PRUDHOE BAY UNIT

APPLICATION FOR THE
FORMATION OF THE WEST BEACH
PARTICIPATING AREA

DECISION AND FINDINGS OF THE COMMISSIONER
ALASKA DEPARTMENT OF NATURAL RESOURCES

April 2, 1993

PRUDHOE BAY UNIT

# FORMATION OF THE WEST BEACH PARTICIPATING AREA

## I. INTRODUCTION AND BACKGROUND

The Prudhoe Bay Unit was approved by the Alaska Department of Natural Resources on June 2, 1977. Currently, the Prudhoe Bay Unit contains 104 leases encompassing approximately 233,419 acres.

The initial Participating Areas, the Oil Rim and Gas Cap Participating Areas, consist of the leases and portions of leases within the Prudhoe Bay Unit that have been determined to be capable of producing or contributing to production of hydrocarbons from the Prudhoe Bay (Permo-Triassic) Reservoir in paying quantities. Only leases that are either partially or wholly included within the Oil Rim and Gas Cap Participating Areas can have hydrocarbon production from the Prudhoe Bay (Permo-Triassic) Reservoir allocated to them.

The two initial Participating Areas were approved simultaneously with the approval of the Prudhoe Bay Unit Agreement on June 2, 1977. Currently, the initial Participating Areas contain all or parts of 92 leases totaling approximately 213,546 acres.

A third participating area within the Prudhoe Bay Unit, the Lisburne Participating Area, was approved by the Department of Natural Resources on December 4, 1986, effective retroactive to December 1, 1986. Production commenced from the Lisburne Reservoir in the Lisburne Participating Area on December 15, 1986. Currently, the Lisburne Participating Area contains all or parts of 38 leases totaling approximately 80,039 acres.

## II. APPLICATION FOR THE FORMATION OF THE WEST BEACH PARTICIPATING AREA

On November 20, 1992, ARCO Alaska, Inc. (ARCO), on behalf of itself and the Exxon Corporation (Exxon) applied to form the West Beach Participating Area within the existing boundaries of the Prudhoe Bay Unit. Initially, the applicants proposed that the West Beach Participating Area encompass a producing reservoir (the "West Beach Reservoir") within the Kuparuk Formation and any other producing reservoir from the surface to the base of the Kuparuk Formation which may be discovered within the boundaries of the proposed West Beach Participating Area. In correspondence dated March 1, 1993, ARCO and Exxon agreed to limit the proposed participating area to the Kuparuk Formation as referenced on Attachment 4, the West Beach #4 Type Log, of the West Beach Participating Area Application.

The leases proposed for inclusion in the West Beach Participating Area along with the proposed tract allocation schedule for the leases are listed in Attachment 1. All of the leases proposed for inclusion in the West Beach Participating Area were issued on State of Alaska lease form DL-1 which reserves a 12.5% royalty share to the state.

The application included a proposed plan of development and operations for the participating area, confidential geological and geophysical data in support of the proposed participating area, a proposed well test allocation methodology for allocating production between the Lisburne Reservoir and the West Beach Reservoir through the shared Lisburne Production Center, a copy of the West Beach Special Provisions to the Prudhoe Bay Unit Operating Agreement, a copy of the Third Amendment to the Lisburne Special Supplemental Provisions to the Prudhoe Bay Unit Operating Agreement, and proposed methods for reporting the allocated production and gas reserve/gas debits from each participating area.

The requested effective date for the West Beach Participating Area is February 22, 1993.

## III. GEOLOGICAL AND ENGINEERING CHARACTERISTICS, AND PREVIOUS EXPLORATION OF THE PROPOSED PARTICIPATING AREA

The entire area proposed for the West Beach Participating Area is already included within the boundaries of the Prudhoe Bay Unit Area. The West Beach oil accumulation overlies both the Prudhoe Bay and Lisburne oil pools, and in relative terms, it is a very small oil and gas accumulation.

Attachments to the participating area application which were submitted provide geological, geophysical, engineering, and well information in support of the applicant's proposed participating area. These data include geologic logs of the West Beach #4 Well, and structure, isopach and hydrocarbon pore foot maps of the Kuparuk Formation within the proposed participating area.

In addition, information submitted by the applicants at the request of the division demonstrate that the West Beach #4 Well in ADL 34628 is capable of production or contributing to production in paying quantities pursuant to 11 AAC 83.361.

A West Beach Field Rules hearing was held at the Alaska Oil and Gas Conservation Commission on January 13, 1993. Geology, descriptive reservoir data, development and production plans as well as a proposed methodology for allocating production between the West Beach and Lisburne Participating Areas through the shared Lisburne production facilities were presented at the hearing by ARCO, the West Beach Operator.

Finally, the data from wells adjacent to the proposed participating area were available to division staff for review. These wells were Gull Island State #1, Gull Island #3, West Beach State #1, and West Beach State #2.

## IV. DISCUSSION OF THE PARTICIPATING AREA DECISION CRITERIA

11 AAC 83.351(a) provides that, upon formation, a participating area 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" is defined by 11 AAC 83.395(4) to mean:

> 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.

An application for approval of a participating area must be evaluated under these standards, as well as those of 11 AAC 83.303.

Under 11 AAC 83.303, the commissioner of the Department of Natural Resources will approve a proposed participating area if the commissioner finds that the participating area is necessary or advisable to protect the public interest. To find that a proposed participating area is necessary or advisable to protect the public interest, the commissioner must find that the proposed participating area will: (1) promote the conservation of all natural resources; (2) promote the prevention of economic and physical waste; and (3) provide for the protection of 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(s) proposed for inclusion in the participating area; (3) prior exploration activities in the proposed participating area; (4) the applicant's plans for exploration or development of the proposed participating area; (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. These criteria as they relate to the evaluation of the proposed West Beach Participating are discussed below.

### (A) Promote the Conservation of Natural Resources.

The formation of oil and gas units and participating areas within unit areas to develop hydrocarbon-bearing reservoirs is a well accepted means of hydrocarbon conservation. A single participating area encompassing that portion of the Kuparuk Formation capable of producing or contributing to the production of hydrocarbons in paying quantities will provide for more efficient, integrated development of the West Beach Reservoir. Adoption of a comprehensive operating agreement and plan of development governing that production will help avoid unnecessary duplication of development efforts on and beneath the surface.

Furthermore, producing hydrocarbon liquids from a new participating area through the existing production and processing facilities, specifically, the Lisburne Production Center, reduces the environmental impact of the additional production. Utilizing the existing facilities, gravel pads, and infrastructure eliminates the need for additional processing facilities. Formation of the West Beach Participating Area provides the most practical method for maximizing oil and gas recovery, while at the same time minimizing negative impacts on other resources.

(B) The Prevention of Economic and Physical Waste.

Formation of the West Beach Participating Area provides for the equitable division of costs and an equitable allocation of hydrocarbon shares, and sets forth a diligent development plan which maximizes physical and economic recovery from the Kuparuk Formation. The formation of the participating area and utilization of facility sharing opportunities provides a means through which a small, economically marginal hydrocarbon accumulation can be developed.

Available infrastructure and excess fluid processing capacity at the Lisburne Production Center will be utilized to eliminate the necessity for construction of stand-alone facilities to process the relatively small volume of oil in the West Beach Participating Area. The applicants have represented that the West Beach Reservoir could not have been developed as a stand-alone project, claiming that for West Beach development, facility sharing was economically necessary.

Further, facility consolidation will save capital, and promote better reservoir management through pressure maintenance and enhanced recovery procedures. In combination, these factors allow the smaller hydrocarbon accumulation, the West Beach Reservoir, to be developed and produced in the interest of all parties, including the state.

(C) The Protection of All Parties in Interest, Including the State.

One aim in forming separate participating areas within approved oil and gas units is protecting the economic interests of all working interest owners of the reservoir(s) forming the participating area, as well as the royalty owner. By combining their interests and operating under the terms of the Unit Agreement and Unit Operating Agreement, as amended to take into account special provisions for the West Beach Participating Area, each individual West Beach working interest owner is assured an equitable allocation of costs and revenues commensurate with the value of its lease(s).

The state's economic interest is furthered by the maximization of hydrocarbon recovery under the leases of the West Beach Participating Area and by the receipt of additional production-based revenue derived from that production. However, additional recovery of hydrocarbons in and of itself, may not always be determinative of the state's best interest. That production must occur under suitable terms and conditions to assume that the economic interests of both the working interest owners and the state are protected. Moreover, although not necessary here, there may be instances where special provisions or amendments to an existing unit agreement or oil and gas lease may be necessary to protect the state's interest. In particular, special provisions or 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, but 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.

To protect the interests of all parties, a production allocation methodology has been established to allocate production between the reservoirs that produce through the Lisburne Production Center. This methodology is designed to accurately and fairly allocate production. It is susceptible to revision if it is determined that those goals are not being met. Also, a gas disposition/reserves volume accounting procedure has been established to account for and to track the gas that is either produced, used, sold, and/or reinjected.

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

(1) <u>The Environmental Costs and Benefits</u>

The sharing of the existing Lisburne production facilities by the Lisburne and West Beach Participating Areas eliminates duplication of surface activities and results in significant reductions in the amount of surface area altered by oil and gas development. The development of the West Beach Reservoir will not significantly alter the existing gravel pads, roads or surface facilities, and no significant additional impacts to nearshore habitat or biological resources will occur because of the additional production.

(2) <u>The Geological and Engineering Characteristics of the Reservoir.</u>

As previously stated, 11 AAC 83.351(a) provides that, upon formation, a participating area 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.

In its January 13, 1993 letter to ARCO in response to the West Beach Participating Area Application and the geological information submitted with the application, the division expressed concern that portions of the proposed participating area did not meet the criteria set forth in 11 AAC 83.351(a). On March 1, 1993, Division of Oil and Gas staff met with technical representatives from ARCO to examine and discuss the geophysical and geological data that define the estimated, productive limits of the West Beach Reservoir. Of primary interest during the meeting was delineating the known and estimated productive limits of the Kuparuk Formation underlying ADL 34626 (Tract 5) and ADL 34629 (Tract 30). Available information already supported the determination that the other tracts proposed for the participating area were appropriate for inclusion into the West Beach Participating Area at this time.

As a result of the March 1st meeting, the division determined that the data reasonably support the inclusion of ADL 34629 (Tract 30) into the proposed West Beach Participating Area, but that the data do not support the inclusion of ADL 34626 (Tract 5) at this time. The data demonstrate the following in support of this determination:

1) The position of the Pt. McIntyre fault, as depicted in the various attachments to the West Beach Participating Area Application, is reasonably mapped using 3-D seismic;

2) West Beach #3B, West Beach #4, Gull Island #1, and Gull Island #3 are four relatively close, but very different Kuparuk penetrations that present evidence of the rapid changes in reservoir quality that are possible over very short distances within the Kuparuk interval;

3) Reasonably estimating reservoir rock quality in ADL 34626 and ADL 34629 sufficient to produce or contribute to production in paying quantities is difficult because of the rapid and unpredictable facies changes in the Kuparuk interval;

4) Some reservoir quality sands are likely to exist within the Kuparuk interval beneath ADL 34629 based on the four earlier well penetrations (West Beach #3B, West Beach #4, Gull Island #1, and Gull Island #3) in the vicinity. Detailed structural mapping of the Kuparuk indicates that these potentially productive reservoir sands are likely to be structurally high enough to be above the lowest demonstrated oil at West Beach #4 in the mapped wedge of Kuparuk beneath ADL 34629;

5) Based upon the available well data and structural mapping, it is unclear whether potential reservoir sands exist at a structurally high enough position to be productive beneath the southwest corner of ADL 34626.

In summary, absent a well penetration in or nearer the acreage encompassed by ADL 34626, the data do not support inclusion of this acreage.

(3) <u>Prior Exploration and Development Activities in the Proposed Area.</u>

To date, two wells have penetrated the West Beach Reservoir in the proposed participating area, West Beach State #3 (3B) and West Beach #4. The West Beach #3 Well in ADL 34627 was certified as capable of production in paying quantities in February 1977. In addition, four wells have been drilled near or adjacent to the proposed area, West Beach State #1, West Beach State #2, Gull Island State #1, and Gull Island State #3.

(4) The applicant's plans for exploration or development of the participating area.

The ultimate development plan for the West Beach Reservoir is uncertain at this time because of the wide range of possible original oil in place values. The estimated values range from 12 to 65 million barrels. At present, the development options envisioned range from a single production well, the West Beach #4, with no reinjection of the produced gas to eleven wells consisting of additional oil producers, water injection wells, and a gas injection well.

Based on the reservoir size as estimated from the West Beach #4 production test results, development will follow one of three plans (1) primary depletion without produced gas injection, (2) primary depletion with produced gas injection or (3) waterflood with or without gas injection. Reservoir pressure and production testing of the West Beach #4 Well planned in the next year will determine the development plans for the West Beach Participating Area. Given the current level of uncertainty regarding the reservoir size and performance, the initially proposed plan of development is consistent with prudent reservoir management practices.

(5) 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 outweigh any perceived costs to the state. Were the leases in the proposed West Beach Participating Area not already within the boundary of the Prudhoe Bay Unit, and as a result already subject to the terms of that Unit's 1980 Settlement Agreement effecting field costs for the state's royalty share, this would not necessarily be the case.

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

These factors are discussed in Article V below.

## V. OTHER ISSUES PERTINENT TO THE WEST BEACH PARTICIPATING AREA APPLICATION

In a letter dated January 13, 1993 to ARCO, the division noted a number of concerns related to the West Beach Participating Area application. The issues addressed in that letter were (1) a paying quantities determination for the proposed participating area and West Beach #4 Well; (2) the lands appropriate for inclusion in a participating area pursuant to 11 AAC 83.351, 11 AAC 83.361, and 11 AAC 83.303; (3) gas disposition and gas volume accounting between the Lisburne Participating Area and the proposed West Beach Participating Area; (4) the proposed production allocation methodology; (5) the taking of royalty-in-kind natural gas liquids ("NGLs"); (6)

proposed amendments to the Prudhoe Bay Unit Agreement; and (7) field cost allowances for the state's royalty share of oil, "NGLs", and dry gas.

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.

Finally, for the royalty hydrocarbon liquids produced from the West Beach Participating Area, the division acknowledges ARCO's response of March 11, 1993 that no quality bank adjustments will be incorporated for the West Beach.

## 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 participating area, the West Beach Participating Area, meets the requirements of 11 AAC 83.303.

2. The available geological, geophysical and engineering data submitted demonstrate that a paying quantities certification is appropriate for the wells in the West Beach Reservoir, in particular, for the West Beach #4 Well, and that the acreage is capable of sustained production or contributing to sustained production in sufficient quantities to justify the formation of the West Beach Participating Area within the Prudhoe Bay Unit.

3. The available geological, geophysical and engineering data submitted in support of the participating area justify the inclusion of all of the proposed tracts, except for Tract 5 (ADL 34626), within the West Beach Participating Area at this time. The entire participating area is wholly contained within the boundaries of the current Prudhoe Bay Unit. 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 of Alaska, the following lands are to be included in the West Beach Participating Area:

T.12.N., R.14.E., U.M., Sec. 24: S/2
(ADL 34624 (Tract 7));

T.12.N., R.14.E., U.M., Sec. 25: N/2, SE/4
(ADL 28301 (Tract 28));

T.12.N., R.15.E., U.M., Sec. 19: S/2, Sec.20 S/2
(ADL 34627 (Tract 6));

T.12.N., R.15.E., U.M., Sec. 28: N/2
(ADL 34629 (Tract 30));

T.12.N., R.15.E., U.M., Sec. 29: N/2, Sec. 30 N/2
(ADL 34628 (Tract 29)).

