PRUDHOE BAY UNIT

APPLICATION FOR THE FORMATION OF THE NORTH PRUDHOE BAY PARTICIPATING AREA

DECISION AND FINDINGS OF THE COMMISSIONER
ALASKA DEPARTMENT OF NATURAL RESOURCES

DECEMBER 30, 1994

PRUDHOE BAY UNIT

FORMATION OF THE NORTH
PRUDHOE BAY PARTICIPATING AREA

I. INTRODUCTION AND BACKGROUND

This matter concerns the formation of the North Prudhoe Bay Participating Area (NPBPA) to be located within the current boundary of the Prudhoe Bay Unit (PBU) and what lands should be included in the proposed NPBPA. Pursuant to Paragraph (d) of the Amended Application for the Proposed Pt. McIntyre Participating Area Prudhoe Bay Unit Expansion (Amended Application), dated October 13, 1993, the North Prudhoe Bay State (NPBS) Acreage (Attachment 1) was granted a deferral of contraction from the PBU. ARCO Alaska, Inc (ARCO) and the Exxon Corporation (Exxon) were required by the terms of the Amended Application to submit an application to form a NPBS Acreage Participating Area by September 30, 1994. If the application was not filed by September 30, 1994, the NPBS Acreage would automatically contract out of the PBU as of that date. ARCO, on behalf of itself and Exxon, applied to form the NPBPA within a portion of the NPBS Acreage on August 18, 1994. The acreage proposed for inclusion in the NPBPA overlies an oil reservoir known as the "North Prudhoe Bay Reservoir".

An oil and gas "unit" is comprised of a group of leases which cover all or part of one or more potential or known reservoirs and which are subject to a "unit agreement." The "unit agreement" is the instrument which is typically executed by those with an interest in the leases, including the royalty owner, and which specifies how unit operations will be conducted, and how costs and benefits will be allocated among the various leases. A second agreement called a "unit operating agreement" controls the relationship between parties which share the costs of unit development. Unitization generally allows a potential or known reservoir to be more efficiently explored, developed, or produced than on a lease by lease basis.

A "participating area" (PA) is usually limited to that part of the unit area which has been shown to be productive of oil or gas in "paying quantities" from a given reservoir. A PA may consist of less, but not more, area than the unit area. If the unit area encompasses more than one reservoir, a separate PA must generally be established for each delineated reservoir. Additionally, if the same reservoir contains both oil and gas, separate PAs may be established to distinguish between the oil rim and the gas cap. For example, the PBU currently consists of six PAs overlying several reservoirs all located within the PBU area: the oil rim and gas gap PAs (collectively the initial participating areas or IPAs) for the Prudhoe Bay or Permo-Triassic Reservoir; the Lisburne PA for the Lisburne Reservoir; the West Beach PA for the West Beach Reservoir; the Pt. McIntyre PA for the Pt. McIntyre and Stump Island Reservoirs; and the Niakuk PA for the Niakuk Reservoir.

The boundaries of PAs can be revised as more wells are drilled and more data are obtained. The regulations governing unitization expressly provide for the expansion and contraction of a PA. Only those parties who own interests within the designated PA will share in the costs of production and revenues from the sale of the oil or gas from the PA.

The Division concludes that ARCO's application to form the NPBPA (as amended on October 14, 1994) should be granted. It further concludes that the NPBPA should be limited to the area proposed by ARCO (October 14, 1994 letter) because only that area has been shown to be "reasonably known to be underlain by hydrocarbons and known or reasonably estimated...to be capable of producing or contributing to production of hydrocarbons in paying quantities." 11 AAC 83.351(a) (emphasis added). If additional data are obtained or submitted in the future which confirm that revision of the PA area is appropriate, the boundaries of the NPBPA may be revised.

II. APPLICATION FOR THE FORMATION OF THE NORTH PRUDHOE BAY PARTICIPATING AREA

ARCO's NPBPA application was submitted pursuant to 11 AAC 83.351 and Section 5.3 of the PBU Agreement. The application included: a proposed plan of development and operations; a tract participation schedule for the leases in the proposed PA; geological and geophysical data supporting the proposed PA; a proposed methodology for allocating production from all the producing reservoirs that will share the Lisburne Production Center (LPC); and a copy of the NPB Special Provisions to the PBU Operating Agreement that was submitted on December 6, 1994. Additional geological and geophysical information was submitted on September 15 and September 19, 1994. ARCO requested that the Division approve the NPBPA effective September 30, 1994.

The acreage proposed for the NPBPA encompasses the NPB Reservoir which includes the Ivishak Formation, the Shublik Formation, and Sag River Sandstone. The NPB Reservoir contains hydrocarbons and is purported to be capable of producing hydrocarbons in paying quantities. The NPB Reservoir is referenced on Attachment 4 of the NPBPA application. In the August 18, 1994 application, portions of two leases were originally proposed for inclusion in the NPBPA (ADLs 28297 and 34624). At the request of the Division of Oil and Gas and with the concurrence of both ARCO and Exxon, the application was modified on October 14, 1994 to delete ADL 34624 from the proposed NPBPA. A map of the NPBPA and the tract participation schedule for the NPBPA are listed as Attachment 2 and Attachment 3, respectively. ADL 28297 reserves a 12.5% royalty share to the state. A reduction of the royalty rate from 12.5% to a discovery royalty rate of 5 percent for all production from the lease was granted on March 6, 1991. The royalty reduction was granted for ADL 28297 because the Pt. McIntyre accumulation was discovered by the drilling of the Pt. McIntyre No. 3 well on that lease. The discovery royalty rate is effective for the period April 1, 1988 through March 31, 1998.

III. GEOLOGICAL AND ENGINEERING CHARACTERISTICS DATA IN SUPPORT OF THE APPLICATION

The proposed NPBPA lies entirely within the boundaries of the PBU. The NPBPA Reservoir encompasses the Ivishak Formation, the Shublik, and the Sag River Sandstone which are the same stratigraphic intervals as the major productive intervals in the Prudhoe Bay Reservoir. ARCO estimates that the reservoir contains between 1.8 and 2.4 million barrels of recoverable reserves.

ARCO provided geological, petrophysical and well information to support its proposed NPBPA. These data include geologic logs of the North Prudhoe Bay State No. 1 and No. 3 wells, and structure and gross hydrocarbon isochore maps of the Ivishak Formation. Only two wells have penetrated the NPB Reservoir within the proposed NPBPA boundary. ARCO and the Division staff discussed additional, significant data, and structural interpretations of the Reservoir. These discussions reviewed pertinent confidential information including proprietary ARCO 3-D seismic data, well logs from the two wells, core and core descriptions from the North Prudhoe Bay State No. 1 Well, interpreted structure maps, isochore maps, geological cross-sections of the NPB Reservoir, and volumetric calculations of the hydrocarbons in-place within the proposed NPBPA. The data and interpretations are discussed later in this Decision and Findings.

IV. DISCUSSION OF THE PARTICIPATING AREA DECISION CRITERIA

11 AAC 83.351(a) provides that a PA may include "only land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through use of geological, geophysical, or engineering data to be capable of producing or contributing to the production of hydrocarbons in paying quantities." "Paying quantities" means:

> quantities sufficient to yield a return in excess of operating costs, even if drilling and equipment costs may never be repaid and the undertaking as a whole may ultimately result in a loss; quantities are insufficient to yield a return in excess of operating costs unless those quantities, not considering the costs of transportation and marketing, will produce sufficient revenue to induce a prudent operator to produce those quantities.

11 AAC 83.395(4). A PA application must be evaluated under these standards, as well as those of 11 AAC 83.303.

Under 11 AAC 83.303, a proposed PA will be approved if the commissioner finds that the PA is necessary or advisable to protect the public interest. To make such a finding, the commissioner must determine that the proposed PA will: (1) conserve natural resources; (2) prevent economic and physical waste; and (3) protect all parties of interest, including the state.

In evaluating the above criteria, the commissioner will consider: (1) the environmental costs and benefits; (2) the geological and engineering characteristics of the potential hydrocarbon accumulation or reservoir proposed for inclusion in the PA; (3) prior exploration activities in the proposed PA; (4) the applicant's plans for exploration or development of the proposed PA; (5) the economic costs and benefits to the state; and (6) any other relevant factors (including mitigation measures) the commissioner determines necessary or advisable to protect the public interest. The following evaluates the NPBPA under these criteria and considerations.

(A) Conservation of Natural Resources

The formation of oil and gas units and PAs within unit areas to develop hydrocarbon-bearing reservoirs generally conserves hydrocarbons. A single PA will provide for more efficient, integrated development of the NPB Reservoir. A comprehensive operating agreement and plan of development governing that production will help avoid duplicative development efforts.

As mentioned in section III. of this Decision and Findings, the NPB Reservoir and the proposed NPBPA lie entirely within the boundaries of the PBU. The production of the hydrocarbon liquids from the NPBPA through existing production and processing facilities, specifically the Lisburne Production Center (LPC), generally reduces the incremental environmental impact of the additional production. Using the existing facilities, gravel pads, and infrastructure eliminates the need for new stand-alone facilities for the new PA. Small hydrocarbon accumulations, like the NPB Reservoir which is estimated at this time to contain only 12 million barrels of oil-in-place, would likely be non-developable without the lower cost structure resulting from a more complete utilization of existing facilities. Forming the NPBPA will maximize oil and gas recovery, while minimizing negative impacts on other resources within the area.

(B) Prevention of Economic and Physical Waste

Generally, forming a PA facilitates the equitable division of costs and allocation of hydrocarbon shares, and provides for a diligent development plan which maximizes physical and economic benefit from a reservoir. Further, the formation of the PA and facility sharing opportunities may allow economically marginal hydrocarbon accumulations to be developed.

The LPC owners have negotiated agreements among themselves to share the existing production capacity of the Lisburne facilities and the PBU infrastructure. Using these facilities and the infrastructure eliminates the need to construct stand-alone facilities to process the relatively small volume of recoverable hydrocarbons in the NPBPA. The state has participated in attempts to reduce the need for additional major processing facilities and thus to minimize any additional surface impacts and costs. The state has agreed to allow commingled production through the existing LPC and has worked to provide for a well test-based production allocation methodology for current and future reservoirs sharing the LPC. The adoption of that methodology is subject to periodic review and reconsideration to assure that the state's royalty and tax interests are protected.

Further, facility consolidation will save capital and promote better reservoir management through future pressure maintenance and enhanced recovery procedures. A long term development plan for the reservoir has not been approved to date. In combination, these factors in the short term allow the NPB Reservoir to be developed and produced in the best interest of all parties.

(C) Protection of All Parties

Forming separate PAs seeks to protect the economic interests of all working interest owners of the reservoirs in the PAs, as well as the royalty owner. By combining interests and operating under the terms of a unit agreement and unit operating agreement, such as the PBU Agreement and PBU Operating Agreement, as amended to account for any special PA provisions, the owners may be assured that costs and revenues will be fairly allocated based on specific ownership interests.

Because hydrocarbon recovery will be maximized and additional production-based revenue will be derived from NPBPA production, the state's economic interest is furthered. Additional recovery of hydrocarbons, however, in and of itself may not always be determinative of the state's best interest. Production must occur under suitable terms and conditions to assure that the economic interests of both the working interest owners and the state, as the royalty owner, are protected. It has been the state's consistent policy of opening the renegotiation of some specific terms of the original lease contracts at the time of unitization decisions. Although not required here, amendments to an existing unit agreement or oil and gas lease may be necessary to protect the state's interest. In particular, amendments may be necessary where an application seeks to include leases which are not already within unit boundaries or leases, which contain different terms and conditions, or which through their commitment to an existing unit agreement, by virtue of the terms of that agreement, its operating agreement or applicable settlement agreements, would prejudice the state's economic interests.

The proposed production allocation methodology further protects the interest of all parties by allocating production between the reservoirs that produce through the LPC. This methodology intends to accurately and fairly allocate production. It may be revised if it does not meet those goals. Also, within the PBU, gas from one PA may be reinjected or stored in another PA. A gas disposition/reserves volume accounting procedure accounts for and tracks gas that is either produced, used, sold, reinjected or stored.

In reviewing the above criteria, the following factors were considered:

(1) The Environmental Costs and Benefits

As discussed in section IV.A., the sharing of some of the existing facilities eliminates duplication and reduces the surface area altered by development. The development of the NPB Reservoir will not significantly alter the existing gravel pads, roads or surface facilities. Further, no significant additional impacts to nearshore habitat or biological resources are anticipated because the additional NPBPA production will share the existing PBU facilities.

(2) The Geological and Engineering Characteristics of the Reservoir and Previous Exploration and Development Activities of the Proposed Participating Area

There are two major faults in the North Prudhoe Bay area, the Prudhoe Bay Fault and the Pt. McIntyre Fault. Both are east/west trending, down-to-the-north normal faults with approximately 1000 feet of throw at the Ivishak level. The area between these two major faults is the location of the NPB accumulation.

Oil and gas in the NPB area was first encountered by the NPB State #1 Well in 1970. The well encountered hydrocarbons in the Sag River and Ivishak Formations. A drill stem test of the Sag River Formation recovered 3.6 MM SCFD of gas and 132 STBD of condensate, while a drill step test of the Ivishak Formation recovered oil at a rate of 2727 STBD. Although the tested intervals in the NPBS #1 well are the same intervals that contain the a majority of the reserves in the Prudhoe Bay Field, the proposed NPB Reservoir is a separate accumulation based on its higher oil gravity, 35 API vs. 28 API, and an oil/water contact at -9289 feet SS, approximately 300 feet deeper than the oil/water contact in the Prudhoe Bay Field.

Following the acquisition of 3-D seismic data in 1990, the NPB State #3 Well was drilled from the West Beach Drill Site in 1993. That well encountered hydrocarbons in the Sag River, Shublik, and Ivishak Formations and has produced over 850,000 STB of oil from the Ivishak

Formation as a Tract Operation in the PBU since October 14, 1994. While the NPBS #3 Well has been certified as capable of production in paying quantities by the ADNR and continues to produce from the Ivishak Formation, the NPBS#1 Well has been plugged and abandoned.

(3) The Applicant's Plan for Exploration or Development of the Participating Area

For the NPB Reservoir, primary recovery with aquifer support is expected to yield 15-20 percent of the original oil in place. ARCO states that further development plans for the NPB Reservoir are uncertain at this time. Immediate plans are to continue producing the NPBS #3 Well and the Reservoir through the permanent production line from the West Beach Drill Site to the LPC. All produced NPB Reservoir gas will be injected into the Lisburne reservoir since no gas injection facilities are available at the West Beach Drill Site.

Given the current level of uncertainty regarding reservoir size and performance (amount of aquifer support), fluid handling capacity limitations at the LPC, and economic conditions, the initially proposed plan of development is consistent with prudent reservoir management practices. However, the Division is concerned that only one well, NPBS #3, may be inadequate to recover oil from the entire area proposed for the NPBPA. The initial plan is adequate for the next year while reservoir performance data is gathered and evaluated. As a condition of approval of the Plan of Development for the NPBPA, the Division will require ARCO, as NPBPA Operator, to address enhanced recovery possibilities and the desirability of drilling additional wells in the PA in future plans of development (POD). Specifically, in the POD for 1996, ARCO should address the issue of whether or not additional wells are justified in the PA, and how ARCO expects to maintain and enhance the physical recovery from the NPBPA.

(4) The Economic Costs and Benefits to the State

As discussed in Article IV (C) above, increased production and revenues, in and of themselves and without consideration of other relevant factors, may not always be in the state's best interest. Here, however, the gain in economic benefits outweighs any perceived costs to the state.

Economic benefits accrue to the state because approval of the NPBPA promotes the ultimate physical recovery of hydrocarbons from the NPB Reservoir and the PBU. Any administrative burdens associated with the new PA are far outweighed by the value of additional royalty and tax benefits derived from the NPBPA production. See section V. below for a further discussion of relevant economic costs and benefits factors.

(5) Any other relevant factors (including mitigation measures) the commissioner determines necessary or advisable to protect the public interest

The factors are discussed in Article V below.

V. OTHER ISSUES PERTINENT TO THE NPB PARTICIPATING AREA APPLICATION

In a letter dated January 13, 1993 to ARCO, the division noted a number of concerns related to the application to form the West Beach Participating Area (WBPA) within the PBU. Some of the issues addressed in that letter are pertinent to this application to form the NPBPA. The attached letters (Attachment 5) dated January 13, 1993 and March 1, 1993 set forth the issues and the agreements between the parties in the WBPA regarding the royalty issues.

These same agreements between the parties regarding the WBPA shall apply to the NPBPA. The Division incorporates the following from Section V. of the Decision and Findings of the Commissioner, Alaska Department of Natural Resources regarding the Application for the Formation of the WBPA, dated April 2, 1993, into this Decision and Findings regarding the formation of the NPBPA.

> A meeting was held between ARCO and division staff on February 23, 1993 to discuss the concerns raised in the January 13, 1993 letter. Prior to the February 23, 1993 meeting, ARCO submitted a written response, dated January 25, 1993, to the state's concerns with the West Beach Participating Area application. In addition, ARCO submitted another letter, dated March 1, 1993, regarding ARCO and Exxon's understanding of the outcome of each of these issues as a result of the February 23rd meeting.
>
> Except for use of ARCO's and Exxon's initially proposed gas disposition and reserve debit report, Item 3 of the March 1, 1993 letter, the division agrees with ARCO's and Exxon's understanding of the outcome of the West Beach Participating Area issues as expressed in ARCO's March 1, 1993 letter. Regarding the gas disposition and gas reserves debit report, the modified report included as Attachment 2 is acceptable to the division for gas volume accounting purposes. A copy of the Match 1, 1993 letter is appended to this Decision and Finding as Attachment 3.

The referenced Attachment 2 and Attachment 3 of the WBPA Decision and Findings will be Attachment 4 and 5 to this NPBPA Decision and Findings.

Finally, per the Amended Application, any of the NPBS Acreage that is not included within a participating area by December 31, 1994, automatically contracts out of the PBU on that date. If additional data supportive of a request for expansion are obtained in the future, ARCO and Exxon may apply to expand the NPBPA to include such acreage.

VI. FINDINGS AND DECISION

Considering the facts discussed in this document and the administrative record, I hereby make findings and impose conditions as follows:

1. The proposed PA, the NPBPA, meets the requirements of 11 AAC 83.303.

2. The available geological, and engineering data submitted demonstrate that the proposed participating area acreage is known to be underlain by hydrocarbons and known or reasonably estimated to be capable of production or contributing to production in sufficient quantities to justify the formation of the NPBPA within the PBU.

3. The geological and engineering data supporting the PA justify the inclusion of the proposed tract within the NPBPA at this time. The entire PA is wholly contained within the boundaries of the current PBU. Under the terms of the applicable regulations governing formation and operation of oil and gas units (11 AAC 83.301 - 11 AAC 83.395) and the terms and conditions under which these lands were leased from the state, the following lands are to be included in the NPBPA:

   T.12.N., R.14.E., U.M., Sec. 22
   (ADL 28297 (Tract 8)).

4. Pursuant to Paragraph (d) of the Amended Application for the Proposed Pt. McIntyre Participating Area Prudhoe Bay Unit Expansion, dated October 13, 1993, North Prudhoe Bay State Acreage not included within the NPBPA automatically contract out of the PBU. The following NPBS Acreage contracts out of the PBU as of December 31, 1994:

   T.12.N., R.14.E., U.M., Sec. 23: S/2, S/2NE/4, and SE/4NW/4
   (ADL 34624 (Tract 7)).

   Within forty-five (45) days of the date of this Decision and Findings, ARCO shall submit to the Division updated Exhibits A and B to the PBU Agreement reflecting the revised PBU Area.

5. The PBU Agreement and the Alaska statutes and regulations governing oil and gas units provide for further expansions of a PA in the future as warranted by additional information and findings. Therefore, the public interest and the correlative rights of all parties, including the state, are protected.

6. Formation of the PA equitably divides costs and allocates produced hydrocarbons, and sets forth an initial development plan designed to maximize physical and economic recovery from the NPB Reservoir within the approved PA.

7. The production of NPBPA hydrocarbon liquids through the existing production and processing facilities within the PBU reduces the environmental impact of the additional production. Utilization of existing facilities will avoid unnecessary duplication of development efforts on and beneath the surface.

8. As of this time, the proposed well test allocation methodology is acceptable for royalty allocation purposes and for allocating the commingled gas and hydrocarbon liquids production among the NPBPA, the West Beach Participating Area, the Niakuk Participating Area, the Pt. McIntyre Participating Area and the Lisburne PA as those streams are processed through the LPC.

   The LPC Operator, ARCO, shall provide the Division with the monthly production allocation reports and well test data for the wells producing through the LPC by the 20th of the following month. The Division reserves the right to request any information it deems pertinent to the review of those reports.

The monthly allocation report shall include a monthly oil, gas, and water allocation factor to be applied uniformly to the respective commingled production streams, a summary of monthly allocation by well, a summary of the allocated volumes of oil, hydrocarbon liquids, gas and water by participating area, oil gravity of the combined stream, and specific well test data for all tests which have been conducted.

9. The Division reserves the right to review the well test allocations to insure compliance with the methodology prescribed in this decision. Such review may include, but is not limited to, inspection of facilities, equipment, well test data, and separator back-pressure adjustments.

10. During the first year in which commingled production from the NPBPA is allocated, reviews of the allocation methodology will be scheduled with the Division. Following its review, the Division, in its sole discretion, may require revision of the allocation procedure. Subsequent reviews may be requested by either the Division or the operator. Following any subsequent review, the allocation procedure may be revised with the written consent of, or upon the written direction of, the Division in its sole discretion.

11. To account for the gas produced from each participating area, the gas volume disposition and gas reserves debited from or credited to each PA using the shared LPC, the NPBPA operator shall submit a monthly gas disposition and reserves debit report using the form indicated in Attachment 4. The gas disposition report shall be submitted with the monthly production allocation reports.

    As with the other PAs sharing the LPC, the Division approves a fuel gas allocation methodology which allocates flare and fuel gas in proportion to the NPBPA's share of total produced gas through the LPC.

12. The field cost allowance for the state's royalty share of oil produced from the approved NPBPA shall be governed by the 1980 Prudhoe Bay Settlement Agreement. Whether the state bears any deductions of any kind whatsoever (whether called allowances, deductions or fees) for the state's royalty share of "NGLs" and dry gas, and if so, the amount of those deductions, shall be subject to the final resolution of the ANS Royalty Litigation.

13. Regarding the production allocated from the NPBPA and the state's taking of any royalty oil in-kind from the NPBPA, it continues to be the state's position that it has only nominated the taking of royalty oil in kind and has never nominated gas for in-kind taking.

14. Diligent exploration and delineation of the NPB Reservoir underlying the approved participating area is to be conducted by ARCO and Exxon under the PBU plans of development and operation approved by the state.

15. The initial plan of development for the NPBPA meets the requirements of 11 AAC 83.303 and 11 AAC 83.343 while reservoir performance data are gathered and evaluated from the NPBS #3 Well. The plan is approved for a period of one year from the effective date of this Decision and Finding subject to the terms and conditions of section IV.(3). Future plans must be submitted in accordance with 11 AAC 83.343 and are also subject to the terms and conditions of section IV.(3) of this Decision and Findings.

16. The State and the Applicants have agreed to change the requested effective date of the NPBPA. Approval of the NPBPA within the PBU is effective January 1, 1995.

For these reasons and subject to the conditions and limitations noted, I hereby approve the North Prudhoe Bay Participating Area within the Prudhoe Bay Unit.

James E. Eason, Director
Division of Oil and Gas

December 30, 1994
Date

For: Marty Rutherford, Acting Commissioner
Alaska Department of Natural Resources

Attachments: Delegation of Authority
Attachment 1: NPBS Acreage Map
Attachment 2: NPBPA Tracts
Attachment 3: Tract Allocation Schedule
Attachment 4: Example Gas Disposition and Reserve Debit Report
Attachment 5: Correspondence dated January 13, 1993 and March 1, 1993

PBU.NPBPA.Appv.txt

DELEGATION OF AUTHORITY

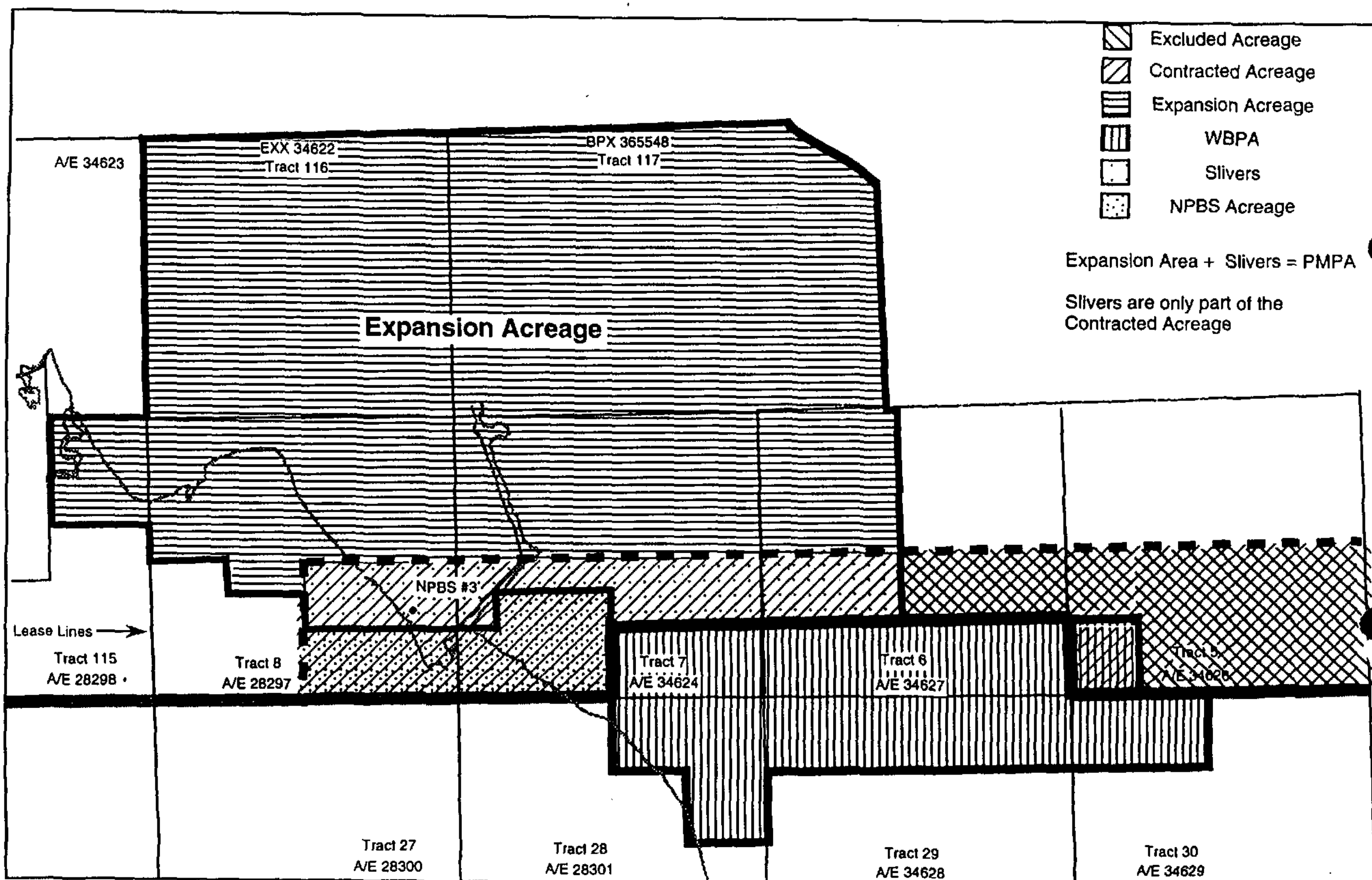
With respect to the Application to Form the North Prudhoe Bay Participating Area within the Prudhoe Bay Unit, I hereby delegate to the Director of the Division of Oil and Gas my authority under 11 AAC 83.343 to Approve/Deny Plans of Development, my authority under 11 AAC 83.351 to Approve/Deny Participating Areas, and my authority under 11 AAC 83.371 to Approve/Deny Allocation of Cost and Production Formulas.

