OIL AND GAS IMPLIED COVENANTS FOR THE TWENTY-FIRST CENTURY

The Next Steps In Evolution

John Burritt McArthur

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open to a lessee, so that there remains a need for the lessee to labor under a duty to secure the best price reasonably possible even in a market-value lease. In addition, the duty remains important to resolve conflict-of-interest situations in which the lessee does not pass on the full value it receives.

D. WHO BEARS THE COST OF PUTTING OIL AND GAS INTO A MARKETABLE CONDITION?

An issue that has been intensely litigated in the last few decades and that has riven oilfield jurisdictions is whether the duty to market requires lessees to bear the full cost of making oil and gas marketable, even if this means absorbing the cost of compression, dehydration, treating, gathering, and other services after the oil or gas emerges from the wellhead. These cases have focused on natural gas, not oil, because natural gas generally tends to be sold only after it has been compressed, dehydrated, treated and processed.

A number of leading oil-and-gas states have held that the duty to market and standard lease language require the lessee to bear all costs necessary to put the product into a market-ready state. These jurisdictions tend to apply this principle even if the lease states that payments shall be made "at the well." The Colorado Supreme Court has noted that this well reference on its face does not say that it has anything to do with costs, the West Virginia Supreme Court that it is ambiguous on costs.[66] "At the well" is effectively a point of valuation in these jurisdictions only if the lessee produces a marketable product at the well. For a lease to allow deductions under any circumstances in these states when the gas is not marketable, it has to identify the specific costs that can be allocated to lessors.

Colorado, West Virginia, Oklahoma, and Kansas are the leading marketable-condition states. They have been joined by Arkansas, Alaska, Virginia, and perhaps New Mexico. Several other states – Nevada, Wyoming, and Michigan – have barred deduction of typical downstream field costs by statute. There is some variation in which costs are deductible (the federal rule, for

[66] See infra notes 95-96, 110-12 & accompanying text.

instance, allows deduction of certain processing costs) and the law has not fully crystallized on how marketability will be defined, but overall a majority of the oil-and-gas jurisdictions to address the issue, judicially or legislatively, have adopted a marketable-condition rule.

By acreage, particularly given the federal government's application of a marketable-condition rule to its property and that most state lease forms apply this standard even in states like Texas that have not accepted marketable-condition principles for private royalty owners, a significant majority of all production in the United States is subject to a marketable-condition rule.

In contrast, courts in jurisdictions that seem to have addressed this issue earliest have hewed to what has been called a "property" approach[67] in which the passage of title to oil and gas at the well, the assertion that the "free of cost" concept for royalties only means free of the costs of getting oil or gas to the surface, or the term "at the well" itself, are applied to allow deduction of the proportionate share of all costs incurred after oil or gas emerges from the wellhead (or at least leaves the lease). Under this view, all costs downstream from the wellhead or some point near the wellhead can be deducted unless the lease very expressly prohibits deductions. The issue often arose under leases that provided for payments "at the well," but these jurisdictions tend to apply the same principle as a general default rule even if the lease has no locational term. Texas and Louisiana, two major producing states, are the leading jurisdictions taking this view, as have courts applying the laws of Kentucky, Mississippi, Montana, Pennsylvania, North Dakota, Utah, and California.

The stark division in marketability standards is shown by the fact that the major oil-and-gas treatises disagree on the appropriate standard. The Kuntz treatise argues that a marketable product is a prerequisite for the "production" upon which royalties are paid.[68]

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[67] See, e.g., Owen Anderson, Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part I, 37 Nat. Res. J. 547, 571-73 (1997)(contrasting "property" and "contract" approaches to royalty interpretation).

[68] 3 KUNTZ, supra note 14, § 40.5, at 351 ("It is submitted that the acts which constitute production have not ceased until a marketable product has been

Hence the lessee must bear marketing costs because all jurisdictions agree that it must bear the costs of production on its own. Maurice Merrill's foundational book on implied covenants, a work that was highly influential in the mid-twentieth century in persuading many courts to adopt today's core set of implied covenants, takes a different route to a very similar destination. Merrill argues that the functional duty to market includes making oil or gas marketable, and in turn requires the lessee to bear the costs of these activities:

> If it is the lessee's obligation to market the product, it seems necessarily to follow that his is the task also to prepare it for market, if it is unmerchantable in its natural form. No part of the costs of marketing of or preparation for sale is chargeable to the lessor.[69]

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obtained. . . . then further costs in improving or transporting such product should be shared by the lessor"); on the marketable-condition generally, see id. § 40.5 and especially the extensive case discussion in that section of the 2008 Supplement. Given the relative brevity of typical lease pricing terms, it is no surprise to see one observer claiming that the gas royalty clause, the clause that has generated most deduction disputes to date, "is one of the most ambiguous and incomplete provisions of an oil and gas lease ever to be brought before the courts." Joseph Sneed, Value of Lessor's Share of Production Where Gas Only Is Produced, 25 Tex. L. Rev. 641, 656-57 (1947).

For an interesting twist on the "production" argument, consider the sophisticated lawyers representing oil companies who argued, citing Texas law, that while "production" in the royalty context is limited to the lease and does not include the "post-production" costs of making gas marketable, in the habendum clause production requires marketability. EnerQuest Oil & Gas, LLC v. Plains Exp. & Prod. Co., 2013 WL 5951952, slip op. at *8 (W.D. Tex. Nov. 7, 2013). This in a supposedly "plain meaning" state, at least, plain meaning in a context that limits royalty owner rights.

[69] MERRILL, supra note 13, at 214-15 (citations omitted); see also RICHARD HEMINGWAY, OIL AND GAS LAW § 7.4, at 387-39 (1991)(compression costs of preparing product for market will fall to lessee; on dehydration and other preparation costs, "better approach would seem to be whether such costs are conceived to be within the implied obligation of the lessee to market . . . . Those cases would charge all such costs to the lessee that they find are within such an implied obligation."; also claiming that "analysis based on the basis of the nature of the cost or the place of sale is unsatisfactory" (citations omitted); Walker, supra note 13, at 313 (oil clauses providing for delivery "free of cost"

into pipeline require lessees to bear expenses of "storage, treatment, and transportation" to purchaser, expenses "sometimes of considerable proportions"; also positing that standard language for payment on oil "produced and saved" requires lessee to bear expenses of treatment because amount "saved" is amount after treatment).

Owen Anderson advanced perhaps the most complex position in a two-article series published in the Natural Resources Journal. In the first article, he traced the condition in which a wide variety of hard-rock minerals had to be delivered as royalty to the landowner over the past several hundred years, in Europe and the United States. He concluded that the product often had to be in saleable condition but that there was no single accepted standard of delivering products, and that the lease language could vary the condition. Anderson Part I, supra note 67, at 573-89 (reviewing examples), esp. id. at 583 (stating conclusion from European mining cases); see also id. at 589-603 (discussing early oil and gas cases), esp. id. at 598 (stating conclusion from early U.S. cases). Anderson also reviewed early commentary that supports a first-marketable-product rule. Id. at 604-08. He found that "historically at least, courts have tended to construe royalty provisions in light of the parties' reasonable expectations, in contrast to a strict and narrow construction of the pre-printed anticipatory language of the parties." Id. at 610 [i.e., not allowing the meaning to be determined by isolated terms like "at the well"].

In his second article, Anderson argued that courts that rely on such terms as "market value at the well" and "proceeds" are taking select terms in what generally are form contracts out of the context of the full lease and ignoring other terms, both "production" and also that a finished product is a requirement for "market value" or "proceeds" sales. See Owen Anderson, Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part II, 37 Nat. Res. J. 611, 611-12, 635-40, 683-84 (1997); esp. id. at 637 ("'proceeds' and 'amount realized' . . . suggest an actual sale"; "for there to be a real market price or market value, there must be a market, a marketable product, a ready and willing seller, and a ready and willing buyer"). He concluded that the mineral lessee does have a duty to put oil or gas into a marketable condition. Id. at 639-50, 685-86.

Anderson then truncated this duty, however, by arguing that activities away from the lease, including to get products to market, should be viewed as activities to enhance value rather then to secure marketability, and that the lessee does not have a duty to undertake enhancement for free. Id. at 640-52. Unfortunately, his focus on the "first sale" caused him to define all downstream sales at higher prices as sales attributable to value enhancement, an activity whose benefits he does not believe the lessee has to share. Id. at 687-92. In an era when both oil and gas are traded at market hubs, often the lower price at the well is a reflection of the power generated by a gathering system in the hands of one or a few companies. The profits from aggregation generally are due to

On the other hand, the Williams and Meyers treatise opines that unless the lease expressly states otherwise, a lessee should be able to deduct the costs of making product marketable proportionately from the royalty share; and a number of commentators, often authors who represent producers or testify as experts for producers, have argued for the deductibility of all costs incurred off the well, at least, under most leases.[70] The primary arguments among those supporting this rule of allowing all deductions once the hydrocarbons emerge from the ground are that a royalty interest is an interest "free of costs" only at the well, so

unrisky efforts that any prudent operator would undertake. Any failure to require lessees to share the benefit of this shift in market structure – putting aside for the moment issues of cost deduction, and the varying interpretations of lease terms on that issue – will deprive lessors of some of the "best" values for the oil and gas produced from their land. Although Anderson set out to find a more consistent standard than courts had found, the factual elements in his position seem likelier to embroil his standard in battles over marketable condition and enhancement. Moreover, in an age in which many fields were developed for markets that are joined at downstream pipelines, the argument that just because some product may be in a condition so that someone will buy a small volume at the well, all of the product is marketable, does not fit the nature of the market and the true requisites of sale.

An article by then Professor Joseph Sneed, one often cited as supporting deductions at the well, admitted that the implied duty to market would seem to indicate that lessees should not deduct the expenses of making the product marketable to the first sale, and separately that at least under a gross proceeds lease marketability expenses should not be deductible, although Sneed also concluded that "the authorities" had not taken that position. Sneed, supra note 68, at 655-56.

[70] Indicative of their sympathies, the authors of the current version of Williams & Meyers do not discuss the marketable-condition rule under the implied covenant to market, but instead cross-reference it to a contract section on "Royalty Clauses." 5 WILLIAMS & MEYERS, supra note 1, § 854, at 394.5. There they list a series of expenses on which they claim the royalty interest is "usually subject to a proportionate share where the royalty or nonoperating interests is payable 'at the well.'" 3 WILLIAMS & MEYERS, supra note 1, § 645.2, at 598-609. But this no-longer-accurate assertion sidesteps today's division among the courts and the majority barring deductions. Only at the end of this section does the treatise mention that "[b]eginning around 1960" a number of courts began to hold otherwise – in a section in which the authors include separate "critique[s] of" two of the leading marketable-condition cases. Id. at 609-612.6(3).

that all downstream costs can be deducted, or that the term "at the well," the most common location term in leases when a location is identified, is meant to indicate that all deductions after that point are allowed.[71]

This same split shows up in the caselaw:

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[71] See Keeling & Gillespie, supra note 47, at 29-31 (approvingly discussing approach of defining "production" as at the well for cost deduction purposes); 86-90 (claiming that both "production" and "at the well" terminology support allowing deductions under plain-meaning analysis); 116-17 (relying on plain meaning of "at the well"); Bruce Kramer, Royalty Interest in the United States: Not Cut from the Same Cloth, 29 Tulsa L.J. 449, 469-70 (1994)(seemingly applying plain-meaning analysis in arguing that "in most situations point of valuation is the wellhead" and that costs downstream of that point should be deductible); Lansdown, supra note 47, at 670-73 (relying on royalty as cost-free at well and "at the well" terminology); David Pierce, The Renaissance of Law in the Law of Oil and Gas: The Contract Dimension, 42 Washburn L.J. 909, 929-30 (2004)(using plain-meaning argument in criticizing Kansas court as his example of courts that would not follow "at the well" language), 930-31 (treating wellhead as location of value even without "at the well" language; claiming that even then "the entire oil and gas lease is structured around a relationship that begins, and ends, at the leased land"). The plain meaning approach and the contrary implied-duty position are reminiscent of John Lowe's division of oilfield approaches into plain-meaning and cooperative-venture approaches in his analysis of judicial approaches to royalty pass-through (or not) of take-or-pay payments. See generally Lowe, supra note 48.

To call the "production" and "at the well" arguments the "primary" arguments is not to suggest that commentators who advocate allowing deductions have not advanced a number of subsidiary arguments, see, e.g., Keeling & Gillespie, supra note 47, at 37-50 (attacking the legal arguments they see in writings supporting marketable-product rule), 81-98 (raising other objections to marketable-condition rule); Lansdown, supra note 47, at 676-82 (criticizing positions of Professors Merrill and Kuntz), 696-701 (criticizing position of Professor Anderson), 701-07 (raising practical objections to duty).

For an article that is primarily a summary of positions rather than analysis, see Rachel Kirk, Comment, Variations in the Marketable-Product Rule from State to State, 60 Okla. L. Rev. 769 (2007). For an influential earlier article arguing that caselaw did not support efforts to have costs incurred beyond the well left solely with lessees, see George Siefkin, Rights of Lessor and Lessee With Respect to Sale of Gas and As To Gas Royalty Provisions, 4 Inst. on Oil & Gas L. & Tax'n 181, 183-86, 192-204 (1953).

1. Jurisdictions that Make the Lessee Pay Marketability Costs

A large group of jurisdictions – a group that accounts for far more than half of the nation's oil and gas production – follows a marketable-condition rule that requires the lessee to bear the cost of putting oil and natural gas into a marketable condition.[72] These

[72] It is unfortunate that some commentators have claimed that the Texas position is the "majority" rule. The Pennsylvania Supreme Court may have given some weight to that incorrect assertion, as have some other courts, when it decided to reject the marketable-condition rule by adopting what it took as the majority position in Kilmer v. Elexco Land Servs, Inc., 990 A.2d 1147, 1151-58 (Pa. 2010); id. at 1157 (citing George Bibikos & Jeffrey King, A Primer on Oil and Gas Law in the Marcellus Shale States, 4 Tex. J. Oil, Gas & Energy L. 155, 168-69 (2008-09), for proposition that allowing deduction of post-production costs is majority position)). Kilmer described the first-marketable-condition position as a "minority" position. Id. at 1155; see also Bice v. Petro-Hunt, L.L.C., 768 N.W.2d 496, 500-01 (N.D. 2009). It would be unfortunate if this perception is what led the court to adopt its narrow "at the well" position because it is wrong. There is a fairly close split on the issue, but with a majority of states favoring marketable-condition rules, and in terms of volumes covered, the marketable-condition rule applies to significantly greater volumes than all-deductions-are-allowable rules. At least five major producing states and two lesser ones recognize, one way or another, a marketable-condition doctrine: Colorado, Kansas, Oklahoma, and West Virginia by caselaw, and Wyoming, Michigan, and Nevada by statute. See infra notes 79-153 & accompanying text. The New Mexico Supreme Court has several times avoided making a final decision on whether it will adopt a marketable-condition rule and, if so, how it will apply such a rule, but gave no indication that it will overturn classes certified based on such a rule. See generally infra note 156. A federal court has found that Arkansas would adopt the marketable-condition rule, and a federal magistrate that Virginia would join this group as well. See infra notes 154, 156. The federal government, the largest landowner in the country, follows a version of the marketable-condition rule. See infra notes 74-78 & accompanying text. Alaska also is likely to follow a marketable-condition rule, certainly in state leases (which source most of the production in Alaska) when those leases are not governed by the existing Royalty Settlement Agreements with major oil companies. See infra note 155.

On the other side, Texas and Louisiana among major producers have firmly rejected the marketable-condition rule, North Dakota has shifted to the Texas camp, federal courts have assumed that Mississippi and Kentucky will allow deductions, the Pennsylvania Supreme Court has taken the same position in Kilmer, Montana and Utah may be in this camp, and California is likeliest to jurisdictions generally do not find lease language clear enough to resolve deduction disputes. Instead, they have applied the duty to market to conclude that to the extent that oil or gas is not marketable when it emerges from the well, the lessee has not fulfilled the responsibilities for which it earns the bulk of the lease revenue. The only exception is when the lease very specifically allows certain deductions. In general, in these jurisdictions the lessee has to bear the cost of making production marketable just as it has to bear the cost of drilling.