4. With regard to the Tract 5 (ADL 34626) acreage, the available data do not indicate that the acreage is capable of production or contributing to production so as to warrant inclusion in West Beach Participating at this time.

5. The Prudhoe Bay Unit Agreement and the statutes and regulations of the State of Alaska governing oil and gas units provide for further expansions of a participating area 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. Within sixty days of the date of this Decision and Finding, the West Beach Operator shall submit to the state updated exhibits of the approved West Beach Participating Area, the legal descriptions of the tracts within the approved West Beach Participating Area, and the revised West Beach tract participations.

7. The approved participating area encompasses the hydrocarbon bearing portion of the West Beach Reservoir that are determined to be capable of production or contributing to production at this time. Formation of the participating area provides for the equitable division of costs and an equitable allocation of produced hydrocarbons, and sets forth a development plan designed to maximize physical and economic recovery from the Kuparuk Formation within the approved participating area.

8. The production of hydrocarbon liquids from the West Beach Participating Area through the existing production and processing facilities within the Prudhoe Bay Unit reduces the environmental impact of the additional production. Utilization of existing facilities will avoid unnecessary duplication of development efforts on and beneath the surface.

9. Based upon the departments's review of the well test allocation methodology represented to the state in ARCO's March 1, 1993 correspondence, as well as the production allocation testimony given at the Alaska Oil and Gas Conservation Commission's West Beach Field Rules Hearing, that methodology is determined to be acceptable for royalty allocation purposes and for allocating the commingled gas and hydrocarbon liquids production between the West Beach Participating Area and the Lisburne Participating Area as those streams are processed through the Lisburne Production Center (LPC).

   The Lisburne and West Beach Operator 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 commingled production, a summary of monthly allocation by well, and specific well test data for all tests which have been conducted.

10. The Division of Oil and Gas 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.

11. During the first year in which commingled production from the West Beach Participating Area is allocated, quarterly reviews of the allocation methodology will be scheduled with the division. Following its review, the division, in its discretion, may require revision of the allocation procedure. Subsequent reviews may be requested by either the division or the Operator. Revision of the allocation procedure shall only be made with the written consent of, or upon the written direction of, the division.

12. In order to account for the gas produced from each participating area, the gas volume disposition and gas reserves debited from or credited to each participating area utilizing the shared Lisburne production facilities, the Lisburne and West Beach Operator shall submit a monthly gas disposition and reserves debit report using the form indicated in Attachment 2. The gas disposition report shall be submitted with the monthly production allocation reports.

13. The field cost allowance for the state's royalty share of oil produced from the approved West Beach Participating Area is governed by the 1980 Prudhoe Bay Settlement Agreement. Whether or not the state bears any field cost allowance for the state's royalty share of "NGLs" and dry gas, and if so, what those costs may be, are part of the Severed Issues in the <u>ANS Royalty Litigation</u>. These field cost allowances, if any, are subject to the final resolution of this litigation.

14. With respect to the production allocated from the West Beach Participating Area and the state's taking of any royalty-in-kind from the West Beach, 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.

15. Diligent exploration and delineation of the West Beach Reservoir underlying the approved participating area is to be conducted by the Unit Operator under the Prudhoe Bay Unit plans of development and operation approved by the state.

16. The plan of development for the West Beach Participating Area meets the requirements of 11 AAC 83.303 and 11 AAC 83.343. The plan is approved for a period of two years from the effective date of this Decision and Finding. Annual updates to the plan of development which describes the status of projects undertaken and the work completed, as well as any changes or expected changes to the plan, as well as a further plan of development, must be submitted in accordance with 11 AAC 83.343.

17. Approval of the West Beach Participating Area within the Prudhoe Bay Unit is effective 12:01 a.m. February 22, 1993.

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

James E. Eason ______ April 2, 1993

James E. Eason, Director
Division of Oil and Gas

Date

For: Glenn A. Olds, Commissioner
Alaska Department of Natural Resources

Attachments

PBU.WBPA.APPRV.txt

# DELEGATIONS OF AUTHORITY FOR THE DIVISION OF OIL AND GAS

| Regulatory Citation | Purpose or Action | Authority Vested in | Authority Delegated to |
|---|---|---|---|
| 11 AAC 82.400 | Parcels Offered for Competitive Lease | Commissioner | No Delegation |
| 11 AAC 82.405 | Method of Bidding | Commissioner | No Delegation |
| 11 AAC 82.410 | Minimum Bid | Commissioner | No Delegation |
| 11 AAC 82.445 | Incomplete Bids | Commissioner | No Delegation |
| 11 AAC 82.450 | Rejection of Bids | Commissioner | No Delegation |
| 11 AAC 82.455 | Tie Bids | Commissioner | No Delegation |
| 11 AAC 82.460 | Additional Information | Commissioner | No Delegation |
| 11 AAC 82.465 | Award Leases | Commissioner | Director, Div. Oil & Gas (DOG) |
| 11 AAC 82.470 | Issue Leases | Commissioner | Director, DOG |
| 11 AAC 82.475 | Bid Deposit Return | Commissioner | Director, DOG |
| 11 AAC 82.600 | Required Bonds | Commissioner | Director, DOG |
| 11 AAC 82.605 | Approve/Deny Assignments of Oil and Gas Leases | Commissioner | Director, DOG |
| 11 AAC 82.610 | Segregate Leases | Commissioner | Director, DOG |
| 11 AAC 82.620 | Transfer of a Lease, Permit or Interest as a Result of Death | Commissioner | Director, DOG |
| 11 AAC 82.625 | Eff. Date of Assignments | Commissioner | Director, DOG |
| 11 AAC 82.635 | Surrenders | Commissioner | Director, DOG |
| 11 AAC 82.640 | Survey Requirement | Commissioner | No Delegation |
| 11 AAC 82.645 | Conforming Protracted Description to Official Surveys | Commissioner | No Delegation |
| 11 AAC 82.650 | Control of Lease Boundaries | Commissioner | No Delegation |
| 11 AAC 82.660 | Excess Area; Partial Termination | Commissioner | No Delegation |

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|---|---|---|---|
| 11 AAC 82.665 | Rental and Royalty Relief | Commissioner | No Delegation |
| 11 AAC 82.700 | Taking Royalty in Kind | Commissioner | No Delegation |
| 11 AAC 82.705 | Bidding Method | Commissioner | No Delegation |
| 11 AAC 82.710 | Notice of Sale | Commissioner | No Delegation |
| 11 AAC 82.800 | Production Records | Commissioner | Director, DOG |
| 11 AAC 82.805 | Test Results | Commissioner | Director, DOG |
| 11 AAC 83.153 | Well Confidentiality | Commissioner | Director, DOG |
| 11 AAC 83.158 | Approve/Deny Lease Plan of Operations | Commissioner | Director, DOG |
| 11 AAC 83.303 | Unit Agreement Approval | Commissioner | Director, DOG |
| 11 AAC 83.306 | Accept Application for Unit Agreement Approval | Commissioner | Director, DOG |
| 11 AAC 83.311 | Publish Public Notice of Unit Agreement Application | Commissioner | Director, DOG |
| 11 AAC 83.316 | Approve/Deny Unit Agreement | Commissioner | Director, DOG |
| 11 AAC 83.326 | Require or Accept Nonstandard Unit Agreement Language | Commissioner | Director, DOG |
| 11 AAC 83.328 | Mandate Unitization (Involuntary Unitization) | Commissioner | No Delegation |
| 11 AAC 83.331 | Approve/Deny Change in Unit Operator | Commissioner | Director, DOG |
| 11 AAC 83.336 | Grant Extension of Unit Term; Grant Suspension of Operations (Force Majeure); Terminate Unit | Commissioner | No Delegation |
| 11 AAC 83.341 | Approve/Deny Plan of Exploration | Commissioner | Director, DOG |
| 11 AAC 83.343 | Approve/Deny Plan of Development | Commissioner | Director, DOG |
| 11 AAC 83.346 | Approve/Deny Plan of Operations | Commissioner | Director, DOG |
| 11 AAC 83.351 | Approve/Deny Participating Area | Commissioner | Director, DOG |

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|---|---|---|---|
| 11 AAC 83.356 | Expand/Contract Unit Area | Commissioner | Director, DOG |
| 11 AAC 83.361 | Certify Wells as Capable of Production in Paying Quantities | Commissioner | Director, DOG |
| 11 AAC 83.371 | Approve/Deny Allocation of Cost and Production Formulas | Commissioner | Director, DOG |
| 11 AAC 83.373 | Sever Leases | Commissioner | Director, DOG |
| 11 AAC 83.374 | Declare Unit in Default | Commissioner | No Delegation |
| 11 AAC 83.383 | Notation of Approval on Joinder | Commissioner | Director, DOG |
| 11 AAC 83.385 | Modification of Unit Agreement | Commissioner | Director, DOG |
| 11 AAC 83.393 | Approval of Federal or Private Party Unit Agreements | Commissioner | No delegation |

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I hereby delegate the authority vested in me through AS 38.05.180 to the Director of the Division of Oil and Gas as noted above. This delegation of authority is effective until revoked by me.

Glenn A. Olds

Glenn A. Olds, Commissioner
Alaska Department of Natural Resources

Date 6/26/92

ATTACHMENT 1

TRACTS WITHIN THE WEST BEACH PARTICIPATING AREA AND
WEST BEACH TRACT PARTICIPATION

| Tract No. | Description | No. of Acres | ADL Serial No. | Basic Royalty | Lessee of Record | Work Interest Ownership | West Beach Tract Participation % |
|---|---|---|---|---|---|---|---|
| 5 | T12N-R15E, Sec 21 SW/4 | 160 | 34626 | 1/8 | ARCO & Exxon | ARCO - 50% Exxon - 50% | 6.382 |
| 6 | T12N-R15E, Sec 19 S/2<br>Sec 20 S/2 | 293<br>320 | 34627 | 1/8 | ARCO & Exxon | ARCO - 50% Exxon - 50% | 24.452 |
| 7 | T12N-R14E, Sec 24 S/2 | 320 | 34624 | 1/8 | ARCO & Exxon | ARCO - 50% Exxon - 50% | 12.764 |
| 28 | T12N-R14E, Sec 25 N/2<br>SE/4 | 320<br>160 | 28301 | 1/8 | ARCO & Exxon | ARCO - 50% Exxon - 50% | 19.146 |
| 29 | T12N-R15E, Sec 29 N/2<br>Sec 30 N/2 | 320<br>294 | 34628 | 1/8 | ARCO & Exxon | ARCO - 50% Exxon - 50% | 24.492 |
| 30 | T12N-R15E, Sec 28 N/2 | 320 | 34629 | 1/8 | ARCO & Exxon | ARCO - 50% Exxon - 50% | 12.764 |

# 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 2

## 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.

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 ANS Royalty Litigation. All parties agreed that it is inappropriate to address these issues outside of the context of ANS Royalty Litigation. All parties agreed that the resolution reached in the ANS Royalty Litigation 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 |

