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I. Introduction

The following is an update on Texas legislative activity and case law relating to oil, gas, and mineral law from August 1, 2022, to July 31, 2023.

II. Legislative and Regulatory Developments

A. RRC Adopts Weatherization Rule for Natural Gas Facilities[1]

On August 30, 2022, the Railroad Commission of Texas adopted the Weather Emergency Preparedness Standards Rule (Statewide Rule 3.66), the state's first weatherization rule for natural gas facilities. The rules implement provisions of Senate Bill 3, passed by the Texas Legislature in 2021, following Winter Storm Uri. The new rule requires critical gas facilities to weatherize to ensure continuing operations during a weather emergency. Critical facilities include natural gas wells, saltwater disposal wells, gas processing plants, intrastate underground natural gas facilities, and gas pipelines that serve electricity generation on the state's Electricity Supply Chain Map.

B. RRC Adopts Amended Carbon Storage Rules[2]

Effective September 19, 2022, the Railroad Commission of Texas adopted amendments to 16 Texas Administrative Code, Chapter 5, relating to Carbon Dioxide. The amendments implemented the changes made by House Bill 1284 and gives the RRC sole jurisdiction over carbon sequestration wells. The amendments also reflect additional federal requirements to allow the RRC to apply for enforcement primacy for federal Class VI Underground Injection Control Program.

C. RRC Amends Rule for Designation of Critical Natural Gas Facilities[3]

Effective November 21, 2022, the Railroad Commission of Texas amended its rules to implement a process for designating certain natural gas entities as critical during an energy emergency. These amendments implement provisions of Senate Bill 3 and House Bill 3648, promulgated by the Texas Legislature. The amendments to 16 Texas Administrative Code

1. New 16 TAC §3.66, Relating to Weather Emergency Preparedness Standards, Aug. 30, 2022, https://www.rrc.texas.gov/media/c5hdc4ga/rule-3-66.pdf.

2. RRC Adopts Amendments to Chapter 5 Rules Relating to Carbon Dioxide (CO2), Sept. 1, 2022, https://www.rrc.texas.gov/announcements/090122-rrc-adopts-amendments-to-chapter-5-rules-relating-to-carbon-dioxide/.

3. Amendments Adopted to Rule on Critical Designation of Natural Gas Infrastructure, Nov. 2022, https://www.rrc.texas.gov/media/umwdldwl/nto-critical-designation-rule-amendments_11-01-2022.pdf.

Rule 3.65 modify the list of natural gas facilities that are critical gas suppliers and critical customers. Gas wells producing less than 250 Mcf per day and oil leases producing less than 500 Mcf per day are excluded, as are certain enhanced oil recovery projects. Facilities not designated as critical under Rule 3.65 are not subject to the weatherization rule in Rule 3.66.

D. HB1500 – Reauthorizes the Public Utility Commission of Texas[4]

Effective September 1, 2023, House Bill 1500 reauthorizes the Public Utility Commission "PUC" of Texas through September 1, 2029. Various amendments to this bill impact the Texas power marketing. HB1500 offers guidance to the PUC on implementing the Performance Credit Mechanism under which certain electricity generators can earn a performance credit for having availability when demand surges. It also creates a services program to allow power generators to bid on a day-ahead and real-time basis for having dispatchable flexibility to address inter-hour operational changes. It requires generation facilities signed into interconnection after January 1, 2027, to maintain electricity output during peak demand periods, using on-site or off-site resources. It also establishes an allowance for building and interconnecting new transmissions line to the grid, a cost previously covered by the ratepayers.

E. SB2627 – Creates a Fund for Constructions and Modernization of Dispatchable-Electric-Generating Facilities[5]

Senate Bill 2627 creates a fund of up to $7.2 billion to encourage construction, maintenance, and modernization of dispatchable-electric-generating facilities in Texas. Separate approval to fund this program will require approval of a constitutional amendment by Texas voters in the fall of 2023. Solar and wind facilities, being non-dispatchable, and electric energy storage facilities are not eligible to receive funding. Funding mechanisms include zero or low interest loans, grants, and completion bonuses.

4. https://capitol.texas.gov/tlodocs/88R/billtext/pdf/HB01500F.pdf.
5. https://capitol.texas.gov/BillLookup/History.aspx?LegSess=88R&Bill=SB2627.

III. Judicial Developments

A. Smith v. Kingdom Investments, Limited [6]

Denbury Onshore, LLC operates the West Hastings unit in Brazoria County, Texas, which includes the Avitts B lease and Lots 36 and 43.[7] W.H. Avitts purchased Lot 43 in 1928.[8] In 1932, W.H. Avitts conveyed an undivided half interest in Lot 43 to their son, Henry, which was to vest upon the death of himself and his wife, Annie.[9] In 1936, W.H. and Annie conveyed an undivided 1/4 royalty in Lot 43 to Henry as his sole and separate property.[10] W.H and Henry purchased Lot 36 in 1929 at which time Henry was unmarried.[11]

In 1934, W.H. and Annie, his wife, and Henry and Ophelia, his wife, executed an oil and gas lease covering Lots 36 and 43 providing for a 1/8 royalty (the "Avitts B Lease").[12] The lessors then conveyed 1/4 of their 1/8 royalty interest to Standard Oil Company and another 1/4 of their 1/8 royalty interest to Gillett Hill.[13]

W.H. Avitts died testate in 1944, devising a life estate in his mineral interests to his wife, Annie, with the remainder to their six children equally.[14] By gift deed, Annie conveyed 1/28 of the 1/8 royalty to each of her six children, retaining a 1/28 interest for herself.[15] In 1964, Annie died testate, and devising her remainder 1/28 of 1/8 royalty interest to her six children equally.[16] After Annie's death, each of their children, including Henry, had received 1/6 of 1/4 of the 1/8 royalty interest in Lots 36 and 43.[17]

In 1974, Henry and Ophelia Avitts created a trust for the benefit of their five daughters. They conveyed to the trust a 0.03125 royalty interest in the Avitts B lease, being community property interest, and expressly excluded a 0.0052083 royalty interest as Henry's separate property.[18] The trust

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6. *Smith v. Kingdom Investments, Limited,* 2022 WL 3725070 (Tex. App. – Houston [14th Dist.] 2022, pet. denied Jan. 20, 2023).
7. *Id*. at 2.
8. *Id*.
9. *Id*.
10. *Id*.
11. *Id*.
12. *Id*.
13. *Id*.
14. *Id*.
15. *Id*. at 3.
16. *Id*.
17. *Id*.
18. *Id*.