The largest single part of the nation's oil-and-gas production comes from federal land, including oil produced offshore in the Gulf of Mexico. In 2010, 34 percent of the nation's oil and 23 percent of its natural gas came from production on federal land.[73] This largest block of producing land has to be counted among the marketable-condition jurisdictions. Federal leases give the Secretary of the Interior broad discretion to define the "value" upon which royalties are paid, and Interior-Department regulations specify that the costs of marketing cannot be deducted from the lease.[74] Regulations promulgated by the Secretary require payment

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join this camp even though it has not squarely addressed the implied-duty argument. See infra notes 157-80 & accompanying text. If one adopts a volume test and properly includes federal properties among properties subject to the marketable-condition rule, a significantly greater share of production occurs on properties governed by a marketable-condition rule. The treatment of federal leases will continue to play a key role in determining production subject to the marketable-condition rule because the Interior Department through its various agencies has responsibility for 1.75 billion offshore acres, 700 million onshore acres, and the 23-million-acre Naval Petroleum Reserve in Alaska. GENERAL ACCOUNTABILITY OFFICE, OIL AND GAS LEASING: INTERIOR COULD DO MORE TO ENCOURAGE DILIGENT DEVELOPMENT 7 (GAO-09-74 Oct. 2008).

[73] The 700,000 onshore mineral acres managed by the Bureau of Land Management are producing 11% of the country's natural gas and 5% of its oil. See http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas.html (accessed June 12, 2012). Offshore federal land in the Gulf of Mexico provides an additional, rapidly increasing 29% of the country's oil and 12% of its natural gas. See http://www.eia.gov/special/gulf_of_mexico/ (accessed June 12, 2012).

[74] The Mineral Leasing Act requires payment under most federal leases on the "amount or value" of production, and standard federal leases allow the Secretary of the Interior to determine the "value of the production removed or sold from

on not less than "gross proceeds" and that the lessees pay all costs of putting gas "into marketable condition at no cost to" the federal government.[75] Although producers have argued that the term "from

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the lease." For statutory authorization of payment on value, see 30 U.S.C. § 226(b)(1)(A)(2008)(in general, on lands leased within known structure of producing field, royalty shall be paid "at a rate of not less than 12.5 percent in amount or value of the production removed or sold . . .")..

For a sample onshore federal lease, see Bureau of Land Management, Department of the Interior, Offer to Lease and Lease for Oil and Gas, Form 3100-11, Lease Terms Sec. 2 (July 2006)(lessor reserving right "to establish reasonable minimum values on products after giving lessee notice and an opportunity to be heard"), available at http://www.blm.gov/pgdata/etc/medialib/blm/ut/lands_and_minerals/oil_and_gas.Par.19089.File.dat/Oil%20&%20Gas%20Lease%20Form.pdf (accessed May 8, 2011); for an offshore lease, see Minerals Management Service, Department of the Interior, Oil and Gas Lease of Submerged Lands under the Outer Continental Shelf Lands Act, Form MMS-2005, Sec. 6(b) (Oct. 2009 rev.)(value "shall never be less than the fair market value . . . . The value of production shall be the estimated reasonable value of the production as determined by the Lessor. . . . Except when the Lessor [decides otherwise in certain conditions], the value of production . . . shall not be deemed to be less than the gross proceeds . . . . "), available at http://www.gomr.boemre.gov/homepg/forms/FormMMS-2005.pdf (accessed May 8, 2011). The federal government's reservation of the power to define "reasonable minimum values" is of long standing. See Ross Malone, Oil and Gas Leases on United States Government Lands, 2 Inst. on Oil & Gas L. & Tax'n 309, 340 (1951).

The Interior Department's authority to define "production" in "value of production" to mean "gas conditioned for market," and therefore to make the lessee absorb compression and certain other costs, was upheld in California Co. v. Udall, 296 F.2d 384, 385-88 (D.C. Cir. 1961). In 1988, the Department adopted regulations requiring the lessee to bear the costs of treating gas to put it into a marketable condition. 30 C.F.R. § 206.152(i)(1988) (now §1205.152(i)(2010)). The rules were upheld against industry trade-group attack in IPAA v. DeWitt, 279 F.3d 1036, 1040-42 (D.C. Cir. 2002)(upholding regulations denying pass-through of downstream marketing costs, aggregation fees, and interhub transfer fees, though reversing Department on unused firm-demand charges by classifying them as transportation charges, id. at 1042-43); see also Amoco v. Watson, 410 F.3d 722, 727-30 (D.C. Cir. 2005) (upholding regulations that required producers to absorb cost of removing CO2 from coal-seam gas in order to make it marketable to pipelines), aff'd on other grounds sub nom. BP Am. Prod. Co. v. Burton, 549 U.S. 84 (2006); Devon Energy Corp. v. Norton, 2007 WL 2422005 (D. D.C. Aug. 23, 2007), aff'd sub nom. Devon Energy Corp. v. Kempthorne, 551 F.3d 1030, 1032-41 (D.C. Cir. 2008).

[75] 30 C.F.R. § 206.152(h)-(i)(1988) (now §1205.152(h)-(i)(2010)).

the lease" in the statutory term "removed or sold from the lease" indicates an "at the well" standard, the Department's contrary interpretation has been upheld and producers forced to absorb the costs of making oil and gas marketable.[76]

There is one notable limitation on the Department's marketable-condition rule: although federal lessees must bear the compression, dehydration, gathering, and treatment costs incurred to make gas marketable, they can bill the government its proportionate share of certain costs for gas processing.[77] This limit is inconsistent with the general thrust of federal regulation, which is that the lessee must bear marketability costs and pay the higher of the raw gas price or the separate prices of the processed gas and the assorted liquids, regardless of how it actually sells the gas.[78] Processing usually is a necessary step for lessees' to get the highest price, and it includes services needed to make gas and its separated liquid constituents ready for sale to the main intended buyers, downstream interstate buyers.

Arkansas, Colorado, Kansas, Oklahoma, West Virginia, and perhaps Alaska, New Mexico, and Virginia, almost all major producing states, follow the marketable-condition rule. Wyoming, Nevada, and Michigan have adopted versions of the rule by statute.[79] The Pennsylvania Legislature is in the process of

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[76] See generally supra note 74.

[77] 30 C.F.R. §§ 1206.158-59 (2010).

[78] Id. § 1206.155.

[79] Wyoming would have to be included in any list of "aggressive" states, but the reason is statutory, not case-based. Wyoming has provided in its Royalty Payment Act that the lessee "pays all costs of production out of his interest, the lessor's interest being free and clear of all those costs." Wyo. Stat. § 30-5-304(a)(i)(1999). Overriding royalty interests also are free of production costs. Id. § 304(a)(ii). And, most importantly, Wyoming defines costs of production to include a wide range of costs including such potentially off-lease activities as gathering, compressing, heater treating, dehydrating, and even transporting oil into tanks and gas into the "market pipeline." Id. § 304(a)(iii). The definition does exclude transporting gas on the market pipeline and costs from a gas processing plant from "costs of production," id., thus making the Wyoming rule, like the federal rule, a marketable-condition rule with a significant limitation. A federal court applied the statute broadly in Wold v. Hunt Oil Co., 52 F.Supp.2d 1330, 1332-37 (D. Wyoming 1999), rejecting efforts to limit costs of production to costs incurred before the outlet of the dehydrator; and the Wyoming Supreme

deciding whether it will join these states.[80] That some legislatures have intervened to impose marketable-condition rules suggests a majority view in those states that their courts have not adequately protected royalty owners on deduction issues.

The most aggressive marketable-condition jurisdictions are Colorado and West Virginia. Both treat almost any lease as not allowing deductions for the cost of making production marketable unless a lease authorizes specific deductions (in general, compression, dehydration, gathering, processing, treatment . . .). In Garman v. Conoco,[81] the Colorado Supreme Court held that when the lease is silent on cost allocations (the way the question had been posed in a certified question from a federal district court), the duty to market requires the lessee to bear the costs of gathering gas to a processing plant, of compression when the gas arrives at the plant, and of dehydration if removing water is necessary for a

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Court enforced the statute's inclusion of gathering among charges the lessee has to bear from its share of the revenue stream in Cabot Oil & Gas Corp. v. Followill, 93 P.3d 238, 241-42 (Wyo. 2004). The Wyoming court described the purpose of the Act as "to stop oil producers from retaining other people's money for their own use." Id. at 242 (citation omitted).

In 1991, Nevada adopted a statute that provides that "the lessee is liable for all costs of production" and that the royalty interest, including overriding royalty interest, "shall not be decreased by the costs of production." Nev. Rev. Stat. Ann. § 522.115.1(b)(West 2000). The statute defines those costs to include gathering, treating, compression, and dehydration, but not what is ordinarily classified as transportation – moving oil from storage tanks to a market and gas from entry into the pipeline [meaning a mainline pipeline, not gathering line] to its final market – or gas processing costs. Id. § 115.3.

A Michigan court of appeals adopted the at-the-well approach in a lease that provided for payment of "gross proceeds at the wellhead" in Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 890-96 (Mich. Ct. App. 1997), leave to appeal denied, 584 N.W.2d 588 (Mich. 1998). Schroeder left open whether Michigan would recognize an implied duty to market under other lease language. Id. at 895-96. In response, the Michigan Legislature passed a statute on gas deductions that prohibits deductions on any lease entered after March 28, 2000 unless the lease "explicitly allows for the deduction of postproduction costs," something that "at the well" does not, and set some limits on costs that can be deducted even in such a lease unless the lease "explicitly and specifically" provides for other deductions. Mich. Comp. Laws Ann. § 324.61503b(1) (1999).

[80] See infra note 180 & accompanying text.

[81] 886 P.2d 652 (Colo. 1994).

purchasing pipeline to accept the gas.[82] It rejected Conoco's argument that the duty to market should be separated from questions of who bears the cost of performing the duty.[83] Instead, it noted, implied duties "related to operations" impose duties on lessees, with responsibility including cost responsibility, and, "[a]ccordingly, the lessee bears the costs of ensuring compliance with these promises."[84]

The Garman court viewed making the lessor pay for the lessee's duty as contradictory: "The purpose of an oil and gas lease could hardly be effected if the implied covenant to drill obligated the lessor to pay for his proportionate share of drilling costs."[85] Just as the lessee's duty to drill makes it bear the costs traditionally treated as "production" costs, so the implied duty to market makes the lessee bear marketing costs.[86] The court did distinguish costs incurred to make a product marketable from those that just enhance the value of an already marketable product, and held that the lessor does have to share the latter.[87] The court did not provide any guidance on how to distinguish marketability and enhanced marketability, an area in which its rule needs clarification.

In another holding of significance, the Colorado court held that for costs that might be recoverable, the lessee has the burden of showing that the costs are reasonable and that royalty revenues increased at least proportionately to costs.[88]

Seven years later, in one of the most controversial oil-and-gas decisions in many years (as controversial as Vela in its time), the Colorado Supreme Court extended this rule in Rogers v.

[82] Id. at 655 n. 8 (describing costs at issue). The issue arose as a certified question from the federal district court, which asked whether "post-production costs such as processing, transportation, and compression" are deductible against an overriding royalty interest when the agreement is silent. Id. at 653.

[83] Id. at 659 ("Conoco argues that the implied covenant to market exists separately from the allocation of marketing costs."). Conoco meant that its bearing the duty to make gas marketable should not determine whether it has to pay the cost of making the royalty share marketable.

[84] Id. at 658-70.

[85] Id. at 659.

[86] Id.

[87] Id. at 660-61 & nn. 26-27.

[88] Id. at 661.

Westerman[89] by holding that even a lease setting royalty payment "at the well" is ambiguous because it does not specifically reference cost deductions. Even under such a lease, costs are not deductible against the royalty interest unless some other part of the lease identifies specific costs that are deductible.

The Rogers dispute was over some 200 natural gas wells that were on leases with various kinds of pricing terms "at the well."[90] These leases included common proceeds and market value terms, and "two-prong" combinations of these terms.[91] The lessors argued that dehydration and compression were required to make the gas ready to meet interstate pipeline specifications.[92] The lessees responded that the gas was usable as it came out of the well and had been used locally for many years.[93]

The jury found that the volumes of gas sold at the wellhead were marketable there, but not the gas sold away from the well.[94] Such a finding is not inconsistent. Most of the United States' major gas fields were developed by interstate pipelines to serve distant markets. A small amount of gas in these fields may serve agricultural and other local needs, but the great bulk of the natural gas would not be sold – and most of the fields never would have been developed -- if it could not reach quite distant markets. Indeed, the development of many of the country's great natural-gas fields did not begin until the arrival of interstate pipelines that could carry the gas to markets far outside the state of production.

To decide the appropriate cost-deduction standard, the Colorado Supreme Court surveyed cases that had found the term "at the well" silent on royalty cost deductions.[95] It agreed that this term – which, notably, says nothing about any particular deductions and certainly would not tell a laymen that it was

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[89] 29 P.3d 887 (Colo. 2001).
[90] Id. at 891 & n.1 (listing four types of leases at issue).
[91] Id.
[92] Id. at 891-92.
[93] Id. at 892. The parties agreed that the Rogers gas was "usable" without processing, but that it had to be gathered, compressed, and dehydrated to enter the interstate pipeline. Id. at 892.
[94] Id. at 894.
[95] Id. at 897-901.

intended to address deductions – is silent on cost deductions.[96] It disagreed with jurisdictions that rely solely on the term "at the well" because "they fail to recognize that the implied covenant to market controls the lessee's duty to make the gas marketable."[97] The court refused to adopt the view that gas is fully "produced" just because it is severed, without regard to how marketable the gas is.[98] In ruling against the lessees, it also applied the principle that in general, leases are to be read strictly against the lessee.[99]

In addition, the court discussed how to define marketability. On this topic, it held that in Colorado the standard for marketability turns not only on the physical condition of the gas, but also on the availability of a market for sale – economic marketability. Treating marketability as a fact question, the court pragmatically held that a product must be "in a physical condition where it is acceptable to be bought and sold in a commercial marketplace" and, in addition, it must be marketable considering the geographic and economic markets actually available.[100] Under this economically sensible standard, Colorado courts will not treat

[96] Id. at 897-900.

[97] Id. at 901. Rogers is controversial in part because the court in passing cited a prominent commentator, Owen Anderson, for the principle that lessees may have intentionally used "at the well" in order to "avoid directly stating their objectives in sharing costs." Id. at 898. Controversial though this phrasing may have been, both the Colorado and West Virginia Supreme courts certainly have a point that if one wanted to plainly let lessors know that costs would be deducted, as well as which costs would be deducted, saying "at the well" or leaving a lease silent is not how one would do so. Why would an average reader expect that language to govern the costs of gas compression, dehydration, gathering, processing, and treatment? Even critics of the marketable-condition rule can admit there is a lack of clarity in commonly used lease terms. See David Pierce, Defining the Role of Industry Custom and Usage in Oil & Gas Litigation, 57 S.M.U. L. Rev. 387, 412 (2004)(listing fact that most leases use "market value" or "proceeds" as pricing term as among reasons that "the customary approach to royalty compensation is a recipe for conflict").

[98] Rogers, 29 P.3d at 899.

[99] Id. at 901-02.

[100] Id. at 905. The Colorado Supreme Court distinguished itself from two other marketable-product jurisdictions, Kansas and Oklahoma, for, in its view, their attempting to define categories of cost that would be deductible, or not, as a matter of law. Id. at 906 n.21.

an entire field as marketable just because there are a handful of local sales of raw, unprocessed gas for use near the wells. This rule should prevent the unrealistic situation in which a few local sales made without significant competition among buyers magically transform an entire field of raw gas into a "marketable" product, even when a prudent operator would not sell substantial quantities at the well. In Rogers, the court agreed that "it may well be, for all intents and purposes, that gas has reached the first-marketable product status when it is in the physical condition and location to enter the pipeline."[101]

The West Virginia Supreme Court has agreed that the term "at the well" is not determinative of cost deductions.[102] Its significant decisions begin with a case in which a hapless lessee acquired its interest following its predecessor's bankruptcy, and had neither drilled nor paid delay rentals on a 200-acre tract. It claimed that its failure to pay was due to a confusion of records, but the court treated the property as abandoned.[103]

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[101] Id. at 905 (citations omitted; emphasis added). When lessees pay royalties based on their volume-weighted sales price, presumably they mix the prices received from their wellhead and downstream sales. It certainly is unrealistic to pretend that all of the gas in a large area should be valued or priced at the amounts that a small share commands for local use, a restricted market in which there are unlikely to be many willing buyers or sellers.

