2014 OIL & GAS CASE LAW UPDATE

Christopher Kulander, Director, Oil & Gas Law Institute
South Texas College of Law
Of Counsel, Haynes and Boone, LLP[*]

TEXAS CASES

I. *KEY OPERATING & EQUIPMENT, INC. V. HEGAR*

On June 20, 2014, the Supreme Court of Texas reversed the holding of the Houston Court of Appeals (First District) and held that a lessee may reasonably use the surface above any properly pooled mineral property to produce the minerals from that tract or any tract pooled therewith.[1]

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* B.S. (Geology) and M.S. (Geophysics), Wright State University; Ph.D., Texas A&M University (Petroleum Seismology); J.D., University of Oklahoma. The author wishes to thank Karl Burrer, Charles Carver, Pierre Grosdidier, Byron Kulander, Glynn Starling, Jonathan Strom, and Lucas Tanner for their assistance with this paper.

1. Key Operating & Equip., Inc. v. Hegar, 435 S.W.3d 794, 795 (Tex. 2014).

Since 1987, Key Operating & Equipment, Inc. (Key) had operated an existing well—the Richardson No. 1 well—on the Richardson Tract (Richardson Tract).[2] In 1994, Key acquired mineral leases on the 191-acre Curbo/Rosenbaum Tract (Curbo Tract) and reworked the Rosenbaum No. 2 well, which was located on that property.[3] Also in 1994, "Key built a road . . . to access both the Richardson No. 1 and the Rosenbaum No. 2."[4] Six years later, the Rosenbaum No. 2 well stopped producing and Key's lease on the Curbo Tract expired.[5] The same year, however, Key purchased an "undivided twelve-and-a-half percent interest in the mineral estate" of the Curbo Tract that it then leased to itself.[6] Subsequently, Key pooled the lease under the Curbo Tract with its lease under the Richardson Tract.[7]

In 2002, the Hegars purchased eighty-five acres of the Curbo Tract (Hegar Tract), including a portion of the road that accessed the Richardson No. 1.[8] The Hegars were aware of Key's existing use of the road when they bought the tract.[9] In 2003, the Hegars built a house on the Hegar Tract.[10] The Hegars did not object to Key's usage of the road until he drilled the Richardson No. 4 well on the Richardson Tract and traffic increased.[11] The Hegars claimed "Key had no legal right to access or use the surface of the Hegar Tract in order to produce minerals from the Richardson Tract."[12]

The trial court enjoined Key from accessing the road on the Hegar Tract.[13] The trial court also found that "the use of the surface of the Hegar [T]ract was not reasonably necessary to extract minerals from beneath the Hegar Tract," and that "no minerals were being extracted from beneath the Hegar [T]ract by wells located on the Richardson Tract."[14] As a consequence, Key's actions constituted a trespass.[15]

The court of appeals initially reversed, but after granting a motion for rehearing, the court withdrew the original opinion and instead affirmed the trial court's decision.[16] It held that "Key had the right to use the Hegars' surface to produce oil only from beneath the Hegar [T]ract."[17] The court of appeals also determined that "evidence supported the trial court's finding that

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2. *Id.* at 796.
3. *Id.*
4. *Id.* Apparently, trucks turned off the public road and crossed the Curbo Tract to get to the Richardson Tract. *Id.*
5. *Id.*
6. *Id.*
7. *Id.*
8. *Id.*
9. *Id.*
10. *Id.*
11. *Id.*
12. *Id.* (internal quotation marks omitted).
13. *Id.*
14. *Id.* at 797.
15. *Id.*
16. *Id.*
17. *Id.*

Key was only producing oil from the adjacent Richardson Tract."[18] Further, it affirmed the trial court's conclusion that "Key had no right to use the Hegars' surface to produce minerals exclusively from the Richardson Tract."[19] Finally, the court of appeals also held that "Key's lease and pooling agreements, which were not part of the Hegars' chain of title, could not contractually expand Key's right to use the Hegars' surface."[20]

Key appealed to the Supreme Court of Texas, contending it had the right to use the Hegars' surface estate to produce minerals from any part of the pooled unit.[21] Key "assert[ed] that the court of appeals erred by relying on the accommodation doctrine and in its application of *Robinson v. Robbins Petroleum Corp*."[22] In *Robinson*, an operator attempted to use a well on the Robinson Tract, of which Robinson owned the surface, which was not part of an adjacent unit pooled to produce salt water for a water flood project.[23] Key also claimed that the court of appeals "incorrectly assumed that because the record did not contain the original document severing the mineral and surface estates, Key's predecessor did not have the right to pool and Key did not have the right to use the road."[24]

The Supreme Court of Texas first noted that, generally, "[t]he right of ingress and egress includes the right to ingress and egress over the surface of any pooled acreage for the purpose of producing minerals from any part of the pooled acreage."[25] Therefore, "Key's owners did not increase the burdens on the surface estate by leasing their mineral interest to Key, nor did Key increase the burdens by pooling the Richardson and [Curbo T]ract minerals."[26] The court, therefore, reasoned that because both leases allowed pooling and "the primary legal consequence of pooling is that production and operations anywhere on the pooled unit are treated as if they have taken place on each tract within the unit," Key had a right to use the surface of the Hegar Tract.[27] The court further stated that the Hegars' claim that the oil and gas leases were not in their chain of title was irrelevant due to the implied surface rights enjoyed by mineral owners and oil and gas lessees.[28]

The court explained that the court of appeals' decision that Key's surface easement was only implicated when it was used to produce oil and gas from the Hegar Tract conflicts with the primary legal consequence of

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18. *Id.*
19. *Id.*
20. *Id.*
21. *Id.*
22. *Id.* (citing Robinson v. Robbins Petrol. Corp., 501 S.W.2d 865 (Tex. 1973)).
23. *Id.* at 799 (citing *Robinson*, 501 S.W.2d at 866).
24. *Id.* at 797.
25. *Id.* at 800.
26. *Id.*
27. *Id.* at 798 (quoting Se. Pipe Line Co. v. Tichacek, 997 S.W.2d 166, 170 (Tex. 1999)) (internal quotation marks omitted).
28. *See id.* at 799.

pooling.[29] Generally, pooling a tract with another tract necessarily provides the operator with the right to conduct operations on the entirety of the pooled lands as if the lands were altogether the same lease.[30] The type of use on a given tract is irrelevant if it is properly pooled.[31]

The court held that the present issue was clearly distinguishable from *Robinson*.[32] In *Robinson*, an operator attempted to use a well on the Robinson Tract, of which Robinson owned the surface, which was not part of an adjacent unit pooled to produce salt water for a water flood project.[33] The court held that "Robinson, as owner of the surface, [was] entitled to protection from uses thereof, without his consent, for the benefit of owners outside of and beyond premises and terms of the [adjacent] Wagoner lease."[34] Because the minerals under the Robinson Tract "had not been, and could not be, pooled with tracts where the water was being used" under the Wagoner lease, *Robinson* did not control the Hegar issue.[35]

The court also held that because the Hegars bought the surface of the Hegar Tract subject to a lease that authorized pooling, and Key owned a portion of the fee mineral estate of the Hegar Tract, Key had a right to use the road.[36] Furthermore, Key's ownership of a portion of the fee mineral estate of the Hegar Tract gave it both the right of ingress and egress to develop and produce minerals as well as the right to pool the estate.[37] "Accordingly, Key's owners did not increase the burdens on the surface estate by leasing their mineral interest to Key, nor did Key increase the burdens by pooling the Richardson and [Curbo] tract minerals."[38]

Key asserted that "the accommodation doctrine was not raised in the trial court or the court of appeals, and even if it were, the court of appeals erred by relying on it to hold that Key trespassed on the Hegars' surface estate."[39] The Hegars acknowledged that the doctrine had not been raised before.[40] The Texas Supreme Court noted, however, that "[b]ecause it was not raised in the trial court, the accommodation doctrine as related to Key's use of the Hegar Tract's surface was not properly before the court of appeals"; thus the court did not determine whether it was correctly applied.[41]

29. *Id.*
30. *Id.*
31. *See id.*
32. *Id.* at 800.
33. *Id.* at 799 (citing Robinson v. Robbins Petrol. Corp., 501 S.W.2d 865, 866 (Tex. 1973)).
34. *Id.* at 799–800 (quoting *Robinson*, 501 S.W.2d at 868).
35. *Id.* at 800.
36. *Id.*
37. *Id.*
38. *Id.*
39. *Id.* at 801.
40. *Id.*
41. *Id.*

II. *FRENCH V. OCCIDENTAL PERMIAN LTD.*

On June 27, 2014, the Texas Supreme Court affirmed the Eastland Court of Appeals' decision regarding the deduction of costs for removing carbon dioxide (CO_2) and hydrogen sulfide (H_2S) from casinghead gas for repurpose in tertiary recovery from royalty payments.[42]

The petitioners (French) were royalty owners of the Cogdell and Fuller Ranches, both within the Cogdell Field and located respectively in Kent County and Scurry County, Texas.[43] The respondent, Occidental Permian Ltd. (Occidental), owned a working interest in the field.[44] As unit operator, Occidental had instigated a tertiary recovery operation using CO_2 purchased from Kinder Morgan CO_2 Company (Kinder Morgan).[45]

The pooled unit was known as the Cogdell Canyon Reef Unit (CCRU) and was formed in 1954.[46] Secondary, and then tertiary, recovery processes have been necessary to make production economically viable in the CCRU.[47] One process used in the CCRU since 2001 is the injection of CO_2 into the productive strata, which results in the wells producing casinghead gas along with oil.[48] The casinghead gas produced is mostly (85%) CO_2.[49] After severance at the wellhead, Kinder Morgan transported the production stream to its Cynara production facility fifteen miles away, where the CO_2 was then removed from the production stream along with two-thirds of the natural gas liquids (NGLs).[50] This extracted CO_2 was then transported back to the CCRU for reuse. "The remaining gas stream and separated NGLs [were] then sent to the Snyder Gas Plant (SGP) where the remaining CO_2 [was] extracted" and sent back to the CCRU.[51] Finally, the NGLs were stabilized, and the stream was processed for sale to Torch Energy Marketing, Inc.[52]

The production area had originally seen up to 30,000 barrels per day but had fallen to a mere 1,500 barrels per day beginning in the 1990s.[53] After Occidental began tertiary recovery by CO_2 injection in 2001, however, the amount realized grew to 5,800 barrels per day.[54] This tertiary operation was

42. French v. Occidental Permian Ltd., 440 S.W.3d 1, 2 (Tex. 2014).
43. *Id.*
44. *Id.*
45. Occidental Permian Ltd. v. French, 391 S.W.3d 215, 217 (Tex. App.—Eastland 2012), *aff'd*, 440 S.W.3d 1.
46. *French*, 440 S.W.3d at 4.
47. *Id.* at 5–6.
48. *Id.* at 6.
49. *Id.* The other 15% of gases in the casinghead is made up of various NGLs, methane, ethane, propane, butane, pentane, and hydrogen sulfide, amongst other contaminants, which are extracted and sold. *Id.*
50. *Occidental Permian Ltd.*, 391 S.W.3d at 217–18.
51. *Id.* at 218.
52. *Id.*
53. *French*, 440 S.W.3d at 5.
54. *Id.* at 6.

conducted pursuant to the terms of a Treating and Processing Agreement between Occidental and Kinder Morgan, which required Occidental to pay Kinder Morgan two bundled fees per month.[55] The first fee was a monetary charge from which no deduction from French's royalty was made.[56] The second "in-kind" fee was comprised of "30% of the NGLs and 100% of the residue gas extracted from the casinghead gas stream produced from the [CCRU]."[57] Because no royalty was paid on this in-kind fee, it was essentially a deduction from royalty.[58]

French and the other royalty owners, or their predecessors in title, had previously ratified a unitization agreement expressly authorizing the working interest owners, at their sole discretion, to inject water, gas, and any other substances into the CCRU area.[59] The unitization agreement defined gas as "natural gas (including casinghead gas) and all of its constituent elements produced from wells on lands and leases in the Cogdell Field producing from the Canyon Reef underlying the unit area."[60] Further, the unitization agreement provided that royalties should be deducted before operation or development and that no royalty would be payable out of production for such "unitized substance" used.[61] The agreement defined unitized substances as "all oil, gas, . . . or any other substance produced and saved from the Canyon Reef underlying the unit area."[62] Finally, the unitization agreement provided that all costs of the enhanced recovery operations would be borne by the working interest "unless such royalty owner [was] already obligated to pay such costs or expenses by the terms of other agreements."[63]

Two oil and gas leases were at issue—the Fuller Lease and the Cogdell Lease.[64] The Fuller Lease contained a gas royalty clause stipulating that royalty was due on the "market value at the well" of one-eighth of the gas.[65] The Cogdell Lease provided that the royalty would be calculated on the proceeds of gas sold.[66] Under both leases, the royalty owner was to share in the post-production processing required to make the gas marketable.[67]

French accepted that the extraction of NGLs and the removal of H_2S at Cynara were post-production costs and did not challenge that Kinder Morgan's recompense was unreasonable.[68] French challenged the royalties

55. *Occidental Permian Ltd.*, 391 S.W.3d at 218.
56. *Id.*
57. *Id.*
58. *Id.*
59. *French*, 440 S.W.3d at 4.
60. *Id.* (quoting the agreement).
61. *Id.* at 5.
62. *Id.* (quoting the agreement).
63. *Id.* (quoting the agreement).
64. *See id.* at 2.
65. *Id.* at 2–3.
66. *Id.* at 4.
67. *See id.* at 3–4.
68. *See id.* at 7.

they received from Occidental, however, claiming that Occidental had inappropriately deducted from French's royalty share the cost of removal of CO_2 from casinghead gas that was extracted and then reinjected into wells for the purpose of aiding in tertiary recovery.[69] French, claiming that removing the CO_2 was a production cost because Occidental reused it in successive production efforts on the same leases, sought to recover royalty they deemed due from the production attributable to the in-kind fee—"30% of the NGLs and 100% of the . . . casinghead gas stream."[70]

French argued at trial that the CO_2 project was a "production activity" and that the in-kind fee constituted an unlawful reduction of the amount of production subject to royalty.[71] French requested instead that Occidental pay them a royalty based on the price of all NGLs outside of the expense of their extraction from the gas and removal of the H_2S.[72] Occidental argued that the removal of the CO_2 was a post-production cost because it was required to make the casinghead gas marketable.[73]

After a bench trial, the court, agreeing with French, held that Occidental had not paid royalty on all of the gas produced from the CCRU, and therefore, royalty was due on 30% of the value of the NGLs and the total value of the casinghead gas stream—which equaled the in-kind gas fee.[74] French received an award of just over ten million dollars, prompting Occidental to appeal.[75]

The Eastland Court of Appeals reversed.[76] Both the Fuller and Cogdell Leases provided that royalty would be the net of the post-production cost of making the gas marketable.[77] As to the Fuller Lease and its "market value at the well" language, the appellate court—noting that not only separation of CO_2, but also compression, removal of H_2S, separation of NGLs, and further transportation took place at Cynara—held that these activities were not production costs but rather post-production costs that could be deducted from royalty.[78]

As for the Cogdell Lease and its "net proceeds" clause, the appellate court—focusing on French's damage calculations, which lumped all of Occidental's activities at Cynara as production costs—again held for

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69. *See id.*

70. Occidental Permian Ltd. v. French, 391 S.W.3d 215, 218 (Tex. App.—Eastland 2012), *aff'd*, 440 S.W.3d 1.

71. *See id.* Interestingly, French also claimed the reduction differentiated this case from nearly all other such reported cases in that they did not challenge the actual royalty payments, but rather the deficiency of the volume component in the royalty payment calculation. *Id.* at 220.

72. *See French*, 440 S.W.3d at 7.

73. *Id.*

74. *Occidental Permian Ltd.*, 391 S.W.3d at 218; *see French*, 440 S.W.3d at 7–8.

75. *French*, 440 S.W.3d at 7; *see Occidental Permian Ltd.*, 391 S.W.3d at 217.

76. *Occidental Permian Ltd.*, 391 S.W.3d at 217, 225.

77. *French*, 440 S.W.3d at 3–4.

78. *See Occidental Permian Ltd.*, 391 S.W.3d at 222–23.

Occidental.[79] The Texas Supreme Court reasoned that this was not necessarily so: some processes, such as the removal of H_2S—which French had admitted was a post-production cost—were conducted at Cynara.[80] Because French provided no evidence of the expenses incurred at Cynara, French had not shown the value of the NGLs and casinghead gas to use in the calculation of their royalty.[81] Therefore, the appellate court did not consider whether removal of the excess CO_2 from the casinghead gas was a production expense.[82]

On appeal to the Texas Supreme Court, therefore, French contended that the reintroduction of CO_2 to aid in tertiary recovery should be considered part of the production costs and thereby exempt from royalty deductions.[83] The court first examined the unitization agreement and the two leases—which it classified as "other agreements" as mentioned in the unitization agreement—considering whether the processing of the casinghead gas stream to remove water and CO_2 at Cynara was a production or post-production expense.[84] Regarding the produced water, the court held that separation of water recovered from injection operations was essential to continued economic production of the oil and was thus a production expense.[85]

The court held that separation of the CO_2 from the casinghead gas stream prior to reinjection was not strictly necessary for operation of the field.[86] Occidental heightened the value of the production stream to both themselves and French by processing the casinghead gas and separating the CO_2 because this work allowed for both the sale of the NGLs and the reinjection of a much more concentrated CO_2 stream.[87]

Generally in Texas, deductions for the costs of the production of gas to the wellhead may not be made against the royalty, but deductions for post-production efforts to make the gas marketable may be.[88] Of course, parties may contract around these provisions by agreement. Here, the court considered that separating gases led to more efficient production of oil and gas and the prevention of waste.[89] The court also noted the benefit the royalty

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79. *See id.* at 222–24; *French*, 440 S.W.3d at 8.
80. *French*, 440 S.W.3d at 8.
81. *Id.*
82. *Id.*
83. *Id.* at 7, 9.
84. *Id.* at 4–6, 8–9.
85. *Id.* at 9–10.
86. *Id.* at 10.
87. *Id.*
88. *See* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 121–22 (Tex. 1996) ("Although it is not subject to the costs of production, royalty is usually subject to post-production costs, including taxes, treatment costs to render it marketable, and transportation costs. However, the parties may modify this general rule by agreement." (citations omitted)); *see also* Alamo Nat'l Bank of San Antonio v. Hurd, 485 S.W.2d 335, 338 (Tex. Civ. App.—San Antonio 1972, writ ref'd n.r.e.) (explaining Texas law regarding royalty–cost relationships).
89. *French*, 440 S.W.3d at 10 & n.32.

owners received when it lauded the fairness of sharing separation costs among the royalty and working interest owners.[90]

Further, Occidental was under no obligation in the unitization agreement to separate the gas prior to reinjection, which would have removed any of French's royalty from NGLs.[91] Royalty on NGLs results from this post-production extraction of gases, not merely from the reinjection of CO_2.[92] Therefore, as French acquiesced to the discretion of Occidental regarding casinghead gas in recovery operations in the unitization agreement, and having received royalty on the NGLs, the court held that French must share in the cost of CO_2 extraction.[93]