terminated in 1988 and distributed the 0.03125 royalty interest to the trust beneficiaries.[19]

In 1996, Henry and Ophelia Avitts conveyed Lots 36 and 43 to the Smiths without a mineral reservation.[20] The Smiths raised challenges regarding the amount of their royalty payments in 2013.[21] Following a bench trial in 2019, the trial court concluded that the Smiths were not entitled to any royalties, and the Smiths brought an appeal.[22]

On appeal the Smiths argued that Henry's royalty interest in Lot 36 was his separate property because it was acquired prior to his marriage, and therefore, it never became a part of the trust.[23] Second, the Smiths argued that Henry's interest in Lot 43 was conveyed to him as his sole and separate property, so that interest never became a part of the trust either.[24] The appellate court agreed with the Smiths that the trial court did not recognize or address the characterization of Henry's interest as separate or community property. The court ultimately decided that Henry intended to transfer his entire 1/4 of 1/8 royalty interest in both lots to his trust, regardless of their characterization as community or separate property.[25]

The Smiths also argued that the trial court erred in finding that Henry conveyed what was effectively his separate property into the trust.[26] The appellate court reviewed the devolution of title and determined that at the time Henry and Ophelia created the trust for their daughters, Henry owned 1/4 of the 1/8 royalty interest in lots 36 and 43, as well as 1/6 of 1/4 of the 1/8 royalty interest in lots 36 and 43, all as his separate property.[27]

Because the appellate court concluded that all of Henry's royalty interest was his separate property, he could not have intended to convey his community property interest to the trust, because he did not have such an interest to convey.[28] Instead of declaring the trust conveyance completely ineffective, the court held that Henry intended to convey his entire royalty interest to the trust.[29] Therefore, the beneficiaries of the trust, Henry's

19. *Id*.
20. *Id*.
21. *Id*.
22. *Id*.
23. *Id*. at 4.
24. *Id*.
25. *Id*.
26. *Id*. at 5.
27. *Id*. at 7.
28. *Id*.
29. *Id*. at 8.

daughters, owned all of said royalty interest, and the Smiths only acquired the surface estate by virtue of the 1996 deed.[30]

B. EnerVest Operating, LLC v. Mayfield[31]

EnerVest Operating, LLC appealed the trial court's decision that it owed royalties on fuel gas and attorney's fees, contending that the trial court misconstrued gas royalty and free-use provisions in the oil and gas leases at issue.[32]

EnerVest operates gas wells in Sutton County, Texas and pays Stanley B. Mayfield and Gerry Ingham royalties for their share of gas under two identical leases. The relevant provision is:

> The royalties to be paid by lessee are . . . on gas, including casinghead gas and all gaseous substances, produced from said land and sold or used off the premises or in the manufacture of gasoline or other product therefrom, the market value at the mouth of the well of one-eighth of the gas so sold or used, provided that on gas sold at the wells the royalty shall be one-eighth of the amount realized from such sale[.][33]

EnerVest collects gas from one location on the leased premises and from one location located off the premises.[34] The gas is transported downstream for processing and sale.[35] EnerVest uses some of the gas, known as fuel gas, to power compressors and dehydrators to deliver to processing plants and downstream pipelines.[36] EnerVest does not pay Lessors Mayfield and Ingham royalty on fuel gas.[37]

Mayfield and Ingham asserted that EnerVest improperly deducted fuel gas as a post-production cost from their royalties.[38] In a declaratory judgment action, they sought reimbursement for all deductions and attorney's fees.[39] EnerVest moved for summary judgment, arguing that the gas royalty provision in the leases provided for royalty payments calculated based on the "market value at the mouth of the well," which required

30. *Id*. at 8, 9.

31. *EnerVest Operating, LLC v. Mayfield*, 2022 WL 4492785 (Tex. App. – San Antonio 2022, no pet. h.).

32. *Id*. at 1.

33. *Id*.

34. *Id*.

35. *Id*.

36. *Id*.

37. *Id*.

38. *Id*.

39. *Id*.

Mayfield and Ingham's royalties to bear their proportionate share of post-production costs, including the deduction of fuel gas from their royalties.[40]

In response, Mayfield and Ingham asserted that the gas royalty provision did not expressly allow for expense deductions and their leases included a the free-use provision, which limited what gas an operator could use free from cost.[41] The free-use provision provides that "Lessee shall have free use of oil, gas, and water from said land, except water from lessor's wells and tanks, for all drilling operations hereunder, and the royalty shall be computed after deducting any so used."[42] Mayfield and Ingham argued that this provision limited free use of gas to drilling operations on premises, and further argued that EnerVest's predecessors paid royalties on fuel gas.[43]

The appellate court noted that royalty provisions specifying "market value at the mouth of the well" require royalty holders to bear their share of post-production costs.[44] Citing language from *Burlington Res. Oil & Gas Co. LP v. Tex. Crude Energy, LLC*, the court determined that when royalty is valued "at the well[,] but the sale takes place after the product has been processed and transported . . . the sales price must be adjusted to properly calculate the royalty payment."[45] The adjustment is made by "subtract[ing] the costs of bringing the product to market (the post-production costs) from the sale price obtained at the market."[46] The court noted that "the market value at the mouth of the well" is a phrase with a commonly accepted meaning in the oil and gas industry that market value is "determined by subtracting post-production costs from downstream sale proceeds."[47]

Mayfield and Ingham argued nothing in the royalty provision requires the deduction of post-production costs, pointing out the oil royalty provision specifically stated the lessor shall bear its share of expenses for treating the oil.[48] The court rejected this argument, because it ignored the gas royalty provision's express language and because Texas precedent dictates that market value is calculated by deducting post-production costs.[49]

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40. *Id*.
41. *Id*.
42. *Id*. at 2.
43. *Id*.
44. *Id*. at 3.
45. *Id.* (citing *Burlington Res. Oil & Gas Co. LP v. Tex. Crude Energy, LLC*, 573 S.W.3d 198, 203 (Tex. 2019)).
46. *Id*.
47. *Id*. at 3.
48. *Id*.
49. *Id*.

