In the
Court of Appeals
Second Appellate District of Texas
at Fort Worth

No. 02-18-00424-CV

Shirlaine West Properties Limited and Nathan K. Griffin, on behalf of the Estate of Lorraine E. West and on behalf of the Estate of Shirley A. West, Appellants

v.

Jamestown Resources, L.L.C. and Total E&P USA, Inc., Appellees

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On Appeal from the 96th District Court
Tarrant County, Texas
Trial Court No. 096-289847-17

Before Birdwell and Wallach, JJ.; and Gonzalez, J.[1] (Judge Gonzalez not participating)
Memorandum Opinion by Justice Wallach

[1]The Honorable Ruben Gonzalez, Judge of the 432nd District Court of Tarrant County, sitting by assignment of the Chief Justice of the Texas Supreme Court pursuant to Section 74.003(h) of the Government Code. *See* Tex. Gov't Code Ann. § 74.003(h).

MEMORANDUM OPINION

This is a breach of contract case involving the interpretation of a natural gas lease royalty clause. Appellants (the Lessors) sued Appellees (the Lessees) for underpayment of royalties, contending that the contract language unambiguously provides for valuing the Lessors' royalty by a percentage of the market value of the gas at the point of sale (wellhead) adjusted by certain factors set forth in the lease royalty clause, essentially rendering their royalty not subject to postproduction costs, directly or indirectly.[2] The Lessees contended that there was no underpayment of royalties because the lease unambiguously provides that the royalty is a percentage of the market value of the gas "at the point of sale," and because the point of sale is at the wellhead, the royalty is subject to deduction for postproduction costs, as reflected by the price the Lessors received from their wellhead gas purchasers.

Lessors moved for partial summary judgment. Lessees moved for traditional and no-evidence summary judgment. The trial court denied the Lessors' motion and granted the Lessees' motions. The trial court granted judgment that Lessors take nothing. In this appeal, the Lessors succinctly draw the question that is determinative

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[2]Chesapeake Exploration L.L.C. and Chesapeake Operating, L.L.C. were two of the Appellees (Lessees) when this appeal was initially filed. After filing for bankruptcy, which suspended this appeal, they eventually settled with Lessors, and we granted Lessors' unopposed motion to dismiss the two Chesapeake entities from the appeal and to reinstate the appeal against the two remaining Lessees, dismissed the two Chesapeake entities, and reinstated the appeal. *Shirlaine West Props., Ltd. v. Chesapeake Expl., L.L.C.*, No. 02-18-00424-CV, 2021 WL 4783171, at *1 (Tex. App.—Fort Worth Oct. 14, 2021, no pet. h.) (per curiam) (mem. op. and order).

of the case, i.e., whether the Lessors' royalty interest is burdened with postproduction costs. Because we conclude that the lease royalty clause is unambiguous and fixes the wellhead as the valuation point for the Lessors' royalty, we hold that the Lessors' royalty is burdened with postproduction costs. We affirm the trial court's take-nothing summary judgment.

I. Factual Background

Shirlaine West Properties Limited (West) leased approximately 98.93 net mineral acres in the Barnett Shale to Chesapeake Exploration, L.L.C. ("CE")[3] in early 2010. The royalty clause in this lease states, in pertinent part,

> 3. As royalty, Lessee covenants and agrees: . . . (b)[1] to pay Lessor for gas including casinghead gas and other gaseous substances produced from said land and sold or used on or off the premises *twenty-five percent (25%) of the market value at the point of sale, use or other disposition of all such gas.* [2] *The market value of all gas shall be determined at the specified location* and by reference to the gross heating value (measured in British thermal units) and quality of the gas. [3] *The market value used in the calculation of all royalty under this Lease shall never be less than the total proceeds received by Lessee in connection with the sale, use or other disposition of oil or gas produced or sold from the leased premises.* [4] The royalty reserved to Lessor hereunder shall be free and clear of all costs and expenses whatsoever, except ad valorem and production taxes. [5] By way of explanation but not limitation, it is agreed between the Lessor and Lessee, that, notwithstanding any language herein to the contrary, all oil, gas or other proceeds accruing to