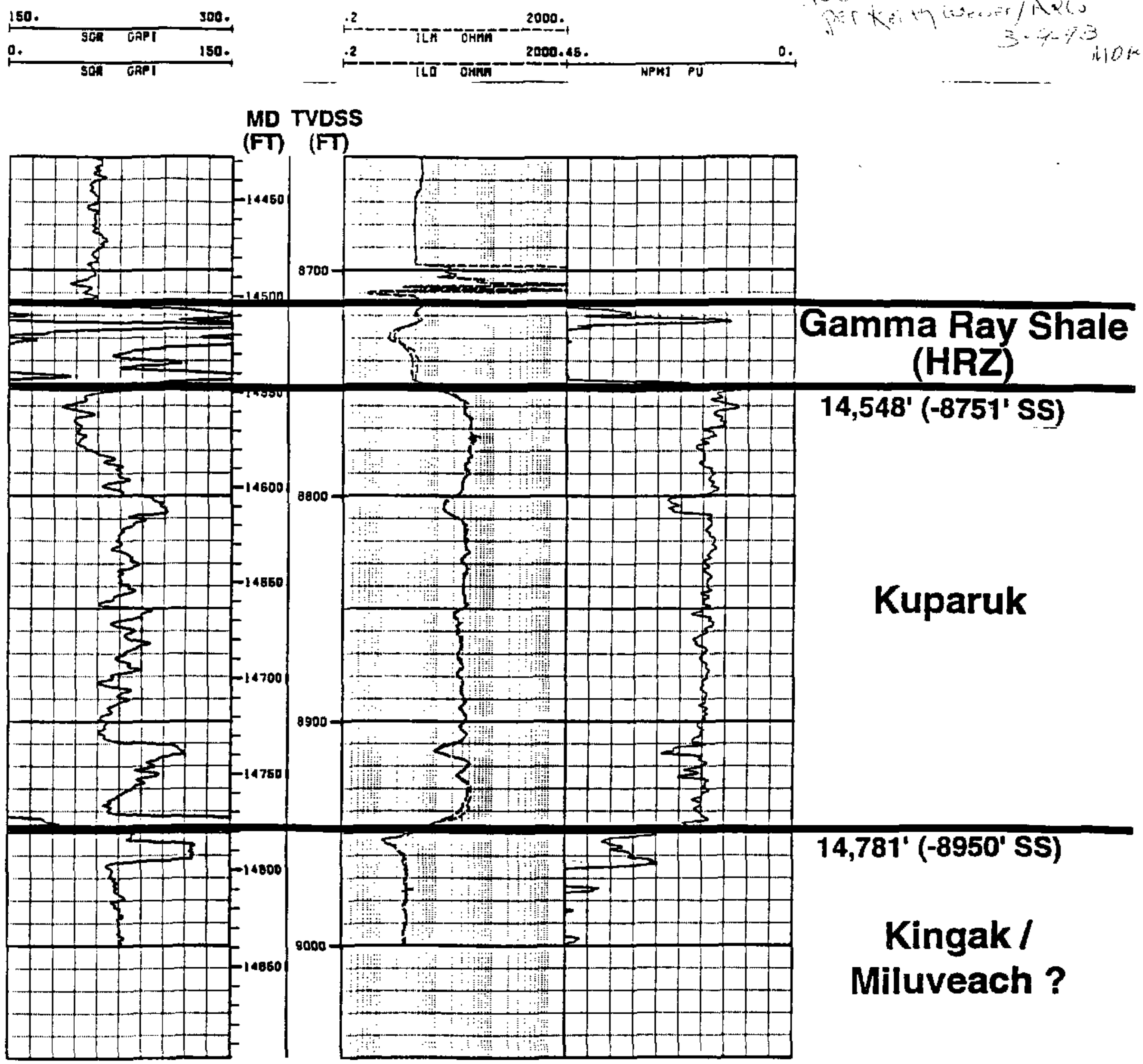
ATTACHMENT 4

From November 20, 1992
West Beach PA Applicat

~~CONFIDENTIAL~~

Not Confidential
per Kelly Weaver/ARCO
3-4-93
MDK

# 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.

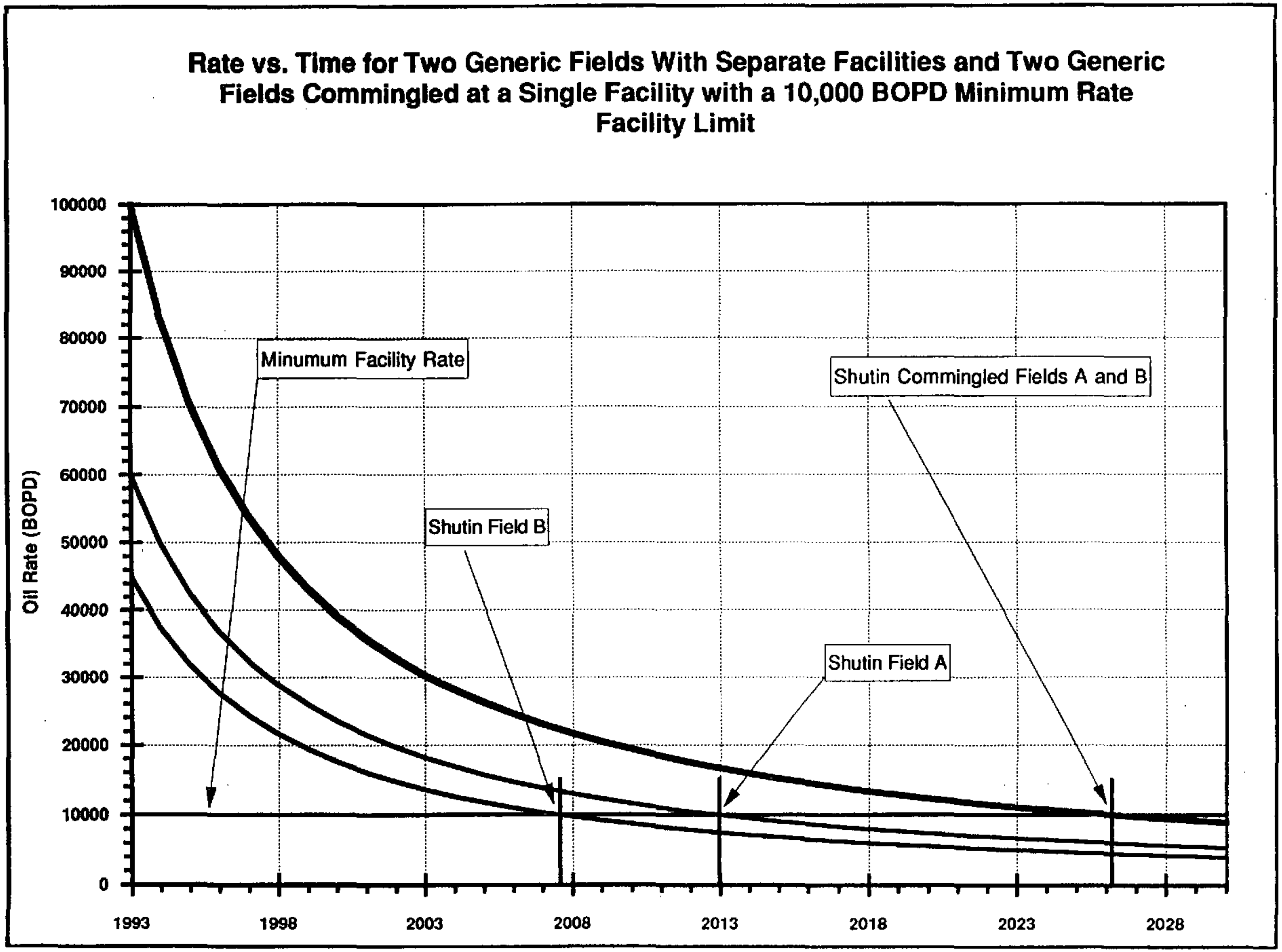
10. The Operator's allocation activities will be reviewed on a periodic basis.

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.