The court next considered fuel gas a post-production cost; citing a decision by the Fifth Circuit, the court recognized fuel gas as a processing cost because "it is all used to facilitate the production of the gas that is sold," and it "contributes to the material enhancement of the value of the gas sold."[50]

Mayfield and Ingham then argued that the free-use provision limits lessee's free use of the gas to gas used for on-premises drilling operations only .Therefore, EnerVest owes them royalties on fuel gas because it was not used for on-site drilling operations.[51] The court determined that this construction ignores the plain language in the gas royalty provision.[52] The court further distinguished this lease from the royalty provisions at issue in *BlueStone Nat. Res. II, LLC v. Randle, 620 S.W.3d 380, 387 (Tex. 2021)*, because in this case the gas royalty provision required Mayfield and Ingham to bear their share of post-production costs.[53] The court harmonized the gas royalty and free-use provisions to give meaning to the "market value at the mouth of the well" language to conclude that the free use clause in the subject leases did not alter the gas royalty provision's requirement that the lessors bear their share of post-production costs.[54]

C. Davis v. COG Operating, LLC [55]

This case construes the language of a 1939 warranty deed.[56] The parties stipulated that Andreas Sessler and his wife, Johann, purchased the entire surface and mineral estate of Section 45 in 1908.[57] In March of 1926, the Sesslers signed a mineral lease with F.K. Campbell covering all of Section 45.[58] On November 1st of the same year, the Sesslers executed a deed titled "Royalty Deed" conveying part of their interest in Section 45 to W.H. Haun (the "1926 Deed").[59] In May of 1939, the Sesslers executed a "Warranty

50. *Id.* at 4 (citing *Piney Woods Country Life Sch. v. Shell Oil Co.*, 905 F.2d 840, 856–57 (5th Cir. 1990) and *Atl. Richfield Co. v. Holbein*, 672 S.W.2d 507 (Tex. App.—Dallas 1984, writ. ref'd n.r.e.) (holding no royalty due for fuel gas volumes where industrywide practice was to deduct allocated volume for fuel gas before computing settlement owed in royalties)).

51. *Id.* at 4.

52. *Id.*

53. *Id.*

54. *Id.*

55. *Davis v. COG Operating, LLC*, 658 S.W. 3d 784 (Tex. App. – El Paso 2022, pet. filed Mar. 22, 2023).

56. *Id.* at 787.

57. *Id.* at 788.

58. *Id.*

59. *Id.*

Deed" in favor of Dora Roberts, as grantee, purporting to convey the remainder of their interest in Section 45, except for a 1/4 non-participating royalty interest (the "1939 Deed").[60]

Haun and his successors have been paid 1/4 of all mineral royalties since the 1926 Deed was executed.[61] Since the execution of the 1939 Deed, the remaining 3/4 of the royalties have been paid to Roberts and her successors.[62] Since 1939, no royalties have been paid to the Sesslers or their successors.[63] In 1984, the heirs of the Sesslers contacted the then mineral lessee, Saxon Oil, claiming they were entitled to the 1/4 non-participating royalty interest under the 1939 Deed.[64] In 2017 and 2018, various Sessler heirs sold their respective interests in the 1/4 non-participating royalty interest to the "Sessler Successors."[65] The Sessler Successors notified COG Operating, LLC, the current lessee, and the Neals, the current successors to Roberts, of their claim to the ¼ non-participating royalty interest in Section 45.[66]

The 1926 Deed conveyed a "1/32 interest in and to all of the oil, gas, and other minerals, in and under and that may be produced from [Section 45] together with the right of ingress and egress[.]"[67] Said Deed indicated the lands were subject to a lease, but the Grantee was acquiring 1/4 of all of the royalty due under the lease.[68] Because the Sesslers used "in and under" language and because the 1926 Deed did not strip the grantee, Haun, of any of the traditional interests included in the mineral estate, the appellate court held the 1926 Deed conveyed an undivided 1/4 mineral interest, rather than a 1/32 mineral interest and a separate 1/4 royalty interest.[69]

The 1939 Deed conveyed all of the Sessler's interest in Section 45, and indicating "that 1/32 of the oil, gas, and other minerals has heretofore been conveyed to W.H. Haun, and this conveyance does not include such mineral interests so conveyed."[70] Next, said Deed reserved "1/4 of the 1/8 royalty usually reserved by a land owner," and "in case of production," the Sesslers would receive "1/4 of the 1/8 royalty," and "this conveyance is executed

60. *Id*.
61. *Id*.
62. *Id*.
63. *Id*.
64. *Id*.
65. *Id*.
66. *Id*.
67. *Id*. at 792.
68. *Id*.
69. *Id*. at 793.
70. *Id*. at 794.

subject to the mineral interest heretofore conveyed to W.H. Haun, and also to the 1/4 royalty interest reserved by us as hereinbefore stated."[71]

No party asserted that the 1939 Deed was ambiguous.[72] However, the court indicated a question arose as to how the 1939 Deed described the excepted interest previously conveyed to W.H. Haun.[73] Did the 1939 Deed put Dora Roberts on notice to an excepted 1/4 mineral interest or only an excepted 1/32 mineral interest? Considering the date of the deed, the estate misconception theory, and prior rulings by the Texas Supreme Court, this court held the 1939 Deed put Roberts on notice that it excluded a 1/4 mineral interest in favor of W.H. Haun.[74]

D. Citation 2002 Investment LLC v. Occidental Permian, Ltd.[75]

In 1987, Shell Western E&P, Inc. assigned numerous assets to Citation 1987 Investment Limited Partnership, pursuant to a Purchase and Sale Agreement and an Assignment (the "Shell-Citation Assignment").[76] Some of the property descriptions in Exhibit A to said Assignment included references to depth restrictions.[77]

In 1997, Shell Western assigned certain oil and gas interests to Altura Energy, Ltd. ("Altura", the assignment the "Shell-Altura Assignment").[78] Some of the interests assigned to Altura were the same interests assigned to Citation in 1987, but they were for deeper depths than referenced in the Shell-Citation Assignment.[79] In 2000, Altura changed its name to Occidental Permian, Ltd. ("Occidental").[80]

In 2006, Citation assigned to Endeavor some portion of the interests it received under the Schell-Citation Assignment.[81] In 2019, Occidental assigned to Rodeo some portion of interests it received under the Shell-Altura Assignment.[82] At dispute in this case are the "deep rights" which are the subject of the Shell-Altura Assignment.[83] Occidental argued (and the

71. *Id*.
72. *Id*.
73. *Id*.
74. *Id*. at 795.
75. *Citation 2002 Investment LLC v. Occidental Permian, Ltd.*, 662 S.W.3d 550 (Tex. App. – El Paso 2022, pet. filed Mar. 8, 2023).
76. *Id*. at 552.
77. *Id*.
78. *Id*.
79. *Id*. at 553.
80. *Id*.
81. *Id*.
82. *Id*.
83. *Id*.

