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OKLAHOMA

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This year, the Oklahoma courts answered who is liable for royalty payments under the PRSA, how a tenant may prove ouster of a cotenant in an adverse possession proceeding, how to sever a joint tenancy involving more than two parties, and how can a court analyze a will which includes a complete restraint on alienation.

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In the federal courts, the Eastern District of Oklahoma and the Tenth Circuit certified class actions related to underpayment of royalties and the breach of the implied duty of marketability, while the Tenth Circuit also discussed the elements of trespass relate to an expired right-of-way on Native American lands.

I. State Cases

A. TexasFile, LLC v Boevers, 2019 OK CIV APP 20, 437 P.3d 211[1]

TexasFile involved whether or not the Oklahoma Open Records Act allows a county clerk to provide electronic access to county land records.

TexasFile provides its customers with access to county land records via the internet. In May of 2016, TexasFile requested a "complete electronic copy of all the Kingfisher County land records that are currently available in electronic format" pursuant to the Oklahoma Open Records Act, specifically all records available on the Oklahoma County Records website.[2] TexasFile did not request the tract indices. The Kingfisher County clerk did not respond to this request.

In January of 2017, TexasFile made a second request, and acknowledged Oklahoma, Blaine, and Logan counties had recently complied with such requests.[3]

In May of 2017, Jeannie Boevers, Kingfisher County Clerk, denied the request, explaining the request:

> does not fall within the provisions of the Act as interpreted by the Oklahoma Supreme County in *County Records, Inc. v Armstrong*.[[4]] Neither the tract index nor the date (land records) inextricably linked to the computer software can be provided for resale. Commercial use or dissemination of these records if prohibited. You are welcome to come to my office like all other persons to inspect and copy documents.[5]

In response, TexasFile filed a declaratory judgment and mandamus action against Boevers asking the trial court to determine it was entitled to an electronic copy of the Kingfisher County land records maintained by the county clerk. In response, Boevers and Lori Fulks, the Garvin County Clerk

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1. TexasFile, LLC v. Boevers, 2019 OK CIV APP 20, 437 P.3d 211.
2. *Id.* ¶ 3.
3. *Id.* ¶ 4.
4. 2012 OK 60, 299 P.3d 865.
5. *Id.* ¶ 5.

(the "County Clerks"), sought a uniform judicial determination of whether the Open Records Act requires the County Clerks to hand over their electronic files so TexasFile may resell those records.[6]

In October of 2017, TexasFile filed a motion for summary judgment arguing Boevers had a statutory duty to maintain land records and provide electronic copies of those records upon request. TexasFile argued section 386, title 19 requires Boevers make the public land records available for viewing and copying. TexasFile conceded the Open Records Act prohibits the copying of the tract index for resale, but the index was not part of the request.[7]

In February of 2018, the trial court denied TexasFile's summary judgment and granted summary judgment for the County Clerks. The Court of Civil Appeals affirmed.

The court cited the Oklahoma Supreme Court's decision in *County Records, Inc. v Armstrong* which pointed out "access to instruments of record shall be for immediate and lawful abstracting purposes only. The sale of the instruments of record for profit to the public either on the internet or any other such forum by any company holding a permit to build an abstract plant is prohibited."[8] The legislature intended production of the tract index and land records would not be limited unless the request is for the sale of that information. Therefore, the Open Records Act "prohibits a county clerk form providing any documents and data from the land records for the intentional sale of that information."[9]

Based on the Oklahoma Supreme Court's decision in *County Records, Inc. v Armstrong*, the Court of Civil Appeals ruled the trial court did not err in denying TexasFile's request for the land records.

B. Hodge v Wright, 2019 OK CIV APP 10[10]

Hodge discussed the elements of adverse possession in Oklahoma and how a cotenant can show ouster of another cotenant. The Court of Civil Appeals reversed the trial court's ruling, finding Hodge had shown an ouster of her cotenants and proven title by adverse possession.

In her 2014 petition, Yvonne Hodge sought to quiet title to a quarter section in Noble County, asserting she owned the property individually and

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6. *Id.* ¶ 7.
7. *Id.* ¶ 8-10.
8. *Id.* ¶ 20 (quoting 2012 OK 60, 299 P.3d 865 (citing OKLA. STAT. ANN. tit.1, §§ 227.10 through 227.30 (2019))).
9. *Id.*
10. Hodge v. Wright, 2019 OK CIV APP 10, 435 P.3d 126.

as the personal representative of the estate of her husband, Leroy Hodge.[11] According to Hodge, Mary Roney owned the property upon her death in 1935, and Mary's son, Charles Roney, possessed the land until he died in 1980. When Mary Roney's estate was probated in 1956, her heirs were unknown except for Charles, and starting in 1971, Glen Hodge, Yvonne's father-in-law, leased the land from Charles Roney. After Charles died in 1980, his estate was distributed to his wife, and when she died, her estate was distributed to her two brothers, Ruben Reimer and Sylvester Reimer, in 1982. Hodge alleged Sylvester Reimer died in 1982 and his estate was never probated in Oklahoma. From 1980 to 1993, Glen Hodge and his son, Leroy, leased the property from the Charles Roney Estate, his heirs, or the estates of his heirs.[12]

Also, Hodge alleged Ruben Reimer's share was distributed to his children in 1993 and Leroy Hodge then bought their interests. Therefore, as of 1993, Hodge owned an undivided 1/8 interest in the property. Hodge claimed she and her husband Leroy have occupied the property without paying rent to another party since 1993, and they have paid taxes, built fences and ponds, and cleared trees, resulting in Hodge acquiring full title to the property by adverse possession.[13]

Hodge alleged the unknown heirs of Sylvester Reimer were one group of defendants, who owned a 1/8 surface interest, and the heirs of the seven half siblings of Charles Roney were the remaining defendants. Hodge asserted Charles Roney held the property adversely to the interests of the half siblings from 1935 (Mary Roney's death) to 1980 (Charles Roney's death).[14]

In an amended petition, Hodge named all potential heirs of Mary Roney's children as defendants, and alleged she satisfied the requirements for adverse possession for more than fifteen years.[15]

Two of the defendants, Sally Stewart and Christy Allyce Lane, requested time to assert an interest in the property. Stewart counterclaimed and asked the court to determine her interest in the property and quiet that interest to her.[16]

The trial court entered default judgment in favor of Hodge against 20 defendants who had failed to answer, as well as several other defendants. However, the trial court denied Hodge's motion for summary judgment

11. *Id.* ¶ 2.
12. *Id.*
13. *Id.* ¶ 3.
14. *Id.*
15. *Id.* ¶ 4.
16. *Id.* ¶ 5.

against Stewart. The trial court also denied Stewart's counterclaim for quiet title because she did not present any evidence establishing an interest in the property, but the court denied Hodge showed she was entitled to the property by adverse possession because she was a cotenant, and therefore she must prove an ouster of the other cotenants in the property.[17] The trial court ruled Hodge must go through a partition proceeding. The Court of Civil Appeals reversed the trial court's finding and ruled Hodge had proven title through adverse possession.