Exhibit VI-25




January 13, 1993

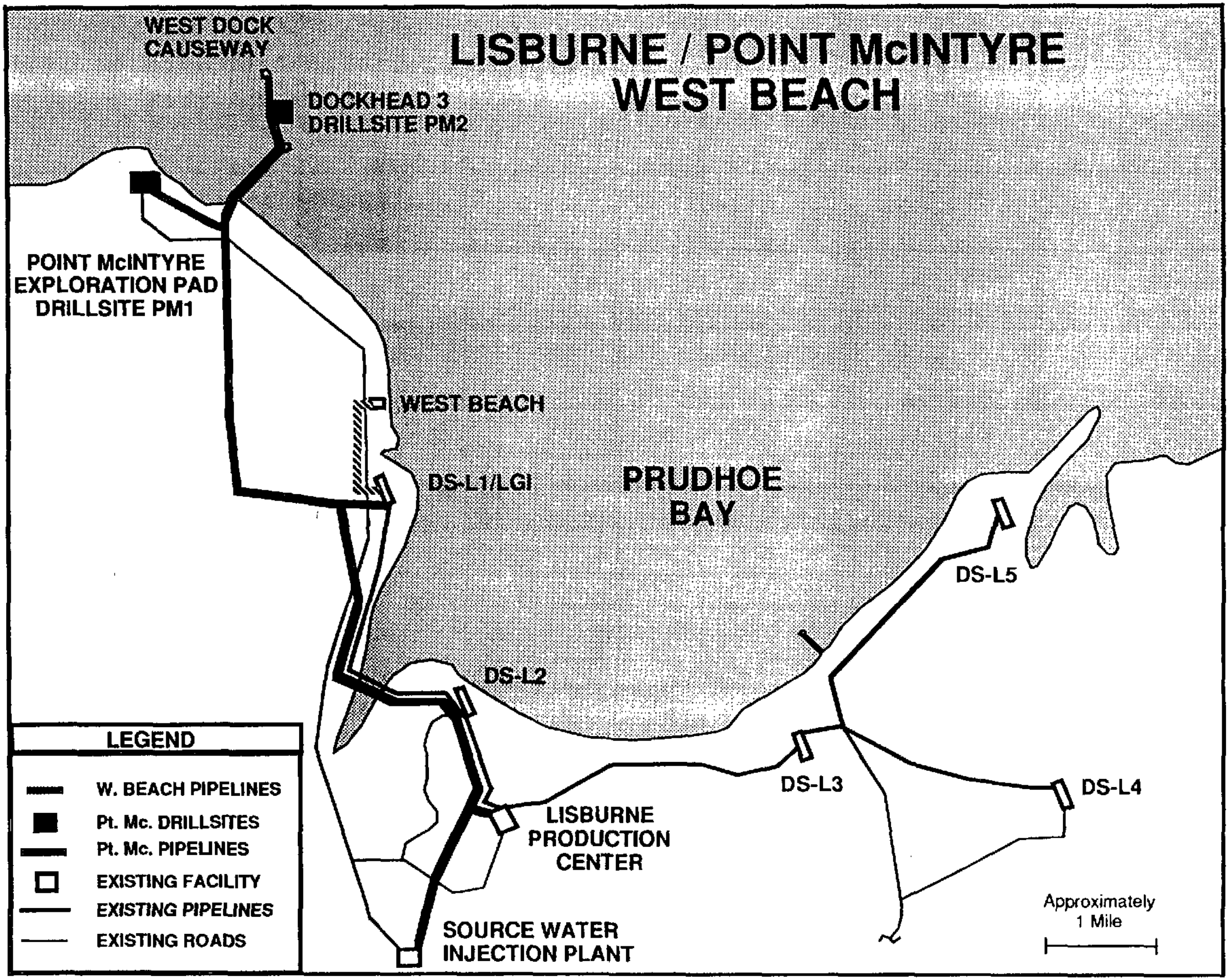



Exhibit VI-26

January 13, 1993

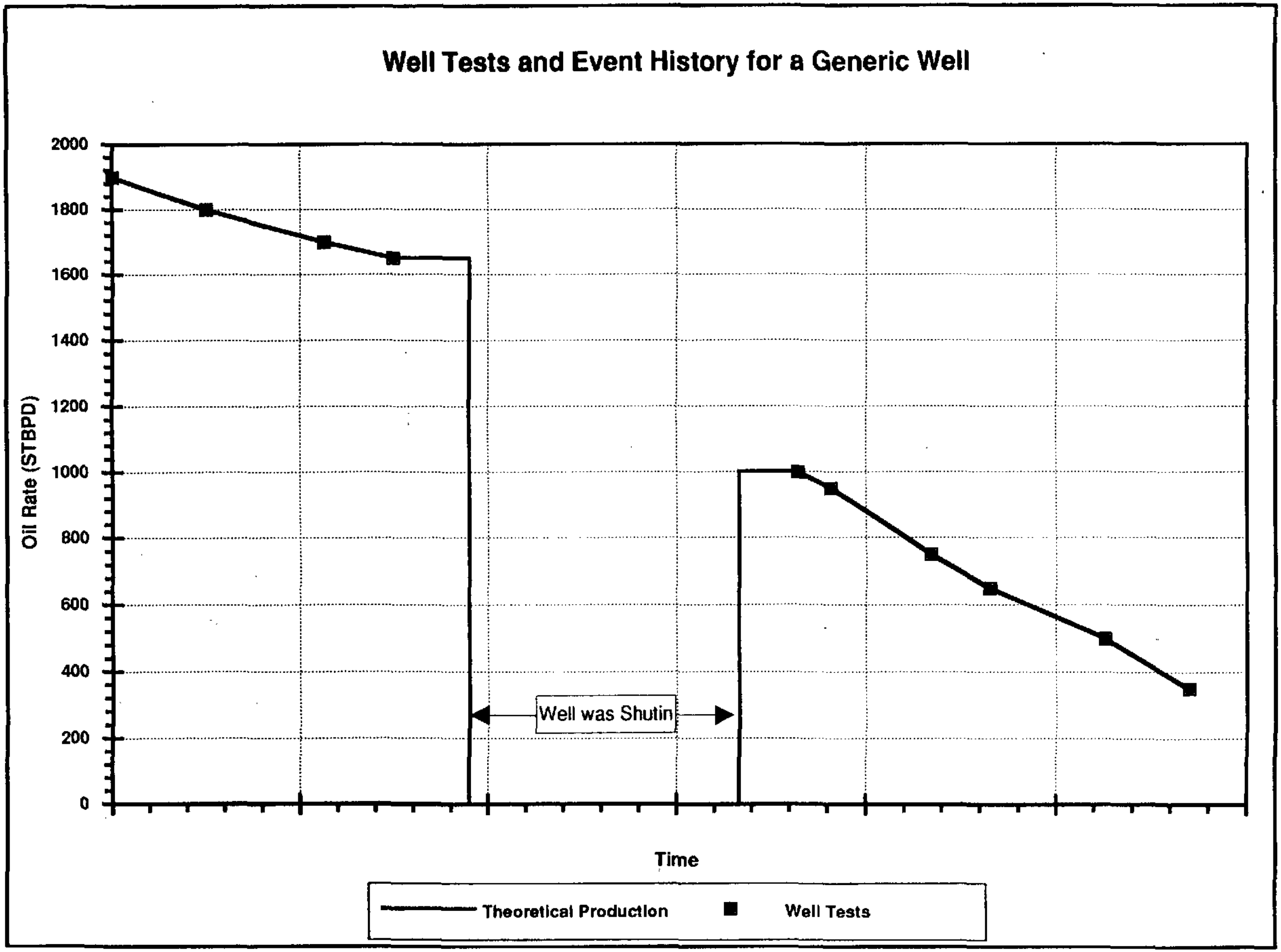



Exhibit VI-27

# Allocation Factor Calculations

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

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

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

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

# 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.**

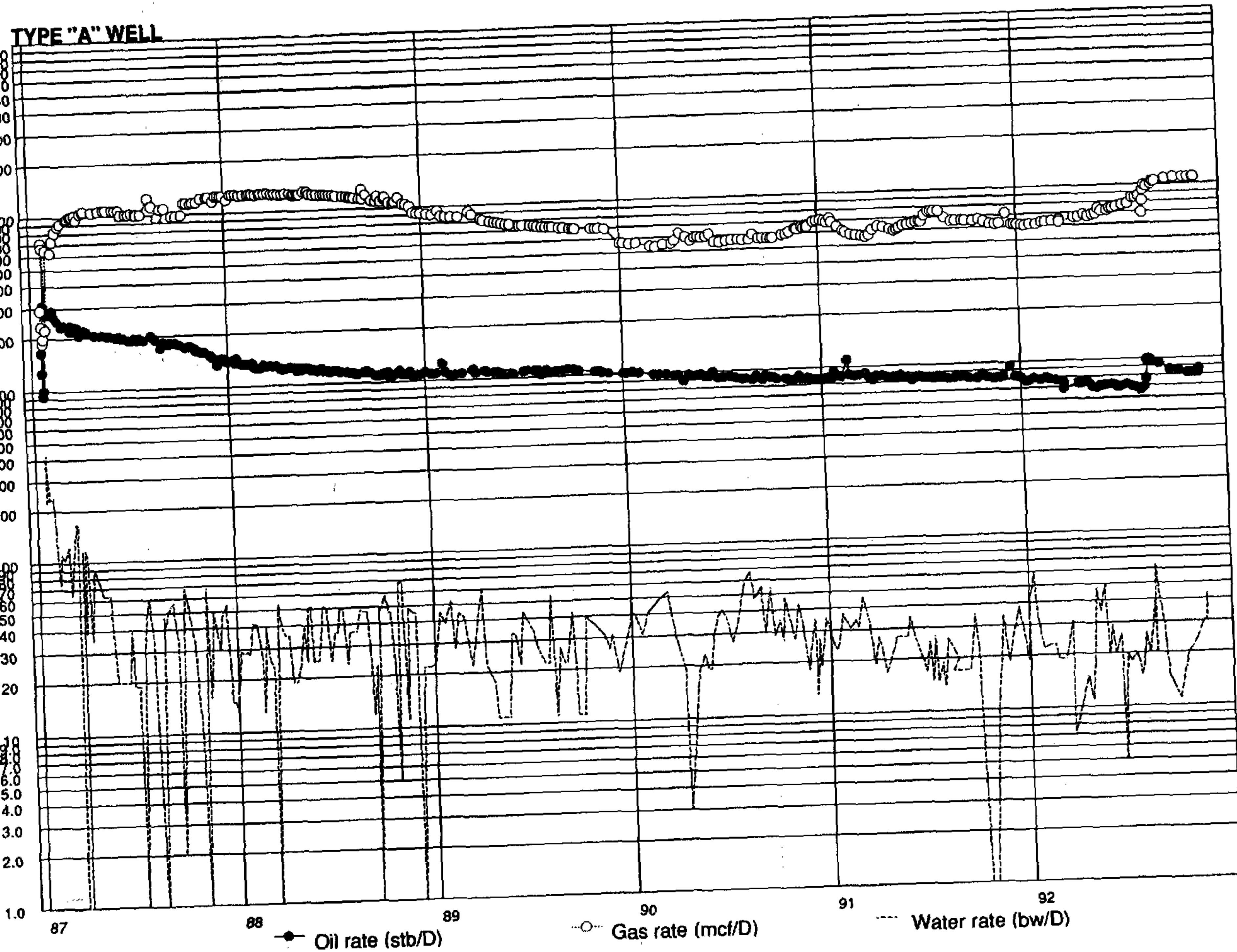



Exhibit VI-30

January 13, 1993

**TYPE "B" WELL**

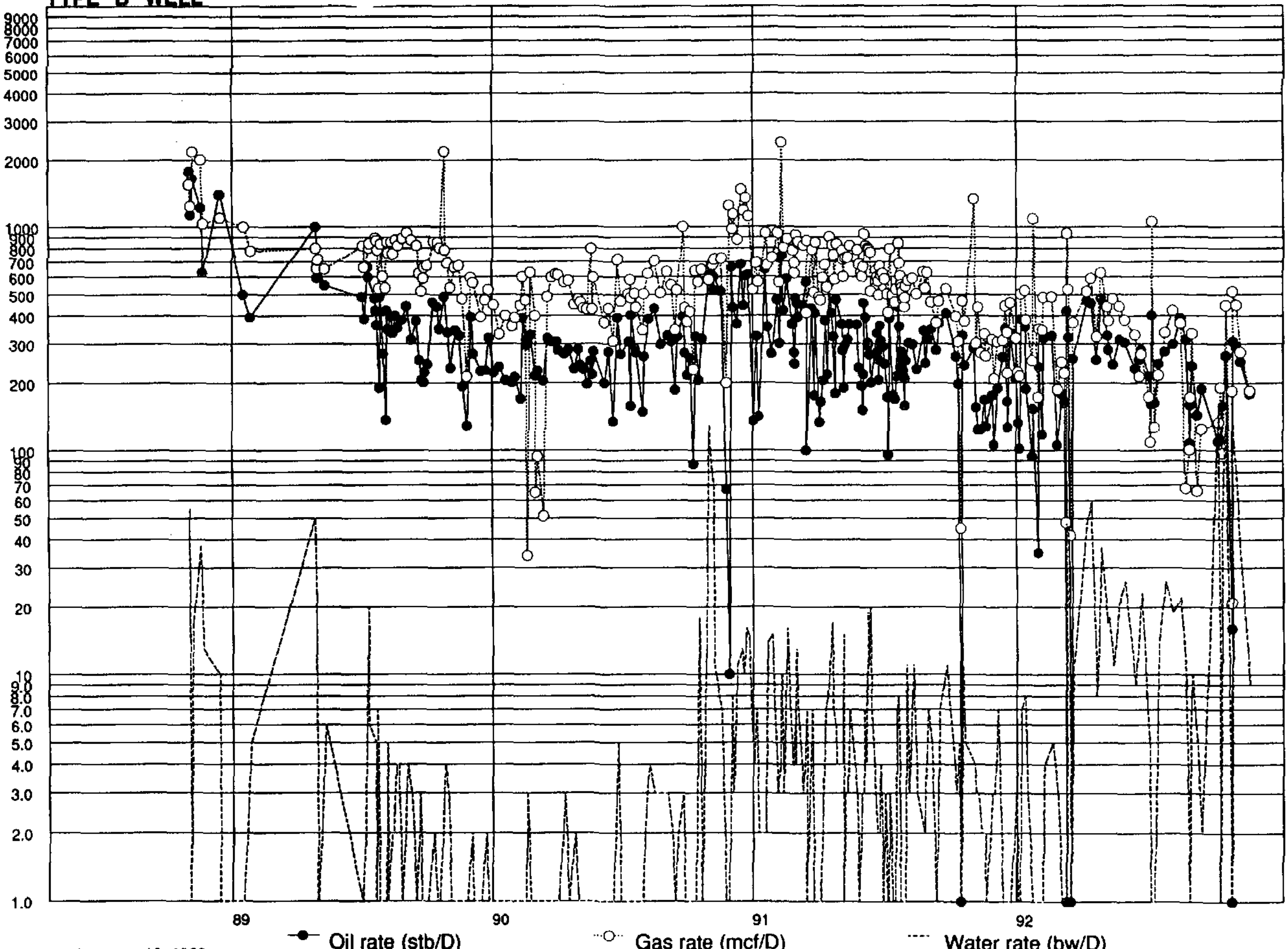



Exhibit VI-31

January 13, 1993

# 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.

## GENERAL METERING AND ALLOCATION EQUATIONS

- 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.

<u>Lisburne Stabilized NGL Volume Determination (Current)</u>

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

Additional Calculations Due to Commingling

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

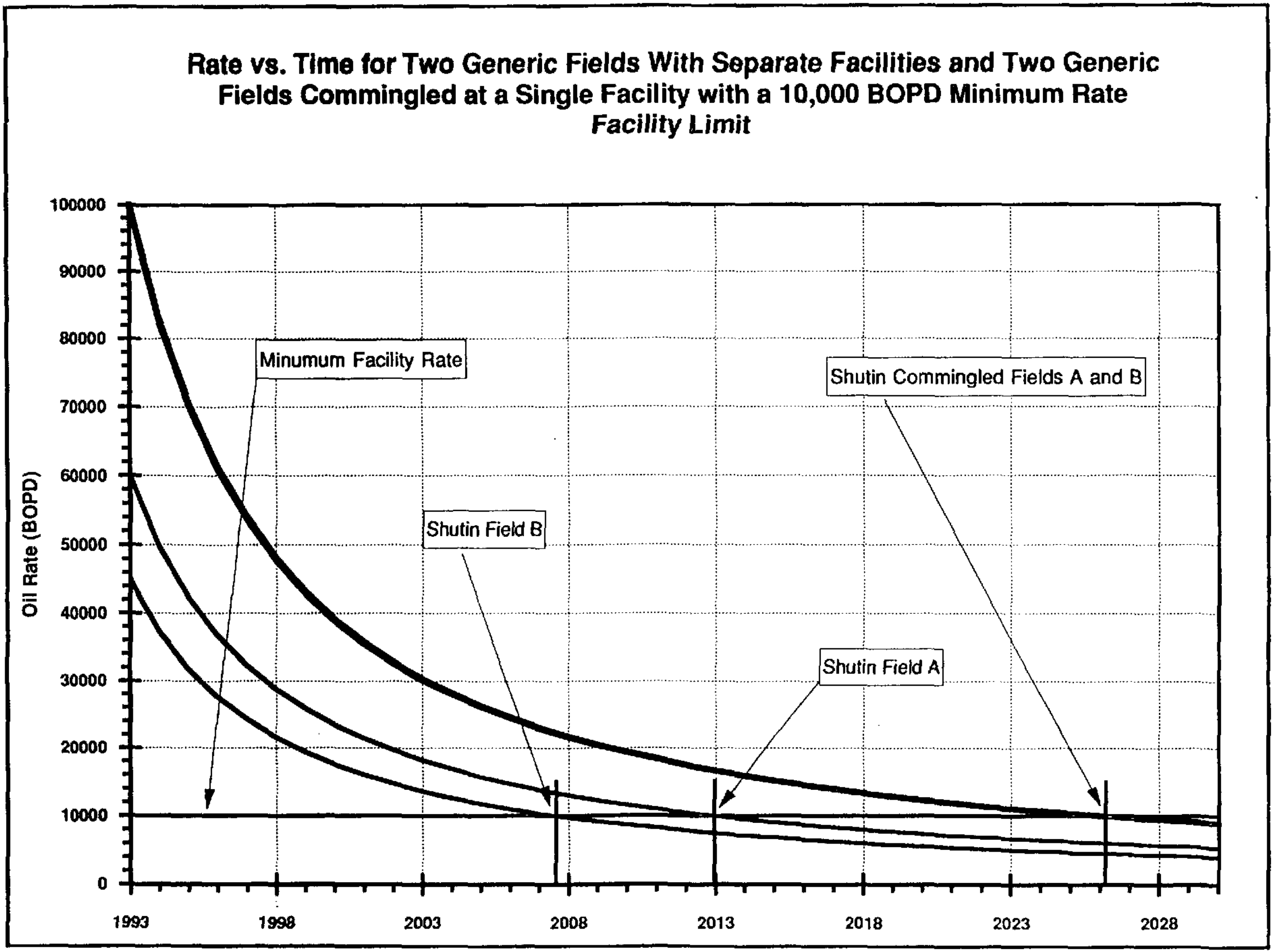
- LPC fuel and flare gas and drill site fuel and flare gas will be divided among the producing fields based on each field's fraction of gas being handled at that facility.
- Load crude and diesel will be tracked by well so that the load crude and diesel can be properly charged to the field that used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

Exhibit 1

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# 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.**

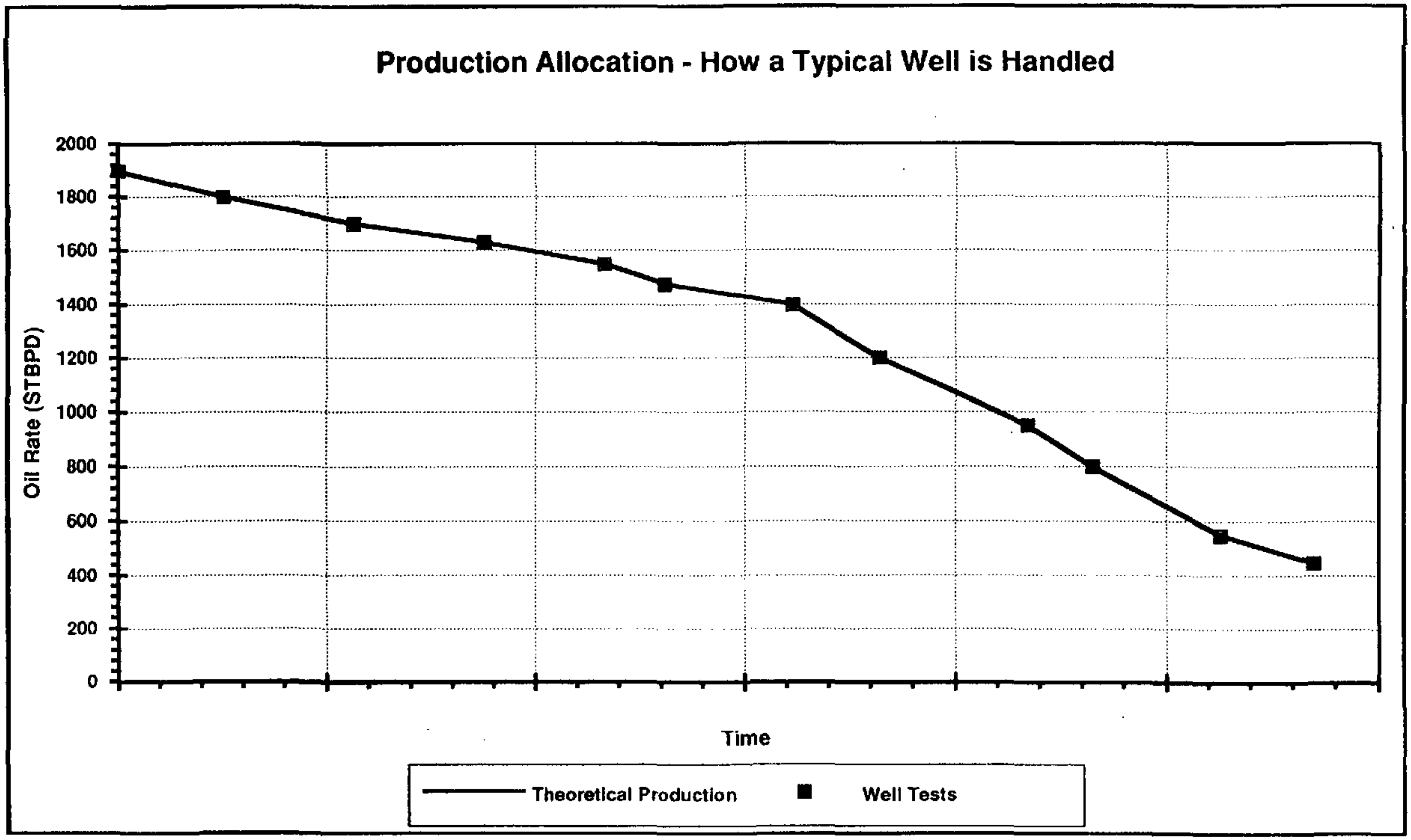
6. **Calculate an allocation factor which compares the sum of theoretical monthly production volumes for all wells in all fields to the "Total Sales" volume as determined by the critical meters.**

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

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

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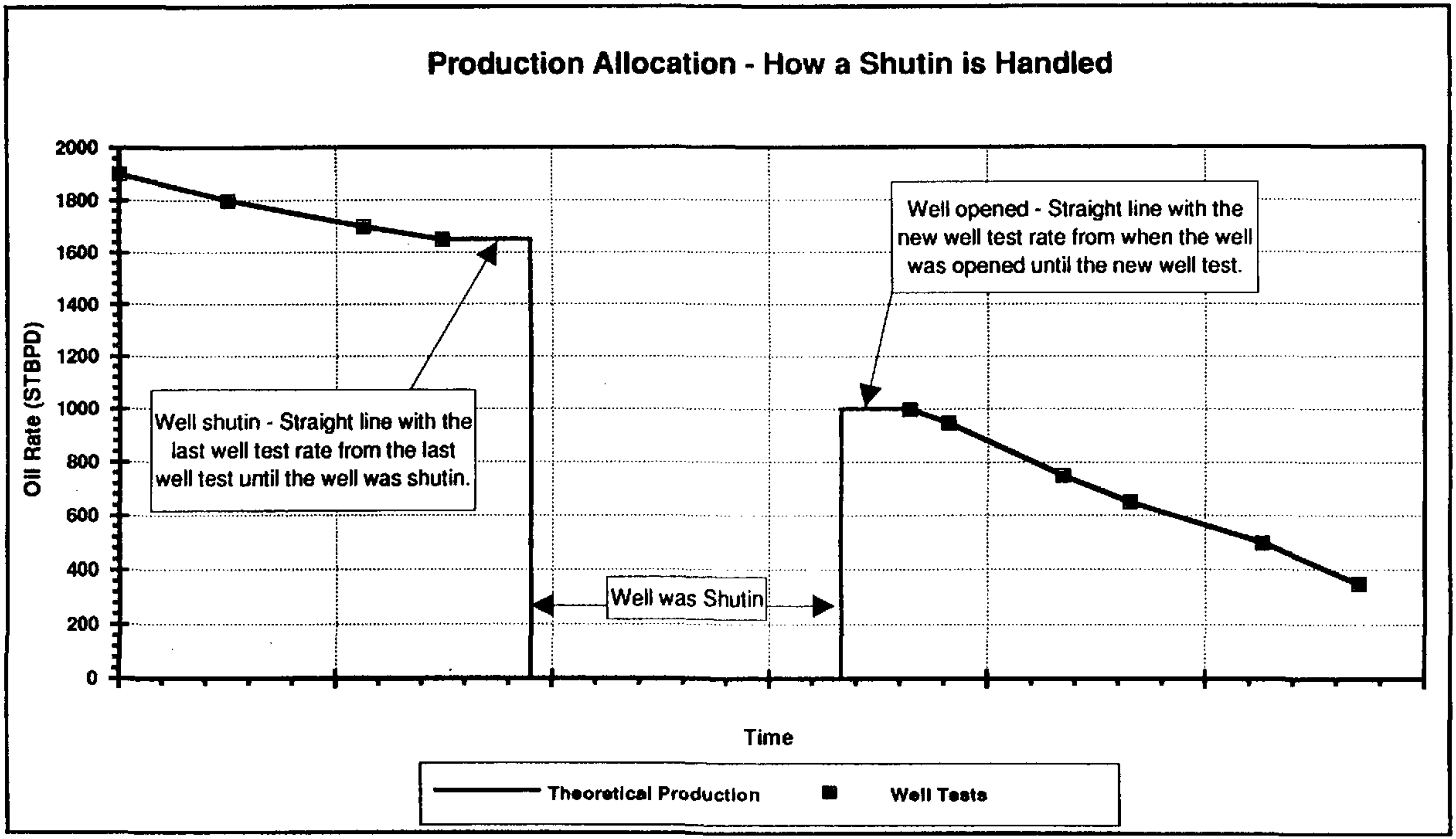
Exhibit 3