trial court agreed) that the leases assigned in the Shell-Citation Assignment were depth limited, leaving deep rights free to be assigned to Altura.[84] Citation argued the Shell-Citation Assignment was not depth limited, and that Citation and Endeavor owned all rights to the leases between them.[85]

The Shell-Citation Assignment included a clause indicating the Assignor intended to assign "all rights and interest now owned by Shell Western…in the leases and other rights described herein, regardless of whether same may be incorrectly described or omitted from Exhibit A[.]"[86] Occidental argued if the court did not treat the depth references in Exhibit A as limitations on the conveyance, and no other meaning could be given to those depths, then the words are rendered meaningless.[87] Citation argued that the depth references were merely descriptions of those well or lese interests subject to agreements with third parties.[88] The appellate court disagreed, noting that Exhibit A contained no limiting language, but instead the depth references merely provided more information about the interests conveyed.[89] The court also pointed to the plain language of the express term and condition of the assignment identifying the intent to convey "all rights and interest now owned by Shell Western…in the leases and other rights described herein, regardless of whether same may be incorrectly described or omitted from Exhibit A."[90]

Finally, the court dismissed the argument that the "all rights and interests" provision was merely a Mother Hubbard clause intended to clean up small errors in legal descriptions.[91] The court specifically declined to define standard language for a Mother Hubbard clause, but noted that Occidental provided no examples of Mother Hubbard clauses which failed to reference strips, gores, or adjacent and contiguous lands.[92] Instead, the court agreed with citation that the "all rights and interests" provision was intended as a general granting clause.[93]

84. *Id*.
85. *Id*.
86. *Id*. at 556.
87. *Id*. at 557.
88. *Id*.
89. *Id*. at 558.
90. *Id*.
91. *Id*. at 559.
92. *Id*. at 560.
93. *Id*.

E. Bridges v. Uhl[94]

In May 1940, Magnus and Mrytle Klattenhoff conveyed a 640 acre tract to Virgil J. Powell via warranty deed (the "1940 Deed"), reserving a non-participating royalty interest equal to "1/2 of the usual 1/8 royalty," and if production is obtained, Grantor would receive "1/2 of the usual 1/8 royalty, or 1/16 of the total production."[95]

In April 1975, the Klattenhoffs conveyed their reserved royalty interest to their daughter (Bridges) via a royalty deed, granting an "undivided 1/2 of the usual 1/8 royalty interest, and being all of Grantor's royalty interest".[96] The parties agree Bridges still owns the non-participating royalty interest, but they disagree as to the nature and quantum of the interest.[97]

In 2013, Bridges contacted then lessee Concho Operating to inquire about its failure to pay her royalties.[98] By August of 2014, Concho Operating had acknowledged her interest and began to pay Bridges on the basis of a 1/16 "fixed" nonparticipating royalty interest.[99] Bridges disputed such calculation, contending she was owed 1/2 of the 1/4 of production based on the royalty terms of the lease.[100]

Citing the use of the double fractions, the estate misconception theory that leases could only provide for 1/8 royalties, and rulings by the Texas Supreme Court, this court held the 1940 Deed reserved a 1/2 floating royalty interest, not a 1/16 fixed royalty interest.[101] The court explained the 1940 Deed included "many of the recognized features of a floating royalty:" the use of double fractions, the multiples of 1/8, the reference to the "usual" 1/8 royalty, and the contemplation that the royalty will take effect at a later time ("if, as and when production is obtained.").[102]

F. Hahn v. ConocoPhillips Company[103]

Prior to 2002, Kenneth Hahn and his three siblings owned the mineral estate under a 74.15 acre tract in DeWitt County equally.[104] In August

94. *Bridges v. Uhl*, 663 S.W.3d 252 (Tex. App. – El Paso 2022).
95. *Id*. at 258.
96. *Id*.
97. *Id*.
98. *Id*. at 259.
99. *Id*.
100. *Id*.
101. *Id*. at 263, 264.
102. *Id*. at 265.
103. *Hahn v. ConocoPhillips Company*, 2022 WL 17351596 (Tex. App. – Corpus Christi-Edinburg 2022, pet. filed Mar. 2, 2023).
104. *Id*. at 2.

2002, Kenneth and George purported to partition their surface interests in said tract, so they each owned the surface to 37.07 acres each: Tract A to Kenneth and Tract B to George.[105]

In December 2002, Kenneth conveyed his interest in Tract A to William and Lucille Gips, reserving "'an undivided 1/2 nonparticipating interest in and to all of the royalty he now owns (same being an undivided 1/2 of his 1/4 or an undivided 1/8 royalty)" for a period of 15 years from June 9, 2002.[106] This conveyance excepted the 3/4 mineral interests owned by Kenneth's siblings.[107]

In July 2010, the Gipses entered into an oil and gas lease with Conoco providing for a 1/4 royalty and allowing for pooling (the "Conoco/Gips Lease").[108] In July 2011, Kenneth ratified the Conoco/Gips Lease.[109] In October 2011, Conoco pooled Tract A into the 307/41-acre Maurer Unit B, and in November 2011, Conoco asked Kenneth and the Gipses to stipulate as to their respective interests.[110] Their resulting stipulation indicated it was the parties' intent that Kenneth reserved 1/8 of royalty for a term of 15 years from June 9, 2002.[111]

In August 2010, Kenneth executed an oil and gas lease with Conoco covering his 1/4 mineral interest in Tract B, which was also pooled into the Maurer Unit B.[112] Later, Conoco told Kenneth it would no longer credit him with his 1/4 mineral interest in Tract B because it interpreted the August 2002 partition deeds between Kenneth and George as covering their surface and mineral interests, and not just their surface interests. This resulted in Kenneth owning no minerals in Tract B.[113]

In March 2015, Kenneth sued Conoco and the Gipses, claiming he owned a 1/4 mineral interest in Tract B and a 1/8 royalty interest in Tract A.[114] The trial court held the partition deeds covered both the surface and mineral estates in Tracts A and B, and Kenneth owned a floating NPRI in Tract A equal to 1/8 of royalty.[115]

On appeal, in February 2018, this court held the partition deeds only covered the surface estates and not the mineral estates, and Kenneth

105. *Id*.
106. *Id*.
107. *Id*.
108. *Id*.
109. *Id*. at 3.
110. *Id*.
111. *Id*.
112. *Id*.
113. *Id*.
114. *Id*.
115. *Id*. at 3, 4.

