CRESON V. AMOCO PROD. CO., 2000-NMCA-081, 129 N.M. 529, 10 P.3d 853

ROBERT P. CRESON, DON E. WILLIAMS, FRED BENNERS, DON MICHAEL DOWDLE, and OLIVER H. DANIELS, TRUSTEES OF THE PUBLIC LANDS ROYALTY TRUST, and GEORGE L. SCOTT, Plaintiffs-Appellants,
vs.
AMOCO PRODUCTION COMPANY, and AMERADA HESS, Defendants-Appellees.

Docket No. 19,794

COURT OF APPEALS OF NEW MEXICO

2000-NMCA-081, 129 N.M. 529, 10 P.3d 853

June 21, 2000, Filed

APPEAL FROM THE DISTRICT COURT OF QUAY COUNTY. Stephen K. Quinn, District Judge.

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COUNSEL

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JUDGES

RUDY S. APODACA, Judge. WE CONCUR: RICHARD C. BOSSON, Judge, M. CHRISTINA ARMIJO, Judge.

AUTHOR: RUDY S. APODACA

OPINION

*{*531}* **APODACA, Judge.**

{1} Plaintiffs sued Defendants for an accounting and damages as the result of alleged miscalculations of royalties owed under an agreement known as the Unit Agreement and involving the Bravo Dome Carbon Dioxide Gas Unit (the Unit). After a non-jury trial and entry of findings of fact and conclusions of law, the trial court entered judgment in Defendants' favor on all of Plaintiffs' claims but ordered Defendants to account to Plaintiffs for all past and future deductions from the actual sales price used to calculate the royalty payment.

{2} Plaintiffs appeal, challenging the trial court's conclusion that the Unit Agreement executed by the parties in 1979 authorized certain deductions for unit expenses in calculating the royalty payment. Plaintiffs also challenge the trial court's determination that the Unit Agreement nullified a prior royalty payment provision in a document known as the Amoco Assignment, which was more favorable to them.

{3} We hold that the Unit Agreement, not the Amoco Assignment, controls the method for calculating royalties and that "net proceeds derived from the sale of Carbon Dioxide Gas at the well," a controlling clause contained in the agreement, is not ambiguous. We also hold that the trial court did not err in determining that post-production, value-enhancing costs were properly used by Defendants under the Unit Agreement to calculate the value of or net proceeds from the carbon dioxide gas sold downstream from the wellhead and the resulting royalty ultimately paid to Plaintiffs. We therefore affirm the trial court's judgment.

I. FACTUAL BACKGROUND

{4} The primary question we must address is whether the Unit Agreement provides for the deduction of unit expenses from the sales price of the gas before calculating the royalties Defendants must pay to Plaintiffs. Defendant Amoco Production Company (Amoco) operates the Unit. Defendant Amerada Hess (Hess) owns some of the leases contained within the Unit. Both Amoco and Hess are working interest owners (the WIOs). Plaintiff George Scott (Scott) owns an overriding royalty interest on production from leases owned only by Hess, and the remaining Plaintiffs, as trustees of the Public Lands Royalty Trust (the Trust), own overriding royalty interests on production from leases owned by both Amoco and Hess. The Unit was formed to consolidate and coordinate the production of carbon dioxide gas in an area consisting of more than 750,000 acres controlled by a variety of leases and with more than one thousand royalty owners. Carbon dioxide gas is injected into oil wells to enhance recovery of oil.

A. The Unit Agreement

{5} Four provisions of the Unit Agreement are particularly relevant. Article 1.16 defined "Unit Expense" as "all cost, expense or indebtedness incurred by the [WIOs] or Unit Operator pursuant to this Agreement and the Unit Operating Agreement for or on account of Unit Operations." Article 1.14 of the Unit Agreement defined "Unit Operations" as "all operations conducted pursuant to this agreement and the Unit Operating Agreement."

