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The Oil and Gas Lease, Part II:
The Royalty Clause in an Oil and Gas Lease

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THE OIL AND GAS LEASE, PART II:
THE ROYALTY CLAUSE IN AN OIL AND GAS LEASE

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Summary: The royalty clause is one of the most important clauses in the oil and gas lease, but drafting and construction of royalty provisions can be challenging. In Texas, the calculation of the royalty obligation created under an oil and gas lease is determined by looking at the specific language contained in the royalty clause. Royalty terms in the lease such as "market value at the well" or "amount realized" establish how the royalty payor must measure and calculate royalty, and what post-production costs can be allocated to the lessor's interest. This paper considers some of the principal phrases used to describe such obligations and how the Texas courts have interpreted them and examines how that same language has been interpreted differently in other jurisdictions. The paper finally considers the impact of division and transfer orders and royalty payment statutes on royalty obligations contained in the lease.

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I. INTRODUCTION

At its simplest, a royalty is this: a cost-free share of production.[1] Yet drafting and interpreting royalty provisions is anything but simple. Numerous texts and treatises have addressed issues arising from lease royalty obligation, each purporting to carry with them the weight of historic custom and equity.[2] Meanwhile, lessors and lessee are negotiating increasingly complex and customized royalty valuation provisions language within the lease in order to address circumstances both foreseen and unforeseen and respond to rapidly shifting technology and case law. This paper catalogs the specific language used in many royalty provisions, Texas' approach to interpreting royalty conveyances, and the impacts of division order and royalty payment statutes on the simple "sharing arrangement" of the lease.[3]

By a narrow construction, the term "royalty" refers to a share of the production or the proceeds therefrom, "reserved to the owner for permitting another to use the property."[4] A royalty interest—or, the right to receive royalties— is one of the five essential attributes of the mineral estate.[5] Thus, regardless of how a state classifies the real property interest in minerals, [6] the royalty interest is considered a non-possessory interest in real property. [7] As one "stick" in the bundle of rights comprising the mineral estate, the mineral owner may convey or reserve the right to receive royalty payments.[8] A royalty interest may be conveyed or reserved as part of a mineral conveyance, granted in consideration for the issuance of an oil and gas lease, or carved out from the lessee's interest in production in the oil and gas lease. These interests are fully alienable: the owner is free to convey the royalty interest to another for the life of the lease or another period of time.[9]

Royalty interests may be long-term, coinciding with the lifetime of the producing well and are considered vested interests in real property. Despite prohibitions against alienations of property

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[1] Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118 (Tex. 1996)

[2] *See, e.g.,* Owen L. Anderson, *Royalty Valuation: Should Royalty Obligations be Determined Intrinsically, Theoretically, or Realistically?*, *Part 1*, 37 NAT. RES. J. 547 (1997); Bruce Kramer, *Interpreting the Royalty Obligation by Looking at the Express Language: What a Novel Idea?*, 35 TEX. TECH L. REV. 223, 224 (2004); PATRICK H. MARTIN & BRUCE M. KRAMER, WILLIAMS & MEYERS OIL AND GAS LAW [hereinafter Williams & Meyers] § 641 (LexisNexis 2018).

[3] Anderson, *supra* note 2, at 584 (citing Wright v. Warrior Run Coal Co, 38 A. 491 (Pa. 1897)).

[4] Carroll v. Bowen, 180 Okla. 215, 68 P.2d 773, 775 (Okla. 1937).

[5] Altman v. Blake, 712 S.W.2d 117, 118 (Tex. 1986) (these rights include: "(1) the right to develop (the right of ingress and egress), (2) the right to lease (the executive right), (3) the right to receive bonus payments, (4) the right to receive delay rentals, (5) the right to receive royalty payments"); *Lyle v. Jane Guinn Revocable Trust,* 365 S.W.3d 341, 351 (Tex. Civ. App. 2010), *cert. denied*; Hamilton v. Morris Res., Ltd., 225 S.W.3d 336, 344 (Tex. Civ. App. 2007) *cert. denied*.

[6] *See* E. KUNTZ, A TREATISE ON THE LAW OF OIL AND GAS § 2.4 (2019).

[7] *Id.;* Ridge Nat. Res., LLC v. Double Eagle Royalty, LP, 564 S.W.3d 105, 113 (Tex. Civ. App. 2018).

[8] *Id.*

[9] Williams & Meyers, *supra* note 2, at § 202.3.

that would violate the Rule Against Perpetuities, the royalty interest may indeed be perpetual.[10] In Texas, where oil and gas in place is corporeal and where the lease is deemed to provide a determinable fee interest,[11] the royalty share of production is a presently vested interest that does not offend the rule against perpetuities.[12] As Professor Meyers has opined:

> That production is uncertain and may never occur should not defeat the interest. The royalty created by a long-term oil and gas lease has never been thought to offend the Rule against Perpetuities, though subject to precisely the same contingency; namely, the discovery and production of oil or gas.[13]

II. Types of Royalty

"Royalty," if strictly construed, refers to a percentage share of production paid to the lessor as main consideration for issuance of a lease.[14] However, royalty interests may be created independent from the terms of a lease. A "non-participating royalty interest" (NPRI) is:

> An interest in the gross production of oil, gas, and other minerals carved out of the mineral fee estate as a free royalty, which does not carry with it the right to participate in the execution of, the [b]onus payable for, or the delay rentals to accrue under oil, gas, and mineral leases executed by the owner of the mineral fee estate.[15]

Thus, a non-participating royalty interest holder possesses an interest in the share of production generated under third-party leases. The non-participating royalty interest owner does not possess executive rights, *i.e.*, to amend or enter into leases.[16] The NPRI owner is frequently referred to as a "non-executive interest owner," while the mineral owner usually retains executive rights.[17]

The "overriding royalty interest" (ORRI) grants a share of production out of the lessors' working interest. Owners of the working interest in a mineral estate may also carve royalty interests from the working interest by assigning to a third party a portion of the working interest.[18] The

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[10] David L. Cruthirds*, Power to Execute Mineral Leases over A Severed Mineral Interest Is A Real Property Interest*, 32 S. TEX. L. REV. 337, 353 (1991).

[11] Williams & Meyers, *supra* note 2, at § 209 ("in Texas severed mineral interests and the interest of an oil and gas lessee are viewed as corporeal estates. The owners of royalty interests lack the right to enter upon the premises for the purpose of exploration and development. . . and hence such interests are incorporeal.").

[12] C. J. Meyers, *The Effect of the Rule Against Perpetuities on Perpetual Non-Participating Royalty and* Kindred Interests, 32 TEX. L. REV. 369, 394 (1954).

[13] *Id*. at 413; *but compare* Lathrop v. Eyestone, 428, 227 P.2d 136, 144 (Kan. 1951) (taking the position that a royalty created outside of a perpetual lease violates the Rule Against Perpetuities).

[14] *See supra* note 4 and accompanying text.

[15] KCM Fin. LLC v. Bradshaw, 457 S.W.3d 70, 75 (Tex. 2015).