reserved a fixed 1/8 royalty in Tract A for a 15-year term.[116] This court remanded the case to the trial court, where additional issues arose.[117]

On remand, Conoco disputed the calculation of Kenneth's 1/8 NPRI in Tract A in the Maurer Unit B.[118] Kenneth argued his interest should be his 1/8 interest multiplied by Tract A's tract participation factor within the unit of 0.12058814, which would be 0.01507352.[119] Conoco argued that since Kenneth ratified the Conoco/Gips Lease, he was bound to all of the lease terms, including the 1/4 royalty.[120] This would turn Kenneth's fixed NPRI into a floating NPRI, and his interest should be reduced by the lease royalty: 1/8 of 1/4 of 0.12058814, or 0.00376838.[121]

Kenneth argued his fixed NPRI was "definitionally not diminishable by the landowner's royalty," and his 2011 ratification did not transform the fixed NPRI into a floating NPRI.[122] The trial court held Kenneth's ratification meant he was bound by all the terms of the Conoco/Gips Lease, and his interest in the pooled unit should be 0.00376838.[123]

On this appeal, the court had to decide whether the ratification transformed a fixed 1/8 NPRI into a floating NPRI subject to the 1/4 royalty in the Conoco/Gips Lease.[124] Kenneth argued (1) a fixed mineral interest cannot be diminished by the landowner's royalty; (2) he could not be bound by the landowner's royalty because he did not enter into the lease; and (3) the Gipses could not lease Kenneth's NPRI on his behalf; the ratification only affected the lease's pooling provision.[125] Conoco argued Kenneth cannot accept the benefits of ratifying a lease without also accepting the burdens of ratifying a lease, and he did not cite any Texas authority allowing a party to ratify a lease for pooling purposes only.[126]

The court explained that by executing a lease with a pooling provision, the Gipses extended an offer to Kenneth to pool his interest.[127] When he ratified the lease, Kenneth agreed to have his fixed 1/8 NPRI be subject to Tract A's tract participation factor in the Maurer Unit B, "and nothing

116. *Id*. at 5.
117. *Id*.
118. *Id*.
119. *Id*.
120. *Id*. at 6.
121. *Id*.
122. *Id*.
123. *Id*.
124. *Id*. at 9.
125. *Id*.
126. *Id*.
127. *Id*. at 11.

more."[128] The court held Kenneth did not agree to have his fixed NPRI burdened by the landowner's royalty.[129]

As to Conoco's argument that Kenneth's ratification bound him to all of the provisions of the lease, the court noted that as a non-executive, Kenneth is not due any of the "entitlements owed to the lessor under the lease," and Conoco "has not fully addressed the practical consequences of its argument."[130] In the end, Kenneth's fixed NPRI is subject to the pooling clause in the Conoco/Gips Lease and nothing else.[131]

G. Van Dyke v. Navigator Group[132]

In 1924, George H. Mulkey and Frances E. Mulkey conveyed their ranch to G.R. White and G.W. Tom, subject to a reservation of "one-half of one-eighth of all minerals and mineral rights in said land."[133] Following such conveyance and reservation, and for 90 years thereafter, the parties, their assignees and third parties engaged in transaction suggesting that each party to the 1924 conveyance owned an equal 1/2 mineral interest.[134] In 2013, after Endeavor Energy began to royalties to both parties in equal shares, the grantees' successors brought a trespass to try title action concerning $44 million in disputed royalties.[135]

The grantee's successors argued that the grantors reserved an undivided 1/16 mineral interest, asserting an arithmetic formula of 1/2 of 1/8, while Mulkey's successors claimed an undivided 1/2 mineral interest, on the basis that the double fraction is a term of art intended to reserve a 1/2 of the mineral interest.[136] The Mulkeys further asserted that even if the deed only reserved a 1/16 interest, they had gained title to 7/16 "by operation of the presumed-grant doctrine."[137] The trial court and appellate court both held the deed reserved a 1/16.[138] Considering the construction of the original deed and the presumed-grant doctrine, the Texas Supreme Court reversed and held both sides owned 1/2 of the mineral estate.[139]

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128. *Id*.
129. *Id*. at 14.
130. *Id*. at 15.
131. *Id*.
132. *Van Dyke v. Navigator Group,* 668 S.W.3d 353 (Texas 2023, rehearing denied).
133. *Id*. at 357.
134. *Id*. at 358.
135. *Id*.
136. *Id*.
137. *Id*.
138. *Id*. at 358, 359.
139. *Id*. at 359.

At the time of the deed, the court noted "1/8 was widely used as a term of art to refer to the total mineral estate."[140] Therefore, due to this estate misconception theory, when confronted with a double fraction (i.e., 1/2 of 1/8) in an instrument, the court held "we begin with a presumption that the mere use of such a double fraction was purposeful and that 1/8 reflects the entire mineral estate, not just 1/8 of it."[141] This language may be rebutted by other language showing the parties had a different intent.[142]

The Court also applied the presumed-grant doctrine, which requires its proponents to establish: (1) a long-asserted and open claim, adverse to that of the apparent owner; (2) nonclaim by the apparent owner; and (3) acquiescence by the apparent owner in the adverse claim.[143] The appellate court attempted to impose a fourth element – a gap in title – but the Court found neither precedent nor support for the doctrine's underlying purpose to support this additional element.[144] The Court determined that the facts conclusively satisfied the elements of the presumed-grant doctrine;[145] For almost 100 years, there was a "long and asserted open claim," including "conveyances, leases, ratifications, divisions orders, contracts, probate inventories, and a myriad of other recorded instruments that provided notice," during which both parties consistently acted as if each side owned 1/2 of the royalties.[146]

H. Railroad Commission of Texas v. Apache Corporation[147]

In 2018 Apache Corporation filed protests to two applications for disposal well permits.[148] Per Railroad Commission Rules, Boykin Energy provided notice to owners and operators within one-half mile of the proposed wells.[149] Apache did not own any surface property within one-half mile of the proposed wells, but did own a leasehold interest approximately two miles away and active wells approximately three miles from the proposed location of the wells.[150] Nevertheless, Apache claimed it

140. *Id*. at 362.
141. *Id*. at 364.
142. *Id*.
143. *Id*. at 366.
144. *Id*.
145. *Id*. at 366, 367.
146. *Id*. at 367.
147. *Railroad Commission of Texas v. Apache Corporation*, 2023 WL 2138962 (Tex. App. – Amarillo 2023, pet. filed Apr. 6, 2023).
148. *Id*. at 1.
149. *Id*.
150. *Id*.