The Court of Civil Appeals set out the elements of adverse possession: "to establish adverse possession, the claimant must show that possession was hostile, under a claim of right or color of title, actual, open, notorious, exclusive, and continuous for the statutory period of fifteen years."[18]

The appellate court noted it was undisputed that Hodge met these elements. The trial court only denied Hodge's claim because it ruled the case must be analyzed as between cotenants, where the general rule is "the tenant in possession is deemed to be holding said possession for himself and for the tenant who is not in possession. The possession of the one is constructively possession for the other. Thus it is that the mere holding of possession, by one tenant, can never be considered adverse to his cotenant until there is some act or conduct on his part which must give the other cotenant notice that his title has bene repudiated or is disputed by the one in possession, or there must be such conduct by the tenant in possession as reasonably would put the other tenant on inquiry."[19]

Oklahoma caselaw states more than mere possession is required, but the caselaw is unclear as to what acts are sufficient to prove ouster of a cotenant. In *Westheimer v Neustadt*, the court held that collecting rents, paying taxes, and representing to the lessee that he owned the property was insufficient to operate as an ouster.[20]

However, in *Wirick v Nance*, the Oklahoma Supreme Court held a cotenant proved title by adverse possession by showing possession was open, visible, continuous and exclusive to the point that his title was not in subordination to any other claimants of title.[21] This case suggested a party could prove ouster of a cotenant with the same evidence one might use to prove adverse possession against a stranger. The appellate court cited two

17. *Id.* ¶ 6-7.
18. *Id.* ¶ 8 (citing Akin v. Castleberry, 2012 OK 79, ¶11, 286 P.3d 638).
19. Preston v. Preston, 1949 OK 59, ¶20, 207 P.2d 313.
20. Westheimer v. Neustadt, 1961 OK 121, 362 P.2d 110, 111.
21. Wirick v. Nance, 1936 OK 98, 62 P.2d 997.

additional cases in support of the idea that a cotenant could prove ouster with similar facts to Hodge's.[22]

The appellate court noted no one ever attempted to assert any claim to the property until Hodge filed her quiet title action, and even then, no one presented any contrary evidence. Also, the court pointed out a partition proceeding would be futile because there was no indication that there is anybody else with whom to partition the property. "The purpose of a quiet title action is to determine who is the real owner of property and put to rest adverse claims."[23]

The trial court did not determine the real owner of the property, and the appellate court ruled this was an error. Based on the undisputed evidence, Hodge proved she owned the property by adverse possession, so the Court of Civil Appeals remanded to the lower court with directions to quiet title to the property in Hodge's name.

C. Goodson v McCrory, 2018 OK CIV APP 59, 426 P.3d 636.[24]

Goodson detailed the requirements for establishing a joint tenancy in title, and how one party can sever a joint tenancy.

In 2001, Kaci Susanne Goodson, Patricia Lynn Farquhar, Mary Beth Guzman, and Sherry Doris McCrory were granted property in Tulsa County "in equal shares in their individual capacities, as joint tenants, and not as tenants in common, on the death of" the grantor. In 2011, the grantor passed away.[25]

Goodson filed the petition in this case in 2017 for quiet title, declaratory relief, and/or a determination of her rights in the property. Goodson contested the validity of a 2002 deed wherein Goodson, Farquhar, and Guzman purportedly conveyed their interest in the property to McCrory. Goodson contested the validity of the 2002 deed as to her interest only and not the interests of Farquhar or Guzman.[26]

Goodson then filed a motion for summary judgment claiming she did not sign the 2002 deed. Her typed name and written signature on the deed were misspelled (Goodman instead of Goodson), and McCrory agreed it was not Goodson's signature on the 2002 deed. Goodson requested an order be

22. Preston & Beaver v. Wilson, 1926 OK 267, 245 P. 34, 117 Okl. 68.
23. *Hodge*, 2019 OK CIV APP ¶12.
24. *Goodson v. McCrory*, 2018 OK CIV APP 59, 426 P.3d 636.
25. *Id.* ¶1.
26. *Id.* ¶2.

entered determining McCrory and Goodson own the property as joint tenants.[27]

McCrory did not respond to Goodson's motion for summary judgment. Therefore, the trial court ruled the property vested in Goodson and McCrory as joint tenants with the right of survivorship.[28] McCrory then filed a motion for new trial contesting the trial court's legal conclusion, although without disputing the underlying facts. McCrory argued she should own 75% of the property and Goodson should own the remaining 25% of the property as tenants in common.[29] The Court of Civil Appeals reversed and remanded the case, disagreeing with both parties.

Fist, the court cited the Oklahoma Supreme Court to explain how a joint tenancy is created: "A joint tenancy is created only when unities of time, title, interest, and possession are present…alteration of any required unity will destroy the joint tenancy."[30] Therefore, McCrory argued the 2002 deed destroyed the joint tenancy created by the 2001 deed.[31]

In fact, the *McGinnis* court explained "if A and B hold as joint tenants and B, with or without the permission of A, conveys to C, the joint tenancy is destroyed because unity of interest is eliminated; the result is A and C hold as tenants in common," one-half each.[32]

However, only two of the four joint tenants conveyed their interests in the 2002 deed. When at least two joint tenants do not convey their interests, "a conveyance by other joint tenants does not destroy the continuance of the joint tenancy among the remaining joint tenants, though it does destroy the joint tenancy as to the conveyed interests."[33]

"If A, B and C are joint tenants and C conveys to D, A and B continue as joint tenants in an undivided two-thirds of the whole estate and D has" the remaining one-third as a tenant in common with A and B.[34]

Therefore, the appellate court explained the 2002 deed severed the joint tenancy as to the shares of Farquhar and Guzman and transferred their interests to McCrory outright. This made McCrory a tenant in common as to an undivided 1/2 interest in the property, being the interest acquired from

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27. *Id*. ¶3.
28. *Id*. ¶4.
29. *Id*. ¶ 5.
30. *See* Am. Nat. Bank & Tr. Co. of Shawnee v. McGinnis, 1977 OK 47, ¶3, 571 P.2d 1198.
31. *Goodson*, 2018 OK CIV APP ¶ 5, 426 P.3d at 638.
32. *Id*. ¶ 9.
33. *Id*. ¶ 10.
34. *Id*.

Farquhar and Guzman in the 2002 deed. However, Goodson and McCrory still own the remaining 1/2 interest in the property as joint tenants because they never severed their interests.[35] The appellate court reversed and remanded the case, instructing the trial court to grant summary judgment to Goodson in a manner consistent with its decision.