[16] *Id.*

[17] *Id.*

[18] *See* EOG Resources, Inc. v. Hanson Production Co., 94 S.W.3d 697, 701 (Tex. Ct. App. 2002).

ORRI is a covenant running with the land, enforceable by the assignor against the assignee.[19] Although the overriding royalty is most frequently measured as a portion of production, and thus can raise many of the same issues associated with non-participating and landowner royalties related to post-production costs, valuation, and measurement, of an over-riding royalty has no interest in the underlying real property.

Another interest, often referred to as "royalty" evades the definition of royalty as relative to production. The "shut-in royalty" is a creation of contract designed to prevent the automatic termination of a lease and frequently serves as a substitute for production. The shut-in royalty clause provides that payments to the royalty interest holder "will maintain the lease in force and effect when a gas well is drilled and for which no market exists.'"[20] Thus, rather than guaranteeing the holder a cost-free share of production, shut-in royalty is often only paid when production is not occurring.

III. History of the Royalty Clause

The royalty serves, and has served for millennia, an important function in mining leases and profits.[21] At its simplest it is a payment for the right to mine.[22] In consideration of the right to explore for, take and remove a depleting substance, a portion of the mined substance is payable to the owner.[23] This provision is the most economically important clause to the lessor—whereas bonus and rentals are usually fixed amounts, a percentage or fractional royalty clause provides the mineral owner with an interest in production. As a result, the royalty clause addresses the information costs and differential expectations associated with the unknown value of production by sharing the risk and benefit of future production between both the lessor and lessee. As such, the lessee can defer much of the capital cost of obtaining the right to produce until after production has begun by assuring the lessor a share thereof.

Given these qualities, the royalty provision gives rise to numerous implied covenants. These implied covenants may be implied in fact—to complete an incomplete contract based on the assumed intention of the parties— or implied in law as a function of the relationship of the parties and the object of the contract.[24] These two views can be synthesized based on construction of the royalty clause as creating a sharing arrangement and the contract principles of cooperation, good faith, and fair dealing to carry out the principals of the agreement.[25] Thus, courts have implied a duty on the part of the lessee to take reasonable actions to maximize the production and value of production for the mutual benefit of both the lessee and lessor, and to prevent mutual losses

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[19] Emerson v. Little Six Oil Co., 3 F.2d 265, 266 (5th Cir. 1924).

[20] BP Am. Prod. Co. v. Red Deer Res., LLC, 526 S.W.3d 389, 394 (Tex. 2017); Hydrocarbon Mgmt., Inc. v. Tracker Expl., Inc., 861 S.W.2d 427, 432 (Tex. Civ. App. 1993).

[21] *Id.* at 572–84.

[22] *Id.*

[23] Frey v. Amoco Production Co. 603 So. 2d 166, 172 (LA. 1992).

[24] David E. Pierce, *Exploring the Jurisprudential Underpinnings of the Implied Covenant to Market,* 48 ROCKY. MTN. MIN. L . INST. 10-1, 10-10 (2002).

[25] Williams & Meyers, *supra* note 2, at §§ 802–802.1.

through drainage.[26] As A.W. Walker has proposed, these implied obligations include "the covenant to use reasonable care in conducting all operations affecting the lessor's royalty interest."[27] These obligations have required the lessee to exercise reasonable care in marketing production, to not prematurely abandon wells, to seek administrative relief where necessary, and to produce a fair share from the leasehold.[28]

The drafting of the lease oil and gas royalty provision has evolved significantly over the past 150 years and continues to be adapt in response to evolving statutory and common law. The earliest oil royalty provisions took the form of profit sharing, at times allocating somewhere between $^1/_3$ to $^1/_2$ of the profits between the lessor and lessee.[29] This quickly evolved into a share of production, typically 1/8th delivered in kind, combined with a flat-rate payment of a fixed amount per well that produced only gas.[30] By 1910, as Professor Kramer details, royalties were customarily drafted in seven principal ways:

> (1) a fixed sum; or an (2) annual or other periodical sum; or (3) a royalty on the amount of the minerals or oil mined or produced, payable at fixed intervals or times; or (4) a royalty, not, however, less in the aggregate than a specified sum each year; or (5) a royalty accompanied by a covenant to mine a certain minimum amount or pay a certain sum thereon; or (6) in case of a gas lease, to bore so many wells and pay so much a well, or forfeit a certain sum per well for a failure to bore the required number; or (7) in case of an oil lease, to pay a certain percentage of the oil taken out of the premises.[31]

Not only are many of these century-old leases still producing, but these same variants are still apparent in the royalty provisions of modern oil and gas leases. There is no standard formula for the calculation and payment of royalty. Instead, the measurement, valuation, and payment of royalty, and the costs which are borne by the royalty interest, are subject to negotiation and are determined by the language of the provisions in the oil and gas lease.[32]

IV. THE PARSING OF LANGUAGE APPROACH

Texas courts, given the opportunity, have declined to reduce the royalty provision to a simple formula. Instead, courts determine the royalty obligation based on the specific language of the royalty clause. As the court described in *Heritage Resources, Inc. v. Nationsbank*, "[i]n construing a contract, courts give terms their plain, ordinary, and generally accepted meaning

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[26] *Id.* at §§ 861–861.5.

[27] A.W. Walker, *The Nature of Property Interest Created by and Oil and Gas Lease in Texas*, 11 TEX. L. REV. 399, 401 (1933).

[28] *Id*.

[29] Kramer, *supra* note 2, at 224.

[30] *Id*. at 225.

[31] *Id*. citing W.W. THORNTON, THE LAW RELATING TO OIL AND GAS 287–88 (1912).

[32] Byron C. Keeling, *In The New Era of Oil and Gas Royalty Accounting: Drafting a Royalty Clause that Actually Says What the Parties Intend It to Mean*, 69 BAYLOR L. REV. 516, 520 (2017).

unless the instrument shows that the parties used them in a technical or different sense. . . Courts presume that the parties to a contract intended every clause to have some effect."[33] This method of "treating the written word as the *sine qua non* of contract interpretation," is known as "the parsing of language" approach.[34] While this approach does not preclude consideration of equitable considerations or the extrinsic intent of the parties or guarantee uniform outcomes, it provides a useful metric for unpacking the key variants contained within the royalty clause.[35]

V. THE MEANING OF PRODUCTION

The first step to determining whether royalty is owed is to determine whether production has occurred. Numerous cases have looked at the meaning of production relative to whether royalty is owned on flared gas or take-or-pay settlement payments.[36] As provided by the Texas Court of Appeals in *Killam Oil Co. v. Bruni*, "it has become well established under Texas law that the term 'production' as used in oil and gas leases means the actual physical extraction of the mineral from the soil . . . royalties are not owed unless and until actual production, the severance of minerals from the formation, occurs."[37] Consistent with Texas' parsing-of-language approach, Texas courts have resolved the issue of take of pay disputes by considering whether there has been a severance of oil and gas from the realty and a sale of that gas: since there is no production, no part of the settlement is due as royalty.[38] Similarly, whether royalty is owed on flared gas, or on other produced substances such as CO_2, will depend on a close reading of the lease and royalty provisions.[39] For example, a royalty provision that provides for payment on "gas produced" could require payment of royalty on flared gas where as a provision providing for payment of royalty on gas "produced, saved, and sold" might not.