Exhibit 4




## 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.

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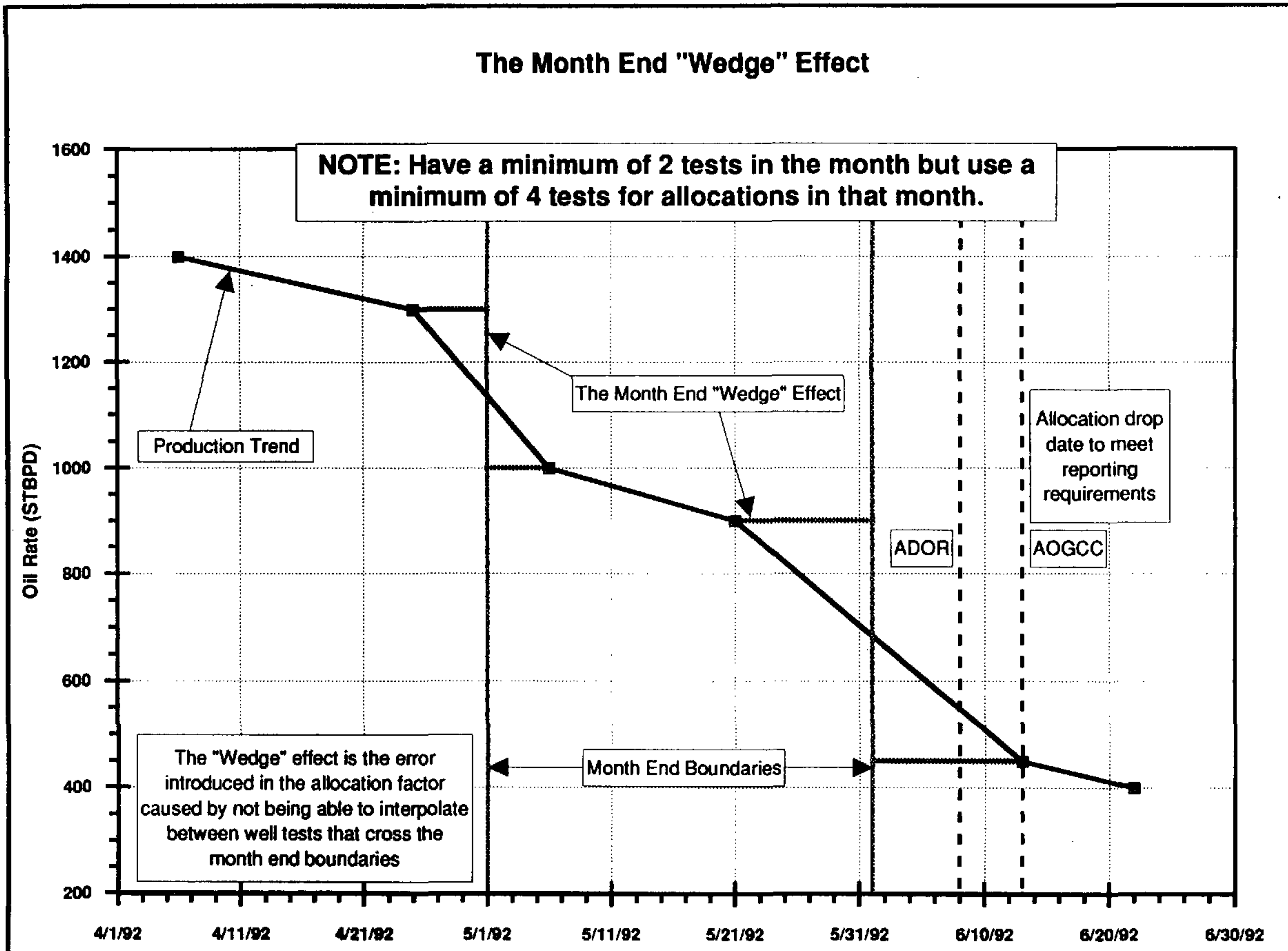
The Month End "Wedge" Effect
NOTE: Have a minimum of 2 tests in the month but use a minimum of 4 tests for allocations in that month.
Oil Rate (STBPD)
1600
1400
1200
1000
800
600
400
200
4/1/92
4/11/92
4/21/92
5/1/92
5/11/92
5/21/92
5/31/92
6/10/92
6/20/92
6/30/92
Production Trend
The Month End "Wedge" Effect
Allocation drop date to meet reporting requirements
ADOR
AOGCC
Month End Boundaries
The "Wedge" effect is the error introduced in the allocation factor caused by not being able to interpolate between well tests that cross the month end boundaries

# MONTH END SUPPORTING DATA

## • Well Test Data

WELL TEST REPORT

| | | | | | TESTED RATES | | | | | | | | | | | | | EXPECTED | | | | | | D | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 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 | 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 |
|---|---|---|---|---|---|---|

Exhibit 6

## • Monthly Oil, Water and Gas Allocation Factors

## • Number of Well Tests per Well by Drill Site and Test Separator Usage Statistics

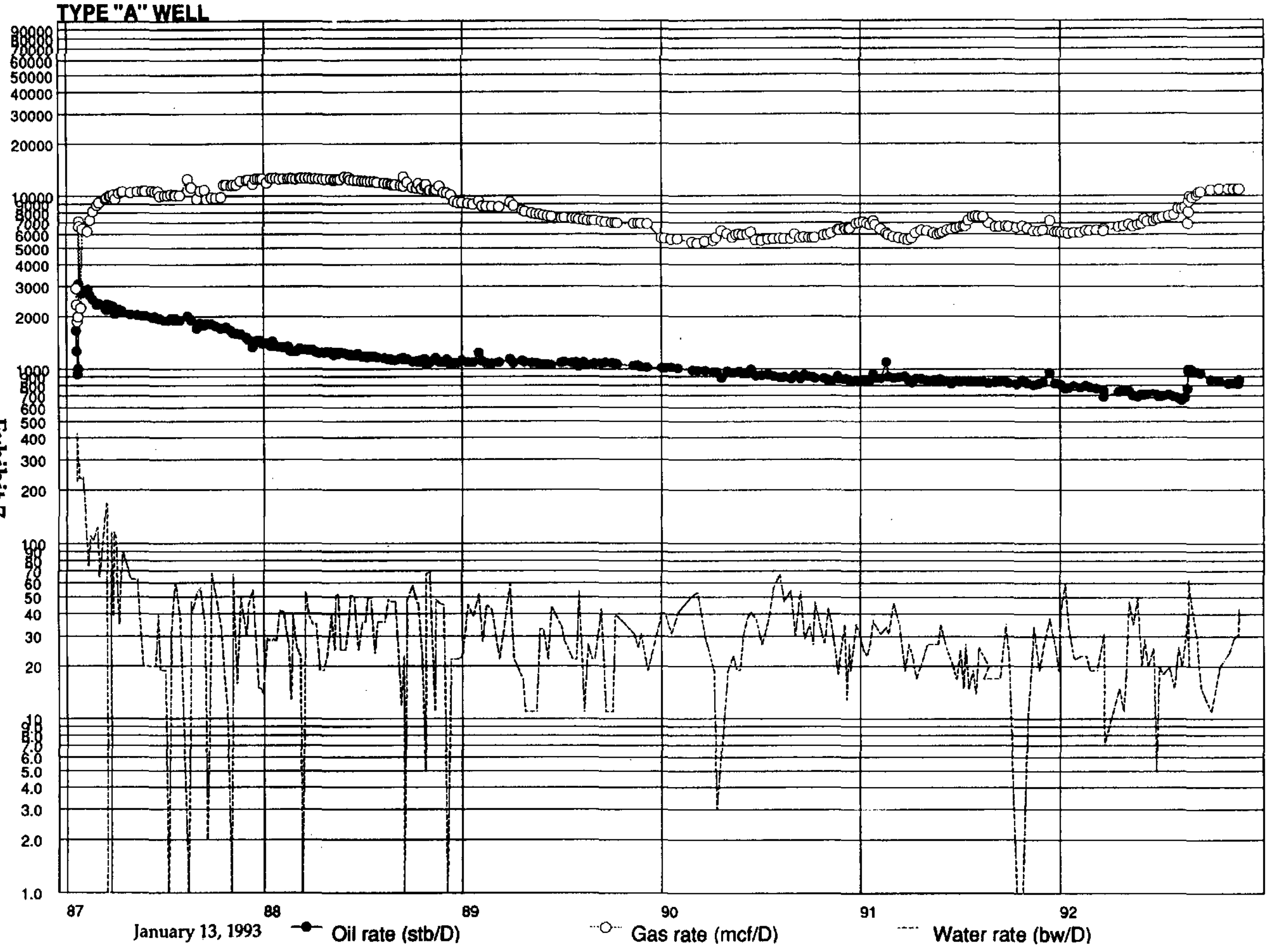


Exhibit 7

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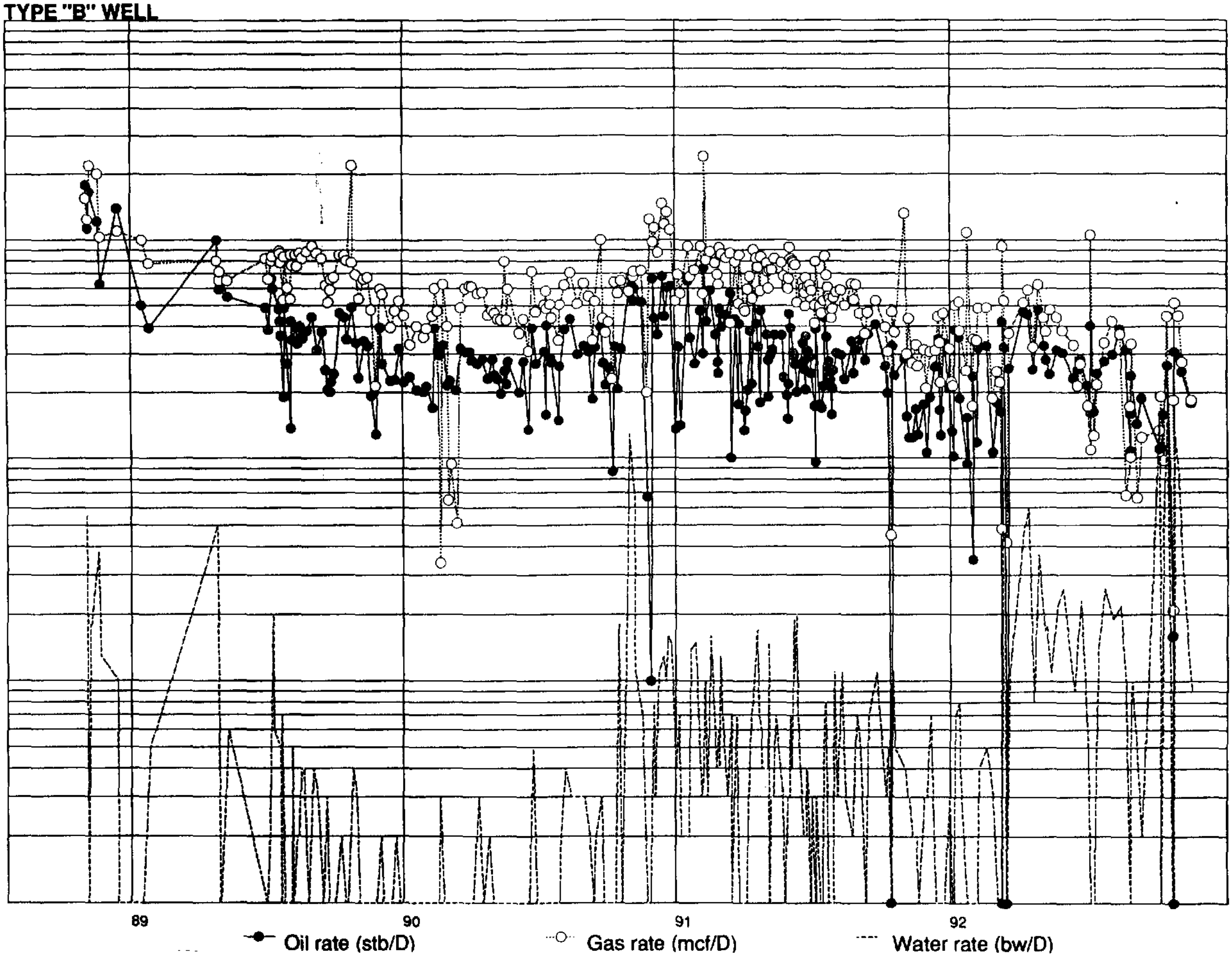
Exhibit 8


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

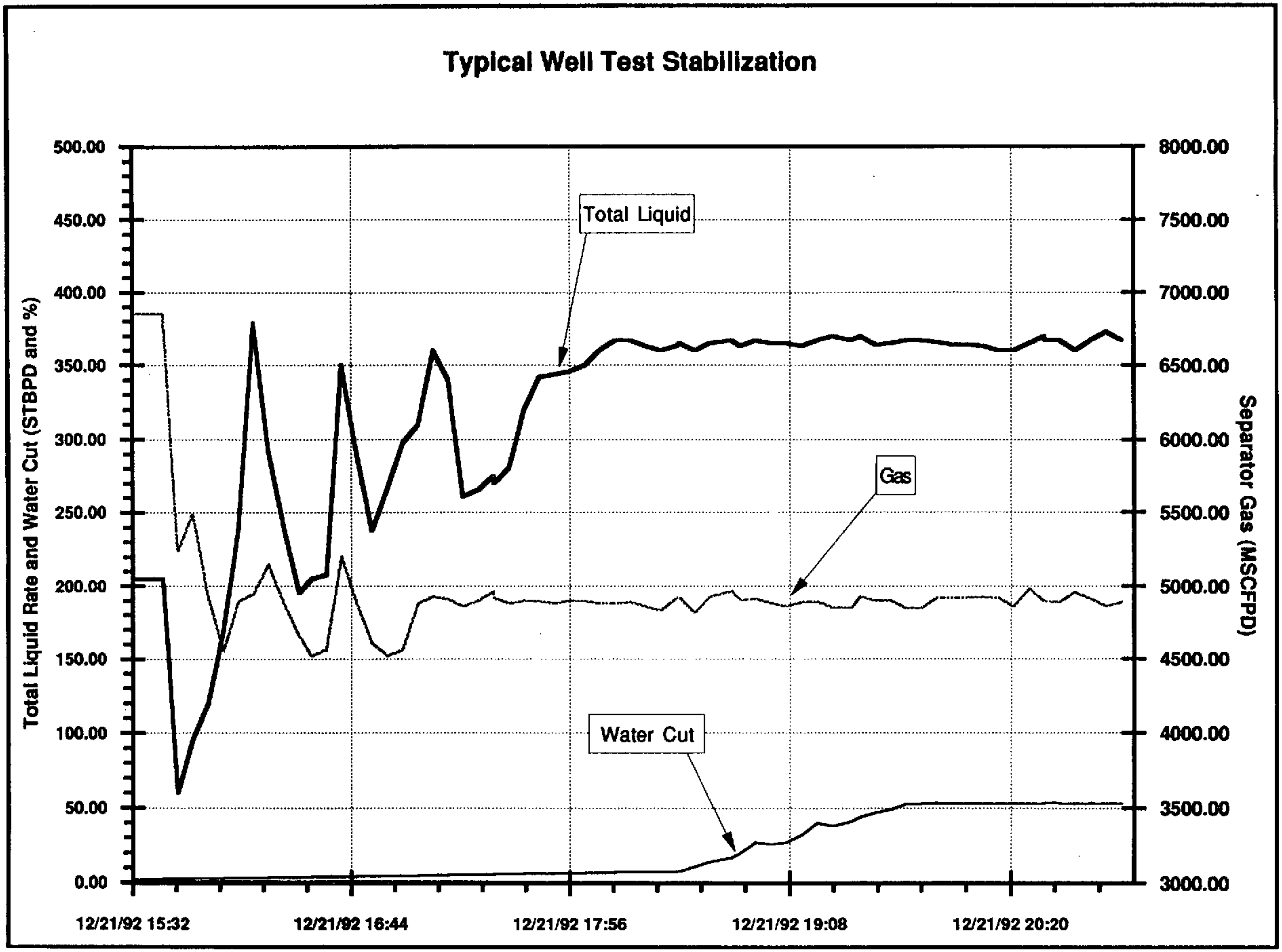

Typical Well Test Stabilization
Total Liquid
Gas
Water Cut
Total Liquid Rate and Water Cut (STBPD and %)
Separator Gas (MSCFPD)
500.00
450.00
400.00
350.00
300.00
250.00
200.00
150.00
100.00
50.00
0.00
8000.00
7500.00
7000.00
6500.00
6000.00
5500.00
5000.00
4500.00
4000.00
3500.00
3000.00
12/21/92 15:32
12/21/92 16:44
12/21/92 17:56
12/21/92 19:08
12/21/92 20:20