D. Tim Abraham v Palm Operating, LLC and Pacer Energy Marketing, LLC, 2019 OK CIV APP 46, 447 P.3d 486.[36]

Palm Operating discussed which party is liable for paying production from a well under the Production Revenue Standards Act – an operator or a first purchaser of production.

In February of 2016, Tim Abraham alleged he owned a 1/32 carried working interest in the Elias-Kerns No. 2 well. Palm Operating, LLC had been the operator of the well since May of 2009, and Pacer Energy Marketing had been the first purchaser of production from the well in January of 2010.[37]

Abraham claimed he demanded payment of proceeds from Palm and Pacer but neither party paid him. Abraham alleged both defendants owed him interest on the unpaid proceeds in violation of the Production Revenue Standards Act ("PRSA"), actual and punitive damages for conversion, and restitution.[38]

Pacer responded that it began purchasing crude oil from the well in December of 2010 and denied Abraham's allegation. Pacer alleged any failure to make payment was because of Abraham's negligence or Palm's (operator) error.[39] In January of 2018, the trial court granted summary judgment in favor of Abraham, and Pacer appealed.

The parties agreed that Palm directed Pacer to pay Palm the working interest proceeds for the production Pacer took from the well. Abraham claimed Pacer owed him interest based title 52, section §570.10(E)(1):

> "Except as provided in paragraph 2 of this subsection, a first purchaser who fails to remit proceeds from the sale of oil or gas production to owners legally entitled thereto within the time limitation set forth in paragraph 1 of subsection B of this section shall be liable to such owners for interest as provided in subsection D of this section on that portion of the proceeds not timely paid.

35. *Id.* ¶ 13.
36. Tim Abraham v. Palm Operating, LLC, 2019 OK CIV APP 46, 447 P.3d 486.
37. *Id.* ¶ 2.
38. *Id.*
39. *Id.* ¶ 3.

> When two or more persons fail to remit within such time limitations, liability for such interest shall be shared by those persons holding the proceeds in proportion to the time each person held such proceeds."[40]

Pacer responded it had no liability for the proceeds after it paid them to Palm, the operator, pursuant to 52 O.S. 2011 §570.10(C)(1):

> "A first purchaser that pays or causes to be paid proceeds from production to the producing owner of such production or, at the direction of the producing owners, pays or causes to be paid royalty proceeds from production to the royalty interest owners legally entitled thereto, or the operator of the well, shall not thereafter be liable for such proceeds so paid and shall have thereby discharged its duty to pay those proceeds on such production."[41]

Abraham argued section 570.10(C)(1) did not apply because Palm was not the producing owner of the production attributable to Abraham's interest – Abraham owned that production himself. However, the appellate court noted if a first purchaser is required to directly pay each working interest owner, then parts of the PRSA would be superfluous.[42]

For example, section 570.4 provides an operator acts in a purely ministerial capacity when it receives and disburses proceeds from producing owners; section 570.5 details how working interest owners may designate a party other than the operator to perform royalty accounting and remittance functions; and section 570.10(C)(1) defines producing owner as "an owner entitled to produce who during a given month produces oil or gas for its own account or the account of subsequently created interests as they burden his interest." Abraham's carried working interest specifically provided he would have no control over the leased premises or the operations.[43]

Since Pacer paid its proceeds of production to Palm, the operator, the appellate court ruled Pacer had discharged its liability under section 570.10(C)(1), and Abraham had no claim against Pacer. Therefore, the appellate court reversed the trial court's judgment in favor of Abraham.

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40. *Id.* ¶ 7 (quoting OKLA. STAT. ANN. tit. 52, § 570.10(E)(1) (2019)).
41. *Id.*
42. *Id.* ¶ 8.
43. *Id.*

E. Estate of Stolba, 2019 OK CIV APP 43, 446 P.3d 528.[44]

The Oklahoma Court of Civil Appeals examined a will to determine what happens when a court is unable to figure out the testator's intent.

Margaret J. Stolba's Will was admitted to probate in December of 2012 and it included the following provision:[45]

> "The home stead will remain in trust, Not to be sold or split. All four of you have got to get along. Work it out, you should be able to have fun doing things there. Everyone should behave themselves."

The will also appointed co-personal representatives and gave them the power to sell any part of the estate without court approval, an apparent contradiction to the excerpt above preventing the homestead from being "sold or split."

Probate was still open in January of 2017, and Mark S. Stolba, one of the decedent's sons, filed an application to distribute the homestead to the decedent's four children equally, in accordance with intestate rules of succession. Mark alleged either the trust failed for lack of required elements, or the homestead provision quoted above created an unenforceable restriction on alienation.[46]

In October of 2017, the district court distributed the homestead per the rules of intestacy. The estate's personal representative, Daniel Lowther, filed a motion for a new trial. The court denied that motion and Lowther appealed.

The appellate court explained the main question is whether the "trust" provision represents an "unenforceable perpetual ban on the alienation of real property."[47] After dispensing with Lowther's jurisdictional arguments, the court explained how the homestead provision apparently violated the first part of title 60, section 175.47 (Suspension of absolute power of alienation – period of suspension):

> "A. Except as otherwise provided in subsection B of this section, the absolute power of alienation of real and personal property, or either of them, shall not be suspended by any limitations or conditions whatever for a longer period than during the

44. Estate of Stolba, 2019 OK CIV APP 43, 446 P.3d 528.
45. *Id.* ¶ 2.
46. *Id.*
47. *Id.* ¶ 6.

> continuance of a life or lives of the beneficiaries in being at the creation of the estate and twenty-one (21) years thereafter."[48]

The court ruled not allowing the homestead to be sold or split violated section 175.47 because it had no time limitation.[49] However, Lowther argued the second part of section 175.47 should apply: "The absolute power of alienation is not suspended if there is any person in being who, alone or in combination with one or more others, has the power to sell, exchange, or otherwise convey the real or personal property."[50]

Lowther argued even though the homestead is not to be sold, the will also gave the personal representatives the power to sell any part of the estate. In response, the court ruled the will's specific restraint on alienation would control over the personal representatives' general power of sale.[51]

Next, Lowther argued the court should rewrite the homestead clause of the will so it complies with section 175.47 pursuant to section 75 ("Reformation of interests violating rule against perpetuities")[52] and section 77 ("Reformation of offending instruments").[53] However, the court declined to rewrite the will, holding this case involved a restraint on alienation, not a perpetuity.[54]

"Restraints upon alienation where there are no provisions for forfeiture or reversion are 'disabling restraints' and void."[55] Sections 75 and 77 apply when an interest may vest too late, but they do not apply to restraints on alienation.[56] A court cannot just shorten the vesting period to affect the testator's wishes; if the testator intends an absolute restriction on alienation, no one can reform that restriction and maintain the testator's intent.

