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April 7, 2000

HAND DELIVERED

Ms. Lori Wrotenbery
Oil Conservation Commission
2040 South Pacheco
Santa Fe, New Mexico 87505

Re: ***REQUEST FOR HEARING DENOVO***
NMOCD CASE 12325
Order No. R-11327
Application of Chesapeake Operating, Inc. for compulsory pooling and an unorthodox well location, Lea County, New Mexico

Dear Ms. Wrotenbery:

On behalf of Chesapeake Operating, Inc., a party of record adversely affected herein, please find enclosed our request for a Hearing DeNovo before the New Mexico Oil Conservation Commission in Case 12325.

Very truly yours,

W. Thomas Kellahin

cc: **Mr. Mark Ashley, Examiner**
Oil Conservation Division
Ms. Lyn Hebert, Esq.
Oil Conservation Division
Chesapeake Operating, Inc.
Attn: Lynda Townsend
William F. Carr, Esq.
Attorney for Altura Energy, Ltd. and Southeast Royalties, Inc.

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

CASE NO. 12325 (DeNovo)
Order No. R-11327

APPLICATION OF CHESAPEAKE OPERATING, INC.
FOR COMPULSORY POOLING AND AN UNORTHODOX
WELL LOCATION, LEA COUNTY, NEW MEXICO

CHESAPEAKE OPERATING, INC.'S APPLICATION FOR A DE NOVO HEARING BEFORE THE NEW MEXICO OIL CONSERVATION COMMISSION

Comes now CHESAPEAKE OPERATING, INC. ("Chesapeake"), a party of record before the New Mexico Oil Conservation Division in Case 12325 and adversely affected by Division Order R-11327 entered March 9, 2000, by its attorneys Kellahin & Kellahin and pursuant to Section 70-2-13 NMSA (1978), hereby requests that the New Mexico Oil Conservation Commission hold a HEARING DENOVO in this matter because Order R-11327 is arbitrary, capricious, contrary to precedents established by the Division and is not supported by substantial evidence because it:

(1) allowed the pooled parties to participate in potential Wolfcamp and Atoka-Morrow production from this well without reimbursing Chesapeake for any of the costs of drilling this well to the base of the Strawn formation;

(2) rejected Chesapeake's proposal to allocate well costs between the Wolfcamp, Strawn and Atoka-Morrow formations based upon the industry accepted method for allocating such costs established in 1965 by COPAS Bulletin No. 2 "Determination of Values for Well Costs Adjustments-Joint Operations"; and

(3) rejected Chesapeake's request for a 200% risk factor penalty to be applied to both drilling and completion costs.

ESSENTIAL FACTS

Chesapeake, by voluntary agreement, consolidated 100% of the working interest owners in the S/2SW/4 of this section and proposed to dedicate this 80-acre tract to a standard 80-acre spacing unit in the Northeast Shoe Bar-Strawn Pool by re-entering a well now redesignated as Chesapeake's College of the Southwest "17" Well No. 1 and directionally drilling it for potential production from this Strawn oil pool.

Chesapeake's reason for re-entering this wellbore was based upon its analysis of 3-D seismic data which indicated a potential Strawn reservoir just to the south of the bottom hole location of the abandoned David Fasken wellbore.

During the drilling of this wellbore, Chesapeake's operational personnel at the well site determined that the Strawn formation was non-productive and elected to continue drilling through the Strawn formation an additional 400 feet to the base of the Atoka/Morrow formation. The well has not been completed but based upon log analysis there is possible gas production from the Atoka-Morrow formation (below the Strawn) and possible oil production from the Wolfcamp formation (above the Strawn).

At the time Chesapeake's operational personnel elected to continue drilling this well, they obtained the concurrence of Fasken Land and Minerals, Ltd and Bonneville Fuels Corporation to continue drilling who they mistakenly believed were all working interests owners. In addition, they were under the mistaken impression that the Wolfcamp was spaced on 40-acre and not on 160-acre spacing units.

After drilling, but prior to completion, Chesapeake determined that while Altura Energy, Ltd. ("Altura") interest in the 80-acre Strawn spacing unit were leased to Chesapeake, Altura's interest in the N/2SW/4 needed to form a 160-acre Wolfcamp spacing unit consisting of the SW/4 and needed to form the 320-acre Atoka/Morrow formation spacing unit consisting of the S/2 were still held by Altura and not by Chesapeake.[1]

In addition, Chesapeake determined that Southeast Royalties owned an undivided 1.666% of the working interest in the 320-acre gas spacing unit to be dedicated to the Atoka formation if it produced.