Of course, if a lessee irrationally offers to sell large volumes of the gas it has produced at the wellhead at its local price, and if allows access to its gathering system at its cost and a reasonable return, large buyers would purchase the gas there and ship it downstream because they, rather than the lessee, would extract substantial profit from the gas. But rational lessees sell downstream because that is where they get the best price reasonably possible in today's market. This issue also came up in Amoco's challenge to rules under which it had to bear the cost of making federal coal-seam gas marketable. Then-judge Roberts pointed out that there might well be one set of sales at the well and another downstream, but that "it is not at all obvious from the text and purposes of the regulations that contracts for one-fifth of the gas should govern the regulatory treatment of the remaining eighty percent." Amoco v. Watson, 410 F.3d 722, 730 (D.C. Cir. 2005), aff'd on other grounds sub nom. BP Am. Prod. Co. v. Burton, 549 U.S. 84 (2006).

[102] Wellman v. Energy Res., Inc., 557 S.E.2d 254 (W. Va. 2001).

[103] Id. at 262-63. The court ended up disregarding a "right to cure" clause, which provided that the lease could not be terminated until a court finally determined

A deduction issue arose because the leases required the lessee, Energy Resources, to pay one-eighth of its proceeds "from the sale of gas as such from the mouth of the well," but it had only paid $0.87 per mcf in royalties even though it was receiving $2.22 per mcf for the gas.[104] The deductions were much more per mcf than the royalty itself.[105] The supreme court noted that the royalty interest is supposed to be free of the cost of production. It took the view that in recent years, lessees have tried to "escape" that standard by labeling certain expenses "post-production expenses."[106] After surveying decisions in Colorado, Oklahoma, and Kansas, states that treat bearing the cost of making oil and gas marketable as part of performing the duty to market unless the lease very specifically requires a different allocation, it adopted that position. In West Virginia, unless a proceeds lease very clearly says otherwise, the lessee has to bear "all costs incurred in exploring for, producing, marketing, and transporting the product to the point of sale."[107] This phrasing should require the West Virginia lessee to bear the costs of finding a commercial market, as in Colorado, and not just the cost of putting oil or gas into a physical condition in which a hypothetical buyer might buy it at the well even if no market exists there. Further, to the extent that a lease does allow deduction of any costs, the lessee bears the duty of proving that the costs are "actually incurred" and "reasonable."[108]

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that the lessee had failed to meet its obligations and then gave it a chance to do so, as a "judicial ascertainment" law that, it decided, should be unenforceable under West Virginia law. Id. at 259-61.

The lessee had reworked a well on a smaller 23.5-acre tract, but had violated an express covenant governing that tract by failing to begin at least one well during the primary term and a provision that the lease would forfeit for failure to satisfy any of the covenants. Id. at 263.

[104] Id at 263. The pricing term is quoted on pages 257-58 of the decision.

[105] Id. at 263.

[106] Id. at 264.

[107] Id. at 264-65. The Wellman court did leave open the possibility that the pricing term proceeds "at the mouth of the well" might be read to harbor an intent that the Wellman lessors should share transportation costs, but it found this possibility moot because the lessee had not introduced evidence of what those costs might be. Id. at 265.

[108] Id. at 265.

In 2006, the West Virginia Supreme Court faced a class action involving 8,000 royalty-owner plaintiffs and 2,258 leases, over half of which had one or another form of "at the well" language, in Estate of Tawney v. Columbia Natural Resources, LLC.[109] Although the court did not go as far as Rogers in finding "at the well" silent on cost allocation, it did find this term ambiguous because the lease did not say "*how* or *by what method* the royalty is to be calculated."[110] "At the well" was ambiguous regardless of whether it was combined with a gross proceeds, market price, or "net of all costs" term.[111] The leases simply did not contain "specific provisions pertaining to the marketing, transportation, or processing of the gas."[112] The court construed the lease against drafter Columbia Natural Resources.[113] It added that for lessees to be allowed to deduct marketing and transportation costs, the lease has to provide three things: it must "provide that the lessor shall bear some part of the costs . . ., identify with particularity the specific deductions the lessee intends to take . . . , and indicate the method of calculating the amount . . . ."[114]

Kansas courts have held that costs incurred after production generally cannot be deducted from the royalty share unless the oil or gas is marketable at the well (in which case, added treatment would not be needed to make the product "marketable").[115] For

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[109] 633 S.E.2d 22, 25 (W. Va. 2006).

[110] Id. at 28 (emphasis in original).

[111] Id. at 28-29.

[112] Id.

[113] Id. at 29-30. Estate of Tawney reaffirmed Wellman's holding that the lessee has to prove that any costs it seeks to deduct are (1) actually incurred and (2) reasonable. Id. at 27-28.

[114] Id. at 30 (emphasis added).

[115] In the leading Kansas case, Gilmore v. Superior Oil Co., 388 P.2d 602 (Kan. 1964), the court held that compression costs were not deductible, even though the pricing term was proceeds "at the mouth of the well," on a record in which the trial court had found the gas marketable only after it was compressed; it was the lessee's duty to prepare product for market and the costs of doing so were not chargeable to the royalty interest. Id. at 605-06. The court distinguished an only seemingly contrary prior case over gathering, processing, and marketing costs because the lessors there stipulated that the reasonable costs of those services were deductible, so deductibility was not tested in that case. Id. at 605 (distinguishing Matzen v. Hugoton Prod. Co., 321 P.2d 576, 581-82 (Kan.

instance, the Kansas Supreme Court has barred deduction of on-lease compression costs incurred after the wellhead in a proceeds "at the mouth of the well" lease because the compression was needed to make the gas marketable.[116]

In the past, interpreting an "at the well" lease in Sternberger v. Marathon,[117] the Kansas Supreme Court has treated the proportionate cost of transportation – even if necessary to reach a viable market – as deductible against the royalty interest, but only in dictum because the plaintiffs did not contest that the gas was marketable at the well.[118] On those facts, the court did not consider the fact that the gas was not economically marketable at the well – that there were not enough buyers to purchase it – as making it unmarketable.[119] The court did stress that when deductions are allowed, they have to be reasonable.[120] Even Sternberger, though,

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1958)). The Kansas Supreme Court followed Gilmore in another challenge to compression costs under similarly worded leases in the same-day decision in Schupbach v. Continental Oil Co., 394 P.2d 1, 4-5 (Kan. 1964). The plaintiff had refused to sign a division order that contained language allowing various specific deductions including compression. Id. The court referred to Gilmore for the rationale of its decision. Id. at 4.

[116] See supra note 115.

[117] 894 P.2d 788, 794-800 (Kan. 1995).

[118] The supreme court noted that it had not seen any evidence that the gas was not marketable, id. at 799-800, and that had the gas not been marketable the shipping services would have been characterized as gathering (and, therefore, presumably not deductible). Id. at 800. The court did seem to agree that the "at the well" lease was silent but not ambiguous on deductions, given the term "market price at the well," id. at 794, but that dictum is questionable given the court's favorable references to the Colorado rule in Coulter v. Anadarko Petrol. Corp., 292 P.3d 289, 305-06 (Kan. 2013), discussed in note 122 infra.

[119] The Sternberger court held that when there is no evidence that gas is not marketable except for the lack of a purchaser – in other words, it is economically not marketable, but there is no evidence that it is not in a physical condition in which at least some untreated gas is being sold to someone somewhere, and the lack of a market connection is the only missing link – the deductions would be characterized as for transportation rather than for gathering and would be deductible. Id. at 799-800. Yet it makes no sense to hold that there can be a theoretical market in which products are "marketable" in some abstract way but buyers cannot be found.

[120] Id. at 805-06.

is rooted in the marketable-condition rule. It affirmed that the lessee "has the duty to produce a marketable product, and the lessee alone bears the expense of making the product marketable" and that, in the absence of a contrary agreement, the "nonworking interest owner is not obligated to bear any share of production expense, such as compressing, transporting, and processing, undertaken to transform gas into a marketable product."[121]

This limit on the Kansas marketable-condition rule may be up in the air because the Kansas Supreme Court recently reaffirmed that it has taken its approach to deductions from Colorado's rule, in a decision in which it acknowledges the Colorado Supreme Court's criticism of the Kansas suggestion that "marketability" can ignore the geography of the market.[122] It is not clear whether the favorable reference to Colorado's approach means that the Kansas Supreme Court will extend its rule to match Colorado's in an appropriate case. The most the court would say is that marketable-condition issues currently raise factual and legal uncertainties in Kansas.[123] In a holding that confirms how far Kansas has left at-the-well jurisdictions behind, in Hockett v. Trees Oil Co. the Kansas Supreme Court agreed that a one-eighth of "proceeds if sold at the well" clause does not envision any deductions for costs incurred from the proceeds the lessee receives when computing royalty payment, except for activities that occur after the lessee has provided a marketable product.[124]

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[121] Id. at 799-800.

[122] Coulter v. Anadarko Petrol. Corp., 292 P.3d 289, 305-06 (Kan. 2013)(court noting that Kansas courts previously had adopted the Colorado rule; that in its decision in Rogers v. Westerman Farm Co., the Colorado Supreme Court rejected what it called (incorrectly, because the issue was not presented by the facts) Kansas' "at the well" interpretation in Sternberger v. Marathon Oil Co., 894 P.2d 788 (Kan. 1995); and that under the Colorado standard, "Sternberger's holding that gas can be in marketable condition at a point at which no market exists may be questionable" -- this last point a gross understatement).

[123] Coulter, 292 P.3d at 307.

[124] 251 P.3d 65, 71 (Kan. 2011)(operative royalty language). In Kansas the unadorned term "proceeds" means the "gross sales price," not the net price. Id. at 72.

Courts applying Kansas law have gone on certifying oilfield class actions that include claims to bar deductions for moving gas away from the well, as if getting to an economic market is part of marketability in Kansas even though the Supreme Court has not squarely said so.[125] The Kansas Supreme Court will have an opportunity to review these issues because it recently granted review in Fawcett v. Oil Producers, Inc.[126] In Fawcett, the trial court certified a gas royalty class action and granted partial summary judgment for the class holding that lessee Oil Producers could not take deductions under a lease providing for "proceeds . . . at the well" when gas was sold at the well.[127] The gas was sold under contracts in which the buyers who provided processing services deducted related costs from the final sales price.[128] The

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[125] In Coulter, the certified and settled class claims were described throughout as "gathering" claims (although they included claims for other costs often discussed separately, for instance compression costs). While Anadarko argued that "raw natural gas" is marketable at the wellsite, the class claimed that all costs of moving the gas to the interstate pipeline inlet were incurred to make the gas marketable. Id. at 296, 306.

In Hockett v. Trees Oil Co., 251 P.3d 65, 71-72 (Kan. 2011), the Kansas Supreme Court gave a broad treatment to the term "proceeds," confirming that at least in pure proceeds cases it will not allow any deductions.

In Hershey v. Exxon, a federal district court stayed a largely parallel state-court class action in part because the Hershey class, by including processing claims, had a broader set of claims than in the related case of Farrar v. Mobil, 234 P.3d 19, 22 (Kan. Ct. App. 2010). Memorandum and Order, Hershey v. Exxon, Cause No. 07-1300-JTM (D. Kan. Mar. 31, 2011), slip op. at 1-2 (listing claims). These are samples of the larger number of cases in which Kansas trial courts have certified classes that do seek recovery of costs incurred to get natural gas away from the well and to an interstate pipeline, costs that help make the gas "marketable" by bringing it to the market as well as to processing plants that will strip out liquids. Other recent oilfield class cost-deduction cases in the Tenth Circuit, including from Kansas, are discussed supra in Chapter One, note 29 and in the text that follows here.

[126] 306 P.3d 318 (Kan. Ct. App. 2013), rev. granted (Dec. 27, 2013).

[127] Id. at 319-20.

[128] Id. at 320. The deductions varied slightly, at least in description, by purchaser: one company deducted gathering, compression, and dehydration costs, another a "conditioning fee" and fuel reimbursement, and a third "all third-party costs, fees, and charges that were associated with selling the gas, including treating, gathering, transporting, and compressing fees." Id.

Kansas Court of Appeals agreed with the trial court that these deductions were impermissible given the lease language and Kansas' marketable-condition precedent.[129] It rejected the argument that a lessee can avoid its duty to bear marketability costs by structuring a sales contract so that the buyer deducts post-production costs from the selling price.[130]

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[129] Id. at 322-25.

[130] Id. at 325-26. That the lessee should not be able to offload its responsibility by negotiating a lower sales price with a third party who agrees in turn to bear a cost the lessee is supposed to pay vis-a-vis its royalty owners also came up in Naylor Farms, Inc. v. Anadarko, 2011 WL 7053787 (July 14, 2011), modified on reconsideration for one lease, 2011 WL 7053791 (W.D. Okla. Sept. 14, 2011). Anadarko sold raw gas at the well to a third party, DCP Midstream, which extracted a percentage of the liquids and dry gas as its processing charge. Id., slip op. at *1. Anadarko paid royalty on the volume-reduced revenue stream. It moved for summary judgment that it was entitled to pay royalty on the reduced proceeds. Some leases provided for pricing "at the well," and the court granted the motion on those leases, because it believed they did allow deductions for costs incurred away from the well and so preempted the general Oklahoma marketable-condition rule. Id. at * 3. (The court's assumption that the term "at the well" allows deductions of post-production costs is incorrect under Oklahoma law, as Naylor's author, Judge Russell, concluded the following year in Hill v. Kaiser-Francis Oil Co., 2012 WL 4327665 (W.D. Ok. 2012)). But it agreed with the plaintiffs that on leases without an at-the-well reference, the lessee could not reduce its duty to pay for making gas marketable by selling the gas as raw gas and letting the buyer perform those services:

> . . . While a lessee may hire a third party to perform the processes necessary to make gas marketable . . . , the lessee may not deduct the costs incurred for such third party's services from amounts paid the lessor(s) or royalty owner(s) but must compute the royalty interest(s) based upon the amounts paid by the interstate pipeline for the residue gas and NGLs unreduced by the amount or percentage of proceeds paid to the third party.

Naylor, slip op. at * 3. In other words, a lessee cannot structure its marketing to avoid its duty to bear the costs of making oil or gas marketable in marketable-condition jurisdictions.

Federal regulations prevent price reductions that reflect offloading the cost of field services onto gas buyers by requiring that gross proceeds be increased by any amount by which the buyer has reduced the price paid to compensate it for services needed to make the gas marketable. 30 C.F.R. § 1206.152(h)(i)(2010) (unprocessed gas), id. § 1206.153(h)(i)(processed gas and liquids ("plant products")).

Surprisingly, jurisdictions that apply marketable-condition rules have not integrated the best-price aspect of the duty to market, its core value, into their marketable-condition analysis. This shortcoming has created a gap in marketable-condition decisions (and litigation) to date. After all, the lessee's duty to bear marketability costs grows out of the duty to market. Yet when considering whether gas is marketable, these courts (and apparently lawyers as well) have failed to discuss the anchoring value of the duty to get the best price reasonable possible. A lessee should not satisfy its duty through local sales when a readily available downstream market yields the best possible price. Moreover, the rule should reflect the fact that since the late 1980s and early 1990s, the active market with multiple buyers and sellers has moved in most fields from wellheads that are usually connected to just one gathering system to downstream market hubs where buyers and sellers look to conduct their transactions and want to buy pipeline ready gas.[131]

Contrast Naylor Farms with the outcome in Occidental Permian Ltd. v. Helen Jones Foundation, 2011WL 291966 (Tex. App. – Amarillo Jan. 31, 2011), in a jurisdiction that does allow deductions away from the well. On "amount realized at the well" leases, the court rejected testimony by the plaintiffs' expert in which he looked to post-processed prices for dry gas and liquids rather than the unprocessed casinghead gas price received at the well. Id. at ** 3-5. The court rejected the plaintiffs' duty to market claim, which challenged the percentage-of-proceeds sales contract, because these contracts had been in place when the current lessee acquired its interest, and so had not been arranged as an affiliate sham. Id. at ** 5-7. And it rejected claims based on market-value leases when the plaintiffs did not have evidence of other prices as well as percentages that other gas buyers were paying. Id. at ** 7-10. Judgment for plaintiffs was reversed, with the expert's not having done adequate work to support his view of the carbon dioxide gas market, in Occidental Permian Ltd. v. French, 391 S.W.3d 215, 221-22, 225 (Tex. App. – Eastland 2012, pet. denied).