Dated: 12-28-94
Anchorage, Alaska

Marty K. Rutherford

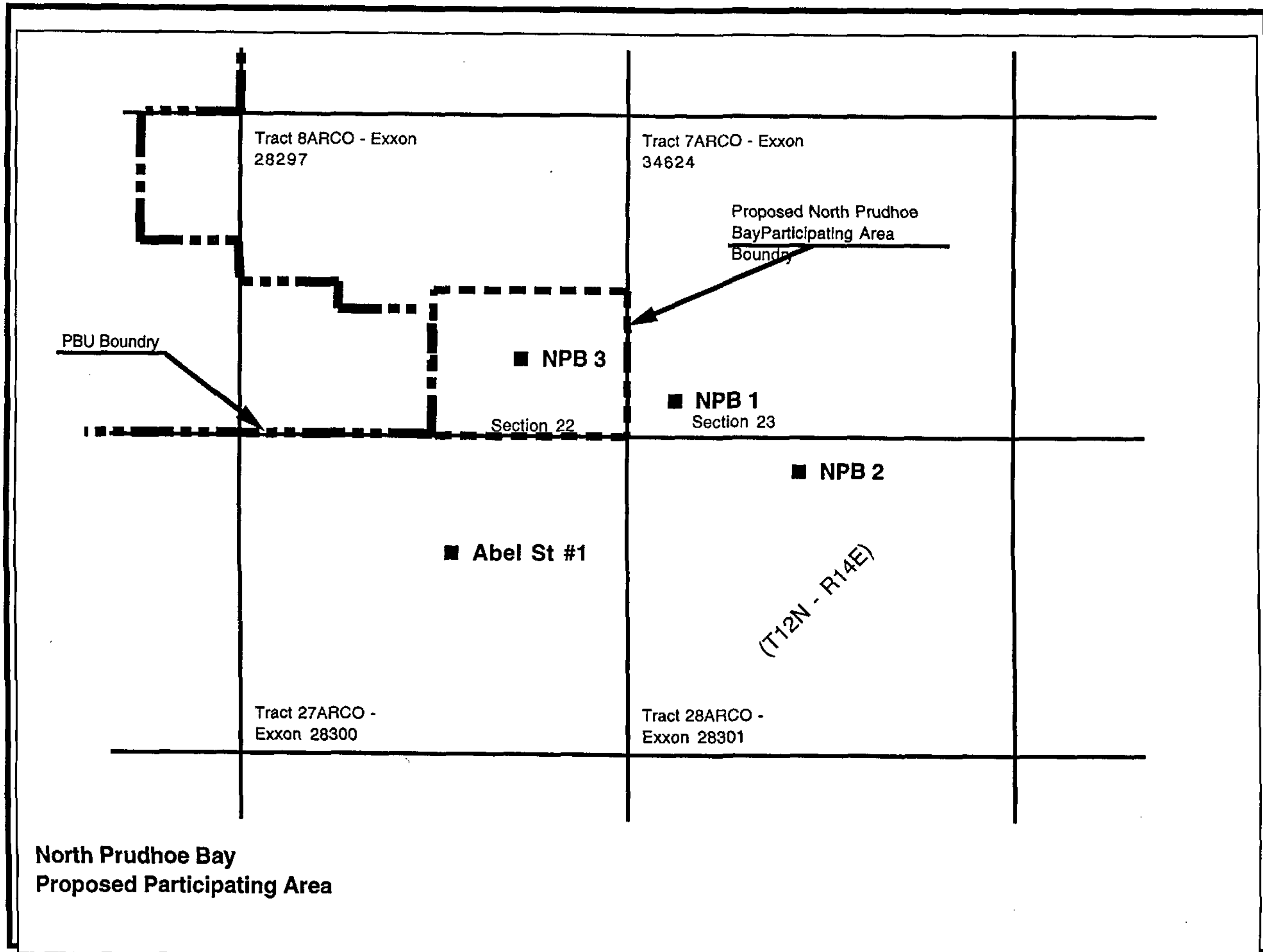
Marty Rutherford, Acting Commissioner
Alaska Department of Natural Resources

Expansion Acreage and Slivers



ATTACHMENT 1

A.D Simon



ATTACHMENT 2

Tracts Within the North Prudhoe Bay Participating Area and North Prudhoe Bay Tract Participation

Tract No.	Description	No. of Acres	ADL No.	ADL Basic Royalty	Lessee of Record	Interest Ownership	OIP MMSTB	Tract Participation %
8	T12N-R14E, Sec 22	640	28297	1/8*	ARCO & Exxon	ARCO - 50% Exxon - 50%	12.1	100%

* This lease is currently subject to the reduced Discovery Royalty rate.

SAMPLE AREA GAS DISPOSITION AND RESERVE DEBIT REPORT

ARCO ALASKA, INC.
VOLUMES ARE IN MCF AT 14.65 PSIA
PRODUCTION MONTH ________

LISBURNE PRODUCTION CENTER

	AAI	BPX	EXXON	TOTAL
OWNERSHIP PERCENTAGES				
Lisburne				
West Beach				
TOTAL HYDROCARBON LIQUIDS PRODUCED (STB)				
Lisburne				
West Beach				
LPC SYSTEM SUMMARY TOTALS				
TOTAL SOG GAS PRODUCED				
LESS TOTAL FUEL GAS USED				
Power generation fuel				
Lease fuel				
LPC fuel				
Total				
LESS POWER GENERATION SALES				
LESS FLARE GAS				
Flare within AOGCC Allowable				
Excess Flare Subject to Tax				
Excess Flare Subj. to Tax/Pnlty				
Total				
LESS NGLS (MCF equivalent)				
TOTAL SOG RESERVE GAS DEBITS				
GAS INJECTED				
PARTICIPATING AREA SHARE BREAKOUTS				
TOTAL SOG GAS PRODUCED				
Lisburne				
West Beach				
LESS TOTAL FUEL GAS USED				
Lisburne				
Power generation fuel				
Lease fuel				
LPC fuel				
LPA Total				
West Beach				
Power generation fuel				
Lease fuel				
LPC fuel				
WBPA Total				
LESS POWER GENERATION SALES				
Lisburne				
West Beach				

ATTACHMENT 4

SAMPLE AREA GAS DISPOSITION AND RESERVE DEBIT REPORT

ARCO ALASKA, INC.
VOLUMES ARE IN MCF AT 14.65 PSIA
PRODUCTION MONTH ________

LISBURNE PRODUCTION CENTER

	AAI	BPX	EXXON	TOTAL
LESS FLARE GAS				
Lisburne				
Flare within AOGCC Allowable				
Excess Flare Subject to Tax				
Excess Flare Subj. to Tax/Pnlty				
LPA Total				
West Beach				
Flare within AOGCC Allowable				
Excess Flare Subject to Tax				
Excess Flare Subj. to Tax/Pnlty				
WBPA Total				
LESS NGLS (MCF equivalent)				
Lisburne				
West Beach				
TOTAL SOG RESERVE GAS DEBITS				
Lisburne				
Current month				
YTD				
ITD				
West Beach				
Current month				
YTD				
ITD				
GAS AVAILABLE FOR INJECTION				
Lisburne				
Current month				
YTD				
ITD				
West Beach				
Current month				
YTD				
ITD				
TOTAL SOG RESERVES INJECTED INTO LPA RESERVOIR				
From Lisburne				
Current month				
YTD				
ITD				
From West Beach				
Current month				
YTD				
ITD				
TOTAL SOG RESERVES INJECTED INTO WBPA RESERVOIR				
From Lisburne				
Current month				
YTD				
ITD				
From West Beach				
Current month				
YTD				
ITD				

NOTE: Each participating area's apportioned share of fuel gas utilized in the LPC and flare gas in any month is based on its apportioned share of total produced gas.

WALTER J. HICKEL, GOVERNOR

DEPT. OF NATURAL RESOURCES

DIVISION OF OIL AND GAS

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

(907) 762-2547

January 13, 1993

ARCO Alaska, Inc.
P.O.Box 100360
Anchorage, Alaska 99510-0360

Attn: Keith Weiser
Lisburne/Pt. McIntyre

Subject: West Beach Participating Area Application

Dear Mr. Weiser:

A number of issues have been raised in the Division of Oil and Gas' review of the application for the formation of the West Beach Participating Area within the Prudhoe Bay Unit. The issues are attached to this letter. I suggest the State and ARCO meet to discuss these issues.

Please call Bill Van Dyke or Mike Kotowski at your earliest convenience to arrange the meeting. If you have any questions on any of the items, please contact them at 762-2547.

Sincerely,

James E. Eason
Director

Attachments

cc: Gary E. Baker - Exxon
Patrick Coughlin - ADOL
Deborah Williams - Condon, Partnow & Sharrock

PBU.WBRESP.Txt

Application for Formation of West Beach Participating Area Within the Prudhoe Bay Unit

An initial review of the Application has raised the following concerns; the State and ARCO should meet to discuss them:

1. Generally, a participating area (PA) may include only land reasonably known to be underlain with hydrocarbons and reasonably estimated to be capable of contributing to production. 11 AAC 83.351(a) provides in pertinent part:

> The participating area may include only the land reasonably known to be underlain by hydrocarbons and known or reasonably estimated through the use of geological, geophysical, or engineering data to be capable of producing or contributing to production of hydrocarbons in paying quantities.

Such a showing is usually established by a certification, in accordance with 11 AAC 83.361, that at least one well in the proposed participating area is capable of producing hydrocarbons in paying quantities. Yet, ARCO has not requested a paying quantities determination for any well within the proposed participating area. Until a paying quantities determination is made, the division lacks a reasonable basis for establishing a properly configured participating area for the West Beach Reservoir.

ARCO has submitted the West Beach 4 type log, a top structure map of the Kuparuk Formation over the proposed West Beach Participating Area, a gross isopach map of the Kuparuk Formation over the proposed area, and a hydrocarbon pore-foot map of the Kuparuk Formation. The additional information necessary to make the paying quantities determination are:

> (a) Well test summaries and chronologies from the West Beach 4 Well and/or the West Beach 3B Well. The data should include test separator meter readings and tank straps during each flow period, surface well pressures, and any static and/or transient reservoir pressure data;
>
> (b) Cost data to show that the well test data indicate production volumes sufficient to yield a return in excess of operating costs. The cash flow analysis should include operating costs and processing costs per barrel of oil and the expected wellhead price. The calculations should represent a one year time period.

2. Based on the geological information contained in Attachments 6

and 7 of the participating area application, the division is concerned that portions of the proposed area do not meet the criteria set forth in 11 AAC 83.351(a). Of particular concern to us are Tract 5, Tract 7, and the SE/4 and NW/4 of Sec. 25 of Tract 28.

Further, we are concerned with the proposal to include within the proposed participating area "any other producing reservoir from the surface to the base of the Kuparuk Formation which may be discovered within the boundaries of the West Beach Participating Area." ARCO needs to explain how the inclusion of these yet to be discovered or delineated lands meets the criteria of 11 AAC 83.351, 11 AAC 83.361, and 11 AAC 83.303.

3. The division will require accounting procedures to properly allocate Lisburne, Pt. McIntyre, and West Beach produced gas, gas used for fuel, flare, gas reinjected into the Lisburne gas cap or another participating area gas cap, and translucent liquid hydrocarbons (otherwise referred to as NGLs).

The ARCO has proposed (1) an area gas disposition and reserves debit report for the three participating areas, and (2) a fuel gas utilization allocation based upon each PA's proportionate share of produced formation gas. In order to be consistent on this issue with what we approved in the Duck Island Unit for the Endicott and Sag Delta North Participating Areas, the division will require the following for the royalty free fuel and flare gas used for the benefit of each respective participating area in the operation of the Lisburne Production Center (LPC) or other participating area operations:

> The use of royalty free gas for the LPC operations (fuel and flare) must be apportioned among the three participating areas using the common production facilities. The basis for apportioning the <u>fuel</u> gas used in development and production operations during a month shall be each participating area's fraction of the total hydrocarbon liquids produced through the LPC that month. The basis for apportioning the <u>flare</u> gas in any month shall be each participating area's fraction of the total produced gas determined from well tests that month.
>
> The Alaska Oil and Gas Conservation Commission has authorized (or will authorize) the flare of a specific amount of gas for safety flare purposes. Any excess flare gas above the authorized amount is subject to a royalty payment.

To properly account for the various monthly dispositions among any participating area using the shared Lisburne facilities, the division will require the attached gas disposition and reserves debit report.

4. The division is concerned with the proposed production allocation methodology among Lisburne, Pt. McIntyre and West Beach. Currently, we do not have a problem with ARCO's proposed methodology because it's based on a minimum of two individual well tests during the month and is similar to what currently is approved for the Milne Point and Duck Island Units. However, at issue may be the appropriate allocation factor for the one production well West Beach Participating Area, and how we handle the so-called "wedge" effect.

As long as there is only one producing well in the proposed West Beach Participating Area, a meter allocation factor different from one (1.0) appears inappropriate. With the one well producing well in the West Beach, the West Beach production volume should be determined using the well test data, and not subsequently adjusted using a meter allocation factor.

Regarding the so-called "wedge" effect, a later well test reporting date and the use of a well test obtained early in the next month may resolve this issue. This would permit the use of four well tests to allocate production for any given month.

5. We note the following with regard to the attachments/exhibits included with the application:

- The Niakuk should be replaced with the West Beach in Exhibit 5. It is our understanding that the Niakuk will be produced at a later date.

- In the Sample Production Allocation/Offtake Schedule, page 2, it continues to be the State's position that it has only nominated the taking of royalty oil in kind. If anything other than the State's nomination of oil is provided, the State will not pay more than the oil field cost allowance pending resolution of Severed Issues of the ANS Royalty Litigation.

6. The royalty-in-kind language in the Prudhoe Bay Unit Agreement, Article 6.4, is not acceptable for the West Beach and Point McIntyre areas. The division desires the flexibility to be able to nominate RIK oil and gas separately from the West Beach and Point McIntyre areas. At this time, a RIK nomination must be based on total unit oil or gas production--not participating area by participating area. The division realizes that the ANS Settlements contain amended RIK language, however, we do not believe that the ANS settlement language is the language to apply either. We will propose new language to Article 6.4 at a later date.

Furthermore, the division is proposing the attached amended language to Article 7.2 of the Prudhoe Bay Unit Agreement. The amended language addresses usage of royalty free fuel gas for participating area operations as well as the injection of Unitized Substances from one participating area into another participating area within the Prudhoe Bay Unit Area.

7. Because the leases proposed for inclusion in the West Beach Participating Area are entirely within the current Prudhoe Bay Unit Area, the division acknowledges that, unless amended now or at a later date, the field cost allowance for the State's royalty share of oil produced from the proposed West Beach Participating Area will be governed by the 1980 Royalty Settlement Agreement. However, the field cost allowances for the State's royalty share of "NGLs" and dry gas are part of the Severed Issues in the ANS Royalty Litigation. These field cost allowances are subject to the final resolution of this litigation.

Prudhoe.WBPA.Response.Txt

Lisburne, Pt. McIntyre, and West Beach Gas Disposition & Reserve Debit Report
Volumes are in MCF at 14.65 PSIA - calculations subject to revision when finalized

Month Year

ADNR Revised
11/17/92

	BPXA	EXXON	ARCO	TOTAL
LISBURNE OWNERSHIP%	20.0000	40.0000	40.0000	100.0000
PT. MCINTYRE OWNERSHIP %				0.0000
WEST BEACH OWNERSHIP %		50.0000	50.0000	100.0000

Total Gas Produced
- SOG Gas Production LPA
- SOG Gas Production PMPA
- SOG Gas Production WBPA

Total Hydrocarbon Liquids Produced
- HCL Production LPA
- HCL Production PMPA
- HCL Production WBPA

Less Fuel Gas Used
- For Power Generation
- For other uses
- Total Gas Fuel Used

Power Generation Sales
(Subject to Royalty Payment)

LPC Total Fuel Gas Used
- For Power Generation
- For other uses
- Total LPC Fuel Gas

LPA Share of Fuel Gas Used
- For Power Generation
- For other uses
- Total LPA Fuel Gas

PMPA Share of Fuel Gas Used
- For Power Generation
- For other uses
- Total PMPA Fuel Gas

WBPA Share of Fuel Gas Used
- For Power Generation
- For other uses
- Total WBPA Fuel Gas

Less Flare Gas
- AOGCC Authorized Flare (20 AAC 25.235)
- Excess Flare Subject to Tax
- Excess Flare Subject to Tax and Penalty
- Excess Flared in violation of AOGCC regs.
- Total Flare Gas

LPA Share of Flare Gas
- AOGCC Authorized Flare (20 AAC 25.235)
- Excess Flare Subject to Royalty
- Excess Flare Subject to Tax and Penalty
- Excess Flared in violation of AOGCC regs.
- LPA Total Flare Gas

PMPA Share of Flare Gas
- AOGCC Authorized Flare (20 AAC 25.235)
- Excess Flare Subject to Royalty
- Excess Flare Subject to Tax and Penalty
- Excess Flared in violation of AOGCC regs.
- PMPA Total Flare Gas

WBPA Share of Flare Gas
- AOGCC Authorized Flare (20 AAC 25.235)
- Excess Flare Subject to Royalty
- Excess Flare Subject to Tax and Penalty
- Excess Flared in violation of AOGCC regs.
- WBPA Total Flare Gas

	BPXA	EXXON	ARCO	TOTAL
LISBURNE OWNERSHIP%	20.0000	40.0000	40.0000	100.0000
PT. MCINTYRE OWNERSHIP %				0.0000
WEST BEACH OWNERSHIP %		50.0000	50.0000	100.0000

Less NGLs (mcf equivalent)
- LPA NGLs
- PMPA NGLs
- WBPA NGL's

Gas Available for Minor Gas Sales
- LPA Share
- PMPA Share
- WBPA Share

Current Month
YTD as of 9/1/92 (gas inj into LPA)
ITD as of 9/1/92 (gas inj. into LPA)

Less Power Generation Sales
(Subject to Royalty Payment)
- LPA Share
- PMPA Share
- WBPA Share

Current Month
debited from inj. into LPA

[illegible]nce to Injection
- LPA Net Injection
- YTD
- ITD

- PMPA Net Injection
- YTD
- ITD

- WBPA Net Injection
- YTD
- ITD

Total LPA SOG Reserve Gas Debits
- Month
- YTD
- ITD

Total PMPA SOG Reserve Gas Debits
- Month
- YTD
- ITD

[illegible] WBPA SOG Reserve Gas Debits
- Month
- YTD
- ITD

Total LPA SOG Reserves Injected into LPA Reservoir
- Month
- YTD
- ITD

Total WBPA SOG Reserves Injected into LPA Reservoir
- Month
- YTD
- ITD

Total WBPA SOG Sold from LPA Reservoir
- Month
- YTD
- ITD

NOTE: (1) Each PA's apportioned share of fuel gas utilized for the LPC is based upon its apportioned share of total produced liquid hydrocarbons.

(2) Each PA's apportioned share of flare gas in any month is based on its apportioned share of total produced gas.

AGREEMENT TO AMEND THE
PRUDHOE BAY UNIT AGREEMENT

The Prudhoe Bay Unit Working Interest Owners and the Department of Natural Resources, State of Alaska, hereby agree to amend the Prudhoe Bay Unit Agreement as follows*:

(1) Amend Article 7.2 as follows:

Royalty Payments. No royalty, overriding royalty, production or other payments shall be payable on account of Unitized Substances used, unavoidably lost, stored or consumed in Unit Operations, including but not limited to, the injection thereof into any formation underlying the Unit Area, except as specified herein. For the Lisburne Participating Area, the Point McIntyre Participating Area, and the West Beach Participating Area within the Prudhoe Bay Unit, no royalty, overriding royalty, production or other payments shall be payable on account of Unitized Substances used, unavoidably lost, stored or consumed in Unit Operations to the extent, and only to the extent, that the Unitized Substances are used in the Lisburne, Point McIntyre or West Beach Participating Areas, respectively. More generally, it has been, and continues to be, the intent of the State of Alaska that this royalty exemption section (§7.2) does not apply to Unitized Substances that are sold, including transactions that result in any credits or debits among the Working Interest Owners.

If Unitized Substances from one participating area (that is, the contributing participating area) are injected into another participating area (that is, the recipient participating area), the Unitized Substances first withdrawn from the recipient participating area shall be considered to be the Unitized Substances from the contributing participating area until an amount equal to that transferred shall be so produced. If Unitized Substances produced from a particular participating area are used or consumed in the operation of any facility the use of which is not exclusively devoted to that Participating Area's [UNIT] Operations, royalty, overriding royalty, production or other payments shall not be payable on the part of the Unitized Substances produced from that particular participating area used or consumed in the facility which fairly is apportionable on a use basis to that participating area's [THOSE UNIT] Operations being served by the facility.

---

* Wording to be added to the existing Prudhoe Bay Unit Agreement is underlined; wording to be deleted from the existing Prudhoe Bay Unit Agreement is capitalized and enclosed in brackets.

This Agreement may be executed in any number of counterparts, each of which shall be deemed to be an original, but all of which shall constitute on and the same instrument.

Unit Operator
ARCO Alaska Inc.

Date:________________

ARCO Alaska, Inc.

By:

PBUAMEND1.txt

ARCO Alaska, Inc.
Post Office Box 100360
Anchorage, Alaska 99510-0360
Telephone 907 263 4275

Andrew D. Simon
Manager
Lisburne/Point McIntyre

March 1, 1993

Mr. James E. Eason
Division of Oil and Gas
Alaska Department of Natural Resources
P.O. Box 107034
Anchorage, Alaska 99510-7034

RE: West Beach Participating Area Meeting

Dear Mr. Eason:

Our February 23 meeting to discuss the West Beach Participating Area (WBPA) issues raised by the DNR in its January 14 letter was very useful in allowing both parties to better understand each other's positions. A clear path forward for the approval of the WBPA appears to have been established. ARCO and Exxon's understanding of the outcome of each issue is noted below.

1. The issue of a paying quantities determination for the proposed (WBPA) was resolved. The DNR acknowledged that West Beach #3B, located within the proposed WBPA boundary, was certified as being capable of producing in paying quantities in February, 1977 and that data supplied for WB-4 established additional certification.

2. Concerning the proposed boundary of the WBPA, ARCO and Exxon agreed to present to members of the DNR technical staff geologic and geophysical data in support of Attachments 6 and 7 of the WBPA. This meeting is scheduled for March 1 at the DNR's office.

In the WBPA application, ARCO and Exxon proposed to include within the WBPA "any other producing reservoirs from the surface to the base of the Kuparuk Formation which may be discovered within the boundaries of the West Beach Participating Area". While this proposal was made to facilitate and encourage the development of any minor reservoirs that may be encountered while drilling the Kuparuk, which are by their nature vulnerable to additional costs, the DNR's alternative proposal to consider including any such reservoir in the WBPA at the time they are actually encountered is acceptable to ARCO and Exxon. Therefore the WBPA will be limited to the Kuparuk as referenced on Attachment 4 (type log) of the WBPA Application (attached).

3. Concerning the gas accounting procedures and fuel gas allocation, all parties agreed to the use of ARCO and Exxon's proposed gas disposition and reserve debit report, as well as a fuel gas allocation methodology which allocates flare and fuel gas in proportion to each participating area's share of total produced gas.

4. With regard to the proposed production allocation methodology, ARCO and Exxon agreed to submit to the DNR a "statement of intent" for the proposed production allocation methodology. Please find attached public testimony given to the State of Alaska Oil and Gas Conservation Commission during the January 13, 1993 Field Rules Hearing which we believe should satisfy this request.

   The DNR agreed that the "wedge effect" is no longer an issue assuming the operator is allowed to submit the allocated data by the 20th of the following month.