[1] As a result of its interest in the N/2SW/4 of Section 17, Altura has a 13.333% working interest in the Wolfcamp formation and a 20% working interest in the Atoka/Morrow formation.

This well is located within one mile of the following pools with the following possible dedications:

(a) S/2 of this section consisting of 320-acres for production Atoka/Morrow formations in the West Lovington-Pennsylvanian Gas Pool ("stateside spacing");

(b) S/2SW/4 of this section consisting of 80-acres for oil production from the Strawn formation in the Northeast Shoe Bar-Strawn Pool (Order R-10848); and

(c) SW/4 of this section consisting of 160-acres for oil production from the Wolfcamp formation of the North Shoe Bar-Wolfcamp Pool (Order R-4657).

THE DIVISION IMPROPERLY DENIED RECOVERY OF DRILLING COSTS

Section 70-2-17.C NMSA (1978) provides that the Division has authority to enter a compulsory pooling order to pool interest owners in a well that has been drilled or is to be drilled. Chesapeake requested Examiner Ashley allow it to recover from Altura a reasonable portion of the drilling and completion costs applicable to the Wolfcamp and to the Atoka-Morrow formations. Altura incorrectly argued that they should not have to pay any of the drilling costs of the wellbore because it amounted to a plugged and abandoned Strawn wellbore and those costs should be borne exclusively by the parties who drilled and abandoned it.

Examiner Ashley agreed with Altura and has allowed Altura to participate as follows:

(a) for the Atoka formation it should pay only its proportionate share of the costs to drill below the base of the Strawn formation to the Atoka formation and then the costs to actually complete that zone;

(b) for the Wolfcamp formation it should pay only its proportionate share of the costs to actually complete that zone if and when a completion is attempted;

In essence, Examiner Ashley treated the wellbore as an abandoned dry hole in the Strawn formation with no value for either the Wolfcamp or Atoka/Morrow formation owners. He has concluded that the working interest owners in the Strawn formation have assumed the entre risk for the costs of the wellbore and are not entitled to any reimbursement for its value even if that wellbore is essential for accessing the Wolfcamp and Atoka-Morrow formations. Examiner Ashley ignored the fact that Chesapeake had not plugged and abandoned this wellbore after penetrating the Strawn, but had continued drilling to the Atoka/Morrow formation. In addition, he either did not know or failed to consider the fact that the Division requires the pooled parties to pay an appropriate share of the value of that existing wellbore if requested by the applicant.

Southeast Royalties contended it is not fair for it to receive a "free well"---meaning that just because Chesapeake had already drilled the well, that fact should not be used as an excuse by another party to avoid paying a fair and reasonable share of those drilling costs.

In entering his order, Examiner Ashley either did not know or chose to ignore numerous prior orders of the Division which are relevant to this case:

(1) if the Division wants to incorrectly treat the Chesapeake well as a plugged and abandoned Strawn well, then it needs to remember that when an operator has re-entered a plugged and abandoned wellbore and when he has requested reimbursement, the Division has required pooled parties to pay their proportionate share of the value of that existing wellbore in addition to the costs for recompletion. See Order R-10143 (Naumann Oil & Gas Inc. (1994); See R-9996 (Merrion v. Markham-1993); and

(2) while the Division might reduce the risk factor penalty because the well was drilled, the Division has always allowed for the value of the existing wellbore if the applicant asked for it. The issue of pooling additional interest owners into an existing wellbore was reviewed by the Commission on several occasions when it increased the size of spacing units from 320-acres to 640-acres in the Gavilan-Mancos Oil Pool. In all those instances, the new working interest owners were required to compensate the owners of the existing wellbore in order to participate in production. See Order R-8639 (Mesa Grande v. Sun Exploration-1988) , Order R-8641 (Dugan v. Amoco-1988). Order R-8262-A (Oryx v. Mallon-1989)

Chesapeake contended that it should not be required to give Altura a "free wellbore" and asked the Division allocate well costs between the Wolfcamp, Strawn and Atoka-Morrow formation based upon the industry accepted method for allocating such costs established in 1965 by COPAS Bulletin No. 2 "Determination of Values for Well Costs Adjustments-Joint Operations". Examiner Ashley rejected Chesapeake's request and in doing so acted arbitrarily and capriciously.

