BULLETIN NO. 2

DETERMINATION OF VALUES FOR WELL COST ADJUSTMENTS JOINT OPERATIONS

BEFORE EXAMINER STOGNER
Oil Conservation Division
CHEVRON'S Exhibit No. 2
Case No. 9998

This bulletin has been reviewed by the Petroleum Accountants Societies through representation on the Council of Petroleum Accountants Societies. It is recommended that the contents of the bulletin be used as a guide to joint interest operations accounting.

The Council is gratified and appreciative to the Petroleum Accountants Society of Denver for research and publication of this bulletin.

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BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
Case No.____ Exhibit No.____
Submitted by____
Hearing Date____

FOREWORD

The basic purpose of this bulletin is to set forth what is considered by the industry in general to be the most equitable basis for the determination of values to be used in connection with well cost adjustments. This is necessitated by the tremendous increase in the various unitizations taking place for which no definite precedent has heretofore been established. The determination of values are normally required as the result of ownership changes which usually occur as the result of one of the following:

1. Change to size of a unit either voluntarily or to conform to edicts of a Regulatory Body.

2. Recompletion of a well in a different zone or formation.

3. Multiple completion of well in zone or zones of different ownership.

4. Failure to obtain production in original objective zone and completion of well in zone of different ownership.

5. The creation of Fieldwide or Reservoir Units.

Prior to execution of the Unit Operating Agreement, the value of the unit well should be agreed upon and written into the agreement. In the creation of Voluntary Units it is recognized that because of other considerations such as obsolete equipment, prior production, secondary recovery, reservoir peculiarities etc., it might be desirable to negotiate a stipulated amount or even to contribute intangibles and/or tangible equipment to the unit.

Well cost, as discussed herein, consists of subsurface equipment, wellhead and wellhead equipment and the associated intangible costs through the Xmas Tree. The lease production equipment, including installation costs, should be treated separately in the negotiations and in most instances should be adjusted in accordance with the Accounting Procedure attached to the Operating Agreement. In some instances the nature of the operations may dictate handling wellhead, wellhead equipment and tubing as separate items. For example, a single completion well being dualled, requiring the Xmas Tree to be changed out for a dual tree and the single string tubing to be changed out for a dual string.

The following suggestions are for use as guide lines only. No attempt has been made to include a suggested solution for all of the contingencies that may occur. It is also recognized that there may be more than one equitable solution to each problem. In these instances alternate suggestions have been included.

INTANGIBLE DRILLING COSTS

Intangible Drilling Costs are defined as those expenditures which are non-recoverable and as such have no salvage value. For the purpose of this bulletin material items classified as non-controllable in the Material Classification Manual most recently recommended by the Council of Petroleum Accountants Society of North America should be included as intangible costs. Intangible Drilling Costs are incurred in drilling and preparing wells for the production of oil and gas. Intangible costs normally end at the first down stream connection on the wellhead, and generally include the following expenses:

DRILLING

- Footage—Contract
- Daywork—Contract
- Cost Plus—Contract
- Turnkey Contract
- Company Tools

LABOR

- Company
- Contract

AUTOMOTIVE EXPENSE

- Automobile
- Truck and Service Equipment

ROADS, CANALS AND LOCATIONS

POWER, FUEL AND WATER

MATERIAL AND SUPPLIES

- Bits and Equipment Rental
- Drilling Mud and Chemicals
- Other

SPECIALIZED SERVICES

- Well Surveys and Test Services
- Cementing Casing
- Shooting, Acidizing and Perforating
- Squeeze Jobs

OTHER INTANGIBLE DRILLING COSTS

- Geological and Engineering
- District Expense
- Administrative Overhead
- Loss and Damage
- Vacation, Sickness and other Employee Benefits
- Other Costs

A. DETERMINATION OF INTANGIBLE DRILLING COSTS

1. The operators' historical actual recorded cost is the preferred basis to be used in determining the one-hundred per cent amount to be allocated. Alternate methods are as follows:

   (a) Fixed or agreed sum. This amount would be an arbitrarily assigned amount acceptable by all parties concerned and would be used as the cost only when the operators' actual recorded cost is either unavailable, unrealistic or unacceptable.