5a. With regard to the reference to Niakuk in Exhibit 5 of Attachment 8 to the WBPA, ARCO and Exxon agreed that in the actual allocation report Niakuk will be replaced by West Beach.

5b,6,7. Each of the remaining issues are tied to the <u>ANS Royalty Litigation.</u> All parties agreed that it is inappropriate to address these issues outside of the context of <u>ANS Royalty Litigation.</u> All parties agreed that the resolution reached in the <u>ANS Royalty Litigation</u> will apply to the WBPA.

This letter outlines ARCO and Exxon's understanding of the DNR's position on these issues. If the DNR's position is different than noted above, please let me know as soon as possible so that any outstanding issue can be quickly resolved.

Sincerely,

A.D. Simon

A. D. Simon
Manager Lisburne/Point McIntyre

SMR:ADS:tg

Attachments

cc:	G. Baker	Exxon
	S. M. Bennett	BPX
	W. D. Morgan	Exxon
	J. Reeder	BPX

ATTACHMENT 4

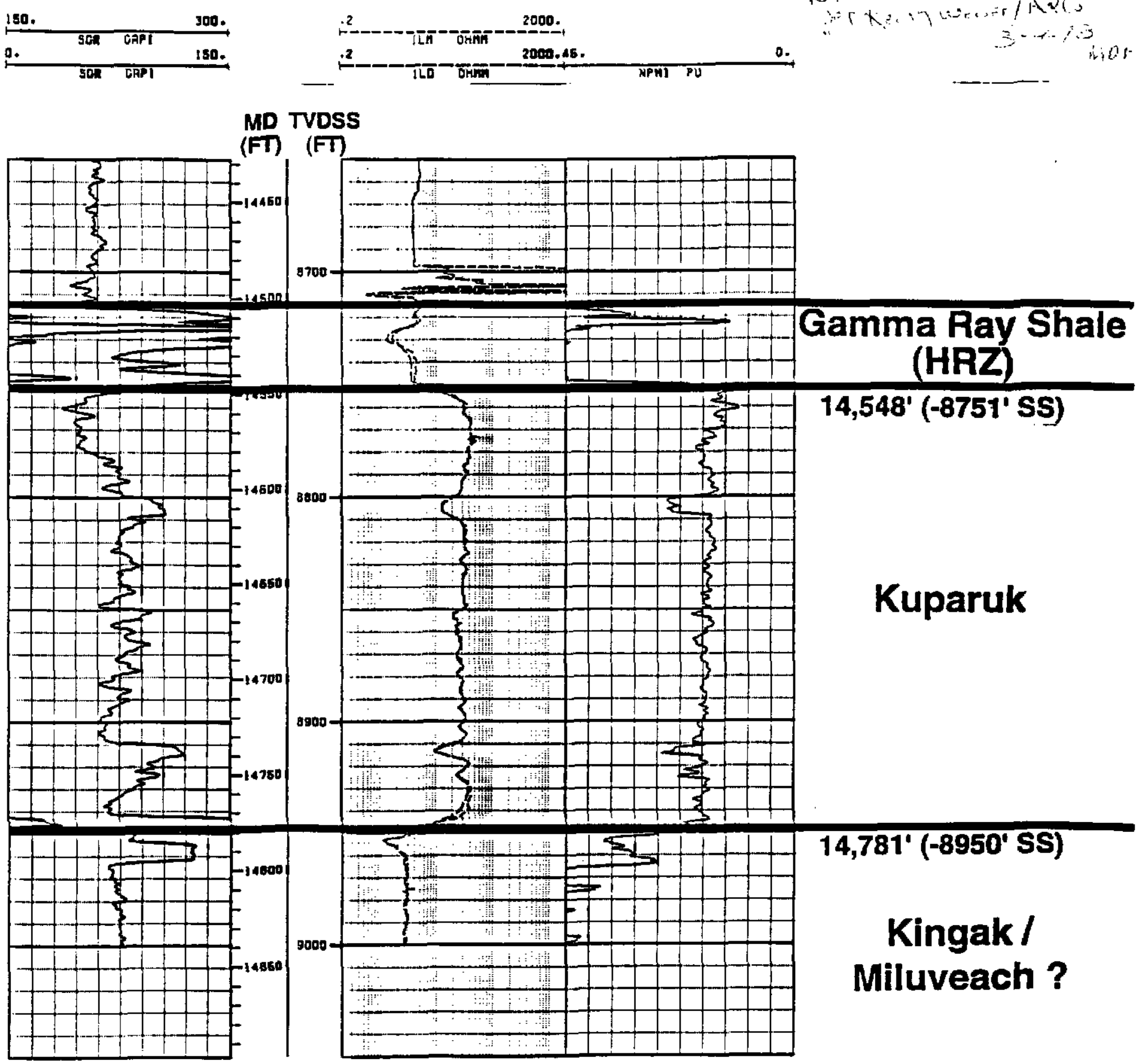
From November 20. 199?

West Beach PA Applicat

~~CONFIDENTIAL~~

Not Confidential per Kerry Walker/ARCO 3-4-93 MDF

West Beach Field
Type Log
ARCO/Exxon *West Beach #4*



Public Testimony Given at the January 13, 1993 West Beach Field Rules Hearing

VI. Production Allocation

My name is Ronald Oba. I am an Engineering Director for ARCO Alaska, Inc., currently supervising the Lisburne/Point McIntyre Operations Engineering Group. I received a Bachelor of Science Degree in Mechanical Engineering in 1972 and a Master of Science Degree in Mechanics in 1974 from the University of Colorado. I have 19 years of experience in the petroleum industry working in the areas of production research, operations engineering, and reservoir engineering. I have been working in Alaska since 1984. My work efforts in Alaska have been directed towards the development of the Lisburne, Point McIntyre, and West Beach accumulations.

In my testimony today, I will discuss the incentives for commingled production, the concept of well test based production allocation, and the details of production allocation activities for West Beach and all of the other fields which will be producing fluids for processing at the LPC.

Successful implementation of commingled production from several producing fields is necessary for the development of small hydrocarbon accumulations on the North Slope. By the term commingled production, I mean the production of fluid streams from individual wells and separate fields which is combined prior to treatment at a common processing facility. At these common processing facilities, the oil, water, and gas are physically separated before measurement. Prior to any sales, the oil and gas streams are metered through standard custody transfer sales meters. Commingled production promotes North Slope resource development by enabling the Producers to reduce capital investments and per barrel operating costs via more complete utilization of existing facilities. Small hydrocarbon accumulations that would otherwise be non-developable resources, become economic reserves because of the lower cost structure resulting from commingled production. An integral part of a successful implementation of commingled production is the allocation of the produced fluids back to the originating field for revenue and reservoir management purposes.

An analysis completed by ARCO indicates that the commingling of production from the Lisburne, Point McIntyre, Niakuk, and West Beach accumulations will result in the additional recovery of 100-150 million barrels. One reason for this additional recovery is illustrated graphically in Exhibit VI-25. All facilities have a minimum physical throughput rate limit which is determined by the installed equipment. As shown in this exhibit, the commingling of production from multiple fields extends the useful life of each individual field by allowing each field to produce at lower rates while still satisfying the minimum production rate required by the facility. This extension of field life results in additional resource recovery.

In a similar manner, commingled production also extends the economic lives of both the common processing facility and the associated fields by spreading the daily operating costs over a larger number of produced barrels. Since the base operating costs for a common facility are generally not directly proportional to fluid rates, the cost to process twice as much fluid is not necessarily twice the initial cost. Since commingled fields can share this base cost over a larger number of barrels, their per barrel costs are lower and the economic field life for each commingled field is extended to recover additional oil.

The overall result of commingled production is a prolonged field life for each commingled field. In some cases, however, commingling of production not only prolongs the field life but is in fact the key to the development of small accumulations that cannot support the costs of standalone development. Commingled production is in the best interest of the State of Alaska as well as the Producers. The State of Alaska gains from the additional revenue resulting from the royalties and taxes associated with the additional resource recovery. Based upon ARCO's estimate of additional recovery, this revenue increase amounts to the equivalent of 13-20 million barrels. Aside from the direct monetary gains to the State of Alaska, the extension of productive field lives will slow the decline in long-term employment and prolong the continued purchases of goods and services. These activities will provide a major benefit to the Alaskan economy. The Producers gain from commingled production by the reduction in the investment and the long-term operating costs required to bring the hydrocarbons to market.

Another significant benefit of commingled production is the reduction of future environmental impacts. The essence of commingled production is utilizing the existing facilities, gravel pads, and infrastructure to minimize the addition of new major facilities. By reducing the need for additional major processing facilities, future surface and atmospheric impacts will be minimized.

ARCO, in conjunction with various other lease Owners, has developed a plan to commingle production from several small hydrocarbon accumulations on the North Slope and process the fluids at the LPC. This plan is possible for several reasons.

First, the Lisburne infrastructure is centrally located. As shown in Exhibit VI-26, all planned developments are within five miles of existing Lisburne surface production facilities. This central location allows the development of these known accumulations with minimal additional surface facility modifications.

Second, the LPC has excess capacity. The facility was designed as part of a Lisburne development plan which envisioned a much larger reservoir than actually materialized. Thus, certain process components are currently being under-utilized, while others, such as the gas handling equipment, are operating at full capacity. Specifically, the liquid processing equipment is currently operating at less than half of the design capacity. As currently forecasted, commingled production will bring all the production streams more into line with the design capacities of this equipment. This is not to say that additions to the LPC will not be made. Funding has already been approved by the

Owners to expand the LPC liquid handling system to more closely match forecasted commingled production rates. This plan will provide for a more effective utilization of all of the LPC equipment on the North Slope.

Finally, the LPC is a relatively new facility. Commissioned in 1986, the LPC is one of the newest major facilities on the North Slope. It was designed and built as a standalone processing facility with state-of-the-art equipment. By standalone, we mean that the LPC does not rely on any other facility to completely process production. It has its own electrical power generation equipment and provides its own gas reinjection compression. This is a fairly unique processing facility on the North Slope as the initial design incorporated state-of-the-art corrosion-resistant duplex stainless steel to mitigate corrosion concerns. Additionally, throughout the short operating life of the LPC, significant modifications and upgrades have been made to maintain equipment quality. Over $7 million has been spent on upgrades to the major equipment, and almost $3 million was recently spent to upgrade the overall metering systems in preparation for anticipated commingled production. Details of these metering upgrades are discussed in Exhibit VI-32.

As with any development of hydrocarbons, the quantification of produced oil, water, and gas volumes is important for both revenue accounting purposes and reservoir management activities under commingled production operations. However, when production from several fields is commingled prior to final processing and metering, separate direct measurements of the oil, water, and gas volumes at standard conditions for each producing field are not possible with existing metering technology. Thus, a production allocation methodology must be adopted. ARCO is requesting that the commingled production from West Beach and all of the other fields producing into the LPC be allocated with a well test based production allocation methodology.

In general, the proposed well test based production allocation methodology focuses on individual well rates from each well producing into the commingled system. The production from an individual well is determined from a combination of periodic well tests and the producing history of that individual well. For example, as shown in Exhibit VI-27, knowing the rate at which a well produces oil, water, and gas and knowing the amount of time that well is on production, it is possible to calculate how much volume that well produced on a daily basis. Summing this calculated daily production volume for all wells in a commingled field provides an estimate of that field's daily production.

Rarely does the sum of the calculated daily field production volumes for all commingled fields exactly equal the volume measured by the final custody transfer meters. Therefore, calculation of allocation factors is required to maintain a proper field split of the produced fluids. Exhibit VI-28 shows in equation form the general calculations used to determine the allocation factors. Variations in well producing rates are the main cause for the discrepancies between the calculated production volumes and the sales volumes. These rate variations result from a variety of causes ranging from natural well production decline to changing surface system conditions. A detailed step-by-step summary of this allocation methodology is presented as Exhibit VI-29. It is worth noting at this time that although daily production allocations are made, only monthly allocated production volumes are generally reported.

The accurate allocation of production between fields depends upon the ability of the Operator to recreate the production rate history for each well producing into the common facility. An aspect of determining each well's production history is the frequency of sample points available from the well testing process. Well test frequency should be derived by the production characteristics of individual wells and should not be set as an arbitrary requirement for all wells. Exhibits VI-30 and VI-31 illustrate this point with two production rate versus time plots taken from two different Lisburne wells. For a Type A well, shown in Exhibit VI-30, production is very stable, predictable, and very few sample points are required to define the "shape" of the production curve. For a Type B well, shown in Exhibit VI-31, the decline changes over time. Clearly, the Type B well would need to be tested more frequently than the Type A well to preserve the same degree of accuracy in estimating produced volumes. Successful implementation of well test based production allocations will depend upon the Operator having the ability to adjust well testing frequency based upon observed well performance.

Well tests should be obtained as uniformly as possible and test separator usage should be maximized within operational constraints to ensure adequate definition of the production decline curves. For the above examples, if a minimum frequency of well tests is stipulated for all wells, then less testing time will be available for the Operator to obtain additional sampling points for wells, such as the Type B wells, which might benefit from the extra data points. In order to build comfort and confidence for all parties involved in the well test based production allocation process, we suggest that a minimum requirement of two well tests per month be established for a period of one year. At the end of that time, this minimum well test frequency stipulation should be evaluated at a production allocation process review conducted between the Operator and the State.

The process of well test based production allocation is not new to operations on the North Slope. It has been used for years for the purposes of reservoir management in Lisburne and other fields with a range of allocation factors of 0.90 to 1.10, with 1.00 representing the ideal case where the calculated theoretical and actual production volumes match. An evaluation of the impact that this historic range of allocation factors would have on the State of Alaska and the field Producers' total revenue has been completed and indicates minimal or no risk to all parties involved. Since in reality over-payments are just as likely as under-payments, there is limited expected risk over the cumulative 30-year producing life of the commingled fields. We must emphasize that well test based production allocation will never be as accurate as direct custody transfer metering. However, by comparing the minimal potential risk to the State of Alaska with the much larger State development benefits derived from commingled production of an additional 13-20 million barrels, one can quickly determine that the slight reduction in accuracy associated with this methodology is completely overshadowed by the losses resulting from potential non-development.

Recognizing the need to reduce as much potential error as possible, the Lisburne Owners over the past year have invested nearly $3 million to upgrade the critical meters used for the allocation of production. The focus of these upgrades was the installation of state-of-the-art mass flow meters and online water cut metering at all drill site test separators. A mass flow meter calibration station has been constructed and installed at the LPC to allow for onsite calibration checks. This onsite station will allow for cost effective meter calibration and provide an opportunity for third party witnessing. Maintenance schedules have been established and operator training has been undertaken. All of this has been done to ensure accurate equipment is available for well testing. Additionally, well testing guidelines such as stabilization time, test duration, and testing frequency continue to be updated as existing well performances dictate. Similar guidelines will be established as commingled fields start production.

As presented, both the State of Alaska as well as the Producers have a vested interest in commingled production and well test based production allocation. It is important that all parties have a firm understanding of the allocation process. It is with this in mind that ARCO fully supports efforts by the State of Alaska to designate a single lead agency to address metering and well test based production allocation issues for the State. We envision that as commingled production begins, all parties should play an active role in determining the appropriateness of the actions taken within the allocation process and should focus on ways to streamline the methodology while meeting the needs of all involved. It is via this partnership that the most efficient, accurate, and fair allocation of commingled production can be achieved.

Specifically addressing West Beach development, ARCO is proposing that production be commingled prior to separation at the LPC and that oil, water, and gas production be allocated back to the producing fields by utilizing well test based production allocations. Exhibit VI-32 is a report describing the details of the proposed implementation of well test based production allocations for commingled production being processed through the LPC. In brief, the proposed implementation involves the following features:

1. Periodic production testing for all wells producing into the LPC.

2. Well test frequency will be maximized using all available test separator capacity at each drill site, within the constraints imposed by operating conditions.

3. The stabilization period and test period duration of each well test will be optimized by the Operator to obtain a representative test.

4. The Operator will attempt to obtain well tests at uniform intervals.

5. Well and field operating condition information required for the construction of a field production history will be maintained.

6. NGLs will be allocated based on gas volume produced and computer simulated process yields.

7. Major test separator meters, major gas system meters, and major water production meters will be installed and maintained according to industry recommended practices or standards.

8. The Operator will maintain records that permit verification of the satisfactory execution of the approved production allocation methodologies.

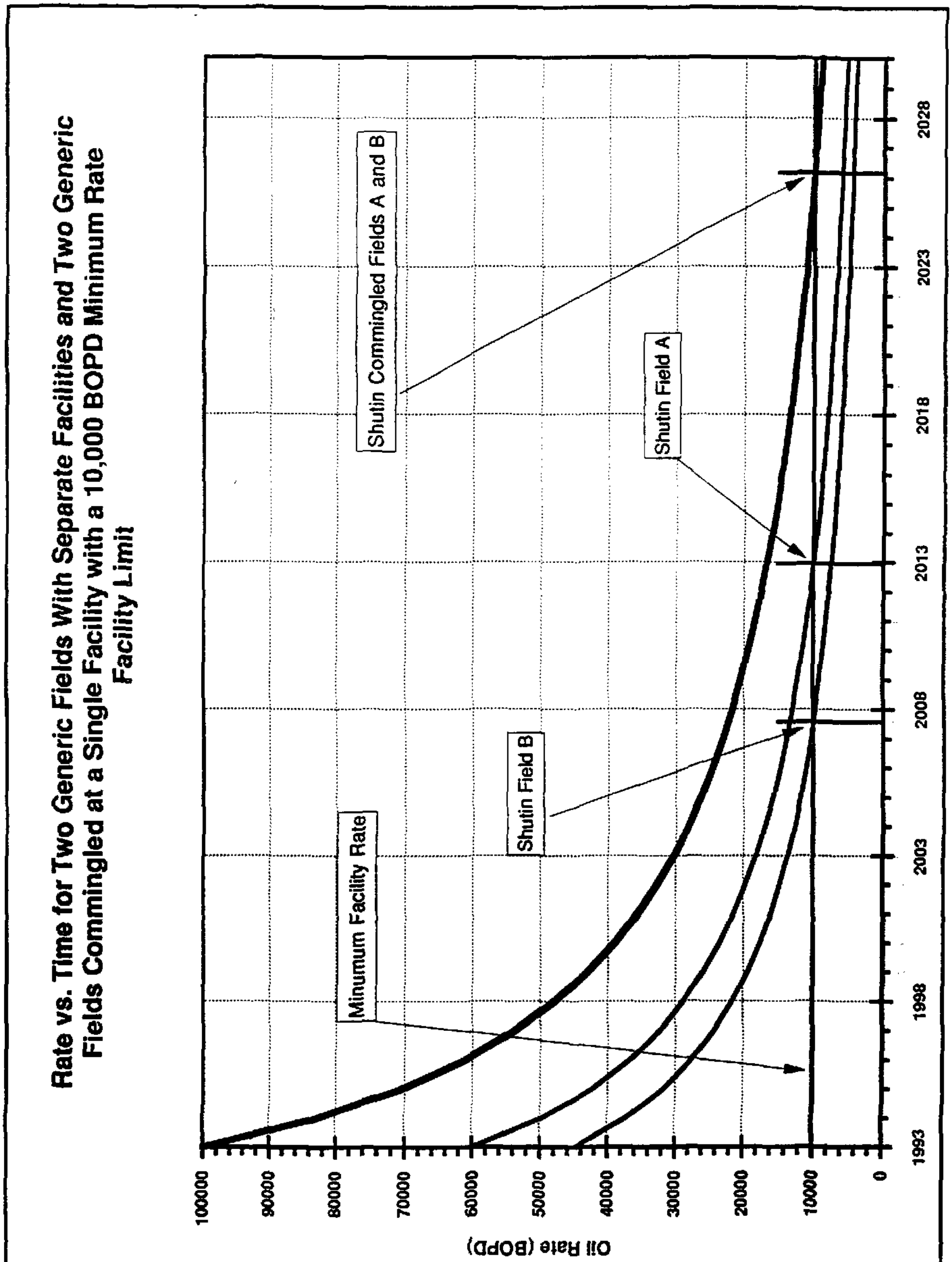
9. The Operator will submit the Production and Injection Report per 20 AAC 25.230 and 20 AAC 24.432 by the 20th of the month following the reporting period.

10. The Operator's allocation activities will be reviewed on a periodic basis.

11. Metering installations for any field whose production will be commingled for processing in LPC will have to meet the same industry standards for metering that Lisburne installations currently meet, and where possible, installation of similar meters will be required. West Beach will initially be tested at DS-L1 so there will not be any new metering required to bring West Beach into the LPC.

In summary, we believe that commingled production prior to final separation and custody transfer metering will benefit both the State of Alaska as well as the Producers. Waste of resources will be prevented and cost effective, environmentally sound development of North Slope resources will be achieved. Coupled with commingled production is the allocation of that production. Well test based production allocation is a complex activity requiring continuous application, development, and refinement. While not exact, the proposed allocation methodology provides for the fair treatment of all produced fluids. Any potential misallocations associated with this methodology are completely outweighed by the benefits derived by all parties involved. From a practical operating viewpoint, commingling and well test based production allocation activities for West Beach and all other fields producing into the LPC need to be conducted in a similar manner.

Thank you for your attention. This concludes my testimony on Production Allocation. Now I would like to turn the floor over to Andy Simon who will summarize our testimony.



January 13, 1993

Exhibit VI-25

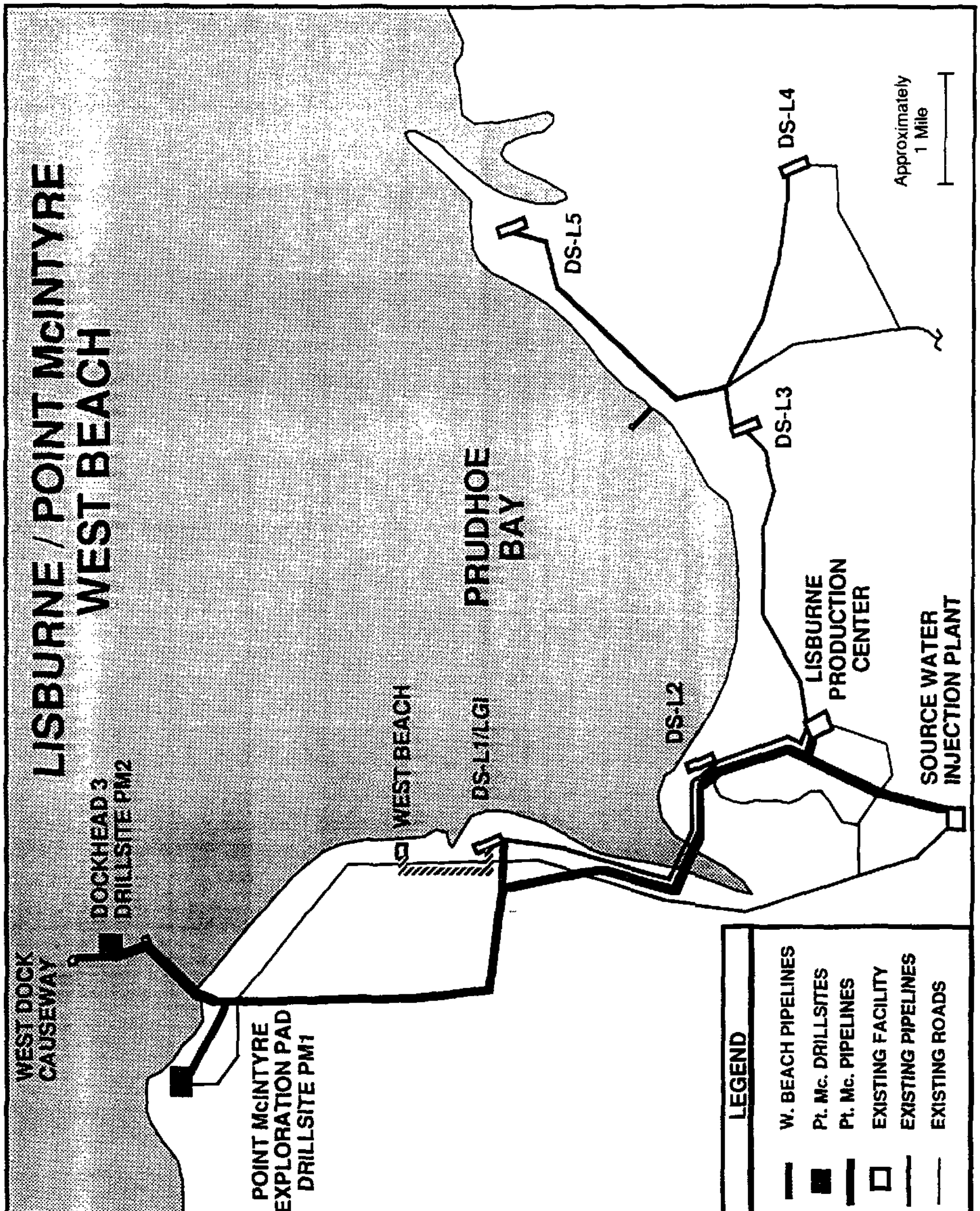


Exhibit VI-26

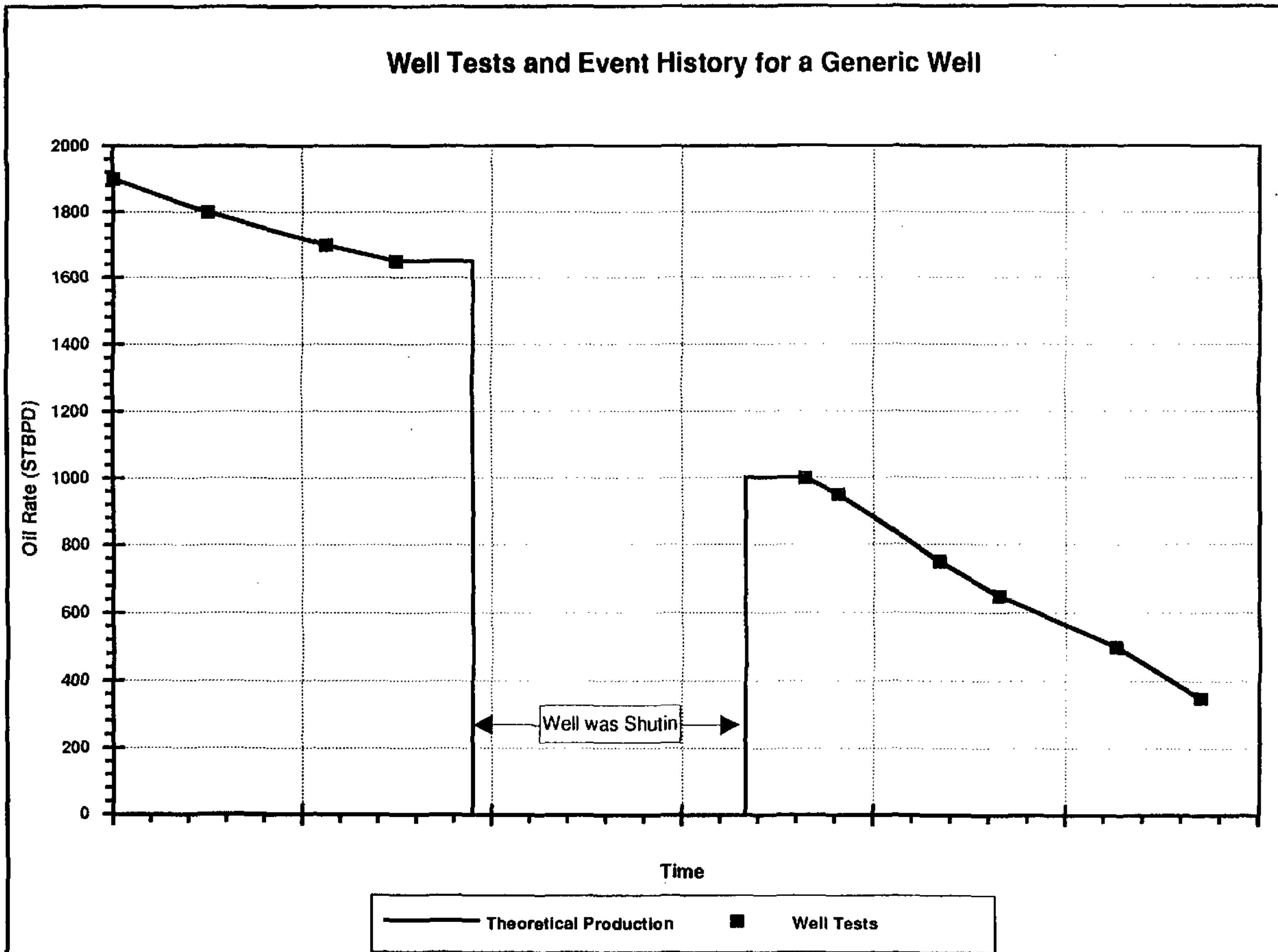


Exhibit VI-27

Allocation Factor Calculations

$$\text{Allocation Factor} = \frac{\text{Actual Produced Volume}}{\text{Theoretical Volume } (\Sigma \text{ Well Tests})}$$