In establishing its role in analyzing a will, the court cited *In re Prather's Estate*: "The rule of construction that the intent of the testator must be carried out if possible does not authorize courts to make a new will to conform to what they may think the testator intended. The intent of the testator must be ascertained from the will as it stands."[57]

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48. *Id.* ¶ 13 (quoting OKLA. STAT. ANN. tit. 60, § 175.47 (2019)).
49. *Id.* ¶ 14.
50. *Id.*
51. *Id.* ¶ 16.
52. OKLA. STAT. ANN. tit. 60, § 75 (2019).
53. OKLA. STAT. ANN. tit. 60, § 77 (2019).
54. Estate of Stolba, 2019 OK CIV APP ¶¶ 17-18, 446 P.3d at 532.
55. *Id.* ¶ 19 (quoting Shields v. Moffit, 1984 OK 42, ¶26, 683 P.2d 530, 534.)
56. *Id.* ¶ 20.
57. *Id.* ¶ 22 (citing 1974 OK CIV APP 24, 527 P.2d 211, 215 n.4).

The court pointed out even if the testator intended his homestead to be sold after a certain time period, she does not specify how that property would be distributed at that time, and the will did not include a residual beneficiary. The court held even if the restraint on alienation could be reformed, no court could rewrite the will without guessing at the testator's intent.[58] Therefore, the court affirmed the district court and distributed the homestead property per the rules of intestacy.

II. Federal Cases

A. Rhea v Apache Corporation, No. CIV-14-0433-JH, 2019 WL 1548909 (E.D. Okla. Feb. 2, 2019).[59]

The Eastern District of Oklahoma certified a class action in a case concerning underpayment of royalties and whether or not royalty owner should be paid for natural gas liquids.

Bigie Lee Rhea filed a class action on behalf of himself and other royalty owners with interests in Oklahoma wells operated by Apache Corporation. Rhea alleged Apache underpaid royalties by failing to obtain the best price available for the gas it sold and produced.[60] Specifically, Rhea claims:

> [Apache] breached its implied duty to market gas and obtain the best price available by (1) marketing the gas under a 'keep whole' contract which did not capture the value of the natural gas liquids ('NGLs') included in the production, and (2) paying excessive fees to the midstream processor even after the keep whole contract was modified to capture the value of the NGL's [sic].[61]

Additionally, Rhea alleged Apache failed to pay royalty on fuel gas used to perform midstream services, despite contrary language in most of the affected leases.[62] Rhea made claims for breach of contract, tortious breach of contract, fraud (actual and constructive), deceit, and for an accounting.[63]

On January 1, 1998, Apache entered into two contracts for gas sales from Oklahoma wells (the "1998 Contracts").[64] A Gathering and Compression Agreement covered gas wells connected to various pipeline systems owned

58. *Id.* ¶ 23.
59. Rhea v. Apache Corp., 2019 WL 1548909 (E.D. Okla. Feb. 15, 2019).
60. *Id.* at *1.
61. *Id.*
62. *Id.*
63. *Id.*
64. *Id.*

or operated by Transok, Inc.[65] A Dedicated Interruptible Service Agreement covered gas wells connected to two more pipeline systems owned by Transok.[66] The 1998 Contracts, which were due to expire at the end of 2012:

> [D]edicated all future wells drilled or recompleted within five miles of one of the pipeline systems to the relevant agreement, required Transok to deliver "thermally equivalent" volumes of gas for the account of defendant after NGLs and other substances were removed during processing. . . and reserved the right to defendant to "process all of its gas and retain all of the oil and liquid hydrocarbons."[67]

The 1998 Contracts are described as "keep-whole" contracts where an operator allows the midstream company to process the gas to remove the NGLs and keep those liquids for its own use or sale.[68] The midstream company keeps the operator "whole" by delivering a "thermally equivalent" amount of residue gas to the operator after processing. Apache paid royalties based on the residue gas.[69]

Rhea alleged that under this type of contract, a royalty owner is not paid on the best price available for the gas sold by its operator.[70] The value of the NGLs removed exceeds the value of the residue gas returned to the operator. The difference between these values is called the "NGL uplift."[71] Therefore, Rhea claimed Apache paid royalties based on a lower price than if the NGLs had not been removed from the gas – Rhea did not receive value for the NGLs.[72] Apache argued "the contracts were reasonable based on the circumstances existing at the time."[73]

On July 1, 2011, Apache entered into a Gas Gathering and Processing Agreement (the "2011 Contract") with Enogex Gathering and Processing.[74] Under this contract, Apache received value for the NGLs and paid royalties based on that value, distinguishing this contract from the 1998 Contracts.[75]

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65. *Id.*
66. *Id*.
67. *Id*.
68. *Id.*
69. *Id.* at *2.
70. *Id.*
71. *Id*.
72. *Id.*
73. *Id*.
74. *Id*.
75. *Id.*

However, Rhea alleged the 2011 Contract included unreasonable fees which "improperly diminished the amount of royalties paid to the class."[76]

Rhea presented a lease chart (5,679 total leases) to the court and claimed, "none of the leases negate the duty to pay the best price available for the gas."[77] Also, Rhea argued 4,159 leases include express language that royalty will be paid on all constituents of gas produced, 538 leases expressly allow for the deduction of various post-production costs, and 4,824 of the leases mandate Apache pay royalty on "fuel gas," gas used to power gathering, compressing, and processing equipment off the lease premises.[78] Rhea claims Apache never paid royalties on the fuel gas.[79]

Rhea represented a class of:

> All non-excluded persons or entities with royalty interests in wells with a Btu content of 1050 or higher where Apache Corporation marketed gas from the well pursuant to the terms of the January 1, 1998 contracts between Transok, Inc. and Apache Corporation and/or the July 1, 2011 contract between Enogex Gathering & Processing LLC and Apache Corporation on or after January 1, 2000.[80]

This class was meant to include only those parties whose gas contained NGLs at the time it was produced.[81]

To determine whether or not to certify the proposed class, the court set out the requirements to certify a class action under Rule 23 of the federal rules of civil procedure: numerosity, commonality, typicality and adequacy, and predominance and superiority.[82]

Numerosity – The plaintiff must show the "class is so numerous that joinder of all members is impracticable."[83] Given the number of wells, the court noted the class could include more than 5,000 persons, easily satisfying the numerosity requirement.[84]

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76. *Id*.
77. *Id*.
78. *Id.*
79. *Id*.
80. *Id.* at *3.
81. *Id.*
82. *Id*.
83. *Id.*
84. *Id*.