was an "affected person" because the disposal wells could contaminate the Rustler Aquifer, a water source Apache relied on for its operations.[151]

Boykin argued Apache did not have standing to challenge their permits because it was not an "affected person."[152] The technical examiner and administrative law judge ruled Apache had standing because the proposed wells may cause injury or economic damage to Apache.[153] The commissioners disagreed, concluding Apache was not an "affected person," and Apache sought judicial review of the Commission's ruling.[154] The Travis County District Court held Apache demonstrated standing, and the Commission appealed.[155]

At issue is whether the Commissions' determination that Apache is not an "affected person" is supported by substantial evidence.[156] The Injection Well Act authorizes the Railroad Commission to issue permits for disposal wells.[157] A person is an "affected person" with standing to challenge a permit application if they have "suffered or will suffer actual injury or economic damage other than as a member of the general public or as a competitor."[158] If an affected person submits a protest, the Commission may hold a contested-case hearing,[159] and if the Commission denies the protest, the protester may seek judicial review.[160]

The court is tasked with determining, not whether the agency made the right decision, but whether there was substantial evidence for its decision.[161] The court held there was substantial evidence to support the Commission's ruling that Apache did not have standing.[162] Apache presented evidence showing the injected waste from Boykin's disposal wells would migrate into the Rustler Aquifer, but Boykin presented conflicting seismic data showing the waste would not affect the aquifer.[163] Based on this evidence, the Commission ruled Apache could not challenge the proposed wells.[164] Because the Commission found this evidence

151. *Id*.
152. *Id*.
153. *Id*.
154. *Id*.
155. *Id*.
156. *Id*. at 2.
157. *Id*. (*citing* TEX. WATER CODE ANN. §§ 27.001–.105).
158. *Id*. (*citing* 16 TEX. ADMIN. CODE § 3.9(5)(E)(ii)).
159. *Id*.
160. *Id.* (citing TEX. GOV'T CODE ANN. § 2001.171).
161. *Id*.
162. *Id*. at 3.
163. *Id*.
164. *Id*.

persuasive, the court deferred to the Commission's decisions which it deemed reasonable in light of the evidence presented to the Commission.[165]

I. Devon Energy Prod. Co., L.P. v. Sheppard[166]

The leases in this case required payment of royalties on gross proceeds without deduction for post-production costs.[167] Another lease provision, called an "add-back" clause, stated: "If any disposition, contract or sale of oil or gas shall include *any reduction or charge for the expenses or costs* of production, treatment, transportation, manufacturing, processing or marketing of the oil or gas, *then such deduction, expense or costs shall be added to ... gross proceeds* so that Lessor's royalty shall *never be chargeable directly or indirectly with any costs or expenses* other than its pro rata share of severance or production taxes."[168] The question before the Court was whether this language indicated an intent to include in the royalty base certain post-sale postproduction costs that add value after the point of sale but are not part of the lessee's gross proceeds.[169]

The lessee sold oil under a contract that set the sales price by using published index prices but subtracted $18 per barrel for the buyer's anticipated gathering and handling costs.[170] The lessee did not add the $18 deduction to the royalty base, paying the lessors on the gross sales proceeds.[171] The lessors later learned lessee conducted other transactions with similar pricing formulas and downward adjustments identified as the buyer's actual or anticipated post-production costs.[172] The lessee did not include these cost adjustments in the royalty base because they believed the royalties were calculated based on gross sales proceeds.[173] The lessors argue that the lease language obligates the lessee to add the deducted amounts to the gross sales proceeds before calculating their royalty amount.[174]

The trial court and appellate court both ruled for the lessors.[175] At the Texas Supreme Court, Devon argued the provision quoted above was "mere

165. *Id*.
166. *Devon Energy Prod. Co., L.P. v. Sheppard*, 668 S.W.3d 332 (Texas 2023, rehearing denied Jun. 16, 2023).
167. *Id*. at 337.
168. *Id*. at 337, 338.
169. *Id*. at 338.
170. *Id*. at 339.
171. *Id*.
172. *Id*.
173. *Id*.
174. *Id*.
175.

surplusage" because (1) payment of royalty on non-proceeds is so unusual that it cannot be required unless the lease plainly states such an intent, (2) the leases emphasize that "gross" really means gross, and (3) the language demonstrates that the parties were focused on lessee's deductions for postproduction costs, not buyer's.[176] The court agreed this add-back provision was unusual, but it unambiguously stated any charge for post-production costs must be added to gross proceeds so the lessor never bears those costs.[177] Therefore, the court agreed with the landowners that their leases were "proceeds plus" and upheld the add-back provision.[178]

J. Point Energy Partners Permian, LLC v. MRC Permian Company[179]

MRC Permian Company ("MRC") owned the exclusive leasehold estate to about 4,000 gross acres in Loving County.[180] The lease's primary term ended on February 28, 2017; MRC drilled five horizontal wells within that term, spudding the last well (Totum) on November 22, 2016.[181]

The lessee could "temporarily suspend automatic termination" of the lease via a continuous drilling program.[182] The continuous drilling program provided for 180 days between wells, so MRC had to spud its next well by May 21, 2017, or the lease would terminate as to all lands and depths not included in a production unit.[183] MRC scheduled June 2nd as the spud date for its sixth well (Toot 211), erroneously identifying June 19th, not May 21st, as the lease's expiration date.[184] MRC discovered the mistake about two weeks after the actual expiration date.[185] Once MRC missed the May 21st date to spud its sixth well, it attempted to invoke the lease's force majeure clause based on an event that occurred on April 21st, claiming 90 days from the resolution of that event to spud the sixth well.[186]

MRC sent the force majeure notice to the lessor on June 13th, 53 days after the event occurred and more than three weeks after the May 21st expiration date.[187] In its notice, MRC identified operational issues with the

176. *Id*. at 345, 346.
177. *Id*. at 346.
178. *Id*. at 348.
179. *Point Energy Partners Permian, LLC v. MRC Permian Company,* 669 S.W.3d 796 (Texas 2023).
180. *Id*. at 800.
181. *Id*.
182. *Id*.
183. *Id*.
184. *Id*. at 801.
185. *Id*.
186. *Id*.
187. *Id*.