   (b) No Value. This method requires no allocation of costs. In using this method it would be pre-determined that each party has contributed a comparable base cost. A no value basis would normally be used in the creation of voluntary Fieldwide or Reservoir Units, which have been fully developed.

2. When operators' actual cost is used, it should be noted that these costs include in addition to the direct expenses incurred, allowances for operators' District Expense and Administrative Overhead. District expense would be calculated in accordance with the operators'

normal practice of allocating these expenses. Administrative Overhead or Combined Fixed Rates should be the amount charged the joint account if the property for which the cost adjustment is being made was originally jointly owned. If the property for which the cost adjustment is being made was not originally jointly owned, Administrative Overhead or Combined Fixed Rates should be calculated at the prevailing rate for the area in which the unitization or change of ownership is taking place. Also included would be any costs incurred in drilling below the unitized formation to a maximum depth of one hundred feet.

Expenses incurred for certain Specialized Services in formations other than the unitized formation should be excluded. Such Specialized Services could include electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc.

3. When operators' actual cost is used such cost should be amortized. The preferred basis is the unit of production method. This factor is determined by a fraction of which the numerator is past production and the denominator is past production plus estimated future reserves.

   In the event both oil and gas are produced from the unit well, then this method of amortization should be amended to use a basis of value rather than unit of production. As an alternate, a straight line method may be used. This factor is determined by a fraction of which the numerator is the number of years produced and the denominator is the number of years produced plus the estimated remaining years of production.

B. ALLOCATION OF INTANGIBLE DRILLING COSTS

This portion of the bulletin pertains to the allocation or association of costs to a portion of the well common to specified zones of operation.

1. The preferred method for the allocation of costs between zones is from a detailed analysis of actual expenditures when practical, utilizing well, drilling and accounting records. Other acceptable methods are as follows:

   (a) A drilling day ratio. This factor for each zone is determined by a fraction of which the numerator is the number of days drilled through that zone and the denominator is the total number of drilling days spent on the well, beginning on the date the well is spudded and terminating when the rig is released. It is desirable to eliminate from this allocation all expenditures known to be applicable to specific producing formations and could include electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc. This would necessitate the elimination of the applicable days required to perform such function. For an illustration, suppose a well completed in three zones required 75 drilling days. If the time from spud date to the base of the first zone, plus the time required to log and set the production string of casing, amounted to 27 days, this zone would receive an allocation of 27/75 or 36% of the intangible drilling costs. If the time required to drill from the base of the first zone to the base of the second zone took eleven days, this zone would receive an allocation of 11/75 or 15%. If the time required to drill from the base of the second zone to the base of the third zone took 37 days, this zone would receive an allocation of 37/75 or 49%.

   (b) A drilling footage ratio. This factor for each zone is determined by a fraction of which the numerator is the footage drilled through that zone and the denominator is the total footage drilled for the entire well. It is desirable to eliminate from this allocation all expenditures known to be applicable to a specific producing formation and could include electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc.

For an illustration, suppose a well completed in three zones was drilled to a total depth of 14,000 feet. If the footage from surface through the first zone was 12,000 feet, this zone would receive 12,000/14,000 or 85.72% of the intangible drilling costs. If the footage from the bottom of the first zone through the second zone was 1,000 feet, this zone would receive 1,000/14,000 or 7.14%. If the footage from the bottom of the second zone through the third zone was 1,000 feet, this zone would also receive 1,000/14,000 or 7.14%.

2. After the costs have been allocated to the zones by one of the methods described above, assuming there are three zones, these costs should be shared by the owners in the following manner:

PROPORTIONATE

(a) Applicable costs identified with the zone from ~~the surface~~ to the base of the first producing formation should be allocated equally to all foramtions with the owners in each formation standing their proportionate share based on their respective interest in each formation.

(b) Applicable costs identified with the zone between the base of the first producing formation and the base of the second producing formation should be allocated equally to all formations below the base of the first formation with the owners in each formation standing their proportionate share based on their respective interest in each formation.

