaks. Later regulatory statutes usually retained the specific prohibitions of the earlier statutes but also included a general prohibition against waste which was defined in broad terms (or more often undefined). Thus, many state conservation statutes (including Alaska's) contain something of a collection of specific prohibitions and some rather broad, but undefined limitations.*

Conservation legislation, no doubt, was necessary because some operators in their haste to produce oil, employed poor production techniques and disregarded the impact of those practices on other resources (e.g. on ground water). However, another consideration was even more significant. Multiple ownership of the land overlying oil reservoirs combined with the rule of capture** to create an overpowering incentive for each owner of a lease to produce as

*/ AS 31.05.020 provides: "The waste of oil and gas in the state is prohibited." "Waste" is defined by AS 31.05.170(11) which because of its length is attached as appendix A hereto. R-100(14)

**/ The rule of capture says that whoever produces the oil owns it, regardless of where it is located underground. Railroad Commission v. Rowan & Nichols Oil Co., 310 U.S. 573 (1939).

much oil as rapidly as possible. This resulted in a number of production practices which frequently caused unnecessary capital expenditures and/or the loss of large quantities of oil. For example, since each producer was competing with other producers in the same reservoir he would usually drill as many wells as possible and operate each well as long as possible. This meant that more wells would be drilled than were actually required to produce all the oil which could be produced from a reservoir; and even more significantly, it usually meant reservoir pressure would be rapidly depleted resulting in less total oil being produced from the reservoir than could have been produced if production had been coordinated. Similarly, large quantities of oil were lost in above ground earthen storage reservoirs which were used because they were the fastest and cheapest way to store the rapidly produced oil. The more modern regulatory statutes (those enacted or amended after 1930) were intended to give state regulators more power to control production practices so as to prevent losses of oil and gas resulting from the competitive race to produce oil as rapidly as possible from each reservoir.

The methods of production control employed by various state regulators have involved a number of overlapping and/or alternative approaches. One of the earliest approaches and also one of the simplest and most widely accepted regulatory methods has been to control the number and spacing of wells. Every state which has a conservation statute expressly authorizes the control of well spacing.* A second method of regulation has been to control directly the quantity of oil and/or gas produced. In practice, this type of regulation has

*/ IOCC, A Study of Conservation of Oil and Gas in the United States, at 180 (1964).

taken two distinct forms, each of which will be discussed in greater detail below. A third method of regulation has been to authorize voluntary or compulsory unitization, and a fourth method of regulation has been to require the use of secondary recovery techniques. Many state statutes authorize one or more of these methods (several authorize all four methods), with individual states relying to varying degrees upon each method.

Direct Control of Production and "Economic Waste"

In the early years of the industry, the price of oil often was very low because producers, in their haste to capture as much oil as possible, frequently produced oil far in excess of market demand. Low prices, of course, meant little profit for the industry and also little revenue for those states which depended heavily on royalty payments and taxation of the oil industry for their income. Out of this situation emerged the concept of "economic waste", that is, the production of oil (or gas) in excess of market demand. In 1915 the Oklahoma conservation statute was amended to prohibit "economic waste" (which was not defined) and on the basis of that language, the Oklahoma regulatory agency adopted a regulatory scheme which allowed the agency to establish a statewide production limit and allocate production back to each well so that total production would not exceed that limit. Although this method of regulation effected prices (many persons charged it fixed prices), limiting production to market demand was found by the courts to be a valid method of preventing waste. Julian Oil and Royalties Co. v. Capshaw, 292 P. 841 (1930); Champlin Refining Co. v. Oklahoma Corp. Commission, 286 U.S. 210 (1932). In Texas, a 1929 amendment to the conservation statute expressly stated that the prohibition against waste was not to be construed to mean "economic waste."

After the 1929 amendment, suits were filed challenging Texas's policy of limiting oil production to market demand. In one case, the court held Texas' regulatory approach valid despite the statutory reference to "economic waste." Danciger Oil and Refining Co. v. Railroad Commission, 49 S.W.2d 837 (1932). In a second case, however, the court held that the Railroad Commission's orders were intended to prevent "economic waste", and that this was in violation of the 1929 amendment. Alfred Macmillan v. Railroad Commission, 51 F.2d 400 (1931). In response to the MacMillan decision, the Texas legislature repealed the reference to "economic waste" and authorized the prohibition of "production of crude petroleum oil in excess of transportation or market facilities or reasonable market demand". Since the MacMillan case, the practice has been to avoid use of the term "economic waste" in conservation statutes.* Rather those states which employ a market demand method of production control have adopted such a regulatory policy through the use of language similar to that in the Texas statute.**

In the light of the above legal history, it is my conclusion that the term "economic waste", when used in reference to oil and gas conservation practices, is best understood to mean regulation which limits production to market demand.***

*/ Only four state statutes use the term "economic waste." The Oklahoma and Kansas statutes each prohibit "economic waste", while the statutes of Illinois and Kentucky prohibit limitation of production to prevent or control "economic waste." 10CC, at 188-89.

**/ Ibid. at 176-79.

***/ One commentator has written: "Despite its apparent breadth, the term 'economic waste' is usually employed narrowly to mean the sale of oil or gas at a price below full cost or actual value and/or the use of oil or gas in ways which fail fully to exploit its intrinsic value". S. McDonald, Petroleum Conservation in the United States; An Economic Analysis 127 (1971).

II.

While the above discussion answers the question you have asked, I believe it might be helpful to discuss "economic waste" as the term might be defined or perceived by others. This discussion, because it is unrelated to any particular regulatory problem is general.