{6} Article 6.3 of the Unit Agreement stated:

> **Basis of Payment to Royalty Owners**. It is recognized by the parties hereto that there is no preeminent market for Carbon Dioxide Gas. Therefore, the parties hereto agree that, as further consideration for entering into this agreement, royalties paid upon the Unitized Substances allocated to each Tract shall be based on the greatest of the following:
>
> (a) **The net proceeds derived from the sale of Carbon Dioxide Gas at the well** whether such sale is to one or more parties to this agreement or to any other party or parties.

The Unit Agreement differed from most unit agreements generally used in the oil and gas industry because it contained the royalty *{*532}* clause provision of Article 6.3. Model forms of unit agreements do not contain royalty clauses because the royalties are generally paid pursuant to the underlying leases. According to Defendants, Article 6.3 was included in the Unit Agreement because there was no market price for carbon dioxide gas and some of the leases involving land within the Unit provided for royalties based on market price.

{7} Yet another provision of the Unit Agreement comes into play in this appeal--Article 14.3. Plaintiffs rely heavily on this article to exempt them, as royalty owners, from payment of any unit expenses. Article 14.3 provided:

> **Royalty Owners Free of Cost**. This Agreement is not intended to impose, and shall not be construed to impose, upon any Royalty Owner any obligation to pay Unit Expense unless such Royalty Owner is otherwise so obligated.

Article 14.3 is a standardized provision in the American Petroleum Institute's model form unit agreement. Plaintiffs argue that, because compression, dehydration, gathering, and depreciation are "unit expenses," as that term is used in Article 14.3, Defendants cannot deduct these costs from the sales price before computing Plaintiffs' royalties.

B. Valuation Method

{8} Plaintiffs ratified the Unit Agreement in June of 1979 after consulting with an attorney who was a board certified specialist in oil and gas law in Texas. Plaintiffs' royalties under the Unit Agreement were based on a percentage of the carbon dioxide gas produced. This percentage is not disputed. What is at issue is the method of valuing the "net proceeds derived from the sale of carbon dioxide gas at the well," the clause used in Article 6.3. It is undisputed that a small percentage of the carbon dioxide gas "is sold in the form in which it emerges from the wellheads prior to processing or transportation" and that the carbon dioxide gas is marketable in its unprocessed state at the wellheads. It is also undisputed that compression, dehydration, and gathering are processes to make the carbon dioxide gas suitable for delivery into the pipeline system and that these expenses, along with depreciation, are unit expenses under the Unit

Agreement. These processes take place on the Unit and within the boundaries of the combined leases.

{9} Defendants have calculated the royalties under the Unit Agreement by subtracting or "netting back" an amount for operating costs, capital costs, and depreciation expenses for the gathering, compressing, and dehydration facilities and functions in the Unit. It is undisputed that the royalties paid to Plaintiffs, even after making these cost adjustments for carbon dioxide gas sold downstream of the wellheads, were still higher than the price received for the carbon dioxide gas actually sold at the wellheads. The trial court also found, and Plaintiffs do not dispute that, since production began on the Unit in 1984, Plaintiffs have received royalties on the same basis as the State of New Mexico and that the state approved the categories and amounts of cost adjustments used to arrive at the value for "net proceeds . . . at the well." The State has not contested these same cost adjustments that Plaintiffs now dispute. Plaintiffs do not claim that the cost adjustments Defendants used were inflated or did not reflect the actual costs incurred to enhance the value of the gas in the marketplace. They only dispute the use of these cost adjustments in calculating the royalties to be paid under the Unit Agreement, in light of Article 14.3, which states that unit expenses shall not be imposed as obligations of Plaintiffs, as royalty owners.