VI. THE ROYALTY SHARE

Most modern leases provide that royalty will be paid as a fraction or percentage of a specified substance. The amount of royalty is negotiated taking into consideration customary rates and practices in the field or territory in which the lease bearing the royalty or override is located. For example, early gas royalty provisions would provide for "an agreed price per thousand feet of

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[33] 939 S.W.2d 118 (Tex. 1996).

[34] *See* Bruce M. Kramer, *Royalty Interest in the United States: Not Cut from the Same Cloth*, 29 TULSA L.J. 449 (1994); Anderson, *supra* note 2, at 547.

[35] Kramer, *supra* note 2, at 236.

[36] Kirk J. Bily, *Royalty on Take-or-Pay Payments and Related Consideration Accruing to Producers*, 27 HOUS. L. REV. 105 (1990).

[37] 806 S.W.2d 264 (Tex. Civ. App. 1991), (citing Diamond Shamrock Exploration Corp v. Hodel, 853 F.2d 1159 (5th Cir.1988)); *see also* Monsanto Co. v. Tyrrell, 537 S.W.2d 135 (Tex. Civ. App. 1976); Energy Oils, Inc. v. Mont. Power Co., 626 F.2d 731 (9th Cir. 1980); Phillips Petroleum Co. v. Adams, 513 F.2d 355 (5th Cir. 1975) ("Texas law provides that oil and gas are realty when in place and personalty when severed from the land by production.").

[38] *See* Alameda Corp. v. TransAmerican Natural Gas Corp., 950 S.W.2d 93 (Tex. Civ. App. 1997); Condra v. Quinoco Petroleum, Inc., 954 S.W.2d 68 (Tex. Civ. App. 1997); TransAmerican Natural Gas Corp. v. Finkelstein, 933 S.W.2d 591 (Tex. Civ. App. 1996); Hurd Enters. v. Bruni, 828 S.W.2d 101, (Tex. Civ. App. 1992).

[39] Comm'r Gen. Land Off. of State v. SandRidge Energy, Inc. 454 S.W.3d 603 (Tex. Civ. App. 2014).

gas produced" or a "periodic flat sum royalty payment" such as $200 per year.[40] This quickly evolved into use of a fixed fraction, commonly 1/8th, of the amount of oil or gas produced. Though not particularly common, leases occasionally provide for a variable rate royalty where the fraction adjusts based on gross volumes of production, may be used.

Even where the royalty provision is clear and unambiguous, calculating the royalty share may be complicated by measurement issues related to "pressure, temperature, quantity, quality, and gravity of the product measured"[41] or whether production —particularly condensate—should be classified as either oil or gas for royalty purposes.[42] These considerations are complicated where production is comingled—either downhole or in consolidated production facilitates—and thus must be allocated to each well.

VII. The Price or Value of Royalty: "Market Value" Versus "Proceeds"

As royalty provisions increasingly provided for payment of royalty in money rather than in kind, royalty clauses were drafted to specify how the value of royalty would be calculated. These provisions outline whether royalty will be paid based on the "'value" or "market price" of the gas produced and saved."[43]

While "market value" and "market price" are not necessarily identical, and have occasionally been distinguished, typically they are used interchangeably in calculation of gas royalty.[44] As Professor Kramer notes:

> In theory there should be a distinction between the terms market price and market value. Market price seemingly refers to an actual sale of the gas in exchange for a cash consideration. Thus, without a sale there is no market price. Market value, however, may exist in the absence of any actual sale because it is based on a hypothetical standard. In fact, a number of courts have made this distinction. But the vast majority of courts have treated market price and market value royalty clauses as functional equivalents. [45]

"Market price" may refer to royalty requiring payment at a posted price.[46] Although frequently employed for determination of oil royalty, it is "only infrequently a measure of the royalty to be paid on gas" as there is rarely a posted price for gas of the quality and in the condition produced

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[40] Williams & Meyers, *supra* note 2, at § 643.2.

[41] *Id.* at § 647 (citing 39 U.S.C. § 1721 (West 2019); Woods Petroleum Corp. v. Delhi Gas Pipeline Corp (Okla. App. 1983)).

[42] Hardwicke, *Evolution of Casinghead Gas Law*, 8 Tex. L. Rev. 1, 11–12 (1929).

[43] Williams & Meyers, *supra* note 2, at § 643.2(a).

[44] *Sowell v. Nat. Gas Pipeline Co. of Am.*, 604 F. Supp. 371, 375 (N.D. Tex. 1985), *aff'd*, 789 F.2d 1151, *reh'g denied*, 793 F.2d 1287 (5th Cir. 1986).

[45] Kramer, *supra note 34, at* 459.

[46] Williams & Meyers, *supra* note 2, at §§ 642.2, 643.3.

in the field.[47] As such, this language has posed challenges for courts seeking to determine the royalty obligation in leases providing for royalty to be paid at market price, with some courts even speculating whether a market price royalty required payment of any royalty at all where no market existed at the location specified.[48] It is also possible that "market price might conceivably be substantially less than market value, because market value assumes that the natural gas is available for sale at the current time."[49] Despite these cases, the terms are considered synonymic in most modern leases.[50]

As a distinct alternative, some parties choose to require payment on the basis of "proceeds" or "amount realized." The choice of this language completely removes the problem of determining market value based on a quality and quantity measured at a specific point in the production process, instead relying on a much more quantifiable metric. While in some instances the proceeds received by the lessee may be equivalent to the market value, "market value" and "proceeds" are not functional equivalents and may not be used interchangeably.[51] "Proceeds" is a specific term referring "to the money obtained in an actual sale."[52] At times, proceeds may differ significantly from the prevailing market value for the leased product at the time of production. For example, in *Texas Oil & Gas Corp. v. Vela*, the producer entered into contracts for sale of the gas "for the life of the lease" at a price of $0.023 per mcf.[53] When the case was before the Texas Supreme Court in 1968, the prices paid in current contracts for the same quality gas were substantially higher. While a lease requiring payment on the basis of proceeds or amount realized might have permitted payment based on the contract rate, in interpreting "market price" the Court held that the lease entitled the lessor to payment of royalties based on the market price at the time of the sale or use.[54] The converse can also be true: if a gas purchase agreement provided for payment at a price in excess of the then prevailing market price, then the owner of a proceeds based non-participating royalty interest may be entitled to a higher payment than the owner of an interest requiring payment based on market value.[55]

[47] Kramer, *supra* note 34; Williams & Meyers, *supra* note 2, at § 643.2.

[48] *See generally* Kuntz *supra* note 6, at § 40.4(c) (discussing problems associated with "market price" royalties clauses where there is no market price for gas at the location specified and examples of cases resolving this question).

[49] Kramer, *supra* note 2, at 242.