Ultimately, the court held that the pro-rata costs of removing CO_2 from the production stream of a tertiary recovery project could be deducted from the royalty owned by the lessor, provided no express terms in the lease barred such deduction.[94]

III. *CHESAPEAKE EXPLORATION, L.L.C. V. HYDER*

On March 5, 2014, the San Antonio Court of Appeals affirmed the holding of the 17th Judicial District Court of Tarrant County.[95] The court held that Chesapeake Exploration, L.L.C. (Chesapeake) breached the royalty and overriding royalty clauses in the Hyder lease.[96] The court of appeals ruled that Chesapeake could not deduct post-production costs from the Hyders' royalty.[97] The Hyders originally filed suit alleging a breach of their lease.[98] Chesapeake counterclaimed to recover overpaid royalties.[99] The trial court, following a bench trial, found in favor of the Hyders and awarded damages for "breach of the royalty and overriding royalty clauses, attorney's fees, and pre-judgment and post-judgment interest."[100] On appeal, the Hyders further asserted that "the trial court erred in holding [that Chesapeake did] not owe royalty on gas lost and unaccounted for."[101] Chesapeake responded that, because there was no "price actually received" for such gas, the trial court correctly held that it did not owe these royalties.[102]

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90. *Id.* at 10.
91. *Id.*
92. *Id.*
93. *Id.*
94. *Id.* at 9–10.
95. Chesapeake Exploration, L.L.C. v. Hyder, 427 S.W.3d 472, 474 (Tex. App.—San Antonio 2014, pet. granted).
96. *Id.*
97. *Id.* at 474–75.
98. *Id.* at 474.
99. *Id.*
100. *Id.*
101. *Id.* at 481.
102. *Id.*

The Hyders originally leased "1,037 surface acres and approximately 948 mineral acres of land located in Johnson County and Tarrant County, Texas" to Four Sevens Oil Co., Ltd.[103] Four Sevens subsequently assigned the lease to Chesapeake.[104] In addition to the leased premises, the lease also permitted Chesapeake "to drill from existing well sites . . . adjacent to or near the leased premises (off-lease wells)."[105] By December 2011, Chesapeake had "drilled and completed twenty-two wells on the leased premises and seven off-lease wells."[106] The lease provided that the Hyders were to receive a 25% royalty on oil and gas produced by wells on the lease and a 5% overriding royalty on any production from the off-lease wells.[107]

"The dispute between the parties arose [over the] interpretation of the royalty and overriding royalty clauses" in the Hyders' oil and gas lease.[108] Chesapeake maintained that "the royalty clause applicable to the wells on the leased premises allow[ed] them to deduct [the Hyders'] share of post-production costs and expenses incurred between the 'point of delivery' and the 'point of sale' from [the Hyders'] royalty payment."[109] Chesapeake also argued that "the overriding royalty clause applicable to the off-lease wells allow[ed] them to deduct [the Hyders'] share of post-production costs and expenses from [the Hyders'] overriding royalty."[110]

The Hyders maintained that "their royalty interest [was] not subject to any post-production costs and expenses, regardless of where such costs and expenses [were] incurred."[111] The Hyders further maintained that "their overriding royalty interest [was] not subject to any post-production costs or expenses" because the parties agreed to a "cost free (except only to its portion of production taxes) overriding royalty."[112] The relevant portion of the Hyders' royalty clause sets forth the royalty obligation as follows:

> [Lessee] covenant[s] and agree[s] to pay [Lessor] the following royalty: (a) twenty-five percent (25%) of the market value at the well of all oil and other liquid hydrocarbons produced and saved from the Leased Premises as of the day it is produced and stored; and (b) for natural gas, including casinghead gas and other gaseous substances produced from the Leased Premises and sold or used on or off the Leased Premises, twenty-five percent (25%) of the price actually received by [Lessee] for such gas . . . . The royalty reserved herein by [Lessor] shall be free and clear of all production and post-production costs and expenses, including but not

103. *Id.* at 474.
104. *Id.*
105. *Id.* (internal quotation marks omitted).
106. *Id.*
107. *Id.* at 476, 479.
108. *Id.* at 475.
109. *Id.*
110. *Id.*
111. *Id.*
112. *Id.* at 475, 480 (quoting the agreement).

> limited to, production, gathering, separating, storing, dehydrating, compressing, transporting, processing, treating, marketing, delivering, or any other costs and expenses incurred between the wellhead and [Lessee's] point of delivery or sale of such share to a third party.[113]

The overriding royalty clause, applicable to off-lease wells, provided the following:

> [Lessee] shall, within sixty (60) days from the date of the first production from each off-lease well, convey to [Lessor] a perpetual, cost-free (except only its portion of production taxes) overriding royalty of five percent (5%) of gross production obtained from each such well payable to [Lessor] (which overriding royalty shall be carved out of the leasehold estate by virtue of which such production is obtained), same to be effective from first production from the well to which such overriding royalty pertains.[114]

Chesapeake's organizational structure played an important role in the court's determination.[115] Chesapeake Operating, Inc. was responsible for the production of gas from the Hyder lease.[116] After the gas was produced, Chesapeake's marketing entity bought the gas from Chesapeake Operating, Inc.[117] At that point, Chesapeake's marketing entity took title to the gas.[118] Chesapeake's midstream entity then gathered the gas and transported it to a central point.[119] Chesapeake's marketing entity then delivered the gas to one of several points of delivery—"physical locations where [Chesapeake's midstream] system connects to larger interstate pipelines owned and operated by unaffiliated third party . . . pipeline companies."[120] The gas was then transported downstream from these points of delivery to various points of sale.[121] At these points of sale—the first arm's length transaction in the Chesapeake value chain—title passed from Chesapeake's marketing entity to a third party purchaser.[122] Chesapeake "made royalty payments to [the Hyders] based on a weighted average sales price calculated on" the first sale to a non-affiliated entity.[123]

Chesapeake acknowledged that production costs and expenses incurred before extraction were excluded from the Hyders' royalty interest, but it argued that "the royalty clause [was] constructed in a manner that permits

113. *Id.* at 476 (emphasis omitted) (quoting the agreement).
114. *Id.* at 478 (emphasis omitted) (quoting the agreement).
115. *Id.* at 475.
116. *Id.*
117. *Id.*
118. *Id.*
119. *Id.*
120. *Id.*
121. *Id.*
122. *Id.*
123. *Id.* at 475–76.

deduction of post-production costs and expenses, such as third party transportation costs incurred between the point of delivery and the point of sale."[124] The parties stipulated that Chesapeake incurred $1,750,000 in unaffiliated third-party transportation costs, allocable between the point of delivery and point of sale.[125] Because these costs and expenses were not originally deducted from the Hyders' royalty payments, Chesapeake brought a counterclaim for money received based on alleged mistaken overpayments.[126]

The Hyders argued that the "free and clear" provision of the royalty clause "prohibit[ed] deduction of all post-production costs and expenses, regardless of whether they [were] incurred between the point of delivery and the point of sale."[127] Conversely, Chesapeake's interpretation of the royalty clause centered around the language: "incurred between the wellhead and [Chesapeake's] point of delivery or sale of such share to a third party."[128] Chesapeake argued that the use of "or" between "delivery" and "sale" was disjunctive, and therefore, "the royalty clause allow[ed] them to choose either the point of delivery, or the point of sale to determine whether the royalty clause permit[ted] deduction of post-production costs and expenses incurred after the point of delivery but before the point of sale."[129]

The royalty clause in the Hyder lease stated that Chesapeake and the Hyders "agree that the holding in the case of *Heritage Resources, Inc. v. NationsBank* . . . shall have no application to the terms and provisions of this Lease."[130] The court disagreed with Chesapeake's interpretation, finding that it ignored the free and clear provision of the royalty clause.[131] The court reasoned that excluding deduction of post-production costs from the wellhead to the point of delivery, but permitting the deduction of post-production costs from the point of delivery to the point of sale, would contradict the plain reading of the royalty clause.[132] The court noted that the parties' agreement to ignore the holding in *Heritage* reinforced its conclusion.[133]

Chesapeake agreed that the Hyders' overriding royalty was free of production costs, but argued that the term "cost free" should not be construed in isolation and, therefore, the overriding royalty should not be free of

124. *Id.* at 476.
125. *Id.*
126. *Id.*
127. *Id.*
128. *Id.*
129. *Id.*
130. *Id.* at 477 (quoting the agreement); *see* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 123 (Tex. 1996).
131. *Hyder*, 427 S.W.3d at 477.
132. *Id.*
133. *Id.* at 477–78.

post-production costs.[134] Chesapeake cited an Oklahoma case, *XAE Corp. v. SMR Property Management Co.*, to argue that the overriding royalty interest was an in-kind interest, and therefore, the Hyders should be entitled to a percentage of production "at the wellhead."[135] The court was unpersuaded by this argument because the Hyder lease expressly provided for a cost-free royalty.[136]

Chesapeake further asserted that the term cost free in the Hyder lease was "equivalent to the 'free and clear' language found in *Martin v. Glass* and *Danciger Oil Refineries v. Hamill Drilling Co*."[137] In each of these cases, the court held that "such language properly allowed for deduction of post-production costs from the lessor's royalty payment."[138] Also, the overriding royalty clauses in these cases limited the costs to be excluded from the overriding royalty to production costs.[139] The court reasoned that the Hyders' overriding royalty clause could be distinguished because "it [did] not limit the types of costs to be excluded from the overriding royalty to production costs alone."[140] Thus, the court found Chesapeake's arguments unconvincing.[141]

The Hyders, on cross appeal, argued "the trial court incorrectly determined the applicable interest rate on their overriding royalty . . . [as] five percent annually instead of the interest rate of one percent per month for all past due payments as provided in paragraph five of the [Hyder] lease."[142] The court interpreted the clause requiring payment of "interest for all past due payments at the rate of one percent (1%) per month" as applying to the royalty interest, but not the overriding royalty interest because the overriding royalty clause was silent with respect to any late payment interest rate.[143] Thus, the court concluded that "the trial court properly applied the default statutory interest rate allowed by Finance Code section 304.003."[144]

The Hyders further argued on cross appeal that "the trial court erred in holding [Chesapeake did] not owe royalty on gas lost and unaccounted for."[145] Chesapeake argued that they did not owe royalty on gas lost or unaccounted for because there was no "price actually received" for such

134. *Id.* at 479.
135. *Id.* (internal quotation marks omitted) (discussing XAE Corp. v. SMR Prop. Mgmt. Co., 1998 OK 51, 968 P.2d 1201, 1202).
136. *Id*.
137. *Id.*; *see* Martin v. Glass, 571 F. Supp. 1406, 1410–17 (N.D. Tex. 1983), *aff'd*, 736 F.2d 1524 (5th Cir. 1984); Danciger Oil & Refineries, Inc. v. Hamill Drilling Co., 171 S.W.2d 321, 323 (Tex. 1943).
138. *Hyder*, 427 S.W.3d at 479–80.
139. *Id.* at 480.
140. *Id.*
141. *Id.*
142. *Id.*
143. *Id.* at 481.
144. *Id.*
145. *Id.*

gas.[146] The Hyders argued that their royalty payment should have been calculated based on the volume measured at the wellhead and that the sale of gas at the wellhead from Chesapeake Operating, Inc. to Chesapeake's marketing entity is the point at which Chesapeake obtains the "price actually received for such gas."[147] The Hyders argued in the alternative that "the fact that [Chesapeake does] not actually receive payment for such gas is irrelevant because they are compensated in other situations where [Chesapeake does] not actually receive payment, such as when gas is used for fuel or other operations."[148] The court found each of these arguments unpersuasive and affirmed the trial court's holding that the Hyders were "not entitled to recover on their counterclaim for lost and unaccounted for gas."[149]

Finally, the court, affirming the trial court, noted that because they found that Chesapeake breached the lease, Chesapeake was liable for reasonable attorney's fees.[150]

IV. *RIPPY INTERESTS, LLC V. NASH*

On August 21, 2014, the Waco Court of Appeals held that operations for drilling conducted before the primary term's expiration continued a lease into the secondary term and did not waive the lessee's repudiation defense.[151] The dispute arose from an oil and gas lease (Range Lease) entered into by William Nash, John Nash, and Charles Nash with Range Production I, L.P. (Range) on January 18, 2006.[152] The Range Lease "had a primary term of three years with an option to extend the term for two years."[153] The parties exercised the option.[154] The Range Lease also included an operations clause providing that as long as "operations" were conducted upon the leasehold with no cessation for more than ninety consecutive days, the lease would not expire.[155] Operations were thereafter defined as:

> *operations for and any* of the following *drilling*, testing, completing, reworking, recompleting, deepening, plugging back or repairing of a well in search for or in an endeavor to obtain production of oil, gas, sulphur or

146. *Id.*
147. *Id.* at 482 (internal quotation marks omitted).
148. *Id.*
149. *Id.*
150. *Id.* at 483.
151. Rippy Interests, LLC v. Nash, No. 10-12-00233-CV, 2014 WL 4114328, at *12 (Tex. App.—Waco Aug. 21, 2014, pet. filed).
152. *Id.* at *1.
153. *Id.*
154. *Id.*
155. *Id.* (emphasis omitted) (quoting the lease).

> other minerals, excavating a mine, production of oil, gas, sulphur or other mineral, whether or not in paying quantities.[156]

Range assigned the Range Lease to Rippy Interests, LLC (Rippy) in September 2009, and thereafter Rippy received a drilling permit for a well on the Range Lease from the Railroad Commission.[157] Subsequently, the Nashes granted a top lease (KingKing Lease) to US KingKing, LLC (KingKing) in September 2010, which was expressly subordinate to the Range Lease and was effective immediately upon the expiration of the Range Lease.[158] The KingKing Lease provided that the Nashes would receive $25 per acre, payable at signing, and $300 per acre, payable upon the KingKing Lease taking effect, plus a 25% royalty on production of oil and gas.[159]

Rippy began production-related activities on the well site around January 1, 2011, and the Nashes "signed a damage release and acknowledged payment for wellsite-pad construction and access road use" on January 7.[160] Rippy was preparing a 2.88-acre well site and 2.92-acre road to the well site, and started constructing the pad by January 17.[161] The Nashes placed a lock on the gate to the jobsite on January 18, but Rippy's workers cut the lock and entered the property.[162] The police were called but no arrests were made.[163] These events led Rippy to file suit against the Nashes on January 24, 2011, seeking injunctive relief to prevent further interference.[164] Rippy filed an amended petition in June to include KingKing as a defendant and added a claim for declaratory relief.[165] "Rippy sought declarations that the Range Lease had been extended by Rippy's operations . . . and that the KingKing Lease was not the controlling lease."[166] KingKing counterclaimed for a declaratory judgment that the KingKing Lease was the only valid lease and "also asserted claims for trespass to try title, to quiet title and remove cloud from title, and for slander of title."[167] Rippy responded to KingKing's counterclaims by claiming an affirmative defense of wrongful repudiation of the Range Lease.[168]

KingKing filed a combined no-evidence and traditional motion for summary judgment, asserting that "there was no evidence that the Range Lease was extended by agreement," no evidence that Rippy conducted

156. *Id.*
157. *Id.*
158. *Id.*
159. *Id.*
160. *Id.* at *1–2.
161. *Id.* at *2.
162. *Id.*
163. *Id.* at *3.
164. *Id.*
165. *Id.*
166. *Id.*
167. *Id.*
168. *Id.*

operations on the lease before expiration of the primary term, "and no evidence that a well or equipment capable of drilling a well existed on the lease" at expiration of the primary term.[169] Additionally, KingKing sought summary judgment on its counterclaims based on superior title because of the Range Lease's expiration.[170] On February 2, 2012, the Nashes filed a motion for joinder in KingKing's motion for summary judgment.[171] Rippy moved for a traditional motion for summary judgment, asserting "that it was entitled to prevail on its claims for trespass to try title, suit to quiet title, and to have the Range Lease declared" the proper and currently effective lease.[172] KingKing filed an amended no-evidence and traditional motion for summary judgment claiming that even if Rippy were conducting operations to hold the Range Lease, the cessation of production for more than ninety days caused the expiration of the Range Lease.[173] KingKing also asserted that there was no evidence of repudiation and, alternatively, if there was repudiation, there was no evidence of Rippy's reliance on it.[174] The Nashes did not file a joinder to KingKing's amended motion and "[t]he trial court dismissed Rippy's claims with prejudice, granted KingKing's amended motion (in part)," and ordered the KingKing Lease to be the effective lease.[175]

Rippy argued that "summary judgment for KingKing was improper because the Range Lease" only required the lessee to conduct drilling operations in order for the lease to extend past its primary term—activities that Rippy had performed.[176] While KingKing and the Nashes agreed with Rippy that, under the Range Lease, "operations" to perpetuate the lease included "operations for drilling," the parties disagreed over "whether the operations for drilling . . . were adequate under Texas law to perpetuate the lease."[177] Before the lease expiration, Rippy had: (1) "obtained a drilling permit and a surface-damage release," (2) "hired a drilling contractor and solicited a bid for a drilling rig," (3) "hired contractors to prepare the well site," (4) begun construction on well site, and (5) installed a conductor pipe.[178] Because of this work, Rippy was able to drill the pilot hole within two months after the expiration of the primary term.[179] Generally, where the lease is silent as to what activities comprise commencing operations, Texas case law only requires activities related to the drilling of a well and not actual

169. *Id.*
170. *Id.*
171. *Id.*
172. *Id.* at *4.
173. *Id.*
174. *Id.*
175. *Id.* (footnote omitted).
176. *Id.* at *4, *6.
177. *Id.* at *6.
178. *Id.* at *7.
179. *Id.*

spudding in, or drilling, of the hole.[180] The court therefore reversed the trial court's decision that the Range Lease was void and no longer effective, concluding that Rippy's work was enough to meet the requirement of conducting operations for drilling before the expiration of the Range Lease.[181]

KingKing amended its summary judgment motion, arguing that even if Rippy had conducted the operations required to take the lease into the secondary term under the operations clause, a cessation of production had occurred lasting for more than ninety days, which triggered the expiration of the Range Lease.[182] "[A]fter completing the pilot hole in March 2011, Rippy ceased operations . . . for more than ninety days" because of the challenge to the leasehold title and the Nashes' alleged repudiation of the Range Lease.[183] Rippy alleged that these actions excused Rippy's cessation of operations for more than ninety days.[184] Under Texas law, a "[l]essor[] who . . . wrongfully repudiate[s] the lessees' title by unqualified notice" of the lease's forfeiture or termination relieves the lessee from an obligation to conduct operations during the period in which the lease's validity is being determined.[185] There are two elements for repudiation of an oil and gas lease—the lease has not expired and the lessor has given unqualified notice of the lease's forfeiture or termination.[186] Additionally, reliance by the lessee on the alleged repudiation of the lessor has also been included as an element in some Texas cases. In this case, the court had already ruled that the lease had not expired, so the focus shifted to whether the lessor gave unqualified notice and the lessee relied on the alleged repudiation.[187] Rippy alleged that when the Nashes' "plac[ed] a lock on the gate to the well site and then call[ed] police," they effectively repudiated the lease.[188] KingKing and the Nashes both argued that neither the lock on the gate nor the call to police were unequivocal challenges to the title.[189] They alleged that the Nashes' motive was to try to get Rippy and KingKing to communicate and determine who controlled the lease.[190] The court determined that reasonable and fair-minded jurors could

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180. *See id.* (citing RICHARD W. HEMINGWAY, THE LAW OF OIL AND GAS 321 (2d ed. 1983) ("[T]he vast majority of well completion clauses have a condition that the lessee must have commenced operations for the drilling of a well prior to the end of the primary term. Such operative language has been generally interpreted to mean that operations for the drilling of a well, and not the actual spudding in or drilling of the hole, must have commenced prior to the end of the primary term.")).