II. DISCUSSION

A. Standard of Review

{10} In determining whether the Unit Agreement is ambiguous, the trial court could properly consider the context of the agreement, including the circumstances surrounding it, and any relevant usage of trade or course of dealing. **See Mark V, Inc. v. Mellekas**, 114 N.M. 778, 781, 845 P.2d 1232, 1236 (1993). The question of whether an ambiguity exists is a question of law. **See id.** If the agreement is found to be ambiguous--in other words, if it is reasonably and fairly susceptible to different constructions--the meaning to be assigned unclear terms then *{*533}* becomes a question of fact. **See id.** If, however, the contract is unambiguous, we determine its meaning as a matter of law. **See Nearburg v. Yates Petroleum Corp.**, 1997-NMCA-69, P7, 123 N.M. 526, 943 P.2d 560. This Court reviews questions of law under a de novo standard of review and questions of fact under a substantial evidence standard of review. **See** 114 N.M. at 781-82, 845 P.2d at 1236-37; **see also Allsup's Convenience Stores v. North River Ins. Co.**, 1999-NMSC-6, PP27-28, 127 N.M. 1, 976 P.2d 1.

B. Interpretation of "net proceeds . . . at the well"

{11} The question posed by Article 6.3 is whether, when the sale of the gas occurs at a place other than the wellhead, Defendants could make post-wellhead cost adjustments in valuing the "net proceeds . . . at the well." Relying in part on expert testimony, the trial court determined that the phrase "net proceeds . . . at the well" had a long standing and unambiguous meaning in the oil and gas industry in computing royalty settlement or payment.

{12} The trial court concluded that "net proceeds" implied that the parties intended to make deductions to account for costs and, because the royalty provision was based on net proceeds at the well, a producer should deduct "from downstream sales proceeds those post production value enhancing costs associated with transporting and processing the gas up to the point of sale." Plaintiffs do not challenge the trial court's holding that the phrase is unambiguous. At oral argument, Plaintiffs conceded the lack of ambiguity. What they do take issue with, however, is the trial court's interpretation of the phrase. Plaintiffs argue that Article 6.3 provides for the payment of royalties based on a percentage of the net of all costs or expenses **except unit expense**. The basis of that argument is that Article 14.3 prohibits assessing those unit expenses on Plaintiffs, which, according to Plaintiffs, Defendants have essentially done by deducting those costs in their computations of royalties.

{13} Commentators have noted that royalty clauses in instruments creating overriding royalty interests generally provide that proceeds will be delivered free of the cost of production. **See, e.g.**, 3 P. Martin & B. Kramer, **Williams and Meyers Oil and Gas Law** § 645, at 594 (1999) (referred to as **Williams and Meyers**). Because of how common these provisions are, "royalty and overriding royalty interests are usually defined as interests [that] are free of production costs." **See id.** The commentators and case law, however, generally distinguish between production costs and costs incurred post-production. **See Williams and Meyers**, § 645.2, at 595. We consider this to be an important distinction. "A royalty or other nonoperating interest in production is usually subject to a proportionate share of the costs incurred subsequent to production where the royalty or nonoperating interest is payable 'at the well.'" **See id.** § 645.2, at 597-98.

{14} In the absence of an express agreement to the contrary, such post-production costs generally include transportation costs, expenses of treatment such as dehydration, expenses of compressing gas so that it can be delivered into a pipeline, and other "costs incurred in adding value to the well-head product." **See Williams and Meyers**, § 645.2, at 601-04; **see also** E. Kuntz, **A Treatise on the Law of Oil and Gas** § 40.4, at 344 (1989) (stating that "if the provision [that] refers to proceeds refers specifically to sales of gas at the well, then the royalty is determined by the value at the well and not by the proceeds of sales elsewhere" and noting that the net value includes reducing the amount of proceeds by allocable costs).

{15} In this appeal, the royalty clause in the Unit Agreement (Article 6.3) *{*534}* provided for payment based on the "net proceeds derived from the sale of Carbon Dioxide Gas at the well." We determine, as did the trial court, that this clause is unambiguous and means that Plaintiffs are entitled to royalties based on the value of the carbon dioxide gas as it emerges at the wellhead.