$$\text{Oil Factor} = \frac{\begin{array}{c}\text{TAPS Volume} - \text{NGL Volume} - \text{TAPS BS\&W} - \\ \text{Exploratory Fluids} + \text{Unrecoverable Oil} - \\ \text{Load Crude/Diesel} \pm \text{Slop Oil Tank Movement}\end{array}}{\Sigma \text{ Well Test Oil Rates}}$$

$$\text{Water Factor} = \frac{\begin{array}{c}\text{Injected Water Volume} - \text{External Water} + \\ \text{TAPS BS\&W} \pm \text{Slop Oil Tank Movement}\end{array}}{\Sigma \text{ Well Test Water Rates}}$$

$$\text{Gas Factor} = \frac{\begin{array}{c}\text{LPC Fuel} + \text{Injected Gas} + \text{DS Fuel} - \\ \text{DS Lift Gas Usage} + \text{NGL Shrinkage} + \\ \text{Flare Assist} + \text{Flare (est)} - \text{PBU Fuel}\end{array}}{\Sigma \text{ Wells Test Gas Rates}}$$

January 13, 1993

Lisburne/Point McIntyre/West Beach Allocation Methodology

1. **Conduct well tests to determine production rates for each well.**

Criteria for determining what wells to test:
- Known well performance
- Significant Events
  - Pre and post well work tests
  - Diagnostic work (i.e. temperature and pressure changes)
  - Tests for engineering purposes
- Date of last test

2. **Review well tests for validity.**

- How does this well test compare with past well tests for this well
- Was the stabilization period long enough
- Was the test duration long enough
- Did the flowing tubing pressure change significantly during the test
- Did the lift gas rate change during the test

3. **Review the significant events for each well.**
   - Examine the event history for shutins, openings, gas lift gas changes and choke changes.
   - Examine the drill site operator shift change notes for why a well was shutin and other items of interest that might have an impact on the oil, water and gas rates of the wells. This includes, flowing tubing pressure and temperature trends, hot oiling, hot gassing, methanol treatments, LPC back pressure, field prorations, etc.

4. **Calculate each well's theoretical monthly production by combining well test rates with significant events for that well.**

Allocating with no significant events:
- Allocate from the beginning of one well test to the beginning of the next well test.

Allocating with significant events:
- Instead of extrapolating as a well is shutin or extrapolating for flush production when a well is brought online, it is assumed that the last well test rates are constant from the beginning of the last well test until the end of the event and that the current well test rates are constant from the end of the event until the beginning of the next well test or event.

5. **Sum the theoretical monthly production volumes for all wells in all fields.**

6. **Calculate an allocation factor which compares the sum of theoretical monthly production volumes for all wells in all fields to the "Total Sales" volume as determined by the critical meters.**

$$\text{Allocation Factor} = \frac{\text{"Total Sales" Volume}}{\text{Sum Of Theoretical Monthly Production Volumes For All Wells}}$$

7. **Calculate each well's allocated monthly production volume as:**

$$\text{Allocated Production Volume} = \text{Theoretical Production Volume} \times \text{Allocation Factor}$$

8. **Sum allocated production volumes for each well in each field to determine the amount of production derived from each field.**

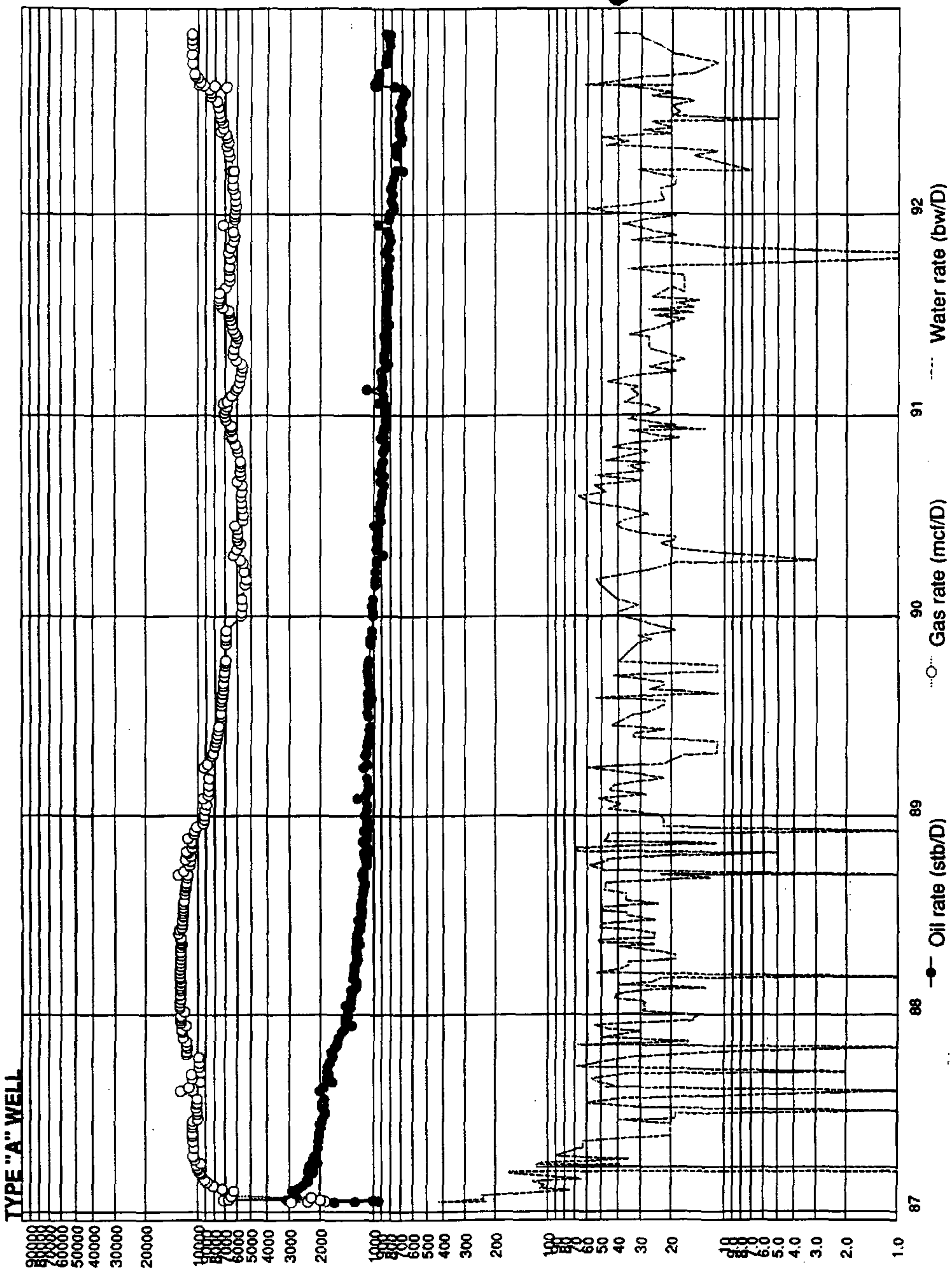


Exhibit VI-30

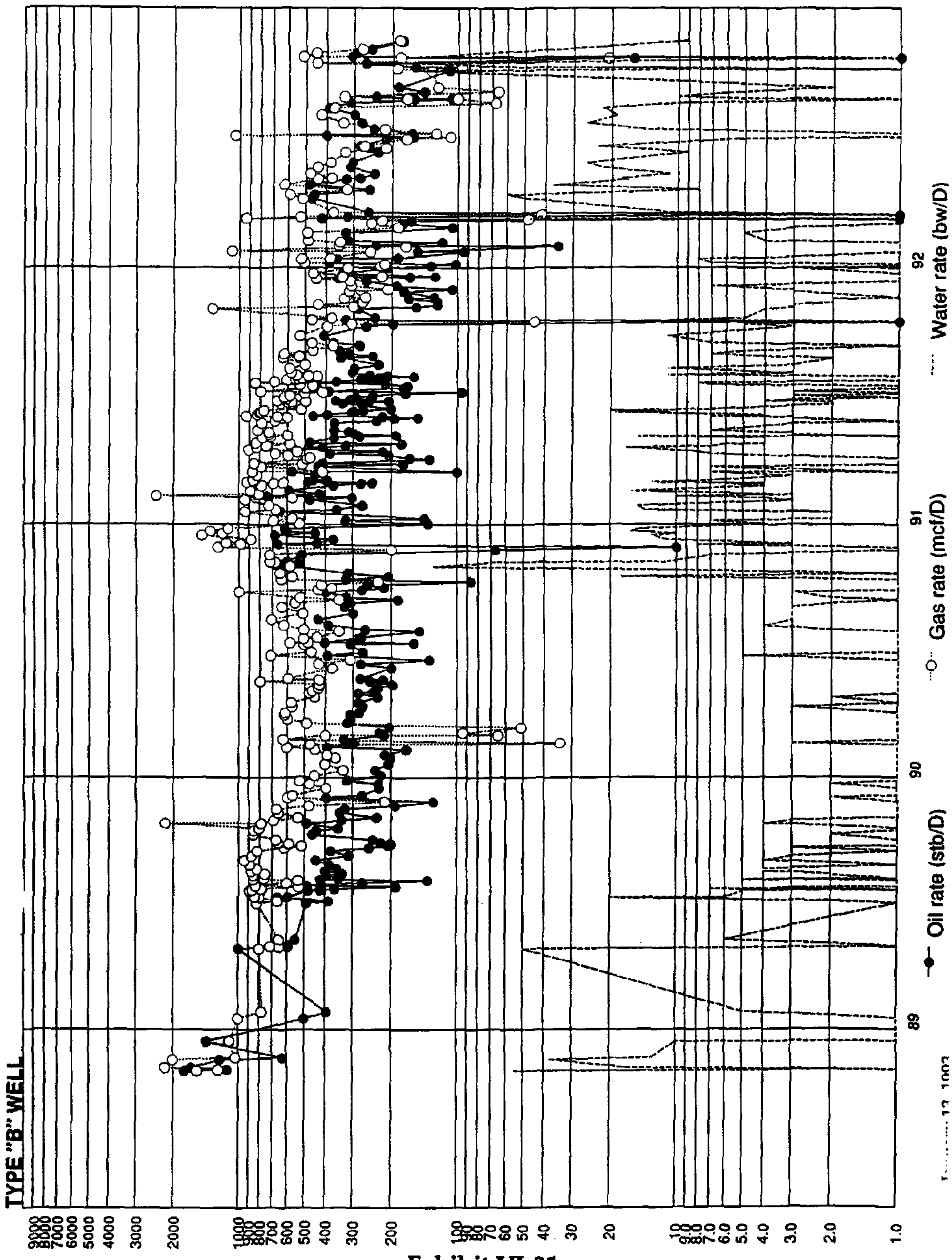


Exhibit VI-31

EXHIBIT VI-32
West Beach Field Rules Testimony Supporting Documentation
Well Test Based Production Allocation

ECONOMIC PERSPECTIVES

Commingling of production will benefit the State of Alaska by preventing waste of the State's hydrocarbon resources by facilitating production of resources that would not be produced otherwise. West Beach is a good example of this, the reservoir size would not support a standalone facility so its resources would never be produced. Another reason that commingling prevents waste of the State's hydrocarbon resources is shown in Exhibit 1. All facilities have a minimum throughput rate that is determined by the turndown rates of the specific equipment installed in the facility. When that minimum throughput is reached then the facility and all of the fields producing into that facility will have to be shutdown. In the example shown in Exhibit 1, which assumes a minimum facility throughput of 10,000 BOPD, Field A is shut down in the year 2013 and Field B is shut down in the year 2007. However, the commingled fields are not shut down until the year 2026. Being able to produce each field to a lower facility limit allows more reserves to be produced. For Lisburne, West Beach, Point McIntyre and Niakuk the additional recovery is estimated to be 100 to 150 million barrels, of which the State of Alaska should receive 13-20 million barrels of this oil in Royalty and Severance Taxes.

Beyond the deferring the attainment of the physical minimum rate limits of a facility, commingled production also extends the economic life of a processing facility and the associated fields by spreading the daily operating costs over a larger number of barrels. Generally, the base operating costs for a facility are not directly proportional to rate, and thus the cost to process 20,000 BOPD is not twice the cost to process 10,000 BOPD. The cost to process 5,000 BOPD is more than half the cost to process 10,000 BOPD. Thus, commingled production allows two fields to produce at 10,000 BOPD production rates while benefiting from lower processing costs that separate fields would have to produce at 20,000 BOPD rates to obtain. The bottom line result is a prolonged economic field life for each commingled field and thus a greater recovery of the resources in place.

Commingling of production allows oil from fields that could not support the capital investments required for their own standalone facility to be produced and additional oil to be produced due to the facility minimum throughput benefits and economic life extensions discussed previously. Implied with commingled production is the allocation of that production. Currently, there is no accepted technology available to directly measure the production from the individual commingled fields. Thus, a well test based production allocation method is proposed. The process of well test based production allocation is not new to operations on the North Slope. It has been used for years for the purposes of reservoir management in Lisburne and other fields with a range of allocation factors of 0.90 to 1.1, with 1.00 representing the ideal case where the theoretical and actual production volumes match. An evaluation of the impact that this historic range of allocation factors would have on the State of Alaska and the field

Producers' total revenue has been completed and indicates minimal or no risk to all parties involved. Since in reality over-payments are just as likely as under-payments, there is limited expected risk to the State over the cumulative 30-year producing life of the commingled fields.

We must emphasize that well test based production allocation will never be as accurate as direct custody transfer metering. However, by comparing the potential risk to the State of Alaska with the State's benefits derived from commingled production of an additional 13-20 million barrels, one can quickly determine that the slight reduction in accuracy associated with this methodology is completely overshadowed by the losses resulting from non-development.

DATA GATHERING SYSTEM

- The Lisburne Data Gathering System (LDGS) provides access to information from almost every part of the field.
- LDGS maintains an event history for each well. Access to flowing tubing pressure and temperature provides a way for the allocation engineer to verify that all of the shut ins were recorded in the event history.
- LDGS keeps on line the last 12 well tests for each well.
- Having LDGS go down does not cause well test data to be lost.
- A month-end backup of LDGS is permanently stored offsite.

The LDGS is an automated data gathering system for the Lisburne production system. LDGS provides access to information from almost every part of the field. Data collected and stored by LDGS is divided into two parts: analog data that is collected every minute and meter data that is accumulated every five minutes. Data from several analog points are usually combined to calculate the meter rates. For example, gas rate would be calculated from the differential pressure across an orifice plate, the static pressure and the temperature. Some of the LDGS data that is used for production allocation is; well test oil, water and gas rates, lift gas rate, choke position, flowing tubing pressure and temperature, plant inlet pressure, separator pressure, and temperature and header pressures and temperatures. The operational data is kept for 44 days so all of this data is available on the month-end backup. LDGS also provides a place to store notes and observations from the field operations personnel for the allocation engineer and the drill site engineers.

LDGS also maintains an event history for each well. The event history records when a well was opened or shut in and any choke and gas lift rate changes. Since Lisburne does not have automated chokes to shut in wells and automated valving to divert wells in and out of test, all of this is done manually by the drill site operator. The event history is kept for 44 days so all of this data is available on the month-end backup. Additionally, having access to flowing tubing pressure and temperature provides a way for the allocation engineer to verify that all of the shut ins were recorded in the event history.

If for some reason the LDGS goes down because of a communication failure, a shutdown to install new programs, an unexpected crash, etc., well testing will not be adversely affected. At the drill sites, data is collected by the Bailey process control system, and then that data is transferred to LDGS; so if the LDGS goes down, the Bailey is still collecting data. Once back on line, LDGS can continue with the well testing in place.

LDGS is backed up with the following schedule: daily backups for one week, weekly backups for four weeks, and then a monthly backup. The monthly backup is taken after all of the production allocation for the month is completed and it contains the official results for that month. The month-end backup is kept offsite and is kept permanently. The monthly backup can be loaded onto an alternate system and all of the data for that month accessed.

DETAILED PRODUCTION ALLOCATION PROCESS

- Conduct well tests to determine production rates for each well.
- Review well tests for validity.
- Review the significant events for each well.
- Using data from the following month will help to eliminate the "wedge" effect and improve production allocation accuracy.
- Calculate each well's theoretical monthly production by combining well test rates with significant events for that well.
- Sum the theoretical monthly production volumes for all wells in all fields.
- Calculate an allocation factor which divides the "Total Sales" volume by the sum of the theoretical monthly production volumes for all wells in all fields.
- Calculate each well's allocated monthly production volume by multiplying the theoretical production by the allocation factor.
- Sum the allocated production volumes for each well in each field to determine the amount of production derived from each field.

Once well tests are obtained, the allocation process begins. Exhibit 2 shows the methodology used in allocating production. The steps used in allocating production are straight forward and leave little room for subjectivity. The only steps that are open to subjective treatment are Steps 2 and 3, reviewing the well test for validity and combining well test rates with significant events. The rest of the steps used are programmed into the LDGS and are out of the control of the allocation engineer.

The first step of allocating after the well tests are obtained is to examine the quality of the well test; was the stabilization period long enough, did the flowing tubing pressure change significantly during test, did the lift gas rate change during the test, etc.

The significant events are combined with the well test data to determine each well's theoretical production. Significant events include shut ins, lift gas changes, choke changes, hot gassing, hot oiling, flowing tubing pressure and temperature changes, plant pressure changes, field prorations, etc. LDGS maintains an event history for each well, the event history keeps track of when a well was brought on line, when it was shut in and the time of any lift gas or choke changes. The drill site operators also maintain shift change notes. These shift change notes are used to pass information of what was done and what needs to be done to the other shift. The shift change notes are a valuable tool for determining why a well was shut in or what work a well had done to it. Other pieces of information that are available on LDGS are the flowing tubing pressure and temperature, the plant inlet pressure, and the drill site header pressures and temperatures.

Sometimes events are missed in the event history or the times might be off be a couple of hours. A way to verify the shut in times is to examine the flowing tubing pressure. The flowing tubing pressure will almost always change immediately when a well is shut in. If a missing event is found, retroactive events can be entered on LDGS to correct the mistake.

If nothing happened since the last well test, then the well production rates are interpolated from the beginning of the previous well test to the beginning of the current well test, as illustrated in Exhibit 3. For cases where a shut in or other significant event occurred between the last test and the current test, the rates are assumed to be equal to the last well test rates and the rates are assumed to be constant from the beginning of the last well test until the end of the significant event. Then from the end of the significant event until the beginning of the current well test, the rates are assumed to be equal to the current well test rates. This is illustrated in Exhibit 4.

There is some potential error built into these basic assumptions. For example, if the event is a shut in, there could be some flush production associated with bringing that well back on line. This could be a positive or negative rate impact which varies well by well, from shut in to shut in, and with the length of the shut in period. Only having well established production performance can help to determine this type of impact, but it is subjective in nature. Since there is no clean, simple, way to consistently estimate the flush production behavior of a well, we have chosen to handle these events by assuming the well was producing at the same rates as the most recent well test. By making this assumption, consistency is maintained in the treatment of all flush production events for all wells, which eliminates the ability of the allocation engineer to introduce a field bias into the allocation factor data. The same assumptions are made for gas lift rate changes, choke changes, wells dying, etc.

Overall, the ability to do retroactive adjustments after changes in the flowing conditions of wells have occurred allows the allocation engineer to handle a variety of situations. For example, if the LPC system pressure increased by a significant amount, causing the flow rates to change on all of the wells, aggressive testing of all the wells could be conducted at the higher pressure. By coupling these new test results with retroactive adjustments, accurate production allocations could be maintained for the period after the system pressure changed.

In determining the theoretical monthly production from a well, all data is used. Specifically, well test data from the past months as well as data from the first part of the following month can be incorporated in the analysis. By using the data from the next month, the "wedge" effect can be reduced. Exhibit 5 illustrates this situation. During the month of October 1992, the "wedge" effect accounted for a 3% change in Lisburne's monthly oil allocation factor. Therefore, extension of the month-end closeout of all data will improve the allocation process. Thus, final allocated production rates will be reported by the 20th day of the following month. An example of additional supporting data to be reported is shown in Exhibit 6.

After the theoretical volumes are determined for all of the wells by combining the well tests with the significant events, all of the theoretical monthly volumes are summed for all of the wells in all of the fields.

An allocation factor is then calculated by dividing the known "Sales" volume by the sum of all of the wells theoretical monthly volumes. Each wells allocated monthly production is then calculated by multiplying that wells theoretical monthly volume by the allocation factor. The allocated monthly volumes for all of the wells in a field are then summed to determine that fields' monthly production.

WELL TEST FREQUENCY

- Frequency should be determined by well behavior—some require less frequent testing and others more frequent testing.
- Well test selection is based on known well performance, significant events, and date of last well test.
- Currently in Lisburne, test separator usage is 80% - 90%.
- Any minimum monthly well testing frequency requirement might not be met under certain circumstances (e.g., pipeline prorations, plant problems, and well failures).
- West Beach development will initially be one well and will be tested at DS-L1. Therefore, there will be no significant impacts on well testing frequency at DS-L1

Accurate allocation of production between fields depends upon the ability of the operator to recreate the production rate history for each well producing into the common facility. One aspect of accurately simulating each well's production history is the frequency of sample points available from the well testing process. Well test frequency should be determined by the production decline characteristics of an individual well and should not be set as an arbitrary across-the-board testing frequency requirement for all wells. Exhibit 7 and 8 illustrate this point with two production rates versus time plots taken from two different Lisburne wells.

For a Type A well, the decline is clearly very stable and predictable and very few sample points are required to define the "shape" of the production curve. In Lisburne, some Type A wells are so stable and predictable that they need only be tested infrequently to satisfy curiosity and verify that production remains on the expected trend.

For a Type B well, the decline changes more over time and requires more sample points to define the "shape" of the production curve. Clearly, the Type B well would need to be tested more frequently than the Type A well to preserve the same degree of accuracy in estimating produced volumes.

In looking at Lisburne historical well test data, we have categorized all wells into three general groups based upon well performance characteristics. Currently, Lisburne wells are evenly divided within these groups. We have examined the impacts of varying well test frequency on the calculated production volume for wells in each category, as shown in Exhibit 21. As can be seen in this exhibit, Type A wells need less frequent testing in order to maintain deviations comparable to highly variable Type B wells.

Operator flexibility is a key issue that will greatly impact the ability of the operator to successfully implement well test based production allocations. Well tests should be obtained as uniformly as possible and test separator usage should be maximized within operational constraints to ensure adequate definition of the production decline curves. For the above examples, if a minimum frequency of well tests is established for all wells, then less testing time is available for the operator to obtain additional sampling points for wells, such as the Type B wells, which might benefit from the extra data points.

The criteria for determination of which wells to test at any one time varies. Under normal circumstances, the primary driver for well test selection is known well performance. As production history is established, confidence in the well test frequency for individual wells improves. Thus, the establishment of rigid guidelines prior to acquisition of any production history is inappropriate. Secondary drivers in determining which wells to test are significant events and the date of the last test. Significant events include pre- and post-wellwork tests, diagnostic evaluations (when temperature and pressure changes), and tests for engineering purposes (production optimization).