[50] Owen L. Anderson, *Royalty Valuation: Should Royalty Obligations be Determined Intrinsically, Theoretically, or Realistically?, Part 2*, 37 NAT. RES. J. 611, 638 (1997) ("Contrary to the implication of an old case, [market price and market value] are essentially synonymous."); *but see* Shamrock Oil & Gas Corp. v. Coffee, 140 F.2d 409, 410 (5th Cir. 1944) ("Market price is the price that is actually paid by buyers for the same commodity in the same market. It is not necessarily the same as 'market value' or 'fair market value' or 'reasonable worth.'").

[51] Waechter v. Amoco Prod. Co., 537 P.2d 228, 249 (Kan. 1975).

[52] *Id*.

[53] 429 S.W.2d 866, 868 (Tex. 1968).

[54] *Id*. at 871; *see also* Foster v. Atl. Refining Co., 329 F.2d 485, 489 (5th Cir. 1964); Martin v. Amis, 288 S.W. 431, 433 (Tex. Comm'n App. 1926).

[55] *See, e.g.,* Yzaguirre v. KSC Res., Inc., 53 S.W.3d 368, 372–73 (Tex. 2001).

However, determination of the actual "price" or "proceeds" may be difficult where portions of production are sold in a split-steam. In that scenario, portions of the gas are taken in kind by co-tenant lessees and separately marketed to different purchasers at different prices. In these scenarios Oklahoma has used a weighted average approach to determining the value of production.[56] Conversely, Texas has adopted a "tract allocation" approach whereby royalty owners are "on basis of amount received by their individual lessee from sale by their lessee of proportion of gas from unit allocated to tract in which royalty owners owned an interest."[57]

Royalty provisions employing "proceeds" language may specify whether such proceeds are "net" or "gross," whereas "market value" royalty provisions do not.[58] This distinction speaks to the very nature of market value. Proceeds refers to the actual amount received in a sale, and accordingly it is necessary to specify whether any deductions may be taken against the proceeds received, such as for processing or transportation, for example. However, a market value provision requires no such distinction. Market value is by definition the value a willing buyer and a willing seller would agree to in an arm's-length transaction for purchase of the produced substance based on the quality of the substance in its condition at the location and time specified.[59]

Acknowledging this difference and the realities of gas production, many leases take a bifurcated approach to payment of royalties. These leases provide different methods for calculating royalty based on location of gas sales as either on or off the premises. Most of these leases apply a proceeds method for royalty on gas sold at the well and a market value at the well method for gas sold off the premises.[60] This approach inherently acknowledges that the proceeds received from gas sold at the well necessarily account for the quality of the gas at the time of production, whereas determining the market value of gas sold off the premises requires consideration of costs associated with bringing the gas to a marketable condition and location.[61]

a. The Market Value Location: "At the Well" and "In the Field"

Market value royalty provisions also specify a location for measurement, typically "at the well" or "in the field."[62] These terms define the point of valuation, and the point at which costs "of production" are distinct from costs "subsequent to production." Most courts interpret "at the well"

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[56] *See, e.g.,* Shell Oil Company v. Corporation Commission, 389 P.2d 951 (Okla.1963).

[57] Puckett v. First City Nat'l Bank of Midland, 702 S.W. 2d 232 (Tex. Civ. App. 1985).

[58] Phillips Petrol. Co. v. Johnson, 155 F.2d 185, 188-89 (5th Cir. 1946) (holding that "net proceeds at the mouth of the well" allowed for deduction of costs of transportation, separation, and marketing); Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203, 1206 (Okla. 1998); Williams & Meyers, *supra* note 2 at § 643.2 ("[B]y the modifying word 'net' is meant proceeds less certain delivery and other costs" whereas "where the lessor chose to use the term 'gross proceeds'… it was a breach of the lease for the lessee to deduct costs incurred between the wellhead and the tailgate of the onshore treatment facility where the natural gas was sold" (citing Exxon Mobil Corp. v. Ala. Dep't of Conservation & Nat. Res., 986 So. 2d 1093 (Ala. 2007)).

[59] Occidental Permian Ltd. v. Helen Jones Found., 33 S.W.3d 392, 403–04 (Tex. Civ. App. 2011); Howell v. Texaco Inc., 112 P.3d 1154, 1159 (Okla. 2005).

[60] *See, e.g.*, Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 122 (Tex. 1996).

[61] Exxon Corp. v. Middleton, 613 S.W.2d 240, 246–47 (Tex. 1981).

[62] Williams & Meyers, *supra* note 2, at § 645.

to denote "that costs incurred by an operator to deliver the lease product to the Christmas Tree [wellhead of a gas well] of the well are borne exclusively by the operator, and that any downstream costs incurred by the operator from the well to the place where the leased product is disposed of in an arm's length transaction are borne pro rata by the owners of operating and non-operating interests."[63] This language clearly indicates that the parties intended to calculate the market value based on the quality and value at the wellhead.[64]

The meaning of the provision "in the field," is slightly different. The definition of "field" itself can be difficult to determine and has been deemed commensurate with the terms "pool," "reservoir," or "separate productive stratum under a single well, lease, or unit."[65] As the Supreme Court of Texas observed in *Railroad Comm'n v. Rio Grande Valley Gas Co.*, "[t]he word 'field' as used in the oil industry has a meaning which is usually determined from the context in which it is used. It may refer to a certain geographical area from which oil is produced or it may be restricted to a particular reservoir."[66] This distinction can create issues relative to determining to location at which market value must be determined. For instance, in *Emery Resource Holdings, LLC v. Coastal Plains Energy, Inc.*, the U.S. District Court for the District of Utah was tasked with interpreting a royalty provision that required royalty to be paid on the basis of "market price for oil of like grade and gravity prevailing in the field where produced."[67] The court held that if royalty is not valued "at the wells" and gas is sold "in an improved condition at some downstream point," then, the leases "are left without a defined royalty valuation point or with a royalty valuation point that can change over time" and "[a]ccordingly, . . . the gas royalty under the Subject Leases must be valued at the wells in the condition at which the gas flows from the wellhead separators and enters the [] gas gathering system."[68]

b. Determining Market Value in the Absence of a Market: The Workback Method

Determining market value in the absence of a sale at the wellhead has proven to be a considerably difficult task, particularly where gas is produced in a condition for which there is no market readily available. As the United States Supreme Court interpreting Louisiana law noted as early as 1944, the "market-value-at-the-wellhead" rule "requires that the price for royalty purposes

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[63] *See* PATRICK MARTIN & BRUCE KRAMER, WILLIAMS & MEYERS, OIL AND GAS LAW § 8-A (2011); *see also* Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 894 (Mich. Ct. App. 1997); Edward B. Poitevent, II, *Post-Production Deductions from Royalty*, 44 S. TEX. L. REV. 709, 716 (2003) ("Lessors that agree to use certain language in the royalty clause, and in particular the phrase "at the well," agree to value production by reference to the value of the raw production at the wellhead at the time title vests in the producer.").