{16} Our determination is amply supported by the case law. In **Martin v. Glass**, 571 F. Supp. 1406 (N.D. Tex. 1983), the court was faced with the question of whether compression charges were properly chargeable to the royalty owners under a lease that provided for payment based on "net proceeds at the well received from the sale [of the gas]." **Id.** at 1410. Interpreting this phrase according to its ordinary, popular, and commonly accepted meaning, the federal court determined that the royalty owners were entitled to the value of the gas delivered or produced to the mouth of the well and this royalty was free of all costs up to that point. **See id.** at 1411. The court also determined that "'net proceeds' clearly suggests that certain costs are deductible." **Id.** ; **see also Phillips Petroleum Co. v. Johnson**, 155 F.2d 185, 188-89 (5th Cir. 1946) ("The stipulation for a share of the 'net proceeds derived' ought to be enforced, effect being given to the words 'net at the mouth of the well' by allowing as expense the cost of transporting, separating, and marketing.").

{17} The parties in **Martin** stipulated that there was insufficient pressure at the wellhead to enable the gas to enter the purchaser's gathering line without compression. **See Martin**, 571 F. Supp. at 1416. Despite the fact that there was no market for the gas as it existed at the wellhead, the court applied Texas law and determined that compression was a marketing expense as opposed to a production expense and was properly deducted from the value used to calculate royalties. **See id.**

{18} In a later case, the Texas Court of Appeals defined production costs as:

> expenses incurred in exploring for mineral substances and in bringing them to the surface. Absent an express term to the contrary in the lease, these costs are not chargeable to the non-operating royalty interest. Costs incurred after production of the gas or minerals are normally proportionally borne by both the operator and the royalty interest owners.

Parker v. TO Prod. Corp., 716 S.W.2d 644, 648 (Tex. Ct. App. 1986). In **Parker**, the compressors were installed to increase production from the wells. **See id.** The court distinguished the facts in **Martin** where compression was necessary, not to bring the gas to the wellhead, but to deliver the gas into the purchaser's gathering line. The court then determined that the costs of compression in **Parker** were production costs to increase the amount of gas recovered at the well and should not have been deducted in calculating the royalty payments. **See id.**

{19} In **Piney Woods Country Life School v. Shell Oil Co.**, 726 F.2d 225, 228 (5th Cir. 1984), the court interpreted leases that provided for royalties based on market value except when the gas was sold at the well. At issue was the propriety of deducting processing costs from the price used to calculate royalties. **See Piney Woods**, 726 F.2d at 230. Noting that different calculations were to be used depending on whether the sale or use was "at the well," the court concluded:

> The purpose is to distinguish between gas sold in the form in which it emerges from the well, and gas to which value is added by transportation away from the well or by processing after the gas is produced. The royalty compensates the lessor [or royalty owner] for the value of the gas at the well: that is, the value of the gas after the lessee fulfills its obligation under the lease to produce gas at the surface, but before the lessee adds to the value of this gas by processing or transporting it.

Id. at 231; **see also Atlantic Richfield Co. v. State**, 214 Cal. App. 3d 533, 262 Cal. Rptr. 683, 688 (Cal. Ct. App. 1989) (construing legislation providing for payment to the state based on "market value at the well" in the context of offshore drilling and concluding that California provides for determining the value at the well by deducting the costs of transporting the produced gas to an onshore processing facility and processing the gas to obtain a commercially marketable product); **Judice v. Mewbourne Oil Co.**, 939 S.W.2d 133, 137 (Tex. 1996) (stating that "'net proceeds' expressly contemplates deductions, and we note once again that 'at the well' means before value is added by preparing the gas for market").