One of the operational constraints on well testing is the drill site operators' time. Unlike other North Slope Fields, the Lisburne system does not have automated well testing capabilities. Future developments are not expected to have this capability either. This means that the LDGS cannot automatically divert wells into and out of the test separator; the drill site operator must do it manually. Currently Lisburne has five day-shift and two night-shift drill site operators in order to maintain efficient operations. During the day there is one lead operator that roams the field and performs numerous tasks. There is a drill site operator at DS-L2, a drill site operator at DS-L4, a drill site operator that watches DS-L3 and DS-L5 together, and a drill site operator that watches DS-L1 and DS-LGI together. At night there are two operators: one for drill sites DS-L1, DS-LGI, and DS-L2, and another operator for drill sites DS-L3, DS-L4, and DS-L5. Drill site manning levels are expected to be similar for future operations. Having the drill site operators spread out like this makes it difficult to achieve 100% utilization of available testing equipment. For example, the drill site operator could be busy doing remedial work on a well or at another drill site when a well test ends. It could be some time before he is able to manually divert another well to the test separator. However, even with one drill site operator covering several drill sites, Lisburne has been able to achieve test separator usage in the range of 80% - 90% (allocatable well testing usage in the range of 70% - 80%) of total available equipment time. This relatively high percentage of allocable well tests is a result of the operators and the engineers ability to monitor wells thru LDGS as they are tested and respond to any anomalies. It is felt that even with the addition of more drill site operators, this equipment utilization cannot be significantly improved.

An inherent problem with establishing any minimum testing frequency is that there are several scenarios that would cause the operator to not meet these requirements. Operation problems such as pipeline prorations, plant upsets, and mechanical well failures are unavoidable. Problems like these are usually unexpected and require the immediate shut in of wells. By establishing arbitrary well test frequencies, the operator will have increased difficulty in accurately predicting produced volumes during and after these upset conditions since valuable testing time could be wasted testing wells solely to meet frequency requirements. In the case of a mechanical well failure, the well might have to be shut in for safety reasons prior to meeting any minimum requirements.

Current operations, as well as future operations, will require wells to be cycled in order to maximize total offtake. Currently, this is due to gas handling constraints. For example, in November 1992 Lisburne had two wells which tested higher than the permissible GOR; one well was online for 15 hours and the other for 8 hours. Both wells had only one test and were shut in for the majority of the month. It would be a waste of effort and a reduction of total offtake to bring these types of wells back into the system solely to meet arbitrary testing requirements.

Initial development of West Beach calls for one well to be commingled at DS-L1. The one West Beach well combined with the ten currently producing DS-L1 wells will not present any well testing frequency problems. If more wells are necessary for full West Beach development, the option of an additional test separator at West Beach will be explored. It is currently estimated that the addition of test separation facilities and associated piping would cost the Owners approximately $10 million.

WELL TEST STABILIZATION AND DURATION

- Optimum well test stabilization and duration times vary from well to well and may vary over time.
- *Well testing guidelines for* Lisburne *wells have been established based on total flow* rate and total gas liquid ratio. These guidelines are periodically reviewed.
- Well testing guidelines for West Beach, and any other commingled field, will be examined after start-up.

In well test based production allocation, it is important that representative well tests be obtained. Some of the more important aspects of well testing are well stabilization time, test duration, and the frequency of well testing. Optimization of each of these aspects will vary from well to well and over time for a given well. As more production history is obtained for any given well, more confidence in test stabilization and duration time can be achieved. Thus establishing rigid guidelines prior to obtaining any production history is inappropriate.

Exhibit 9 shows typical well stabilization behavior; the gas rate stabilizes first, then total liquid rate stabilizes, and finally the water cut stabilizes. This type of behavior is reflective of the physical process of flushing out the testing flowlines and the test separator and is highly dependent upon the producing characteristics of the well being tested and its distance from the test separator. Generally, the higher the producing rate the shorter the required stabilization and testing period. Conversely, low GOR, low flow rate, and intermittently gas lifted wells tend to require longer stabilization and testing times. Additionally, the slugging characteristics of the well plays a key role. This is best understood by looking at Exhibits 10 and 11 which show plots of production rate versus time for two types of wells. Exhibit 10 shows a well with the flow rate relatively constant, and therefore a representative value can be acquired by measuring production rates over a short period of time. Exhibit 11 shows a well with the flow rate varying significantly with time. This well must be tested for a longer period of time to obtain a value that is representative of the well's average production rate.

Based upon these general well performance characteristics, generic well testing guidelines for Lisburne wells have been established. By examining stabilization time versus flow rate data, such as shown in Exhibit 12, we have determined with a high level of confidence that a stabilization period of one hour is sufficient for a well producing >1,300 BLPD, four hours is sufficient for a well producing between 300 and 1,300 BLPD, and eight hours is sufficient for a well producing <300 BLPD. In a similar manner, we have established guidelines for test duration as a function of gas liquid ratio (GLR); if the GLR is <15,000 SCF/STB then the well test duration is eight hours, and if the GLR is >15,000 SCF/STB then the well test duration is four hours.

These testing guidelines are reviewed and updated periodically as well performance and field operating conditions change over time. For example, with the installation of online water cut meters, Lisburne is evaluating the resulting data to determine if a significant refinement of the existing testing guidelines is possible. These testing guidelines are utilized as a starting point for well testing duration and the actual well tests are monitored during and after the test to ensure representative flows are obtained. Well testing stabilization and duration times for West Beach and any other commingled fields will be examined after start-up.

WELL TEST BACKPRESSURE ADJUSTMENTS

- Testing wells in a test separator imposes an incremental backpressure on a well. This backpressure will cause the well to test at slightly different rates than the normal production rates.

- The impact of the back pressure effect is determined by the productivity index of a well.

- If there are large errors introduced by the backpressure effect, then the well test rates can be corrected.

- It is anticipated that the backpressure effects for West Beach and Lisburne will be relatively small and that no adjustments will be necessary.

During the execution of a well test, the production from a well is redirected from the normal production piping system into a test piping system. Generally, this change imposes an incremental backpressure of 0-20 psi on the well as it is being tested and will result in the measurement of a production rate that is slightly different (lower) than the normal production rate. The magnitude of the incremental backpressure is determined by the size of the test equipment and flowlines and the relative amounts of oil, water, and gas being measured. The overall impact of this incremental backpressure is determined by the individual well's productivity index. Productivity index is defined as the change in well producing rate with a change in pressure.

In the case where the combination of well productivity index and incremental backpressure exerted by the test separator are significant, the raw well test rates could be adjusted using the well's productivity index. The productivity index would be determined via additional well tests performed at several different backpressure conditions on a periodic basis, as dictated by changing well performance characteristics (such as GOR, water cut, or total fluid rate). A typical productivity index range for wells producing into the LPC will be on the order of less than one to five barrels per day per psi of pressure change.

Due to the combination of small well productivity indices and small well test incremental backpressures, the current backpressure impacts in Lisburne are relatively small, and it is anticipated that the backpressure impact for West Beach will also be relatively small. No adjustments are anticipated. Other fields that are commingled into the LPC will be examined for backpressure impacts. As production histories are established, future backpressure adjustments may be made. Additionally, tests are currently underway to operationally reduce the magnitude of the backpressure when a well is in test.

- There are 46 values involved in the calculation of the oil, water, and gas allocation factors.
- Original Lisburne metering design was for reservoir management purposes which required less meter accuracy
- During 1992, approximately $3 million was spent to upgrade the test separator liquid meters, the gas injection meters, and the LPC fuel meter and to install master artificial lift gas meters.
- Any field that will be commingled into the LPC will have to meet the same industry standards for metering.
- Since West Beach will be commingled at DS-L1, no additional metering will be required.
- Lisburne has developed a specific flow measurement manual and trained a meter calibration group.
- To facilitate the calibration of the mass meters, a gravimetric proving skid has been installed at the LPC.

An important part of well test based production allocation is accurate metering of the produced and disposed of fluids. Lisburne facilities were originally designed with a reservoir management basis for determining metering requirements. This design basis resulted in generally requiring less measurement accuracy.

Metering emphasis has now shifted from a reservoir management basis to a revenue determination basis. Therefore, in 1992 the Lisburne Owners spent nearly $3 million to upgrade several critical meter stations. The test separator meters were upgraded from turbine meters to mass flow meters. Online microwave water cut meters were installed to augment periodic well test shakeout samples. Plans are underway to install a new metering run on the produced water line. All liquid metering stations should fully meet accepted standards.

There are currently 46 values used for the calculation of the oil, water, and gas allocation factors. Exhibit 13 shows all of the critical meters for Lisburne production allocation. Exhibit 14 shows the equations used in the calculations of the oil, water ,and gas allocation factors.

The LGI injection gas meters and the LPC fuel gas meter were upgraded and new drill site master gas lift meters were installed. With these gas meter upgrades, meters responsible for measuring 99.5% of the produced gas processed by the Lisburne production system meet AGA-3 and API standards. The remaining 0.5% of the total produced gas is associated with the five drill site fuel meters, the flare assist meter, and the high and low pressure flare volumes.

The low and high pressure flare volumes are estimated by examining the plant conditions before, during, and after a flare event. Direct measurement of these flare volumes is not feasible since a very wide range in potential rates would need to be covered and varying amounts of liquid carryover would need to be handled. Attempts to improve the measurement of these flare gas volumes would significantly impair the primary safety relief functions of the flare systems. Since May 1991, the historical gas volumes involved in flare situations, including flare assist gas, has been less than 0.1% of the total gas processed at the LPC.

While the five Lisburne drill site fuel gas meters and the flare assist gas meter were not upgraded, their accuracy is still ±2% and the volume of gas they measure less than 0.5% of the total produced gas processed by the Lisburne production system. No upgrades for these meters are planned since their impact on gas allocation is extremely small.

It is anticipated that metering installations for any field whose production will be commingled for processing in the LPC will have to meet the same industry standards for metering that Lisburne currently meets, and where possible, installation of similar meters will be required. West Beach will initially be tested at DS-L1, so there will not be any new metering required to bring West Beach into the LPC.

Concurrent with upgrading of the physical instrumentation used in the production allocation process, the Lisburne Maintenance Group has accepted the responsibility for meter calibration and maintenance. While the Prudhoe Bay Flow Measurement Group will continue to be available as a technical information resource, the primary responsibility will reside with Lisburne Operations. This group is developing a flow measurement manual that outlines everything relating to flow measurement including required training for personnel, calibration equipment, calibration frequency, and calibration procedures. Increased training for personnel includes several industry and internal courses including the International School of Hydrocarbon Measurement and the API - PETEX School of Liquid Measurement. Calibration frequency for all critical meters is currently planned on a monthly basis. However, this could change as more field performance data is received.

To facilitate the calibration of the mass meters, a gravimetric proving skid has been installed at the LPC. A schematic is included as Exhibit 15. This gravimetric proving skid duplicates the same calibration procedures that the manufacturer uses to calibrate all of the mass meters that it produces. Having the gravimetric skid at the LPC allows us to more easily verify the accuracy of the mass meters and eliminates continually shipping meters back to the factory for calibration.

Simply stated, the gravimetric skid works by pumping water from a holding tank, through the mass meter and onto a very accurate scale. The weight of the water on the scale is then compared to the weight of water measured by the mass flow meter. The resulting meter factor is then calculated. The weights used to calibrate the scales are certified by the National Institute of Standards and Testing and will be recertified with the State of Alaska Division of Weights and Measurements every two years.

The density portion of the mass meter is verified with a two-point test, one point with air and one point with water, and a linear density is assumed between the air and water densities. This is also the same procedure used by the manufacturer for density calibrations.

OIL METERING AND ALLOCATION

- The TAPS sales volume is accepted as "truth" and is measured with a turbine meter proved daily and compensated for BS&W by a 24-hour composite sampler.

- The test separator total liquids are measured with Micro Motion mass flow meters. The water cut is measured with Phase Dynamics water cut meters.

- The unstabilized NGL volume is measured with a Micro Motion mass flow meter.

- Load crude and diesel volumes will be tracked by well, allowing each field to be charged for its usage.

- Exploratory fluids and unrecoverable oil volumes have been insignificant but are accounted for.

The calculation of the oil allocation factor uses the actual produced volume sold to TAPS and the sum of the individual well tests. The actual produced volume sold to TAPS is corrected for the TAPS BS&W volume, the stabilized NGL volume, the load crude and load diesel volumes, the exploratory oil volume, and the unrecoverable oil volume. The actual numerical equation used in the allocation of oil production is shown in Exhibit 14.

The TAPS volume is measured by Alyeska with a turbine meter, which is proved daily and has an accuracy of ±0.10%. The values measured by the TAPS meter are taken as the ground truth for the well test based oil production allocation process.

The unstabilized NGL volumes are measured by a Micro Motion mass flow meter with an accuracy of ±0.20%, and the stabilized NGL volumes are determined from a computer process simulation to be discussed in detail later.

The TAPS BS&W volume is determine by Alyeska at Pump Station No. 1 and reported to the LPC each day. The TAPS BS&W is determined from a 24-hour composite sampler at Pump Station No. 1 and is typically less than 0.02%.

Exploratory fluids are produced during testing of exploratory wells in the area and the fluids typically are trucked to the LPC and added to the Slop Oil Tank. Exploratory fluids are typically measured very accurately during well testing. Additional volume measurements are made as the fluid is transferred from the truck and as the Slop Oil Tank level changes. Since LPC start-up, the exploratory oil volume has been insignificant.

Unrecoverable oil includes spilled oil and oil that cannot be processed and is sent offsite for disposal. If the unrecoverable oil is due to a spill, then the volume can only be estimated. If the oil is taken to offsite for disposal, then the Slop Oil Tank level and the truck volumes are used to calculate the volume. Since LPC start-up, the unrecoverable oil volume has been insignificant.

Load crude comes from Prudhoe Bay Flow Station No. 1 (metered at ±1%) and is used in wells for remedial treatments such as hot oil jobs and stimulations. Load diesel (metered at ±0.5%) comes from the Crude Oil Topping plant and is used as a remedial treatment fluid and to freeze-protect wells and flowlines. The total load crude and load diesel volumes are subtracted from the total sales volume at the end of each month. Individual field usage will be accounted for. Since October 1991, the load crude and diesel was less than 0.25% of the total oil processed by the LPC.

The sum of the individual well tests from all fields provides the denominator for the numeric allocation factor equation shown in Exhibit 14. The test separator meters provide the cornerstone for these measurements. The test separator fluid measurement meters have been upgraded to Micro Motion mass flow meters (±0.2%). The mass meter was tested against a turbine meter at DS-L2 prior to installing the mass meters at all of the drill sites. Exhibit 16 shows an overlay of the mass meter and turbine meter rates. Phase Dynamics microwave water cut meters (±0.5 to 1.0%) provide online water production measurements and are supplemented by periodic shakeout sampling. The water cut meter performance was verified at DS-L2 prior to installing them at all of the drill sites. Working in combination, these two meters accurately measure the amount of oil and water produced during a well test.

Thus, the oil allocation factor is derived from the calculation of an adjusted sales volume divided by the produced volume derived from the well testing program.

WATER METERING AND ALLOCATION

- The meter on the disposal well will soon be upgraded to an ultrasonic meter in order to provide more reliable, long-term, consistent service.
- External water would include water from pit dewatering and exploratory water.
- The test separator total liquids are measured with Micro Motion mass flow meters and the water cut is measured with Phase Dynamics water cut meters.
- Well test shakeouts will supplement online water cut measurements.

The calculation of the water allocation factor uses the actual disposed or injected volume and the sum of the individual well tests. The actual disposed or injected volume is corrected for the TAPS BS&W volume and the external water added to the slop oil tank volume. The actual numerical equation used in the allocation of water production is shown in Exhibit 14.

The metering on the water disposal line is analogous to the TAPS oil sales meter and is considered to be "truth." The accuracy of the turbine meter currently installed on the production water disposal line is ±5.0%. Recognizing that additional accuracy is required in future operations, the Lisburne Owners plan to install a new ultrasonic meter run during early 1993. The accuracy of the new replacement ultrasonic meter is ±2%. The main advantage to this upgrade is that the ultrasonic meter should provide more reliable, long-term, consistent service due to it not being affected by entrained solids.

The TAPS BS&W volume is determine by Alyeska at Pump Station No. 1 and reported to the LPC each day. The TAPS BS&W is determined from a 24-hour composite sampler at Pump Station No. 1 and is typically less than 0.02%.

External water could be from several sources including exploratory wells or pit dewatering during breakup. External water is usually trucked to the LPC and added to the slop oil tank. If the water is exploratory water, then exploratory volumes are typically measured at the well very accurately. If not, the level control on the slop oil tank and the volume of the trucks used to transport the fluid are used to determine the volume. Since LPC start-up, the external water volume has been insignificant.

The sum of the individual well tests from all fields provides the denominator for the numeric allocation factor equation shown in Exhibit 14. The test separator meters provide the cornerstone for these measurements. The test separator fluid measurement meters have been upgraded to Micro Motion mass flow meters (±0.2%). The mass flow meter was tested against a turbine meter at DS-L2 prior to installing the mass flow meters at all of the drill sites. Phase Dynamics microwave water cut meters (±0.5 to 1.0%) provide online water production measurements and are supplemented by periodic shakeout sampling. The water cut meter performance was verified at DS-L2 prior to installing them at all of the drill sites. Data collected since the water cut meters were installed shows very good agreement between the shakeouts and the water cut meter readings and is shown in Exhibit 17. Shakeouts will be used as a backup if something unforeseen should happen to the water cut meter. To ensure that the shakeouts are of as high a quality as possible, new sample ports were installed in order to obtain a representative production sample.

GAS METERING AND ALLOCATION

- In the calculation of the gas allocation factor, there is not a single meter that provides a direct total produced gas measurement analogous to the oil "sales" meter.
- The test separator gas meters, the LPC fuel gas meter, the IPA fuel gas meter, and the artificial lift master meters meet current AGA-3 and API standards for sales orifice meters and are responsible for measuring 99.5% of the produced gas processed by the Lisburne production system.
- The NGL shrinkage volume is calculated by the same computer facility process simulator that calculates the stabilized NGL volume.

- The flare volumes are estimated and are historically quite small.
- The five drill site fuel and the flare assist meters do not meet current industry standards for sales meters. However, these meters handle less than 0.5% of the total gas processed by the Lisburne production system.

In the calculation of the gas allocation factor, there is not a single meter that provides a direct total produced gas measurement analogous to the oil "sales" meter. In Lisburne, there are currently 22 meters or calculated volumes that are used to perform the gas allocation. There are six gas injection meters, the LPC fuel meter, the five drill site fuel meters, the high and low pressure flare volumes, the NGL shrinkage volume, the five master gas lift meters, the flare assist meter and the IPA fuel meter. These critical meters and volumes are shown in the critical metering diagram. The actual numerical equation used in the allocation of gas production is shown in Exhibit 14.

The five test separator gas meters, the LPC fuel meter, the six gas injection meters and the IPA fuel gas meter have recently been upgraded and meet current AGA-3 and API standard for orifice meters and are accurate to ±0.5%. These meters are responsible for measuring 99.5% of the produced gas processed by the Lisburne production system. It is currently anticipated that these meters will be calibrated monthly. However, as more field performance data is gathered, the timing of the calibrations might change.

The NGL shrinkage volume is calculated by the same facility process simulator computer program that calculates the stabilized NGL volume. This will be discussed in detail in another section.

The flare volumes are estimated by examining the plant conditions before, during, and after a flare event. Direct measurement of these flare volumes is not feasible since a very wide range in potential rates would need to be covered and varying amounts of liquid carryover would need to be handled. Attempts to improve the measurement of these flare gas volumes could significantly impair the primary safety relief functions of the flare systems. Since May 1991, the historical gas volumes involved in flare situations, including flare assist gas, has been less than 0.1% of the total gas processed at the LPC. Exhibits 18 and 19 show the number of flare events, the size of the flare events and the flare gas percentage of the total gas processed at LPC.

The five Lisburne drill site fuel gas meters and the flare assist gas meter do not meet current industry standards for sales meters. These meters are flange fitting orifice meters with online pressure and temperature compensation. The accuracy of the drill site fuel and the flare assist meters is in the range of ±2%. The volume of gas these meters measure is less than 0.5% of the total produced gas processed by the Lisburne production system.

NGL MEASUREMENT

- Field NGL volumes will be determined by the field's volume of produced gas and field NGL yield factors.

- The methodology used for NGL stabilization calculations will remain the same.
- Field NGL yield factors will be calculated based upon field conditions and process simulation.

As shown in Exhibit 20, unstabilized crude enters the crude oil surge drum where light hydrocarbons are flashed to achieve the true vapor pressure specification requested by Alyeska. The surge drum off-gas was originally contained in the unstabilized crude entering the surge tank from the treaters and the unstabilized NGLs entering from the NGL plant. Since the exact volume of stabilized NGLs cannot be directly metered, a process simulation's program (Simulation Science's PROCESS) is used to determine the amount of stabilized NGLs contained in the liquid sales volume leaving the LPC. This program is an industry accepted tool for modeling plant operations and uses thermodynamic data and equations of state to predict plant behavior. A field test conducted in April of 1992, during which the NGL plant was taken offline and all other LPC and field conditions were kept constant, verified the volume of NGLs predicted by the current methodology used to calculate stabilized NGLs. When the NGL plant was taken offline, the total rate to TAPS decreased by the volume that the process model was calculating.

Lisburne Stabilized NGL Volume Determination (Current)

A process model of the LPC has been developed that matches the rates and compositions observed at the LPC. The model is run twice for a given set of operating conditions, once with the NGL stream blended with the crude, and once with no NGLs blended in. The difference in the calculated sales liquid rate is the amount of NGLs that stabilize with the crude. A simulation derived Stabilization Factor (SF) is then calculated as the ratio of stabilized NGLs over total unstabilized NGLs. This SF is then applied to Meter 660 (actual plant unstabilized NGL rate from the depropanizer to the crude surge drum) to determine actual stabilized NGL rate. Meter 660 is a Micro Motion mass flow meter capable of ±0.2% accuracy. The shrinkage volume is the amount of gas equivalent to the stabilized NGL volume.

SF and Shrinkage Factors (SHF) have been determined for several different plant conditions covering the normal operating range of the LPC and are entered into lookup tables in LDGS. LDGS interpolates the SF by taking hourly averages of slug catcher pressure, depropanizer pressure, and reboiler temperature and reading from lookup tables generated from process data.

The following list and example show how the SF and total stabilized NGL volume are currently determined at the LPC. The actual data gathering and calculations are automatically done on LDGS. The numbers used are for illustration purposes only.

1. Record hourly averages of pertinent plant operating conditions.

2. Calculate hourly SF and SHF based on operating conditions.

3. Calculate the LPC hourly and daily stabilized NGL and shrinkage volumes:

Hourly NGL(STB) = (Meter 660) x (SF)
Hourly Shrinkage (MSCF) = (Meter 660) x (SF) x (SHF)

Daily Total NGL (DTN) = Sum of hourly NGL volumes
Daily Total Shrinkage (DTS) = Sum of hourly Shrinkage volumes

Total rate to TAPS including NGLs *:	36,000 STB/D
Total rate to TAPS without NGL plant *:	31,500 STB/D
Stabilized NGLs blended with crude :	(36,000-31,500) = 4,500 STB/D
Total unstabilized NGL rate out of depropanizer*:	8,300 AB/D
NGL SF:	(4,500/8,300) = .5422 = 54.22%
Actual hourly NGL rate blended with crude :	(Meter 660) X (SF)
Daily Total NGL volume (DTN) :	Sum of hourly NGL volumes
Total produced gas to injection without NGL plant *:	450,000 MSCFD
Total produced gas to injection with NGL plant *:	442,000 MSCFD
Equivalent NGL gas Volume *:	(450,000-442,000) = 8,000 MSCFD
SHF:	(8,000/4500) = 1.77 MSCF/STB
Actual hourly Shrinkage Volume :	(Meter 660) X (SF) X (SHF)

* Note: This value has been calculated by process simulator.

<u>NGL Volume Determination (Commingling Lisburne and West Beach)</u>

The Daily Total NGL (DTN) and Shrinkage (DTS) volumes will be calculated as they are currently when multiple fields are commingled into the LPC. However, in order to calculate the contribution of each field (Lisburne and West Beach) to the stabilized and unstabilized NGL volumes, it is necessary that the components making up each reservoir be labeled and tracked separately. Thus, the Lisburne methane component will be labeled as $LISC_1$, the West Beach methane component as WBC_1 with the remaining components being similarly labeled ($LISC_2$, $LISC_3$, ..., WBC_2, WBC_3, ..., etc.). In this way, the model is able to differentiate the makeup of each stream by component and the field that produced that component. From this data, NGL yield tables (Stabilized STB NGL/MMSCF produced gas) are developed for each field over the operating range of the LPC. These yield tables are used in combination with the current methodology to determine the volume of stabilized NGLs for each field. The following list shows the steps involved and how the methodology would apply for calculating the stabilized NGL volumes for a two field case (Lisburne and West Beach). The same approach will be used when additional fields are commingled.