[3]Chesapeake Operating, L.L.C. (CO), on behalf of CE, was the sole operator of the two gas wells involved in this dispute (the Duke United 1H and Duke United 2H wells). Subsequent to the original lease, CE assigned an undivided 25% interest in all of its Barnett Shale leases, including this lease, to Total. CE also assigned an undivided 2.5% interest to Jamestown in the Duke United 1H well. In November 2016, CE assigned its remaining interest to Total. Chesapeake, Jamestown, and Total may be collectively referenced as Lessees. CE administered all royalties for the Lessees.

> the Lessor under this lease or by state law shall be without deduction for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and marketing the oil, gas and other products produced hereunder to transform the product into marketable form; however, any such costs which result in enhancing the value of the marketable oil, gas or other products to receive a better price may be deducted from Lessor's share of production so long as they are based on Lessee's actual cost of such enhancements. [6] However, in no event shall Lessor receive a price that is less than, or mare [sic] than, the price received by Lessee. [7] *If Lessee realizes proceeds of production after deduction for any expenses of production, gathering, dehydration, separation, compression, transportation, treatment, processing, storage or marketing, then the proportionate part of such deductions shall be added to the total proceeds received by Lessee for purposes of this paragraph.* [8] Lessor and Lessee hereby agree that the holding in *Heritage Resources, Inc. v Nations Bank*, 939 S.W.2d 118 (Tex. 1996) shall have no application to the terms of this lease.[4] [Emphasis and sentence numbers added.]

Gas was not produced under the lease until 2012. No royalties were paid under the lease until September 2015 because of a title dispute.

CO sold the gas it produced from the leased premises for CE and Jamestown to Chesapeake Energy Marketing, L.L.C. (CEM). Title to the gas sold to CEM transferred at the custody meter at the wellhead. CEM and CO had a Base Contract for Purchase and Sale of Natural Gas (Base Contract), which established the gas price that CEM paid to CO on behalf of CE. The price was calculated as the weighted average sale price (WASP) that unaffiliated downstream purchasers paid CEM in arms-length transactions less the actual postproduction costs that CEM paid to third

[4] Sentence 8's disclaimer of the holding in *Heritage Resources* does not affect this court's decision. The court will look to the text of the agreement to ascertain the royalty obligations. *See Chesapeake Expl., L.L.C. v. Hyder*, 483 S.W.3d 870, 876 (Tex. 2016) (op. on reh'g).

parties to move the gas from the wellhead to the downstream points of sale. The reasonableness of the WASP calculations was not challenged. CEM charged CO a 3% marketing fee. CO added that 3% fee back to the proceeds it received from CEM.[5] It is undisputed that when the Lessors signed the lease, they were aware that CO would sell the gas to an affiliated company at the wellhead.

CO did not engage in post-production activities such as compressing, transporting, processing, or treating the gas it sold to CEM at the wellhead. The gas produced from the lease required no special treatment of any kind to be sold and transported off the lease. It was lean, unprocessed, and produced at low pressure, and it was in a marketable form at the wellhead.

The gas purchased at the wellhead by CEM went to its gathering pipeline system, which transported the gas to intrastate or interstate pipelines. While CEM sold some of the gas at the connection to the intra/inter-state pipelines to third parties, CEM paid third party pipeline owners to transport most of the gas further downstream on transmission pipelines for sale at a higher price to unaffiliated third parties.[6]

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[5]Lessors have not been harmed by the deduction and it is not an issue in this appeal.

[6]On or about August 7, 2014, West distributed its interest in the Lease to Lorraine E. West and to Nathan K. Griffin, on behalf of the Estate of Shirley A. West, in equal shares. Lorraine West died in 2016 and Griffin was appointed as her estate's personal representative.