[64] *Atl. Richfield Co. v. State of California*, 214 Cal. App. 3d 533, 542 (Cal. Ct. App. 1989) ("The term 'at the well' when used with reference to oil and gas royalty valuation, is commonly understood to mean that the oil and gas is to be valued in its unprocessed state as it comes to the surface at the mouth of the well.").

[65] *See Bolton v. Coats*, 533 S.W.2d 914, 917 (Tex. 1975) ("Numerous 'fields' (one for each physically separate productive stratum) can lie under a single well, lease, or unit"); Martin & Kramer, *supra* note 63 at § 8-F.

[66] 405 S.W.2d 304, 309 (Tex. 1966).

[67] 915 F. Supp. 2d 1231, 1237–38 (D. Utah 2012).

[68] 915 F. Supp. 2d 1231, 1238 (D. Utah 2012); *see also,* Kramer, *supra* at note 34, at 459 (noting that to compute market price there would have to be an "actual sale of the gas in exchange for cash consideration" at the location specified).

be ascertained at a place and time at which few commercial sales of gas occur."[69] As one commentator has noted, downstream sales to pipeline companies may have little relationship to market value at the well where "many considerations influenced those prices which made them irrelevant in the determination of the market price at the well."[70] In the absence of an actual sale at the well, determination of "market value at the well" requires payment on the basis of a "hypothetical standard"[71] to determine what a willing buy and a willing seller would pay for the product at the wellhead. This determination may involve either comparable sales,[72] or in the absence of comparable sales, determination of the "fair value at the well" taking into consideration "every factor properly bearing upon its establishment."[73] This method, commonly referred to as the "netback" or "workback" method, permits the lessee to deduct transportation, marketing, and processing costs from the price it receives in a sale off the leased premises for purposes of calculating market value at the well.[74]

Perhaps the most comprehensive case evaluating the deductions of costs subsequent to production is the Fifth Circuit's 1984 decision in *Piney Woods Country Life School v. Shell Oil Co.*[75] This suit, like many others at the time, arose from controversies arising in the wake of the "unforeseen and unprecedented rise in natural gas prices" resulting from OPEC's actions in the 1970s.[76] The lessor sought to recover royalty for sour gas under leases entered into in the 1960s requiring payment for "market value at the well," under the theory that the lessee had improperly deducted costs of transporting and processing the gas. The court found that "lessors under these leases are therefore entitled to royalty based on the value or price of unprocessed, untransported gas . . . therefore, the lessors may be charged with processing costs, by which we mean all expenses, subsequent to production, relating to the processing, transportation, and marketing of

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[69] *Sartor v. Ark. Nat. Gas Corp.*, 321 U.S. 620, 622 (1944).

[70] Joseph T. Sneed, *Value of Lessor's Share of Production Where Gas Only is Produced*, 25 TEX. L. REV. 641, 647 (1947).

[71] Kramer, *supra* note 34, at 459.

[72] Kuntz, *supra* note 48 § 40.4 ("[I]t is possible to arrive at a market value or market price from sales of gas made under uniform conditions." (citing *Ark. Nat. Gas Co. v. Sartor*, 78 F.2d 924 (5th Cir. 1935); *Phillips Pet. Co. v. Bynum*, 155 F.2d 196 (5th Cir 1946))).

[73] *Sartor*, 321 U.S. at 622-23 ("Included in these are the fixed royalties obtaining in the leases in the field considered in the light of their respective dates, the prices paid under the pipe-line contracts, and what elements, besides the value as such of the gas, were included in those prices, the conditions existing when they were made, and any changes of conditions, the end and aim of the whole inquiry, where there was no market price at the well, being to ascertain, upon a fair consideration of all relevant factors, the fair value at the well of the gas produced and sold by defendant." (internal citation omitted)).

[74] *Oil and Gas Law Scope* in Williams & Meyers, *supra* note 2.

[75] 726 F.2d 225, 227 (5th Cir. 1984).

[76] *Id.*

gas and sulfur."[77] Courts adopting this approach have generally permitted reasonable deductions for gathering and transportation, compression, processing, fuel use, dehydration, and refining.[78]

In more recent cases, the process of determining market value at the well by using "the market price on the distant market after deducting from such price the costs of transportation to such market" has been referred to as either the "netback" or "workback" method.[79] As defined by the Supreme Court of North Dakota in *Bice v. Petro-Hunt, L.L.C.*, under this "method the lessee calculates the market value of the gas at the well 'by taking the sale price that is received for its oil or gas production at a downstream point of sale and then subtracting the reasonable post-production costs (including transportation, gathering, compression, processing, treating, and marketing costs) that the lessee incurred after extracting the oil or gas from the ground.'"[80] This reasoning is consistent with the idea that production functions are separate, and should be differentiated from, entrepreneurial functions such as marketing, transportation, and processing.[81] Most jurisdictions utilized this approach through the 1960s and "received nearly universal acceptance through the 1970s."[82] In addition to North Dakota, the workback or netback method

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[77] *Id*. at 240.

[78] Holbein v. Austral Oil Co., 609 F.2d 206 (5th Cir. 1980); Clayton La Grone, *Calculating the Landowner's Royalty*, 28 ROCKY MT. MIN. L. INST. 803 (1982); Jefferson D. Steward and David F. Maron, *Post-Production Charges to Royalty Interests: What Does the Contract Say and When Is It Ignored?*, 70 MISS. L.J. 625, 659–68 (2000).

[79] Occidental Permian Ltd. v. French, 391 S.W.3d 215, 222 (Tex. Ct. App. Eastland –2012) (quoting from Heritage Res. Inc. v. NationsBank, 939 S.W.2d 119, 123 (Tex. 1996)), *aff'd*, 440 S.W.3d 1 (Tex. 2014); Kuntz, *supra* note 48, § 40.4 (1989).

[80] 768 N.W.2d 496, 501 (N.D. 2009) (quoting Byron C. Keeling & Karolyn King Gillespie, *The First Marketable Product Doctrine: Just What is the Product?*, 37 ST. MARY'S L.J. 1, 32 (2005)).

[81] John S. Lowe, *Defining the Royalty Obligation*, 49 SMU L. REV. 223, 257–58 (1996) ("History and logic suggest that the scope of the royalty obligation should be limited to the fruits of lessees' production functions, which typically occur at or near the wellhead, and should not extend to entrepreneurial functions such as marketing, transportation or processing.").

[82] Kramer, *supra* note 2, at 246.

has been adopted in Montana,[83] Texas,[84] Louisiana,[85] Utah,[86] California,[87] New Mexico,[88] Mississippi,[89] Kentucky,[90] and Pennsylvania.[91]

c. Post Production Costs and Other Expenses Burdening Royalty Interests

It is well established that a royalty is paid free of the costs of production (e.g., expenses for drilling and completing wells and operating production equipment like pumps).[92] However, "[i]mplicit in such provisions and definitions is the assumption that the royalty or other non-operating interest is or may be subject to certain costs, viz., costs subsequent to production."[93] As Professors Kramer and Martin note in the *Williams & Meyers* treatise, operating and non-operating interest holders traditionally shared costs *subsequent* to production, including: gross production and severance taxes; transportation from the well-head to the point of sale; "[e]xpenses of treatment required to make the mineral produce salable," including expenses of dehydration and gathering; "[e]xpenses of compressing gas to make it deliverable into a purchaser's pipeline;" and "[m]anufacturing costs incurred in extracting liquids from gas" and "costs incurred in adding value to the well-head product."[94]

The majority of disputes regarding costs-of-production and use of the netback method concern natural gas royalties.[95] Prior to deregulation of the natural gas industry nearly all gas sales

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[83] Mont. Power Co. v. Kravick, 586 P.2d 298, 302–04 (Mont. 1978).