(c) Applicable costs identified with the area below the base of the second producing formation will be charged to the deeper formation.

TANGIBLE COSTS

Tangible Drilling Costs are defined as those material items installed in connectios with drilling and completing a well through the Xmas Tree and which, are ordinarily considered to have salvage value, regardless of whether such items may actually be salvaged after they are installed. Such materials are classified as controllable in the Material Classification Manual most recently recommended by the Council of Petroleum Accountants Society of North America.

A. DETERMINATION OF TANGIBLE COSTS

1. BASE PRICE

(a) Actual recorded cost reduced by a depreciation factor set forth in 2 below. Some companies price material to their 100% properties as well as joint properties on a current market basis, therefore, actual recorded cost would be appropriate. However, some companies price material to their 100% properties on a depreciated or average cost basis, therefore the basis in (b) or (c) below might be more equitable.

(b) Current Market (New) value at date of installation reduced by a depreciation factor set forth in 2 below.

(c) Current Market (New) value at date of unitization reduced by a depreciation factor set forth in 2 below.

2. DEPRECIATION

Depreciation should be limited to such amount so as to produce a value of equipment in an amount not to be less than the salvage value after deducting the cost of salvage.

(a) Unit of production method. The amount of depreciation is determined by a fraction of which the numerator is past production and the denominator is past production plus estimated future reserves. In the event both oil and gas are produced from the unit well, then this method of depreciation should be amended to use a basis of value rather than unit of production.

(b) Straight line method. The amount of depreciation is determined by a fraction of which the numerator is the number of years produced and the denominator is the number of years the well produced plus the estimated remaining years of production.

(c) Agreed condition percentage.

B. ALLOCATION OF TANGIBLE COST

In most unitizations it will be necessary for the operator to allocate the equipment serving the unit and/or units in the same wellbore on an equitable basis. Due to deep drilling in some wells, larger, heavier and more expensive casing, and in some cases a protection string may be set in the well that would not have been required had the well been drilled to the unit sand only. To attempt to adjust for this situation brings up many problems and would require an estimate of the tangible as well as the intangible cost for a hypothetical well to the unit sand which is not recommended. Since the operator assumed all the risks of drilling the well and the non-operator has usually benefited from this, it is suggested that no adjustment be made for these costs in determining the value of the unit well.

To assure adequate penetration through the unit sand, in most adjustments the depth of a unit is considered to be 100′ below the base of the unit sand. The total depth of the well may be slightly greater than the 100′ and in these cases it is suggested that the adjustment include total depth. A string of casing may consist of casing of different weights and grades set at various depths, but for the purpose of making an allocation to the unit the total average cost of the casing string should be used.

Assuming three completions in a single well bore, the cost of tangible well equipment should be allocated as follows:

1. CASING

(a) Total average cost of the casing from the surface to the base of the first zone should be allocated equally to all zones in the wellbore.

(b) Total average cost of the casing from the base of the first zone to the base of the second zone should be allocated equally to the second and third zones.

(c) Total average cost of the casing from the base of the second zone to the base of the third zone should be allocated entirely to the third zone.

2. WELLHEAD

Wellhead and wellhead equipment through the Xmas Tree should be allocated equally to all producing formations served.

3. TUBING

   In those instances when each unit reservoir is produced through a separate string of tubing then each unit will be charged with the respective tubing string. In those instances when one unit reservoir is produced through the casing then the total cost of the tubing will be shared proportionately by the units served with the appropriate adjustment for tubing below the individual unit reservoirs.

Tangible controllable equipment not specifically mentioned above should be allocated on an equitable basis to the zone or zones served.

CONDITIONS OF UNITIZATION

Following are the conditions for which the determination of values for well cost adjustments may be required:

1. Straight up lease well or wells to unit in same reservoir.

   A. Originally drilled as 100% or joint well —

   (1) Not produced from unit sand.

   (2) Produced from unit sand.