Total took in kind its working interest share of the gas produced from the lease. Total then sold its share of the gas at the wellhead to Total Gas & Power North America, Inc. (Gas & Power). Title to the gas transferred from Total to Gas & Power at the custody transfer meter at or near the wellhead. Total had a Base Contract for Sale and Purchase of Natural Gas with Gas & Power to purchase its in-kind share of the gas at the wellhead, which was the point of sale. Gas & Power then moved the gas downstream to locations for commercial resale of the gas.

Gas & Power calculated its WASP for the gas, calculating the market-value-at-the-wellhead based on its WASP adjusted to account for Gas & Power's actual costs to move the gas from the wellhead to the downstream resale points. The actual costs (postproduction costs) included gathering and transportation costs that enhanced the value of the already marketable gas sold at the wellhead.[7]

II. Standard of Review

This court applies a de novo standard of review to summary judgments. *Travelers Ins. Co. v. Joachim*, 315 S.W.3d 860, 862 (Tex. 2010). If competing summary judgment motions are filed, each party must bear its burden of establishing that it is entitled to judgment as a matter of law. *Tarr v. Timberwood Park Owners Ass'n, Inc.*,

[7]CEM and Gas & Power calculate the WASP differently: CEM calculates the WASP based on the price that it receives from the downstream, third-party sales, while Gas & Power calculates the WASP based on indices published at the downstream resale points. This difference is not relevant, however, because Lessors do not challenge either WASP calculation as reflected in their Owner Accounting Reconciliation Statement (OAR).

556 S.W.3d 274, 278 (Tex. 2018); *City of Garland v. Dall. Morning News*, 22 S.W.3d 351, 356 (Tex. 2000). "If the trial court grants one motion and denies the other, the reviewing court should determine all questions presented and render the judgment that the trial court should have rendered." *City of Garland*, 22 S.W.3d at 356–57 (cleaned up); *BlueStone Nat. Res. II, LLC v. Randle*, 601 S.W.3d 848, 854 (Tex. App.—Fort Worth April 18, 2019), *rev'd in part on other ground*s, 620 S.W.3d 380 (Tex. 2021).

When a motion for summary judgment presents both no-evidence and traditional grounds, the court first reviews the propriety of the summary judgment under the rule 166a(i) no-evidence standards. *Lightning Oil Co. v. Anadarko E&P Onshore, LLC*, 520 S.W.3d 39, 45 (Tex. 2017); *Ford Motor Co. v. Ridgway*, 135 S.W.3d 598, 600 (Tex. 2004). If a non-movant failed to produce more than a scintilla of evidence under the no-evidence standards, there is no need to analyze whether a movant's summary judgment proof satisfied the burden related to traditional summary judgment motions. *Blackard v. Fairview Farms Land Co.*, 346 S.W.3d 861, 868 (Tex. App.—Dallas 2011, no pet.). We consider the evidence in the light most favorable to the non-movant, indulging every reasonable inference from the evidence in that party's favor. *Sudan v. Sudan*, 199 S.W.3d 291, 292 (Tex. 2006); *Blackard*, 346 S.W.3d at 868.

The movant in a traditional summary judgment bears the burden of proving there is no genuine issue of material fact regarding at least one essential element of the cause of action being asserted and that it is entitled to judgment as a matter of law. Tex. R. Civ. P. 166a(c); *Nassar v. Liberty Mut. Fire Ins. Co.*, 508 S.W.3d 254, 257 (Tex. 2017). When reviewing a traditional motion for summary judgment, the court reviews the evidence in the light most favorable to the non-movant, indulges every reasonable inference in favor of the non-movant, and resolves any doubts against the motion. *Lightning Oil Co.*, 520 S.W.3d at 45; *City of Keller v. Wilson*, 168 S.W.3d 802, 824 (Tex. 2005).