[84] Heritage Res. v. NationsBank, 939 S.W.2d 118, 122 (Tex. 1997) ("Royalty is usually subject to post-production costs, including taxes, treatment costs to render it marketable, and transportation costs.").

[85] Wall v. United Gas Pub. Serv. Co., 152 So. 561, 564 (La. 1934).

[86] Emery Res. Holdings, LLC v. Coastal Plains Energy, Inc., 915 F. Supp. 2d 1231, 1240–42 (D. Utah. C.D. 2012)

[87] Atl. Richfield Co. v. State of California, 214 Cal. App. 3d 533, 541–42 (Cal. Ct. App. 1989).

[88] ConocoPhillips Co. v. Lyons, 299 P.3d 844, 852-53 (N.M. 2012); Elliott Indus. Ltd. P'ship v. BP Am. Prod. Co., 407 F.3d 1091, 1109-11 (10th Cir. 2005) (following Creson v. Amoco Prod. Co., 10 P.3d 853 (N.M. Ct. App. 2000) (finding that the "meaning of the "at the well" language "clear and unambiguous" and that royalties are "to be paid on the value of the gas in its unprocessed state as it comes to the surface at the mouth of the well before it is transported and processed")).

[89] Piney Woods Country Life Sch. v. Shell Oil Co., 726 F.2d 225, 231 (5th Cir. 1984).

[90] Reed v. Hackworth, 287 S.W.2d 912, 913 (Ky. 1956).

[91] Kilmer v. Elexco Land Servs., Inc., 990 A.2d 1147, 1157-58 (Pa. 2010).

[92] Kuntz, *supra* note 48, § 40.5 ("Unquestionably, under most leases, the lessee must bear all costs of production."). Although Kuntz advocated for the first-marketable product approach, he notes that "[t]he decisions are not at all consistent with this analysis." *Id*.

[93] Williams & Meyers, *supra* note 2, at § 645; *see also* Lowe, *supra* note 81, at 262–263.

[94] Williams & Meyers, *supra* note 2, at § 645.2.

[95] Williams & Meyers, *supra* note 2, at § 645.

were "at the well."[96] Accordingly, the amount realized under many royalty provisions was equivalent to the market value at the well. The transition away from wellhead pricing following the deregulation of the natural gas industry required development of new methods – namely the netback method - to determine the value of natural gas "at the well." In states like Texas that have taken a literal approach to interpretation of royalty provisions, use of the term "at the well" has been construed to allow lessees to deduct the lessors share of all post-production costs to determine the "intrinsic" wellhead value of production.[97]

Lessors in Texas have sought to contract around the deduction of post-production costs from royalty in market-value leases though the inclusion of a "no-deductions" clause with mixed results.[98] In *Heritage Resources, Inc. v. Nationsbank,* the Texas Supreme Court permitted use of the netback method despite language provided that "there shall be no deductions from the value of Lessor's royalty by reason of any required processing, cost of dehydration, compression, transportation, or other matter to market such gas."[99] The Court found that there was no inconsistency between the "market value at the well language" and the "no deduction" language since the no-deduction clause provided there was no deduction from the *value* of the Lessor's royalty, which was calculated at the well and thus already net of those post-production costs.[100] The 5th Circuit in *Warren v. Cheaspeake Exploration, LLC* reached a similar result where the non-deduction clause was included as an addenda to a market value lease. The court found that use of the terms "at the well" or "at the mouth of the well" were clear that royalty should be based on established methodology to determine wellhead value.[101] Inclusion of provisions directly seeking to disclaim the holdings of *Heritage Resources* have had little effect.[102]

However, consistent with Texas' literal approach to construing the royalty provision, the precise wording of the royalty clause matters. For example, courts have distinguished between royalty provisions requiring payment based on market value "at the well" and those specifying market value "in the pipeline."[103] Where the market value is at the well, expenses incurred downstream of the wellhead are deductible. But where a royalty requires the lessee to bring the gas to the pipeline on behalf of the lessor, the lessor is not subject to costs of bringing the gas to the quality and location required by the pipeline purchaser.[104] Accordingly, lessors may prohibit

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[96] Anderson, *supra* note 2, at 553 "deregulation is one reason for some of this litigation, especially the recent litigation over post-wellhead costs because, during regulation, gas buyers often purchased gas at or near the wellhead, thereby absorbing most post-wellhead costs."

[97] Phillips Petrol. Co. v. Bynum, 155 F.2d 196, 198 (5th Cir. 1946).

[98] Robert Theriot & Josh Downer, *Our Texas Heritage: The Summer of the No Deductions Clause*, 52-DEC HOUSTON LAWYER 26, 27 (2014).

[99] 939 S.W.3d 118, 120 (Tex. 2006).

[100] *Id.*

[101] 759 F.3d 413, 415 (5th Cir. 2015).

[102] Chesapeake Expl., LLC v. Hyder, 483 S.W.3d 870, 875–76 (Tex. 2016).

[103] Anderson, *supra* note 50, at 650 ("Consistent with nearly all case law, the latter provision [providing for delivery "free of cost, in the pipeline"] contemplates that the lessee must absorb all costs of delivering oil or gas into a pipeline near the well, but is not obligated to deliver oil or gas to some distant pipeline or market.").

[104] For a comprehensive summary of the cases addressing this language, *see* Adam Marshall, *Note, Oil &*

deduction of post-production cost from their interest through careful drafting. For example, the lessors who unsuccessfully disclaimed the holding of Heritage Resources in *Chesapeake v. Hyder,* were able to achieve their desired end result through inclusion of "free and clear" or "cost-free" language in a royalty provision that omitted a yard stick such as "market value."[105] Similarly, Texas courts have disallowed the deduction of post-production costs from proceeds leases[106] or leases that have moved the point of valuation downstream, for example, to the "point of sale." [107]

However, even the use of a proceeds or amount realized lease does not absolutely preclude deductions of post-production costs.[108] A reference to the wellhead, the pipeline, or to market value within a royalty valuation provision may, when harmonized with other provisions of the lease or other agreements, be interpreted to permit deduction of post-production costs even in a proceeds or amount realized lease. In March of 2019, the Texas Supreme Court issued an opinion interpreting the royalty valuation provisions of an assignment of overriding royalty in *Burlington Resources Oil and Gas Co., LP v. Texas Crude Energy, LLC*.[109] In that case, the parties provided that royalty could be delivered "into the pipeline. . . free and clear of all development, operating, production and other costs" or, at assignees option, payable in value based either on the "amount realized" in an arms-length sale either on or off the premises, or "in all other cases, the market value at the wells."[110] The parties agreed that royalty was paid in cash and that the gas was sold in an arms-length transaction off the premises.[111] The Court found that the language "in the pipeline" was equivalent to language requiring delivery "at the wellhead or nearby" and thus allowed the deduction of post-production costs from the overriding royalty interest.[112] Although the Court emphasized that its role was not to establish a firm rule, but rather to interpret the contract based on "a fair reading of its text,"[113] *Burlington* indicates that Texas courts interpret contracts consistent with a strong presumption that post-production costs can be deducted.