rig they planned to use to drill the Toot 211 well, which caused a delay in drilling beyond their control.[188] The notice claimed the Toot 211 well was scheduled to be spudded on May 11, 2017, rather than June 2nd.[189] The delay caused by wellbore instability in April lasted 30 hours and occurred while the rig was drilling a well on an unrelated lease 60 miles away; according to MRC, the delay pushed back every well on the rig's schedule by approximately 30 hours, including the Toot 211.[190] MRC admitted it could have moved the rig to the Toot 211 in time to spud the well before the May 21st expiration date, but it chose to drill two other wells on an unrelated lease first.[191]

On June 7, Point Energy Partners Permian, LLC ("Point") took new leases from the lessors, arguing the lease had expired because MRC had missed its deadline to drill its sixth well.[192] Point claimed any attempt to drill the Toot 211 well would be a bad faith trespass.[193]

Regarding the force majeure clause, the Court focused on what it means when "lessee's operations" are delayed by a force majeure event and whether that requirement "interacts with lease deadlines."[194] MRC argued the June 2nd spudding of the Toot 211 well was the operation delayed, and it is undisputed that if there had been no delay, MRC would have missed the lease expiration deadline of May 21st if it had carried out its operations as intended.[195] MRC claimed that it was irrelevant that the operation commenced after the deadline because "nothing in the [force majeure] clause here ties force majeure to performance or compliance [with lease deadlines] – just delayed operations."[196] The Court held the clause did not account for the delay of an operation that would not have maintained the lease even in the absence of that delay.[197] The force majeure clause is meant to prevent the lease from expiring due to an event, but it does not apply to events that would not have maintained the lease.[198] If there had been no delay, MRC would have spudded the Toot 211 well after the expiration of the lease.[199]

188. *Id*.
189. *Id*.
190. *Id*. at 802.
191. *Id*.
192. *Id*.
193. *Id*.
194. *Id*. at 807.
195. *Id*.
196. *Id*.
197. *Id*. at 809.
198. *Id*.
199. *Id*. at 810.

K. Railroad Commission of Texas and Magnolia Oil & Gas Operating LLC v. Opiela[200]

EnerVest Operating, L.L.C. ("EnerVest") applied for an allocation well permit for the Audioslave A 102H well.[201] The Opielas, current lessors of a 1955 lease, filed a complaint with the Railroad Commission ("RRC") because their lease did not authorize the Lessee to pool their lands.[202] The RRC issued the permit on the basis that EnerVest showed a good-faith claim to the right to drill, and EnerVest began drilling four days after the permit was issued, all before the Opieas served their complaint.[203] EnerVest responded to the complaint by saying it did not need to pool the tracts crossed by the wellbore under RRC decisions in prior cases.[204]

Magnolia Oil and Gas Operating, LLC ("Magnolia") succeeded EnerVest before the dispute was resolved and applied to convert the permit to a PSA well, which request was granted.[205] The Opielas amended their complaint to challenge the permit issued to Magnolia.[206] After a hearing, the RRC examined found that the RRC determined that written oil leases overing tracts traversed by the Well are a "reasonably satisfactory showing of a good-faith claim to operate an allocation well" and that "written agreements with 65% of all mineral and working interest owners or each tract the Well produces from would be sufficient to get a permit to operate a well."[207] The examiners also found that Magnolia had production sharing agreements ("PSAs") with over 65% of the mineral and working interest owners.[208] The Opielas sought judicial review, contending that the RRC granted the permit pursuant to informal rules promulgated outside the APA and that Magnolia does not have a good-faith claim of right to drill a well because the agreements used to reach the 65% threshold included consents to pool and because their lease prohibited pooling and allocation of production.[209]

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200. *Railroad Commission of Texas and Magnolia Oil & Gas Operating LLC v. Opiela*, No. 03-21-00258-CV (Tex. App. – Austin, no pet. h.).

201. *Id*. at 2.

202. *Id*.

203. *Id*.

204. *Id*.

205. *Id*.

206. *Id*. at 3.

207. *Id*.

208. *Id*.

209. *Id*.

First, the Appellate Court addressed the RRC's power to issue drilling permits for multi-tract wells without pooling authority.[210] The court determined that the RRC's reliance on its decision in *Klotzman*[211] indicated that it "found that the anti-pooling clause did not prevent Magnolia from showing a good-faith claim of the right to operate and drill the Well" and that "a lack of pooling authority alone does not prohibit drilling under a PSA ."[212]

Second, the court turned to the RRC's authority to "adjudicate the validity of leases."[213] The trial court held the RRC erred in concluding that it has no authority to review the lease terms to determine whether the applicant has the authority to drill a well.[214] The court held the RRC has no power to determine property rights,[215] only whether the applicant has a good faith claim to drill a well.[216]

Third, the court addressed whether the RRC had adopted rules for allocation and PSA wells in compliance with the Administrative Procedure Act ("APA") and determined resolution of this issue was unnecessary to final disposition of the appeal.[217]

Fourth, the court reviewed the trial court's finding that Magnolia had a good faith claim to operate the well.[218] The RRC granted the PSA permit because Magnolia obtained written agreement from 65% of the mineral interest owners on how to share proceeds, whether through a PSA, a consent to pool, or a ratification of a unit.[219] Opiela argued the ratifications were not production sharing agreements, so they should not count towards the 65% threshold.[220] The RRC determined that a production sharing agreement only has to be a document where the parties agree on how to share production.[221]

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210. *Id*. at 7.

211. *Id*. at 8 (citing *Application of EOG Resources, Inc. for Its Klotzman Lease (Allocation), Well No. 1H(Status No. 744730), Eagleville (Eagleford-2) Field, Dewitt County, as an Allocation Well Drilled on Acreage Assigned from Two Leases*, Oil and Gas Docket No. 02-0278952 (Final Order issued Sept. 24, 2013) (*Klotzman*) at 1).

212. *Id*. at 8.

213. *Id*.

214. *Id*.

215. *Id*. at 9 (citing *Jones v. Killingsworth*, 403 S.W.2d 325, 328 (Tex. 1965)).

216. *Id*. at 9.

217. *Id*. at 9, 10.

218. *Id*. at 10.

219. *Id*. at 11.

220. *Id*.

221. *Id*.