Commonality – Rhea needs to show there are "questions of law or fact common to the class." Determining this common question must "resolve an issue that is central to the validity of each one of the claims in one stroke."[85]

Rhea argued common questions included:

> (1) whether defendant owed a uniform duty to pay royalties on the best price available for the gas; (2) whether defendant used a uniform royalty payment methodology; (3) whether defendant's royalty payment methodology breached the duty to pay royalties on the best price available; (4) whether subclass leases contained an express lease clause that required the payment of royalty on fuel gas; (5) whether defendant breached the fuel gas clause; and (6) whether an elevated fee initially charged under the 2011 contract breached duties to the class.[86]

In response, Apache argued the commonality question in this type of case was answered in *Foster v. Apache Corp*.[87] In *Foster*, the plaintiff attempted to certify a class of more than 10,000 royalty owners in more than 1,200 wells.[88] However, that case involved gas sales under 30 different marketing arrangements with numerous purchasers.[89] The *Foster* court ruled the plaintiff failed to establish commonality because of variations in lease languages.[90]

The court distinguished this case from *Foster* because here Rhea claimed the leases had something in common: ***none*** of the leases included language negating Apache's duty to obtain the best price available for the gas.[91] The court determined this pointed towards a collective resolution. "[W]hether defendant had a uniform duty to pay royalties on the best price available, used a uniform royalty payment method to pay those royalties, and, in doing so, breached the duty to pay royalties on the best price available are all questions common to the proposed class."[92]

The court dismissed Apache's other arguments against commonality regarding fuel gas provisions in the leases and whether or not the processing

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85. *Id*.
86. *Id*.
87. 285 F.R.D. 632 (W.D. Okla. 2012).
88. *Rhea*, 2019 WL 1548909 at *3.
89. *Id.*
90. *Id.* at *4.
91. *Id*.
92. *Id*.

fee in the 2011 Contract was excessive.[93] However, the court did note part of the proceedings may not be appropriate for class-wide resolution: Apache's evidence that not all gas produced from the wells was processed to extract NGLs.[94] Therefore, the court found Rhea's proposed class of "persons with royalty interests in wells with a Btu content of 1050 or higher" as overly broad because it could include "rich gas" wells where NGLs were not removed. If NGLs were not removed, Rhea's claim for lost royalty would fail.[95]

However, the court ruled this meant only that it would modify the class instead of decertifying it altogether.[96] The court decided the class should be "only those wells whose gas was actually processed."[97]

Typicality and Adequacy – Apache argued Rhea's claims were not typical of the rest of the class. Apache noted Rhea's lease is a "market value at the wellhead lease" which has been "held to require royalties to be paid on the condition of the gas at the wellhead before processing."[98] However, the court pointed out this did not negate Rhea's argument "that the value of the gas at the wellhead would include the value of the NGLs contained therein."[99]

Also, Apache argued Rhea was paid differently than other class members because his lease prevented deductions for post-production costs.[100] But Apache acknowledged that prior to 2012, it did not distinguish between royalty owners whose leases allowed for such deductions and those that did not.[101] As a result, such costs were deducted from all class members, meaning Rhea was treated the same as the rest of the class despite any differences in lease language.[102]

Predominance and Superiority – Apache argued individual questions predominate the class because of the varying obligations and contracts typically involved in royalty underpayment cases.[103] In response, Rhea claimed this is not a typical royalty underpayment case. Rhea did not argue when the gas became marketable or whether or not the processing costs were reasonable; Rhea only requested "royalties to be paid on the value of the

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93. *Id.*
94. *Id.*
95. *Id.* at *5.
96. *Id.*
97. *Id*.
98. *Id*.
99. *Id*.
100. *Id.* at *6.
101. *Id.*
102. *Id*.
103. *Id.* at *7.

residue gas plus the value of the NGLs removed during the processing[.]"[104] This would be Rhea's best price available for the gas. He argued *Mittelstaedt v. Santa Fe Minerals, Inc.* would not apply to this case.[105]

However, the court noted that under the 1998 Contracts, "the value of the NGLs appears to have been transferred to the midstream processor as at least a partial fee for processing."[106] According to the court, *Mittelstaedt* would therefore apply to this case and "operators may charge post-production costs to the lessor if (1) once the gas is in a marketable condition; (2) the post-production costs enhanced the value of the gas; (3) the costs are reasonable; and (4) the costs increased royalties proportionally."[107] Usually, it is not possible to determine when gas becomes marketable on a class-wide basis, thus defeating class certification. However, this issue is not present because Rhea did not contest whether the gas was marketable at the wellhead.

Rhea does not challenge the fees charged by the midstream processor; Rhea only argued Apache should pay royalties on the NGL uplift.[108] The court ruled the NGL fee is the only fee at issue, and it is charged against all class members uniformly.[109] Therefore, the questions are "whether evaluation of the value of the NGLs as fees enhanced the value of the residue gas, whether that was a reasonable fee, and whether royalties increased in proportion to that value[.]"[110] The court determined these common questions predominated over any individual questions.[111]

Since Rhea met the four requirements for class certification, the court granted Rhea's motion for class certification as modified.

B. Naylor Farms, Inc. v Chaparral Energy, LLC, 923 F.3d 779 (10th Cir. 2019).[112]

Naylor is another federal case concerning a potential class action involving deduction of gas treatment costs. The Western District of Oklahoma granted plaintiff's motion to certify, and the Tenth Circuit affirmed.

104. *Id*.
105. *Id.* (relying on *Mittelstaedt v. Santa Fe Minerals*, 1998 OK 7, 954 P.2d 1203).
106. *Id*.
107. *Id*. (quoting *Mittelstaedt*, 1998 OK ¶¶ 23-30, 954 P.2d at 1209).
108. *Id.*
109. *Id.* at *8.
110. *Id.*
111. *Id*.
112. Naylor Farms, Inc. v. Chaparral Energy, LLC, 923 F.3d 779 (10th Cir. 2019).