Direct Production Control and
the Maximum Efficient Rate of Production

In those states which do not employ a market demand method of production regulation, production is regulated on a reservoir-by-reservoir basis, with total production from a reservoir being limited to the maximum efficient rate (MER). Typically, the MER is determined with respect to engineering factors rather than economic considerations. Thus, the MER is that rate which will maximize the total output of oil (in an oil reservoir). A rate which causes total oil production to diminish (because, say reservoir pressure is dissipated too rapidly) will be in excess of the MER and will not be allowed. Once the MER is established, shares of production are allocated to each producer and/or well.

Although in practice, engineering considerations have dominated the determination of the MER, it is clearly possible that economic criteria could equally be used as the efficiency criteria. If this were done, the regulatory agency might establish rates designed to maximize total present value rather than total output. Thus, at a time of declining real prices for oil (or perhaps ever slowly rising prices) the regulator might well determine that the MER was at a rate which

sacrificed future oil production for increased present production.*

There is certainly nothing express in AS 31.05 which would prevent the Conservation Committee from implementing production control using economic, rather than engineering criteria, to determine the MER. Indeed, words such as "unnecessary", "inefficient", and "excessive" might well connote economic criteria (at least to an economist) rather than engineering criteria. Nevertheless, I believe use of economic criteria, rather than engineering criteria, would represent a drastic change in regulatory practice in Alaska (and anywhere else for that matter) and thus, should only be undertaken in response to clear legislative directive in the form of amendments to the conservation statute.

I do not agree since the terms "physical waste" & "underground waste" are in the definition.

Having noted that the regulatory practice in Alaska and elsewhere is to use engineering, rather than economic criteria to determine the MER, it should not go unstated that economic considerations are involved in many conservation decisions at least in a gross sense. For example, where the Conservation Committee is considering whether to require a water injection program, it certainly must compare the cost

*/ The most striking difference between the use of engineering criteria and economic criteria may occur where a reservoir contains both oil and non-associated gas, and the production of one results in a diminshment of the other which can be produced. In that case, engineering criteria might call for maximization of total hydrocarbons (BTU's) while economic criteria would call for consideration of the present and probable future value (price) of each and maximization of the present value.

It should be noted that this is not the regulatory problem you face with the Prudhoe Bay field, since (based on my understanding) hydrocarbon production can be maximized provided gas production is held within reasonable bounds (which bounds may be zero if water flood is not employed; however, in that event, the field can be blown down once oil production ceases). Thus, if one is willing to indulge the assumption that gas prices will increase at a rate at least equal to the discount rate, the MER will be the same using either engineering or economic criteria.

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Division of Oil and Gas Conservation

of such a program with the expected increase in recovered hydrocarbons. In doing so, the Conservation Committee need not adopt the economic criteria used by the producers, thus, a water injection program which the producer did not wish to undertake because the rate of return was too small (in their opinion) might still be required by the Conservation Committee. However, in the extreme case, where costs greatly exceeded any possible economic benefits to be derived, constitutional limitations likely would prevent the Committee from requiring an injection program.

Unitization of a Reservoir

One commentator has concluded that state conservation statutes "should require unitization of every oil reservoir within a reasonable time following discovery", and that such a statute "should supplant all present regulations (e.g. of well spacing and production rates) except those designed to protect other resources from damage by oil operations." The conclusion is incorrect because it embodies a false assumption (which will be discussed below) but it nevertheless highlights an important consideration. That is, by eliminating the competition among producers of oil from a reservoir, one eliminates most of the incentive to engage in "wasteful" practices. In a unitized reservoir, all producers will be better off if production is maximized.

If a unitized reservoir was unregulated, production rates would be determined in accordance with procedures adopted by the unit participants. In such case, one would expect the unit participants acting as profit maximizing entities to produce the reservoir in a fashion which

*/ S. McDonald, Unit Operation of Oil Reservoirs as an Instrument of Conservation, 49 Notre Dame Lawyer 305 (1973).

maximized the reservoir's present value.* Such rate of production likely would not correspond to the MER as determined by engineering principles. The public's interest ~~interest~~ in the production of nonrenewable oil and gas resources will correspond exactly with the producers' interest only in the hypothetical world of economists where competition is infinite and institutional constraints non-existent. In practice, the public's interest may be served by requiring the operators of a unitized reservoir to operate at a rate different from that which they would choose on their own. For example, the unit operators may decide against fluid injection because the anticipated rate of return is too low (in their view). The public's interest, however, might best be served by requiring an injection program. Or to give another example, where oil prices are controlled, maximization of present value by the producers likely will run counter to the public's interest.

Regulators of unitized fields have in the past required maximization of hydrocarbons while considering at least in gross terms economics factors. As before, regulators could well require maximization of other objective criteria. However, I would not advise such a course of action without clear Legislative direction in the form of amendments to the present conservation statute.

*/ For various reasons in practice production rates may not be such as to maximize present value. For example, integrated producers may be facing crude shortages and willing to sacrifice future revenues while others may face a glut situation. The actual rate may represent a compromise. Some producers may want to hold back production to speculate on future market conditions, while others may prefer to follow less venturesome corporate policies. In short, producers may each have different discount rates.

Mr. Hoyle Hamilton, Director
Div. of Oil and Gas Conservation

February 14, 1977
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Sincerely,

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ATTORNEY GENERAL

Frederick H. Boness

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Assistant Attorney General

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