[131] The qualifier about the best price is important because, given the large increase in value between the wellhead and interstate pipeline, some interstate buyers might be delighted to buy gas at the wellhead at low wellhead prices, have it gathered and processed at their expense, and then sell it at the pipeline inlet – or even to final-use end customers at the pipeline outlet. Why don't lessees sell in bulk at the well in most situations, if there is a real "market" there? Because they know they will not get the best price possible there compared to market centers, even after considering field costs. It is no accident that the gas buyers who claim gas is marketable at the well because they may

Getting the best price is a core aspect of the duty to market. Most large natural-gas fields were developed to supply interstate pipeline systems, which in turn sold natural gas to distant markets. Naturally there can be some local use – some agricultural buyers, some consumption for gas field operations, some demand for local residential and other commercial uses, sometimes even some purchases for resale. Local sales would not have justified the cost of drilling the wells, of developing these fields, or of building pipeline connections and large gathering systems. The demand came from large (usually interstate) buyers.

At least since the time that natural gas became valued for its own sake, interstate pipelines have connected the bulk of natural-gas buyers to the country's gas fields. In the early years sales often were at the well, with the buyers regulated companies that took the gas all the way to end-use customers; today's sales generally are at market hubs. To say that a field of raw natural gas is marketable "at the well" because some local buyers acquire part of the gas, when there is no demand for the rest of the gas at the well, is to ignore economic realities.[132] It would be equally unrealistic to treat gas as "marketable," as if a "market" exists, if the gas happens to emerge from the ground in pipeline-acceptable physical condition near a lease gathering line with no buyers or only the gathering company offering to buy the gas at the well.

make some incidental sales at that location choose not to sell the bulk of their own gas there. Nor is it an accident that published prices are at market hubs, not wellhead locations. Gas companies know they will get a better price at market hubs downstream from the field.

[132] The development of an unregulated gas market draws into question the traditional rule that "comparable" wellhead sales are the best evidence of market value, e.g. Abraham v. WPX, 685 F.3d 1196, 1200 (10th Cir. 2012), and a netbacked price from a market away from the well only a second-best method of determining price. In today's market, downstream hub markets are the market drivers. They usually are the best evidence of price or "value." Markets that are near the well may reflect market power, lack of options for gathering the product, and an absence of buyer competition at that location. The fact that major producers do not auction their production at the well, but usually try to get it to market centers, is one indication of where the reasonably available best value of production resides.

Concurring judge McAnany in Fawcett made just this point when he rejected the producer argument that a product is marketable just because it can be sold to someone:

> . . . But a demand curve can be drawn for any item that may be subject to a commercial transaction. I do not ascribe to the notion that because there is some point on every such curve where *somebody* would be willing to pay for the item, each and every item passes the test of marketability. Under that test, the notion of marketability becomes superfluous. That seems to defy a level of common sense . . . ."[133]

So, too, the idea that activities that "enhance" the value of gas can be readily distinguished from those that make it marketable is an oversimplification that courts espousing this difference ultimately will need to address. One can almost always find a buyer if one reduces prices far enough. When the lessee has a duty to get the best price reasonably possible, why would it ever satisfy that duty to sell untreated gas at the well for far less than is available (whether after netting costs or not) by treating and processing the gas and moving it to a market hub? This outcome would not satisfy the price portion of the duty to market generally. If courts do adopt a marketable-condition rule, they should use the sales generating the price that satisfies the best-price duty as the benchmark for marketability.

In Oklahoma, the other major oilfield jurisdiction that has given detailed consideration to the marketable-condition rule, the supreme court has also rejected the idea that the term "at the well" is sufficient to answer the deduction question. Instead, it has held that the lessee generally has to bear on its own account the costs of making oil or gas marketable under the implied duty to market.[134]

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[133] Fawcett v. Oil Producers, Inc., 306 P.3d 318, 327 (Kan. Ct. App. 2013)(McAnany, J. concurring), rev. granted (Dec. 27, 2013),

[134] In one early decision that sounded close to the Texas and Louisiana authority, the Oklahoma Supreme Court held that even in a gross-proceeds lease, but one that provided for payment of gross proceeds "at the prevailing market rate," the lease intended a rate "at the wellhead or in the field." Johnson v. Jernigan, 475 P.2d 396 (Okla. 1970). The lessee was required to market natural gas to get the

"highest possible market value" it could get, but the court interpreted "gross proceeds" to refer to the gas' value on the lease premises, and held that the lessee did not have to bear all of the cost of transporting the gas ten miles away. Id. at 399. In a tip to the future, however, the court distinguished costs of "care and preparation of gas before delivery," which would not be deductible. Id. at 400. Johnson is an oddly underdeveloped case because there is no sign that the court distinguished in-field gathering, which many marketable-condition courts hold is not deductible, from post-processing transportation, which is. It is not consistent with later Oklahoma cases.

Courts generally have not treated transportation – as opposed to in-field gathering – as a cost required to make natural gas marketable – just as the Wyoming royalty statute disallows most possible costs as royalty deductions, including gathering costs, but allows the lessee to bill the cost of transportation, Wyo. Stat. § 30-5-304(a)(iii)(1999).

The Oklahoma Supreme Court turned away from the Texas approach in Wood v. TXO, 854 P.2d 880 (Okla. 1992). In a 5:4 decision, a majority rejected "at the well" analyses and found compression costs not deductible, holding that the lessor did not have to share compression costs unless the agreement specifically required it to do so. Id. at 880-83. The issue arose on a certified question from federal court, which asked whether compression costs would be deductible under a "market price at the well" lease. Id. at 880. The court explicitly rejected the Texas/Louisiana rule under which off-the-well costs are called "post production" and can allocated proportionately to the royalty share. Id. at 881. Treating the lessee's larger share of the revenue stream as one of the considerations for its bearing the cost of developing the minerals, it squarely held that "[w]e interpret the lessee's duty to market to include the cost of preparing the gas for market." Id. at 882-83. Another reason the court decided the lessors should not bear these costs was that they had no input into marketing decisions, and should not have to pay for decisions they could not influence. Id. at 883.

Two years later, the court required a lessee to bear marketability costs in TXO v. Commissioners of the Land Office, 903 P.2d 259 (Okla. 1994). The dispute involved compression, dehydration, and gathering costs under a state lease that allowed payment of "market value" without any geographical reference. Id. at 260. The lessees had the option to take gas in kind, in which case the gas was to be delivered "without cost into pipelines." Id. The court held that if TXO paid market value, it was market value of the in-kind royalty, which was to be without cost. Id. at 261. It found such a reading supported by Wood and its holding that in Oklahoma, "the lessee's duty to market involves obtaining a marketable product." Id. at 262, citing Wood, 854 P.2d at 882-83. The court separately analyzed the dehydration and gathering charges and concluded that, under the Wood approach, they were not deductible from the royalty interest either. Id. at 262-63.

It has treated the costs needed to make production marketable as a fact issue, although it pretty clearly views classic transportation away from the field as deductible and it has held that services that merely "enhance" a marketable product are deductible.[135]

Lessees challenging state cases in Oklahoma and Kansas have drawn encouragement from a pair of recent Tenth Circuit gas-royalty class-action decisions, one applying Kansas law, one Oklahoma law, that remanded certified classes to the trial judge for more detailed consideration. Neither state supreme court is likely, however, to jettison its core marketable-condition rule and join the all-deductions-are-allowed camp, though, as the Tenth Circuit implicitly acknowledged by not reversing and rendering in either case. Instead, the cases, Wallace B. Roderick Revocable Trust v. XTO[136] and a companion Oklahoma case against XTO,[137] simply

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The court returned to marketable-condition issues a few years later in Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203 (Okla. 1998). Here the Oklahoma Supreme Court answered a certified question from the Tenth Circuit of whether a lessee under a gross proceeds lease can deduct "transportation, compression, dehydration, and blending costs" from the royalty share. Id. at 1204-05. The court held that transportation costs are deductible when there is no market at the lease, under Johnson v. Jernigan, id. at 1207; but noted that it is "common knowledge that raw or unprocessed gas usually undergoes certain field processes necessary to create a marketable product" including "separation, dehydration, compression, and treatment to remove impurities," id. at 1208; and held that dehydration, blending, and compression are not deductible if needed to make a product marketable, even though "excess" services that enhance the value of an already marketable product are deductible as long as the costs are reasonable, id. at 1209-10. Costs to enhance a marketable product are deductible if reasonable and if revenues increase at least proportionately to the costs. Id. at 1208 (citing Colorado rule in Garman on requirement of reasonableness and proportionate contribution).

[135] Owen Anderson has criticized the Kansas and Oklahoma courts for adopting categorical distinctions for deductibility that would define which costs are deductible as a matter of law, a question that to him should be a question of fact. Anderson Part II, supra note 69, at 664-65. For the Oklahoma rule on enhancement services, as opposed to marketability services, see the discussion of Mittelstaedt v. Santa Fe Minerals, Inc in note 134 supra.

[136] 725 F.3d 1213 (10th Cir. 2013).

[137] Chieftain Royalty Co. v. XTO, 528 Fed. Appx. 938, 940-43 (10th Cir. 2013). In Roderick, the court notes that the Oklahoma claims initially included in

held that the trial judge had to consider the possibility of individual differences more carefully on two issues, potential lease variability and marketability.

The court's discussion of leases in Roderick is unfortunate because it could mislead lower courts about the nature of lease terms. It treated leases as if they can be almost infinitely variable, even though this is not the nature of oil-and-gas leases. The lessee, XTO, had produced a sample of leases that it claimed was representative. The trial court, after considering the variations, held that the Kansas marketable-condition rule applies over all the leases presented.[138] The Tenth Circuit nonetheless reversed certification as improvidently granted in part on this issue.[139] It held that, given the variation that might exist among the remaining unsampled leases (a variation it did not show was likely to be material), the Trust had the burden to show affirmatively across all leases that common lease questions predominate over individual.[140]

Roderick ended up in Chieftain Royalty Co. v. XTO, 528 Fed. Appx. 938, 940-43 (10th Cir. 2013), the case the court addressed in its same-day decision.

[138] The class covered thousands of royalty owners whom TXO paid from Kansas production, 650 leases governing this production, and over 300 wells. Roderick, 725 F.3d at 1215. XTO had analyzed a sample of one-fifth of its leases in its effort to show that individual issues predominated over common questions and claimed that it found twenty variations in just the sample. Id. at 1216. But the court, in response, pointed to XTO's uniform payment methodology as supplying the common question, and the Trust to the implied duty of marketability "in every class member's lease." Id. at 1216-18. The Trust did not supply its own lease analysis, presumably assuming that the Kansas rule was clear enough to impose a marketable-condition rule on all leases. The trial court considered many of XTO's lease-variation arguments, and nonetheless held that the law of Kansas, Colorado, and Oklahoma all impose versions of the lessee's duty to bear the costs of making gas marketable even in "at the well" leases. Wallace B. Roderick Revocable Trust v. XTO, 679 F.Supp.2d 1287, 1294-95 (10th Cir. 2010), rev'd on other grounds, 725 F.3d 1213 (10th Cir. 2013). The Tenth Circuit, not mentioning XTO's representation that its sample was representative of the full set of class leases, held that with approximately 430 leases unexamined the Trust had not proven commonality.

[139] Roderick, 725 F.3d at 1218-19.

[140] Id. at 1218.

With approximately 430 leases unexamined, the court thought the Trust had not proven commonality of lease terms.[141]

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[141] Id. at 1219. Roderick does not (and cannot, as a federal decision) change Kansas' marketable-condition rule, nor does it stand for the principle that class cases cannot be certified under it. It is a closer-look case. The Tenth Circuit did not hold that it thought the court had overlooked material differences in the leases that had been categorized and it had reviewed. Instead, it expressly noted that after reviewing all of the leases, the trial court still might agree with its prior decision and hold that "no lease type negates the IDM [implied duty to market]." Id. Nor did the Tenth Circuit show any reason to believe that the remaining 430 leases would have variations that had not appeared in the many leases that had been examined, or that ultimately the case could not be certified.

In a practice tip, the court did indicate that the lease analysis it envisions does not require the trial judge himself or herself to read every lease. After all, parties rely on summaries all the time. The Trust could "create a chart classifying lease types" and, based on this evidence, the court ultimately might decide that none of the leases negated Kansas' implied duty to market. Id. at 1219. Yet it was a waste of judicial and party resources to send the case back for yet another review of leases, when producer XTO had agreed that the sample leases it produced were representative of the full set of class leases and the court had found no material variation in the sample that XTO had selected.

Given the limited range of royalty payment clauses, most of which contain "proceeds" or "market value" terms or a limited number of their variants, many classes should be susceptible of certification analysis on a sampling basis without anyone having to read every lease. In a time when courts rightly encourage discovery efficiency and sampling in areas like electronic production, they should not create artificial hurdles to class certification by finding complexity where material differences do not exist. Reasonableness also suggests that courts should not need to identify every lease term before certification. In a marketable-condition state, the main difference is likely to be between leases that allow deductions and those that don't. The vast majority of traditional leases will fall into the latter category. Indeed, as long as the class is defined to exclude express-deduction leases, there is no good reason that the parties could not identify and exclude those leases after certification.

The lessee should be in the best position to know what its contract obligations are and what is in its files. The burden of proving that a case is ripe for certification is of course upon the class. But if a class can show from a reasonable sample of leases that there is no material variation in lease terms, courts should shift the burden to the defendant to show a need to review all leases at the certification stage. If the defendant cannot, it should have to live with the sample review unless it later brings forward proof of some different category of lease. Reasonableness in discovery and proof is not less important just because the case is a class action.

It is unfortunate that the Tenth Circuit did not consider the fact that oil-and-gas leases have very little variation in their pricing terms. It treated these industry leases as much more variable than they really are. Oil and gas lease tend to be standard forms. Most are one or another iteration of the various "Producers 88" forms or similar forms. Industry groups have drafted the forms, not the particular lessee and certainly not the lessor. The relevant terms are housed in a short clause in a lease that itself is quite brief.

Oil-and-gas royalty payment terms fall into a small number of terms: proceeds and a few variants, market value and a few variants, and the two-prong combination of these two terms. In many jurisdictions (all the non-Vela jurisdictions), even seeming differences like proceeds and market value mandate use of the same price in royalty computations. Sometimes one finds a few old fixed-price leases, in some areas a small number of same-as-paid-to-the-federal-government leases applying to production from federal land, or a similar state term related to state land, and sometimes a few leases, often modern leases, that expressly allow or prohibit deductions. But if a statistically significant sample of leases shows no variation in material terms, the plaintiff should not have to read every lease just to show again and again that there is no variation that matters. A reasonable sample should suffice.

The other basis upon which Roderick was remanded is marketability. The Tenth Circuit ordered the trial court to consider individual differences in marketability. The class argued that all of the gas is marketable at the well or none of it (with it claiming none); XTO that there is no "universal point of marketability."[142]

XTO was able to argue that marketability might vary by well because of the Kansas Supreme Court's past separation of physical marketability, which the Kansas rule requires lessees to provide, from economic marketability, which thus far it has not (in spite of recent favorable language about the Colorado rule). The issue can be viewed as a price paid for the court's failure thus far to integrate the marketable-condition rule with the duty to market more generally. Thus far in Kansas, then, at least in theory there can be a "marketable" product at locations where there are no buyers or too

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[142] Roderick, 725 F.3d at 1217, 1219.

few buyers to clear the market, although whether this still is the Kansas Supreme Court's position is questionable.[143] In the real world, the sales of a small part of an inventory for local use do not create a market for all products at the local level. Some gas may be sold in the field, but most natural gas has only been produced for sale to interstate markets.[144]

In Roderick, the court was ordered to reconsider whether marketability can be established as a common question.[145] The Tenth Circuit reversed in part on this ground in the sister Oklahoma case, too.[146] Like the Kansas Supreme Court, so the Oklahoma Supreme Court was asked to review a case on certifying a marketable-condition class, this time an intermediate decision that reversed certification after relying heavily on Roderick and its companion decision.[147] A court of appeals had reversed certification and rendered on this issue because of perceived differences in leases and marketing in a 75,000-lease, 1100-field purported class.[148] The supreme court withdrew the intermediate

143 On the status of the current Kansas rule, see supra note 122.

144 This is the conclusion the jury reached in Rogers v. Westerman, supra note 94 & accompanying text.

145 Roderick, 725 F.3d at 1219.

146 Chieftain Royalty Co. v. XTO, 528 Fed.Appx. 938, 943 (10th Cir. 2013).

147 Fitzgerald v. Chesapeake Operating, Inc, Cause No. 111,566 (Ok. Civ. App. Feb. 14, 2014), cert. denied, intermediate decision withdrawn from publication sub nom. Fitzgerald Farms, LLC v. Chesapeake Operating, Inc. (Okla. June 2, 2014).