2. A. Revision of an existing unit from 100% ownership to joint.

   B. Revision of an existing joint unit — same parties, different interest, or bring in additional interest.

3. Single well completion dualled subsequently into unit reservoir original completion remains 100% and unit completion becomes joint.

4. Dual completion — one or more completions unitized.

5. Single completion depleted and recompleted in higher unitized reservoirs.

6. Single completion depleted and drilled deeper to unitized reservoir.

7. Dry hole reworked into unitized reservoir.

8. Single completion depleted and recompleted for injection or disposal well for unit.

9. Dry hole recompleted for injection or disposal well for unit.

10. Operator furnish substitute well to supplement production from a unit on rental basis.

INFORMATION TO BE FURNISHED TO NON-OPERATORS BY OPERATOR

Upon completion of the evaluation of the unit well and prior to the execution of the Unit Operating Agreement, the following information should be furnished by the operator to all non-operators:

A. Copy of well record or well completion report.

B. Itemized priced list of tangible controllable equipment and basis of pricing, depreciation

and allocation. The well equipment through the Xmas Tree is subject to verification by an audit of the operator's well records and an inventory.

C. Summary of intangible cost by type of expenditure with a brief statement as to how the costs were determined, depreciated and allocated.

D. Brief daily resume of drilling operations including mud weights.

CONCLUSION

It is believed that the most common conditions of unitizations may be resolved by the recommendations set forth above, and the accountants role in the negotiation of unit operating agreements brought to a timely conclusion.

Owners of working interests in new units formed should be charged their proportionate share of the agreed well value based on their respective interest in the unit; and the selling owners should be credited with their proportionate interest sold.

The unit operator should act as a collection and disbursing agent for all parties with appropriate protection authorized by the operating agreement. So as not to place an undue burden on the operator, purchasers of an interest should remit promptly after being billed and the operator should make payment to sellers immediately after receiving payment from all purchasers. All future accounting for the unit should be governed by the provisions of the operating agreement entered into between the parties.

STATE OF NEW MEXICO
ENERGY, MINERALS, AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION DIVISION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 9867
CASE NO. 9868
Order No. R-9124

APPLICATION OF MALLON OIL COMPANY FOR COMPULSORY POOLING, EDDY COUNTY, NEW MEXICO.

APPLICATION OF GEORGE MITCHELL d/b/a G.P. II ENERGY, INC. FOR COMPULSORY POOLING, EDDY COUNTY, NEW MEXICO.

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 8:15 a.m. on February 7 and 21, 1990, at Santa Fe, New Mexico, before Examiners David R. Catanach and Michael E. Stogner, respectively.

NOW, on this 27th day of February, 1990, the Division Director, having considered the testimony, the record, and the recommendations of the Examiner, and being fully advised in the premises,

FINDS THAT:

(1) Due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) Division Case Nos. 9867 and 9868 were consolidated at the time of the hearing for the purpose of testimony, and inasmuch as both cases concern the same acreage, namely the NW/4 NE/4 of Section 28, Township 26 South, Range 29 East, NMPM, Eddy County, New Mexico, one order should be entered for both cases.

(3) The applicant in Case No. 9867, Mallon Oil Company (Mallon), seeks an order pooling all mineral interests in the Brushy Draw-Delaware Pool underlying the NW/4 NE/4 (Unit B) of Section 28, Township 26 South, Range 29 East, NMPM, Eddy County, New Mexico, forming a standard 40-acre oil spacing and proration unit for said pool. Said unit is to be dedicated to the Amoco Red Bluff Federal Well No. 3 located at a previously approved unorthodox oil well location 130 feet from the North line and 1805 feet from the East line (Unit B) of said Section 28.

(4) The applicant in Case No. 9868, George Mitchell d/b/a G.P. II Energy, Inc. (Mitchell), seeks an order pooling all mineral interests from the surface to the base of the Cherry Canyon formation underlying the NW/4 NE/4 (Unit B) of Section 28, Township 26 South, Range 29 East, NMPM, Eddy County, New Mexico, forming a standard 40-acre oil spacing and proration unit for any and all formations and/or pools developed on 40-acre spacing within said vertical extent which presently includes but is not limited to the Brushy-Draw Delaware Pool. Said unit is to be dedicated to a well to be drilled at a standard well location thereon.