III. Rules of Contract Construction

Contract language which can be given a certain or definite meaning is unambiguous. In that situation, the court interprets the contractual language as a matter of law. *DeWitt Cnty. Elec. Coop., Inc. v. Parks*, 1 S.W.3d 96, 100 (Tex. 1999); *Castillo Info. Tech. Servs., LLC v. Dyonyx, L.P.*, 554 S.W.3d 41, 45 (Tex. App.—Houston [1st Dist.] 2017, no pet.). Contract language is not ambiguous simply because it is unclear or because the parties "assert forceful and diametrically opposing interpretations." *In re D. Wilson Constr. Co.*, 196 S.W.3d 774, 781 (Tex. 2006) (orig. proceeding); *DeWitt Cnty. Elec. Coop.*, 1 S.W.3d at 100. An ambiguity arises only after the application of established rules of interpretation leaves the language susceptible to more than one reasonable meaning. *DeWitt Cnty. Elec. Coop.*, 1 S.W.3d at 100. An oil and gas lease is a contract, and its terms are interpreted according to rules of contract construction. *Tittizer v. Union Gas Corp.*, 171 S.W.3d 857, 860 (Tex. 2005); *BlueStone*, 601 S.W.3d at 854–55. The rules of construction applicable to oil and gas lease contracts were aptly summarized by this court in *BlueStone:*

> "In construing an unambiguous oil and gas lease, . . . we seek to enforce the intention of the parties as it is expressed in the lease." [*Tittizer*, 171 S.W.3d at 860]. "We give terms their plain, ordinary, and generally accepted meaning[s] unless the instrument shows that the parties used them in a technical or different sense." *Heritage Res., Inc.* . . . , 939 S.W.2d [at] 121 . . . .
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> "We examine the entire lease and attempt to harmonize all its parts, even if different parts appear contradictory or inconsistent." *Anadarko Petroleum Corp. v. Thompson*, 94 S.W.3d 550, 554 (Tex. 2002) (citing *Luckel v. White*, 819 S.W.2d 459, 461 (Tex. 1991)). A court examines all of the lease's provisions "because we presume that the parties to a lease intend every clause to have some effect." *Id.* (citing *Heritage Res.*, 939 S.W.2d at 121). Finally, we "cannot change the contract merely because we or one of the parties comes to dislike its provisions or thinks that something else is needed in it."

BlueStone, 601 S.W.3d at 855.

IV. Analysis

Like *BlueStone*, this case is yet another episode in the endless struggle in the oil and gas context between lessors and lessees in the allocation of post-production costs in the calculation of royalty payments. We addressed the basic structure of oil and gas lease royalty terminology in *BlueStone* and encourage its review for the historical legal background of the treatment of oil and gas lease royalty clauses.

For now, we will focus on three main principles. First, a mineral lease is a contract and is governed by the rules of contract law. *Id.* at 854–55. Second, oil and gas lease law, though framed in contract terms, has developed unique legal interpretations of royalty clauses, which can make understanding these contracts difficult for the unwary. *See id.* at 855–60. Third, even though these unique applications may make words and phrases about royalties mean something different than they would appear, or maybe mean nothing at all, the parties may agree to alter those unique meanings by the terms of their contract. The ultimate answer in each case depends on whether the words used clearly express the intent of the parties to deviate from the traditional meanings. *Burlington Res. Oil & Gas Co. v. Tex. Crude Energy, LLC*, 573 S.W.3d 198, 204 (Tex. 2019); *Heritage Res.*, 939 S.W.2d at 121; *BlueStone*, 601 S.W.3d at 867; *see also Warren v. Chesapeake Expl., L.L.C*, 759 F.3d 413, 415 (5th Cir. 2014).