THE EXAMINER WAS WRONG TO REJECT CHESAPEAKE'S COPAS BASED METHOD FOR ALLOCATING COSTS AMONG OWNERS OF MULTIPLE FORMATIONS

In opposition to Chesapeake, Altura, with a 13.333% interest in the Wolfcamp and a 20% interest in the Atoka/Morrow, sought to participate in both the Wolfcamp and the Atoka/Morrow by only paying $27,000.00 for a completed well which Chesapeake estimated would cost about $840,000. It is interesting to compare the Chesapeake proposed costs with the fact that the estimated dry hole costs for a Wolfcamp well would exceed $600,000 and for an Atoka/Morrow well would exceed $800,000.

Examiner Ashley's order allowed Altura a separate election in the Wolfcamp and in the Atoka/Morrow such that:

> (a) Altura would pay $28,012.00 as its share of the costs remaining to set tubing and perforate/stimulate/log and produce the Wolfcamp formation.[2]
>
> (b) Altura would pay $55,267.29 as its share of the costs spent to drill below the base of the Strawn ($101,836.45) and the costs remaining to set tubing and perforate/stimulate/log, and produce the Atoka/Morrow formation ($174,500).[3]

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[2] Because the well has been drilled but not completed, the following Wolfcamp costs are still to be incurred: tubing, cased hole logging, perforating, stimulation, artificial lift, downhole equipment, etc for a total estimated cost of $210,500 of which Altura's share is 13.333% Examiner Ashley's decision assumes that the tubing is run in the wellbore and used only for the Wolfcamp completion. If the Commission adopts the COPAS allocation method, the estimated costs of the tubing have already been apportioned between the Wolfcamp and Atoka/Morrow formations.

[3] Examiner Ashley's Atoka/Morrow decision assumes that the tubing is run in the wellbore and used only for the Atoka/Morrow completion. The drilling costs below the Strawn are $100,724.25 for intangibles ($478,500 x 21.05%) and

Chesapeake proposed to make the necessary adjustments to its AFE, and to apply the COPAS allocation method such that the total cost allocated to the Atoka/Morrow owners is $549,451.98 and the total cost allocated to the Wolfcamp owners is $290,309.00. If Altura elects to participate in the Atoka/Morrow and Wolfcamp its share is $118,956.84. If they do not then, Chesapeake will pay Altura's share of those costs and be entitled to recover an additional 200% as compensation for carrying Altura's interest.

Thus, Altura should be required to make a single election as to both the Wolfcamp and Atoka/Morrow formations, then Altura's 20% share of the costs allocated to the Atoka/Morrow formation is $109,890.40 and Altura's 13.333% share of the costs allocated to the Wolfcamp formation is $9,066.44. This result occurs because much of the equipment will be utilized for both zones. Chesapeake considers it unfair to allow Altura to "split" its election among the two formations because to do so would allow Altura to benefit from certain expenses which it did not pay for and will result in Altura paying less than its fair share of costs.[4]

However, if the Commission affirms Examiner Ashley's decision, then Altura will have the benefit of a "split election". If Altura goes "non-consent" in the Atoka/Morrow and elects to participate in the Wolfcamp, then Altura should be required to pay $38,706.91 which is $13.33% of $290,309.00 which should be the costs allocated to the Wolfcamp based upon a "split election" option.

The COPAS method for allocating well costs addresses numerous possible situations where drilling and completion costs for drilled wells or proposed wells need to be allocated as a result of ownership changes caused by any number of reasons including different zones with different interests.

The Forward in the COPAS Bulletin No. 2 specifically indicates the applicability of this allocation method to the facts of the Chesapeake case when it states:

$1,112.20 for tangibles ($33,500 x. 3.32%) plus the remaining Atoka/Morrow completion costs are $174,500 (tubing, logging, stimulation/perforation, etc) for a total of $276,336.45

[4] The option of a split election has already been rejected by the Commission. See **Viking Petroleum, Inc. v. Oil Conservation Commisino and Harvey E. Yates**, 100 NM 451 (1983)

"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 costs...occurring as the result of one of the following:

(1) change in size of unit;
(2) recompletion of a well in a different zone;
(3) multiple completion of well in zones of different ownership;
(4) failure to obtain production in original objective zone and completion of well in zone of different ownership;
(5) creation of field wide or reservoir units." [paraphrased]

It is interesting to note that most, if not all, of these items are involved in the subject case.