181. *Id.* at *12.

182. *Id.* at *4.

183. *Id.* at *8.

184. *Id.*

185. *Id.* (quoting Ridge Oil Co. v. Guinn Invs., Inc., 148 S.W.3d 143, 157 (Tex. 2004)).

186. *See id.* (citing Chesapeake Exploration, L.L.C. v. Valence Operating Co., No. H-07-2565, 2008 WL 4240486, at *1, *4 (S.D. Tex. Sept. 10, 2008)).

187. *Id.* at *9–12.

188. *Id.* at *9.

189. *Id.*

190. *Id.*

conclude that placing the lock on the gate and calling the police, coupled with the Nashes challenge of Rippy's title to the lease, constituted "unqualified notice to Rippy that the Nashes considered the Range Lease to have expired," and that the trial court erred in granting KingKing's amended motion in that respect.[191]

Rippy testified that, after completing the pilot hole, he "did not complete the horizontal portion of the well and stopped working" because of the Nashes' challenge to the title.[192] KingKing argued that "there was no reliance on the alleged repudiation because Rippy continued working for several months after the alleged repudiation," and that the subsequent cessation of operations was for reasons other than the alleged repudiation.[193] The court cited *Chesapeake Exploration, L.L.C. v. Valence Operating Co.* in concluding that continuing operations was not a waiver of a repudiation defense.[194] In *Chesapeake Exploration*, the lessor argued that actions by the lessee after the alleged repudiation did not comport with its repudiation argument.[195] The court disagreed, finding no Texas case law holding that "a party claiming repudiation of a lease with an operations clause waives the repudiation defense by continuing operations," wryly noting that "it seems rather a paradox to find that a lessee can lose his right to perform more operations under the lease by performing operations under the lease."[196] In the present case, KingKing argued that Rippy did not cease operations because of the alleged repudiation, but rather because the initial rig was inadequate to complete the well and Rippy was struggling financially.[197] The court determined that there was "a genuine issue of material fact on why Rippy ceased operations," and ruled that the trial court erred in granting KingKing's amended motion for summary judgment.[198]

V. *LAMONT V. VAQUILLAS ENERGY LOPENO LTD.*

On December 11, 2013, the San Antonio Court of Appeals affirmed the decision of the 49th Judicial Court of Webb County, Texas, and held that Lamont misappropriated the Lopeno Prospect Treasure Map (Treasure Map), conspired to interfere with certain Prospect Generation Agreements (PGAs),

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191. *Id.* at *10 (internal quotation marks omitted).
192. *Id.* at *3, *10.
193. *Id.* at *7, *10.
194. *Id.* at *10–11.
195. *Id.* at *10 (quoting Chesapeake Exploration, L.L.C. v. Valence Operating Co., No. H-07-2565, 2008 WL 4240486, at *6 (S.D. Tex. Sept. 10, 2008)).
196. *Id.* (quoting *Chesapeake Exploration, L.L.C.*, 2008 WL 4240486, at *6).
197. *Id.* at *12.
198. *Id.*

and intentionally did so.[199] The court awarded Vaquillas $4.9 million in lost profits.[200]

As background, Lamont created Ricochet Energy, Inc. (Ricochet) in 1996 to develop oil and gas prospects.[201] "In 2003 and 2004, Ricochet entered into [PGAs] with Vaquillas Energy Lopeno Ltd., LLP [(Vaquillas)] and JOB Energy Partners II, Ltd. [(JOB)] whereby Ricochet agreed to generate oil and gas prospects."[202] As part of the agreements, Vaquillas and JOB were to cover Ricochet's overhead costs while it was looking for prospects.[203] Under the PGAs, Ricochet was required to "(1) identify oil and gas prospects in Texas and (2) present prospects with seismic maps to Vaquillas and JOB for their first right of refusal for exploration and development."[204] The agreements also gave Vaquillas and JOB a proprietary interest in "all acquired or generated data and interpretations of any accepted prospects."[205]

In September 2004, Ricochet successfully identified the Lopeno Prospect gas reservoir in Zapata County, Texas, under the terms of one of the PGAs.[206] "The reservoir was approximately 161 acres in size, contained between ten billion and twelve billion cubic feet of gas, and had an estimated value of between $40 million and $60 million."[207] The Lopeno Prospect was located beneath two contiguous tracts—the Worley property and the El Milagro property.[208]

Lamont began discussing the Lopeno Prospect with Vaquillas and JOB in September 2005.[209] As a result of these discussions, "Vaquillas agreed to participate as a 20% working-interest owner and JOB agreed to participate as a 15% working-interest owner."[210] Ricochet retained the remainder of the working interest.[211] Ricochet then worked to acquire leases over the surface properties, but quickly decided to lease only the Worley tract because litigation over a previous lease clouded the title to the El Milagro property.[212] During the development of the Lopeno Prospect, the Treasure Map was never made public.[213]

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199. Lamont v. Vaquillas Energy Lopeno Ltd., 421 S.W.3d 198, 205–08 (Tex. App.—San Antonio 2013, pet. denied). The Treasure Map, prepared by Ricochet's geologist, Chris Maier, was a seismic map depicting and identifying the Lopeno Prospect gas reservoir. *Id.* at 205–06.

200. *Id.*

201. *Id.* at 205.

202. *Id.*

203. *Id.*

204. *Id.*

205. *Id.*

206. *Id.*

207. *Id.* at 205–06.

208. *Id.* at 206.

209. *Id.*

210. *Id.*

211. *Id.*

212. *Id.* at 206–07.

213. *Id.*

In August 2006, Lamont decided to separate from Ricochet.[214] The agreed-upon separation arrangement between Lamont and Ricochet allowed Lamont to continue to participate in Ricochet prospects identified under the PGAs.[215] Lamont elected to participate in the Lopeno Prospect as a 29% working-interest owner.[216]

In January 2007, Lamont met with Carranco and offered Carranco 10% of Lamont's working interest in the Lopeno Prospect.[217] On February 22, 2007, Lamont met with Carranco again, at which point "Lamont provided Carranco with seismic maps of four different prospects, including the . . . Treasure Map."[218] After this meeting, Carranco wrote Lamont a check in the amount of $65,592.00 in return for 10% of Lamont's interest on each prospect.[219]

"On February 27, 2007, Lamont received a copy of the well log for Worley No. 1 and shared the findings with Carranco."[220] "Carranco testified that based on the Worley log, and no other seismic data, he quickly realized the importance of leasing the El Milagro property."[221] In late February, under the name of Montecristo Energy II (Montecristo), Lamont and Carranco undertook efforts to lease the El Milagro property.[222] Ricochet also started negotiating a lease for the same property but did not know that Lamont was involved with Montecristo.[223]

Montecristo continued to negotiate for a lease on the El Milagro property throughout the spring and summer of 2007 without obtaining any seismic data.[224] On June 4, 2007, L.O.G. Energy Development, Ltd. (LOG), owned by Lamont, hired David Miller to research the El Milagro property.[225] One week later, Montecristo offered a cash bonus in excess of $600,000.[226] Three days later, Lamont signed a contract to have a seismic reflection survey conducted on the El Milagro property.[227] Ultimately, Montecristo paid in excess of $1 million as a bonus for the El Milagro property.[228] "Shortly thereafter, Montecristo . . . assigned 60% working-interest in three wells on

214. *Id.* at 207.
215. *Id.*
216. *Id.*
217. *Id.*
218. *Id.* at 208.
219. *Id.*
220. *Id.*
221. *Id.*
222. *Id.*
223. *Id.*
224. *Id.*
225. *Id.*
226. *Id.*
227. *Id.* The opinion does not make clear whether Lamont was acting individually, as a representative of LOG, or as a representative of Montecristo when he executed this contract. *Id.* At this point, however, Lamont was generally operating as a principal of Montecristo and as a principal of LOG. *See id.* at 221–22. The opinion suggests LOG was the operating arm of Carranco and Lamont's joint venture. *See id.*
228. *Id.* at 208.

the El Milagro lease to [LOG] . . . ."[229] Over the next six months, LOG "depleted the Lopeno Prospect gas reservoir, thereby preventing Ricochet from withdrawing" gas from the Lopeno Prospect.[230] Third parties in interest, including Vaquillas, sued Lamont and Carranco for trade secret misappropriation, among other claims.[231] A jury awarded the plaintiffs $4.9 million in damages.[232]

The parties and the court, citing *In re Bass*, acknowledged that the Treasure Map was a trade secret.[233] Lamont argued, however, that because Ricochet failed to require potential investors or employees to sign confidentiality agreements before viewing the map and allowed Lamont to view the map after leaving Ricochet, the map's trade secret status was destroyed.[234] Vaquillas countered, arguing that Ricochet only showed the Treasure Map to Lamont "for the limited purpose of negotiating his agreement and electing his percentage of working-interest in the Lopeno Prospect."[235] Furthermore, Vaquillas argued that "the Treasure Map was shown only to potential Lopeno Prospect working-interest investors."[236]

The court agreed with Vaquillas.[237] The court relied primarily on the "long tradition of Texas law forbidding employees 'from using trade secret information acquired during the employment relationship in a manner adverse to [their] employer'"—even after the termination of employment.[238] The court stated that Ricochet's actions did not destroy the trade secret status of the map.[239]

Lamont also argued that he did not discover the Treasure Map by improper means because it was voluntarily provided to him by Vaquillas after he was no longer employed with Ricochet, and that he and Carranco "did not rely on the Treasure Map to lease . . . the El Milagro property," but relied on the Worley No. 1 log instead.[240] Vaquillas countered, arguing that Lamont deceived it as to how the map would be used and noted "that the Treasure Map was the only seismic information confirming the existence of gas under the El Milagro property when [Lamont] began negotiating the lease for that property."[241]

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229. *Id.* The opinion is unclear, but the author believes these wells were drilled subsequent to the lease to Montecristo.

230. *Id.*

231. *Id.*

232. *Id.* at 208–09.

233. *Id.* at 210 (citing *In re* Bass, 113 S.W.3d 735, 739 (Tex. 2003)).

234. *Id.* at 210–11.

235. *Id.* at 211.

236. *Id.*

237. *Id.*

238. *Id.* (quoting Reliant Hosp. Partners, LLC v. Cornerstone Healthcare Grp. Holdings, Inc., 374 S.W.3d 488, 499 (Tex. App.—Dallas 2012, pet. denied)).

239. *Id.* at 212.

240. *Id.* at 213.

241. *Id.*

The court again agreed with Vaquillas.[242] The court explained that "[t]he acquisition of a trade secret can be improper even if the means of acquisition are not independently wrongful."[243] The court also noted that "[t]he mere fact that knowledge of a trade secret may be acquired through lawful means . . . does not preclude protection as a trade secret" if that knowledge is secured through improper means.[244] The court iterated that "Carranco and Lamont, as potential investors, could properly review the seismic map when deciding whether they wanted to participate as working-interest owners in the Lopeno Prospect."[245] The court, however, stated that Lamont and Carranco's "review of the Treasure Map was proper solely for the purpose of deciding whether to invest in the Worley wells."[246] In assessing Lamont and Carranco's impropriety, the court based its reasoning on the timing of Montecristo's acquisition of the El Milagro property, the geographic location of the El Milagro property, and the fact that LOG was assigned a 60% working interest in the lease soon after taking the lease.[247]

Lamont argued vehemently that he and Carranco relied only on the Worley No. 1 log.[248] He argued that he was justified in interfering with the PGAs because he was entitled to exercise his contractual rights to view the map.[249] Vaquillas argued that the map was obtained by deceit, which precluded Lamont's justification defense.[250] The court rejected Lamont's argument, holding that Lamont did not conclusively establish all vital facts in support of his affirmative defenses of legal justification or privilege.[251] In assessing Lamont's culpability, the court found determinative the fact that Lamont improved his position by partnering with Carranco and Montecristo, and that Lamont's separation agreement did not allow Lamont to retain any seismic data for the Lopeno prospect.[252] The court also found it extremely telling that neither Lamont nor Carranco conducted any independent research of the Lopeno reservoir before paying a $1 million bonus for the lease.[253] The court ultimately affirmed the trial court, finding that Lamont's actions fell "below the generally accepted standards of commercial morality and reasonable conduct."[254]

242. *Id.* at 215.
243. *Id.* at 213 (quoting RESTATEMENT (THIRD) OF UNFAIR COMPETITION § 43 (1995)).
244. *Id.* (citing Sharma v. Vinmar Int'l, Ltd., 231 S.W.3d 405, 424 (Tex. App.—Houston [14th Dist.] 2007, pet. denied)).
245. *Id.* at 214.
246. *Id.* (emphasis omitted).
247. *See id.*
248. *See id.* at 214–15.
249. *Id.* at 219.
250. *Id.*
251. *Id.* at 220.
252. *See id.* at 221.
253. *See id.*
254. *Id.* at 215 (quoting E. I. DuPont de Nemours & Co. v. Christopher, 431 F.2d 1012, 1015–16 (5th Cir. 1970); Sharma v. Vinmar Int'l, Ltd., 231 S.W.3d 405, 424 (Tex. App.—Houston [14th Dist.] 2007,

Turning to damages, Lamont argued that the jury's award of lost profits was too speculative because only Lamont and Carranco could have drilled on the El Milagro property.[255] Lamont further argued that Vaquillas' expert based his calculation model on the "assumption that if [LOG] had not drilled on the El Milagro lease, no other operator would have drilled on that property."[256] Vaquillas argued that Lamont missed the broader, three-pronged point—whether a third party would have drilled on the El Milagro property or not was irrelevant because:

> (1) drilling on the El Milagro property was not an activity dependent on changing markets or speculative profits; (2) the calculation of net profits was based on certainty because it was based on actual production of gas, on geological data, and on actual profit from the El Milagro wells; and (3) [Lamont and Carranco] drained the gas reservoir.[257]

The court held that Vaquillas' expert properly calculated the lost profits and his calculations "provided a reasonably certain basis by which the jury could establish damages."[258] Accordingly, the court affirmed the jury's award of $4.9 million in lost profits to Vaquillas.[259]

VI. *LIGHTNING OIL CO. V. ANADARKO E & P ONSHORE, LLC*

On October 29, 2014, the San Antonio Court of Appeals affirmed the holding of the 365th Judicial Court of Dimmit County, Texas, and found that Lightning Oil Company (Lightning) was not entitled to "a temporary injunction to enjoin Anadarko E & P Onshore, LLC [(Anadarko)] from drilling one or more horizontal wells through its mineral estate to access and produce from Anadarko's adjacent mineral estate . . . [b]ecause Lightning failed to prove an imminent and irreparable injury."[260]

Anadarko obtained permission from Briscoe Ranch, the surface owner, pursuant to a Surface Use and Subsurface Easement Agreement, which allowed Anadarko to build drill pads and drill a well on a tract in which Anadarko had no mineral interest but was contiguous to a tract on which Anadarko owned the leasehold interest.[261]

Pursuant to two leases collectively known as the Cutlass Lease, Lightning owned leaseholds covering approximately 3,251.53 acres in

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pet. denied)).

255. *Id.* at 225.

256. *Id.*

257. *Id.*

258. *Id.* at 226.

259. *See id.*

260. Lightning Oil Co. v. Anadarko E & P Onshore, LLC, No. 04-14-00152-CV, 2014 WL 5463956, at *1 (Tex. App.—San Antonio 2014, pet. filed) (mem. op.).

261. *Id.*

Dimmit County, Texas (mineral estate).[262] Briscoe Ranch owned the severed surface estate, known as the Cochina East Ranch.[263] Briscoe Ranch also owned the rest of the mineral interest in the Cochina East Ranch and leased the interest to Anadarko.[264]

South of the mineral estate

> lies the approximately 15,200-acre Chaparral Wildlife Management Area ("Chaparral WMA") which is a wildlife sanctuary managed by the Texas Parks and Wildlife Department ("TPWD"). TPWD own[ed] the surface estate of the Chaparral WMA and a 1/6 mineral interest. The Light family, some of which formed Lightning Oil, own[ed the remaining] 5/6ths of the mineral estate.[265]

In October 2009, Anadarko obtained a lease to develop the Chaparral WMA.[266] The Chaparral WMA lease required Anadarko "to utilize off-site drilling locations 'when prudent and feasible.'"[267] As of the date of this case, "Anadarko has not drilled from the surface of the Chaparral WMA, but has drilled horizontally" from other tracts that it has leased adjacent to the Chaparral WMA.[268] "Anadarko ha[d] been attempting to negotiate a surface use agreement with TPWD for the last few years" before this litigation.[269]

Upon Anadarko informing Lightning that it intended to stake a well on the surface of the mineral estate, "Lightning opposed Anadarko's planned drilling operations and staked its own proposed well site, the Cutlass Well No. 3, at the same surface location."[270] After discussions between Lightning and Anadarko stalled, Lightning sued Anadarko seeking declaratory and injunctive relief.[271] "Based on the allegations in Lightning's petition, the trial court granted a temporary restraining order" enjoining Anadarko from using the surface of the mineral estate.[272]

At the temporary injunction hearing, Lightning offered expert testimony to describe its plans to develop the mineral estate, the nature of formations and drilling procedures in the area, and a leaseholder's obligations generally.[273] Lightning claimed Anadarko's proposed wells could potentially harm its future drilling operations.[274] "[T]he trial court found that

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262. *Id.*
263. *Id.*
264. *Id.*
265. *Id.* (footnote omitted).
266. *Id.*
267. *Id.* (quoting the lease).
268. *Id.*
269. *Id.*
270. *Id.*
271. *Id.* at *2.
272. *Id.*
273. *Id.*
274. *Id.*

Anadarko's conduct may [have] constitute[ed] a trespass . . . , but, based on the evidence presented, 'there [was] no interference' with Lightning's mineral interests under the Cutlass Lease."[275]

The court of appeals only considered whether the injunction was appropriate pending a trial on the merits.[276] The court deferred to the trial court on the merits to determine "whether Anadarko's plan to drill through Lightning's Mineral Estate to reach its own adjacent mineral estate [would] constitute a trespass" and "whether a third party surface owner with no interest in the Mineral Estate has the right to consent to such drilling activity."[277]

The court first acknowledged that to obtain a temporary injunction, Lightning must show that "it would suffer an imminent and irreparable injury if Anadarko was permitted to proceed with its plan to drill through the Mineral Estate to reach the Chaparral WMA mineral estate."[278] Anadarko argued that no evidence existed "in the record that any injury to Lightning's Mineral Estate [was] 'probable' as opposed to potential, 'imminent' as opposed to future, or 'irreparable' as opposed to compensable in damages."[279] Mr. Light, Lightning's owner, countered that "if Anadarko was allowed to drill through the Mineral Estate it 'certainly could' harm the value of the Mineral Estate" by causing damage to the producing formations through use of inadequate casing during drilling.[280] Mr. Light further explained that Anadarko's proposed plan to build "15 drill pads with five wells each . . . would place a 'tremendous burden' on Lightning" and would utterly disrupt its drilling plan.[281] "If Lightning did not timely drill the offset wells, it would 'have to pay a compensatory royalty . . . or . . . give up acreage.'"[282] Lightning went on to argue more points of possible injury to their operations in the future.[283] The court held that the evidence presented by Lightning showed:

> a potential for injury to Lightning's mineral interests in the future, and a potential for increased costs to Lightning in the future. Further, Lightning did not prove that these potential injuries [were] not susceptible to quantification and compensation, and thus failed to prove the absence of an adequate remedy at law.[284]

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275. *Id.*
276. *Id.*
277. *Id.* at *3.
278. *See id.*
279. *Id.*
280. *Id.* at *4.
281. *Id.*
282. *Id.* (alteration omitted) (quoting Mr. Light's trial testimony).
283. *See id.*
284. *Id.* at *5.

