ENHANCING RECOVERY AND ROYALTIES: THE FLAWED DECISION IN *FRENCH V. OCCIDENTAL PERMIAN LTD.* AND HOW LESSORS CAN OVERCOME LEASE LANGUAGE BARRIERS TO PROHIBIT POST-PRODUCTION DEDUCTIONS

Comment*

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I. INTRODUCTION: THE BIRTH OF CARBON DIOXIDE INJECTION FOR ENHANCED OIL RECOVERY

In 1949, a small West Texas town's population grew from 2,000 to more than 20,000.[1] The population in Snyder, Texas increased so rapidly that many people set up camp underneath trees.[2] According to a former Snyder city councilman, "There were as many people living in cars as people living in houses."[3] It took residents more than an hour to travel only five miles across the town because of increased traffic.[4] Due to the number of families that moved to Snyder that year, many children had to attend classes in local churches until the school district built new facilities.[5] As the town's population grew, Snyder's business community thrived.[6] New restaurants, apartments, and hotels, many of them national brands, opened in Snyder to serve the town's new residents.[7]

What caused Snyder's population and prosperity to increase so quickly? A classic oil boom.[8] In late 1948, Standard Oil Company, by chance,

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1. Interview by Jeff Townsend with K.O. Pitner & L.E. Griffin in Snyder, Tex. (Aug. 22, 1972) [hereinafter Pitner & Griffin Interview]; Interview by Jeff Townsend with C.L. Williamson in Snyder, Tex. (Sept. 16, 1972) [hereinafter Williamson Interview]. Recordings of both interviews are available through the Southwest Collection Library at Texas Tech University.

2. Pitner & Griffin Interview, *supra* note 1.

3. Williamson Interview, *supra* note 1.

4. Pitner & Griffin Interview, *supra* note 1.

5. Williamson Interview, *supra* note 1.

6. *See* John Mangalonzo, *Snyder Already Rich in Oil History–and That's Before Cline Shale*, ABILENE REP.-NEWS (Feb. 9, 2013), http://www.reporternews.com/business/snyder-already-rich-in-oil-and-history-8212-and (discussing the success of businesses in Snyder during the oil boom).

7. *Id.* (stating that several new apartments and hotels opened in Snyder during the oil boom); Pitner & Griffin Interview, *supra* note 1 (stating that many national brand businesses opened in Snyder during the oil boom).

8. Pitner & Griffin Interview, *supra* note 1; Williamson Interview, *supra* note 1.

discovered the Canyon Reef formation near Snyder while drilling for oil in another formation—"[a]nd with that, the rush was on."[9] Twenty-three operators began drilling in what later became known as the Kelly–Snyder Field.[10] At the peak of the boom in 1950, 150 to 200 drilling rigs operated in Scurry County, where most of the Kelly–Snyder Field is located.[11] By 1952, however, the boom slowed and annual production declined to 2.5 million barrels of oil.[12] Production continued to decline in 1953, as the field produced only 1.5 million barrels of oil that year.[13] Up to that point, operators managed to produce only 23.6% of the "original oil in place" in the formation.[14] Operators and royalty owners "realized the necessity of preserving reservoir pressure, which was lost by rapid production."[15] Operators unitized the field and began operating it as the Scurry Area Canyon Reef Operators Committee Unit (SACROC).[16] The use of secondary recovery operations in the form of a water flood began in 1954 and continued for more than a decade.[17]

In 1968, field engineers recommended the injection of carbon dioxide to increase reservoir pressure and enhance ultimate oil recovery.[18] This process started in 1972 and was the first of its kind in the nation.[19] Carbon dioxide injection proved successful in increasing production and led SACROC to produce its one billionth barrel of oil in 1979.[20] Today, SACROC continues to be one of the best producing fields in Texas with more than one million barrels of oil produced in January 2014.[21]

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9. Mangalonzo, *supra* note 6.

10. Julia Cauble Smith, *Kelly–Snyder Oilfield*, HANDBOOK TEX. ONLINE (June 15, 2010), http://www.tshaonline.org/handbook/online/articles/doksu.

11. *See id.* (stating the boom began peaking in February 1950 when there were 179 drilling rigs operating in Scurry County); Pitner & Griffin Interview, *supra* note 1 (estimating that 150 drilling rigs operated in Scurry County during the peak of the boom); Williamson Interview, *supra* note 1 (estimating that 200 drilling rigs operated in Scurry County during the oil boom's peak).