Specifically, in the Chesapeake case, Chesapeake's AFE for a gas well drilled to a depth of 12,100 feet was estimated to be $856,000 for a producing gas well in the Strawn formation which included $258,000 for tangible costs and $598,000 for intangibles including $50,000 for seismic costs and certain other anticipated but unspent costs associated with producing the Strawn formation had it not been "dry".

Chesapeake proposed to make the necessary adjustments to this AFE, and to apply the COPAS allocation method such that the total costs allocated to the Atoka/Morrow owners is $549,451.98 based upon the following:

(1) the following anticipated intangible costs which were not used in the Strawn, are deducted from the intangibles and allocated 100% to the Atoka/Morrow:

item 430:	completion unit:	$20,000
item 431:	cased hole logging/perf	$10,000
item 434:	formation stimulation	$10,000
	surface rental	$ 1,000
	contingency 10%	$10,000
	supervision	$ 3,500
	TOTAL: $54,500	

(2) the remaining AFE intangibles of $543,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Atoka/Morrow owners were allocated 49.995% being $271,722.83.

(3) an additional $65,000 was added to item 434 for the fracture treatment anticipated for the Atoka/Morrow formation;

(4) the following anticipated tangible costs which were not used in the Strawn, are deducted from the tangibles:

production casing:	$82,000
tubing	$40,000
wellhead equipment	$ 4,000
Downhole equipment	$ 3,000
Artificial lift pump	$50,000
Production Equipment	$30,000
Non-controllable equip.	$ 1,000
contingency 10%	$14,500
Total:	$228,500

(5) the remaining AFE tangibles of $29,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Atoka/Morrow owners were allocated 36.37% being $10,729.15

(6) 100% of the following anticipated tangible costs attributable to the Atoka/Morrow were added:

production casing:	$82,000
tubing	$40,000
wellhead equipment	$ 4,000
Downhole equipment	$ 3,000
Production Equipment	$30,000
Non-controllable equip.	$ 1,000
contingency 10%	$14,500
Total:	$174,500

If Altura elects to participate in **both** the Atoka/Morrow and the Wolfcamp, then its 20% share of the Atoka/Morrow is $109,890.44. Because certain of the costs allocated to the Atoka/Morrow can also be utilized in the Wolfcamp such that the only additional Wolfcamp costs will be the cost of cased hole logging/perforating and stimulation of $18,000 plus $50,000 for artificial lift equipment. Altura's interest in the Wolfcamp formation is 13.333% and thus would pay an additional $9,066.44.

If, however, Altura goes "non-consent" in the Atoka/Morrow and elects to participate in the Wolfcamp, then Altura would be required to pay $38,706.91 being $13.33% of $290,309.00 based upon the following allocation:

(1) the following anticipated intangible costs would be deducted from the intangibles in Chesapeake's AFE and allocated 100% to the Wolfcamp:

item 430:	completion unit:	$20,000
item 431:	cased hole logging/perf	$ 8,000
item 434:	formation stimulation	$10,000
	surface rental	$ 1,000
	contingency 10%	$ 4,000
	supervision	$ 3,500
	Total:	$46,500

(2) the remaining AFE intangibles of $501,500.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Wolfcamp owners are allocated 21.05% being $105,565.75.

(3) the following anticipated tangible costs are deducted from the tangibles:

Artificial lift pump	$50,000
Non-controllable equip.	$ 1,000
contingency 10%	$ 5,000
Total:	$56,000

(4) the remaining AFE tangibles of $202,000.00 were apportioned among the Wolfcamp, Strawn and Atoka/Morrow owners using the COPAS allocation method such that the Wolfcamp owners were allocated 30.566% being $61,743.32

(5) an additional $20,000 was added for the downhole equipment for the Wolfcamp formation;

(6) 100% of the following anticipated tangible costs attributable to the Wolfcamp were added:

Artificial lift	$50,000
Non-controllable equip.	$ 1,000
contingency 10%	$ 5,000
Total:	$56,500

Chesapeake, using the COPAS allocation method, proposed to exclude those costs chargeable to the Strawn formation so that Altura would pay only those costs directly associated with the Wolfcamp and the Atoka-Morrow formations. For example, instead of paying for 100% of the costs of the wellbore to the Wolfcamp, the Wolfcamp owners would pay for the Wolfcamp completion costs and only one-third of the drilling costs to the base of the Wolfcamp and nothing below that depth.