Moreover, "Lightning failed to prove that any injury to its Mineral Estate, and its rights to develop the Mineral Estate, [was] 'probable, imminent and irreparable' in the interim pending trial as required for the issuance of a temporary injunction."[285]

Texas case law does not provide a clear answer for the legal issues left for the trial court in *Lightning Oil*. *Humble Oil & Refining Co. v. L. & G. Oil Co.* established that a leasehold owner only needs permission from the surface owner to effectively drill from a tract in which it has no leasehold interest to penetrate a tract in which it holds a leasehold interest.[286] The court followed this holding two years later in *Atlantic Refining Co. v. Bright & Schiff*.[287]

Conversely, the court in *Chevron Oil Co. v. Howell* ignored the two earlier decisions on the issue and granted an injunction against Chevron from drilling a directional well from a surface tract on which it did not own the leasehold interest.[288] The court reasoned that "any time you drill into something there is bound to be some damage."[289] The Supreme Court of Texas refused review of all three of these past decisions, leaving this area of the law unsettled. *Lightning Oil* may finally provide clarity on the issue.

VII. *FOREST OIL CORP. V. EL RUCIO LAND & CATTLE CO.*

On July 24, 2014, the Houston Court of Appeals (First District) affirmed the 55th District Court in Harris County, Texas, upholding an arbitration award of $15,000,000 in actual damages, $500,000 in punitive damages, and $6,800,000 in attorneys' fees.[290] At issue was whether the Texas Railroad Commission (RRC) had exclusive and primary jurisdiction over a dispute arising from a breach of contract claim pursuant to a surface use agreement between Forest Oil Corporation (Forest Oil); James Argyle McAllen; El Rucio Land and Cattle Company, Inc.; San Jacinto Land Partnership, Ltd.; and McAllen Trust Partnership (collectively, the McAllens), or whether the arbitration award, confirmed by the trial court, was proper.[291]

Forest Oil had a lease covering 1,400 acres of the McAllen Ranch (Ranch), a 27,289.5-acre ranch in Hidalgo County, Texas.[292] Forest Oil

285. *Id.*
286. Humble Oil & Ref. Co. v. L. & G. Oil Co., 259 S.W.2d 933, 936 (Tex. Civ. App.—Austin 1953, writ ref'd n.r.e.).
287. *See* Atl. Ref. Co. v. Bright & Schiff, 321 S.W.2d 167, 169–70 (Tex. Civ. App.—San Antonio 1959, writ ref'd n.r.e.).
288. Chevron Oil Co. v. Howell, 407 S.W.2d 525, 528 (Tex. Civ. App.—Dallas 1966, writ ref'd n.r.e.).
289. *Id.* (quoting the appellant's witness).
290. *See generally* Forest Oil Corp. v. El Rucio Land & Cattle Co., 446 S.W.3d 58 (Tex. App.—Houston [1st Dist.] 2014, pet. filed) (upholding the district court's award of damages).
291. *Id.* at 64–65.
292. *Id.* at 64.

previously drilled wells on the Ranch and operated a gas treatment plant on 5.75 acres of the Ranch.[293]

In 2005, the McAllens filed suit against Forest Oil, seeking money for environmental damage allegedly caused by Forest Oil's hazardous waste disposal techniques.[294] In addition, the McAllens claimed Forest Oil donated pipe to the Ranch that contained Naturally Occurring Radioactive Material (NORM).[295] The pipe allegedly containing the NORM was subsequently used to build pens to hold endangered rhinoceroses on the McAllen-owned Santillana Ranch.[296] Further, the McAllens claimed "that James Argyle McAllen . . . had handled the NORM contaminated pipe," and such exposure had led to cancer in his leg, which required amputation.[297]

Forest Oil moved to compel arbitration based on a settlement agreement signed by Mr. McAllen and Forest Oil in 1999.[298] The 1999 settlement agreement arose from prior litigation concerning the proper payment of royalties and oil and gas leasehold development.[299] The settlement agreement resolved the royalty issues and incorporated a separate surface agreement.[300] "The Surface Agreement provided for the ongoing care and remediation of the surface estate by Forest Oil."[301]

The McAllens initially opposed arbitration of their environmental claims.[302] The Supreme Court of Texas, however, held that the arbitration clause in the settlement agreement was enforceable.[303] During the arbitration proceedings, the McAllens asserted a breach of contract action for breach of the surface agreement found within the settlement agreement.[304]

"Forest Oil assert[ed] that the trial court erred by denying its motion to vacate the Arbitration Award" and appealed the judgment of the arbitration panel, identifying five primary issues—the most relevant on appeal being that the RRC had exclusive or primary jurisdiction over the dispute.[305] Forest Oil argued that the RRC had exclusive jurisdiction over the dispute pursuant to

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293. *Id.*
294. *Id.* at 64–65.
295. *Id.* at 65.
296. *Id.*
297. *Id.*
298. *Id.*
299. *Id.*
300. *Id.*
301. *Id.*
302. *Id.*
303. *Id.* (citing Forest Oil Corp. v. McAllen, 268 S.W.3d 51, 62 (Tex. 2008)).
304. *Id.* at 66.
305. *Id.* at 68. The other four issues were the following: (1) "the arbitrator selected by the McAllens exhibited evident partiality," (2) "the arbitrators exceeded the scope of their authority," (3) "the actual damages awarded by the arbitrators resulted from gross mistake or a manifest disregard for the law," and (4) "the exemplary damages award violated the contractual limits on the arbitrators' authority." *Id.*

numerous Texas statutes.[306] Furthermore, Forest Oil reminded the court that the RRC "ha[d] been investigating the environmental contamination at the McAllen Ranch since 2007, and Forest Oil ha[d] been in the agency's voluntary cleanup program since that time."[307] Forest Oil cited this as evidence that the RRC had primary jurisdiction over the issue.[308]

In response, the court explained that the primary jurisdiction and exclusive jurisdiction doctrines are often confused.[309] Further, the court noted that each doctrine has entirely different consequences when applied.[310] "Despite similar terminology, primary jurisdiction is prudential whereas exclusive jurisdiction is jurisdictional."[311] Therefore, if the RRC had exclusive jurisdiction, as Forest Oil asserted, neither the trial court nor the arbitration panel would have had subject matter jurisdiction to make the award.[312] To that end, "[w]hether the legislature has vested exclusive jurisdiction in an agency is determined by examination and construction of the relevant statutory scheme."[313] On the other hand, primary jurisdiction, a judicially created doctrine, "operates to allocate power between courts and agencies when both have authority to make initial determinations in a dispute."[314] Thus, the court stated:

> [T]rial courts should employ the primary jurisdiction doctrine to allow an agency to initially decide an issue when "(1) an agency is typically staffed with experts trained in handling the complex problems in the agency's purview; and (2) great benefit is derived from an agency's uniformly interpreting its laws, rules, and regulations, whereas courts and juries may reach different results under similar fact situations."[315]

The court held that none of the statutory authority cited by Forest Oil clearly or plainly established intent by the legislature to vest exclusive jurisdiction in the RRC "to abrogate or to supplant a landowners' [sic] right to obtain common-law relief for injuries caused to his property by environmental contamination."[316] The court noted that "[n]othing in the statutory scheme prohibits a landowner from suing a polluter under established common-law causes of action, such as nuisance and trespass, to

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306. 16 TEX. ADMIN. CODE §§ 4.201–.635 (2014); TEX. HEALTH & SAFETY CODE ANN. § 401.415 (West 2010); TEX. NAT. RES. CODE ANN. § 91.101 (West 2011); TEX. WATER CODE ANN. § 26.131(a)(1) (West 2008).
307. *El Rucio Land & Cattle Co.*, 446 S.W.3d at 72.
308. *Id.* at 72–73.
309. *Id.* at 68.
310. *Id.*
311. *Id.* (citing Subaru of Am., Inc. v. David McDavid Nissan, Inc., 84 S.W.3d 212, 220 (Tex. 2002)).
312. *Id.*
313. *Id.*
314. *Id.* (citing *Subaru of Am., Inc.*, 84 S.W.3d at 221).
315. *Id.* (quoting *Subaru of Am., Inc.*, 84 S.W.3d at 221).
316. *See id.* at 68, 71.

obtain established common-law remedies."[317] "The statutes also do not provide the [RRC] with authority to grant a remedy for wrongs that arise under the common law."[318] The court reasoned that determining that the RRC had "exclusive jurisdiction to address property damage caused by oilfield operations through the agency's regulatory authority would foreclose a landowner's redress for injury to his property for which he is entitled under the common law."[319]

With regard to primary jurisdiction, the court found that because "the causes of action presented and the relief pursued by the McAllens in the arbitration" were not derived from "Forest Oil's non-compliance with [RRC] rules and regulations[,] . . . . the claims [did] not require the agency's regulatory or administrative expertise or an interpretation of the [RRC's] rules or regulations."[320] Thus, the RRC did not have primary jurisdiction as asserted by Forest Oil.[321] The court reasoned that simply because the RRC "might have jurisdiction to determine some facts related to a controversy does not [preclude] a court, or in this case, the arbitrators, of jurisdiction to make the underlying factual determinations."[322]

VIII. *CADE V. COSGROVE*

On April 3, 2014, the Fort Worth Court of Appeals delivered an opinion reversing the trial court's summary judgment and holding that the doctrine of merger does not necessarily bar an equitable claim for reformation, and that the statute of limitations period does not begin to run against a claimant seeking deed reformation because of mutual mistake until the claimant knows—or with reasonable diligence should have known—of the mutual mistake.[323] Because the court of appeals found there were questions of fact regarding when the claimant knew or should have known of the mistake in the deed, the court remanded the action for trial.[324]

"On September 21, 2006, the Cades and the Cosgroves executed a contract for the sale of the Cades' property in Arlington, Texas."[325] The parties' sales contract expressly provided that the Cades would reserve all mineral rights.[326] At the time of contract execution, the mineral rights had been leased to an oil company.[327] The warranty deed, executed at closing in

317. *Id.* at 71.
318. *Id.*
319. *Id.*
320. *Id.* at 73.
321. *Id.* at 74.
322. *Id.* at 73.
323. Cade v. Cosgrove, 430 S.W.3d 488, 489 (Tex. App.—Fort Worth 2014, pet. granted).
324. *Id.*
325. *Id.* at 492.
326. *Id.*
327. *Id.*

October 2006, however, contained no mineral reservation.[328] On December 11, 2008, the Cades sent the lessee a letter notifying the company of their address change.[329] Subsequently, the lessee "sent the Cades two shut-in [royalty] checks dated January 7, 2009 and January 21, 2010."[330] "On October 25, 2010, [the lessee] mailed the Cades a letter informing them of their rights as royalty owners."[331]

It was not until 2010 that the Cades learned of the warranty deed's title issue and that Chesapeake—tipped off by parties unmentioned in the opinion—had instead sent deposit royalty forms to Cosgrove.[332] The Cades asked Cosgrove to execute a correction deed providing that the mineral rights had not been conveyed, but Cosgrove refused to sign.[333]

The Cades filed suit in February 2011, seeking declaratory judgment that they owned the minerals, "fee forfeiture, tortious interference with contractual relationship, and civil theft."[334] "The Cades filed a motion for partial summary judgment, and Cosgrove filed a motion for summary judgment" asserting that the statute of limitations and the merger doctrine precluded the Cades' causes of action as a matter of law.[335] Next, "[t]he trial court signed an order granting Cosgrove's motion for summary judgment, denying the Cades' motion, and dismissing the Cades' claims."[336] Then, "[t]he trial court signed a final judgment denying Cosgrove's motion [for attorney's fees], stating that 'it would be inequitable and unjust to award attorney's fees based on the facts in this lawsuit.'"[337] Both sides appealed.[338]

The court of appeals, reviewing the appeals de novo, first discussed the application of the merger doctrine.[339] The Cades never denied that the warranty deed had conveyed the interest.[340] "Cosgrove argued that the doctrine of merger prohibited the Cades from using the terms of the sales contract to contradict the terms of the deed."[341] The court noted that, "[g]enerally, the terms of a sales contract are merged into the deed, and the deed is considered the final expression of the parties' agreement."[342]

328. *Id.*
329. *Id.*
330. *Id.*
331. *Id.*
332. *Id.*
333. *Id.*
334. *Id.*
335. *Id.*
336. *Id.*
337. *Id.*
338. *Id.*
339. *Id.* at 493.
340. *Id.* at 494.
341. *Id.* at 493.
342. *Id.* (citing Harris v. Rowe, 593 S.W.2d 303, 306 (Tex. 1979); Munawar v. Cadle Co., 2 S.W.3d 12, 16–17 (Tex. App.—Corpus Christi 1999, pet. denied)).

Application of the merger doctrine can be avoided, however, "by alleging and proving a mistake in the execution of the deed."[343]

The Cades countered that "the deed should be reformed because the deed's omission of their reservation of their mineral interest was a mutual mistake."[344] The court agreed that "[a] deed may be reformed on the ground of mutual mistake" and that a "[u]nilateral mistake by one party, and knowledge of that mistake by the other party, is equivalent to mutual mistake."[345] Therefore, the merger doctrine did "not prevent the Cades from seeking reformation of the deed based on mutual mistake."[346] Noting that the contract expressly provided that the Cades would retain the property's mineral rights—a fact Cosgrove did not deny—and that the Cades had raised other fact issues regarding the existence of a mutual mistake, summary judgment should not have been granted for Cosgrove regarding application of the merger doctrine.[347]

Turning to the statute of limitations issue, the court first observed that more than four years had passed between the execution of the warranty deed and the present litigation—a period the Cades admitted was longer than the statute of limitations.[348] The court then cited the general Texas rule that a grantor is presumed to have notice of the contents of a deed.[349] This presumption causes the statute of limitations to begin running at execution of the deed and can be rebutted, the court noted, in various circumstances such as when subsequent conduct indicates that a mutual mistake has occurred.[350] Analyzing Texas case law, the court further noted instances where the presumption was rebutted because of mention in the deed of a prior reservation earlier in the chain of title, apparently allowing the grantor in those cases to seek equitable relief.[351] Concerning the timing of when the party seeking reformation due to mutual mistake *should* have known of the mistake, the court noted an instance of the party seeking reformation when receiving delay rentals "indicate[d] that there may be an issue of fact" about whether the party should have known of the mistake.[352] The court took particular interest in the most recent Texas Supreme Court case to consider deed reformation after limitations had run, *Lesley v. Veterans Land Board*,

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343. *Id.* (citing *Harris*, 593 S.W.2d at 306; Turberville v. Upper Valley Farms, Inc., 616 S.W.2d 676, 678 (Tex. Civ. App.—Corpus Christi 1981, writ denied)).

344. *Id.*

345. *Id.* (citing Davis v. Grammer, 750 S.W.2d 766, 768 (Tex. 1988)).

346. *Id.*

347. *Id.* at 493–94.

348. *Id.* at 494.

349. *Id.* (citing Sullivan v. Barnett, 471 S.W.2d 39, 45 (Tex. 1971)).

350. *Id.*

351. *Id.* at 494–95 (discussing Miles v. Martin, 321 S.W.2d 62, 67 (Tex. 1959)). The *Miles* court noted that the parties "may have been mutually mistaken as to the legal effect of [the deed's] provisions and believed that the instrument effectively reserved . . . a one-fourth mineral interest in addition to that already owned by [the previous grantor]." *Miles*, 321 S.W.2d at 67.

352. *Miles*, 321 S.W.2d at 70.

wherein the supreme court held that the party seeking reformation in a deed with a "confusing mineral reservation" was not barred by the statute of limitations.[353]

Ultimately, the *Cade* court expressly held that "a mutual mistake in a deed is a type of injury for which the discovery rule is available" to overcome the presumption that parties are on notice of the contents of the conveyances they execute.[354] Because the presumption may be rebutted, the court held that "a grantor may introduce, and the factfinder may consider, evidence disputing that the grantor actually knew of the deed's contents at the time of its execution and that the grantor should have known of the deed's contents within the limitation period."[355] The court decided "a mutual mistake in a deed is an injury that a grantor is unlikely to discover within the prescribed limitations, despite due diligence, unless some circumstance puts the grantor on notice of the mistake."[356] Noting that the Cades had presented sufficient evidence to raise a fact issue about whether they actually knew or should have known of the deed's contents within the limitations period, the court held "that the trial court should not have granted summary judgment for Cosgrove on the reformation claim based on [the statute of] limitation[s]" and therefore remanded the claim.[357]

<u>**CASES FROM OTHER STATES**</u>

IX. *WARREN V. CHESAPEAKE EXPLORATION, L.L.C.*

On July 16, 2014, the Fifth Circuit considered a Texas oil and gas lease and found that, despite language in the lease explicitly prohibiting deduction of post-production costs from the lessor's royalty, since the royalty clause provided that the "amount realized" was to be computed at the wellhead, deduction of post-production costs incurred by lessees in getting marketable natural gas from the wellhead to market was permitted.[358] The court reasoned that the use of the phrase "amount realized by Lessee, computed at the mouth of the well" in the royalty clause resulted in a royalty based on net proceeds and, therefore, the physical point to use as a basis to calculate net proceeds was the mouth of the well.[359]

Charles Warren and Robert Warren initially "brought suit against Chesapeake Exploration, L.L.C. and Chesapeake Operating, Inc. (collectively, the Chesapeake Entities), claiming that they breached royalty

353. *Cade*, 430 S.W.3d at 500 (discussing Lesley v. Veterans Land Bd., 352 S.W.3d 479, 484–86 (Tex. 2011)).
354. *Id.* at 502.
355. *Id.* at 503.
356. *Id.* at 504.
357. *Id.* at 506.
358. Warren v. Chesapeake Exploration, L.L.C., 759 F.3d 413, 417–18 (5th Cir. 2014).
359. *Id.*

provisions in oil and gas leases by deducting post-production costs from the sales proceeds of natural gas."[360] The Javeeds later joined the suit, asserting similar claims.[361] Applying Texas law found in *Heritage Resources, Inc. v. NationsBank*, the Federal District Court for the Northern District of Texas granted the Chesapeake Entities' motion to dismiss and held the plaintiffs' claims were precluded as a matter of law.[362]

The Texas Supreme Court held in *Heritage* that a lessee could deduct transportation costs for gas from royalties owed because the lease in question provided that gas royalties would be "the market value at the well of 1/5 of the gas so sold or used . . . provided, however, that there shall be no deductions from the value of the Lessor's royalty by reason of any required processing, cost of dehydration, compression, transportation or other matter to market such gas."[363] The court ruled the lessee could still deduct transportation costs despite the language.[364]

On appeal, the Fifth Circuit first noted that the relevant provisions in Chesapeake Exploration's leases with the Warrens were all identical.[365] The Warren leases included a pre-printed lease form and an attached addendum.[366] The attached addendum of each lease included the following language:

> Notwithstanding anything to the contrary, herein contained, all royalty paid to Lessor shall be free of all costs and expenses related to the exploration, production and marketing of oil and gas production from the lease including, but not limited to, costs of compression, dehydration, treatment and transportation. Lessor will, however, bear a proportionate part of all those expenses imposed upon Lessee by its gas sale contract to the extent incurred subsequent to those that are obligations of Lessee.[367]

The addendum to the Warrens' leases further stated:

> It is expressly agreed that the provisions of this Exhibit shall super[s]ede any portion of the printed form of this Lease which is inconsistent herewith, and all other printed provisions of this Lease, to which this is attached, are in all other things subrogated to the express and implied terms and conditions of this Addendum.[368]

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360. *Id.* at 414.
361. *Id.*
362. *Id.* at 414–15; *see* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 120 (Tex. 1996).
363. *Heritage Res., Inc.*, 939 S.W.2d at 120–21.
364. *Id.* at 122–23.
365. *Warren*, 759 F.3d at 416.
366. *Id.*
367. *Id.*
368. *Id.* (alteration in original).