Exhibit 10

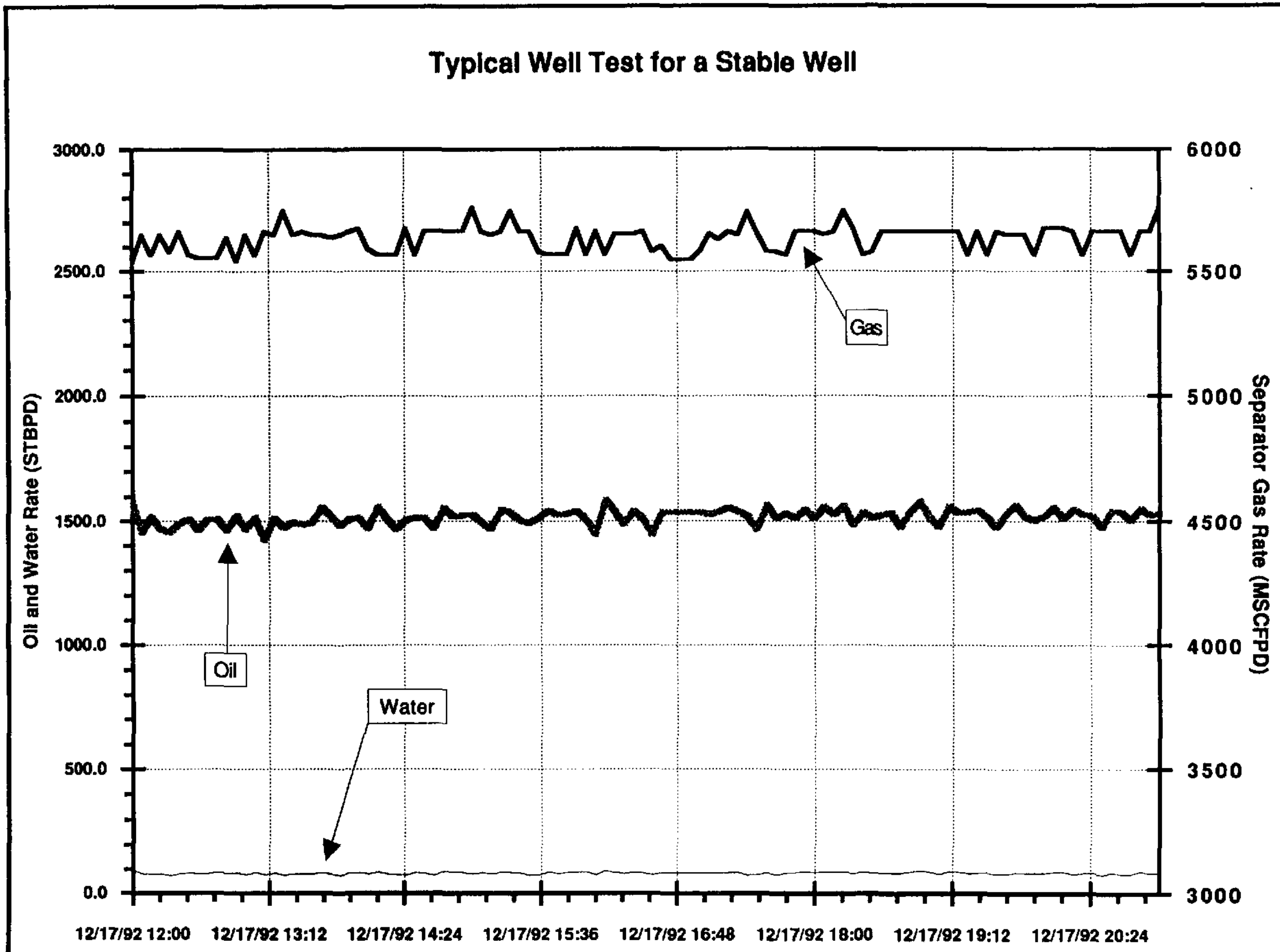



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Exhibit 11

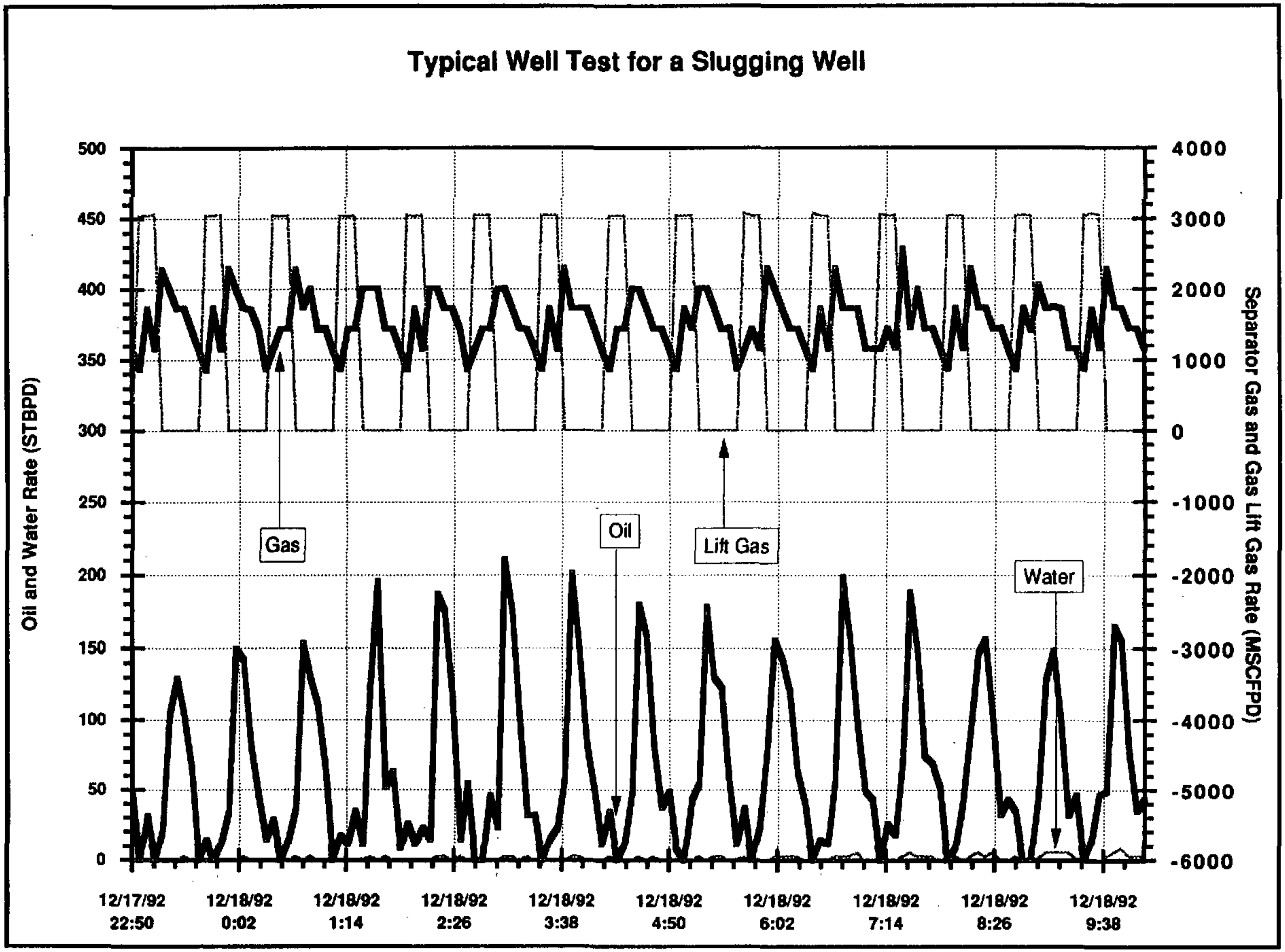


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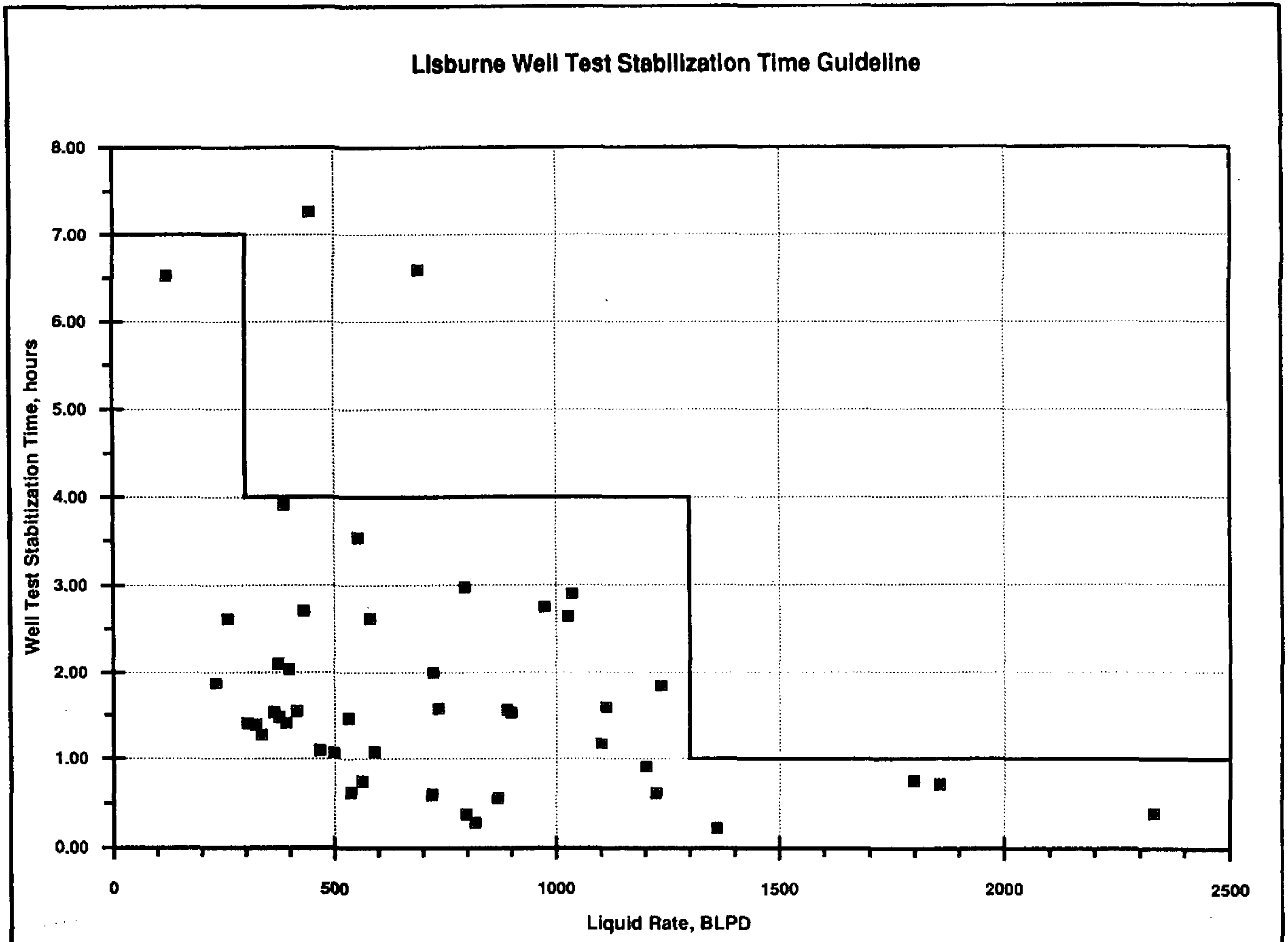
Exhibit 12