Under Oklahoma law, Chaparral Energy, LLC and other lessees have an implied duty of marketability ("IDM"), or "a duty to provide a marketable production available to market."[113] Raw or unprocessed gas typically must undergo field processes such as gathering compressing, dehydrating, transporting, and producing (GCDTP services) to make it marketable.[114] Therefore, in Oklahoma, lessees usually bear the costs for those services.[115]

Invoking this duty, Naylor Farms, Inc. sued Chaparral and asserted claims for breach of contract, breach of fiduciary duty, fraud, unjust enrichment, and failure to produce in paying quantities.[116] Naylor claimed Chaparral improperly deducted GCDTP service costs from royalties paid to Naylor and other royalty owners.[117] Specifically, Naylor alleged Chaparral agreed to wellhead sales contracts with midstream processing companies wherein the midstream processor would acquire title/possession of the gas at or near the wellhead, but it would not pay Chaparral for the gas until after it had completed the GCDTP services.[118]

Once those services were completed, Naylor claimed "the midstream companies (1) take the gross proceeds they receive from the downstream sales; (2) deduct from those gross proceeds the costs and fees associated with performing the GCDTP services; and (3) pay Chaparral for the gas they previously acquired at the wellhead by giving Chaparral the resulting net proceeds."[119] Then Chaparral paid royalties based on the net proceeds received from the midstream processor, instead of paying royalties based on the gross proceeds the processor received from the downstream sales.[120] Naylor alleged that as a result, Chaparral forced the royalty owners to pay their share of the costs to transform the gas into a marketable product.[121]

Naylor argued class certification for it and other similarly situated royalty owners was appropriate "because (1) whether Chaparral breached the IDM is a common question, and (2) this and other common questions predominate over any individual ones."[122]

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113. *Id.* at 783.
114. *Id.*
115. *Id.*
116. *Id.*
117. *Id.*
118. *Id.*
119. *Id.*
120. *Id.*
121. *Id.* at 784.
122. *Id.*

Chaparral responded that an alleged breach of the IDM is not a common question because an answer would require reviewing the language in each separate lease and the gas produced from each separate well.[123] Also, Chaparral argued these specialized questions predominate over any common questions, and therefore, Naylor can not satisfy the requirements for class certification.[124] The district court disagreed with Chaparral and granted Naylor's motion to certify, ruling Naylor "identified at least one common question: whether Chaparral breached the IDM."[125]

On appeal, Chaparral made three arguments: (1) marketability is an individual question which necessarily predominates over any common questions; (2) distinctions in lease language give rise to individual questions which predominate over common ones; and (3) in the absence of evidence that Chaparral uses a uniform payment methodology, certification is inappropriate.[126]

1. Marketability

Naylor argued Chaparral breached the IDM by charging royalty owners their share of the costs for the GCDTP services. The court notes both parties agree the issue is when the gas becomes marketable. However, the parties disagree whether they need an individual analysis of each well to answer this issue.[127]

To decide whether class certification is appropriate, the court gave an overview of Oklahoma state law concerning when gas becomes marketable.[128] The court cited *Mittelstaedt* for gas marketability, but noted this case differs in that it deals with wellhead sales contracts.[129] Therefore, in the absence of Oklahoma Supreme Court ("OSC") authority on the specific issue at hand, the court indicated it must predict how the OSC would rule.[130] Of course, the court looked to *Mittelstaedt* to answer that question.[131]

In *Mittelstaedt*, the OSC explained the IDM forces lessees to provide a marketable product, and raw or unprocessed gas must usually undergo

123. *Id.*
124. *Id.*
125. *Id.*
126. *Id*.
127. *Id.*
128. *Id.*
129. *Id.*
130. *Id.* at 785.
131. *Id.*

GCDTP services to make it marketable.[132] Therefore, the OSC ruled if those services are necessary to make the gas marketable, then the lessee must bear the costs of those services. However, if the gas is in a marketable condition at the wellhead, and the lessee has those GCDTP services performed to increase the value of the gas, then the lessee may charge those costs to the royalty owner under certain circumstances.[133]

Now the court did note that *Mittelstaedt* did not define the term "marketable," and it did not identify the factors which determine when and where gas becomes marketable.[134] The court also pointed out the OSC has declined to answer those questions in a couple 2018 cases: *Whisenant v Strat Land Expl. Co.* and *Pummill v. Hancock*. However, the Oklahoma Court of Civil Appeals ("OCOCA") reached decisions in both cases.

In *Whisenant*, the OCOCA held the "answer to the marketability question will always turn, at least in part, on the quality of the gas at issue."[135] This means an individualized, fact-intensive review would be necessary to determine if a lessee breached the IDM.

However, in *Pummill*, the OCOCA ruled it may be possible to determine gas marketability without such a review.[136] In that case, the gas was not marketable at the wellhead and it was not sold until it was transferred into a pipeline. Therefore, the operator was "not in the wellhead market," but rather in the high-pressure pipeline market.[137] In that case, the OCOCA focused on when the gas was first capable of being sold into the market in which the operator chose to participate[138] – "gas becomes marketable when it's subject to an actual sale."[139] In *Naylor*, the plaintiffs argued Chaparral sold its gas at the pipeline, not at the wellhead, and therefore the gas had to undergo at least one GCDTP service to become marketable, or sold into the pipeline, making Chaparral more like the lessee in *Pummill*.[140]

It may appear that the OCOCA issued two opposite rulings in these cases. In *Whisenant*, the court held an individualized review may be necessary to determine if a lessee breached an IDM,[141] while in *Pummill*, the court held

132. *Mittelstaedt*, 1998 OK ¶¶ 20-21, 954 P.2d at 1208.
133. *Naylor Farms*, 923 F.3d at 785-86.
134. *Id.* at 786.
135. Whisenant v. Strat Land Expl. Co., 2018 OK CIV APP 65, 429 P.3d 703.
136. Pummill v. Hancock Expl. LLC, 2018 OK CIV APP 48, 419 P.3d 1268.
137. *Id.* ¶ 36, 419 P.3d at 1278.
138. *Id.* ¶ 44, 419 P.3d at 1279.
139. *Naylor Farms*, 923 F.3d at 788.
140. *Id.*
141. *Whisenant,* 2018 OK CIV APP 65, 429 P.3d 703.

such a review would be unnecessary.[142] However, the 10th Circuit pointed out the *Whisenant* court left open the possibility that a fact-intensive review may not be necessary in all cases, and the *Pummill* case fit in that open space.[143]

After reviewing these Oklahoma court decisions, the court turned to analyzing Rule 23's certification requirements, and decided only two of those are at issue: commonality and predominance.[144] The district court ruled whether Chaparral breached the IDM was a common question which predominated over any other questions.[145] To do so, it narrowed the class to "only those royalty owners whose leases contain clauses that are similar to the royalty clauses (collectively, *Mittelstaedt* Clauses) the OSC considered in three cases: (1) *Mittelstaedt*, (2) *TXO Production Corp, v State ex rel. Commissioners of Land Office*…and (3) *Wood v TXO Production Corp.*[.]"[146] Since the OSC held these clauses do not negate the IDM, the district court ruled "any remaining variations in lease language do not defeat commonality or predominance."[147]

Regarding Chaparral's argument that the court must determine when the gas from each well became marketable, the district court ruled that would be unnecessary because all of the gas in question required at least one GCDTP service to become marketable.[148] The class does not include gas which was already marketable at the wellhead. Therefore, the court ruled marketability in this case is subject to class-wide proof because variations in the quality of the gas are irrelevant to the predominant question.[149]

2. Lease Language

Next, Chaparral argued the language in each lease would have to be analyzed separately, thus defeating commonality and predominance. The district court disagreed, holding this type of analysis would be unnecessary because it limited the class to leases with *Mittelstaedt* clauses.[150]

142. *Pummill*, 2018 OK CIV APP 48, 419 P.3d 1268.
143. *Naylor Farms*, 923 F.3d at 788.
144. *Id*.
145. *Id.* at 784.
146. *Id.* at 790.
147. *Id.* (internal quotation omitted).
148. *Id*.
149. *Id.* at 794.
150. *Id.* at 795.