However, without explanation, Examiner Ashley rejected the application of the COPAS allocation method to this case. Instead, he attempted, without success, to distinguish the Chesapeake case from the Yates case, in which the Division used the COPAS allocation method in a compulsory pooling case. In doing so, he failed to recognize that the COPAS allocation method still applies to the Chesapeake case.

CHESAPEAKE IS STILL ENTITLED TO REIMBURSEMENT FOR DRILLING COSTS FROM ALTURA EVEN THOUGH THE WELL WAS DRILLED PRIOR TO PROPOSING IT TO ALTURA

Chesapeake, by voluntary agreement, consolidated all interest owners in the Strawn formation, and drill the College of Southwest "17" Well No. 1 to the Strawn formation which was "dry". Chesapeake, under the mistaken belief that all of Altura's interest in the Atoka/Morrow formation was also leased by Chesapeake, continued drilling an additional 400 feet to the base of the Morrow formation. Prior to completing the well, Chesapeake recognized its mistake and contacted Altura and proposed that Altura pay its share of reasonable well costs. Altura and Chesapeake have not been able to reach an agreement.

Examiner Ashley has denied Chesapeake the right to recover any of the drilling costs from Altura, in part, because the well was drilled prior to providing Altura with an opportunity to participate.

Case law requires working interest owners to pay for their share of drilled wells even in circumstances where the operator is guilty of trespass. For example, in **Champlin Refining Co. v. Aladdin Petroleum Corp,** 238 P.2d 827 (OKLA 1951) the operator was allowed to recover all well costs for a well drilled as a dry hole, then plugged back to within 300 feet of the surface and drilled directionally to a new bottom hole location and obtained production because "the well was drilled in good faith and the costs thereof, being reasonable and necessary..."

More importantly the Division has already decided this matter in prior decisions. Unfortunately, Examiner Ashley has entered an order contrary to past precedents established by the Division.[5]

THIS ORDER IS CONTRARY TO PRIOR DIVISION ORDERS ADOPTING THE COPAS ALLOCATION SOLUTION IN A COMPULSORY POOLING CASE

Chesapeake reminded Examiner Ashley that in a previous pooling case[6] involving a drilled well the Division had adopted the COPAS allocation method so that the pooled party would pay only those costs properly associated with each formation.

In the Yates case, before the well was drilled, Yates offered to Chevron a chance to participate only in the Bone Springs. After the well was drilled and the Bone Springs determined to be dry, Yates completed the well, up hole, in the San Andres and then offered Chevron a chance to participate in the San Andres production if Chevron would pay its share of the drilling and completion costs for **both** the Bone Springs and the San Andres portions of the wellbore. Yates wanted Chevron to pay its share of the total well costs which included both the Bone Springs which was found to be non-productive and the San Andres which was productive. Chevron contended that pursuant to the COPAS allocation method it should pay only those costs associated with the productive San Andres. The Division agreed with Chevron and adopted the COPAS allocation method.

Examiner Ashley attempted to distinguish the Chesapeake case from the Yates case in five ways, all of which are wrong:

> (a) Examiner Ashley attempted to distinguish the Yates decision because it involved adding an uphole formation while the Chesapeake sought to add a deeper zone. In fact the Chesapeake case involves **both** a shallower (Wolfcamp) and a deeper zone (Atoka Morrow). Examiner Ashley has chosen a difference without a distinction. Why should this difference matter? It does not--the Forward of the COPAS Bulletin addresses both shallower and deeper zone allocation;

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[5] See the following section of this application which discusses Order R-9093-C entered in Case 9998 (Reopened). Also see Order R-8245 entered in Case 8897.