148 Fitzgerald v. Chesapeake Operating, Inc., Cause No. 111,566, slip op. at 3 (Ok. Ct. App. Feb. 14, 2014)("variety of leases and the varying marketability of gas throughout the class wells will require individual determinations of whether royalties were underpaid"), cert. denied, intermediate decision withdrawn from publication sub nom. Fitzgerald Farms, LLC v. Chesapeake Operating, Inc. (Okla. June 2, 2014). Chesapeake alleged that there are at least five variations among its leases that affect costs that can be deducted: "raw gas," "as such," "at the mouth of the well," "market value at the well," and "gross proceeds." Slip op at 9. The Fitzgerald court relied heavily on Roderick and Chieftain, as well as the Supreme Court's decision in Wal-Mart Stores, Inc. v. Dukes 131 S.Ct. 2541 (2011). It is hard to see how Wal-Mart v. Dukes could be relevant unless any case that is not certified somehow augurs against certification in the next case. It has nothing to do with contract-based royalty claims. Instead, considering its employment facts, the Wal-Mart majority clearly was skeptical of a sociologist-expert who tried to claim that the company had a "culture" that is "vulnerable" to discrimination, but admitted he could not predict how often this culture would

decision from publication, thus expressing its disapproval of that decision.[149]

The Fitzgerald trial court certified a class even though some leases did use the general "at the well" language. This language was not determinative: what was is that less than 1 percent of the leases specifically allowed gathering, compression, dehydration, treatment, processing, and conditioning charges.[150] On marketability, it noted a classic battle of experts over whether all of the gas was marketable at the well, or none.[151] This sounds like a quite conventional certification decision, but the court of appeals reversed, citing Roderick and its sister case, and going further by holding that there was too much variability in leases and marketability to certify a class.[152] Had it decided the case on the merits, the Oklahoma Supreme Court could have addressed in detail what marketability means and whether the marketable-

affect employment decisions, and was equally skeptical about what it treated as a few "anecdotal" episodes in a company with a huge national base of employees. See id. at 2549, 2553-54 & n.8, 2556. This discrimination question has nothing to do with whether variation between a handful of different lease terms in a gas field should defeat certification, and whether one can generalize about which gas is marketable.

[149] The supreme court decision is Fitzgerald Farms, LLC v. Chesapeake Operating, Inc., Cause No. 111,566 (Okla. June 2, 2014).

[150] Fitzgerald v. Chesapeake, Cause No. Cf-10-38, slip op. at 20 (Ok. D. Ct. Feb. 11, 2013), subsequent history omitted. The trial court acted consistently with Oklahoma law in holding that only the 1% of leases with express allowance for deductions would not have an implied marketable-condition rule, and that "at the well" and similar terms are not enough to negate that covenant under Oklahoma law. Id. at 31-32.

[151] Id. at 19-20.

[152] The court of appeals cited with approval language in its prior decision in Panola Independent School Dist. No. 4. v. Unit Petroleum Co., 287 P.3d 1033, 1036-37 (Okla. Ct. App. 2012), that proceeds and market value at-the-well leases can pose material differences on deductions, without discussing the clear Oklahoma holdings in Wood v. TXO, 854 P.2d 880 (Okla. 1992), and Mittelstaedt v. Santa Fe Minerals, Inc., 954 P.2d 1203 (Okla. 1998) that this is not the case. See discussion supra note 134. In Panola, the court discussed proceeds and market value leases as if their rule for deductions is different, but its description of the standards did not identify any material differences (with both depending upon the point at which a marketable product is produced). See Panola, 287 P.3d at 1036-37.

condition rule applies as a matter of law in spite of certain variations in lease terms. The court should have taken the opportunity to discuss the need for any marketability standard to yield a product salable for the best price reasonably possible, not at just any price regardless of whether a true market exists.

When the Oklahoma Supreme Court someday does address the nature of marketability, it, like the Kansas Supreme Court in Fawcett, should consider its definition in the context of the duty to get the best price reasonably possible. The idea that the marketability of natural gas may vary by well in fields connected to the same gathering systems ignores the way field-service systems and gas markets work as well as the best-price duty. Lessees connect gas from individual wells to gathering lines that ultimately feed into processing and treating plants. After leaving the plant, the "dry" processed residue gas flows into large mainline pipelines, while the combined Y-grade liquids stream is fractionated into liquids products.

As soon as the gas enters the gathering system, it loses its well-specific characteristics. One cannot trace an individual molecule from a well to a final sale. And for efficiency reasons, pipelines apply the same field services to this commingled gas stream without distinguishing which well sourced which molecule, and charge a "postage-stamp" rate for the service. Any differences in charges (for instance, if wells in one field connected to a gathering line require wellhead compression but not in another field) tend to determine where there is a charge that might be deducted and its amount, but not whether the lease allows deductions.

Fitzgerald offered the Oklahoma Supreme Court a chance to reunite marketability with sensible economic concepts and the larger duty to market by requiring that gas be economically marketable and satisfy the lessee's duty to get the best price reasonably possible. When the court does finally reach this issue in another case, it should adopt a rule that does not treat as marketable any gas in a physical condition in which a hypothetical person might buy it at some location at some price, even if no one does.

In fields developed for interstate pipeline markets, where lessees tend to sell their gas in hub markets after gas has been processed and liquids separated from the dry gas, it is widely understood that the market that satisfies the best price is this downstream market price. If sales do occur at the well, they are very unlikely to match the best price reasonably available. The reason large, sophisticated natural gas producers generally do not sell gas at the well in the deregulated natural-gas market is that they know they can get a better price net of costs at active markets with multiple buyers. In the absence of such a market for a viable price at the well, they use downstream hub prices, often plus a premium if they offer advantages like larger volumes or a longer term, and "netback" the price to deduct costs when the lease and state law allow deductions:

> . . . . In order to determine the market value of the unprocessed gas at the well, producers sell refined natural gas and NGLs at the tailgate of the processing plant (i.e., after processing) to establish a base sales amount, and deduct from that amount costs for transportation, processing, etc. This is called a "netback" or "workback" method, and it is widely accepted as the best means for estimating the market value of gas at the well where no such market exists.[153]

Another marketable-condition state, Arkansas, has required the lessee to bear downstream compression costs necessary to meet the pressure requirement in the lessee's sales contract in a lease providing for "proceeds . . . at the well";[154] an Alaska trial judge has taken a marketable-condition approach in an unpublished decision;[155] and the New Mexico Supreme Court thus far has

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[153] Abraham v. BP America, 685 F.3d 1196, 1200 (10th Cir. 2012).

[154] The Arkansas holding came in Hanna Oil & Gas Co. v. Taylor, 759 S.W.2d 563, 564-65 (Ark. 1988). The court relied on the plain meaning of "proceeds," a term not qualified by "net," and noted that even if an unqualified proceeds price term could be ambiguous (the ambiguity perhaps possible because the lease did also say "at the well"), it would construe the lease against Hanna Oil as its drafter. Id. Although it is not a reliable expression of Arkansas law, in 2009 a federal trial court refused to certify a common-question class after arguing that Hanna does not unambiguously put Arkansas into the camp of marketable-product states; it also incorrectly treated the marketable-product position as a "minority" position. Riedel v. XTO Energy, Inc., 257 F.R.D. 494, 503-05 (E.D. Ark. 2009).

[155] In Alaska, in which the great majority of oil is produced on state lands, production in early "DL-1" state form leases, which have "at the well" pricing

allowed courts interpreting private-lease cases to certify royalty classes as a matter of law, even though it recently rejected such a rule in what it treated as a sui generis case involving various state lease forms and it has indicated that it is awaiting a fuller record before finally articulating the state's rule for private leases.[156] All

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terms, is governed by a settlement that allows some field deductions, but a court analyzing that lease prior to the settlement held that "at the well" could not be applied literally and field costs should not be deducted, Memorandum of Decision and Order, Cause No. 1JU-77-84, slip op. at 12-13 (Sup. Ct. Alaska Apr. 9, 1979)(Opinion on Compton, J.); that the provision on value was inserted by an industry-supplied consultant without any indication that the state intended a change in existing lease language, id. at 6-12; and that the language appeared copied "verbatim" from Federal Mining and Leasing Act language under which payment of royalty on "production" requires payment on a marketable product, id. at 13-18. When added to the constitutional requirement that Alaskan resources be administered for the "maximum benefit" of its people," id. at 18, these factors persuaded the court that the lease did not allow lessees to deduct field costs prior to the "LACT" measurement point, id. at 20, a holding superseded by the settlement. In a decision 13 years later, another judge found "at the well" an ambiguous term. Memorandum Opinion Concerning the Applicability of ¶ 16 to Destination-Market Transactions, Cause No. 1JU-77-847, slip op. at 12-17 (Sup. Ct. Alaska Mar. 25, 1992)(Opinion of Carpeneti, J.).

[156] In 2009, the New Mexico Supreme Court affirmed certification of a class that was predicated in part on common questions involving the marketable-condition rule, thus implying it will apply in at least some circumstances, even though the court did not decide the issue. Davis v. Devon Energy Corp., 218 P.3d 75, 78-81 (N.M. 2009). A year later, the court held that whether a marketable-condition duty applies can be a question of law or of fact, depending upon the record, but it did nothing to suggest that it will refuse to recognize this duty in at least some circumstances. Ideal v. Burlington Res. Co., 233 P.3d 362, 363 (2010).

The producers in Davis v. Devon, presumably buoyed by the Conoco v. Lyons decision discussed below, petitioned the New Mexico Supreme Court to rule on the marketable-condition rule before a scheduled Fall 2014 trial. The court rejected this effort. The Justices repeatedly stated that they are waiting for a full factual record before they rule on New Mexico's marketable-condition standard for private leases. Transcript of Proceedings, Davis v. Devon, Cause No. 34,442, in the Supreme Court of New Mexico (Feb. 12, 2014).

In ConocoPhillips v. Lyons, 299 P.3d 844 (N.M. 2012), the court could have addressed the marketable-condition issue, but it instead decided the deduction issue under the lease's "net proceeds in the field" term. Id. at 850-54. The court's repeated failure to define a clear position on what is clearly – given the number of cases – a major issue affecting the state's welfare may reflect a division within the court. Yet its failure to reject the marketable-condition rule, in all, a marketable-condition rule applies in a majority of producing states and to a considerable majority of production in the United States.

2. Jurisdictions That Let the Lessee Deduct Marketability Costs

In the other camp on the marketable-condition rule are courts that take an "at the well" approach to the royalty computation. Several major producing states, led by Texas, hold that all costs downstream of the well are deductible in an oil or gas lease unless specific deductions are very expressly prohibited. The Texas trend was summarized by a federal trial court in the mid-1980s in Martin v. Glass.[157] At issue was whether the lessee could deduct compression charges against royalty and overriding royalty payments. The lease provided for payment on "net proceeds at the well," while overriding royalty interests were governed by a different agreement that fell under a standard that royalties on oil or gas delivered to any pipeline should be "free and clear of all cost of drilling, exploration or operation" except for taxes.[158]

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something that would have been easy to do in Davis, Ideal, or Lyons if it does not intend to adopt some version of the rule, suggests that it is likely to endorse a form of the rule. The Lyons court limited its decision to certain state leases and relied heavily upon what it perceived as the New Mexico Legislature's policy decisions about those leases. It warned those tempted to apply the decision to speculate about changes in the private New Mexico standard: "This opinion should not be interpreted as affecting private oil and gas lease agreements." Id. at 860. For a thoughtful review of this precedent by a federal judge who reaches the conclusion that New Mexico most likely will adopt a marketable-condition rule, see The Anderson Living Trust v. ConocoPhillips, 2013 WL 3456913, slip op. at •• 27-28, 37-39 & n.7 (D. N.M. June 28, 2013).

A federal magistrate predicted that Virginia will adopt the first marketable-condition rule in Legard v. EQT Prod. Co., 2011 WL 86598, at *9-13 (Jan. 11, 2011), denying motion to certify question to Virginia Supreme Court, 2011 WL 1087160 (W.D. Va. Mar. 24, 2011).

[157] 571 F.Supp. 1406 (N.D. Tex. 1983), aff'd mem. op., 736 F.2d 1524 (5th Cir. 1984). For an overview of the division on the "at the well" term, see Randy Sutton, Sufficiency of "At The Well" Language in Oil and Gas Leases to Allocate Costs, 99 A.L.R.5th 415, 422-23 (2002 & Supp. 2011).

[158] Martin, 571 F.Supp. at 1410.

The court reviewed authorities that conclude that "net" proceeds suggests that certain costs must be deductible, and other authorities stating that "at the well" should mean that the wellhead is the point of "production" and that lessees can deduct all costs incurred after that point.[159] It then held that when gas has sufficient pressure to reach the surface (even if not pressure enough to enter a buyer's gathering line unaided), compression to send it downstream is a "post-production" cost that is deductible under this net-proceeds lease.[160] The court acknowledged the duty to market, but called it a "separate and independent step, once or more removed from production, and as such [] a post-production [and therefore deductible] expense."[161] In other words, the duty to market was irrelevant to its cost analysis.

Texas has firmly wedded itself to the view that in almost all instances, costs for activities downstream of the well are deductible. A majority of the Texas Supreme Court has refused to allow deductions even when the lease included a specific prohibition 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."[162] In spite of this very plain language focusing precisely

[159] Id. at 1411-15, including citations to Danciger Oil & Refs, Inc. v. Hamill Drilling Co., 171 S.W.2d 321 (Tex. 1943) and Le Cuno Oil Co. v. Smith, 306 S.W.2d 190 (Tex. Civ. App. – Texarkana 1957, writ ref'd n.r.e.).

[160] Martin, 571 F.Supp. at 1415-16. The court discarded the overriding royalty claim in spite of the stronger language in the agreements governing these rights by holding that "free and clear" even of "operating expenses" [which ordinarily would be post-production costs distinguished from production costs] "refer[red] only to costs incident to getting the gas to the surface," thus improperly treating such expenses as if they are costs of production. Id. at 1416-17. Ignoring such clear lease language hints at a result-oriented decision.

[161] Id. at 1416.

[162] Heritage Res. Inc. v. Nationsbank, 939 S.W.2d 118, 120-23 (1996)(emphasis added), reh'g denied, 960 S.W.2d 619 (Tex. 1997). Given the no-deduction language, it is somewhat extraordinary that a concurring opinion argued that to deny deductions would "re-write the agreement for the parties." Id. at 124, 131 (Owen, J., joined by Hecht, J., concurring). More realistic was a dissent in which Justice Gonzalez objected, after citing the no-deduction language, "What could be more clear? This provision expresses the parties' intent in plain English, and I am puzzled by the Court's decision to ignore the unequivocal intent of

on specific deductions, with transportation costs one of the prohibited deductions, the parties disputed whether the lessee could deduct the cost of "transporting" gas from the well to the point of sale.