<u>Current</u>

1. Record hourly averages of pertinent plant operating conditions.

2. Calculate hourly SF and SHF based on operating conditions.

3. Calculate the LPC hourly and daily stabilized NGL and shrinkage volumes:

$$\text{Hourly NGL(STB)} = (\text{Meter } 660) \times (\text{SF})$$
$$\text{Hourly Shrinkage (MSCF)} = (\text{Meter } 660) \times (\text{SF}) \times (\text{SHF})$$

Daily Total NGL (DTN) = Sum of hourly NGL volumes
Daily Total Shrinkage (DTS) = Sum of hourly Shrinkage volumes

<u>Additional Calculations Due to Commingling</u>

4. Calculate average daily yield (Y_{Lis}, Y_{WB}, etc.) for each field based on LPC operating conditions.

5. Calculate Apparent and Total Apparent NGL (AN_{Lis}, AN_{WB}, TAN) volumes for each field based on daily yield and gas rates:

$$AN_{Lis}\ (\text{STB}) = (Y_{Lis}) \times (Gas_{Lis})$$
$$AN_{WB}\ (\text{STB}) = (Y_{WB}) \times (Gas_{WB})$$

$$\text{TAN (STB)} = AN_{Lis} + AN_{WB}$$

6. Allocate stabilized NGL and Shrinkage volumes for each field:

$$NGL_{Lis}\ (\text{STB}) = \frac{(AN_{Lis})}{TAN} \times DTN$$

$$\text{Where: } \frac{AN}{TAN} = \text{NGL Fraction by Field}$$

$$NGL_{WB}\ (\text{STB}) = \frac{(AN_{WB})}{TAN} \times DTN$$

$$Shrink_{Lis}\ (\text{MSCFD}) = \frac{(AN_{Lis})}{TAN} \times DTS$$

$$Shrink_{WB}\ (\text{MSCFD}) = \frac{(AN_{WB})}{TAN} \times DTS$$

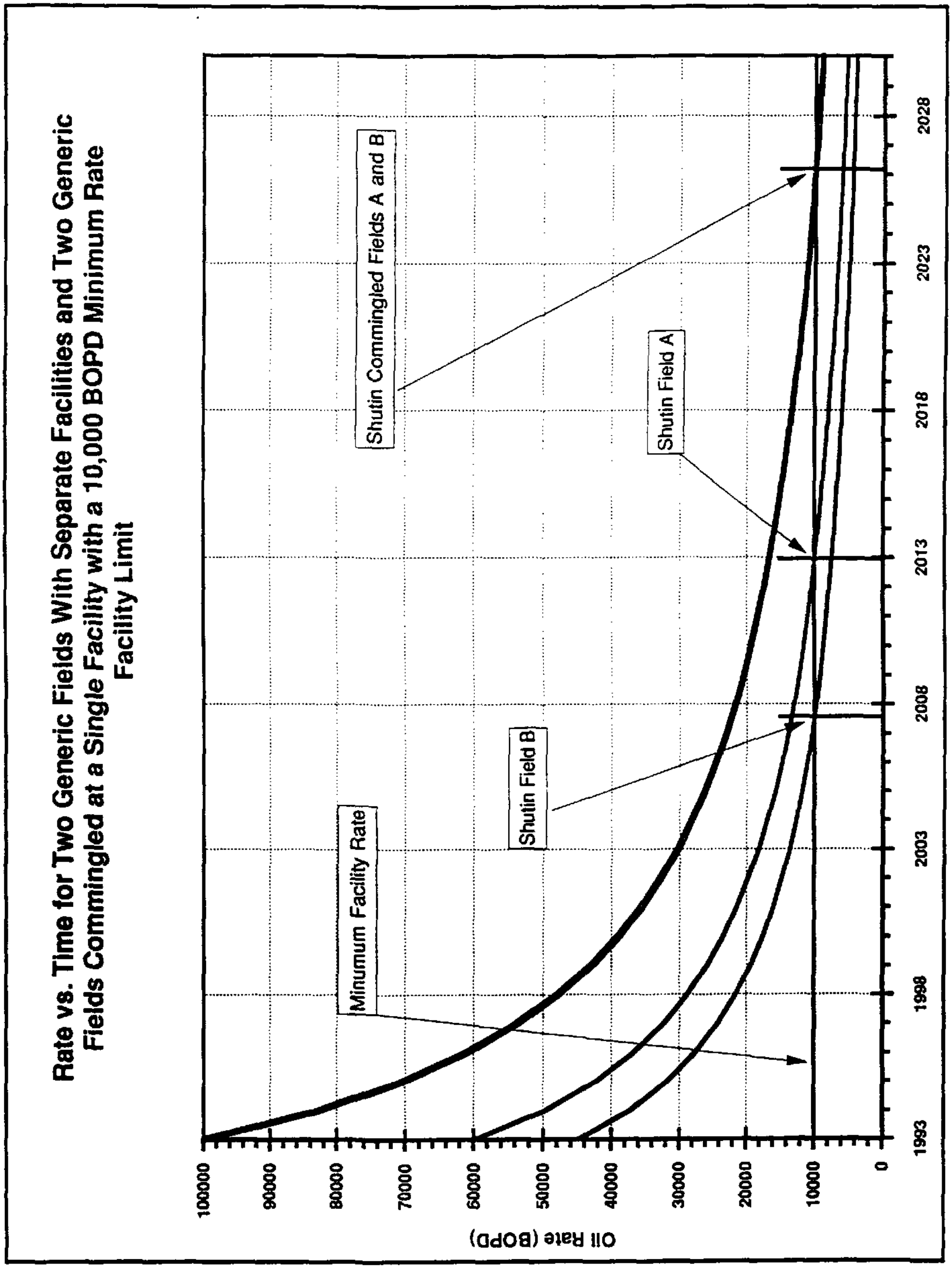
USAGE OF MISCELLANEOUS FLUIDS

- LPC fuel and flare gas and drill site fuel and flare gas will be divided among the producing fields based on each field's fraction of gas being handled at that facility.
- Load crude and diesel will be tracked by well so that the load crude and diesel can be properly charged to the field that used it.
- Unrecoverable oil will be split among fields based on each field's fraction of the oil produced at the facility where the oil was lost.

- External water will be subtracted from the water disposal meter.
- Exploration oil will be subtracted from the TAPS sales oil and will be credited to the exploration Owner(s).

LPC fuel and flare gas will be divided among producing fields based upon the gas fraction produced through the LPC by each field. At the LPC, 86% of the fuel is used to run the gas compressors that handle the produced gas. Drill site fuel and flare gas will be divided among the fields producing into each drill site based upon the gas fraction produced through that drill site. All of the drill site fuel is used to run the drill site heaters. The major reason for adding heat to the drill site fluid before it is sent to the LPC is the cooling caused by the entrained gas.

The flare gas at the LPC and the drill sites will be divided among fields producing based upon the fraction of gas each field produced through that facility.



January 13, 1993

Exhibit 1

Lisburne/Point McIntyre/West Beach Allocation Methodology

1. Conduct well tests to determine production rates for each well.

Criteria for determining what wells to test:
- Known well performance
- Significant Events
  - Pre and post well work tests
  - Diagnostic work (i.e. temperature and pressure changes)
  - Tests for engineering purposes
- Date of last test

2. Review well tests for validity.

- How does this well test compare with past well tests for this well
- Was the stabilization period long enough
- Was the test duration long enough
- Did the flowing tubing pressure change significantly during the test
- Did the lift gas rate change during the test

3. Review the significant events for each well.

- Examine the event history for shutins, openings, gas lift gas changes and choke changes.
- Examine the drill site operator shift change notes for why a well was shutin and other items of interest that might have an impact on the oil, water and gas rates of the wells. This includes, flowing tubing pressure and temperature trends, hot oiling, hot gassing, methanol treatments, LPC back pressure, field prorations, etc.

4. Calculate each well's theoretical monthly production by combining well test rates with significant events for that well.

Allocating with no significant events:
- Allocate from the beginning of one well test to the beginning of the next well test.

Allocating with significant events:
- *Instead of extrapolating as a well is shutin or extrapolating for flush production* when a well is brought online, it is assumed that the last well test rates are constant from the beginning of the last well test until the end of the event and that the current well test rates are constant from the end of the event until the beginning of the next well test or event.

5. Sum the theoretical monthly production volumes for all wells in all fields.

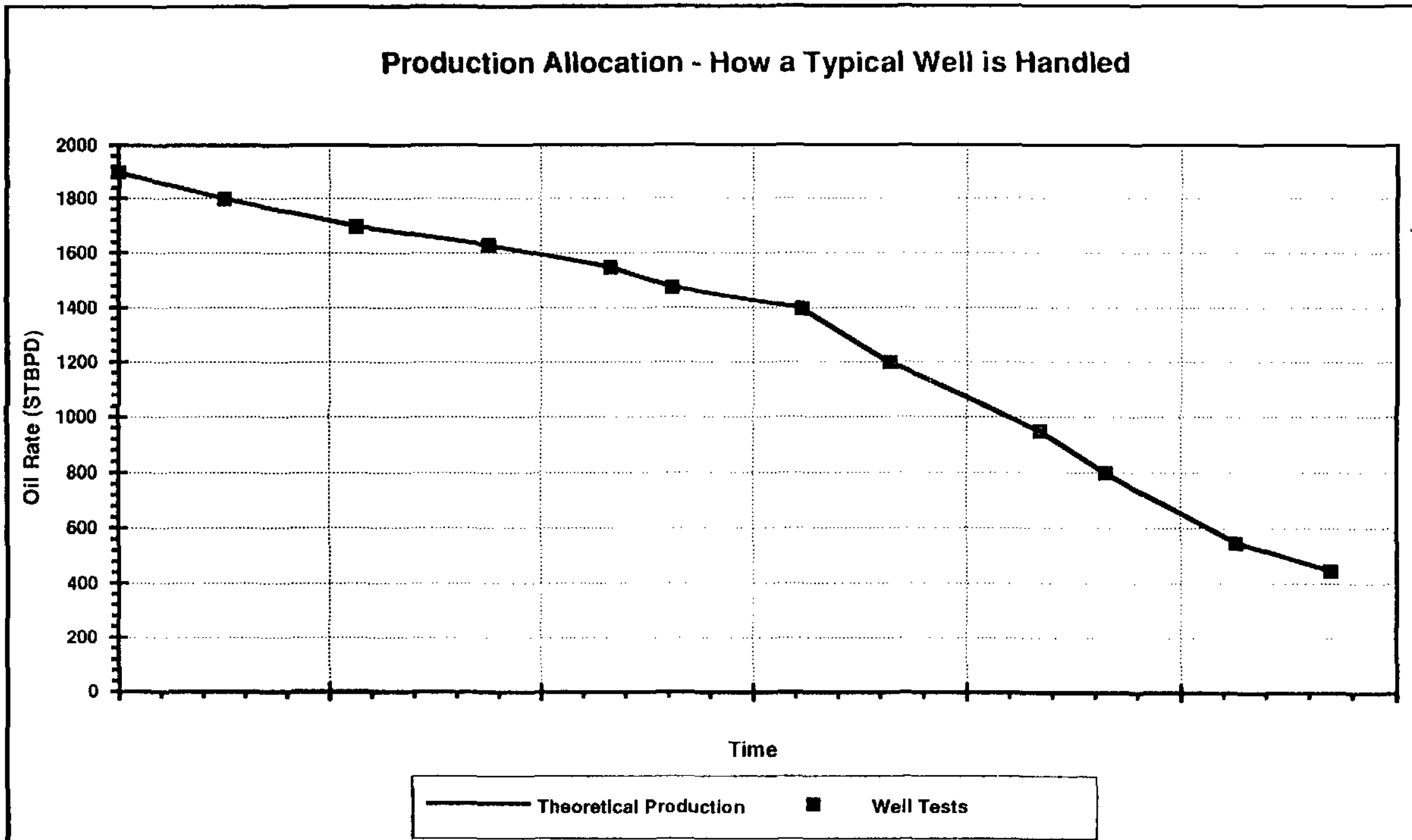
6. **Calculate an allocation factor which compares the sum of theoretical monthly production volumes for all wells in all fields to the "Total Sales" volume as determined by the critical meters.**

$$\text{Allocation Factor} = \frac{\text{"Total Sales" Volume}}{\text{Sum Of Theoretical Monthly Production Volumes For All Wells}}$$

7. **Calculate each well's allocated monthly production volume as:**

$$\text{Allocated Production Volume} = \text{Theoretical Production Volume} \times \text{Allocation Factor}$$

8. **Sum allocated production volumes for each well in each field to determine the amount of production derived from each field.**

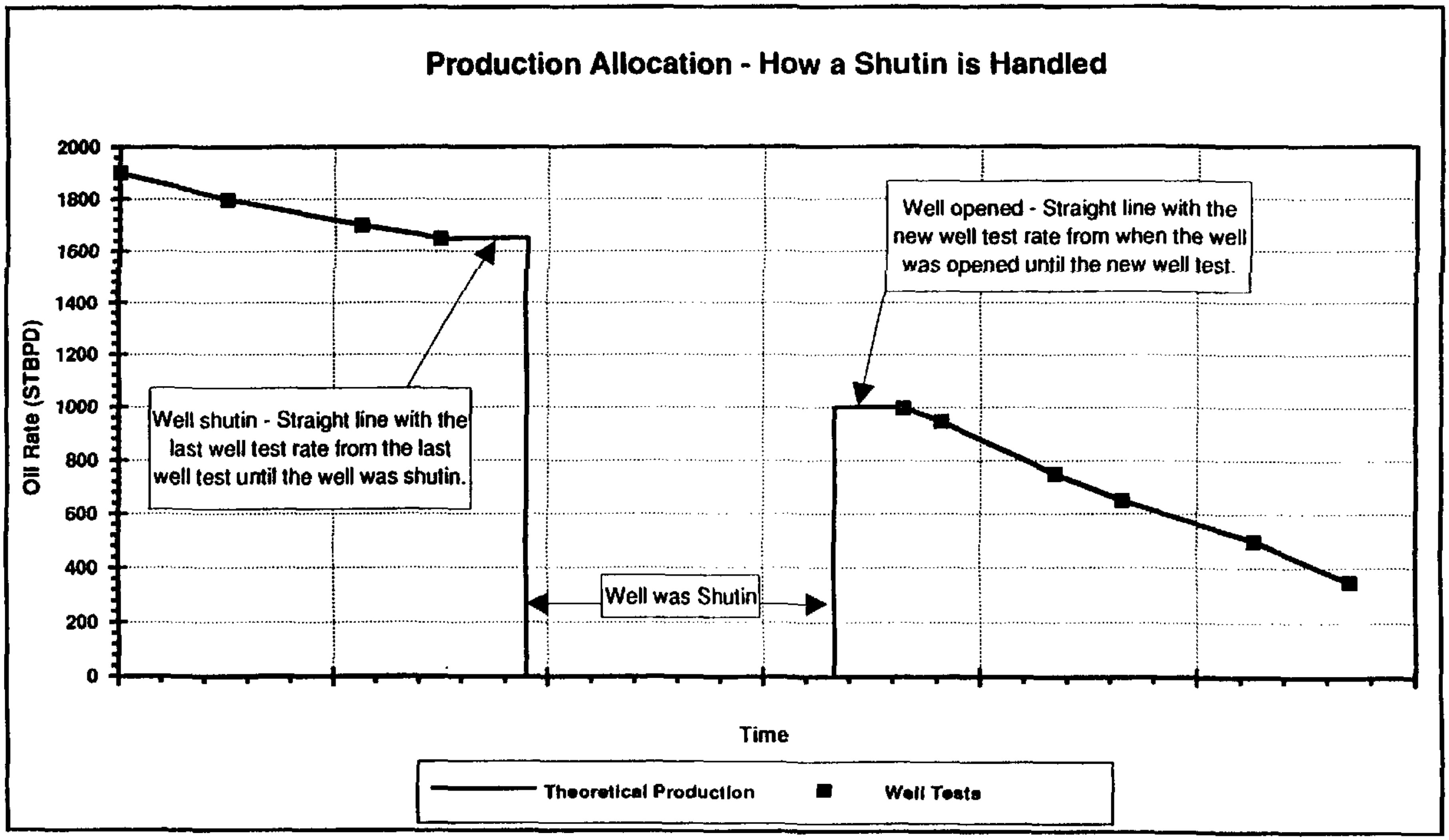


How Allocations Are Typically Handled:

- Allocate from beginning of test to beginning of test

January 13, 1993

Exhibit 3

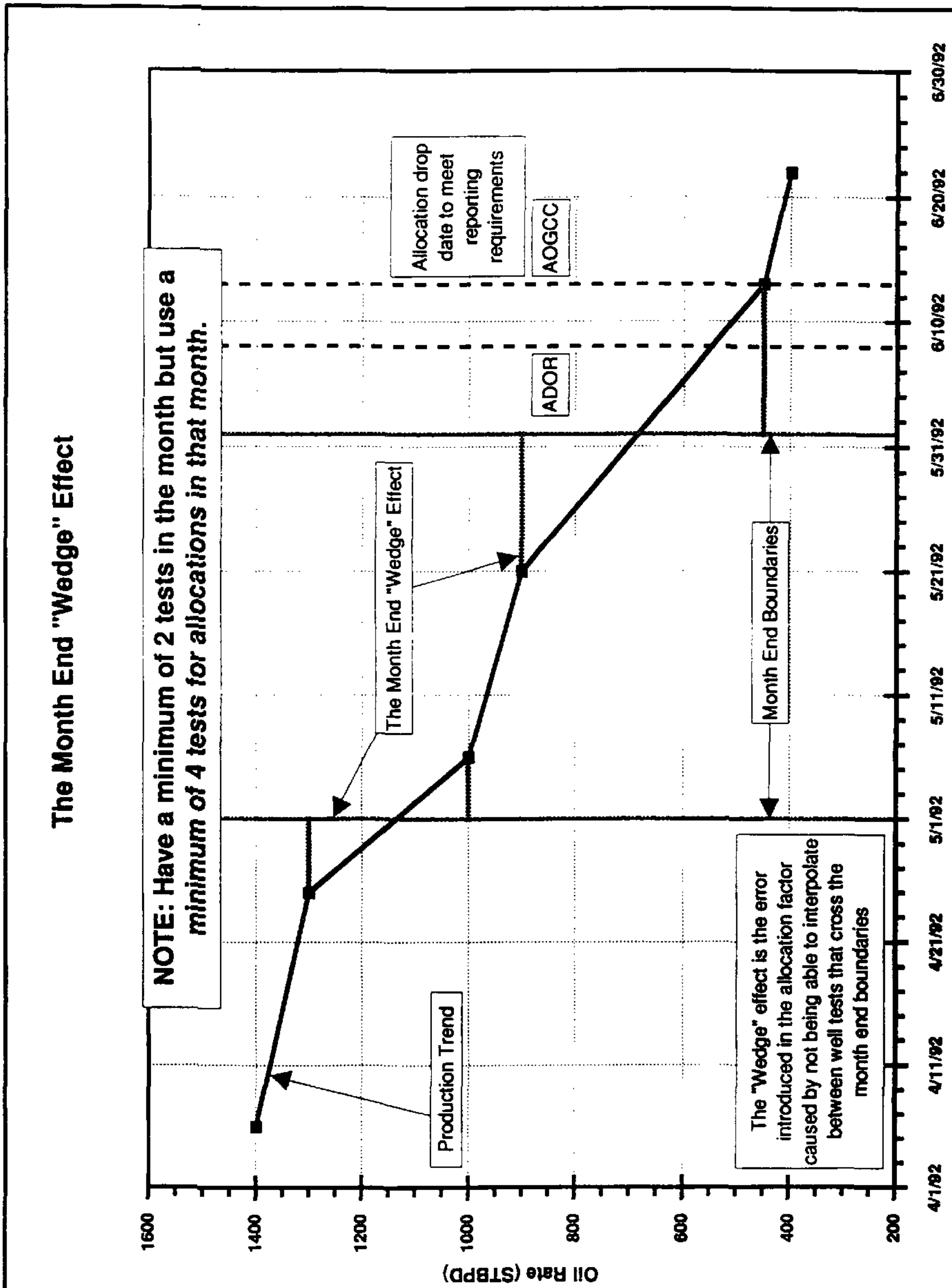


How Allocations for Shutin's and Other Similar Events Handled:

- Beginning of Well Test to Event, Event to Event or Event to Beginning of Well Test
  - *Typical Events Include:* Shut-ins, Hot Oiling, Hot Gassing, Choke Changes, Gas Lift Changes, Significant Slugcatcher Increases/Decreases and Pressure and Temperature Trends.

January 13, 1993

Exhibit 4



January 13, 1993

Exhibit 5

MONTH END SUPPORTING DATA

- **Well Test Data**

WELL TEST REPORT

								TESTED RATES										EXPECTED								
WELL NO.	DATE COMP	TIME COMP	STRT TIME	CHK POS	AVG WELL TEMP	AVG FTP TEST	AVG SEP PRES	OIL STBD	WTR BPD	TOTAL GAS MSCFD	LIFT GAS MSCFD	% WTR	FORM GOR SCF/B	TOTAL GOR SCF/B	TOTAL GLR SCF/B	STAB TIME HRS	TEST TIME HRS	OIL STBD	FORM GOR SCF/B	% WTR	T S T	T Y P	A L L	D F L G	F L G	ORIFC DIA INCHES

- **Event Summary**

PROCESSING FACILITY 1 EVENT SUMMARY REPORT
FOR 12-01-92 TO 12-31-92

WELL	SHUT-IN DAYS	SHUT-IN HOURS	REASON	OIL RATE	TOTAL GOR	TOTAL GAS RATE	START OF EVENT MM-DD-YY	START OF EVENT HHMM	END OF EVENT MM-DD-YY	END OF EVENT HHMM

PROCESSING FACILITY 1 CHOKE & GAS LIFT CHANGE SUMMARY REPORT

WELL	EVENT TIME MM-DD-YY	EVENT TIME HHMM	CURRENT CHOKE SETTING	PREVIOUS CHOKE SETTING	CURRENT LIFT GAS RATE	PREVIOUS LIFT GAS RATE

- **Monthly Oil, Water and Gas Allocation Factors**

- **Number of Well Tests per Well by Drill Site and Test Separator Usage Statistics**