The Warrens argued that the district court was too quick to apply *Heritage* and failed to consider all the specific lease language in the Warrens' leases and how it differed from the lease language encountered in *Heritage*.[369] The court disagreed, opining that *Heritage* expressly recognized that parties may contract to make royalty payable to the lessor in an oil and gas lease free of post-production costs, but that the Warrens' leases failed to accomplish this.[370]

The Warrens' leases provided that the lessors were "entitled to 22.5% 'of the amount realized by Lessee, computed at the mouth of the well.'"[371] The court reasoned that if the lease had instead provided simply that the Warrens would "receive 22.5% of the amount realized by Lessee, there would be little question that the Warrens would be entitled to 22.5% of the sales contract price that the lessee received, with no deduction of post-production costs."[372] But, since the phrase "'amount realized by Lessee, computed at the mouth of the well' means that the royalty is based on net proceeds, . . . the physical point to be used as the basis for calculating net proceeds is the mouth of the well."[373]

The court, quoting *Judice v. Mewbourne Oil Co.*, noted that "the phrase 'net proceeds' contemplates deductions."[374] Thus, "[a]bsent the addendum to the leases, Chesapeake Exploration was entitled to deduct [reasonable] post-production costs incurred in delivering marketable gas from the mouth of the well to the actual point of sale" from its sales.[375]

The court considered the addendum to be irrelevant because it was consistent with the royalty clause in the printed portion of the lease.[376] Furthermore, the addendum did not change the point at which royalty was to be calculated, which was the mouth of the well.[377] The court reiterated that if the parties had intended for the Warrens to receive 22.5% of the actual proceeds of sale regardless of the location, they could have and should have said as much in the oil and gas lease or the addendum thereto.[378]

"The Warrens acknowledge[d] that the first sentence in the addendum addressing post-production costs [was] functionally equivalent to the 'no deductions' clause in *Heritage* and [did] not accomplish the result they desire[d]."[379] The Warrens, however, asserted that the inclusion of the second sentence—"Lessor will, however, bear a proportionate part of all

369. *Id.*
370. *Id.* at 417.
371. *Id.*
372. *Id.*
373. *Id.*
374. *Id.* (quoting Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996)).
375. *Id.* at 417–18.
376. *Id.* at 418.
377. *Id.*
378. *Id.*
379. *Id.*

those expenses imposed upon Lessee by its gas sale contract to the extent incurred subsequent to those that are obligations of Lessee"—distinguished their leases from the leases in *Heritage*.[380]

The Warrens specifically asserted that the inclusion of the second sentence created two sets of obligations.[381] First, the obligations that were the "responsibility of Chesapeake Exploration under the first sentence (exploration, production, and marketing of gas, including costs of compression, dehydration, treatment, and transportation), and [second,] certain shared obligations under the second sentence (any costs incurred subsequent to Chesapeake Exploration's performance of [the first set of obligations])."[382] The crux of the Warrens' argument was that the Chesapeake Entities wrongfully deducted costs and expenses that fell into "the first set of obligations, and thus were the sole responsibility of the Chesapeake Entities."[383]

The court was not swayed by the Warrens' argument.[384] The court reasoned that the expenses "incurred subsequent to those that are obligations of Lessee" expressly provided that the lessor would bear a proportionate part of all those expenses, but did not change the fact that proceeds net of reasonable post-production costs were properly computed at the mouth of the well.[385] The court explicitly held that *Hyder* did not control.[386] The court noted that the royalty clause at issue and the facts in *Hyder* were markedly different than the *Warren* case.[387]

The court of appeals affirmed the district court's decision and dismissed the Warrens' complaint with prejudice.[388] This portion of the case is a reaffirmation and furtherance of *Heritage* insofar as oil and gas leases that include "computed at the mouth of the well" language will continue to permit lessees to deduct reasonable post-production costs incurred in getting the gas from the wellhead to the point of sale despite the inclusion of explicit cost-free royalty language.[389] Furthermore, to effect a proper cost-free royalty, lessors will have to include "computed at the point of sale" language, or leave out "mouth of the wellhead" language altogether.[390]

The court found that the Javeeds' royalty language differed substantially from the Warrens' royalty provisions.[391] In the Javeeds' pre-printed lease

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380. *Id.*
381. *Id.*
382. *Id.*
383. *Id.*
384. *Id.*
385. *Id.* at 418–19.
386. *Id.* (citing Chesapeake Exploration, L.L.C. v. Hyder, 427 S.W.3d 472, 476 (Tex. App.—San Antonio 2014, pet. granted)).
387. *Id.* (citing *Hyder*, 427 S.W.3d at 475–78).
388. *Id.*
389. *See id.* at 415–19.
390. *See id.*
391. *Id.* at 420.

form, the royalty provision provides: "As royalty, Lessee covenants and agrees . . . (b) to pay Lessor for gas and casinghead gas produced from said land (1) when sold by Lessee, 20% of the amount realized by Lessee, computed at the mouth of the well."[392] The Exhibit attached to the Javeed lease provided the following:

> Notwithstanding any of the provisions contained in the oil and gas lease to which this exhibit is attached, the following provisions shall apply:
>
> 13. The royalties to be paid by lessee are: . . . (b) on gas, including casinghead gas or other gaseous substances produced from said land or sold or used off the premises or for the extraction of gasoline or other products therefrom, the market value at the point of sale of 20% of the gas so sold or used. However, in no event shall the royalty paid to Lessor be less than the Lessor's royalty share of the actual amount realized by the lessee from the sale of oil and/or gas. Notwithstanding anything to the contrary herein contained, all royalty paid to Lessor shall be free of all costs and expenses related to the exploration, production and marketing of oil and gas production from the lease including, but not limited to, costs of compression, dehydration, treatment and transportation. Lessor will, however, bear a proportionate part of all those expenses imposed upon Lessee by its gas sale contract to the extent incurred subsequent to those that are obligations of Lessee.[393]

The court noted that the Warrens and the Javeeds filed a joint initial brief, but the initial brief "did not fully quote the provisions of the Javeeds' lease."[394] Because the Javeeds' royalty provisions differ from the Warrens' royalty provisions and the arguments in the initial briefings did not address the differences in the Javeeds' royalty provisions, the Fifth Circuit modified the district court's ruling as to the Javeeds' claim.[395] The court held that the district court should not have dismissed the Javeeds' claim with prejudice because it was not apparent from the face of the complaint that the Javeeds could not conceivably state a cause of action.[396]

X. *BRETON ENERGY, L.L.C. V. MARINER ENERGY RESOURCES, INC.*

On August 12, 2014, the United States Court of Appeals for the Fifth Circuit held that lessees of an offshore oil and gas lease had, to the extent required by Federal Rule of Civil Procedure 12(b)(6) to avoid dismissal, adequately alleged that one of several prior lessees/operators of a neighboring

392. *Id.* at 419 (quoting the lease between Chesapeake and the Javeeds).
393. *Id.* at 419–20.
394. *Id.* at 420.
395. *Id.*
396. *Id.*

lease had committed waste.[397] The court of appeals also held, however, that the lessees had failed to state a claim for unlawful drainage and trespass—claims separate from that of waste.[398]

The dispute arose from a Joint Operating Agreement (JOA) entered into by Conn Energy, Inc. (Conn) and Breton Energy, LLC (Breton) (collectively, Appellants) in 2009.[399] Conn owned a mineral lease named West Cameron 171 (WC 171), located in the Gulf of Mexico Outer Continental Shelf off the coast of Louisiana, and the JOA permitted Breton to explore WC 171 for hydrocarbons.[400] The Appellants planned to reenter a well on WC 171, specifically targeting a depth interval defined as the K–1 sands within a larger area known as the Upper Cib Op Zone.[401] The Appellants requested records from federal regulators, which revealed that a well was completed in 1999 in the K–2 sands, a target located in the lower zone—known as the Middle Cib Op Zone—and below the K–1 sands.[402] The federal records showed that the K–1 sands had yielded no production in the earlier well.[403] Appellants spent $6 million to drill and complete the K–1 sands in WC 171, but the results were meager.[404] Appellants believed that the reservoir had been depleted.[405] Appellants sued the owners and operators of the neighboring lease, the West Cameron 172 (WC 172), alleging unlawful perforation of the K–1 sands in WC 172—the hydrocarbon reservoir that WC 171 and WC 172 shared.[406] Apache Corporation (Apache) was the operator and an interest owner in WC 172's northern half.[407] Apache was the successor in interest to Mariner Energy Resources (Mariner), and before Mariner, IP Petroleum Company (IP), Pure Resources (Pure), and Forest Oil Corporation (Forest) (collectively, Appellees).[408]

Specifically, Appellants alleged that IP had perforated the K–1 sands when it drilled in the northwestern corner of WC 172 in 1998.[409] At that time, IP submitted drilling plans to the Mineral Management Service (MMS)[410] "for approval and notified Conn of its intention to drill in an area neighboring WC 171."[411] Seismic data showed two possible oil and gas reserves in the

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397. Breton Energy, L.L.C. v. Mariner Energy Res., Inc., 764 F.3d 394, 405 (5th Cir. 2014).
398. *Id.* at 409.
399. *Id.* at 396.
400. *Id.*
401. *Id.*
402. *Id.* at 396–97.
403. *Id.* at 397.
404. *Id.*
405. *Id.*
406. *Id.*
407. *Id.* at 396.
408. *Id.*
409. *Id.* at 397.
410. *Id.* "Now known as the Bureau of Ocean Energy Management, Regulation, and Enforcement ('BOEMRE')." *Id.* at 396 n.7.
411. *Id.* at 397.

WC 171 area, one in the K–1 sands and another below in the K–2 sands.[412] Although Conn objected to IP's proposed well location, MMS approved the plan, with the requirements that IP (1) produce the reservoirs as two separate completions and (2) select one zone for its completion and then obtain MMS approval for any subsequent completion, thus preventing dual completions of both the K–1 and K–2 sands.[413] In 1999, IP informed MMS that it had completed the well in the K–2 sands, but the Appellants alleged that IP had simultaneously completed the K–1 sands in addition to the K–2 sands.[414] Appellants' original complaint alleged unlawful drainage in violation of federal and Louisiana law.[415] The district court dismissed Appellants' complaint but granted leave to amend.[416] Appellants filed a second amended complaint, alleging a claim for waste "in addition to a claim for 'unlawful drainage and trespass.'"[417] The district court dismissed Appellants' second amended complaint, and Appellants appealed.[418]

The conduct alleged occurred on the Outer Continental Shelf, so the Outer Continental Shelf Lands Act (OCSLA) applied to the dispute.[419] Under the OCSLA, the law of the adjacent state—in this case Louisiana—"applies 'to the extent' it is 'not inconsistent' with federal law."[420] Like almost all states, Louisiana law incentivizes the development of oil and gas through application of the rule of capture, which prohibits claims for drainage except in the instance of negligent or intentional waste of the correlative rights of landowners in a common reservoir.[421] In the instant case, "Appellants allege[d] that Appellees committed waste by reducing the quantity of [recoverable] oil and gas," dissipating reservoir energy, and physically wasting hydrocarbons.[422] In proving the reduction of the quantity of recoverable oil and gas, Appellants made four interrelated allegations.[423]

First, Appellants alleged that, contrary to the MMS order, IP had made completions in the K–1 and K–2 simultaneously.[424] Appellants argued that the expected bottom-hole pressure of their later completion in the K–1 sands should have been approximately 5,900 pounds per square inch (psi), but the actual reservoir pressure encountered was only 1,332 psi.[425] The court considered statements from Apache's representative, Paul Gluth, who

412. *Id.*
413. *Id.*
414. *Id.*
415. *Id.*
416. *Id.*
417. *Id.*
418. *Id.*
419. *Id.* at 398; 43 U.S.C. § 1333 (2014).
420. *Breton Energy, L.L.C.*, 764 F.3d at 398 (citing 43 U.S.C. § 1333(a)(2)(A)).
421. *Id.*
422. *Id.* at 399–400.
423. *Id.* at 400–02.
424. *Id.* at 400.
425. *Id.*

confirmed that the lower pressure was a result of substantial drainage of the K–1 sands.[426] Gluth also stated that there was no geological communication between zones, no defect in the cement bond sealing, and no other explanation for the depletion of K–1 other than a perforation by IP.[427]

Second, Appellants claimed that there was commingling between the two reserve zones.[428] Appellants alleged that IP and its successors would ultimately recover more than 30% more hydrocarbons than expected from the K–2 completion "and that IP has estimated that they [would] eventually recover 50% more than expected."[429] Appellants claimed that "[t]his significant overproduction . . . suggests that the hydrocarbons in the K–1 sands had become commingled with the hydrocarbons in the K–2 sands."[430] Appellants also argued that the pressure in the two reserve zones was virtually equal—further evidence that the two wells were in communication and that commingling existed between K–1 and K–2.[431]

Third, Appellants alleged that the commingling between the reserve zones prevented the maximum recovery of oil and gas from each reserve zone and that this loss constituted waste.[432] Appellants relied on Gluth's statement that the commingling of two zones that are not related or not in communication naturally may not produce the same amount of hydrocarbons that the two zones would if completed separately.[433]

Fourth, Appellants alleged that IP violated MMS's dual completion notification requirement that was aimed at preventing waste.[434] Gluth explained that the dual completion requirement was a matter of conservation that protected Appellants' correlative rights because the dual completion threatened the maximum recovery of oil and gas.[435]

In summary, Appellants, noting the reduction in reservoir pressure in the K–1 sands, alleged IP had improperly used the reservoir energy by violating the MMS requirements and causing physical waste by unnecessarily dissipating reservoir energy.[436] The drop in expected bottom-hole pressure in the K–1 sands reduced the total amount of recoverable oil and gas; if IP and subsequent Appellees produced the K–1 and K–2 sands separately, the proper use of reservoir energy in the K–1 sands would have resulted.[437] Therefore, Appellees' actions resulted in physical waste as

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426. *Id.* at 400–01.
427. *Id.* at 401.
428. *Id.*
429. *Id.*
430. *Id.* (quoting the complaint) (internal quotation marks omitted).
431. *Id.*
432. *Id.*
433. *Id.*
434. *Id.*
435. *Id.*
436. *Id.* at 404.
437. *Id.* at 404–05.

defined by Louisiana law: "[T]he inefficient, excessive, or improper use or dissipation of reservoir energy . . . or producing of an oil or gas well in a manner which results, or tends to result, in reducing the quantity of oil or gas ultimately recoverable from a pool."[438]

Appellees responded to Appellants' claims with numerous interrelated arguments. First, Appellees argued that Appellants did not specifically "allege any act by any [Appellee] that resulted in the actual physical reduction of the [total] amount of oil or gas."[439] Appellees also argued that Appellants had simply "allege[d] that a greater than expected amount of oil and gas was recovered," rather than alleging that the amount recoverable was reduced, as a determination of waste would require.[440] Lastly, Appellees argued that commingling by itself is not necessarily wasteful.[441]

In response to Appellees' arguments, the court stated that at that stage in the case, the focus was on whether Appellants had plausibly alleged that commingling occurred and resulted in the loss of recoverable hydrocarbons, which Appellants had done.[442] Furthermore, the alleged breach of the dual completion notification requirement supported the inference that IP acted intentionally or negligently.[443] The court cited Appellants' complaint that Appellees reduced the recovery of oil and gas and stated that the fact "[t]hat K–2 [was] producing beyond expectations [did] not defeat an allegation that the total recoverable oil and gas in the wells has been reduced."[444] The court vacated and remanded the district court's ruling concerning Appellants' waste claim against IP, concluding that waste had been adequately alleged.[445]

Appellants also alleged that the non-perforating defendants—those in the WC-172 chain of leasehold title subsequent to IP—"committed waste by failing to submit reports to the MMS reflecting IP's perforation of K–1."[446] Appellants alleged that had those reports been submitted, the commingling of hydrocarbons from the K–1 and K–2 sands would have been prevented.[447] The court disagreed, stating that Appellants simply assumed in their pleadings "that the non-perforating defendants knew [of the] perforation of K–1 . . . and that MMS would have intervened . . . to prevent the loss of the amount of oil and gas."[448] Therefore, the Fifth Circuit upheld the district

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438. LA. REV. STAT. ANN. § 30:3(16)(a) (2007 & Supp. 2015); *see Breton Energy, L.L.C.*, 764 F.3d at 404.

439. *Breton Energy, L.L.C.*, 764 F.3d at 403.

440. *Id.* (emphasis omitted).

441. *Id.*

442. *Id.* at 403–04.

443. *Id.* at 402.

444. *Id.* at 403.

445. *Id.* at 405.