[6] OCD Case 9998 (Reopened), Division Order R-9093-C (Yates Petroleum Corporation v. Chevron (1990)

(b) Examiner Ashley attempted to distinguish the Yates decision because it involved two zones (the Bone Springs (deep zone) and the San Andres (shallow zone) both on 40-acre spacing while the Chesapeake case involved 80-acre (Strawn) 160-acre (Wolfcamp) and 320-acre (Atoka-Morrow) formations. Why should this difference matter? It does not--Examiner Ashley has failed or refused to understand the COPAS Bulletin deals with various sized units. See Conclusion COPAS Bulletin at page 8. In addition, Doyle Hartman increased the size of the spacing unit and pooled Chevron and was allowed to recover from Chevron's share of production the value of the existing wellbore he had on the original spacing unit. See Order R-9332 (1990);

(c) Examiner Ashley attempted to distinguish the Yates decision because, unlike the Chesapeake case, the interest owners were the same in all formations. Presumably, he would apply the COPAS solution only in those cases where ownership is common for all zones. Again, Mr. Ashley has failed to read or understand the COPAS Bulletin which specifically deals with multiple zones of different ownership (See Forward page 2) When there has been a change in the size of the spacing unit, the Division has required payment of well costs. See Order R-8282-D (Marathon v. Davidson-1988) Order R-8071-A (HCW Exploration v. Hartman-1986)

(d) Examiner Ashley attempted to distinguish the Yates case by incorrectly concluding that the pooled parties in the Yates case were provided an opportunity to participate before the well was drilled while in the Chesapeake case the well was drilled first. Examiner Ashley has relied upon a statement which is factually wrong. In the Yates case before the well was drilled, Chevron was offered a chance to participate only in the Bone Springs. After the well was drilled and the Bone Springs determined to be dry, Yates first completed the well in the San Andres and then offered Chevron a chance to participate if Chevron would pay for **both** the Bone Springs and the San Andres cost portions of the wellbore. In the Chesapeake case, Chesapeake had obtained a lease from Altura for Altura's interest in the Strawn formation and drilled the well but **before** completing the well in either the Wolfcamp or the Atoka-Morrow, offered Altura the opportunity to participate if Altura would pay its share of the costs pursuant to the COPAS allocation method. Once, again, Examiner Ashley attempt to distinguish the Yates case is based upon a reason that, frankly, does not matter even if it were factually correct which it is not.

(e) Examiner Ashley incorrectly states that the COPAS allocation method was used to decrease the costs to the pooled parties in the Yates case while in the Chesapeake case it was used in increase the costs to the pooled parties. Nothing could be more incorrect. In **both** cases the COPAS method was used so that the pooled parties paid only for those costs fairly attributed to the zone in which they had an interest and excluded them from paying for costs in zones where they had no interest. In **both** cases it resulted in the pooled parties costs being reduced.

Having attempted to distinguish the Chesapeake case from the Yates case, Examiner Ashley failed to recognize that the COPAS allocation method still applied to the Chesapeake case. None of his reasons for distinguishing Yates case form a logical or rational basis for excusing his failure to apply COPAS allocation method to the Chesapeake case.

The Risk Factor Penalty

Chesapeake recommended to the Division the adoption of a 200% risk factor penalty despite the fact that the well has been drilled[7] and logged because:

(a) there is no Atoka production within 3 miles of this well;

(b) both the original David Fasken which Chesapeake re-entered in Unit M of Section 17 and the Yates' Robert AGX State Well No 1 in Unit A of Section 20 had log indication of the presence of sandstone in the Atoka formation but failed to produce; and that the Atoka log indications for the College of Southwest 1-17 well are poorer than either of those wells.

(c) The nearest well to the subject College of Southwest well is Yates' Robert AGX State Well No 1 in Unit A of Section 20 which has only produced 1,451 barrels of oil from the Wolfcamp since 1996 which is not economic.

(d) The next closest well which produced from the Wolfcamp is located almost a mile away in Unit A of Section 17 and produced 77,776 barrels of oil which was not sufficient to pay for the costs of that well.

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[7] Division Order R-8245 (1986) awarded Mesa Grande a 200% risk factor against Chevron even though the well had been drilled.

(e) a log comparison of the Wolfcamp formation in the subject College of Southwest well with the Yates' well indicates that, at best, the College of Southwest well might be comparable to the Yates well, and if so, then production would not be sufficient to pay for the cost of the College of Southwest Well No. 1.

Altura recommended to the Division that a 100% risk factor penalty be assessed against them only for the costs of completion because:

(a) Chesapeake should be punished for its mistake in failing to consolidate Altura's interest in the Wolfcamp and Atoka formations prior to re-entry of the well.

(b) Altura wanted a chance to participate "risk free" in either the Atoka or Wolfcamp formations.

Examiner Ashley awarded a 100% risk factor only on the completion costs. Chesapeake requests that the Commission enter a DeNovo order awarding a 200% risk factor to be applied to both drilling and completion costs because:

(a) the availability of log data and the drilling of the well has not diminished the risk involved in this well to less than the statutory maximum and the maximum 200% risk factor should be awarded.