January 13, 1993

# LISBURNE, POINT MCINTYRE AND WEST BEACH CRITICAL METERING DIAGRAM

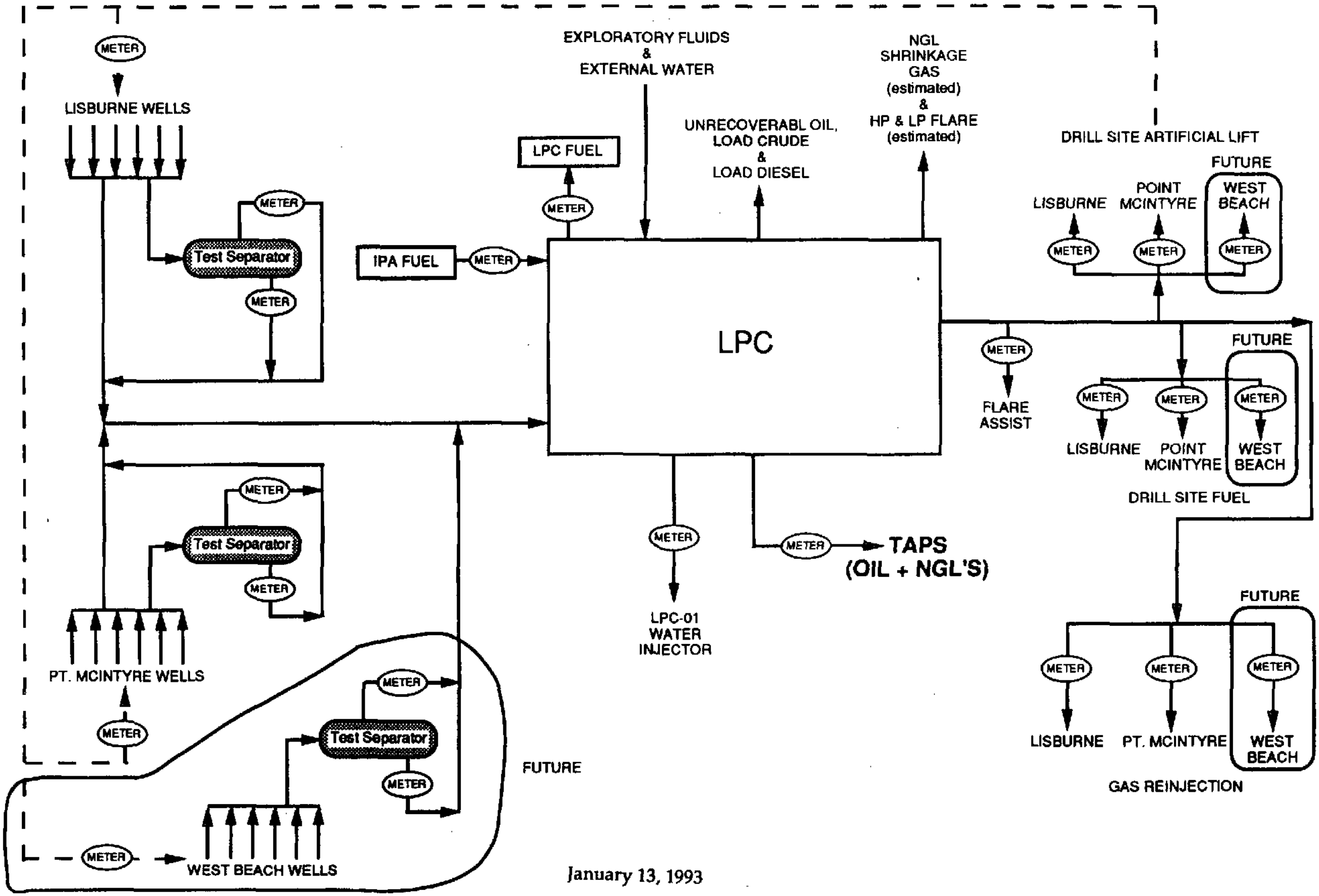



Exhibit 13

January 13, 1993

# Allocation Factor Calculations

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

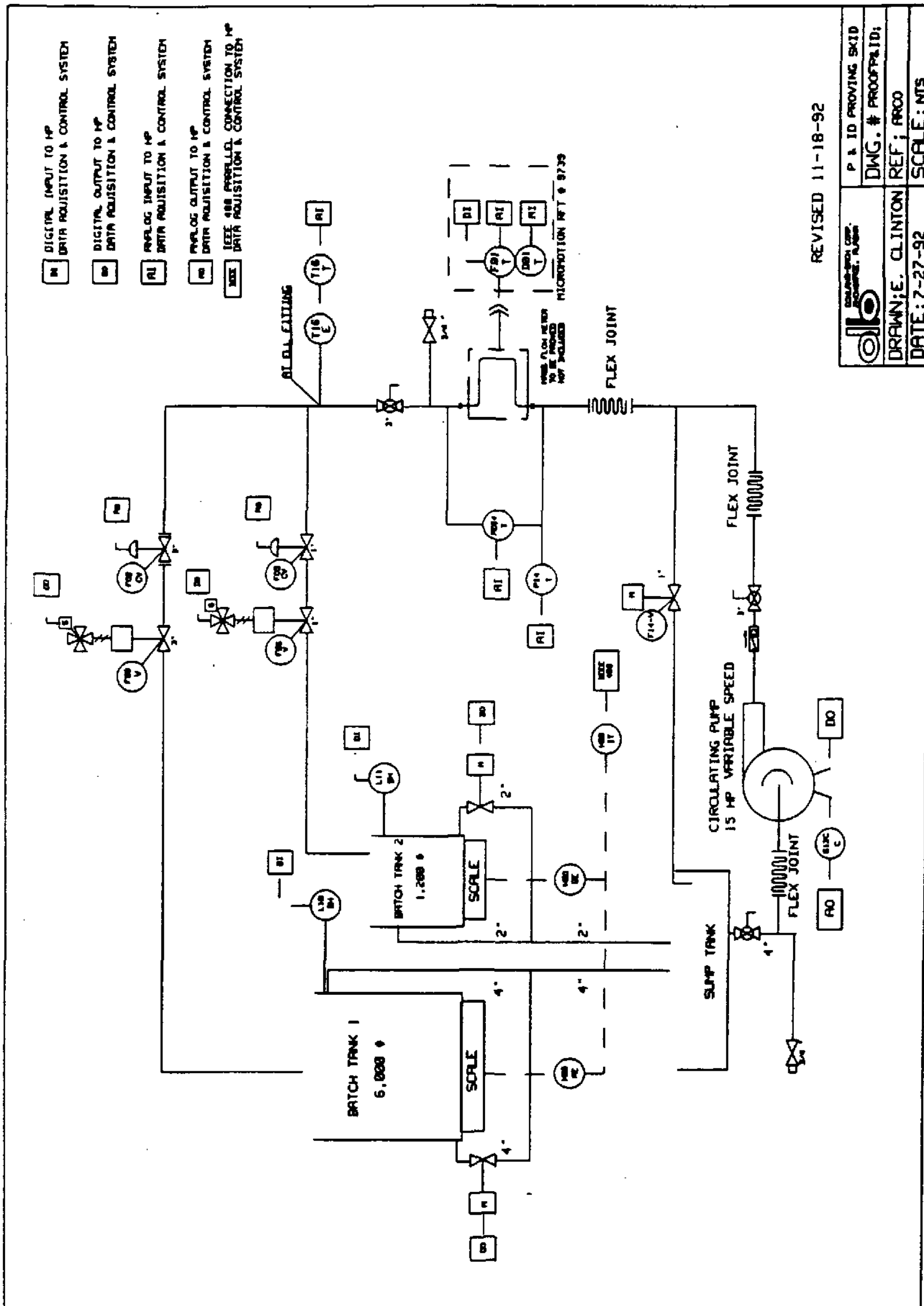
$$\text{Oil Factor} = \frac{\text{TAPS Volume} - \text{NGL Volume} - \text{TAPS BS\&W} - \text{Exploratory Fluids} + \text{Unrecoverable Oil} - \text{Load Crude/Diesel} \pm \text{Slop Oil Tank Movement}}{\Sigma \text{ Well Test Oil Rates}}$$

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

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

Exhibit 14

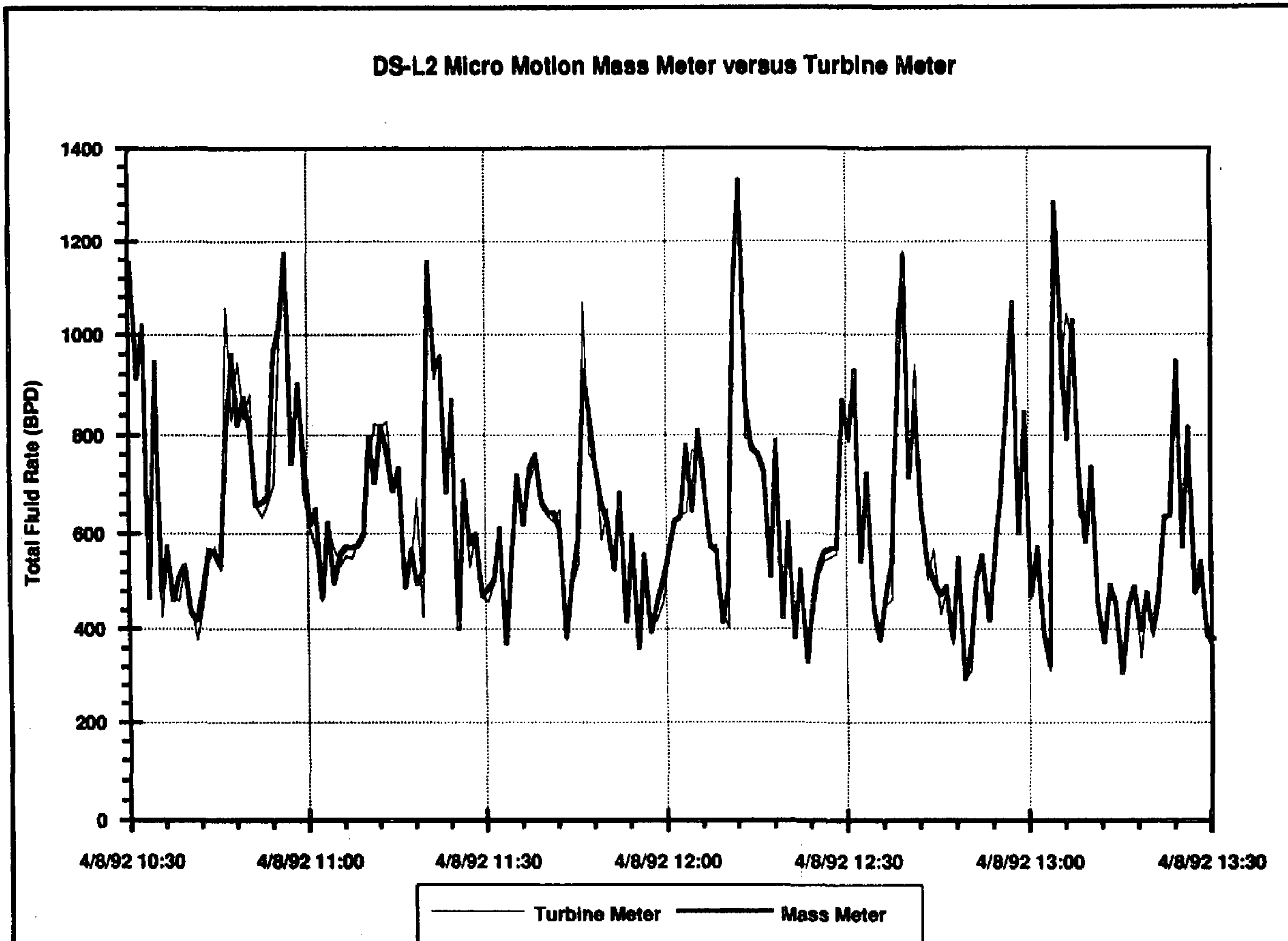
January 13, 1993



DIGITAL INPUT TO HP DATA AQUISITION & CONTROL SYSTEM
DIGITAL OUTPUT TO HP DATA AQUISITION & CONTROL SYSTEM
ANALOG INPUT TO HP DATA AQUISITION & CONTROL SYSTEM
ANALOG OUTPUT TO HP DATA AQUISITION & CONTROL SYSTEM
IEEE 488 PARALLEL CONNECTION TO HP DATA AQUISITION & CONTROL SYSTEM
MICROMOTION RFT # 9739
FLEX JOINT
FLEX JOINT
FLEX JOINT
BATCH TANK 2
1,200 #
SCALE
BATCH TANK 1
6,000 #
SCALE
SUMP TANK
CIRCULATING PUMP
15 HP VARIABLE SPEED
REVISED 11-18-92
P & ID PROVING SKID
DWG. # PROOFP&ID;
DRAWN; E. CLINTON
REF; ARCO
DATE; 7-27-92
SCALE; NTS