{20} In **Piney Woods**, the WIOs passed expenses to the royalty owner for treating and transporting the natural gas according to a complex formula that compensated it for these expenses and capital investment. **See Pine Woods**, 726 F.2d at 240. Because the royalty clause provided for payment based on value "at the well," the court rejected the royalty owners' argument that they could not *{*535}* be charged for these expenses as costs of discovery and production and that production costs included any costs necessary to make the gas marketable.

{21} In allowing royalty owners to be charged with processing costs, including all post-production expenses relating to processing, transportation, and marketing, the court emphasized "that processing costs are chargeable only because, under these leases, the royalties are based on value or price at the well. Processing costs may be deducted only from valuations or proceeds that reflect the value added by processing." **Id.** The court noted that the function of processing costs in determining royalties based on market value at the well is to adjust for imperfect comparisons. Deductions for these costs may be "an indirect means of determining what a buyer would have paid . . . at the wellhead." **Id.** ; **accord Merritt v. Southwestern Elect. Power Co.**, 499 So. 2d 210 (La. Ct. App. 1986).

{22} We recognize that other states have not allowed costs of compression, dehydration, and gathering to be charged to the royalty owner under certain circumstances. Those circumstances are not present in this case, however. **See, e.g.**, **Garman v. Conoco, Inc.**, 886 P.2d 652, 654 (Colo. 1994) (en banc) (answering a question certified to the court without considering specific contractual terms, the court concluded that post-production costs undertaken to convert raw gas into a marketable product were not deductible based on the implied covenant to market). In this appeal, Plaintiffs have conceded that the carbon dioxide gas was marketable at the wellhead and that some small portion of the gas was actually sold at the wellhead. **Cf. Gilmore v. Superior Oil Co.**, 192 Kan. 388, 388 P.2d 602, 607 (An. 1964) (disallowing the costs of compression as part of the lessee's duty to market the gas produced); **Sternberger v. Marathon Oil Co.**, 257 Kan. 315, 894 P.2d 788, 791 (An. 1995) (determining that, although expenses in making the product marketable were not deductible, where the gas is marketable at the wellhead, but for the lack of a purchaser at that location, the costs of transportation may be properly deducted).

{23} In **West v. Alpar Resources, Inc.**, 298 N.W.2d 484 (N.D. 1980), the court determined that a royalty clause providing for payment based on "proceeds from the sale of the gas" was ambiguous, and the court thus disallowed deductions for any costs incurred by the WIO. **West**, 298 N.W.2d at 491. In construing the contractual provision against the WIO as lessee, the court noted that the WIO's predecessor in interest could easily have limited royalty payments to the net proceeds received from the sale after allowance of certain costs. **See id.** ; **see also Hanna Oil & Gas Co. v. Taylor**, 297 Ark. 80, 759 S.W.2d 563, 564-65 (Ark. 1988) (interpreting a provision based on "proceeds received . . . at the well"). In this appeal, however, the royalty clause provides expressly for "net proceeds" rather than proceeds. **See Hurinenko v. Chevron, USA, Inc.**, 69 F.3d 283, 285 (8th Cir. 1995) (distinguishing **West** as having been based on the "proceeds" clause where the clause in **Hurinenko** used "market value at the well" and, therefore, processing costs could be deducted from gross sales revenues).

{24} Article 6.3, the royalty clause, expressly used the term "net proceeds," and it is undisputed that the carbon dioxide gas was marketable and was actually marketed at the wellhead. Even under cases from other jurisdictions, such as **Garman** and **Sternberger**, the costs of compression, gathering, and dehydration in this case would be deductible. Because the carbon dioxide gas was marketable at the wellhead, this would be considered post-production, value enhancing costs that could be deducted from the value of the gas at its termination point as a means of establishing the value of the gas at the wellhead, before the gas was sold downstream at an enhanced value. We thus hold that the post-production values Defendants added was properly deducted before calculation of royalties due.