446. *Id.*

447. *Id.*

448. *Id.*

court's dismissal of Appellants' waste claim against the non-perforating defendants.[449]

In addition to waste, Appellants also claimed unlawful drainage, which they alleged was actionable under Louisiana law.[450] Specifically, under § 31:14 of the Louisiana Code (Article 14), "[a] landowner has no right against another who causes drainage . . . if the drainage results from drilling or mining operations on other lands," but this preclusion does not affect claims for relief for negligent or intentional waste under §§ 31:9–31:10.[451] Appellants argued that a violation of correlative rights had occurred, constituting waste within Article 14's meaning.[452] The court disagreed, stating that Appellants had blurred the distinction between actionable waste claims under §§ 31:9–31:10 and drainage claims squelched by § 31:14, as the definition of correlative rights excluded claims for drainage losses.[453] The court further opined that if all claims for drainage were claims for waste, the exception for negligent or intentional waste would effectively nullify Article 14's safe harbor.[454]

Appellants also argued that trespass had occurred in this instance and, alternatively, that under the Louisiana Code, the rule of capture did not apply when the landowner produced minerals in violation of MMS regulations.[455] The court disagreed with Appellants' trespass argument, stating that Appellants did not allege a physical trespass by Appellees, but rather a trespass of federal property through the violation of the terms of the lease.[456] The court recognized that even if Appellants were correct that there was a trespass, the trespass was on federal property that would constitute "other lands" under the text of Article 14.[457] Regarding non-application of the rule of capture, the court held that a regulatory violation did not fall under the trespass exception to Article 14.[458] The court stated that a landowner's regulatory noncompliance was relevant to a waste claim rather than a trespass claim.[459] The court affirmed the district court's decision denying Appellants' unlawful drainage and trespass claims.[460]

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449. *Id.* at 406.
450. *Id.*; LA. REV. STAT. ANN. §§ 31:9–:10, :14 (2000).
451. LA. REV. STAT. § 31:14; *Breton Energy, L.L.C.*, 764 F.3d at 406.
452. *Breton Energy, L.L.C.*, 764 F.3d at 406.
453. *Id.*
454. *Id.* (citing Williams v. Humble Oil & Ref. Co., 432 F.2d 165, 171–72 (5th Cir. 1970).
455. *Id.* at 407.
456. *Id.*
457. *Id.* at 408.
458. *Id.*
459. *Id.*
460. *Id.*

XI. *ALLIANCE PIPELINE L.P. V. 4.360 ACRES OF LAND, MORE OR LESS, IN THE S/2 OF SECTION 29, TOWNSHIP 163 NORTH, RANGE 85 WEST, RENVILLE COUNTY, NORTH DAKOTA*

Leonard and Ione Smith, owners of a farm located in North Dakota, brought suit against Alliance Pipeline, L.P. (Alliance) claiming they did not receive proper notice of a condemnation action Alliance brought under the regulations of the Federal Energy Regulatory Commission (FERC) to procure an easement over the Smiths' land.[461] Alliance first applied for a certificate of public convenience and necessity from FERC, as is necessary to initiate the private power of eminent domain.[462] Alliance completed the application and publicly registered it by February 2012.[463] During the same month, Alliance approached the Smiths and, through its representatives, asked to purchase an easement across their land.[464] The Smiths refused.[465] Alliance later returned with a state court order allowing it to conduct surveys.[466] On September 20, 2012, FERC approved Alliance's application, and on October 16, 2012, Alliance moved for the condemnation action to acquire the pipeline easement.[467] Finally, less than a month after FERC issued the certificate, Alliance filed a condemnation action against the Smiths' property.[468] The United States District Court for the District of North Dakota granted the motion for summary judgment, condemning the property and granting Alliance immediate use and possession of the land pending a trial on damages.[469]

The Smiths appealed to the Eighth Circuit, which reviewed the case de novo.[470] The Smiths' main contentions were that: (1) they were not provided with proper notice of Alliance's application to FERC as required by the Natural Gas Act (NGA), and more broadly, the U.S. Constitution; (2) the condemnation of the Smiths' land granted under FERC inappropriately preempted North Dakota law; (3) FERC neglected to consider criteria for siting pipelines as provided for in North Dakota law; and (4) Alliance failed to follow the regulations for proper negotiation prior to condemnation.[471]

As to the validity of the FERC application and the Smiths' other non-constitutional claims, the Eighth Circuit affirmed that the Smiths brought the

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461. Alliance Pipeline L.P. v. 4.360 Acres of Land, More or Less, in the S/2 of Section 29, Twp. 163 N., Range 85 W., Renville Cnty., N.D., 746 F.3d 362, 364 (8th Cir.), *cert. denied*, 135 S. Ct. 245 (2014).
462. *Id.*
463. *Id.*
464. *Id.*
465. *Id.* at 365.
466. *Id.*
467. *Id.*
468. *Id.*
469. *Id.*
470. *Id.*
471. *Id.* at 365–67.

action before it was ripe for judicial review, citing the NGA, which creates an internal review and administrative appeal process that must be exhausted before an action can be brought on an FERC decision.[472] Specifically, any party has thirty days to appeal to the FERC for rehearing of a decision, and then an unsatisfied party has sixty days after FERC's decision to file for review in district court.[473] Therefore, in order for the Smiths' action to be ripe, there must have first been a hearing before FERC.[474]

As to the Smiths' first contention, the court opined that notice of the FERC application must be "reasonably calculated . . . to apprise" the Smiths of Alliance's application.[475] The court held that since Alliance contacted the Smiths multiple times before the FERC Certificate was issued, and since Alliance filed its condemnation action before the thirty-day rehearing period expired, adequate notice existed.[476]

The Smiths also alleged that the granting of the condemnation right by FERC to Alliance constituted a violation of North Dakota Century Code (NDCC) § 32-15-06(1), which provides for a duty to negotiate prior to condemnation actions, and § 32-15-22, which mandates a jury's determination of value for condemned property.[477] Furthermore, according to the Smiths, § 717f(h) of the NGA requires a party seeking private condemnation power to comply with relevant state procedural law.[478]

In response, the court noted that the state-law directive of § 717f(h) had been diminished by several prior opinions.[479] Specifically, the court cited Federal Rule of Civil Procedure 71.1, which deals directly with the procedural process of condemnation and eminent domain actions, and in which Congress granted uniform condemnation procedure and mandated that "[a]ll laws in conflict with [the Federal Rules of Civil Procedure] shall be of no further force or effect after such rules have taken effect."[480] Therefore, the court held the Smiths' claim of state procedural jurisdictional primacy was in error.[481] Further, Alliance's mere use of state courts and state law to gain access for the surveying of the captioned land was insufficient to bring its condemnation action under state procedural jurisdiction.[482]

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472. *Id.* at 365–66 (citing Natural Gas Act § 19, 15 U.S.C.A. § 717r(a)–(b)).
473. *Id.*
474. *Id.* at 366.
475. *Id.* (quoting Mullane v. Cent. Hanover Bank & Trust Co., 339 U.S. 306, 314 (1950)).
476. *Id.*
477. *Id.* (citing N.D. CENT. CODE §§ 32-15-06(1), -15-22).
478. *Id.* at 366–67 (citing 15 U.S.C.A. § 717f(h)).
479. *Id*. (citing N. Border Pipeline Co. v. 64.111 Acres of Land in Will Cnty., Ill., 344 F.3d 693, 694 (7th Cir. 2003); S. Natural Gas Co. v. Land, Cullman Cnty., 197 F.3d 1368, 1372–73 (11th Cir. 1999)). *See generally* Pub. L. No. 80–245, 61 Stat. 459 (1947) (stating that Congress amended § 717f to include subsection (h) in 1947).
480. *Alliance Pipeline*, 746 F.3d at 367 (alterations in original) (quoting 28 U.S.C. § 2072(b)).
481. *Id.*
482. *Id.*

The Smiths' third contention was that the FERC failed to consider criteria for siting pipelines, which are set forth by North Dakota law. The court, however, concluded that it lacked jurisdiction to consider the Smiths' statutory challenge.[483]

Fourth, the Smiths claimed a lack of good-faith negotiation on the part of Alliance.[484] In response, the court made specific mention of good-faith negotiation and that its necessity was missing from the language of the NGA, citing in pertinent part:

> When any holder of a certificate of public convenience and necessity cannot acquire by contract, or is unable to agree with the owner of property to the compensation to be paid for, the necessary right-of-way to construct, operate, and maintain a pipe line or pipe lines for the transportation of natural gas, and the necessary land or other property, in addition to right-of-way . . . it may acquire the same by the exercise of the right of eminent domain in the district court of the United States . . . .[485]

The court then noted this passage had raised issues as to whether an implied covenant for good-faith negotiation prior to proceeding to condemning land existed within the language of the NGA.[486]

Ultimately, however, the court held that even if an implied covenant that required good-faith negotiation existed within the NGA, Alliance met such a requirement when it made the offer that the Smiths refused without a counteroffer.[487]

The Smiths' last issue covered the immediate use of their land for the pipeline.[488] The court established the balancing factors used in an application for preliminary relief: "(1) the threat of irreparable harm to the movant; (2) the state of the balance between this harm and the injury that granting the injunction will inflict on other parties litigant; (3) the probability that movant will succeed on the merits; and (4) the public interest."[489]

After consideration of these factors, the court held that the Smiths' arguments against the immediate relief ordered by the district court did not

483. *Id.* at 365–66.
484. *Id.* at 367.
485. *Id.* (quoting 15 U.S.C.A. § 717f(h)).
486. *Compare* USG Pipeline Co. v. 1.74 Acres in Marion Cnty., Tenn., 1 F. Supp. 2d 816, 822 (E.D. Tenn. 1998) (stating that courts have imposed a good-faith requirement on the holder), *and* Kern River Gas Transmission Co. v. Clark Cnty., Nev., 757 F. Supp. 1110, 1113 (D. Nev. 1990) (claiming that a holder must negotiate in good faith before acquiring the property), *with* Maritimes & Ne. Pipeline, L.L.C. v. Decoulos, 146 F. App'x 495, 498 (1st Cir. 2005) (per curiam) (contending that the plain language of the UGA fails to impose a good faith obligation on the holder).
487. *Alliance Pipeline L.P.*, 746 F.3d at 368.
488. *Id.*
489. *Id.* (quoting Dataphase Sys., Inc. v. C L Sys., Inc., 640 F.2d 109, 113 (8th Cir. 1981)); *see* N. Border Pipeline Co. v. 86.72 Acres of Land, 144 F.3d 469, 471–72 (7th Cir. 1998).

measure up against the costs to Alliance—estimated to be $540,000/day—and the interests of the public if the Smiths prevailed.[490]

Therefore, without being able to demonstrate (1) the primacy of a North Dakota state law over that of the FERC, (2) that good-faith negotiations past those that took place were required by Alliance, or (3) that the injunction sought by Alliance was more harmful to the Smiths than Alliance, the Smiths did not prevail and the court of appeals affirmed the ruling of the District Court of North Dakota in favor of Alliance.[491]

XII. *RODRIGUEZ V. KRANCER*

One of the notable vectors of litigation involving hydraulic fracturing (fracing) operations is the disclosure of the type and concentration of the chemical additives used in fracing fluid. The ingredients of fracing fluids and the concentrations of chemicals included in them are closely guarded trade secrets.[492] In 2012, the Pennsylvania General Assembly enacted an amendment to the Oil and Gas Act (Act) that requires disclosure of the amount and mixing ratios of fracing chemicals in the event of a medical emergency.[493] The plaintiff, Rodriguez, a doctor specializing in renal diseases, challenged a portion of this amendment, calling it a "Medical Gag Act" because it allows a vendor or manufacturer of the chemicals used in fracing fluid to require that disclosure of their industry secret be made subject to a confidentiality agreement.[494] Rodriguez had treated patients exposed to high levels of the various individual components of the chemical mix that typically comprises 0.5%–1.0% of the total volume of fracing fluid.[495] While he had never been asked to sign any confidentiality agreement by a vendor or manufacturer regarding a disclosure as part of a medical emergency, Rodriguez asserted that as part of his professional ethical obligation in the medical profession, he must challenge laws that are contrary to the best interests of the patient.[496] Rodriguez asserted a professional and medical obligation to obtain and collect relevant data of fracing fluids without the hindrance of confidentiality agreements, and argued that by not bringing this suit, he would be in violation of the code of medical ethics.[497] At issue was

490. *Alliance Pipeline L.P.*, 746 F.3d at 368.
491. *Id.* at 368–69.
492. 58 PA. STAT. ANN. § 3222.1(b)(11) (West Supp. 2014).
493. *Id.*
494. *Id.*; Rodriguez v. Krancer, 984 F. Supp. 2d 356, 358 (M.D. Pa. 2013).
495. *Rodriguez*, 984 F. Supp. 2d at 357.
496. *Id.* at 358; *Principles of Medical Ethics*, AM. MED. ASS'N, http://www.ama-assn.org/ama/pub/physician-resources/medical-ethics/code-medical-ethics/principles-medical-ethics.page (last visited Apr. 7, 2015).
497. *Rodriguez*, 984 F. Supp. 2d at 358–59.

whether the plaintiff had provided sufficient standing to bring suit on the constitutionality of the Act.[498]

Specifically, Rodriguez brought 42 U.S.C. § 1983 constitutional claims under the First and Fourteenth Amendments, alleging the Act harmed his ability to communicate medical information to a patient.[499] Since he could potentially fall under the restrictions of a confidentiality agreement, Rodriguez asserted that in the future he could possibly be prevented from conveying important information to a patient for diagnosing and treating an ailment caused by the chemical ingredients of fracing fluid.[500] In addition, Rodriguez asserted that the Act impeded his First Amendment rights by unlawfully conditioning the police power of the state on the waiver of his rights to free speech.[501] The defendants, the Secretary of the Pennsylvania Department of Environmental Protection, amongst other state officials and agencies, filed a motion to dismiss the plaintiff's lack of standing under Federal Rules of Civil Procedure 12(b)(1) and 12(b)(6).[502] The U.S. District Court of the Middle District of Pennsylvania agreed with the defendants.[503]

As standing is a jurisdictional issue, the plaintiff must demonstrate the factual basis of his complaint and has the burden of proof.[504] Essential to satisfy the standing requirement:

> [A] plaintiff must show (1) [he has] suffered an "injury in fact" that is (a) concrete and particularized and (b) actual or imminent, not conjectural or hypothetical; (2) the injury is fairly traceable to the challenged action of the defendant; and (3) it is likely, as opposed to merely speculative, that the injury will be redressed by a favorable decision.[505]

Further, the plaintiff must satisfy the prudential limitations on standing, which require that:

> (1) a litigant assert his [or her] own legal interests rather than those of third parties, (2) courts refrain from adjudicating abstract questions of wide public significance which amount to generalized grievances, and (3) a litigant demonstrate that her interests are arguably within the zone of interests intended to be protected by the statute, rule, or constitutional provision on which the claim is based.[506]

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498. *Id.* at 360.
499. *Id.* at 359.
500. *Id.*
501. *Id.*
502. *Id.* at 359–60.
503. *Id.* at 364.
504. *Id.* at 359–60.
505. *Id.* at 360 (quoting Friends of the Earth, Inc. v. Laidlaw Envtl. Servs. (TOC), Inc., 528 U.S. 167, 180–81 (2000)).
506. *Id.* (alteration in original) (quoting Freeman v. Corzine, 629 F.3d 146, 154 (3d Cir. 2010)).

Harm that is merely speculative or hypothetical of an injury is insufficient to establish standing.[507] Here, the court held that Rodriguez's claim was unsubstantiated by anything but mere conjectural harm and that he did not demonstrate how a hypothetical confidentiality agreement caused him, or his patients, any actual harm, but rather only speculated that such an agreement may cause harm in the future.[508] The claim that the Act harmed Rodriguez's ability to communicate medical information was mere conjecture.[509] Second, the court held that Rodriguez had not actually signed or submitted to any confidentiality agreements and, therefore, could not assert any violation of his First Amendment rights arising from the Act.[510] Further, the claim that he could be in violation of his ethical duty was not rooted in any actual harm to Rodriguez himself, as he was not under any disciplinary review, but was instead merely speculating that he could come under review.[511] Therefore, Rodriguez was found to not have standing owing to the lack of "injury-in-fact."[512]

Rodriguez argued that he had standing to bring suit because of a "well founded or reasonable fear of prosecution" and alleged that he would face a financial burden in protecting himself.[513] The court disagreed, opining that Rodriguez had not sought any information arising under the Act and that he was not required to implement any compliance measures because of the confidentiality aspect of the Act.[514] The court noted that if Rodriguez had merely done nothing but comply with the Act, he would have incurred no cost.[515] Finally, the court noted that Rodriguez's alleged injury was grounded in his speculation that the Act could have caused him to violate ethical requirements—which is insufficient to maintain standing on constitutional grounds.[516]

Therefore, the court held that Rodriguez had failed to demonstrate any actual harm and only claimed unsubstantiated, speculative harm, and thereby lacked standing.[517] Further, the court held that Rodriguez's attempt to salvage the claim of speculative harm by establishing reasonable foreseeability was without merit.[518] The case was then dismissed.[519]

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507. *Id.* at 361 (citing Reilly v. Ceridian Corp., 664 F.3d 38, 42 (3d Cir. 2011)).
508. *Id.* at 362–63.
509. *Id.*
510. *Id.* at 362.
511. *Id.* at 363.
512. *Id.*
513. *Id.* at 362 (quoting the Act).
514. *Id.* at 363.
515. *Id.*
516. *Id.*
517. *Id.* at 362–63.
518. *Id.*
519. *Id.* at 364.

XIII. *COOPERSTOWN HOLSTEIN CORP. V. TOWN OF MIDDLEFIELD* AND *NORSE ENERGY CORP. USA V. TOWN OF DRYDEN*

The contention surrounding fracing operations has led some local governments to enact total bans on drilling and other exploration and extraction activities. The towns of Dryden and Middlefield, New York, enacted such legislation and plaintiffs brought suit claiming the state Oil, Gas and Solution Mining Law (OGSML) preempted the local government code.[520]

Cities, towns, and villages in New York have "home-rule" powers, giving them the authority to manage local affairs.[521] These home-rule powers can, however, be preempted by the state under certain conditions.[522] New York municipalities operate with authority from the state by application of the Municipal Home Rule Law (MHRL) and the Town Law, which gives wide powers to local governments in matters concerning zoning laws.[523] The MHRL grants a measure of discretion to local authorities to enact laws that could protect the aesthetic and environmental aspects of their communities.[524]

The New York towns of Dryden and Middlefield permanently banned gas drilling through the use of zoning laws.[525] The plaintiffs, wanting to develop natural gas reserves, challenged both sets of laws.[526] In the first action, a lessor who owned approximately four hundred acres of minerals challenged Middlefield's law.[527] The lessor charged that the OGSML preempted all local regulation of natural gas drilling, including zoning laws.[528] In 2012, a state supreme court denied the lessor's motion for summary judgment and granted summary judgment for Middlefield, upholding the town's zoning law banning natural gas drilling.[529] Following a review of the legislative history of the OGSML, the court held:

> Neither the plain reading of the statutory language nor the history of [the OGSML] would lead this court to conclude that the phrase "this article shall supersede all local laws or ordinances relating to the regulation of the oil, gas and solution mining industries" was intended by the Legislature to

520. Cooperstown Holstein Corp. v. Town of Middlefield, 943 N.Y.S.2d 722, 726 (N.Y. Sup. Ct. 2012), *aff'd*, 964 N.Y.S.2d 431 (N.Y. App. Div. 2013), *aff'd sub nom.* Wallach v. Town of Dryden, 16 N.E.3d 1188 (N.Y. 2014); Norse Energy Corp. USA v. Town of Dryden, 964 N.Y.S.2d 714, 716 (N.Y. App. Div. 2013), *aff'd sub nom. Wallach*, 16 N.E.3d 1188.

521. *See Cooperstown*, 943 N.Y.S.2d at 728; *Norse*, 964 N.Y.S.2d at 718.

522. *See Cooperstown*, 943 N.Y.S.2d at 728–29; *Norse*, 964 N.Y.S.2d at 718–19.