**Exhibit 15**

Exhibit 16


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

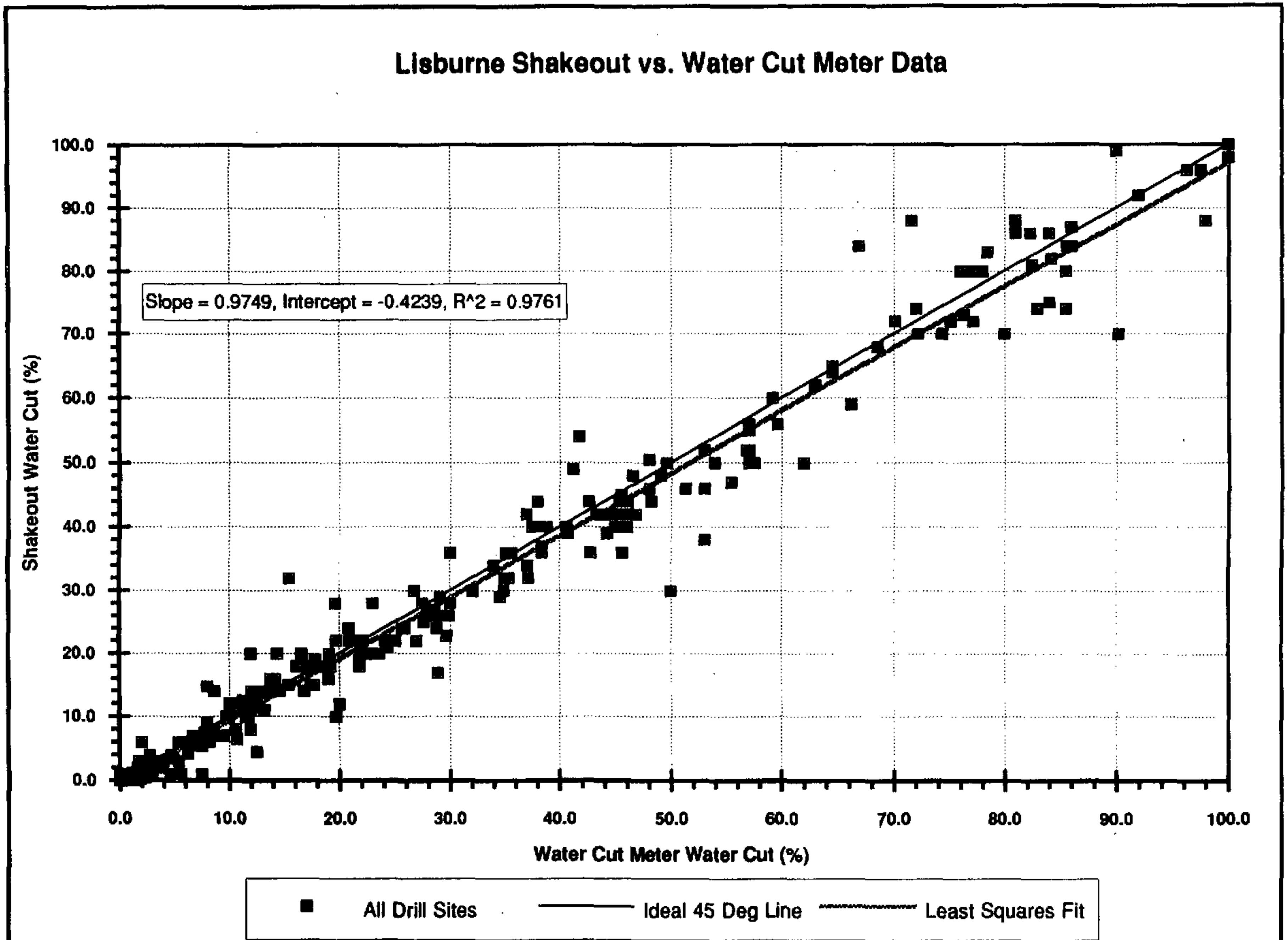



Exhibit 17

LAST UPDATE: 11/9/92

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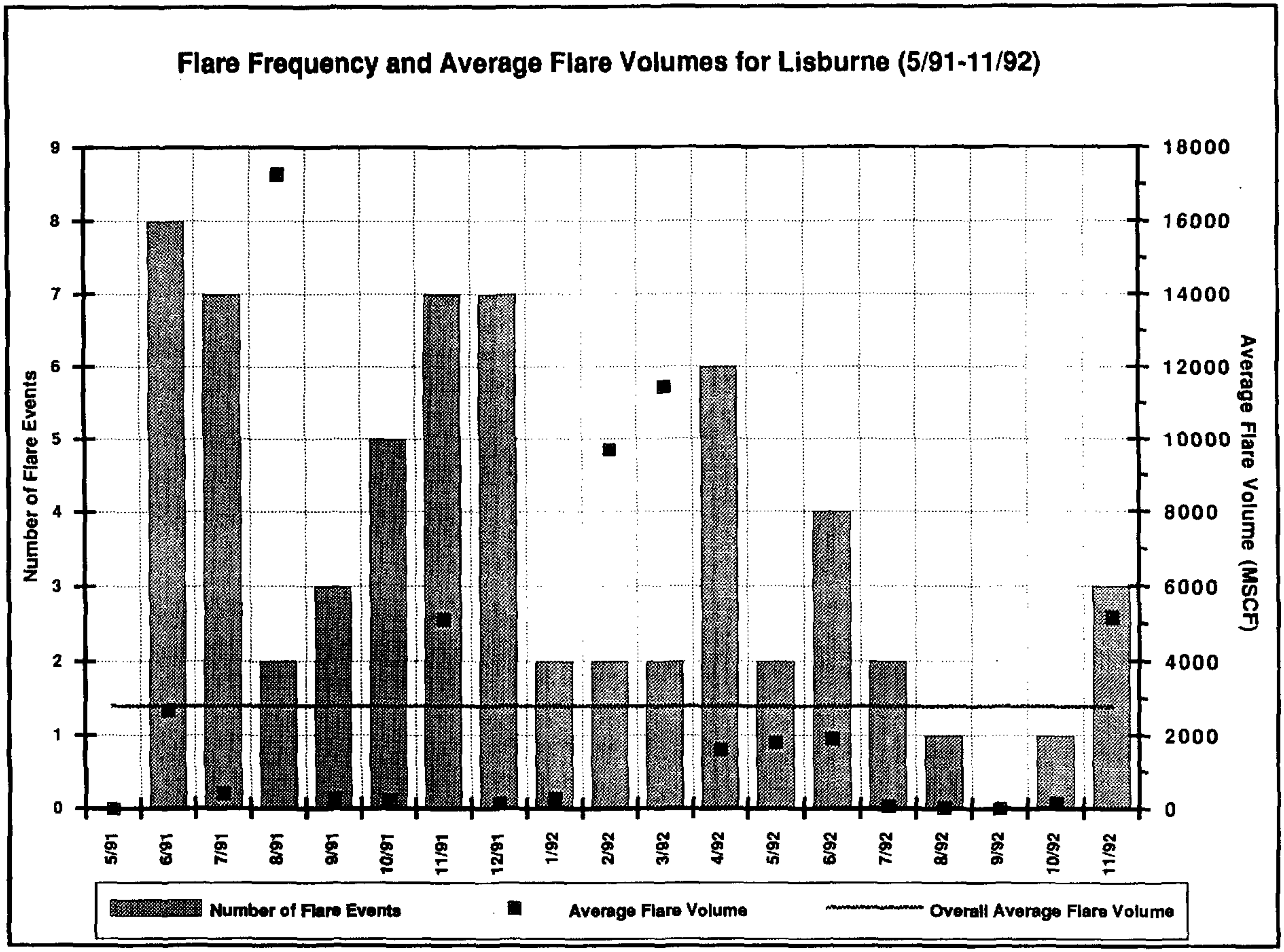
Exhibit 18




January 13, 1993

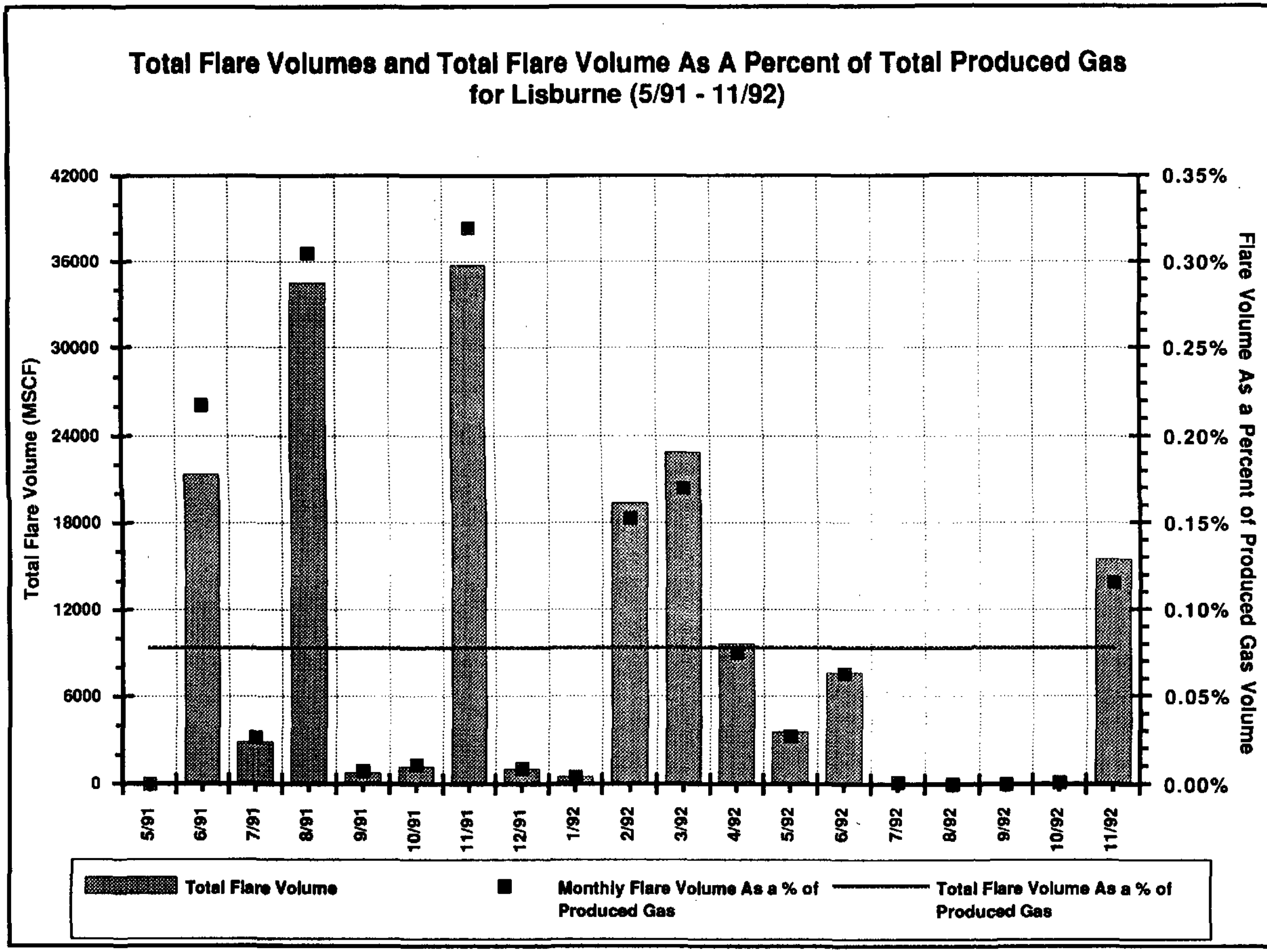



Exhibit 19

January 13, 1993

# LPC NGL PLANT
# SIMPLIFIED FLOW DIAGRAM

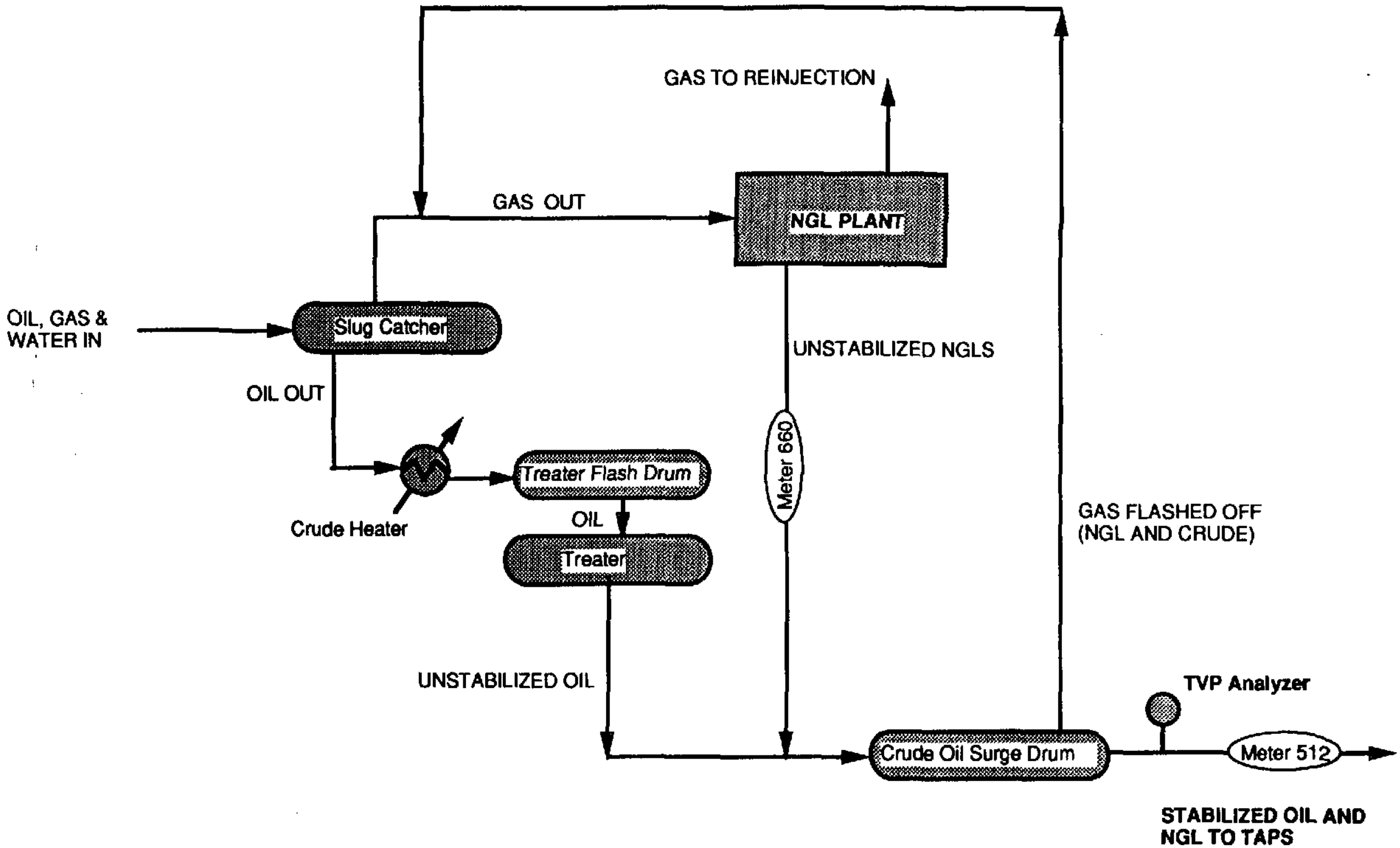



Exhibit 20

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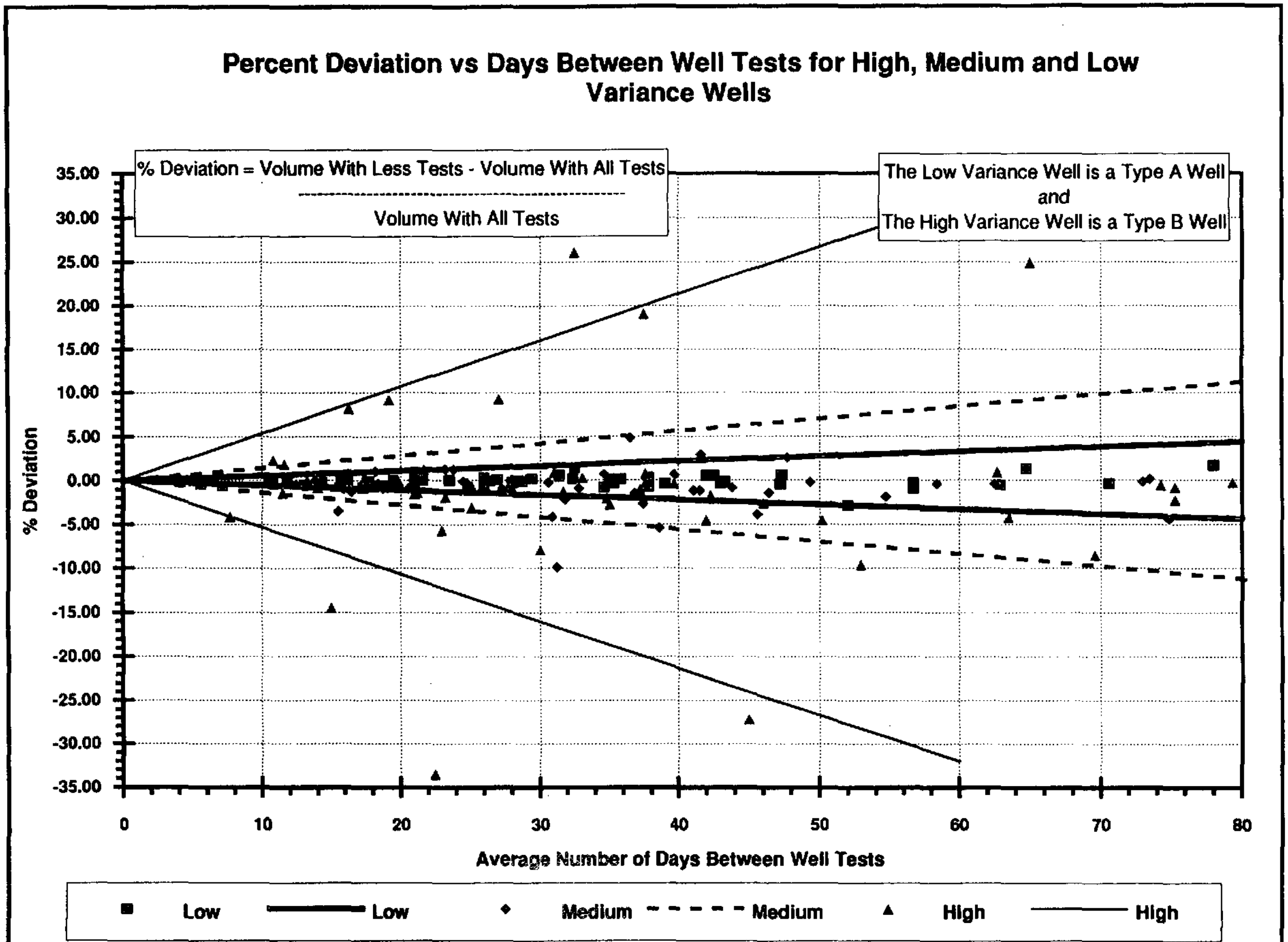
Exhibit 21




January 13, 1993