Chaparral argued the district court merely relied on Naylor's claims that the leases in questions contain *Mittelstaedt* clauses.[151] The Tenth Circuit disagreed, noting Naylor prepared a lease chart categorizing the different language in each lease because that was what it was supposed to do.[152] Also, the district court independently verified the chart was "generally accurate." Additionally, Chaparral did not provide evidence that Naylor's lease chart was inaccurate.[153]

Chaparral also argued the leases included different royalty provisions and the leases were ambiguous; this ambiguity would allow the introduction of extrinsic evidence. However, the court pointed out Chaparral waived its extrinsic evidence argument because it did not preserve it on appeal and failed to adequately brief it anyway.[154]

3. Uniform Payment Methodology

Finally, Chaparral argued Naylor did not demonstrate Chaparral used a uniform payment methodology to calculate royalty payments and "this lack of a common payment methodology defeats class certification."[155] The court noted that while existence of such a methodology is not enough to establish predominance by itself, its existence is also not necessary to establish predominance.[156]

Ultimately, the Tenth Circuit affirmed the district court's decision to certify the class action and held Chaparral failed to show how the lower court's decision fell outside the bounds of "rationally available choices."[157]

C. Davilla v Enable Midstream Partners L.P., 913 F.3d 959 (10th Cir. 2019).

Davilla dealt with the ramifications of the expiration of a pipeline easement on Native American lands, and whether a landowner must first demand removal of the pipeline before it can prove a trespass.[158]

Enable owned and operated a natural gas pipeline which crossed Native American allotted lands in Anadarko, Oklahoma.[159] The pipeline was built

151. *Id.*
152. *Id.* at 795-96.
153. *Id.*
154. *Id.* at 796-97.
155. *Id.* at 798.
156. *Id.*
157. *Id.*
158. Davilla v Enable Midstream Partners L.P., 913 F.3d 959 (10th Cir. 2019)
159. *Id.* at 962.

pursuant to a 20 year term easement which expired in 2000.[160] Enable never renewed the easement and they never removed the pipeline. Therefore, some Native American Allottees sued Enable for trespass, arguing Enable had no right to be on the land once the term expired.[161] The Western District of Oklahoma granted summary judgment to the Allottees, ruling Enable trespassed on the land.[162] The district court also issued a permanent injunction and ordered Enable to remove the pipeline.[163] The Tenth Circuit affirmed the summary judgment, reversed the permanent injunction, and remanded for further proceedings.[164]

The Court described the various federal laws enacted in the late nineteenth and early twentieth centuries aimed at Native American assimilation.[165] Congress divided Native American reservations into allotments and assigned parcels of land to individual Native Americans.[166] However, many Native Americans lost their lands through dubious or fraudulent transactions, so Congress passed the Indian Reorganization Act in 1934.[167] This Act ended the allotment period in favor of the federal government holding the allotted lands in trust for the benefit of the individual Native Americans indefinitely.[168] This did not affect lands the government had already patented, so while some Native Americans owned their lands in fee, other adjacent Native American landowners may have only "owned" their lands subject to a trust in favor of the government.[169] The land at issue in this case was allotted in 1901 to a Kiowa woman named Emaugobah, but because she never received a patent for the land, the government held it in trust.[170]

While the population moved west across the Great Plains, Congress passed several right-of-way statutes.[171] They empowered the Secretary of the Interior to approve easements across all lands held in trust for individual Native Americans or Native American tribes.[172] However, if an allotment was shared between multiple Native Americans, the Secretary needed

160. *Id.*
161. *Id.*
162. *Id.*
163. *Id.*
164. *Id.*
165. *Id.* at 963.
166. *Id.*
167. *Id.*
168. *Id.*
169. *Id.*
170. *Id.* at 964.
171. *Id.*
172. *Id.*

consent of a "majority of the [equitable] interests" to grant the right-of-way.[173]

So, in 1980, the Secretary approved a 25 foot wide pipeline easement across a portion of Emaugobah's allotment for a 20 year term.[174] Same expired in 2000 and Enable, who acquired the easement from the original owner, tried to secure a new 20 year easement from the Allottees and the Bureau of Indian Affairs.[175] However, Enable never gained approval from a majority of the allottees and the Bureau canceled their application for the new easement.[176] Since Enable continued to operate the pipeline, some of the Allottees sued claiming Enable was trespassing on their land and demanded the pipeline be removed.[177]

On appeal, Enable argued the district court erred in granting summary judgment on the trespass claims and in issuing a permanent injunction to enforce the ruling.[178]

1. Summary Judgment

a) Consent as a Defense to Trespass

The Tenth Circuit noted it reviews a summary judgment ruling by asking if there is a genuine issue of material fact, and all evidence is construed in favor of the movant.[179] However, the court pointed out federal law complicates this issue.[180] Federal law must govern when Native American allotted lands are at issue, but Congress has not created a federal right of action for trespass.[181] Therefore, the court must look at "federal common law." However, the court "lack[ed] a federal body of trespass law to protect the Allottees' federal property interests, [it] must borrow state law to the extent it comports with federal policy."[182]

In Oklahoma, a trespass occurs when one person physically invades someone else's property without the permission of the person in lawful possession of that property.[183] This led the court to consider three elements

173. *Id*.
174. *Id.*
175. *Id*.
176. *Id.*
177. *Id*.
178. *Id.* at 964-965.
179. *Id.* at 965.
180. *Id.*
181. *Id.*
182. *Id.*
183. *Id.*

related to a trespass: (1) the Allottees must be entitled to possession of the allotment; (2) they must show "Enable physically entered or remained on the allotment;" and (3) the Allottees must show Enable had no legal right to remain on the allotment.[184]

Enable argued it had consent sufficient to show it could maintain the pipeline even after the 20-year term expired.[185] In *Nahno-Lopez*, the court held "consent forms a complete defense to trespass" under Oklahoma law.[186] In 2004, Enable obtained written consent forms from five of the thirty-seven allottees allowing the company to maintain the pipeline.[187] Despite not obtaining consent from anywhere near 50% of the allottees, Enable argued this effort at least created a material fact sufficient to defeat a summary judgment motion.[188]