A royalty is generally defined as the landowner's share of production. Although not subject to the costs of production, a royalty is usually subject to post-production costs such as taxes, treatment costs to render the gas marketable, and transportation costs. However, the parties may alter this general rule by agreement. *Burlington Res.*, 573 S.W.3d at 203; *Heritage Res.*, 939 S.W.2d at 121–22. Royalties that are calculated based on market value at the wellhead generally burden the lessor's royalty with a proportionate share of postproduction costs. *Burlington Res.*, 573 S.W.3d at 204; *Heritage Res.*, 939 S.W.2d at 122–23. In leases that value the lessor's royalty based on market value at the wellhead, provisions that purport to deduct or exempt postproduction costs from the lessor's royalty are considered mere surplusage. *Heritage Res.*, 939 S.W.2d at 123 (holding that, in market-value-at-the-well lease, royalty language reciting that lessor's royalty interest would be free and clear of, or without deductions for, postproduction costs was mere surplusage); *see also Burlington Res.*, 573 S.W.3d at 204 (overriding royalty interest assignments which required oil or gas to be delivered "into the pipeline" fixed the valuation point at the wellhead, which allowed the lessee to deduct postproduction costs from the overriding royalty despite language that the royalty would be free of postproduction costs and a valuation clause providing that value from a sale on or off the lease would be based on the "amount realized" from the sale of such oil or gas in arms-length transactions).

However, courts have upheld the right of lessors and lessees to contract for a lessor's royalty to be free of postproduction costs. Two examples are "proceeds" leases and "amount realized" leases. A proceeds lease is found in *Hyder*, involving separate oil and gas royalty clauses. 483 S.W.3d at 871. The lessor's oil royalty, according to the Texas Supreme Court, bore postproduction costs because it was paid on the market value of the oil at the wellhead. *Id.* at 873. By contrast, the gas royalty language provided for a royalty of "25% of the price actually received by Lessee" and further provided that the "royalty [was] expressly free and clear of all production and post-production costs and expenses" and listed examples of such expenses. *Id.* at 871–72. The Court said that

> [t]he gas royalty in the lease does not bear postproduction costs because it is based on the price Chesapeake actually receives for the gas through its affiliate, Marketing, after postproduction costs have been paid. Often referred to as a "proceeds lease," the price-received basis for payment in the lease is sufficient in itself to excuse the lessors from bearing

> postproduction costs. And of course, like any other royalty, the gas royalty does not share in production costs. But the royalty provision expressly adds that the gas royalty is "free and clear of all production and post-production costs and expenses," and then goes further by listing them. This addition has no effect on the meaning of the provision. It might be regarded as emphasizing the cost-free nature of the gas royalty, or as surplusage.
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> . . . .
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> The gas royalty does not bear postproduction costs, not because it is based on a volume other than full production, but because the amount is based on the price actually received by the lessee, not the market value at the well.

Id. at 873, 875 (footnotes omitted). From this we see that the operative language is the "actual proceeds received" language, the "free and clear" language being either surplusage or mere emphasis language.

Likewise, "amount realized" clauses require the calculation of the royalty based on the amount the lessee receives under its contract for the sale of the gas. *Bowden v. Phillips Petrol. Co.*, 247 S.W.3d 690, 699 (Tex. 2008). As noted by the Fifth Circuit in *Warren*,

> The Warrens' leases provide in the pre-printed royalty clause that they are entitled to 22.5% "of the amount realized by Lessee, computed at the mouth of the well." As the Warrens recognize in their brief, the term "amount realized" "require[s] measurement of the royalty based on the amount the lessee in fact receives under its sales contract for the gas." Had the lease provided only that the Warrens are to receive 22.5% of the amount realized by Lessee, there would be little question that the Warrens would be entitled to 22.5% of the sales contract price that the lessee received, with no deduction of post-production costs. But that is not what the lease provides.

759 F.3d at 417. The court then went on to point out that the "computed at the mouth of the well" language rendered the proceeds to be net of postproduction costs.