(5) Within the NW/4 NE/4 of said Section 28, Mallon owns or controls a 71.54% working interest, while Mitchell owns or controls a 28.46% working interest.

(6) Despite ongoing negotiations between Mallon and Mitchell which commenced in July, 1989, both parties have been unable to reach an agreement concerning the subject acreage. The following chronology of events prior to the hearing on February 7, 1990, is relevant to this order:

a. July 12, 1989; Mallon formally proposed to Mitchell the drilling of the Amoco Red Bluff Federal Well No. 3 by sending AFE and operating agreement and requested that Mitchell participate by voluntary agreement.

b. August, 1989; Mitchell met with Mallon to discuss concerns about the estimated well costs for the proposed Amoco Red Bluff Federal Well No. 3.

c. October 26, 1989; Mitchell sent its own AFE for the subject well to Mallon and requested that it be allowed to operate the well and possibly take over all of Mallon's operations in New Mexico.

d. November 28, 1989; Mallon sent an amended AFE to Mitchell denoting a change in the proposed well location and requested that Mitchell respond by December 10, 1989.

e. December 5, 1989; Mitchell advised Mallon that he would not be participating in the drilling of the subject well but would consider farming out his interest.

f. December 26, 1989; Mallon advised Mitchell that the terms of the farmout proposal are probably not acceptable.

g. December 29, 1989: Mallon advised Mitchell that forced pooling proceedings would be initiated.

Amoco Red Bluff Federal Well No. 3 was spudded in compliance with a drilling deadline provision contained within Amoco Production Company-Mallon farmout agreement.

h. January 3, 1990; Mallon filed forced pooling application with the Division.

(7) Testimony and evidence presented indicates that as of the date of the hearing, the Amoco Red Bluff Federal Well No. 3, as described in Finding No. (3) above, has been drilled to the Delaware formation by Mallon and is currently waiting on completion.

(8) In its attempt to be named operator of the subject proration unit, Mitchell has presented evidence and testimony which indicates that it has experience in drilling and operating Delaware wells in this area and can in fact drill Delaware wells for substantially less cost than Mallon.

(9) Insofar as the question of operatorship is concerned, the drilling cost evidence presented by Mitchell is irrelevant in this case inasmuch as the well has already been drilled and the costs already incurred.

(10) As indicated by Finding No. (6) above, Mallon was the first to propose drilling the subject well and in fact has drilled the well, and has made a good faith effort to secure voluntary agreement with Mitchell.

(11) In addition, Mallon is the majority interest owner in the subject proration unit, and as such, stands to gain or lose substantially more than Mitchell.

(12) To avoid the drilling of unnecessary wells, to protect correlative rights, to avoid waste, and to afford to the owner of each interest in said unit the opportunity to recover or receive without unnecessary expense his just and fair share of the production in any pool completion resulting from this order, the application of Mallon Oil Company should be approved by pooling all mineral interests, whatever they may be, within said unit.

(13) The application of George Mitchell d/b/a G.P. II Energy, Inc. for compulsory pooling should be denied.

(14) Mallon Oil Company should be designated the operator of the subject well and unit.

(15) Any non-consenting working interest owner should be afforded the opportunity to pay his share of estimated well costs to the operator in lieu of paying his share of reasonable well costs out of production.

(16) In addition to the issues in this case presented heretofore, Mitchell has attempted, via subpoena issued by the Division on February 5, 1990, upon request by Mitchell, to obtain certain documents from Mallon regarding the Amoco Red Bluff Federal Well No. 3, including well logs, daily drilling reports, completion data, and production data.

(17) Upon motion by Mallon, the Division has ruled to quash the subpoena, inasmuch as such data would give Mitchell an unfair advantage in deciding whether or not to voluntarily join in Mallon's well at this point in time, and would in fact relieve Mitchell of any risk penalty the Division determines might be appropriately assessed against him.

(18) Mallon has proposed that a risk penalty of 200% be assessed against Mitchell in this case.