Like the Martin court, so the Texas Supreme Court discussed the term "royalty" as generally meaning an interest free of the cost of production. It then treated the term "market value at the well," language also found in the contested leases, as indicating that all post-production costs are deductible[163] without any effort to explain how this position could fit the narrower, more precise language specifically denying deductions, including "transportation."[164]

Having decided from these general concepts that post-production costs could be deducted, the court applied this interpretation even though it admitted that its reading "arguably renders" the no-deduction language "surplusage" in at least two of the three leases it was interpreting. The court inexplicably did not enforce the narrower, more specific language that so clearly disallows all deductions, and it did indeed render this language meaningless.[165] This absolutist approach treats "at the well" as

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sophisticated parties who negotiated contractual terms at arm's-length." Id. at 131 (Gonzalez, J., joined by Abbott, J., dissenting)(citation omitted). In a later dissenting opinion, he argued that by the time of rehearing, only one Justice supported the original decision, so that it should have no precedential value. See Heritage, 960 S.W.2d 619, 190-20 (Gonzalez, J., joined by Cornyn, Spector, and Abbott, JJ., dissenting from denial of rehearing)(Tex. 1997). Yet the poorly reasoned decision has helped set the broad, very producer friendly allowance of deductions in Texas. The dissenters criticized the court's "unprecedented refusal to enforce the contract as written . . . ." Id. at 619.

[163] Heritage Res. Inc. v. Nationsbank, 939 S.W.2d 118, 122-23 (1996), reh'g denied, 960 S.W.2d 619 (Tex. 1997).

[164] The court did attempt to distinguish the "no deduction" language by noting that it only applied "from the value of the Lessor's Royalty," and then circularly argued that this value was a royalty value already defined as at the well, id., but it made no effort to show that language as plain as "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," 939 S.W.2d at 121-23, is ambiguous, or to show how some of these charges (transportation, for instance), could ever occur at the well.

[165] In the same day decision of Judice v. Mewbourne Oil Co., 939 S.W.2d 133 (Tex. 1996), the court held that a lease providing for "market value at the well"

magic words that fully determine what deductions are allowed, as the beginning and end of the analysis, and that when present leave no room for other terms no matter how specific they are. The analysis is contrary to ordinary rules of construction, which would give priority to the most specific lease language, the clause barring specific deductions.[166]

Another major producing state, Louisiana, has determined that questions of cost deductibility should be resolved in general by allowing deductions of all costs beyond the well, in the absence of contrary lease language, as have courts applying the laws of Kentucky, Mississippi, Montana, the newly ascendant oil producing state North Dakota, and Utah.[167] A Louisiana court of

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allows deduction of reasonable post-production compression costs; that division orders providing for payment on "gross proceeds realized at the well" for gas sold are ambiguous; and that the trial court did not err in entering judgment on a jury finding that the parties did not intend to allow compression deductions under the gross proceeds language; but that the trial court erred in finding deductions prohibited under another division order that provided for "net proceeds realized at the well." Id. at 135-37; but see Parker v. TXO, 716 S.W.2d 644, 648 (Tex. Civ. App. 1986, no writ)(discussing Martin favorably, but reversing when no evidence supported trial court's conclusion that compression was necessary to make gas deliverable into pipeline, and production engineer testified that compression was needed to "*increase production* from the wells"; compression therefore was appropriately treated as a nondeductible expense of production (emphasis in original)).

For subsequent cases, see Phillips v. Yarbrough, 405 S.W.3d 70 (Tex. 2013); see also OXY v. The Helen Jones Found., 2011 WL 291966 (Tex. App. – Amarillo Jan 31, 2011, rev. denied); Potts v. Chesapeake, 2013 WL 874711 (N.D. Tex. Mar. 11, 2013).

166 The court's refusal to apply the language that so plainly covers deductions, and prohibits them, drew a strong dissent from Justices Gonzalez and Abbott. See supra note 162.

167 The Sixth Circuit read Kentucky law as allowing deduction of gathering, compression, and treatment costs in leases providing for royalty payments on the "wholesale market value of such gas at the well based on the usual price paid therefore in the general locality of said leased premises" in Poplar Creek Development Co. v. Chesapeake Appalachia, L.L.C., 2011 WL 535107, at *3-*7 (6th Cir. Feb. 17, 2011).

In Piney Woods Country Life School v. Shell, 726 F.2d 225, 230-38 (5th Cir. 1984), the Fifth Circuit treated Mississippi law as putting that state into "at-the-well" jurisdictions.

appeals allowed deduction of compression costs needed to move gas into the pipeline (as opposed to nondeductible "production" compression required to get it up to the wellhead), summarizing its view of past Louisiana precedent and relying heavily on Martin v. Glass as well.[168] It discussed a series of Louisiana Supreme Court

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In S Bar B Ranch v. Omimex Canada, LTD., 942 F.Supp.2d 1058, 1061-62 (D. Mont. 2013), a federal trial judge interpreted Montana law, in particular Montana Power Co. v. Kravik, 586 P.2d 298 (Mont. 1978), as adopting the "at the well" approach to deductions. Montana Power v. Kravik does indeed talk about market price meaning the "current market price being paid for gas at the well" when there is no "stipulation to the contrary." 586 P.2d at 302. But that discussion arose in a case in which the dispute was whether the district court was correct to look to a nearby federally regulated price in setting the price for intrastate gas.

In West v. Alpar, 298 N.W.2d 484 (N.D. 1980), the North Dakota Supreme Court resolved a dispute over the cost of extracting hydrogen sulfide by finding "one-eighth of the proceeds" ambiguous and construing the lease against the lessee drafter, id. at 487-91, without determining whether the expenses were "production" or "processing" expenses or any implied duty issues, id. at 491. But in Hurinenko v. Chevron, 69 F.3d 283, 284-85 (8th Cir. 1995), the Eighth Circuit held that North Dakota would allow deduction of processing costs under a "market value at the well" term. A few years later, the North Dakota Supreme Court, agreeing with Hurinenko's reasoning, shifted to join the Texas-Louisiana "at the well" camp when the leases specified "market value of the gas at the well" in Bice v. Petro-Hunt, L.L.C., 768 N.W.2d 496, 499-02 (N.D. 2009).

The Utah Supreme Court's reasoning in the relatively early uranium cost-deduction case of Rimledge Uranium and Mining Corporation v. Federal Resources Corporation, 374 P.2d 20, 23 (Utah 1962), suggests that Utah also will take a position allowing deductions if the issue is presented to it in an oil-and-gas setting. A federal district court in Utah relied on Rimledge in predicting that Utah will join the "at the well" jurisdictions, although unfortunately it, like Kilmer, relied on the erroneous assumption that this is the majority rule. Emery Res. Holdings, Ltd. v. Coastal Plains Energy, Inc., 915 F.Supp.2d 1231, 1230-42 (D. Utah 2012).

[168] Merritt v. Southwestern Elec. Power Co., 499 So.2d 210, 213-15 (La. Ct. App. 1986). For recent cases following Merritt, see Culpepper v. EOG, 92 So.3d 1141, 1143-44 (La. Ct. App. 2012); cf. also the intriguing, rejected effort of a plaintiff to claim part of the lessee's hedging profits, Cimarex Energy Co. v. Chastant, 2012 WL 6652360 (W.D. La. Dec. 18, 2012), aff'd, 537 Fed. Appx. 561 (5th Cir. 2013). In Dickson v. Sklarco L.L.C., 2013 WL 1828051 (W.D. La. Apr. 29, 2013), though, the court found ambiguity when the leases not only contained a "market value at the well" term, but also a clause stating that post-production costs could only be deducted if they enhanced the value of the

cases from the 1930s that had tried to draw a clear line around services performed at the well, and allowed deductions for charges on services performed away from that point.[169] The Louisiana Supreme Court has not squarely addressed today's split in marketing cases, so one cannot be certain about what it will make of modern marketable-condition arguments, but if it follows its old approach it will stick to the rule allowing deductions.

Several older California cases have addressed royalty cost-deductibility questions and allowed deductions, even though none have formally considered the marketable-condition doctrine. At this point California is likelier to be in the deduction-allowing camp than in the marketable-condition camp, but its position should not be viewed as fully settled because it has not been presented with or addressed the pros and cons of the marketable-condition rule.

By taking a very factual approach, the California cases began from a very different position than the categorical approach of the

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product or were required to make it marketable, with treating, processing, and dehydrating to meet pipeline specifications deemed services that enhance product values. Id., slip op. at ** 6-9.

[169] In Wall v. United Gas Public Service Co., 152 So. 561, 564 (La. 1934), the Louisiana Supreme Court noted in dictum that under Louisiana law, in a "market price" lease where there were no sales in the field, the proper royalty computation would be to deduct the cost of moving gas to its point of sale; and also held that the lessees could deduct the cost of gasoline extraction. See also Coyle v. Louisiana Gas & Fuel Co., 144 So. 737, 738-40 (La. 1932)(holding that when natural gas was unfit for "domestic consumption" without removing gasoline, lessors were not directly chargeable with cost of building gasoline extraction plant, id. at 739-40, but then on rehearing holding that where gas provision (unlike oil) did not say "free of cost," parties had no reason to think that cost of making gas merchantable by extracting gasoline would be "free of cost" and such costs could be deducted, id. at 742-44), cited with approval in Critchton v. Standard Oil Co., 150 So. 668, 669 (La. 1933)(upholding payment of royalty on unprocessed wet gas when lessee was not equipped to extract gasoline from gas and sold it to processor on the same terms as paid to others in area). In Sartor v. United Gas Public Service Co., 173 So. 103, 105-08 (La. 1937), the court interpreted Louisiana law to allow deduction of gathering charges by reading "market value" to mean "the current market price paid for gas at the well or in the field where it is produced," in the absence of a contrary stipulation in the lease.

courts that today do allow full cost deductions.[170] The leading California royalty-deduction case is a 1935 California Supreme Court decision, Alamitos Land Co. v. Shell.[171] Alamitos did not discuss implied duties, but instead decided the challenge to oil treatment deductions by interpreting express contract language. The issue was whether Shell could deduct the cost of dehydrating oil in the Signal Hill field in Los Angeles under a lease that set the royalty share at one-sixth of "petroleum oil" and required basing royalty payments on the "current price paid by the Lessee for oil of like grade and gravity at the wells of production in the same vicinity."[172] The lease required Shell, at the lessor's option, to deliver the oil into tanks or containers to be stored "without charge" for a period of not more than 30 days.[173] The trial court had ordered Shell to repay the royalty owners the amounts it had deducted for dehydration.[174] Reversing, the California Supreme Court decided that the terms "petroleum oil" and "royalty oil" on which royalties depended refer to oil in its "natural state," which to it meant "petroleum fluid together with such water and other foreign matter as may be emulsified therein" and therefore not dry or cleaned oil.[175] Even with this plain-meaning analysis, the court looked at practices in the field, which it believed supported Shell,

[170] But see MERRILL, supra note 13, at 215 (claiming that in California, lease provisions imposing proportionate costs of treating unmarketable oil or other hydrocarbons "apparently are customary" and that California allows lessees to deduct costs "regardless of stipulation" (citations omitted)). This is an exaggeration of the California cases, as the text shows. The California courts have tended to engage in a detailed inquiry into practices in the field before determining which costs can be deducted, an approach inconsistent with any absolute rule.

[171] 44 P.2d 573 (1935).

[172] Id. at 575 (emphasis added).

[173] Id.

[174] Id. at 574.

[175] Id. at 576-77. In reaching the conclusion that "oil" means oil in its "natural state," the California Supreme Court disregarded a letter Shell wrote some years earlier in which it agreed with the plaintiff's position. In the letter, written when it was not facing litigation, Shell stated that "[w]e think that the proper interpretation of the 'Oil Produced and Saved' clause is the actual clean oil which is delivered to the marketing company or pipe line." Id. at 577.

as if the lease was ambiguous.[176] For these reasons, Shell was not required to treat the royalty share oil at its own expense.[177]

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[176] The court gave great weight to what it described as the custom of the major buyers in the Signal Hill field to purchase oil on a wet-oil (untreated) basis at Standard Oil's posted field price. Id. at 577-78. Shell used Standard Oil's posted price to pay royalties. Id. at 578. The court added, somewhat punitively, that "the slightest diligence on the part of plaintiff would have disclosed to it the uniform practice in the Signal Hill field as well as the same practice by defendant." Id. at 577-78. Yet field practices hardly could have been this clear when as sophisticated a company as Shell earlier had agreed in writing that "oil" means cleaned oil, not untouched oil as it emerges from the well. See supra note 175.

[177] The lessor argued on appeal that Shell was supposed to clean the oil by removing water and only then conduct the volume measurement upon which royalties would be based. Id. at 576. Shell disagreed, arguing that neither the lease nor any "necessary implication" made it clean or process the oil. Id. at 575. The lease, the supreme court noted, was silent on how the oil should be tested and did not specifically require Shell to clean it. Id. at 576. The lease did not expressly require clean oil when the lessor took in kind and, the court reasoned, if such a duty "is absent when the royalty oil is delivered in kind, it is absent when the royalty oil is to be purchased." Id.

Alamitos was followed a year later by another California Supreme Court deduction decision, in a case in which the lease appeared to expressly allow deductions. In Meyers v. Texas Co., the lease provided for payment of proceeds "less cost of handling after leaving tank or container." 59 P.2d 132, 133 (Cal.1936). The lease contained a price floor of not less than Standard Oil's "posted market price." Id. It stated that "in the event it becomes necessary to treat any of the oil . . . to make some marketable," and the lessee built a plant, it would treat lessors' oil "charging therefore only the net cost of such treatment." Id. at 134. Thus here the parties appeared to agree that they would proportionately bear treatment costs.

The effect of the Meyers' holding was to apply this treatment language with "less cost of handling after leaving tank or container" as written. Although the bulk of the case was devoted to the court's holding that the Texas Company was improperly measuring the oil, a discussion that seems to have assumed that the lessors would bear their portion of treating costs, it included the following in that discussion: "It seems obvious, however, that plaintiffs either had the right to demand a one-sixth part of the oil after dehydration and their payment of a one-sixth part of the cost or, in the event the whole was handled and marketed by defendant, to a one-sixth of the proceeds." Id. at 134 (emphasis added). The court did not indicate whether it read the "proceeds" payable if the plaintiffs did not take their oil in kind as net of the costs of handling or as gross proceeds.

The parties disputed as well the cost of gasoline extraction, but on that issue the lease also had specific language: if the Texas Company built an extraction plant, California courts have allowed deductions after Alamitos in several other cases, requiring the lessors to bear their share of treating charges and the like, but in general with lease language that provided "at the well" pricing or expressly authorized deductions.[178] Their approach to date makes them likelier to join

it was to pay one-sixth of proceeds as royalty on gasoline "after deducting the cost of extraction." Id. at 136. The court determined that other authorities had little relevance to the dispute, which was to be decided by the lease "in the light of all attending circumstances," and not surprisingly (given this language) allowed gasoline-extraction deductions. Id. at 136-37.

Conversely, if the lease does provide for the lessee to bear costs, of course, it will have to do so. In Transport Oil Co. v. Bush, 1 P.2d 1060, 1062 (Cal. Ct. App. 1931), the lease stated that the lessee would "extract[] and produce[]" oil, gas or other hydrocarbons at its "sole cost and expense"; that it would sell production on behalf of the lessor "at the highest price reasonably obtainable therefore"; and do so "without any deduction for the expense of selling, handling or otherwise, ..." Oil from the property was worth much more if gas and water were separated from the oil, but the process of dehydration and emulsion to do so was not necessary to profitably market the oil. Id. at 1061, 1064. Apparently reading the "without any deduction" language in an unnaturally narrow manner, the court held that the lessee would have to bear the full cost of treating oil if needed to secure the highest price possible, but not otherwise. Id. at 1064. (This may have been an error without a difference, because presumably the main reason a lessee would treat oil is to get a higher price – it is hard to see why it would treat oil if it could sell untreated oil at the same price.).