523. *See Cooperstown*, 943 N.Y.S.2d at 728; *Norse*, 964 N.Y.S.2d at 718.

524. *See Cooperstown*, 943 N.Y.S.2d at 728–29; *Norse*, 964 N.Y.S.2d at 718–19.

525. *Wallach*, 16 N.E.3d at 1191–93.

526. *Id.*

527. *Cooperstown*, 943 N.Y.S.2d at 722–24.

528. *Id.* at 723–24.

529. *Id.* at 730.

> abrogate the constitutional and statutory authority vested in local municipalities to enact legislation affecting land use.[530]

In the second action, the Supreme Court, Appellate Division (Third) examined a similar zoning law being challenged by a (now bankrupt) producer.[531] The court noted that the town's zoning ordinance does not regulate mineral developers, but rather "simply establishes permissible and prohibited uses of land within the Town for the purpose of regulating land generally."[532] Therefore, the ordinance was focused on regulating traditional land use considerations such as "proximity to nonindustrial districts, compatibility with neighboring land uses, and noise and air pollution."[533] The court noted that even though the state has a policy of fostering and promoting mineral development, it does not mean municipalities have no control over mineral development within their city limits.[534]

Ultimately, on June 30, 2014, in a 5–2 decision covering both cases, the Court of Appeals of New York, the state's highest court, held that the supersession clause in the OGSML does not preempt the home-rule authority vested in municipalities to regulate land use, and therefore, state law does not preempt municipal zoning laws prohibiting natural gas drilling within city limits.[535] Much like in *Robinson Township v. Pennsylvania*,[536] the court here gave wide discretion to local governments to regulate industries that affect the environment.[537]

Similar arguments to those made by the plaintiffs in both cases were made in *State ex rel. Morrison v. Beck Energy Corp.*, in which the Ohio Ninth Court of Appeals held that a state conservation commission's permit to drill preempted any local ban on fracing under the theory that such police powers were reserved to the state.[538] The New York court, however, took a different tact in their interpretation of the plain language and history of the OGSML, coming to the opposite conclusion that the state law, though similar to the one in Ohio, did not preempt the local ban.[539] Local governments in New York are, therefore, given broader ability to ban fracing and other oil and gas exploration activity within their jurisdictions.

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530. *Id.* at 728 (quoting N.Y. ENVTL. CONSERV. LAW § 23.0303(2)).
531. Norse Energy Corp. USA v. Town of Dryden, 964 N.Y.S.2d 714, 716 (N.Y. App. Div. 2013), *aff'd sub nom. Wallach*, 16 N.E.3d 1188.
532. *Id.* at 719 (citing Frew Run Gravel Prods., Inc. v. Town of Carroll, 518 N.E.2d 920, 922 (N.Y. 1987)).
533. *Id.* at 723.
534. *Id.* at 719–20.
535. *Wallach*, 16 N.E.3d at 1202–03.
536. Robinson Twp., Wash. Cnty., Pa. v. Pennsylvania, 83 A.3d 901, 978–82 (Pa. 2013).
537. *Wallach*, 16 N.E.3d at 1202–03.
538. State *ex rel.* Morrison v. Beck Energy Corp., 2013-Ohio-356, 989 N.E.2d 85, 89, *aff'd*, 2015-Ohio-485.
539. *See supra* notes 531–34 and accompanying text.

XIV. *HIGH COUNTRY CONSERVATION ADVOCATES V. UNITED STATES FOREST SERVICE*

The Sunset Roadless Area of Colorado is comprised of 5,800 acres of local fauna and flora traversed with streams that hug the west flank of 12,700-foot Mount Gunnison and the West Elk Wilderness in western Colorado.[540] These roadless lands are managed by the U.S. Forest Service (USFS) and are part of the North Fork Valley in western Colorado, known for coal deposits, scenery, and recreational uses.[541] Intervernors in the case, subsidiaries of the Arch Coal group, wanted to explore for coal in portions of the Sunset Roadless Area, a process requiring knocking down trees and building roads.[542] To do this, they required the approval of the U.S. Department of the Interior, the Bureau of Land Management (BLM), the U.S. Department of Agriculture, and the USFS.[543] In 2012, the USFS conducted a study and released an Environmental Impact Statement (EIS) that considered the impact of certain "Lease Modifications" sought by the Arch Group subsidiaries that would allow an existing operation nearby to expand into 1,701 acres of the Sunset Roadless Area.[544] While estimating the projected recoverable coal in place, and the potential revenue from same, within the exploration area, the USFS generally examined impacts to lands adjacent to the proposed exploration area and the proportional effects to the surface vegetation.[545] The BLM conducted further studies and, in June 2013, released an Environmental Assessment (EA) that approved the coal companies' "Sunset Trail Area Coal Exploration Plan" within the 1,701-acre lease modifications area of the Sunset Roadless Area.[546]

The High Country Conservation Advocates and other environmental groups (collectively, HCCA) brought suit against the various state and federal agencies involved, alleging, among other issues, a failure by the agencies to accurately disclose the impact of various air emissions in the EIS on the lease modifications area of the Sunset Roadless Area administered by the BLM and the USFS.[547] HCCA argued that the requirements arising under the National Environmental Policy Act (NEPA)[548] mandated such disclosure

540. High Country Conservation Advocates v. U.S. Forest Serv., No. 13–cv–01723–RBJ, 2014 WL 2922751, at *1, *2–3 (D. Colo. June 27, 2014).

541. *Id.* at *1–2.

542. *Id.* at *3.

543. *Id.* at *3–4.

544. *Id.* at *4.

545. *Id.*

546. *See id.* An EA, which includes a less thorough analysis than an EIS, may be prepared in advance to evidence whether an EIS is necessary or to secure a Finding of No Significant Impact (FONSI). *Id.* at *2.

547. *See id.* at *6. The BLM manages the mineral leases of the USFS under the Mineral Leasing Act. *Id.* at *3.

548. *See id.* at *6. NEPA is a procedural statute guiding the federal agencies in their decisions to lease or engage in development on federal land. *See id.* at *1. NEPA provides for public comment and

in each relevant EIS.[549] HCCA also questioned application of Colorado state law, specifically the Colorado Roadless Rule (CRR) and whether the exceptions therein, as applied to the captioned mineral exploration area, complied with federal NEPA disclosure and analysis requirements.[550]

After participating in the public comment period for leasing of the exploration plan, the HCCA appealed the USFS's decisions to allow exploration and temporary road construction as allowed under the CRR, supported by the findings of the applicable EIS.[551] The HCCA also appealed approval of the exploration plan submitted to the BLM that called for building six miles of road to drill sites.[552]

First, the Federal District Court of Colorado established the standards courts generally follow when considering agency decisions.[553] The court noted it may only set aside the agency's decision to approve the exploration plan under the arbitrary and capricious/abuse of discretion standard.[554] Determining if a decision is arbitrary and capricious requires examination of four factors to determine whether the agency:

> (1) entirely failed to consider an important aspect of the problem,
> (2) offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise,
> (3) failed to base its decision on consideration of the relevant factors, or
> (4) made a clear error of judgment.[555]

A plaintiff must also demonstrate standing to bring these claims. Standing results from an injury-in-fact, a causal connection between the injury and conduct, and a likelihood "that the injury will be redressed by a favorable decision."[556]

As another preliminary matter, the court also considered when licenses were necessary for exploration and mining. Generally, if exploration takes place within an existing lease, it may be approved without additional approval or leasing.[557] If the exploration area is outside the original lease, an additional separate license is required.[558] The area proposed for exploration,

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transparency of the federal decision by issuing an EIS, which also details reasonable alternatives. *See id.* at *1–2.

549. *See id.* at *6.
550. *See id.* at *12.
551. *See id.* at *3–4.
552. *See id.* at *4.
553. *See id.* at *5.
554. *Id.* at *4–5.
555. *Id.* at *5 (quoting New Mexico *ex rel.* Richardson v. Bureau of Land Mgmt., 565 F.3d 683, 704 (10th Cir. 2009)).
556. *Id.* (quoting Lujan v. Defenders of Wildlife, 504 U.S. 555, 560–61 (1992)).
557. *See id.*
558. *Id.*

the Sunset Roadless Area, is somewhere between the definition of "pristine" and "disturbed," as defined in various regulations, with a diverse and expansive ecology but also with notable human activity.

First, the HCCA argued that the approved lease modification and attached EIS did not consider in enough detail the potential indirect impact upon adjacent lands that might be affected due to the proposed mineral exploration.[559] Specifically, the court noted that, under the pertinent regulations, the agency is required in its decision to make reasonable, good faith, and objective observations in enough detail to allow for meaningful public comment and informed decision making with regards to possible impacts.[560] The HCCA argued for a more specific description by the USFS describing where and how mining would take place.[561]

In response to the challenge of the HCCA, the USFS claimed that any more detail would be merely conjecture without a more specific mining plan to consider.[562] The court agreed that requiring more analysis by the government would lead to some measure of speculation because, while the general surface acreage where exploration would be permitted was known, the exact layout and methodology of mines had yet to be determined.[563] The court held it was not arbitrary or capricious, however, for agencies to speculate on indirectly affected lands based on foreseen effects on the current leased area.[564]

Second, the HCCA took issue with the adequacy of the disclosure by agencies as to the cost associated with the release of greenhouse gases (GHG) associated with the coal to be recovered.[565] The federal agencies provided analysis of the effect of GHGs in general, which they claimed was sufficient under NEPA.[566] The HCCA noted, however, that an EIS must disclose all direct, indirect, and cumulative effects of any proposed action.[567] Countering, the Government argued that it had no ability to meaningfully speculate on these effects.[568] The HCCA answered by noting the cumulative effect of the release of GHGs from several sources—such as methane and CO_2 from coal production—on global climate change, and argued that such local effects should therefore be addressed in the EIS.[569]

The court acknowledged the existence of studies considering the social costs of CO_2 and other emissions, such as the Interagency Working Group on

559. *Id.* at *6.
560. *Id.* at *7 (quoting Colo. Envtl. Coal. v. Dombeck, 185 F.3d 1162, 1177 (10th Cir. 1999)).
561. *Id.* at *8.
562. *Id.* at *7.
563. *See id.* at *8.
564. *Id.*
565. *See id.* at *6.
566. *See id.* at *8.
567. *Id.* at *9.
568. *Id.*
569. *See id.* at *8–9.

Social Cost of Carbon Technical Support Document, which details the weighing of economic benefits against the costs to flora from emissions into the atmosphere.[570] The USFS was aware of this document and even removed its analysis from the EIS after a senior official called it "controversial."[571] While the court did not require that the document needed inclusion in its original state, failure by the USFS to include any mention of such evidence and analysis—even just to describe why it was not considering such evidence—was misleading and resulted in an EIS that did not provide the necessary information as required by NEPA.[572]

Third, the HCCA challenged the sufficiency of the EIS regarding volatile organic compound (VOC) emissions from coal bed methane.[573] The agencies argued that the potential emissions were highly speculative and that existing data suggested those emissions were marginal.[574] They further offered data to demonstrate that its decision to allow development was not arbitrary, but was based on mathematical reasoning, and that the quantifying of VOC pollution would be unreliable.[575] Further, the agencies noted that in a conflict over technical data, deference is given to the agency's position.[576] The court noted that, in the past, the agencies involved in the case had acknowledged that VOC pollution was a particularly important issue, but had made no showing of quantifying any VOC pollution data in the present instance.[577] The court held that if the agencies had provided reasonable justifications for not using GHG data—or had at least given it minimal consideration—then there would be no shortcoming in the completeness of its EIS; however, completely ignoring the data without justification was arbitrary and capricious.[578]

Regarding the EIS in relation to the CRR, the HCCA again alleged inadequacy of compliance by the Government with the CRR's disclosure requirements.[579] The Government did not utilize any GHG emission data, claiming the information was too speculative.[580] The court noted, however, that the reports were able to speculate as to the number of jobs to be created by the proposed projects and even measured the economic benefits of the project to the nearest $100,000.[581] Further, the agency had speculated over the potential use of coal scrubbing, future efficiency of coal plant technology,

570. *Id.*
571. *Id.*
572. *See id.* at *10–11.
573. *Id.* at *11–12.
574. *Id.* at *12.
575. *Id.*
576. *Id.* (citing Wyoming v. USDA, 661 F.3d 1209, 1246 (10th Cir. 2011)).
577. *Id.* at *15.
578. *Id.* at *11.
579. *Id.* at *12.
580. *Id.* at *13.
581. *Id.*

and future coal consumption.[582] Further still, the economic data was based on three existing mines, illustrating that the comparison between those mines and the proposed mine was possible.[583] The court found it inconsistent for the Government to claim in the same EIS that it could reasonably estimate the amount of coal that could be produced from the proposed mining operation, but at the same time, claim that it was mere speculation to estimate emissions from the same amount of coal.[584]

The agencies also asserted that future developments in emission efficiency could reduce the output of coal emissions.[585] The court considered this as a purely speculative adoption of future technologies that was not allowed by NEPA.[586] The agencies also argued that future coal emissions may change as demand for coal changes in the future.[587] The court flatly rejected the idea that global supply and demand fluctuations of a resource like coal could measurably affect consumer consumption and, therefore, emissions from this particular mine.[588]

Further, the agencies did not give adequate analysis to the alternatives proposed by the HCCA and "[t]he existence of a viable but unexamined alternative renders an alternatives analysis, and the EA which relies upon it, inadequate."[589] While the agencies did conclude that the alternatives proposed by the HCCA were not viable for safety concerns, they did not document the justification of their reasoning.[590] While a proposed alternative that is too remote, speculative, impractical, or ineffective may not warrant analysis, the court held the agencies did not adequately show this was the case.[591]

The court held that the Government must undertake a comprehensive analysis of all environmental impacts before taking action that may impact the environment.[592] Calling this a "look before you leap" policy, the court admonished that the NEPA procedures are supposed to "ensure[] that important effects will not be overlooked or underestimated only to be discovered after resources have been committed or the die otherwise cast."[593]

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582. *Id.* at *13–14.
583. *Id.* at *14.
584. *Id.*
585. *Id.* at *15.
586. *Id.* (citing Neighbors of Cuddy Mountain v. U.S. Forest Serv., 137 F.3d 1372, 1381 (9th Cir. 1998)).
587. *Id.*
588. *Id.*
589. *Id.* at *17 (quoting Diné Citizens Against Ruining Our Env't v. Klein, 747 F. Supp. 2d 1234, 1256 (D. Colo. 2010)).
590. *Id.*
591. *Id.*
592. *Id.*
593. Robertson v. Methow Valley Citizens Council, 490 U.S. 332, 349 (1989); *see also* Marsh v. Or. Natural Res. Council, 490 U.S. 360, 371 (1989) (requiring NEPA compliance beforehand so that the agency does not "regret its decision after it is too late to correct").

Therefore, even if the HCCA later prevailed on the merits, compliance with NEPA, after bulldozing for roadcuts and drill pad construction, would make it impossible for the Government to conduct an unbiased environmental analysis of the Exploration Plan (or of the subsequent mining of the Lease Modifications, or the Colorado Roadless Rule) due to the bureaucratic momentum for a project already underway.[594]

Ultimately, the court asserted that the EIS and EA omitted information that NEPA deemed vital.[595] While the HCCA had not sought any specific remedies, the court enjoined the USFS from proceeding with facilitating development of the captioned land in any manner above or below ground, including exploration.[596] The omissions in the EIS and EA, therefore, resulted in halting any exploration or potential development.[597]

XV. *HESS CORP. V. ENI PETROLEUM US, LLC*

In September 2007, Hess Corporation (Hess) entered into a "Base Contract" with ENI Petroleum (ENI), a Delaware corporation.[598] The Base Contract was a form prepared by North American Energy Standards Board (NAESB), whereby Hess agreed to "receive and purchase" the natural gas, which ENI agreed to produce and transport.[599] The NAESB Base Contract was a broad agreement that allowed further purchases and sales to be detailed in "Transaction Confirmations" forms.[600]

In November 2007, the parties entered into Transaction Confirmations for the months of December 2007 through April 2008.[601] These Transaction Confirmations provided for a firm obligation of the purchase, sale, and delivery of 20,000 MMBtu of gas per day.[602] These agreements did not specify which party would transport the natural gas, nor that ENI would produce the gas.[603] Additionally, the form did not list "special conditions."[604] The *force majeure* clause, standard for the NAESB Base Contract, provided that "[n]either party shall be liable to the other for failure to perform [a Firm obligation,] to the extent such failure was caused by a Force Majeure. The term 'Force Majeure' as employed herein means any cause not reasonably within the control of the party claiming suspension."[605] In addition, the

594. *See High Country Conservation Advocates*, 2014 WL 2922751, at *16–18.
595. *See id.*
596. *See id.* at *18.
597. *See id.*
598. Hess Corp. v. ENI Petrol. US, LLC, 86 A.3d 723, 724 (N.J. Super. Ct. App. Div. 2014).
599. *Id.*
600. *Id.*
601. *Id.*
602. *Id.* at 725.
603. *Id.*
604. *Id.*
605. *Id.* at 726.