Gas Law: Royalty Valuation: Rogers v. Westerman Farm Co.: Burdening Lessees with an Implied Duty to Deliver Gas to a Marketable Location, 56 OKLA. L. REV. 233, 237, n.32 (2003); Kramer, *supra* note 2, at 227 ("It was generally perceived in the 1920s that an express covenant to deliver to a pipeline carried with it the duty to put the oil in marketable condition by the removal of water, basic sediments, or other foreign substances that might contaminate the oil stream.").

[105] 483 S.W.3d 870.

[106] *See* Chesapeake Expl., LLC v. Hyder, 427 S.W.3d 472 (Tex. Civ. App. 2014), *aff'd*, 483 S.W.3d 870 (Tex. 2016).

[107] Potts v. Chesapeake Exploration, LLC 760 F.3rd 470 (5th Cir. 2014).

[108] Burlington Res. Oil & Gas Co. LP v. Texas Crude Energy, LLC, No. 17-0266, 2019 WL 983789 (Tex. 2019). ("We have never held that an "amount realized" valuation method frees a royalty holder from its usual obligation to share post-production costs even when the parties have agreed to value the royalty interest at the well.")

[109] *Id.*

[110] *Id.* at 2.

[111] *Id.*

[112] *Id.*

[113] *Id.*

In contrast to Texas, in many other states, courts have taken the position that post-production costs are nearly never deductible. These courts have rejected the historical idea that production has an "intrinsic" value at the wellhead, instead opting to determine royalty based on the proceeds realized from the actual sale of the "first marketable product." Although versions of the rule vary between the four states that have adopted it— Colorado, Kansas, Oklahoma, and West Virginia—the basic principle is the same: the implied covenant to market requires that the lessee bear all of the post-production costs to achieve a marketable product.[114] Although parties may contract around the rule, courts have found that use of language creating a yardstick by which to measure the value of production, such as "at the well," is either meaningless or ambiguous.[115]

Federal regulations also impose a version of the first marketable product rule. Although versions of the duty originated much earlier, in 1988 the Department of Interior substantially revised the federal royalty valuation regulations to require the lessee to bear certain marketing costs "at no cost" to the lessor if the lessee's gas is not "sold at the wellhead or in the field before downstream compression, transportation, or processing."[116] This prohibits the lessee from deducting costs to place the gas in marketable condition.[117] Like the version of the marketable product rule adopted in Kansas, the revised regulations do not prohibit all deductions. The 1988 regulations continued to allow deductions of the "reasonable actual costs" of processing and of transporting gas where the sale occurs off the leased premises.[118]

d. Statutory Enactments Affecting the Royalty Valuation

Several states have also adopted statutory enactments that modify common law constructions of royalty provisions in certain leases.[119] Unlike the first marketable product rule, which has been imposed as an extension of the implied covenant of the lease, these statutes were enacted independently and without reference to the first marketable product rule.[120] Accordingly, application of these statutes require a close reading of the statutes, as well as the royalty clauses and other agreements at issue. For instance, in 1989 the State of Wyoming's legislature amended the Wyoming Royalty Payment Act to define non-deductible costs of production for purposes of calculating royalty, in the absence of a specific writing to the contrary, as including "gathering, compressing, pressurizing, heater treating, dehydrating, separating, storing or transporting the oil to the storage tanks or the gas into the market pipeline."[121] This includes the costs of gathering, which Wyoming courts have defined as "to collect gas and move it to a point where it can be

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[114] Keeling, *supra* note 32, at 535–36.

[115] Rogers v. Westerman Farm Co., 29 P.3d 887 (Colo. 2001).

[116] 30 C.F.R. § 1206.152(i) (2018); Xeno, Inc., 34 Interior 172 (IBLA 1995).

[117] Marketable condition is defined as "sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 C.F.R § 1206.151 (2018).

[118] 30 C.F.R. §§ §§ 1206.156(a), 1206.157(a)(1)(i), 1206.158(a), 1206.159(a)(1)(i) (2018); Exxon Corp., 118 Interior 221 (IBLA 1991).

[119] *See*, MICH. COMP. LAWS SERV. § 324.61503b(1) (LexisNexis Supp. 2015); NEV. REV. STAT. ANN. § 522.115(1)(a) (West Supp. 2015); WYO. STAT. ANN. § 30-5-304(vi) (West Supp. 2015).

[120] Wold v. Hunt Oil Co., 52 F.Supp.2d 1330, 1336–37 (D. Wyo. 1999).

[121] WYO. STAT. ANN. § 30–5–304(a)(vi) (West 2019); Wyo. Sess. Laws ch. 255 § 3 (1989).

processed or transported to the user."[122] However, Wyoming's cost of production amendments do not apply in all scenarios. In fact, the statute expressly provides that it does not apply where the parties have an express writing to the contrary.[123] Wyoming courts have not yet determined whether a lease using the term "market value at the well" will be sufficient to satisfy the express-writing requirement of the act.

Lessors have challenged the retrospective application of statutes that redefine royalty to leases that predate the statutes enactment on constitutional grounds. For instances, in addition to having the strictest version of the first marketable product rule, West Virginia's Flat Rate Statute prohibits issuance of a permit for any wells subject to a flat-rate lease unless the lessee supplants the flat-rate royalty provisions with a volume-based payment formula providing for 1/8th of the sales price to an unaffiliated third party.[124] EQT Production Company, a lessee in West Virginia, has challenged the Flat Rate Statute as violating the contract clause.[125]

State statutes known as "check stub" statutes may also supplant the royalty provision of the lease with additional provisions relative to the timing of payments and reporting obligations to the Lessor. These statutes modify the common law relative to royalty payment. Texas' "division order statute" for example, enumerates instances in which production can be withheld and placed in suspense accounts and provides timelines for payment of royalty after production.[126] These statutes also frequently provide reporting obligations for certain information, and provide penalty interest on late or missed payments.[127]

VIII. DIVISION ORDERS & CHECK STUB STATUTES

Faced with litigation over market values, complex divisions of interest including overrides and terminable interests, assignment of royalties or mineral interests, and questions regarding the deduction of post-production costs, third-party purchasers and lessees have sought to clarify the royalty provision of the leases and protect themselves from liability for underpayment through division orders. By authorizing payment in a specified manner, division orders can limit the liability of the distributor of proceeds for underpayments to the parties thereto.