After pointing out Enable had confused the law on trespass, the court noted federal law dictates the prerequisites to obtain a right-of-way: Enable must secure the right-of-way from the Secretary of the Interior, who must have the allottees' approval.[189] Until that process is completed, Enable has no right to enter the land or continue operating the pipeline.[190] In other words, even if Enable obtained consent forms from every allottee, it still needed the Secretary to approve the easement.[191]

Turning to common law, Enable attempted to equate the several allottees with tenants in common, arguing a single owner may enter into a lease without the co-owner's consent.[192] The court held these allottees are not traditional tenants in common and Enable did not provide any persuasive authority anyway.[193]

The court held the undisputed facts (expiration of the easement) showed Enable had no right to be on the land. Obtaining a few consent forms did not change this fact, so the court affirmed the summary judgment motion.[194]

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184. *Id.* at 966.
185. *Id.*
186. Nahno-Lopez v. Houser, 625 F.3d 1279 (10th Cir. 2010).
187. *Davilla*, 913 F.3d at 966.
188. *Id.*
189. *Id.*
190. *Id.* at 967.
191. *Id.*
192. *Id.*
193. *Id*.
194. *Id.*

b) Demand for Removal

Enable argued it had no duty to remove the pipeline because the Allottees never demanded the pipeline be removed.[195] In response, the court noted Enable did not raise this argument at the district court level.[196] Enable argued the Allottees never included the demand for removal in their briefs, so Enable did not respond to same.[197] However, the 10th Circuit held even an "incomplete view of the law" may support a summary judgment motion, and it is not up to the court to fill in the blanks for the movant if it is not necessary to the ruling.[198]

However, the court noted Oklahoma case law has not established a demand requirement, instead turning to the Restatement (Second) of Torts to show "the lapse of any specified period of time by which the consent is restricted" would terminate consent.[199] "According to these rules, the easement's expiration created a duty to remove the pipeline."[200]

2. Permanent Injunction

Regarding the district court's awarding of a permanent injunction, Enable argued the lower court "incorporated a simplified injunction rule from Oklahoma law when it should have adhered to basic tenants of federal equity jurisprudence."[201] The Tenth Circuit agreed and reversed the injunction order.[202]

The lower court applied Oklahoma law to determine "equity will restrain a continuing trespass," but it should have applied the usual four-factor test federal courts use to grant permanent injunctive relief.[203] Whether a federal court should apply state law to a matter is rarely a black and white issue, but the Tenth Circuit held this case presented "a distinct need for nationwide legal standards."[204] The federal right-of-way statute applies to all lands held in trust by the United States, and "the nationwide application of this right-of-way statute suggests a need for a uniform federal standard."[205]

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195. *Id.* at 968.
196. *Id.*
197. *Id.*
198. *Id*.
199. *Id.*
200. *Id.* at 969.
201. *Id.*
202. *Id.* at 971.
203. *Id*.
204. *Id*.
205. *Id*.

Since the Secretary of the Interior has power over lands in multiple states, the court ruled it would be helpful to treat easement holders in Oklahoma the same as easement holders in Kansas.[206] Therefore, the district court should have applied the federal permanent-injunction standard. The lower court should consider "(1) whether an injunction is necessary to prevent irreparable harm, (2) whether the threatened injury outweighs the harm that the injunction may cause to the enjoined party, and (3) whether the injunction would adversely affect the public interest."[207] Therefore, the court reversed the permanent injunction and remanded so the lower court could apply the federal standard instead of the state test.[208]

III. State Regulatory Developments

A. Oklahoma Corporation Commission Regulatory Updates

On May 28, 2019, the Governor approved revised permanent rules promulgated by the Oklahoma Corporation Commission (the "Commission"),[209] which became effective on August 1, 2019, and made numerous revisions and updates to Commission rules affecting oil and gas development. Notable changes include the following:

(a) Okla. Admin. Code Section 165:10-3-5, which pertains to drilling, completion, recompletion, and remedial operations on wells located within the boundaries of underground storage facilities, was amended to require that well operators provide notice of an application for a Permit to Drill a well to the storage operators and the Director of the Public Utility Division as part of the application for Permit to Drill process if (i) the proposed well falls within one mile of the certified boundary of an underground storage facility or (ii) the completion intervals for the proposed well will, at any point, be located within 600 feet of an underground storage facility. Under the revised rule, notices required prior to logging, plugging and casing operations must now be provided at least 48 hours in advance. The revised rule also requires cement plugs for noncommercial wells to cover not less than 300 feet (previously 100 feet) below the base to not less

206. *Id.*
207. *Id.* at 973.
208. *Id.*
209. *See* 36 OKLA. REG. 1675–1744 (July 15, 2019) for a comprehensive list of the rules.

than 300 feet (previously 100 feet) above the top of the underground storage facility.[210]

(b) Okla. Admin. Code Section 165:10-3-10, which pertains to well completion operations, was revised to require operators to notify the operator of a producing spacing unit or well within one mile (previously one-half mile) of the perforated interval of the proposed well within five days of obtaining Conservation Division authorization to use diesel fuel as the base fluid for hydraulic fracturing operations. Prior to the 2019 revisions, operators were also required to provide five business days notice prior to the commencement of hydraulic fracturing operations on a horizontal well to operators of producing wells located within one-half mile of the completion interval of the subject well that were completed in the same common source of supply as the horizontal well. Under the revised rule, operators must notify operators of producing wells located within one mile of the completion interval of the subject well, regardless of whether such wells were completed in the same common source of supply as the horizontal well.[211]

(c) Okla. Admin Code Section 165:10-3-15, which pertains to the venting and flaring of gas, was revised to include a new requirement that operators notify the appropriate Conservation Division District Office or Field Inspector within 24 hours of initiating the flaring of gas with an H2S content exceeding 100 ppm. The revised rule also (i) extends the temporary permit exemption period for gas vented or flared in excess of 50 mcf/day during initial flowback from a newly completed or recompleted well from 14 days to 21 days, and (ii) extends the temporary permit exemption period for gas vented or flared in excess of 50 mcf/day after initial flowback from a newly completed or recompleted well from 30 days to 45 days.[212]

(d) Okla. Admin. Code Section 165:10-3-16, which pertains to oil and gas operations in hydrogen sulfide areas, was revised to expand the scope of operations subject to the rule. The revised rule lowers existing ppm thresholds to increase the rule's applicability, and

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210. OKLA. ADMIN. CODE § 165:10-3-5 (2019).
211. OKLA. ADMIN. CODE § 165:10-3-10 (2019).
212. OKLA. ADMIN. CODE § 165:10-3-15 (2019).

new ppm thresholds are added. Safety measures applicable to townsites and cities are now applicable to rural residential subdivisions. Under the revised rule, the Commission may now impose fines of up to $5,000 for violations.[213]

213. OKLA. ADMIN. CODE § 165:10-3-16 (2019).