We must now apply these principles to the West lease. Sentences 1 and 2 of the royalty clause (the third numbered paragraph) set the direction for the ultimate outcome of the dispute. They state that Lessee agrees

> [1] to pay Lessor for gas including casinghead gas and other gaseous substances produced from said land and sold or used on or off the premises *twenty-five percent (25%) of the market value at the point of sale, use or other disposition of all such gas.* [2] *The market value of all gas shall be determined at the specified location and by reference to the gross heating value (measured in British thermal units) and quality of the gas.* [Emphasis and sentence numbers added.]

These sentences fix market value as the measure of value and set the location of the value at the point of sale. It is uncontroverted that the point of sale of the gas in question was at the wellhead. A lease need not use the words "at the wellhead" to expressly fix the location. As the Texas Supreme Court noted in *Burlington Resources*,

> To sum up, the Valuation Clause [of the lease in question] specifies that the royalty payment shall be calculated based on the "amount realized" from the sale, but the agreements also provide that the royalty interest shall be delivered "into the pipelines, tanks, or other receptacles with which the wells may be connected." In the context of these agreements, this latter term fixes the royalty's valuation point at the physical spot where the interest must be delivered—at the wellhead or nearby.

573 S.W.3d at 211. Having established that the agreements provided for royalty payments on the amount realized from the sale of the gas at the pipeline, the Court held that "[t]his gives Burlington the right to subtract post-production costs from the 'amount realized' in downstream sales prices in order to calculate the product's value

as it flows 'into the pipelines, tanks or other receptacles with which the wells may be connected.'" *Id.*

Having established that the West lease is a market-value-at-the-well lease, we can evaluate the impact of the other provisions of the royalty clause. Sentences 4, 5, and 6 are the types of provisions that in "market-value-at-the-well" royalty provisions are considered surplusage, or restatements of existing law, as a matter of law. *Heritage Res.*, 939 S.W.2d at 122–23. As stated by Justice Owen in her concurring opinion in *Heritage Resources*,

> There is little doubt that at least some of the parties to these agreements subjectively intended the phrase at issue to have meaning. However, the use of the words "deductions from the value of Lessor's royalty" is circular in light of this and other courts' interpretation of "market value at the well." The concept of "deductions" of marketing costs from the value of the gas is meaningless when gas is valued at the well. Value at the well is already net of reasonable marketing costs. The value of gas "at the well" represents its value in the marketplace at any given point of sale, less the reasonable cost to get the gas to that point of sale, including compression, transportation, and processing costs. Evidence of market value is often comparable sales, as the Court indicates, or value can be proven by the so-called net-back approach, which determines the prevailing market price at a given point and backs out the necessary, reasonable costs between that point and the wellhead. But, regardless of how value is proven in a court of law, logic and economics tell us that there are no marketing costs to "deduct" from value at the wellhead.

939 S.W.2d at 130 (Owen, J. concurring).

We turn next to sentences 3 and 7 of the third numbered paragraph of the lease. Sentence 3 reads, "The market value used in the calculation of all royalty under this Lease shall never be less than the total proceeds received by Lessee in connection with the sale, use or other disposition of oil or gas produced or sold from the leased premises."

There is no dispute that Lessees have paid Lessors their royalties using not less than the total proceeds received by Lessees. This, of course, leads to the central dispute in the case, which revolves around Sentence 7. Sentence 7 reads, "If Lessee realizes proceeds of production after deduction for any expenses of production, gathering, dehydration, separation, compression, transportation, treatment, processing, storage or marketing, then the proportionate part of such deductions shall be added to the total proceeds received by Lessee for purposes of this paragraph."