(b) Altura has the benefit of having the Chesapeake log data from which to base its decision concerning participation and if it elects not to participate then it will being doing so based upon the conclusion that it is too risky to participate;

(c) If Altura elects not to participate, it will be an admission that the risk is substantial and Altura should be subject to the maximum 200% penalty.

(d) Altura, after using Chesapeake's log data to analyze risk, can avoid any risk factor penalty by electing to participate.

(e) the fact remains that Chesapeake has paid for Altura's share of the costs of the well and should be reasonably compensated for having done so. The form of that compensation is a risk factor penalty.

CONCLUSION

In conclusion, Chesapeake requests that the Commission conduct a DeNovo Hearing, amend Examiner Order R-11327 and find that:

(a) Altura's contention concerning costs is without merit because it seeks to avoid making its fair and reasonable contribution for use of that portion of the wellbore from the surface to the base of the Strawn formation without which it would be impossible for Altura to share in any production from the Atoka formation;

(b) Altura's argument ignores the fact that the Chesapeake well was a continuous drilling operation and did not constitute an abandoned wellbore. (For Example, See Division Order R-10764-A);

(c) Altura's argument fails to address why it should not pay for its share of the costs of drilling to the shallower Wolfcamp formation in exchange for receiving its share of that production;

(d) Altura's argument fails to address why it should not pay for its share of the costs of drilling from the surface to the deeper Atoka/Morrow formation in exchange for receiving its share of that production;

(e) allocation of costs as set forth in the COPAS Bulletin No. 2 is considered by the industry to the most equitable basis for the determination of values to be used in connection with the cost issues involved in this compulsory pooling case;

(f) here is no compelling reason in this case to reject the precedent set by the Division in Order R-9093-C when it allocated costs among multiple formations in a contested compulsory pooling case based upon COPAS Bulletin No. 2;

(g) The Division should adopt the Chesapeake proposed COPAS allocation method; and

(h) there is no compelling reason in this case to reject the precedent set by the Division in Order R-8245 when it awarded a 200% risk factor penalty for a well which had already been drilled but which was awaiting completion. (Also See Division Order R-8282-D)

Respectfully Submitted:

W. Thomas Kellahin, Esq.
Attorney for Chesapeake Operating, Inc.

ALTURA ENERGY, INC.
Allocation of Well Costs - COPAS

A. Intangibles
(1) Using Drilling Day Ratio allocation:
total days – 19

12 day to drill to base of Wolfcamp: 12/19 = 63.16%

3 days to drill to base of Strawn 3/19 = 15.79%

4 days to TD (base of Atoka) 4/19 = 21.05%

(2) allocation to owners of each zone

(a) Wolfcamp WI:	1/3rd of 63.16%	21.05%
(b) Strawn WI:	1/3rd of 63.16%	
	plus ½ of 15.79%	28.945%
(c) Atoka WI:	1/3rd of 63.16%	
	plus ½ of 15.79%	
	plus 100% of 21.05%	49.995%

(3) allocation to Altura

(a) 13.333% of Wolfcamp
(b) 20.0% of Atoka

B. Tangibles:

(1) Using footage Ratio allocation:
total footate = 12,050'

11,050 feet to base of Wolfcamp 11,050/12,050 = 91.7%

600' to base of Strawn 600/12,050 = 4.97%

400' to TD (base of Atoka) 400/12,050 = 3.32%

(2) allocation to owners of each zone:

(a) Wolfcamp WI:	1/3rd of 91.7%	30.566%
(b) Strawn WI:	1/3rd of 91.7%	
	plus ½ of 4.97%	33.051%
(c) Atoka WI:	1/3rd of 91.7%	
	plus ½ of 4.97%	
	plus 100% of 3.32%	36.37%

(3) allocation to Altura:

(a) 13.333% of Wolfcamp
(b) 20% of Atoka

EXHIBIT 7

CHESAPEAKE OPERATING, INC.