NAESB provided that "Force Majeure shall include, but not be limited to . . . interruption and/or curtailment of Firm transportation and/or storage by Transporters."[606]

In early April 2008, an intermediary pipeline that would transport the gas to the designated delivery pipeline—called the Tennessee Gas Pipeline on the 2i–Zone L–500 Leg (the Tennessee 500)[607]—began to leak, halting its use until June.[608] ENI sent notice that it was claiming *force majeure* per the terms of the Base Contract, which included in pertinence "but not . . . limited to . . . interruption and/or curtailment of Firm transportation and/or storage by Transporters."[609] Hess brought an action for breach of contract on the theory that, because many different intermediaries feed into the Tennessee 500 and because ENI did not specify which of these pipelines it was using in the contract, other options existed to satisfy delivery of the gas, and therefore, ENI could not claim *force majeure*.[610] The trial court agreed with Hess that ENI was under no obligation to use a specific pipeline without specifying a transporter of the gas, and that other sources may have been used, making *force majeure* unavailable as a defense to the breach of contract and damages claims resulting from eventual sale of the gas at a lower price.[611]

ENI appealed, questioning whether the ambiguous *force majeure* clause covered the failed delivery caused by the leak in the intermediate pipeline or whether ENI needed to utilize another available transporter for the gas in fulfillment of the contract.[612]

The Superior Court of New Jersey held that, without specifying a particular transporter to provide the gas to the Tennessee 500, ENI was obligated under the express terms of the contract to provide for delivery of the gas to Hess.[613] Where the *force majeure* clause did not specify a particular transporter, ENI's duty to perform hinged upon delivery, not the method of delivery.[614] Specifically, the superior court opined that ENI "was required to have gas available in the Tennessee 500 pool for plaintiff [Hess], regardless of how it got there."[615] Because ENI was free to choose another transporter, it was under no obligation to continue its use of the transporter with the leaking intermediate pipeline.[616]

The superior court also denied that the language of the NAESB providing that a *force majeure* event specifically includes interruption or

606. *Id.* (quoting the contract).
607. This is not a Winston Cup NASCAR race.
608. *Hess Corp.*, 86 A.3d at 725–26.
609. *Id.* at 726.
610. *Id.*
611. *Id.* at 726–27.
612. *Id.* at 727–28.
613. *Id.*
614. *Id.*
615. *Id.* at 728.
616. *See id.*

curtailment of firm gas transmission by the producer/transporter excused ENI's performance.[617] The court noted that *force majeure* clauses are narrowly construed and "[o]rdinarily, only if the *force majeure* clause specifically includes the event that actually prevents a party's performance will that party be excused."[618] Citing Texas case law, the superior court explained that even without an underlying agreement to provide gas via a certain pipeline, an obligation to deliver a "gas supply" to the final pipeline still exists—here, the Tennessee 500.[619] Therefore, the court held that a leak at a particular transporter's pipeline did not allow the use of the *force majeure* clause to excuse the obligation to deliver the gas.[620] ENI was obligated to deliver the gas to the Tennessee 500 pipeline regardless of which pipeline ENI used to accomplish this end goal.[621]

Because ENI did not provide for using a specific pipeline in its contract, it could not claim *force majeure* as a defense for failing to meet the obligations of the contract.[622] The Superior Court of New Jersey, therefore, rejected ENI's defense argument by the express and unambiguous words of the contract with Hess.[623]

XVI. *IN RE JOHNSON*

On July 2, 2014, the Bankruptcy Court for the Southern District of Illinois held that a debtor's working interest in oil and gas properties, including the profits earned from the sale of the extracted oil, was property of the bankruptcy estate.[624] On March 5, 1980, Raymond W. Clayton entered into a lease agreement (Clayton Lease) in which he became the lessee and operator.[625] The dispute arose out of a Joint Operating Agreement (JOA), dated September 3, 1982, by and between Raymond Clayton (the operator) and Jerry Johnson (the debtor), in which the debtor—as an interest holder in the Clayton Lease—would pay the operator a sum of money to complete a well under the terms of the JOA.[626] On November 27, 1982, pursuant to the JOA, "[the operator] assigned a 5/16 'working interest' in the Clayton Lease to [the debtor]."[627] Additionally, on August 14, 1985, Cecil and Bobbie Karnes, also interest holders in the Clayton Lease, "assigned a 1/32 'working

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617. *Id.* at 729.
618. *See id.* at 727 (citing Kel Kim Corp. v. Cent. Mkts., Inc., 519 N.E.2d 295, 296 (N.Y. 1987)).
619. *See id.* at 728 (referencing Va. Power Energy Mktg., Inc. v. Apache Corp., 297 S.W.3d 397 (Tex. App.—Houston [14th Dist.] 2009, pet. denied)).
620. *Id.* at 729.
621. *Id.*
622. *Id.*
623. *Id.*
624. *See In re* Johnson, 513 B.R. 333, 344 (Bankr. S.D. Ill. 2014).
625. *Id.* at 335.
626. *Id.*
627. *Id.* at 335–36.

interest' in the same . . . lease to [the debtor]."[628] On June 7, 2012, the debtor filed a voluntary petition for relief under Chapter 13 of the Bankruptcy Code.[629] The debtor's Chapter 13 case was later dismissed on February 4, 2013, without a confirmed plan.[630] On May 30, 2013, the debtor filed a voluntary petition under Chapter 7 of the Bankruptcy Code and a Chapter 7 trustee (the trustee) was appointed to administer the case.[631]

After his appointment, the trustee filed a motion for turnover of the debtor's working interest and the proceeds of the working interest.[632] The debtor opposed the motion, arguing that his working interest in an oil well, and the revenue earned from the sale of the extracted oil, were not property of the bankruptcy estate pursuant to 11 U.S.C. § 541(a)(1), but rather income of the debtor, which would be excluded from the definition of property of the estate.[633] Although the Bankruptcy Code sets forth the parameters of what constitutes "property of the estate," applicable state law—here Illinois law—determines the nature of an interest in the property.[634] In analyzing Illinois law, the court cited *In re Fullop* when explaining the hybrid character of an oil and gas interest.[635] In *Fullop*, the court determined that, under Illinois law, an oil and gas lease "grants to the lessee the right to enter upon the surface of the land and to reduce the oil and gas to the lessee's possession."[636] Illinois case law has classified an oil and gas leasehold as a freehold estate subject to real estate law.[637] When the hydrocarbons are brought to the surface and separated at the wellhead they are thereafter classified as personal property and governed by personal property law.[638] The court in *Fullop* decided that, while the oil and gas lease conveys a real property interest, the transactions concerning the extracted oil involve personal property interests.[639]

After describing the oil and gas property interests, the court addressed the meaning of "working interest" and noted that working interest, when

628. *Id.* at 336. Both assignment documents reflected that the debtor became an "assignee" under each assignment and not a lessee or operator. *Id.*

629. *Id.*

630. *Id.*

631. *Id.*

632. *Id.* at 340.

633. *Id.* at 335. During the period between the Chapter 13 and Chapter 7 bankruptcy cases, the debtor contended in his Chapter 7 filing that he was allowed to keep the income from his working interest in the oil and gas lease. *Id.* at 336. If the working interest was a contractual right to payment based upon the debtor's provision of post-petition services, the income from the working interest would be excluded from the bankruptcy estate under 11 U.S.C. § 541(a)(6). *Id.* at 340.

634. *Id.* at 336.

635. *Id.* (citing Karnes v. Salem Nat'l Bank (*In re* Fullop), 125 B.R. 536, 539 (Bankr. S.D. Ill. 1990), *aff'd*, 133 B.R. 627 (S.D. Ill. 1991), *aff'd as modified sub. nom.* Jones v. Salem Nat'l Bank (*In re* Fullop), 6 F.3d 422 (7th Cir. 1993)).

636. *Fullop*, 125 B.R. at 539.

637. *Id.*

638. *Id.*

639. *Id.*

describing a lessee's interest as the operator, includes the right to enter upon the land and drill the well.[640] In contrast, the term becomes narrower after the lessee assigns a fraction of the lessee's working interest, as was the case in *Johnson*.[641] Under an oil and gas lease, the working interest in an assignment of a fractional working interest "has the accepted meaning in the oil industry as the assigning of the fractional portion of the oil and gas produced from the premises, after the royalty for the share paid to the lessor is first deducted."[642]

The court found that the debtor's working interest in the Clayton Lease did not have a real property component, but was rather a personal property interest.[643] The court reasoned that none of the documents of record granted the debtor rights to enter the land and reduce the oil and gas to his possession, which is essential for a freehold estate in oil and gas in Illinois.[644]

Having determined that the working interest of the debtor was personal property, the court turned to the nature of the debtor's personal property interest in the Clayton Lease.[645] The debtor argued that he had a personal property interest in a commodity—an interest that arose upon its removal from the ground.[646] The court agreed with this assertion, but determined that this personal property interest extended beyond the interest in the oil extracted and profits realized prior to the bankruptcy filing.[647] The court also concluded that the interest included the contractual rights to post-petition oil production and accounts.[648] The court further reasoned that the assignment to the debtor gave the debtor contractual rights to payments for oil extracted in the future, and that these contractual rights to payments are personal property under Illinois law.[649]

After determining that the debtor's property interest included post-petition oil production and accounts, the court considered if this interest was property of the bankruptcy estate.[650] The debtor argued "that a contractual right to receive future payments [was] not property of the estate because it [was] income."[651] The court disagreed with this assertion, stating that "[a] post-petition payment on a pre-petition contractual interest belong[ed] to the bankruptcy estate [so long as] the payment [was not]

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640. *In re Johnson*, 513 B.R. at 337.
641. *Id.*
642. *Id.* (quoting Monica C.M. Leahy, *Assignment of Lease; Transfer*, 26 ILL. L. & PRAC. *Mining, Oil, & Gas* § 64 (Thomson Reuters May 2014)).
643. *Id.*
644. *Id.* at 337–38.
645. *Id.* at 338.
646. *Id.*
647. *Id.* at 339.
648. *Id.*
649. *Id.*
650. *Id.*
651. *Id.*

attribut[ed] to []or conditioned upon the debtor's post-petition services."[652] The trustee argued that the debtor was combining income from an asset—the working interest, which is property of the estate—with income from personal services following the commencement of the debtor's Chapter 7 case, which was not property of the estate.[653] The court agreed with the trustee, finding that the debtor did not earn the oil and gas profits from performance by the debtor.[654] Therefore, the profits failed to fall within the exception of § 541(a)(6), the portion of the Bankruptcy Code that describes what property the bankruptcy estate includes.[655] Specifically, § 541(a)(6) defines property of the estate as, "[p]roceeds, product, offspring, rents, or profits of or from property of the estate, except such as are earnings from services performed by an individual debtor after the commencement of the case."[656] According to § 541(a)(6), "where mineral rights are included as property of a bankruptcy estate, the oil and gas lease," along with any payments received now or in the future, are also property of the estate.[657]

The debtor next argued that because the bankruptcy court treated the oil and gas profits as income in the previous Chapter 13 bankruptcy, the court should treat the funds the same in the present case.[658] The court disagreed, stating that even if the argument had merit, "the debtors did not have a confirmed plan when their chapter 13 case was dismissed," leaving the debtor with "no judicial approval of their retention of the funds as income."[659]

The debtor also made an equitable claim for retention of the oil and gas interest.[660] The debtor formed the Johnson Farm Trust (Trust) and, as settlor, retained the power to amend or revoke the trust.[661] The trustee argued "that the Trust [was] property of the bankruptcy estate because the bankruptcy trustee [was] authorized to exercise [the debtor's] retained power to revoke [the] self-settled trust."[662] The debtor "retain[ed] the power[] to amend or revoke the Trust throughout his lifetime," thus making him the beneficiary of the trust.[663] The court determined that upon the date of the bankruptcy filing, the trustee obtained the rights of revocation.[664] Although the debtor argued that the trust would lose its purpose if the court ruled in favor of the trustee, the court stated that "it [was] not free to disregard legal provisions

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652. *Id.* at 339–40 (quoting Longaker v. Bos. Scientific Corp., 715 F.3d 658, 661 (8th Cir.), *cert. denied*, 134 S. Ct. 537 (2013)).
653. *Id.* at 340.
654. *Id.*
655. *Id.*; *see* 11 U.S.C. § 541(a)(6) (2012).
656. 11 U.S.C. § 541(a)(6).
657. *In re Johnson*, 513 B.R. at 340.
658. *Id.*
659. *Id.*
660. *Id.*
661. *Id.* at 341–42.
662. *Id.* at 340–41.
663. *Id.* at 342.
664. *Id.* at 343.

under § 541 [of the Bankruptcy Code] that define the property of [the] bankruptcy estate."[665]

XVII. *WINDSOR ENERGY GROUP, L.L.C. V. NOBLE ENERGY, INC.*

On July 30, 2014, the Supreme Court of Wyoming released an opinion that held that the doctrine of laches was an available defense "for breach of an oil and gas contract even though the statute of limitations had not expired."[666] The dispute arose from a JOA, entered into on June 30, 2000, between J.M. Huber Corporation (Huber), the operator, and Suncor Energy (Suncor), the sole non-operator.[667] The JOA "required the operator to notify the non-operator of lease development activities and obtain non-operator consent for certain expenditures."[668] Additionally, the JOA required the operator to bill the non-operator on a monthly basis for its share of expenses through the Joint Interest Bills (JIBs).[669] The JOA applied to successors and assignors and gave the non-operator the right to contest and audit the JIBs within two years.[670]

"On May 1, 2004, Suncor assigned its interest to Dolphin Energy Corporation (Dolphin)," and on September 1, 2004, Huber assigned its interest to Windsor Energy Group (Windsor).[671] In January 2005, Windsor began sending JIBs to Dolphin, which included lease expenses.[672] Dolphin failed to pay any JIBs, and Windsor eventually filed suit in 2007.[673] Dolphin subsequently declared bankruptcy in 2008, having never paid Windsor.[674] In December 2009, Windsor sent a demand letter to Suncor claiming that Suncor was obligated to pay the JIBs that Dolphin failed to pay.[675] Suncor did not pay the JIBs, and Windsor filed suit in district court in March 2010, alleging that Suncor, as the assignor, remained liable for the costs because Suncor had not been expressly released under the JOA or assignment.[676] Windsor sought a breach of contract claim for over $625,000 and subsequently "amend[ed] its complaint to include on-going damages, bringing the total [claim] to more than $900,000."[677]

665. *Id.* at 341, 344.
666. Windsor Energy Grp., L.L.C. v. Noble Energy, Inc., 2014 WY 96, 330 P.3d 285, 287, 291 (Wyo. 2014).
667. *Id.* at 287.
668. *Id.*
669. *Id.*
670. *Id.*
671. *Id.*
672. *Id.*
673. *Id.*
674. *Id.*
675. *Id.*
676. *Id.*
677. *Id.*

Windsor alleged in its motion for summary judgment that, "as a matter of law, . . . Suncor was liable for the costs even though [Suncor] had assigned its interest."[678] Suncor filed a motion for summary judgment, alleging that "it was not liable for the expenses incurred after its assignment to Dolphin," and alternatively, the doctrine of laches should bar Windsor's claim.[679] Partial summary judgment was granted in favor of Windsor, but the court ruled that there was an issue of material fact concerning the amount of damages.[680] "The district court held a bench trial in June 2013 and ruled Windsor's claim was barred by laches."[681] Windsor appealed the court's ruling on laches, while Suncor appealed the court's ruling that it was still liable as the assignor under the JOA.[682]

Two questions were before the supreme court: (1) whether the equitable doctrine of laches applies to breach of contract claims, and (2) whether the district court abused its discretion by deciding that Windsor's claim was barred by laches.[683] Windsor again argued that Suncor breached its duties under the JOA by not paying the JIBs, and that the doctrine of laches did not apply when a statute of limitations governed an action.[684]

The district court relied on *Moncrief v. Sohio Petroleum Co.* in deciding that the laches doctrine was an available defense in a breach of contract claim involving oil and gas interests.[685] The court in *Moncrief* stated that "the doctrine of laches [was] particularly applicable to oil and gas . . . claims" because such property interests typically have extremely volatile values.[686] Windsor claimed the district court erred in applying *Moncrief* as "it involved an equitable claim for specific performance of a contractual duty" while Windsor's claim was "a legal claim for monetary damages based on breach of contract."[687]

The court reviewed the case history of laches as a defense, "conclud[ing] that both the statute of limitation[s] and the doctrine of laches could be used as defenses" in the proper oil and gas law instances.[688] The court first noted that generally laches is an equitable defense that considers the parties' conduct, while the statute of limitations focuses on arbitrary time limits.[689] Windsor argued that laches did not apply because Windsor was not

678. *Id.* at 287–88.
679. *Id.* at 288.
680. *Id.*
681. *Id.*
682. *Id.* Although Noble Energy had acquired Suncor's interest during the course of litigation, and thus became the named defendant, the opinion continued to refer to Suncor as the defendant because the relevant documents used the name Suncor. *Id.*
683. *See id.* at 288, 291.
684. *Id.* at 289.
685. *Id.*
686. *Id.* (quoting Moncrief v. Sohio Petrol. Co., 775 P.2d 1021, 1025 (Wyo. 1989)).
687. *Id.*
688. *Id.* at 290.
689. *Id.* at 291 (citing Eblen v. Eblen, 234 P.2d 434, 442–43 (Wyo. 1951)).

seeking to recover an oil and gas interest, unlike the plaintiff in *Moncrief*.[690] The court disagreed, stating that the value of the interests in this case greatly decreased while the expenses greatly increased, all while Windsor failed to notify Suncor of its responsibility "for the costs or to keep it informed about the activity on the leases."[691] The court stated that due to the volatility of the value of the assets and the increasing financial liability involved in the present case, it was appropriate for the court to consider application of the doctrine of laches.[692] Windsor also argued that because the statute of limitations had not run, the defense of laches did not apply.[693] The court again disagreed, stating that if laches would be inapplicable when the statute of limitations governed a claim, such jurisprudence would essentially make laches useless because all actions under Wyoming law are governed by a statute of limitations.[694]

After concluding that the district court properly ruled that laches was available as a defense, the court next considered whether the district court abused its discretion when concluding that laches barred Windsor's claim.[695] To prove a defense of laches, Suncor had to demonstrate that Windsor's delay in asserting its claim was both inexcusable and that Suncor or others suffered injury, prejudice, or a disadvantage as a result.[696] "The evidence [at trial] showed that Windsor was not diligent about seeking payment from Dolphin."[697] Windsor silently waited almost two years, during which time Dolphin did not pay a single JIB, before sending a demand letter to Dolphin.[698] It took an additional three years for Windsor to send a demand letter to Suncor, which had not had an interest in the property in almost five years.[699] Windsor never sent Suncor any indication that Dolphin was not paying its JIBs or that Windsor would hold Suncor accountable for its assignee's failure to pay.[700] Windsor argued that it was not responsible for notifying Suncor of Dolphin's non-payment, yet the court concluded that "Windsor was in a better position . . . to know whether the JIBs were being paid, and Windsor should have promptly informed Suncor of Dolphin's non-performance."[701] Once Windsor did send the demand letter to Suncor in 2009, it still sent the JIBs to Dolphin until April 2013.[702] The court agreed with the district court's finding that the delay in notifying Suncor, the delay

690. *Id.* at 291–92.
691. *Id.* at 291.
692. *Id.*
693. *Id.* at 289.
694. *Id.* at 291.
695. *Id.* at 291–92.
696. *Id.* at 292.
697. *Id.*
698. *Id.*
699. *Id.*
700. *Id.*
701. *Id.*
702. *Id.*

in sending JIBs to Suncor, and the refusal to produce the underlying documents all constituted undue delay.[703]

In deciding the second element of the laches defense, the court determined that the undue delay was prejudicial to Suncor.[704] Suncor was not able to examine the JIBs for errors and "Suncor was not allowed to participate in decisions regarding the operation of the wells."[705] Suncor was also not able to protect its interests or review the JIBs to make sure the costs themselves were legitimate.[706] Additionally, Windsor waited to sue Suncor until Dolphin was long insolvent, leaving Suncor with no way of seeking subrogation or indemnification from Dolphin.[707]

Finally, Windsor argued that "Suncor was not prejudiced . . . because Suncor had no rights under the JOA to receive or inspect the JIBs."[708] Windsor claimed that Suncor was responsible for monitoring its assignee and should have asked Dolphin to seek an audit on behalf of Suncor.[709] The court disagreed with Windsor, stating that even if Suncor was responsible for getting Dolphin to demand an audit, Windsor's delay led to the expiration of the right to audit.[710] Windsor failed to provide Suncor with authorizations for expenditures (AFEs) or JIBs, and Windsor did not include Suncor in any partner meetings or in the decision-making process.[711] The court determined that Suncor could not oversee or test the costs without these AFEs or JIBs.[712] Windsor had also failed to retain most of the documents or produce the ones that still existed, making it very difficult for Suncor to understand the damages sought.[713] The court concluded that its decision that laches barred Windsor's claim against Suncor made it unnecessary to address the issue of whether Suncor was still liable under the JOA after having assigned its interest to Dolphin.[714]

703. *Id.*
704. *Id.* at 293.
705. *Id.*
706. *Id.*
707. *Id.*
708. *Id.* at 294.
709. *Id.*
710. *Id.*
711. *Id.*
712. *Id.*
713. *Id.*
714. *Id.*