[178] See Fowler v. Associated Oil Co., 63 P.2d 1146, 1148-54 (Ct. App. 1936), rev'd, 74 P.2d 727 (Cal.), vacated for settlement, 79 P.2d 728, 728-32 (Cal. 1938); Vedder Petroleum Corp. v. Lambert Lands Co., 122 P.2d 600, 601-05 (Cal. Ct. App. 1942); Western Gulf Oil Co. v. Title Insurance & Trust Co., 206 P.2d 643, 644, 647-48 (Cal. Ct. App. 1949). In 1989, a California court of appeals, interpreting "at the well" as authorizing deductions, adopted an analysis closer to the general deductions-allowed rule as it interpreted an older California statute governing a state lease form, but still without addressing the duty to market. Arco v. State involved a portion of the Public Resources Code that governs an older, now-superseded State lease form for tidelands leases, on which royalties were due as a percentage of "the current market price at the well . . . ." Arco v. State, 262 Cal.Rptr. 683, 687 (Cal. Ct. App. 1989). The statute was amended in 1976 to disallow deductions for "treatment, dehydration, or transportation," except in the case of net-profits leases (which obviously intend netting of at least certain costs), for leases let after January 1, 1977. Cal. Pub. Res. Code 6827 (2001). This court treated "at the well" as a determinative sign that the parties had agreed that costs for operations conducted downstream of the wellhead could be netted against the royalty price before payment to the state. It

deduction-allowing jurisdictions than those that prohibit deductions.

The latest addition to this group is Pennsylvania, a state that is becoming an increasingly important producing state once again because of the Marcellus shale natural-gas deposits within its borders. The Pennsylvania Supreme Court has read the state's Guaranteed Minimum Royalty Act, which requires that lessors receive at least one-eighth of "all oil, natural gas or gas of other designations removed or recovered from the property," to mean one-eighth of these minerals at the wellhead and to allow deduction of costs required to get the product from there to the point of sale, in a decision in which it rejected what it called the "First Marketable Condition Rule."[179]

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read California law as having a default rule that "unless there is clear language to the contrary, the lessor . . . bears its proportionate share of processing costs incurred downstream of the well," Arco v. State, 262 Cal.Rptr. at 688, a reading that ignores the fact that Alamitos and its immediate progeny generally found lease language sufficiently opaque to force courts to look at the customs and practices in the relevant field.

Owen Anderson has made a heroic effort to reconcile Alamitos, Vedder, and Arco v. State with the first marketable-condition rule, but nothing in either opinion suggests that either court was considered the marketable-condition doctrine. See Anderson, supra note 69, at 687-92.

Although the California cases on deductions have not been cited often in other jurisdictions, its cases have had some influence on the developing caselaw, which has treated California as being in the "at-the-well" camp. Schroeder v. Terra Energy, Ltd., 565 N.W.2d 887, 893 (Ct. App. 1997), leave to appeal denied, 584 N.W.2d 588 (Mich. 1998); Creson v. Amoco, 10 P.3d 853, 858 (N.M. Ct. App. 2000); Bice v. Petro-Hunt, LLC, 768 N.W.2d 496, 501 (N.D. 2009); Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 124, 129 (Tex. 1996)(Owens, J., joined by Hecht, J., concurring); cf. Schmidt v. Texas Meridian Res., Ltd., 1994 WL 728059, at * 5 (Ohio Ct. App. Dec. 30, 1994).

[179] Kilmer v. Elexco Land Servs., Inc., 990 A.2d 1147, 1151-58 (Pa. 2010). Pennsylvania's Minimum Guaranteed Royalty Act, which the plaintiffs claimed is the only such statute in the country, id. at 1153, was passed in 1979. The Kilmer plaintiffs had a lease the court described as common in Pennsylvania that expressly allowed the deductions they sought to avoid through the statute; it entitled them to proceeds, but only "less this same percentage share of all Post Production Costs," with the lease then listing almost every category of cost that might be deductible. Id. at 1150. This was a lease that presumably would have satisfied even the West Virginia test for authorizing deductions. See, e.g, text

The Pennsylvania rule may be up for grabs. A committee in the House of Representatives has approved a bill that would prevent any deductions that drive royalties below 12.5% of the proceeds, in effect reinstating the lessors' preferred reading of the Guaranteed Minimum Royalty Act up to that level of royalty and overruling the Pennsylvania Supreme Court for royalties of one-eighth or less.[180] So the rule in this state may be in play.

3. Areas of Agreement and Disagreement

With this background, some of the contours of this mixed body of cost-deduction law seem to be fairly well fixed.

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accompanying notes 112, 114 supra. So it was a bad case for plaintiffs to use as a test case. There were more than 70 similar lawsuits pending in Pennsylvania courts. Kilmer, 889 A.2d at 1151. After Kilmer, the statute sets a floor on the percentage of royalty proceeds share, but not on deductions.

One fact that made the Kilmer plaintiffs' position unattractive was that their leases included bonuses of only $100 an acre, but they were trying to cancel those leases and re-lease their properties at a time when lessees were paying signing bonuses of as much as $2800 an acre for new leases. See id. at 1150 n.5. Thus they fell afoul of a much enforced, although not always articulated, oilfield principle that a party does not get to redo its deal.

The Pennsylvania Supreme Court surveyed the varying judicial positions on the marketable-condition rule; was not swayed by the landowners' argument that Pennsylvania already had taken a position on this issue in Iams v. Carnegie Natural Gas Co., 45 A. 54 (1899); found legislative history unhelpful; and ultimately seems to have been swayed most by its belief that at the time of passage of the Guaranteed Minimum Royalty Act in 1979 (just as gas deregulation was beginning under the Natural Gas Policy Act of 1978), "virtually all royalties to landowners were [according to the court] based on the sale of unprocessed gas from the producer to the pipeline company at the wellhead," and by the Williams & Meyers' definition of "royalty" as an interest free of the costs of production at the well, but not free of downstream costs. 990 A.2d at 1155-58.

For a decision following Kilmer generally and refusing to make the lessee share its hedging gains, but finding fact issues on certain affiliate issues over marketing costs, see Pollock v. Energy Corp. of Am., 2013 WL 275327 (W.D. Pa. Jan. 24, 2013).

[180] See Marie Cusick, "House panel approves bill to limit gas royalty deductions," available at https://stateimpact.npr.org/pennsylvania/2014/03/17/house-panel-approves-bill-to-limit-gas-royalty-deductions/ (Mar. 17, 2014: accessed April 9, 2014).

The Jurisdictional Division Will Continue. Most importantly, the gap between the marketable-condition and no-deduction camps is unlikely to be bridged. The camps have irreconcilable views on this issue. Courts that treat production as requiring a marketable product and see one of the lease's core purposes, and the lessee's core duties, as providing the lessor with a marketable product are not likely to join the Texas-type jurisdictions. Conversely, courts like Texas courts that do treat royalties as free only of production costs, and not free of downstream costs; define the term "at the well" as sufficient to allocate specific field costs; and find meaning in a passage of title at the well are not likely to make lessees bear the marketability costs incurred on the royalty share. Nor are at-the-well jurisdictions likely to decide that the historic, post-deregulation downstream shift in the location of where natural gas is marketable, and with it the location of the best price reasonably available, alters their determination to allow deductions of all costs incurred away from the well.

While the gap between these camps may not be bridged, it may be narrowed in some jurisdictions by statute. The frequency with which the marketable-condition rule is a part of current public leases may point to the one factor that might shift the balance between jurisdictions further toward marketable-condition states. Public lessors have much more relative bargaining power than the average lessor. The federal government bars marketable-cost deductions except for processing costs, and almost all marketable-condition states bar " post-production" deductions.[181] Of the eight states with the largest oil-and-gas production (on public and private land combined), Texas, Louisiana, Wyoming, Oklahoma, New Mexico, Alaska, Colorado, and California, the state lease forms in all but Oklahoma and New Mexico specifically bar these deductions.[182] State leases bar deductions even in the most core

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[181] See supra notes 79-156 supra & accompanying text.

[182] The Texas University Land Office lease bars deductions, Texas University Land Office, Sample Oil and Gas Lease, Form 44, § 3(f) (2011 lease)(Lessee to pay royalties without deduction for "the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, transporting, and otherwise making the oil, gas and other products hereunder ready for sale or use" and

"[n]o field deductions for lost product will ever be allowed. All such costs shall be the responsibility of the Lessee."), as does the General Land Office lease, General Land Office Relinquishment Act Lease Form § 7 (rev. Sept. 1997)("Lessee agrees that all royalties accruing under this lease . . . shall be without deduction for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and otherwise making the oil, gas, and other products hereunder ready for sale or use"; section 4.C allows no reduction in residue gas volumes but does allow some reduction (but not more than a 50% reduction) under some circumstances if the lessee has to enter a percentage-of-proceeds contract to separate and process liquids). The 1981 Louisiana lease, State of Louisiana, Louisiana State Lease Form (rev. 1981), bars deductions generally, although it allows deduction of certain off-field transportation costs for oil, id. § 6(a) and natural gas, id. § 6(b), and certain processing costs, id. § 6(c). Except for these exclusions, specifically prohibited deductions include "gathering or transporting production in the field" and any costs of dehydration, decontaminating, or "in any way processing production to make it marketable," without regard to whether the process occurs in or outside of the field. Id. § 6(b)(1)-(2). The current version of the recently adopted Wyoming lease effectively incorporates a marketable-condition rule. State of Wyoming, Oil and Gas Lease, Oil and Gas Terms attachment, sec. 1(d)(i)-(ii) (effective Aug. 4, 2011). It bans a long list of traditional post-production costs, id., although it allows deduction of actual, reasonable, unreimbursed costs of not more than half the value of residue gas for transportation and on liquids it allows deduction of "the reasonable, actual, unreimbursed cost of extraction" as long as it is not more than two-thirds of the liquids value (unless written permission is given for higher deductions). Id. §§ 1(d)(ii)-(iii). The Alaska "new form" lease broadly bars deductions on royalty payments by requiring royalty to be "free and clear of all lease expenses," including free of expenses incurred off the lease and including but not limited to costs for such activities as "separating, cleaning, dehydration, gathering, saltwater disposal, and preparing the oil, gas, or associated substances for transportation off the leased area." Department of Natural Resources, State of Alaska, Competitive Oil and Gas Lease, Form No. #DOG 200604, § 37 ("PLAN OF OPERATIONS")(March 2009 rev.). The Colorado lease has a broad no-deduction clause that makes the Lessee put the product in marketable condition, which for natural gas means ready for transmission into an interstate pipeline, with no deduction for the "direct or indirect expense" of doing so. State of Colorado, Board of Land Commissioners, Oil and Gas Lease § 3.D (rev. 04/2011). The lease bars a long set of marketable-condition costs including processing, gathering, and transporting as needed to convert the products into marketable condition. Id. It sets the point of marketability at the "storage tank or other facility" where oil is stored for delivery to a "purchaser or refinery," id. § 3.A., while natural gas is marketable when it "meets the location, quality and pressure specifications for transmission into an interstate pipeline," with separate lessor-favoring terms for payment of the "gross no-deduction jurisdictions of Texas and Louisiana. The frequent ban on deductions in state leases is a sign that royalty owners with knowledge, experience, and at least some leverage tend to view marketable-condition rules as a necessary part of an adequate oil-and-gas lease. If producers in these states try to blanket new fields with leases allowing all deductions, they may create a backlash in which royalty owners try to use their greater numbers to put these costs back on the lessee and secure the same protection that the state itself enjoys as a lessor.

Best-Price Sales at the Well Satisfy the Duty. A generalization that can be made safely is that if a truly prudent sale occurs with an arm's-length buyer at the well, a sale that satisfies the duty to get the best price possible under the given market conditions – a big if – then the deduction issue disappears because all approaches agree that the lessee alone has to bear the costs of production up to that point. No deductions would be allowed.

This seemingly clear principle is limited in application, though, because today the wellhead price so often is not an adequate price. The best price reasonably available rarely is at the well in today's deregulated marketplace. To limit the price to wellhead prices would deprive lessors of the benefits from the market-hub transformation in the late twentieth century that increased values for sellers of natural gas by creating more active markets downstream of processing plants. This change should

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sales value" of processed natural gas and the liquids that pass through a processing plant, id. § 3.B.

The history in California is varied. The State contended that its form lease prohibited deductions for processing and transportation, but lost that argument in Arco v. State, 262 Cal. Rptr. 683 (Cal. Ct. App. 1989). In a state in which the vast majority of production is oil, not natural gas, the legislature amended the law to prohibit deductions for oil treatment, dehydration, or transportation on state leases (except net-profits leases) with effective dates after January 1, 1977. See supra note 178.

In contrast, the Oklahoma lease does not specifically address deduction terms. The State of New Mexico Land Commissioner has interpreted that state's major lease forms as embodying the marketable-condition rule, but the New Mexico Supreme Court disagreed, finding deductions barred by express lease terms for two of the major lease forms, the 1931 and 1947 forms, after considering other factors in addition to lease language, in ConocoPhillips v. Lyons, 299 P.3d 844 (N.M. 2012).

benefit both sides of the lease, not just the lessee. Even if a buyer can be found at the well, its price often will not satisfy the best-price portion of the marketing duty.

Most cases gloss over the wellhead versus downstream price issue because the lessee sells its product downstream. The issues they face are what the lessee truly receives for the sale (the issue in affiliate cases) and whether it can take deductions (the classic marketable-condition question). The bottom line is that in "at the well" jurisdictions, but only in at-the-well jurisdictions, that terminology may define the point of deductions, but it should not answer the which-price-is-the-best-price question.[183] In marketable-condition states, in contrast, the location where deductions begin depends upon where the lessee produces a marketable product.

Even At-the-Well States Rejecting a Marketable-Condition Rule Should Bar Deductions under Some Leases. To the extent that deduction-allowing jurisdictions espouse a plain meaning approach that applies "at the well" to allow deduction of all costs downstream from the well, to be consistent their courts should refuse to allow deductions in leases that provide for unrestricted payments by using the terms "gross proceeds," "total proceeds," or "proceeds"[184] (or "amount realized" or "amount received"), or the

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[183] Thus consider a case which accepts the wellhead price for sales in "amount realized" terms set at the well, but in which those price terms were part of two-prong leases that would have required market-value pricing for sales away from the well. Occidental v. Helen Jones Foundation, 2011WL 291966, slip op. at * 4 (Tex. App. – Amarillo 2011). Surely the prior lessee had an implied duty to seek out downstream sales subject to market-value pricing if it could have gotten a better price that way at the time it committed the gas to a sales contract.

An extreme case arises if the lessee claims that even though it is not actually selling gas at the well, production is complete when gas emerges from the ground in its wet state, so that the lessee does not have to pay for embedded liquids at the liquids price even though it sends the gas to a processing plant and then sells the dry gas and liquids separately. This is the position that Williams Production, LLC and various affiliates are taking in Abraham v. WPX Energy Production, LLC, Case No. 12-CV-00917-JB-ACT (D. N.M.).

[184] The Kansas Supreme Court addressed the meaning of "proceeds" not long ago in Hockett v. Trees Oil, 251 P.3d 65 (Kan. 2011), and determined that it means the "gross sales price." Id. at 72.

market-value/market-price variations, without limiting geographic language like "at the well." The plain meaning of such terms is that the lessor is to receive the proceeds or value received upon sale by the lessee. Even "at the well" jurisdictions should have to admit, because they profess to use plain-meaning analysis, that leases requiring such proceeds or value payments without restriction ought to be enforced as they are written, too.[185] The contrary argument, that there is a default rule allowing deductions even if the lease is silent on location, is inconsistent with plain meaning analysis because it treats all leases (except, perhaps, some gross proceeds leases) as net proceeds or value leases.

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[185] For instance, even though the Texas Supreme Court has treated "at the well" as a default position, and in recent years seems to have struggled as hard as possible to let lessees take as many deductions as possible, even in leases that specifically state that no deductions are allowed as in Heritage Resources, Inc. v. Nationsbank, 939 S.W.2d 118 (Tex. 1996) discussed supra notes 162-66 & accompanying text, yet in Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136-37 (Tex. 1996) the court did agree that "gross proceeds" on its own requires payment on the gross proceeds received, that the term "gross proceeds realized at the well" in certain division orders was ambiguous, and upheld a jury finding that under this language the parties did not intend compression-cost deductions. In general, if a court in a jurisdiction like Texas is going to apply a plain meaning analysis of "at the well" without considering the purposes of the parties, or whether lessees traditionally have to deliver a marketable product, it should not refuse to enforce the plain meaning of "gross proceeds" or "proceeds" when those terms appear without restrictions. Under plain-meaning analysis, even the term "proceeds" should equal gross proceeds, because had the parties intended to allow cost deductions, they easily could have said so and referred to specific allowable costs, or provided for "net proceeds" at the well or some other point (a common pricing term used to indicate some deductions, often to a specified geographic point), see Hanna Oil and Gas Co. v. Taylor, 759 S.W.2d 563, 564-65 (Ark. 1988).