AUTHORIZATION FOR EXPENDITURE

Project Area: Lovington
Well Name: College of the SW 1-17 (Re-entry)
Operator: Chesapeake Operating, Inc.
AFE #: 952332
Spacing Unit: S/2 Section 17-16S-36E

County, State: Lea, New Mexico
Date: October 22, 1999
Total Depth: 12,100'
Formation: Strawn/Atoka

CODE		INTANGIBLE COSTS	WORK DESCRIPTION			DRY HOLE	PRODUCER
233400		Location:	Roads, Location, Pits			$20,000.00	$20,000.00
233405			Reclamation			$20,000.00	$20,000.00
233401			Damages			$6,000.00	$6,000.00
233402		Legal:	Governmental Filings			$2,000.00	$2,000.00
233403			Title Opinions			$3,000.00	$3,000.00
233404			Seismic Costs			$50,000.00	$50,000.00
233406		Drilling:	Top Drive			$0.00	$0.00
233408			Pipeline Construction			$0.00	$0.00
233410			Drilling Contractor: 18 days @ $5,300/day			$95,000.00	$95,000.00
233411			Directional Services			$46,000.00	$46,000.00
233413			Rig Mobilization/Demobilization			$20,000.00	$20,000.00
233414			Contract Labor			$10,000.00	$15,000.00
233415			Bits			$30,000.00	$30,000.00
233416			Supplies and Utilities			$1,000.00	$3,000.00
233417			Cement Conductor			$0.00	$0.00
233417			Cement Surface Casing			$0.00	$0.00
233417			Cement Intermediate Casing			$0.00	$0.00
233417			Cement Production Casing			$0.00	$20,000.00
233417			Cement Drilling Liner			$0.00	$0.00
233417			Cement Production Liner			$0.00	$0.00
233418			Mud Logging			$11,000.00	$11,000.00
233419			Drilling Fluids, Mud, Chem.			$20,000.00	$20,000.00
233421			Drill String Inspection			$0.00	$0.00
233423			Open Hole Logging			$22,000.00	$22,000.00
233427			Fishing			$0.00	$0.00
233428			Downhole Rental Equipment			$10,000.00	$10,000.00
233430		Completion:	Completion Unit			$0.00	$20,000.00
233431			Cased Hole Logging/Perforating			$0.00	$10,000.00
233433			Jetting			$0.00	$0.00
233434			Formation Stimulation			$0.00	$10,000.00
233437		General:	Surface Equipment Rental			$18,000.00	$19,000.00
233438			Transportation			$0.00	$3,000.00
233441			Frac Fluid Hauloff			$0.00	$0.00
233442			Blowout/Emergencies			$0.00	$0.00
233443			Company Supervision/Engineering			$10,000.00	$15,000.00
233444			Consultants			$8,000.00	$8,000.00
233446			Company Overhead			$8,000.00	$13,000.00
233447			Insurance			$5,000.00	$5,000.00
233449			Major Construction Overhead			$0.00	$2,000.00
233450			Plug to Abandon			$0.00	$0.00
			20% Contingency			$83,000.00	$100,000.00
TOTAL	INTANGIBLES		Total Intangible Costs			$498,000.00	$598,000.00
CODE		TANGIBLE COSTS	WORK DESCRIPTION				
230100		Tubulars:	Surface Casing:			$0.00	$0.00
230100			Intermediate Casing:			$0.00	$0.00
230100			Production Casing:	12,100'	5 1/2"	$0.00	$82,000.00
230100			Drilling Liner:			$0.00	$0.00
230100			Production Liner:			$0.00	$0.00
230100			Tubing:	11,500'	2 7/8"	$0.00	$40,000.00
230104			Float Equipment			$0.00	$2,000.00
230106		Lease Equipment:	Wellhead Equipment			$3,000.00	$7,000.00
230107			Downhole Equipment			$0.00	$3,000.00
230111			Artificial Lift-Pumping Unit			$0.00	$50,000.00
230113			Production Equipment			$0.00	$30,000.00
230115			Compressor/Compression			$0.00	$0.00
230116			Pipeline Equipment			$0.00	$0.00
230120			Non-Controllable Equipment			$1,000.00	$1,000.00
			20% Contingency			$1,000.00	$43,000.00
TOTAL	TANGIBLES		Total Tangible Costs			$5,000.00	$258,000.00
			Total Costs			$503,000.00	$856,000.00

Prepared by: JKO

Approved by: JML

OPERATOR'S APPROVAL ______________________ DATE ________
Operations/Geology

OPERATOR'S APPROVAL [signature] DATE 10/22/99
Land/Accounting

NON-OPERATOR'S APPROVAL ______________________ DATE ________