(19) Mitchell has proposed that no risk penalty be assessed in this case inasmuch as the subject well has already been drilled, and no risk exists at the present time.

(20) The geologic evidence presented in this case might justify a 200% risk penalty; however, the fact that Mallon had sufficient opportunity to obtain a forced pooling order and establish a risk penalty prior to drilling the subject well, and the fact that Mallon had sufficient confidence in the probability of drilling a successful well that it carried Mitchell's interest at the time the well was drilled, indicates that the maximum risk penalty of 200% is not appropriate in this case.

(21) Mallon did, nonetheless, assume some risk at the time the subject well was drilled.

(22) The risk penalty assessed against Mitchell should be adjusted in accordance with Finding Nos. (20) and (21) above.

(23) Any non-consenting working interest owner who does not pay his share of estimated well costs should have withheld from production his share of the reasonable well costs plus an additional 75 percent thereof as a reasonable charge for the risk involved in the drilling of the well.

(24) Any non-consenting interest owner should be afforded the opportunity to object to the actual well costs but actual well costs should be adopted as the reasonable well costs in the absence of such objection.

(25) Following determination of reasonable well costs, any non-consenting working interest owner who has paid his share of estimated costs should pay to the operator any amount that reasonable well costs exceed estimated well costs and should receive from the operator any amount that paid estimated well costs exceed reasonable well costs.

(26) $3056.00 per month while drilling and $334.00 per month while producing should be fixed as reasonable charges for supervision (combined fixed rates); the operator should be authorized to withhold from production the proportionate share of such supervision charges attributable to each non-consenting working interest, and in addition thereto, the operator should be authorized to withhold from production the proportionate share of actual expenditures required for operating the subject well, not in excess of what are reasonable, attributable to each non-consenting working interest.

(27) All proceeds from production from the subject well which are not disbursed for any reason should be placed in escrow to be paid to the true owner thereof upon demand and proof of ownership.

(28) Should all the parties to this forced pooling reach voluntary agreement subsequent to entry of this order, this order shall thereafter be of no further effect.

(29) The operator of the well and unit shall notify the Director of the Division in writing of the subsequent voluntary agreement of all parties subject to the forced pooling provisions of this order.

IT IS THEREFORE ORDERED THAT:

(1) The application of George Mitchell, d/b/a G.P. II Energy, Inc. (Mitchell), for an order pooling all mineral interests from the surface to the base of the Cherry Canyon formation underlying the NW/4 NE/4 (Unit B) of Section 28, Township 26 South, Range 29 East, NMPM, Eddy County, New Mexico, forming a standard 40-acre oil spacing and proration unit for any and all formations and/or pools developed on 40-acre spacing within said vertical extent which presently includes but is not limited to the Brushy-Draw Delaware Pool, said unit to be dedicated to a well to be drilled at a standard well location thereon, is hereby denied.

(2) All mineral interests, whatever they may be, in the Brushy Draw-Delaware Pool underlying the NW/4 NE/4 (Unit B) of Section 28, Township 26 South, Range 29 East, NMPM, Eddy County, New Mexico, are hereby pooled to form a standard 40-acre oil spacing and proration unit for said pool. Said unit shall be dedicated to the existing Amoco Red Bluff Federal Well No. 3 located at a previously approved unorthodox oil well location 130 feet from the North line and 1805 feet from the East line (Unit B) of said Section 28.

(3) Mallon Oil Company is hereby designated the operator of the subject well and unit.

(4) Within 7 days after the effective date of this order, the operator shall furnish the Division and each known working interest owner in the subject unit an itemized schedule of estimated well costs.

(5) Within 14 days from the date the schedule of estimated well costs is furnished to him, any non-consenting working interest owner shall have the right to pay his share of estimated well costs to the operator in lieu of paying his share of reasonable well costs out of production, and any such owner who pays his share of estimated well costs as provided above shall remain liable for operating costs but shall not be liable for risk charges.