{25} We also observe that, in contrast to the plentiful authority in support of the trial court's interpretation, Plaintiffs have not offered any contrary authority under similar facts and circumstances. For this reason, we are confident that the trial court's interpretation and application of the "net proceeds . . . at the well" clause is fully supported by all *{*536}* judicial opinions on the subject. Plaintiffs would have us deviate from accepted law on the basis of little or no authority, a course we do not choose to embark upon.

C. Depreciation of Capital Expenditures

{26} Plaintiffs argue that, even if this Court affirms the trial court's interpretation of the Unit Agreement, the trial court erred in allowing deductions for depreciation of capital costs. Plaintiffs do not, however, provide us with any more specific arguments or with any authority on this issue. We understand this argument to raise an issue regarding the method of accounting or the formula Defendants used to arrive at the royalty based on net proceeds at the well for sales that occurred downstream. We note that Plaintiffs did not assert below that the cost adjustments used to derive a "net proceeds at the well" value were inflated or did not reflect the actual costs incurred to enhance the value of the gas.

{27} But even beyond those findings, because Defendants are required by the final judgment to provide Plaintiffs with an accounting of the deductions taken in the past as well as all future deductions, we determine that the specific issue of whether depreciation expenses were proper is not ripe for review. In this regard, we note that deductions for depreciation of capital investments may be proper if those capital expenditures related to enhancing the value of the gas after it reached the wellhead in a marketable state. **See generally Piney Woods**, 726 F.2d at 240 ("[Royalty owners] may be charged with processing costs, by which we mean **all expenses**, subsequent to production, relating to the processing, transportation, and marketing . . . ."). (Emphasis added).

D. Article 14.3

{28} The trial court concluded that Article 14.3 set forth the general proposition that royalty owners would not bear the capital intensive costs of developing the producing property. The court also concluded that there was no conflict between Articles 6.3 and 14.3. Finally, the court concluded that the deductions for unit expenses in calculating royalties did not violate this provision. Plaintiffs challenge these conclusions and assert that the plain language of the Unit Agreement required that Article 6.3 be subject to the free-of-cost provision of Article 14.3.

{29} This assertion fails in two respects. First, as we discuss later in this section, Article 6.3 did not shift costs to Plaintiffs but was merely used to determine the "net value at the wellhead," on which the Unit Agreement clearly states royalties were to be calculated. Additionally, even if we were to agree with Plaintiffs that Article 6.3 did in fact shift some of the cost to them and that Article 14.3 freed Plaintiffs of all costs, we are still unpersuaded. Article 14.3 provided that Plaintiffs were free of costs "unless [Plaintiffs were] otherwise so obliged." Reading this part of Article 14.3 in conjunction with Article 6.3 would indicate that Plaintiffs were "so obliged." In either case, Plaintiffs' contention that the two provisions cannot be read in conformity with one another fails.

{30} Plaintiffs would distinguish cases such as **Martin** and **Piney Woods** because the facts there do not state that they contained a "free of cost" provision. As noted in **Williams and Meyers**, however:

> Inasmuch as gas royalty is ordinarily payable in money rather than in kind and is measured by value or proceeds at the wellhead, it is not customary, as in the case of oil royalty payable in kind, to specify that the royalty is free of cost of production. Freedom from such costs of production is implicit in the provision for payment of a share of the proceeds or value at the wellhead. However an occasional lease makes this specific even in the case of the gas royalty.

Williams and Meyers § 643.2, at 530.1. We interpret Section 14.3 as an explicit statement of what is implicit in most leases providing for the payment of royalties based on "net proceeds at the well." In other words, Section 14.3 specifies that the royalties will be free from the costs of production. The section does not permit royalty owners to reap the benefits of an enhanced value of the gas sold downstream. **See, e.g., Danciger Oil** *{*537}* **& Refineries, Inc. v. Hamill Drilling Co.**, 141 Tex. 153, 171 S.W.2d 321, 323 (Tex. 1943) (determining that a royalty clause providing for payment "free and clear of operating expenses" referred to expenses necessary to production and not to post-production expenses). Free of cost provisions are not inconsistent with allowing post-production, value-enhancing costs to be used to calculate the value of the gas at the wellhead. **See id.**