Contrast this straightforward approach with the analysis in an influential early Kentucky case, which properly interpreted an unqualified "proceeds" lease to mean total proceeds, but then improperly took away much of the meaning of this holding by adding that proceeds would be determined by sales at the well even though the lease did not contain that limitation, Warfield Nat. Gas Co. v. Allen, 88 S.W.2d 989, 991-92 (Ky. Ct. App. 1935). Were this holding repeated in the modern natural-gas market, it would deprive lessors – but not lessees – of the substantial economic benefits that have come from the development and integration of the post-deregulation natural-gas market.

Leases providing "at the well" pricing are quite common. It is impossible to separate the frequency of courts allowing full deductions from the fact that the leases in most of those cases contain this term. Yet, as the Colorado and West Virginia courts particularly have emphasized, "at the well" is not clear language to tell someone costs are going to be deducted, much less which costs and how the costs should be computed. If a court adopting the no-deduction approach is going to treat this term as a clear deduction term, then, when a lease only requires payment of gross proceeds or an unqualified proceeds, amount realized or value without adding "at the well," they should not abandon plain-meaning analysis and pretend that terms whose natural meaning is full proceeds mean net proceeds at the well anyway.

The Equities Include the Downstream Shift in Marketability. Courts analyzing these issues should not assume that the downstream shift after natural-gas deregulation of the point of prudent sales from the wellhead, which was the common (but by no means universal) sales location in the industry's early years, to the market hubs downstream of gas processing plants means that a marketable-condition rule would impose new costs on gas buyers.[186] In states like Texas, this issue may not matter because the Texas Supreme Court has so fully protected lessees in its decisions on market value and deductions. But in other states, perceptions of the equities can matter. Gas buyers sometimes argue that it is unfair for them to have to share downstream sales if lease pricing terms state "at the well" because, they claim, the well is where many sales occurred in the industry's early days. An extreme application of this principle would be a buyer that refuses to pay royalties on the processed methane and the liquids that are sold separately at the outlet of processing plants, and that instead pays for

[186] Courts still analyzing their rule should consider evidence that in fields developed by interstate pipelines on their own leases, there was no price as such negotiated for the pipelines' own gas and royalty owners did not bear field-service costs. But in many fields pipelines did buy gas at the well from other sellers. In addition, when pipelines bought gas in the field, the prices they paid for independent producers' gas were rolled into their operating expenses and passed on to their distant customers, along with the cost of field services. Colorado Interstate Gas Co. v. FPC, 324 U.S. 581, 596-97 (1945).

the unprocessed volumes of liquid-laden raw gas on the methane value only, even though this is not how it sells the product.[187]

The claim that sharing hub prices would impose a new cost on gas buyers is an inaccurate description of the transition to a deregulated gas market. The United States, whose first large-scale experience with natural gas was from manufactured coal-gas used to light various older cities, saw the development of major natural-gas fields in the 1920s and 1930s and again in the period after World War II when there was more experience with large diameter pipelines.[188] Many of the country's natural-gas fields were leased and developed in these great build-outs of the national interstate gas delivery system. Unlike oil pipelines, which were common-carrier systems, natural gas pipelines owned the gas that flowed through their lines. The pipelines leased and developed many of the reserves that flowed into their lines, and they bought the rest in the field, sometimes at the wellhead but sometimes downstream of processing plants from large producers like Phillips Petroleum, which built its own gas gathering and processing systems.[189]

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[187] Various affiliates of the Williams Companies are arguing in a New Mexico federal court case concerning gas from the San Juan Basin in Colorado and New Mexico that the leases envision sales of the "raw" (i.e., unprocessed) gas at the well, even if no one buys gas there rather than the separate methane and liquids sales that are the way that Williams actually sells its gas downstream from processing plants. In Defendants Response in Opposition to Plaintiffs' Motion for Class Certification, Abraham v. WPX Energy Production, LLC, Cause No. 12-CV-00917-JB-CG, at (D. N.M. Feb. 17, 2014), WPX is sponsoring an expert who argues that industry practice is to pay royalties at the well on raw, unprocessed gas without any payment for the liquids. This is how Williams has paid royalties, applying an index price for methane gas to all of the BTU-weighted gas without sharing any of the prices it received for the liquids in the gas stream. WPX calls this method a "keep whole" method, id. at 9, even though the method strips the higher value of the liquids and pays none of it to the royalty owners.

[188] RICHARD VIETOR, CONTRIVED COMPETITION 93-94, 96-98, 100-01 (1994).

[189] In the Matter of El Paso Natural Gas Company et al. Application for Certificates of Public Convenience and Necessity, 5 F.P.C. 115, 122 (1946)(discussing El Paso supply before build-out of San Juan Basin system as coming primarily from gas associated with oil production in Permian Basin contracts with Phillips Petroleum (from Panhandle and Hugoton fields as well as Permian Basin), Gulf, Shell, and Warren Petroleum).

When pipelines developed reserves on their own leases, as many did, there was no real sale at the wellhead. Pipelines simply took possession of the gas there. The pipeline arranged marketing to distant industrial and residential customers and those ratepaying customers picked up the costs of making gas marketable, a cost that was not borne directly by royalty owners and ultimately not by the pipelines either. In 1954, the Supreme Court interpreted the Natural Gas Act of 1938 to require the same regulatory treatment of gas interstate pipelines bought from independent producers for resale into interstate commerce, with Phillips Petroleum the producer at issue in the cases.[190]

Regulated prices went through various permutations, and were replaced with a series of statutory maximum lawful price categories in the Natural Gas Policy Act of 1978. The price categories under the Act were phased out beginning in the mid-1980s and the Federal Energy Regulatory Commission pushed to make pipelines open up their space to competing shippers. Competition for gas sales then developed at market "hubs" downstream from processing plants. Most marketing moved downstream to these wells. It is a sign that the location of the best price reasonably available generally moved to downstream hubs that this is where industry price services report "index" prices today.

Although pipelines in theory could make gas pipeline-ready at the well, it would be hopelessly inefficient to try to perform on an individual-well basis such processes as treatment, the processing that divides the methane from the liquids stream, and the fractionation that separates liquids from each other. Pipelines move these processes downstream because they gain significant economies of scale and it is efficient to do so. They therefore perform the main tasks of making gas marketable downstream of the wells, often far downstream, at processing and fractionation plants.

As the price of gas services became unbundled from its regulatory structures, pipelines naturally tried to shift a share of the newly unregulated costs onto royalty owners, as it is in their economic interest to do. Presumably this is the sense in which the West Virginia Supreme Court interprets this history as one of

[190] Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954).

lessees trying to escape their responsibility by labeling field service costs "post-production" expenses.[191]

Securing a market – getting the market connection and finding the best price reasonable possible – are duties whose costs pipeline customers bore under the old regulated structure. That lessees perform these services is one reason why they get the great majority of the revenue stream. When pipelines claim that they can impose a share of field costs on the royalty owners (rather than try to recover the costs from downstream customers), they are seeking a different position than during the regulated era. And when they claim that the royalty owner, who already has assigned the lessee the great majority of the revenue stream in order to receive revenue from a marketable product sold at the best price possible in return, they are trying reduce royalty payments via a cost that pipeline customers in end markets traditionally bore.

Some Leases Will Expressly Allocate Deductions. Some newer leases solve this dispute by addressing deductions specifically, as do a smaller number of old leases. In areas like the new shale gas plays in which lessors have had significant power, leases or lease addendums may bar all deductions. In areas where demand is not as strong, the lessee may be able to impose more favorable terms, at least, unless the applicable Legislature imposes marketability costs on the lessee as a matter of law. But if lessees become too successful at imposing cost deductions on royalty owners, they will encourage states to protect royalty owners legislatively.

E. THE QUESTION OF ACTUAL COST: A NEW DISPUTE?

One important goal, even for courts that do allow all deductions, should be to preserve the integrity of the lessor/lessee relationship and not let lessees charge a higher share of their costs than justified by any actual, reasonable costs they actually incur. This issue is discussed here and again in Chapter Nine.

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[191] Wellman v. Energy Res., Inc., 557 S.E.2d 254, 264 (W. Va. 2001)(discussing the expense of treating or altering gas to make it marketable, the court claimed that it was "[t]o escape the rule that the lessee must pay the costs of discovery and production [that] these expenses have been referred to as 'post-production expenses.'").

A recent, potentially significant decision by the New Mexico Supreme Court, ConocoPhillips v. Lyons,[192] raises the possibility of a new issue becoming significant, an issue that would best be handled in a separate, clear new implied duty on costs as discussed in Chapter Nine. The duty should be launched only after a more detailed and thoughtful discussion than the off-the-cuff holding of the New Mexico court.

The Lyons issue arose in a battle between ConocoPhillips and the State of New Mexico over the meaning of certain State of New Mexico form leases. One issue was whether, even if ConocoPhillips can take deductions, it only can charge the royalty account the actual and reasonable cost of its services.[193] Conoco argued that it only has to charge reasonable costs, but without regard to its actual cost (and, therefore, that it can deduct more than its costs). The State disagreed. It claimed that even if some costs of making natural gas marketable are deductible under its form lease (which the State denied), Conoco should be limited to the actual, reasonable cost of those services.

The State's position drew on the basic structure of the traditional lease. The lease gives the lessee the duty of doing the best job on behalf of the common venture. The New Mexico Supreme Court has long held that the lessee must act for the lessor as well as itself.[194] It is for the lessee to find, develop, produce, and market oil and natural gas. The lessor generally does not contribute to the cost of this process. The lessee is supposed to make its money on its share of production, not by taking added profits from the lessor. So it should not be expanding its agreed share of revenues by adding profits beyond the set royalty in the lease.

Unfortunately, the court dealt with the cost question as an incidental issue in four short paragraphs at the end of its decision.

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[192] 299 P.3d 844 (N.M. 2012).

[193] Id. at 860-61.

[194] In Libby v. De Baca, 179 P.2d 263 (N.M. 1947), the court held that the lessee's duty continues beyond doing the minimum to develop a property. In addition, he has to consider both sides' interests in marketing: "He must proceed with reasonable diligence as viewed from the standpoint of a reasonably prudent operator, having in mind his own interest as well as that of the lessor, to market the product." Id. at 265.

It spent no time on the purpose of the lease, the role of cost deductions, precedent from other jurisdictions, or the views of commentators. And the cost record in Lyons was wholly undeveloped. The decision recites no evidence about ConocoPhillips' costs or charges, or those of other companies, including whether ConocoPhillips' affiliate costs differ from the costs of other companies. Ultimately, the court held that it would not treat these affiliate charges any differently from third-party charges, and that the only limitation on the costs allowed under certain State leases is their reasonableness.[195]

In cases not discussed by the New Mexico Supreme Court, oilfield courts have long treated affiliate costs differently than costs charged between strangers, and prevented lessees from inflating the costs they deduct above their actual costs, just as they do not let lessees pay royalties on less than the price they receive.[196] In many cases, actual costs have not been at issue because both sides assumed that a lessee could not bill for costs never incurred. But that deducted costs have to be real – actually incurred – seems common sense. In West Virginia, for example, the Supreme Court expressly requires that costs deducted from the royalty interest be "actually incurred" as well as "reasonable."[197]

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[195] Certain aspects of this Lyons holding are discussed in more detail in Chapter Nine, Section C.

[196] Samples of the treatment of affiliate issues are discussed in notes 30-33, 40-42 & accompanying text supra. The author has previously discussed actual cost and affiliate issues for equity investments in John Burritt McArthur, A Twelve-Step Program for Copas to Strengthen Oil and Gas Accounting Protections, 49 S.M.U. L. Rev. 1447, §§ II.A-C (1996), and the need for allowed costs and for benefits in the lease relationship to be on an equal, mutual footing in John Burritt McArthur, The Mutual Benefit Implied Covenant for Oil and Gas Royalty Owners, 41 N.M. L. Rev. 795 (2001). Chapter Nine discusses in more detail the reasons why a limitation to actual costs is most consistent with the nature and purpose of the oil and gas lease.

[197] Estate of Tawney v. Columbia Natural Res., LLC, 633 S.E.2d 22, 27 n.5 (W. Va. 2006). Most economists will agree that a "market" is a place where willing buyers and sellers engage in independent, arm's-length negotiations. Affiliate transactions do not meet this test. Scrutiny of the actual formation of affiliate contracts not infrequently shows that the same person was on both sides of the "transaction," or that one person dictated the substance of the agreement pursuant to a larger single corporate policy.

Careful cost scrutiny is important because, as the Oklahoma Supreme Court has noted, in royalty disputes "it is in the producer's best interest to maximize the costs and expenses [at least, those billed to the royalty owner]," so "the courts must carefully scrutinize the figures to determine the correct amount."[198]

The suggestion that courts might jettison an actual-cost requirement is particularly unfortunate because large lessees often can achieve much lower costs than market averages because they have signed up so many lessors and therefore gain the cost economies of large volumes. Large companies rightly tout their expertise and management abilities, but they achieve many of their economies of scale precisely because they gather and process such large volumes of gas from their royalty owners' land. This is a benefit produced by the lessors' gas. There is no reason that the lessees should not have to share this benefit with their lessors.

Lyons almost certainly is not the last word. The court's holding that lessees can only deduct reasonable costs is in tension

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[198] Howell v. Texaco, 112 P.3d 1154, 1158-60 (Okla. 2004). Even an earlier New Mexico court of appeals decision that was hostile to the idea that lessees might deduct costs away from the well, Creson v. Amoco, 10 P.3d 853 (N.M. Ct. App. 2000), implicitly and rightly assumed that lessors would have a right to challenge costs that were not actually incurred. See id. at 856 (noting in discussion of valuation method that the plaintiffs "do not claim that the cost adjustments Defendants used were inflated or did not reflect the actual costs incurred to enhance the value of the gas in the marketplace"). Another example of the ginger treatment often accorded affiliate transactions is the federal government's treatment of affiliated processing charges. While the Secretary of the Interior has limited its marketable-condition rule by allowing lessees to charge for processing, it restricts the amounts that affiliates can deduct because of concerns over the lack of market pressure in affiliate transactions. The government's broad definition of "affiliate" is at 30 C.F.R. § 1206.151 (2010). The government requires use of the gross proceeds received by any affiliated marketing entity if the gas is transferred to an affiliate for sale. Id. §§ 1206.152(b), 1206.153(b)(less applicable transportation and other [processing] allowances for processed gas); if the gas is not sold at some point in the chain in an arm's-length transaction, regulations provide other ways of determining the gross proceeds of sale, id. §§ 1206.152(c), 1206.153(c). Not only do the regulations cap the amount of processing deductions, but they distinguish arm's-length and non-arm's-length transportation contracts, id. § 1206.157. They similarly differentiate between processing allowances in arm's-length contracts and affiliate contracts. Id. § 1206.159.

with the decision that costs need not be actual. Could it be reasonable to deduct costs the lessee does not incur? Can lessees charge higher costs than they pay by not sharing discounts or delay payments they may receive on third-party services? If they realize economies of scale that push their costs below competitors' costs, do they have to share that economic benefit with royalty owners? All these issues remain to be decided even in New Mexico.

Chapter Nine recommends that courts adopt an implied covenant that spells out that lessees, when they are allowed to take deductions, cannot deduct more than their actual, reasonable costs. It explores the reasons for such an approach in more detail. The suggestion of a contrary rule in Lyons does not consider the purpose of the lease, the past practice of courts in allowing netback deductions only for costs incurred, or the need to preserve the lessee's incentive to act fairly in the joint interests of lessee and lessor. Nor does it consider the raft of affiliate cases that have refused to accept the surface accounting of related companies, with all their potential for mismatched incentives and mischief in setting costs and prices.

The duty to market is likely to remain the most contested covenant for some time to come, at least, unless courts begin putting more teeth into a duty to restore that becomes a bigger factor in environmental litigation. The core applications for connecting to markets and getting the best price reasonably possible should not be controversial, except perhaps under market-value leases in Texas. The major producing states have staked their positions on the marketable-condition rule. Legislative action may continue to extend protection to royalty owners in states whose courts refuse to place these costs fully on the lessee but, as with the Vela market value/proceeds issue, the marketable-condition rule is likely to present issues that continue to divide large parts of the oilpatch and spawn more litigation.