Division orders are documents that affirm the payees' interests in production and provide terms relative to payment.[128] A division order customarily contains the following provisions: land description affected by the order, warranty of ownership in the proportions specified, effective date and hour of the order, revocability of the order, specific terms relative to price, quality, and

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[122] Cabot Oil & Gas Corp. v. Followill, 93 P.3d 238, 242 (Wyo. 2004).

[123] WYO. STAT. ANN. § 30–5–304(a)(vi) (West 2019).

[124] W. VA. CODE § 22-6-8(e) (2018).

[125] EQT Production Company v. Caperton, Civil Action No. 1:18-cv-72, *Complaint for Declaratory Relief* (filed Apr. 12, 2018).

[126] TEX. NAT. RES. CODE § 91.401, *et seq*. (West 2018).

[127] *See, e.g.* N.D. CENT. CODE § 47-16-39.3 (West 2019); OKLA. REV. STAT. ANN. §§ 52, 570.10 (West 2019); TEX. NAT. RES. CODE § 91.408 (West 2018); WYO. STAT. ANN. § 30-5-304 (West 2019).

[128] EARNEST E. SMITH AND JACQUELINE LANG WEAVER, TEXAS LAW OF OIL AND GAS § 6.5, 289 (1996).

method of settlement, provision relieving the purchase for responsibility for under payment or over payments, and authorization to withhold proceeds in the event of disputes concerning title.[129]

Division orders are almost as important for what they are not, as for what they are. Notably, a division order is not a conveyance and thus does not supplant a lease or deed or change the underlying ownership of interests in the parcel.[130] However, a division order signed by both the lessor and lessee may relieve the lessee from certain obligations arising under the royalty provisions of the lease.[131] Cases relieving the lessee of obligations under the lease have been decided on both contract and estoppel grounds. The Texas Supreme Court, in *Exxon Corp. v. Middleton*, held that a division order was an enforceable contract modifying the lease where the lessee had obligated itself to new requirements for reporting and making records available to royalty owners.[132] Relying on estoppel grounds, the *Middleton* court also found the division orders binding, even in the absence of detrimental reliance. The Court held that division orders are binding "for the time and to the extent that they have been, or are being acted on and made the basis of settlements and payments," but can be unilaterally revoked by either party.[133] As a result, parties that are underpaid based on a division order may recover from the operator only to the extent of the underpaid royalty the operator has retained.[134]

Numerous states have modified the common law and industry custom of division orders through the passage of check-stub statutes.[135] These statutes address numerous issues with division orders and were enacted in response to competing concerns between royalty payors and payees.[136] These statutes principally address 1) whether a lessee can be required to sign a division order, and 2) the extent to which a division order may modify the settlement terms of the lease.[137] For example, Oklahoma's statute provides that the only condition to payment is demonstration of marketable title, thus modifying the common law that a payor can require execution of a division order as a condition to precedent.[138] While not specifying whether a royalty owner can be required to sign a division order, Wyoming and Montana's statutes provide that a division order may not modify a lease and is void to the extent that it conflicts with the written terms of a lease.[139] Texas'

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[129] Williams & Meyers, *supra* note 2, at § 704.1

[130] *See* Gavenda v. Strata Energy, Inc. 705 S.W.3d 690 (Tex. 1986); Masgas v. Anderson, 310 S.W. 3d 567 (Tex. Civ. App. 2010); Louisiana Land & Exploration Co. v. Pennzoil Exploration & Production Co, 962 F. Supp. 908 (E.D. La. 1997); Bomar Oil & Gas, Inc. v. Loyd, 281 S.W.3d 689 (Tex. Civ. App. 2012).

[131] Exxon Corp. v. Middleton, 613 S.W.3d 240 (Tex. 1981)

[132] *Id*.

[133] *Id*.

[134] *Gavenda*, 705 S.W.3d at 692.

[135] *See, e.g.,* 52 OKLA. STAT ANN. § 540 (West 2019); N.D. CENT. CODE § 47-16-39.3 (West 2019); TEX. NAT. RES. CODE ANN. § 94.401-91.406 (West 2019); WYO. STAT. ANN. §30-5-301 (West 2019).

[136] Laura Burney, *The Interaction of the Division Order and the Lease Royalty Clause*, 28 ST. MARY'S L.J. 353, 430 (1997).

[137] *Id.*

[138] Hull v. Sun Refining and Marketing Co, 789 P.2d 1272 (Okla. 1989).

[139] MONT. CODE. ANN. § 82-10-110 (West 2019); WYO. STAT. § 30-5-305 (West 2019).

statute, consistent with its common law valid-until-revoked rule, addresses both: it provides that an owner may be required to sign a division order as a condition to payment, and that a division order may clarify the terms of a lease. [140]

VIII. CONCLUSION

The calculation and payment of royalties under and oil and gas have serious implications for both the lessor and the lessee. Failure to pay royalty or underpayment of royalty may result in litigation and damages for breach of the royalty covenant,[141] can give rise to penalty interest, attorneys' fees, or other statutory remedies under royalty payment statutes,[142] or, rarely, result in lease cancellation.[143] However, the interpretation and construction of royalty provisions is complex, particularly where the lease instruments contain ambiguities or inconsistencies, or where payments must be calculated and paid based on situations that the parties did not foresee at the time of execution.

In Texas, the calculation of the royalty obligation created under an oil and gas lease is determined by looking at the specific language contained in the royalty clause. Royalty terms in the lease such as "market value at the well" or "amount realized" establish how the royalty payor must measure and calculate royalty, and what post-production costs can be allocated to the lessor interest. In other states, obligations arising out of the implied covenant to market may impose additional burdens on the lessee regarding the payment of royalty, even where the lease contains specific language to the contrary. State statutes may impose additional royalty payment obligations regarding the calculation of production costs, reporting by the lessee, and the timing of payment and modify the common law regarding division orders. As a result, the express terms of the lease must be construed together with other contracts affecting the payment of royalty based on the statutory and common law of the state where the property is located. As A.W. Walker wrote in 1932, and as Professor Kramer has quoted, "Too much care cannot be devoted to the preparation of a royalty clause in an oil and gas lease."[144]

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[140] TEX. NAT. RES. CODE ANN. §§ 94.401–91.406 (West 2019).

[141] Mitchell Energy Corp. v. Samson Resources Co., 80 F.3d 976 (5th Cir. Tex. 1996).

[142] LA. REV. STAT. ANN. §§ 31:138—31:141 (West 2019); ND CENT. CODE § 47-16-39.1 (West 2019); TEX. NAT. RES. CODE. § 91.403 (West 2019); WYO. STAT. ANN. § 30-5-303 (West 2019); *see also* Joshua M. Morse III, *Nonpayment of Production Royalties Under a Producers 88 Lease: A Legislative Prescription to Cure a New Disease*, 9 FLA. ST. L. REV. 447 (1981).

[143] Cannon v. Cassidy, 542 P.2d. 514 (Okla. 1975).

[144] A.W. Walker, Jr., *The Nature of the Property Interests Created by an Oil and Gas Lease in Texas*, 7 TEX. L. REV. 1, 32 (1928), 10 TEX. L. REV. 291 (1932).