Exhibit 6

TYPE "A" WELL

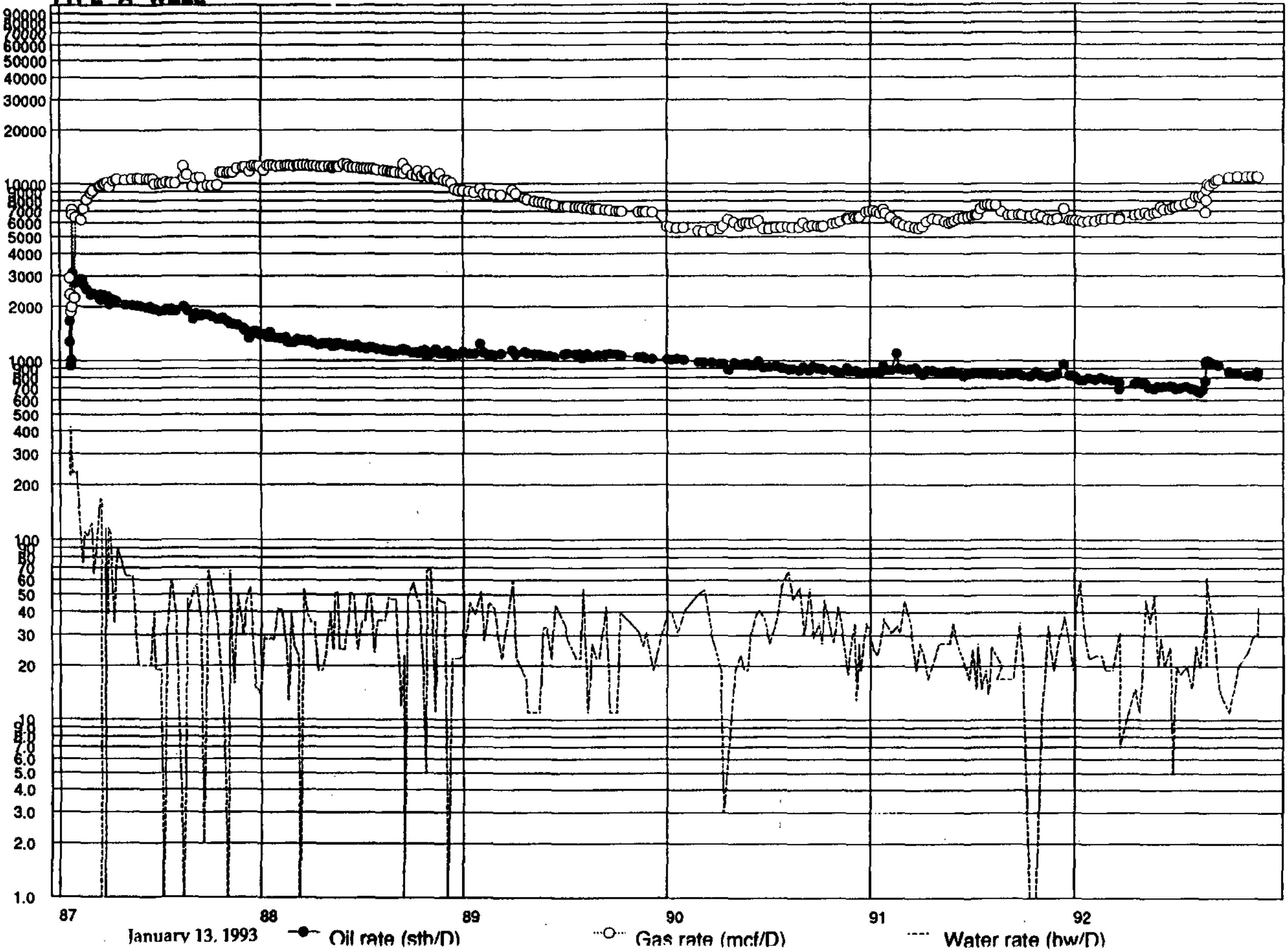


Exhibit 7

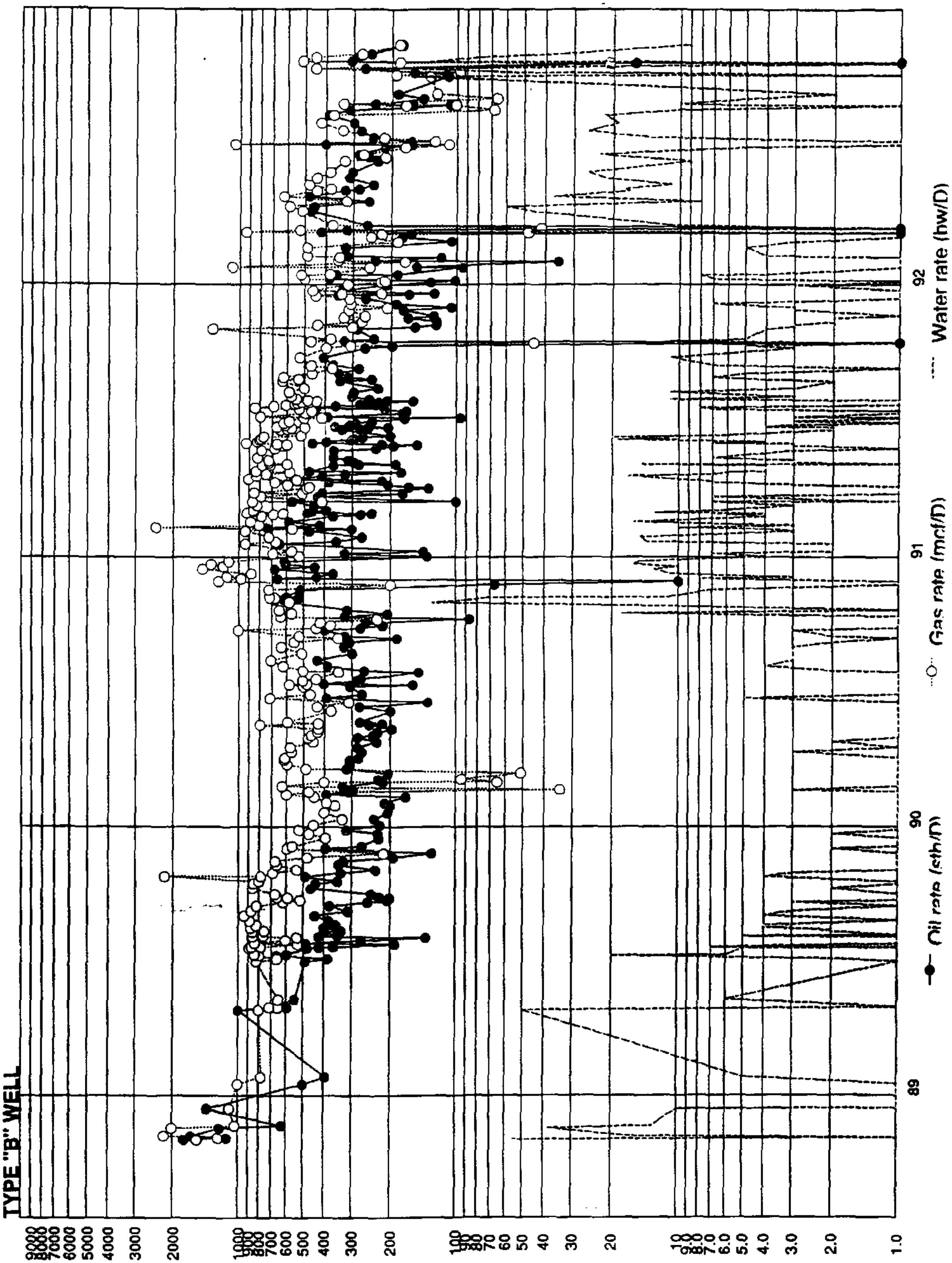
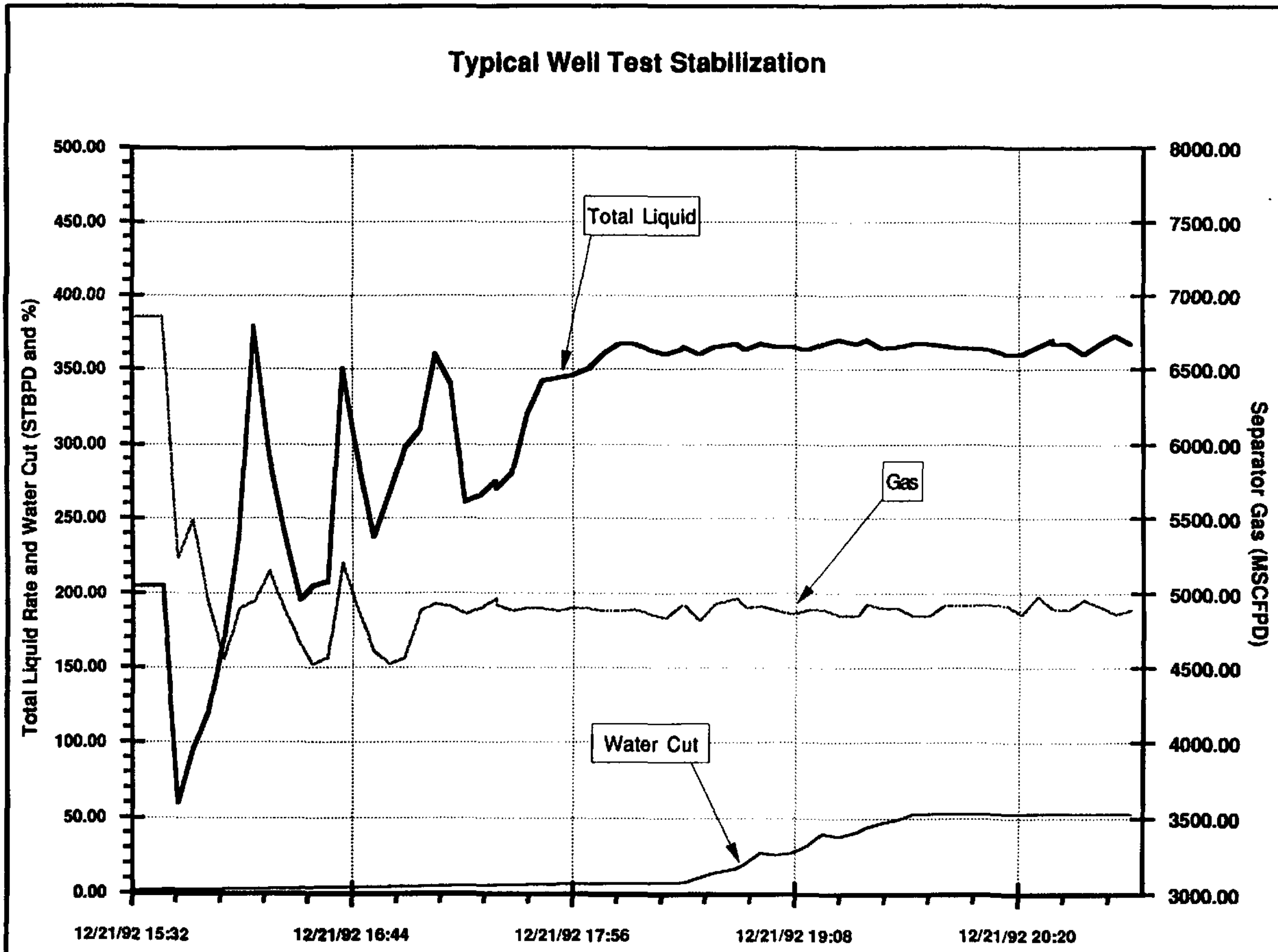
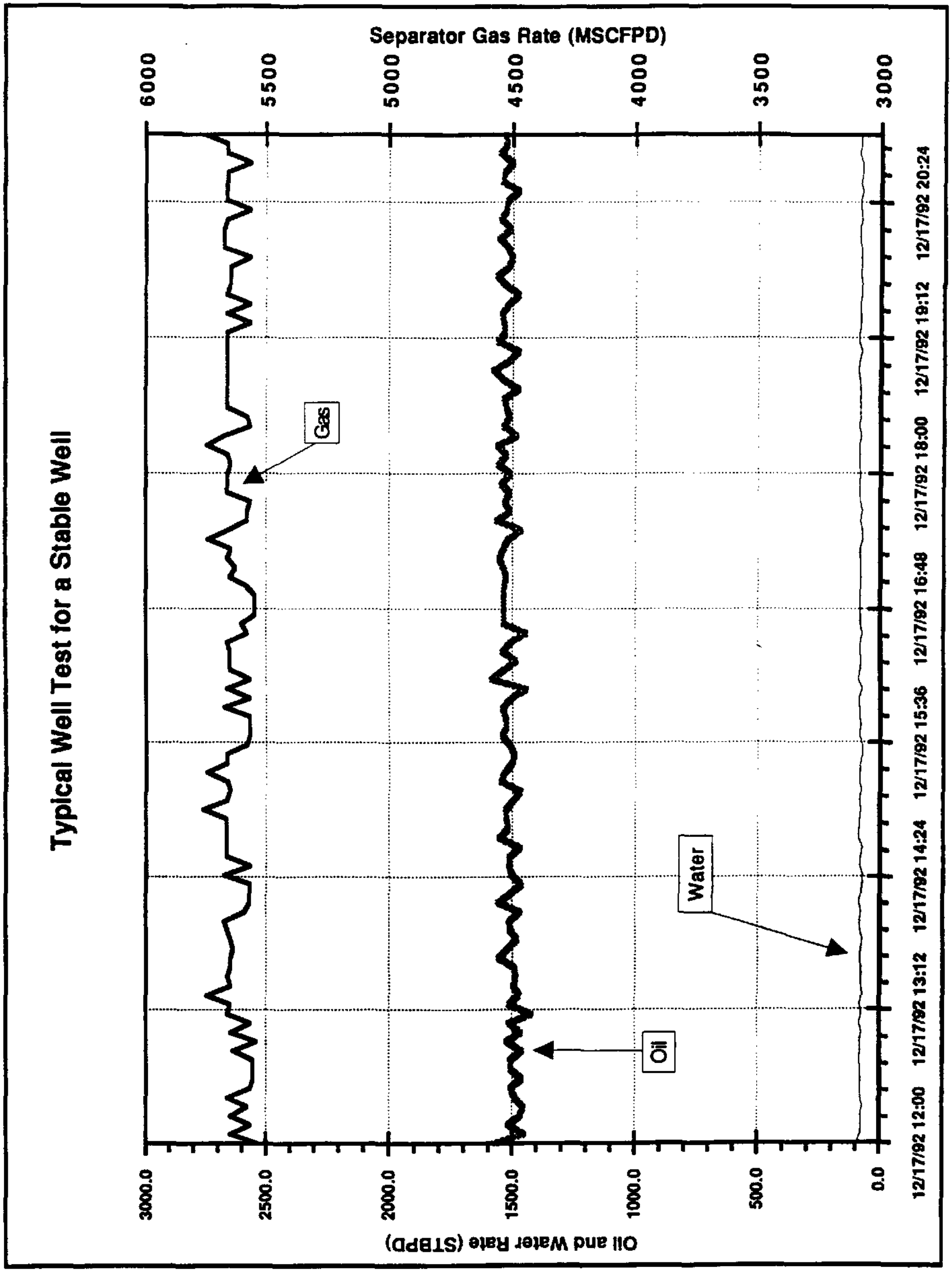

TYPE "B" WELL
89
90
91
92
Oil rate (stb/D)
Gas rate (mcf/D)
Water rate (bw/D)
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
10
20
30
40
50
60
70
80
90
100
200
300
400
500
600
700
800
900
1000
2000
3000
4000
5000
6000
7000
8000
9000

Exhibit 8



January 13, 1993

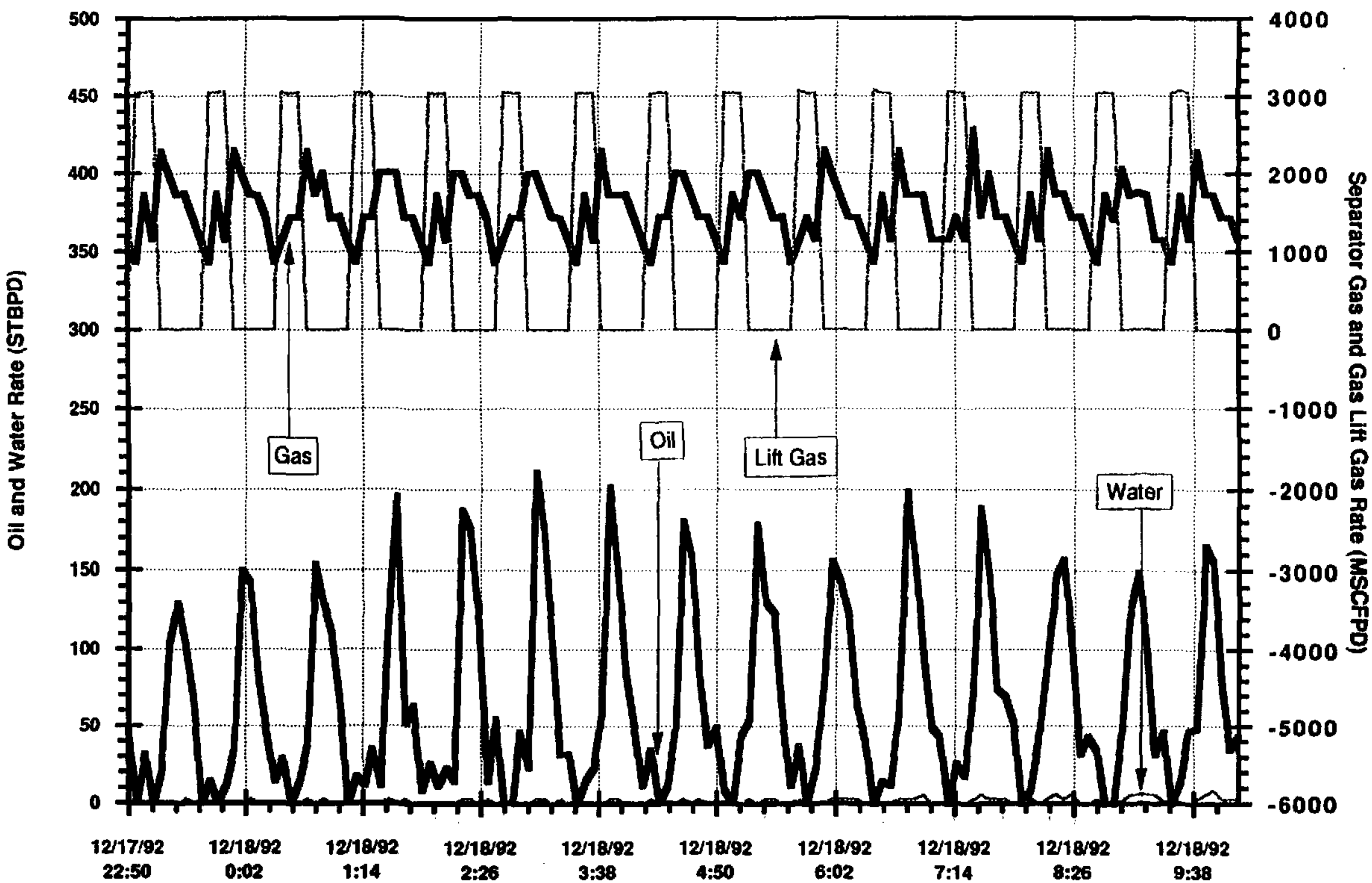
Exhibit 9



January 13, 1993

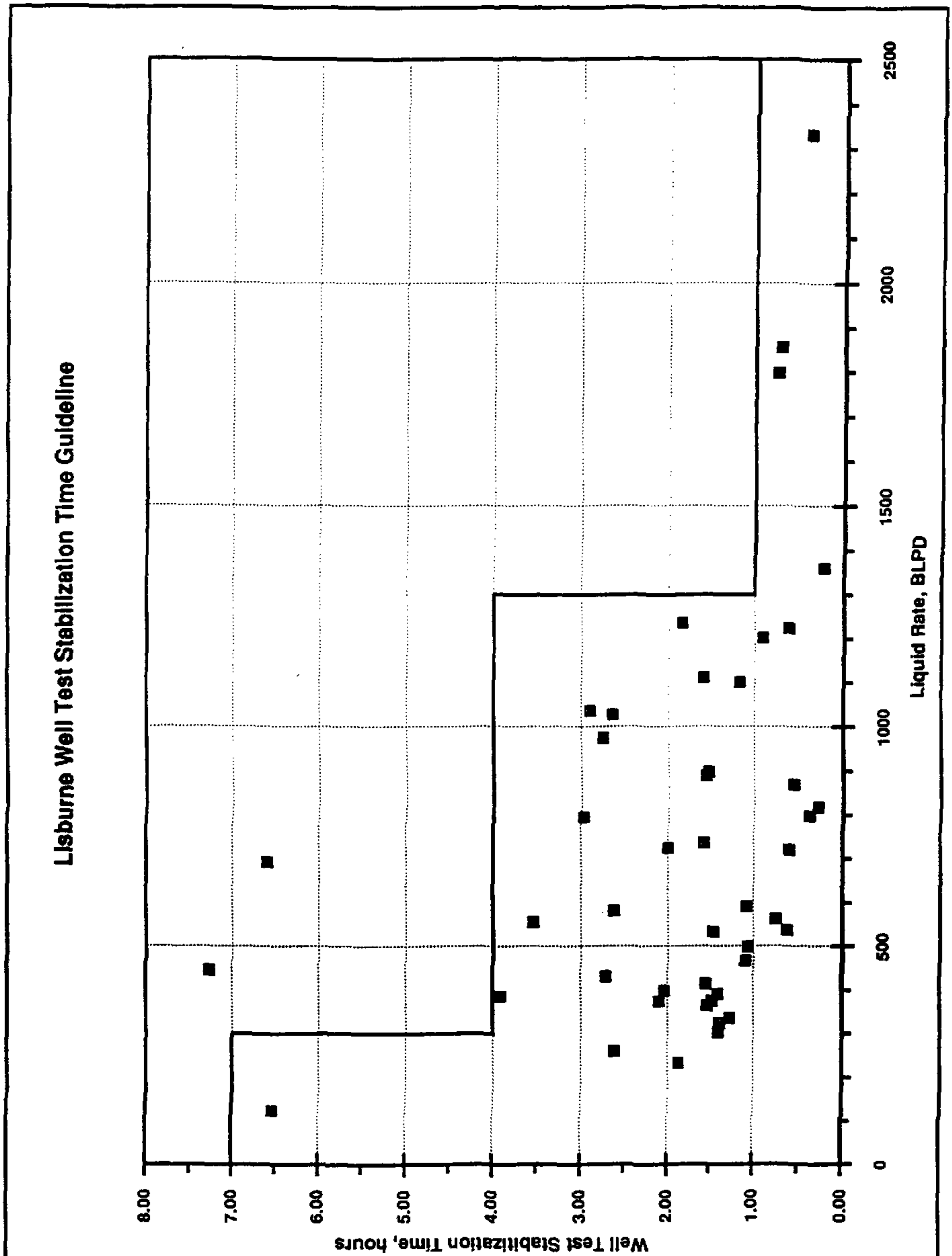
Exhibit 10

Typical Well Test for a Slugging Well



January 13, 1993

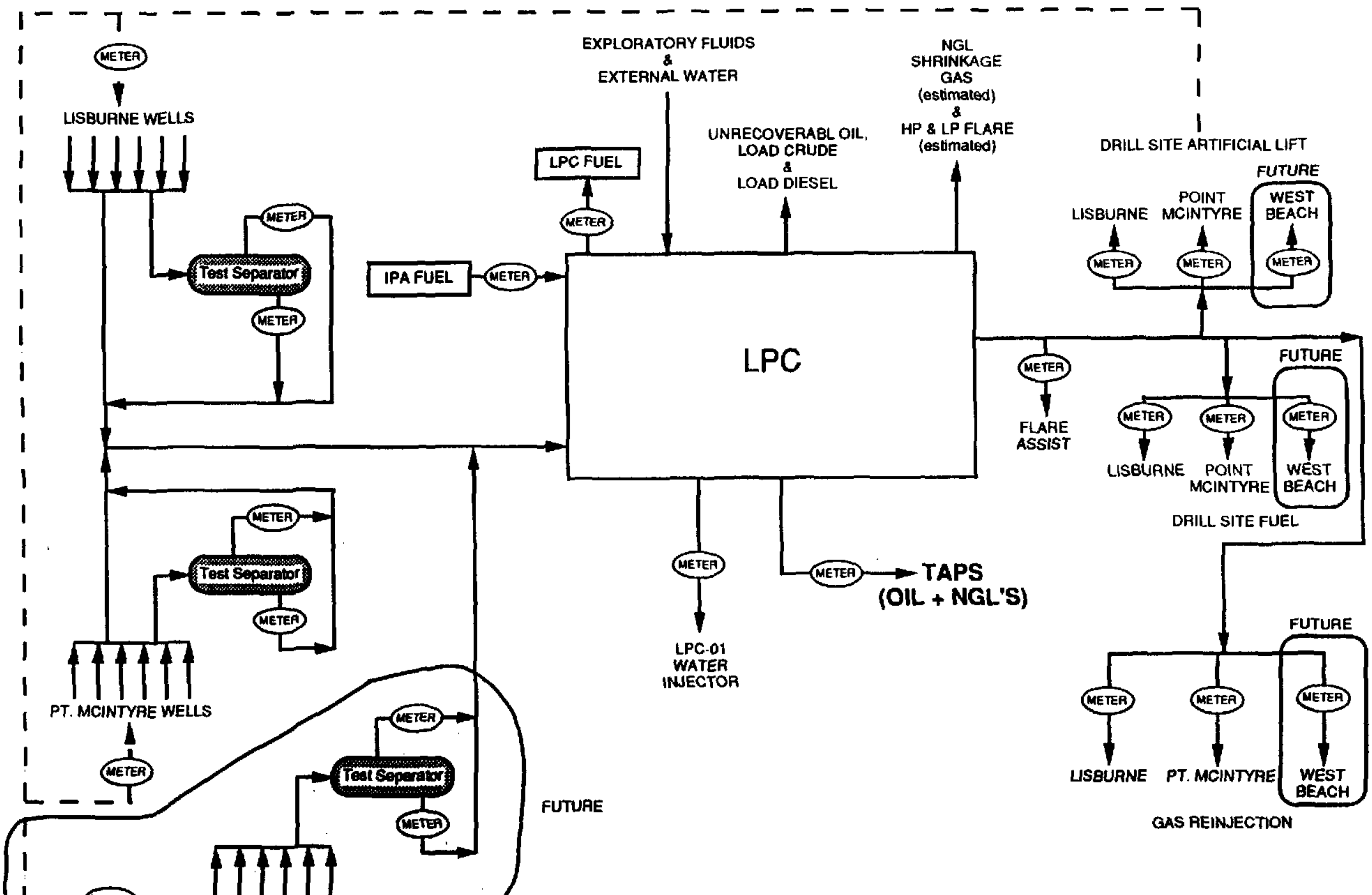
Exhibit 11



January 13, 1993

Exhibit 12

LISBURNE, POINT MCINTYRE AND WEST BEACH CRITICAL METERING DIAGRAM



January 13, 1993

Exhibit 13

Allocation Factor Calculations

$$\text{Allocation Factor} = \frac{\text{Actual Produced Volume}}{\text{Theoretical Volume } (\Sigma \text{ Well Tests})}$$

$$\text{Oil Factor} = \frac{\begin{array}{c}\text{TAPS Volume} - \text{NGL Volume} - \text{TAPS BS\&W} - \\ \text{Exploratory Fluids} + \text{Unrecoverable Oil} - \\ \text{Load Crude/Diesel} \pm \text{Slop Oil Tank Movement}\end{array}}{\Sigma \text{ Well Test Oil Rates}}$$

$$\text{Water Factor} = \frac{\begin{array}{c}\textit{Injected Water Volume} - \textit{External Water} + \\ \text{TAPS BS\&W} \pm \text{Slop Oil Tank Movement}\end{array}}{\Sigma \text{ Well Test Water Rates}}$$

$$\text{Gas Factor} = \frac{\begin{array}{c}\text{LPC Fuel} + \text{Injected Gas} + \text{DS Fuel} - \\ \text{DS Lift Gas Usage} + \text{NGL Shrinkage} + \\ \text{Flare Assist} + \text{Flare (est)} - \text{PBU Fuel}\end{array}}{\Sigma \text{ Wells Test Gas Rates}}$$