{31} Plaintiffs also argue that the parties' course of dealing and Defendants' conduct after the Unit Agreement was ratified established the parties' intent that the royalty owners would not bear any cost of the unit operations. It is clear that Defendants repeatedly represented, before and after ratification, that royalty owners would not pay or be liable for any of the expenses involved in the Unit and that the unit operator would pay all the expenses of the Unit. This is evidenced by the Unit Agreement itself**,** the brochure outlining the program for unit operations that was sent to royalty owners prior to ratification, and solicitation letters sent by Amoco.

{32} In testimony before the State Energy and Minerals Department in July of 1980, Amoco's representative was asked if the Unit Agreement contemplated that a royalty owner would pay any of the costs of the Unit and the unit operation and the response was "No. All such costs will be borne by the working interest owners." In orally explaining the Unit Agreement in March 1980 to royalty owners, Amoco's representative stated that Article 6 provided for royalty payments based on the greater of the "net proceeds per mcf. derived from the sale of CO at the well or [a] minimum value of 12 [cents] at the well." We are not persuaded, however, that deductions for the costs of compression, gathering, dehydration, and capital depreciation used to establish "net value at the well" for downstream sales is equivalent to requiring Plaintiffs to pay for or bear these costs.

{33} Instead, these costs were used as a means of calculating the value of the carbon dioxide gas at the wellhead for those sales that occurred downstream. Because there is no "net proceeds at the well" for downstream sales, it is necessary to reconstruct this value for these sales. Use of these costs for this limited purpose, in our view, is not equivalent to assessing those costs directly to the royalty owners. As another court stated in the context of reconstructing a market value where one did not exist,

> all increase in the ultimate sales value attributable to the expenses incurred in transporting and processing the commodity must be deducted. The royalty owner shares only in what is left over. . . . In this sense he bears his proportionate part of that cost, but not because the obligation (or expense) of production rests on him. Rather, it is because that is the way in which Louisiana law arrives at the value of the gas at the moment it seeks to escape from the wellhead.

Freeland v. Sun Oil Co., 277 F.2d 154, 159 (5th Cir. 1960); **see also Danciger**, 171 S.W.2d at 323 (determining that a royalty clause providing for payment "free and clear of operating expenses" referred to expenses necessary to production and not to post-production expenses).

{34} Similarly, we are persuaded that the deductions for post-production, value-enhancing expenses in this case when used as a means of valuing the net proceeds at the well does not mean that an obligation of production or unit expenses is being imposed on Plaintiffs. Although it is undisputed that unit expenses include costs of compression, gathering, dehydration, and capital depreciation, we are not persuaded that this precludes these expenses, to the extent they are post-production, value-enhancing expenses, from being used to assess the value of gas sold downstream solely for the purpose of determining the value at the wellhead, on which the royalty was calculated under the Unit Agreement. Defendants bore all the responsibility for financing and constructing the facilities used for these purposes. Plaintiffs were not required to pay for these expenses. We thus hold that using these costs in a formula to value the carbon dioxide gas at the wellhead when the gas had been sold at an enhanced value downstream does not violate Article 14.3 of the Unit Agreement.

{35} Nor are we persuaded that Amoco's post-ratification conduct evinces a *{*538}* different intent. Plaintiffs cite to Amoco's negotiations with the State regarding the specific deductions used to determine the value of the gas for State royalty purposes and internal Amoco documents discussing the company-wide policy and procedures for calculating and reporting "gas marketing costs" as an aid to valuing gas produced under various royalty clauses providing for payment based on a value "at the wellhead" or proceeds received by Amoco. In our view, this evidence does not change the meaning or interpretation of "net proceeds at the well." At most, it documents that the specific method of calculating the net proceeds at the well was not established in the Unit Agreement.