The RRC's authority to issue a PSA permit traced back to a 2008 pronouncement that 65% of the owners had to sign "the production sharing agreement."[222] Here, 15.625% signed a PSA, while the remaining parties signed a consent or a ratification.[223] Because less than 65% of the mineral owners signed a "production sharing agreement," the court affirmed the trial court's holding that Magnolia did not show it had a good faith claim to operate the well under a PSA permit: being "not persuaded that signing a consent to pool can substitute for signing a PSA absent a good-faith showing that the consents to pool and the PSA call for the same sharing of production for the horizontal well across tracts that are not pooled."[224] In the alternative, Magnolia argued it should be entitled to a permit for an allocation well, but the court decided that permit was not before the court, and it remanded that issue to the trial court.[225]

L. PBEX II, LLC v. Dorchester Minerals, L.P.[226]

This appeal addresses whether a non-operated working interest may be adversely possessed.[227] In 1982, Felmont Oil Corporation owned 25% of the working interest in Section 4, a tract of land in Midland County, pursuant to the Willis lease.[228] In 1983, Felmont entered into a Joint Operating Agreement ("JOA") and the operator drilled two producing gas wells: Moreland No. 1 and Moreland No. 2.[229]

In 1989, Torch succeeded to Felmont's interest, and in May 1990, Torch conveyed all its interest to SASI and Baytech, the predecessors to Dorchester Minerals.[230] The operator under the JOA, Santa Fe Minerals, Inc., issued a division order confirming the reduction of Torch's interest in Section 4 to 0%, and Torch signed the order.[231]

From May 1990 through September 21, 2016, Dorchester and its predecessors performed all the functions of a working interest owner, including paying their share of production costs and making elections under the JOA.[232] On June 1, 2016, Torch assigned all its interest in the Willis

222. *Id*.
223. *Id*.
224. *Id*.
225. *Id*. at 12.
226. *PBEX II, LLC v. Dorchester Minerals, L.P.*, 670 S.W.3d 374 (Tex. App. – Amarillo, pet. filed Aug. 11, 2023).
227. *Id*. at 377.
228. *Id*. at 378.
229. *Id*.
230. *Id*.
231. *Id*. at 379.
232. *Id*.

lease to PBEX II.[233] On September 21, Torch advised Dorchester that Torch "mistakenly notified the operator that Torch had assigned its leasehold working interest in the Moreland Wells to [Dorchester's predecessors]," which allowed Dorchester's predecessors to take "possession of Torch's interest."[234] Torch claimed it rescinded and canceled all authority previously granted to Dorchester's predecessors to possess the working interest.[235] Torch attempted to get Dorchester to execute a correction confirming Torch retained its working interest back in 1990, but Dorchester refused.[236]

Dorchester claimed title to Torch's working interest through adverse possession under the twenty-five year statute of limitations.[237] PBEX/Torch argued the working interest is non-possessory in nature because it is a non-operator interest, so it is not subject to adverse possession.[238] The Amarillo Appellate Court disagreed, pointing out all working interests are possessory under Texas law, and there is no distinction between operating and non-operating interests.[239] Reviewing the statute, the court held Dorchester met the requirements to claim adverse possession, including holding itself out as the owners in a manner hostile to and inconsistent with Torch's claim.[240]

M. Mark S. Hogg, LLC v. Blackbeard Operating, LLC[241]

Betty, George and Mark Hogg executed two separate oil and gas leases to Three B Oil Company in 1994 and 1998.[242] Mark S. Hogg, LLC is the successor in interest to the original lessors.[243] The 1994 Lease covered 160 acres, being "all of the SE/4 of Section 24, Block B-10 Public School Lands," while the 1998 Lease covered 120 of those same acres being "all of the SE/4 of SE/4 and the N/2 of the SE/4 of Section 24, Block B-10, Public

233. *Id*.
234. *Id*.
235. *Id*.
236. *Id*.
237. *Id*. at 380.
238. *Id*. at 381.
239. *Id*.
240. *Id*.
241. *Mark S. Hogg, LLC v. Blackbeard Operating, LLC*, 656 S.W.3d 671 (Tex. App. – El Paso 2022, no pet. h.).
242. *Id*. at 673, 674.
243. *Id*. at 674.

School Lands."[244] The parties all agree that Three B drill the Hogg #2 well on the 1998 Lease.[245]

In 2005, Three B assigned oil and gas interests to Stanolind Oil and Gas Corporation, purporting to grant all of their identified "properties and assets," including Leases and Lands, Wells, Units and Properties, referencing Exhibit A and Exhibit A-1 (the "Assignment").[246] Exhibit A identified the 1994 Lease, but not the 1998 Lease.[247] Exhibit A-1 identified the Hogg #2 well, but not the 1998 Lease.[248] Stanolind replaced Three B as the operator of the Hogg #2 well, and in 2008, Stanolind assigned the 1998 Lease to Eagle Rock Acquisition Partnership II, LP.[249] Eagle Rock then assigned the 1998 Lease to Blackbeard Resources, LLC.[250]

In May 2019, Blackbeard filed suit against Hogg for trespass to try title and to quiet title in the 1998 Lease.[251] The trial court granted Blackbeard's motion for summary judgment.[252] On appeal, Hogg argues the Assignment did not convey the 1998 Lease when the conveyance language expressly limited Leases to those specifically described in Exhibit A, nor did the Assignment convey the 1998 Lease merely because Exhibit A-1 identified the name of a unit.[253]

The court found nothing ambiguous about the Assignment.[254] The court determined that, read together, the "eight subparagraphs under the granting clause make clear that the Assignors intended to transfer all of their interests in the Assets described."[255] Hogg argued that the limited definition of "Leases" as further described in Exhibit A, and the non-inclusion of the 1998 Lease on Exhibit A, precludes its assignment.[256] Blackbeard argued that after defining "Leases," the language goes on to convey "all other properties and interests of the Assignor, including, but not limited to, any and all interests of the Seller in… . . . the lands covered by the Leases. . .

244. *Id*.
245. *Id*.
246. *Id*.
247. *Id*.
248. *Id*.
249. *Id*.
250. *Id*.
251. *Id*.
252. *Id*. at 674, 675.
253. *Id*. at 675.
254. *Id*. at 678.
255. *Id*. at 678, 679.
256. *Id*. at 679.

including, but not limited to those lands that are described on Exhibit 'A'."[257]

Because the 1994 Lease covered 160 acres and the Assignment included all of the Assignor's interest in those 160 acres, the additional leasehold interest in 120 of those same acres, covered by the 1998 Lease, was included in the Assignment by virtue of the granting language.[258] Further, the court found, Exhibit A-1 clearly identified the Hogg #2 well, which the parties agreed was drilled under the 1998 Lease and by the Assignment's plain terms conveyed "all leasehold interest" in the Hogg #2 well.[259] Accordingly, the court concluded that the Assignment conveyed all of Three B's interest in the 1998 Lease.[260]

257. *Id*.
258. *Id*.
259. *Id*.
260. *Id*. at 680.