January 13, 1993

Exhibit 14

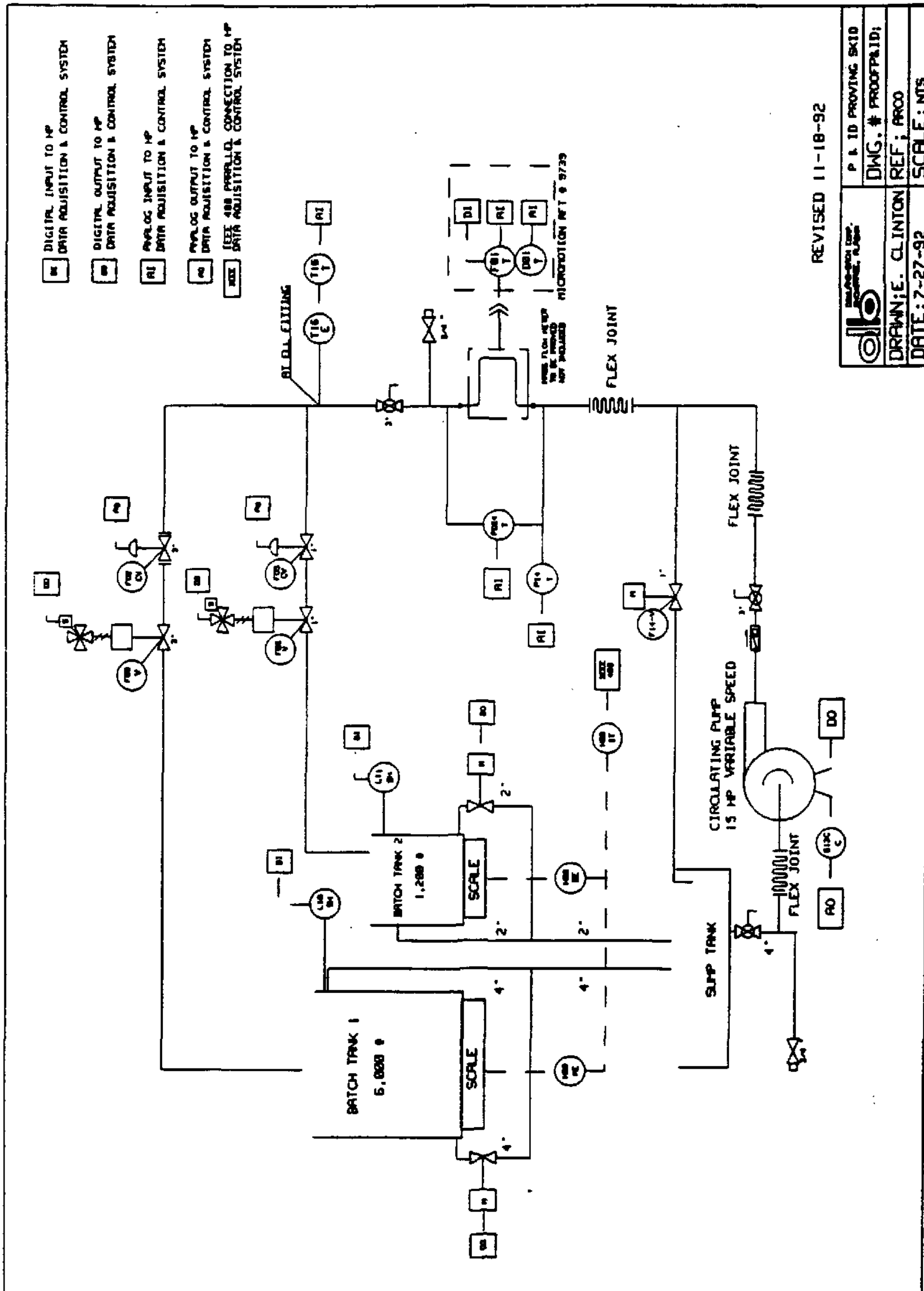


Exhibit 15

January 13, 1993

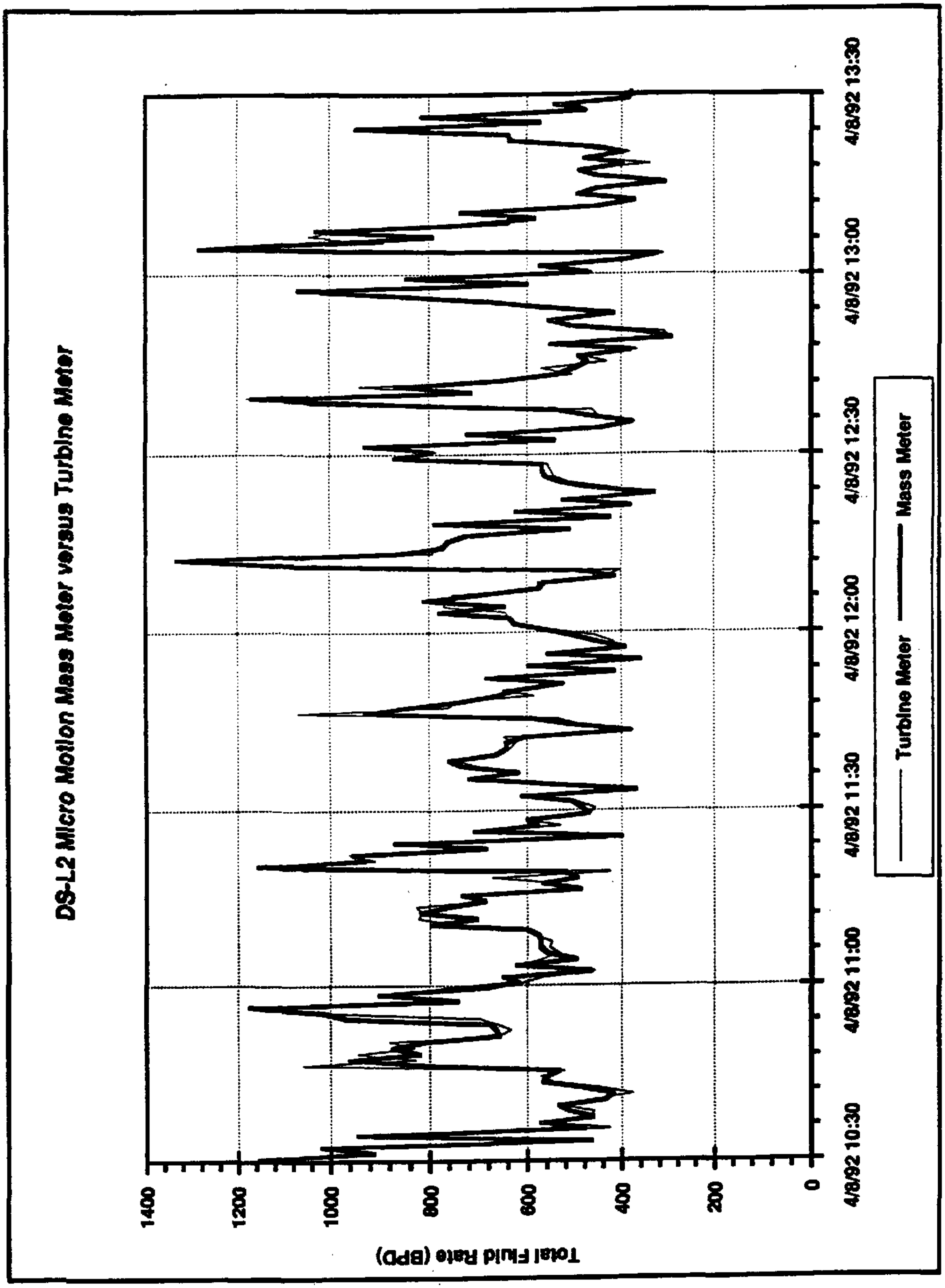
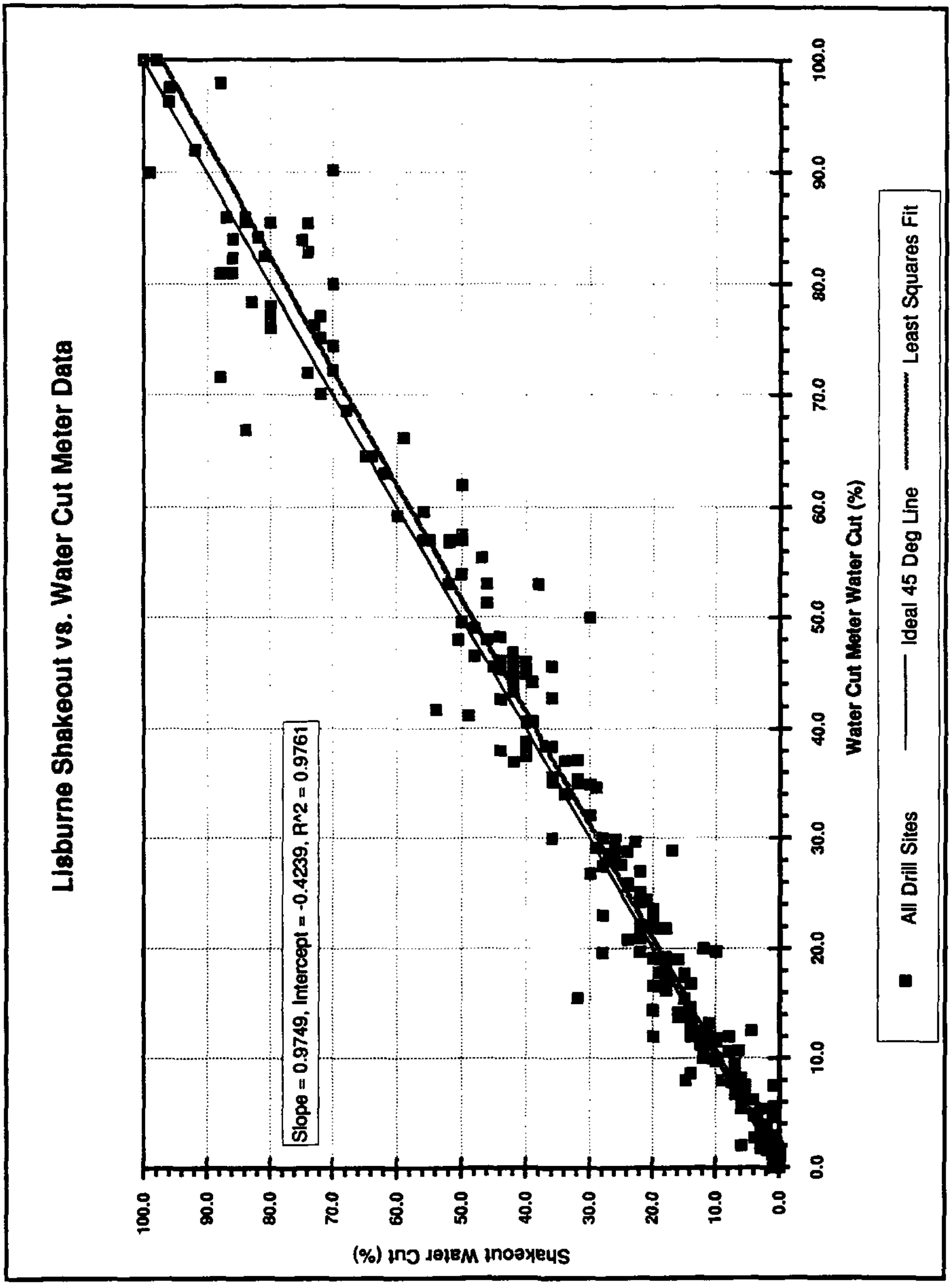

DS-L2 Micro Motion Mass Meter versus Turbine Meter
Total Fluid Rate (BPD)
1400
1200
1000
800
600
400
200
0
4/8/92 10:30
4/8/92 11:00
4/8/92 11:30
4/8/92 12:00
4/8/92 12:30
4/8/92 13:00
4/8/92 13:30
Turbine Meter
Mass Meter

Exhibit 16



LAST UPDATE: 11/9/92

Exhibit 17

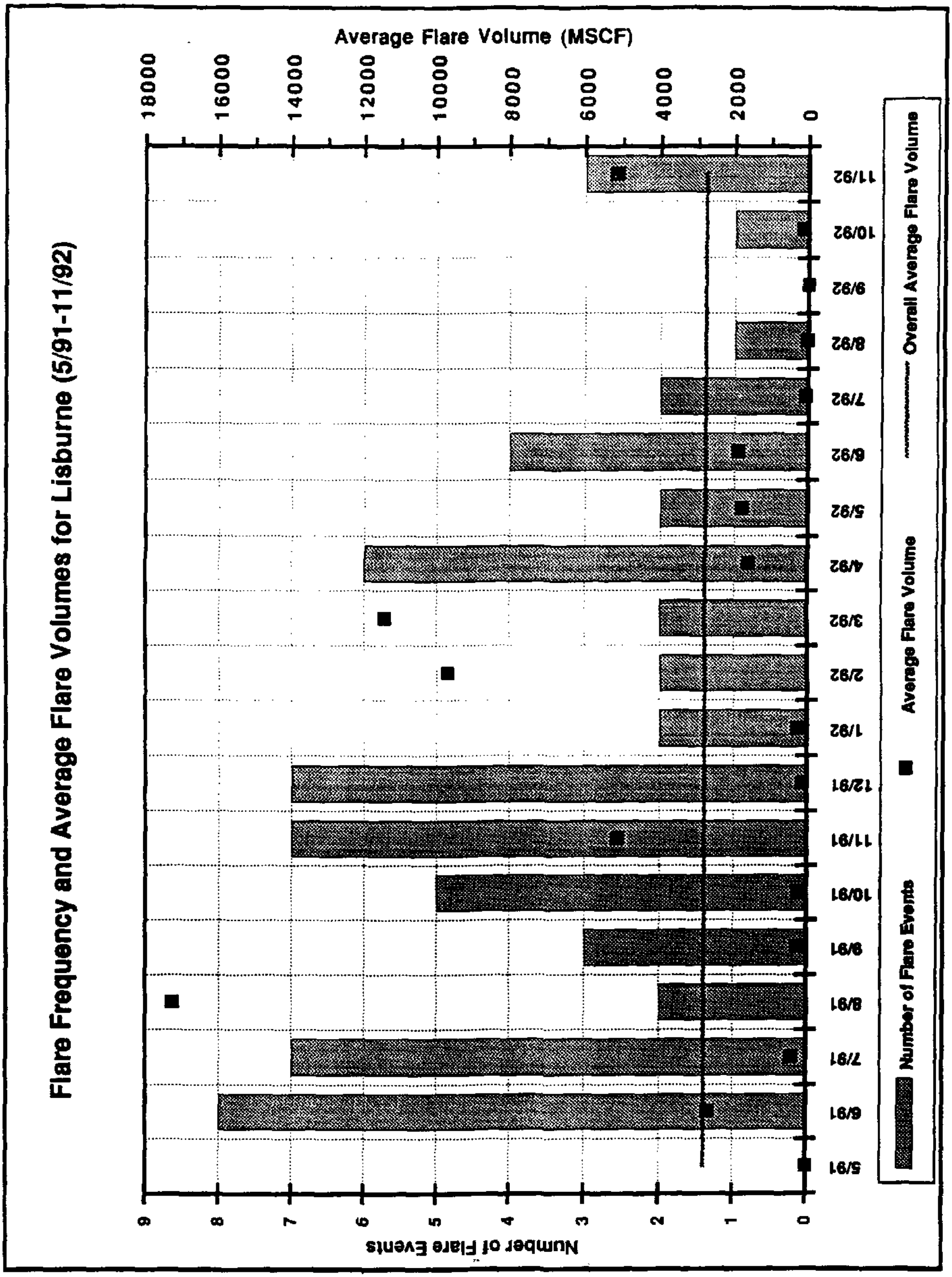

Flare Frequency and Average Flare Volumes for Lisburne (5/91-11/92)
Average Flare Volume (MSCF)
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
Number of Flare Events
9
8
7
6
5
4
3
2
1
0
5/91
6/91
7/91
8/91
9/91
10/91
11/91
12/91
1/92
2/92
3/92
4/92
5/92
6/92
7/92
8/92
9/92
10/92
11/92
Number of Flare Events
Average Flare Volume
Overall Average Flare Volume

Exhibit 18

Total Flare Volumes and Total Flare Volume As A Percent of Total Produced Gas for Lisburne (5/91 - 11/92)

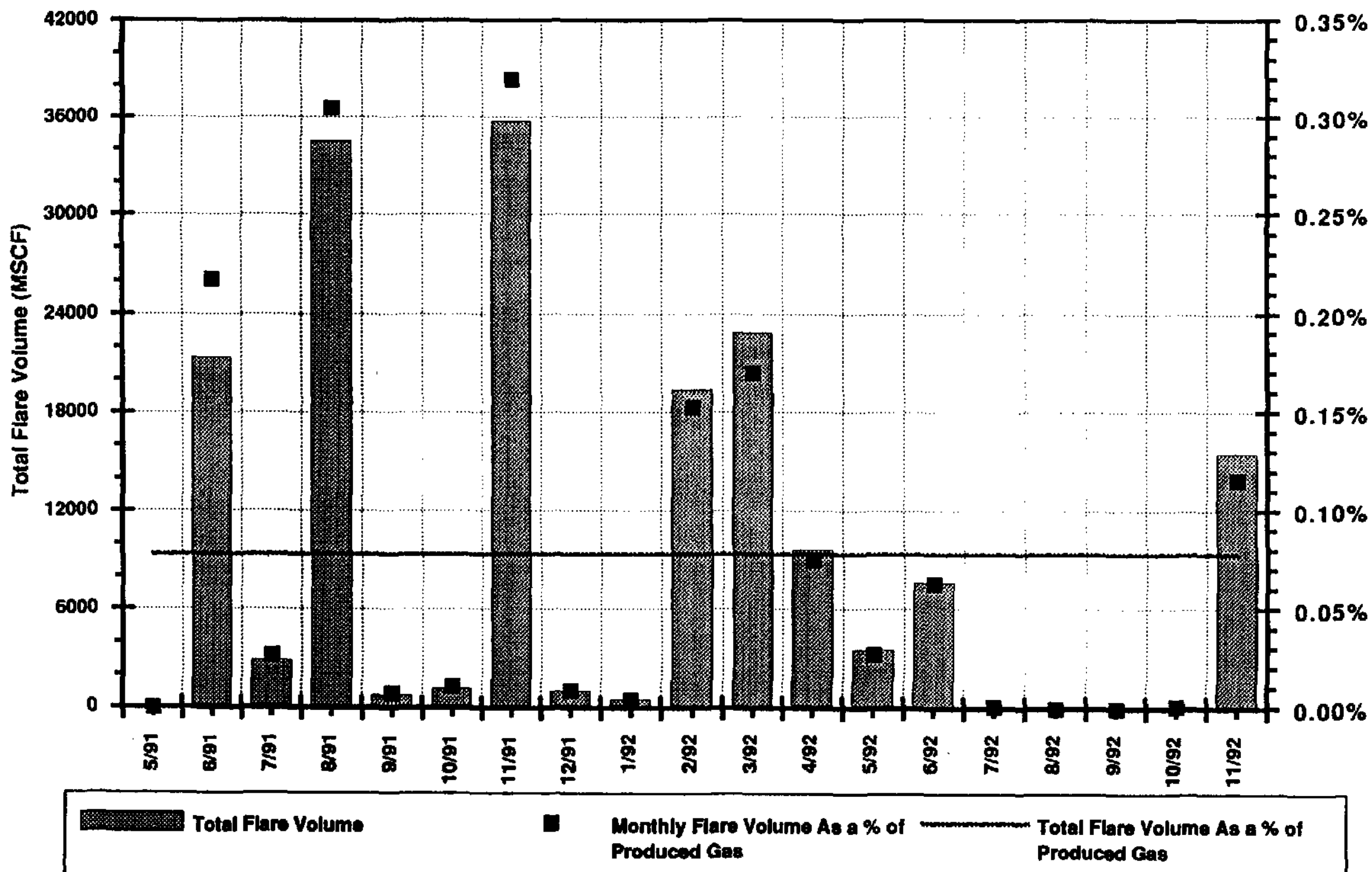
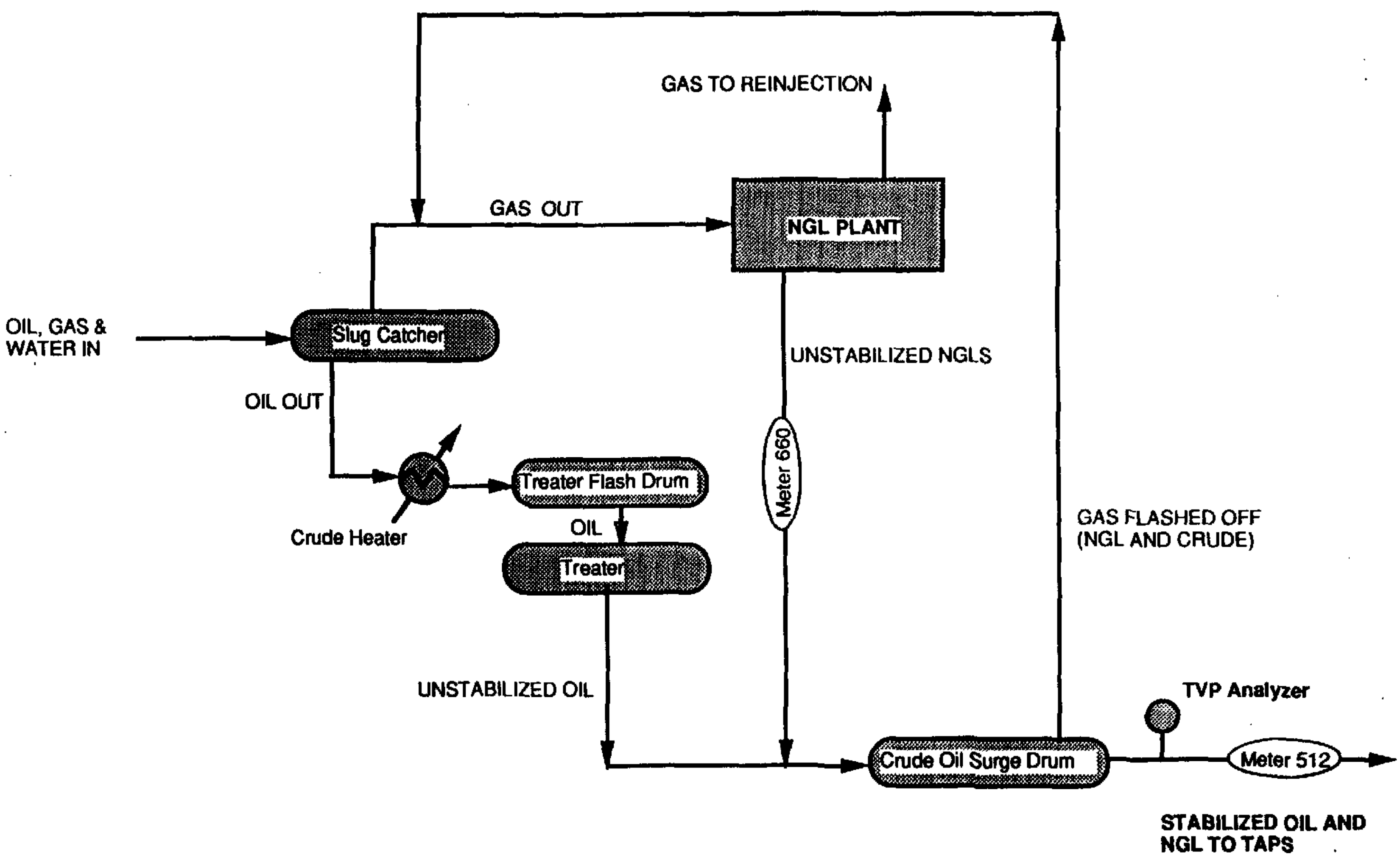


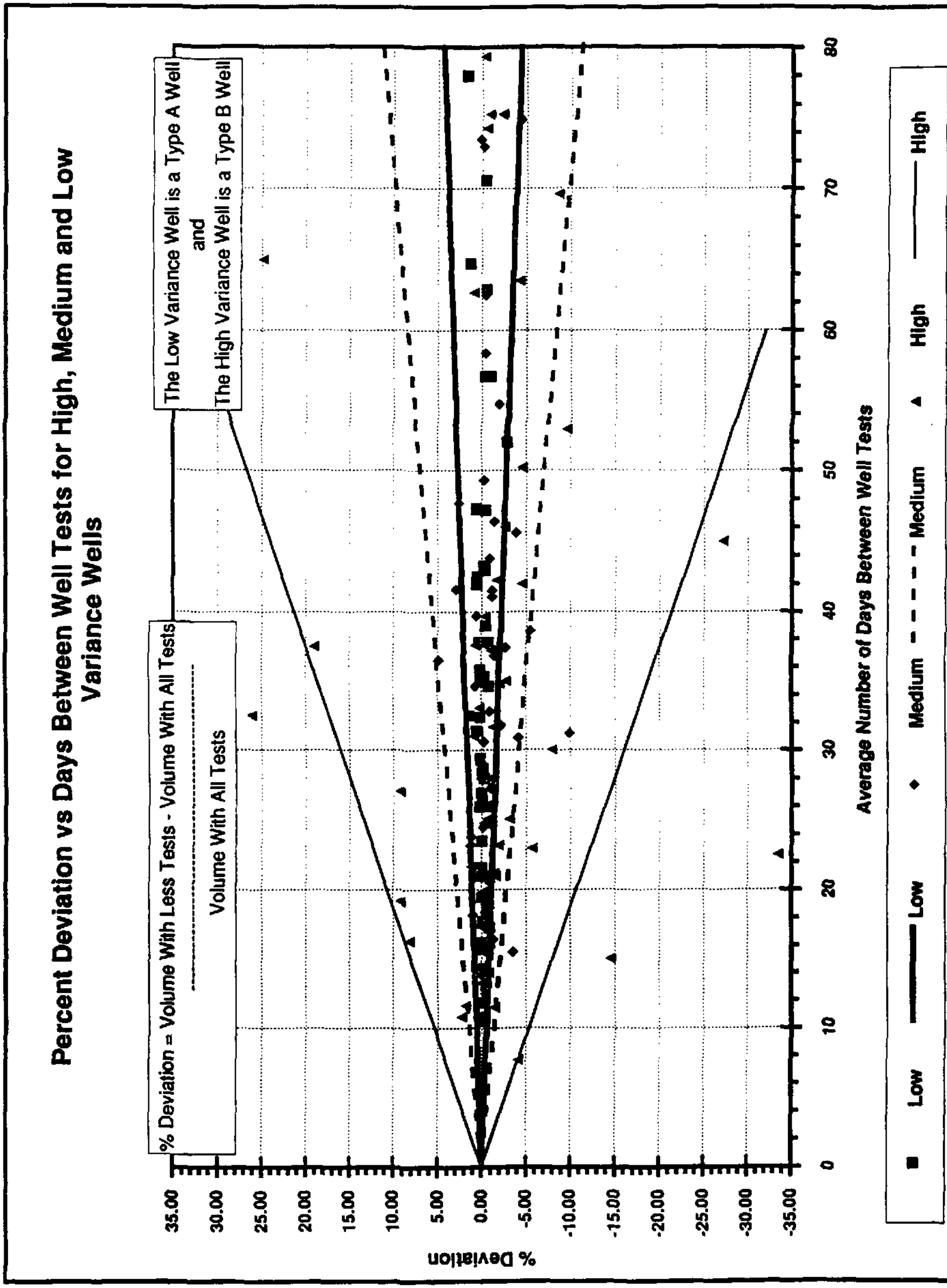
Exhibit 19

LPC NGL PLANT
SIMPLIFIED FLOW DIAGRAM



January 13, 1993

Exhibit 20



January 13, 1993

Exhibit 21