{36} In summary, because "net proceeds . . . at the well" is an unambiguous phrase and evinces a clear intent that deductions will be made and the gas is to be valued at the wellhead, we affirm the trial court's determination that the computations of Plaintiffs' royalties for gas sold downstream were subject to deductions for post-production, value-enhancing costs.

E. The Amoco Assignment

{37} Plaintiffs argue that the Unit Agreement did not nullify its 1975 Amoco Assignment involving the Trust. In the Amoco Assignment, Amoco acquired mineral leases that the Trust's predecessor in interest, Public Lands Exploration, Incorporated (PLEI), had purchased. The Amoco Assignment provided that Amoco would calculate and pay royalties based on calculations used to pay the United States or the State of New Mexico, whichever was greater. This provision was referred to as the "Limited Favored Nations Clause." PLEI later assigned its royalty interest from the Amoco Assignment to Plaintiffs, effective December 31, 1976.

{38} The Unit Agreement provided in part:

> 3.3 **Leases and Contracts Conformed and Extended.** The terms, conditions, and provisions of all leases, subleases, and other contracts relating to exploration, drilling, development, or operation for oil and gas, including but not limited to Carbon Dioxide Gas, on lands committed to this agreement are hereby expressly modified and amended to the extent necessary to make the same conform to the provisions hereof but otherwise shall remain in full force and effect. **Further, the parties hereto hereby expressly consent**. . . for the Lessors as to other [than federal or state] leases . . . **to hereby establish, alter, change, or revoke the** drilling, producing, rental, **minimum royalty, and royalty requirements of** Federal, State, and other **leases committed hereto and the regulations in respect thereto to conform said requirements to the provisions of this agreement**. . . .

(Emphasis added.) Plaintiffs argue that the plain language of this Article conforms only the contract provisions relating to "exploration, drilling, development and operations" for carbon dioxide gas and does not conform prior leases or contracts regarding the distribution of unitized substances or their proceeds. We note that, in making this argument, Plaintiffs neglected to quote the second sentence of Article 3.3, which expressly includes minimum royalties and royalty requirements as being conformed to the Unit Agreement.

{39} In their reply brief, Plaintiffs argue that the Limited Favored Nations Clause is not a royalty requirement but a method for calculating the required royalties. Without citation to authority, they assert that the term "royalty requirements" refers to a requirement that royalty be paid under certain circumstances. We are not persuaded that the phrase "royalty requirements" would not include the calculation of royalties. Even assuming Plaintiffs' interpretation had merit, however, their argument ignores that part of the Article conforming the minimum royalty of other leases to the provisions of the Unit Agreement.

{40} Because Article 3.3 expressly provides for the minimum royalty and royalty requirements of other leases to be conformed to the Unit Agreement, we determine that the Unit Agreement, rather than the Amoco Assignment, controlled Amoco's obligations regarding the payment of royalty in this case. **Cf. Hitzelberger v. Samedan Oil Corp.**, 948 S.W.2d 497, 508 (Tex. Ct. App. 1997) (interpreting a conforming clause as an amendment *{*539}* to "individual leases to the extent necessary to make them conform to the unit agreement").

III. CONCLUSION

{41} We conclude that the trial court was correct in determining the Unit Agreement was not ambiguous in using the phrase "net proceeds derived from the sale of carbon dioxide gas at the well." We hold that post-production, value-enhancing costs were properly included by Defendants in calculating the royalty owed to Plaintiffs. We thus conclude that the trial court's determination in this regard was not error. Finally, we conclude that the provisions of the Unit Agreement, and not the Amoco Assignment, governed the manner in which royalties were to be calculated. We therefore affirm the trial court's judgment in favor of Defendants.

{42} IT IS SO ORDERED.

RUDY S. APODACA, Judge

WE CONCUR:

RICHARD C. BOSSON, Judge

M. CHRISTINA ARMIJO, Judge