(6) The operator shall furnish the Division and each known working interest owner an itemized schedule of actual well costs within 90 days following completion of the well; if no objection to the actual well costs is received by the Division and the Division has not objected within 45 days following receipt of said schedule, the actual well costs shall be the reasonable well costs; provided however, if there is objection to actual well costs within said 45-day period the Division will determine reasonable well costs after public notice and hearing.

(7) Within 60 days following determination of reasonable well costs, any non-consenting working interest owner who has paid his share of estimated well costs in advance as provided above shall pay to the operator his pro rata share of the amount that reasonable well costs exceed estimated well costs and shall receive from the operator his pro rata share of the amount that estimated well costs exceed reasonable well costs.

(8) The operator is hereby authorized to withhold the following costs and charges from production:

(A) The pro rata share of reasonable well costs attributable to each non-consenting working interest owner who has not paid his share of estimated well costs within 14 days from the date the schedule of estimated well costs is furnished to him.

(B) As a charge for the risk involved in the drilling of the well, 75 percent of the pro rata share of reasonable well costs attributable to each non-consenting working interest owner who has not paid his share of estimated well costs within 30 days from the date the schedule of estimated well costs is furnished to him.

(9) The operator shall distribute said costs and charges withheld from production to the parties who advanced the well costs.

(10) $3056.00 per month while drilling and $334.00 per month while producing are hereby fixed as reasonable charges for supervision (combined fixed rates); the operator is hereby authorized to withhold from production the proportionate share of such supervision charges attributable to each non-consenting working interest, and in addition thereto, the operator is hereby authorized to withhold from production the proportionate share of actual expenditures required for operating such well, not in excess of what are reasonable, attributable to each non-consenting working interest.

(11) Any unleased mineral interest shall be considered a seven-eighths (7/8) working interest and a one-eighth (1/8) royalty interest for the purpose of allocating costs and charges under the terms of this order.

(12) Any well costs or charges which are to be paid out of production shall be withheld only from the working interest's share of production, and no costs or charges shall be withheld from production attributable to royalty interests.

(13) All proceeds from production from the subject well which are not disbursed for any reason shall immediately be placed in escrow in Eddy County, New Mexico, to be paid to the true owner thereof upon demand and proof of ownership; the operator shall notify the Division of the name and address of said escrow agent within 30 days from the date of first deposit with said escrow agent.

(14) Should all parties to this forced pooling order reach voluntary agreement subsequent to entry of this order, this order shall thereafter be of no further effect.

(15) The operator of the well and unit shall notify the Director of the Division in writing of the subsequent voluntary agreement of all parties subject to the forced pooling provisions of this order.

(16) Jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year *hereinabove designated.*

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

WILLIAM J. LEMAY
Director

S E A L

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION OF NEW MEXICO FOR
THE PURPOSE OF CONSIDERING:

CASE NO. 9867 (DE NOVO)
CASE NO. 9868 (DE NOVO)
Order No. R-9124-A

APPLICATION OF MALLON OIL COMPANY
FOR COMPULSORY POOLING, EDDY COUNTY,
NEW MEXICO.

APPLICATION OF GEORGE MITCHELL d/b/a
G.P. II ENERGY, INC. FOR COMPULSORY
POOLING, EDDY COUNTY, NEW MEXICO.

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9 o'clock a.m. on May 24, 1990, at Santa Fe, New Mexico, before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission."

NOW, on this 7th day of June, 1990, the Commission, a quorum being present, having considered the record and being fully advised in the premises,

FINDS THAT:

George Mitchell d/b/a G.P. II Energy, Inc., as applicant for hearing De Novo in these cases, has requested dismissal thereof and such request should be granted.

IT IS THEREFORE ORDERED THAT:

Cases Nos. 9867 De Novo and 9868 De Novo are hereby dismissed and Division Order No. R-9124 is hereby continued in full force and effect until further notice.

-2-
Case No. 9867 (De Novo)
Case No. 9868 (De Novo)
Order No. R-9124-A

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

WILLIAM R. HUMPHRIES, Member

Bill Weiss

WILLIAM W. WEISS, Member

WILLIAM J. LEMAY, Chairman and Secretary

S E A L

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