Lessors contend that by Lessees selling the gas to Gas & Power and CEM with postproduction costs deducted from the purchase price, Lessees realize proceeds after deduction for expenses identified in Sentence 7, and Lessors are therefore entitled to have these expenses added back into the "total proceeds" to be used for calculating royalties under Sentence 3. Such an interpretation would create an internal conflict between the market-value-at-the-well provisions in Sentences 1 and 2 and the combination of sentences 3 and 7 to form a "total proceeds" lease. This interpretation would effectively convert a market-value-at-the-well lease into a "total proceeds" lease, which is not consistent with precedent. As noted by the Texas Supreme Court in *Burlington Resources*,

> We have never construed a contractual "amount realized" valuation method to trump a contractual "at the well" valuation point. To the contrary, prior decisions suggest that when the parties specify an "at the

> well" valuation point, the royalty holder must share in post-production costs regardless of how the royalty is calculated. This is generally the case even when the agreement calls for payments based on the "amount realized" or "proceeds." Allowing the holder of an "at the well" royalty to escape his responsibility for post-production costs would improperly convert the royalty interest from a royalty on raw products at the well to a royalty on refined, downstream products.

573 S.W.3d at 205 (internal citations omitted).

In construing a lease, courts will "examine and consider the entire writing in an effort to harmonize and give effect to all the provisions of the contract so that none will be rendered meaningless." *Valence Operating Co. v. Dorsett*, 164 S.W.3d 656, 662 (Tex. 2005); *accord Hysaw v. Dawkins*, 483 S.W.3d 1, 4 (Tex. 2016); *Heritage Res.*, 939 S.W.2d at 121; *Westport Oil & Gas Co., L.P. v. Mecom*, 514 S.W.3d 247, 251 (Tex. App.—San Antonio 2016, no pet.). Remembering that Sentences 1 and 2 provide that market value is at the point of sale, not necessarily at the well, other potential sales at other points might appropriately fall within the ambit of Sentence 7. But we are not presented with such facts and need not prognosticate about them. For this circumstance, Sentence 7 is simply not applicable and cannot be used by Lessors to avoid sharing postproduction costs in a sale at the well which they have agreed to value at the well. *See Burlington Res.*, 573 S.W.3d at 206.

Lessors rely heavily on the Supreme Court's opinion in *Hyder*. This reliance is misplaced. The *Hyder* holding concerns an overriding royalty interpretation. Overriding royalties, like royalties, are generally not subject to costs of production but are generally subject to postproduction costs. 483 S.W.3d at 872. The *Hyder* lease provided for "'"a perpetual, cost-free (except only its portion of production taxes) overriding royalty of five percent (5.0%) of gross production obtained from directional wells drilled on the lease but bottomed on nearby land."' *Id.* Although the Court held that the overriding royalty created by this language was free of postproduction costs, its rationale was never clearly explained. What is clear is that the *Hyder* overriding royalty language did not value the royalty on the market value at the well. Thus, *Hyder* does not control in this case.

V. Conclusion

Lessors' only cause of action against Lessees is for breach of contract. Lessees filed no-evidence motions for summary judgment based on no evidence of breach of an agreement and no evidence of damages, both of which are elements of Lessors' actions against Lessees. *See City of Colony v. N. Tex. Mun. Water Dist.*, 272 S.W.3d 699, 739 (Tex. App.—Fort Worth 2008, pet. dism'd). The trial court granted the no-evidence motions. Finding the lease agreement unambiguous, no evidence of breach of the lease agreement, and no damages caused by any alleged breach, we affirm the take-nothing summary judgment in favor of Lessees Jamestown Resources, L.L.C. and Total E&P USA, Inc. Having affirmed the granting of the no-evidence motions, we need not address the traditional motions for summary judgment. *See Ridgway*, 135 S.W.3d at 600; *Solano v. Landamerica Com. Title of Fort Worth, Inc.*, No. 02-07-152-CV, 2008 WL 5115294, at *4 (Tex. App.—Fort Worth Dec. 4, 2008, no pet.) (per curiam) (mem. op.). We affirm the trial court's judgment for Jamestown Resources, L.L.C. and Total E&P USA, Inc.

/s/ Mike Wallach
Mike Wallach
Justice

Delivered: November 18, 2021