12. Smith, *supra* note 10.

13. *Id.*

14. Mangalonzo, *supra* note 6. *Original oil in place* is an industry term defined as "[t]he estimated number of stock tank barrels of crude oil in known reservoirs prior to any production." PATRICK H. MARTIN & BRUCE M. KRAMER, WILLIAMS & MEYERS MANUAL OF OIL AND GAS TERMS 719 (15th ed. 2012).

15. Smith, *supra* note 10.

16. *Id.* Unitization is a conservation method designed to maintain reservoir pressure through the joint operation of a producing reservoir. MARTIN & KRAMER, *supra* note 14, at 1101. Unitization makes secondary and tertiary recovery operations economically feasible. *Id.*

17. Smith, *supra* note 10. Water flooding is a secondary recovery method "in which water is injected into an oil reservoir for the purpose of washing the oil out of the reservoir rock and into the bore of a producing well." MARTIN & KRAMER, *supra* note 14, at 1126.

18. Smith, *supra* note 10.

19. *Enhanced Oil Recovery*, U.S. DEP'T ENERGY, http://www.energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery (last visited Oct. 20, 2015).

20. Smith, *supra* note 10.

21. *See Specific Lease Query Results*, RAILROAD COMMISSION TEX., http://rrc.state.tx.us (follow hyperlink to "Data—Online Research Queries"; then follow hyperlink to "Launch Application" for "Production Data Query (limited area)"; then follow hyperlink to "Specific Lease Query"; then select "Oil

The number of enhanced oil recovery projects utilizing carbon dioxide increased after its implementation at SACROC as other operators sought to emulate the program's success in their own fields.[22] This process, however, presents unique legal issues. For example, who owns the carbon dioxide once it is injected into a reservoir?[23] Moreover, who pays to separate the non-native carbon dioxide from the reservoir's casinghead gas once the gases commingle?[24] As Texas courts begin to answer these questions, a problem is clearly emerging: their answers cannot be reconciled with one another. On one hand, as the Seventh Court of Appeals of Texas held in *Occidental Permian Ltd. v. Helen Jones Foundation*, an operator retains its personal property interest in carbon dioxide injected to enhance oil production.[25] On the other hand, the Texas Supreme Court recently held in *French v. Occidental Permian Ltd.* that a lessee can deduct from a lessor's royalty the cost of separating the injected carbon dioxide from the reservoir's casinghead gas.[26] The *French* decision puts royalty owners at substantial risk of having their gas royalties reduced due to deductions of post-production expenses.[27]

This Comment explains how the decisions in *Helen Jones* and *French* are inconsistent.[28] Specifically, this Comment argues that the Texas Supreme Court incorrectly decided *French* because it classified the process of separating extraneous carbon dioxide from native casinghead gas as a post-production operation rather than a production operation.[29] Providing the fundamentals of the oil industry, Part II offers a background on the three phases of oil production and discusses how Texas public policy actively

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Leases"; then type "03137" in the "Lease No." field; then select "8A" in the "District" field; then select "Jan" and "2014" for the "Date Range" fields; then follow "Submit" hyperlink) (last visited Sept. 20, 2015); *Yearly Production for Top 10 Current Largest Permian Basin Fields Part 2/2, Ranking 6-10*, RAILROAD COMMISSION TEX., http://rrc.state.tx.us/media/1470/top_5_yearly_graph_2_of_2.pdf (last visited Oct. 20, 2015) (showing the Kelly–Snyder field to be the sixth best producing field in the Texas Permian Basin).

22. *See* NAT'L ENERGY TECH. LAB., U.S. DEP'T OF ENERGY, CARBON DIOXIDE ENHANCED OIL RECOVERY 10 (Mar. 2010), http://energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery [hereinafter NETL, CARBON DIOXIDE] (follow hyperlink to "Primer on CO2-Enhanced Oil Recovery") (stating that the success at SACROC lead to the construction of three carbon dioxide pipelines, which caused increased carbon dioxide injection activity in the Permian Basin).

23. *See* Occidental Permian Ltd. v. Helen Jones Found., 333 S.W.3d 392, 408–11 (Tex. App.—Amarillo 2011, pet. denied) (holding that injected carbon dioxide remains the personal property of the operator).

24. *See* French v. Occidental Permian Ltd., 440 S.W.3d 1, 8–10 (Tex. 2014) (holding that royalty owners must share their proportionate share of expenses related to separating carbon dioxide from casinghead gas). The terms *non-native* and *extraneous* are used interchangeably in this Comment to describe gases not originally in place in a specific reservoir. *See* MARTIN & KRAMER, *supra* note 14, at 633 (defining *native gas* as "[g]as originally in place in a particular underground structure as opposed to injected gas").

25. *Helen Jones*, 333 S.W.3d at 408–11.

26. *French*, 440 S.W.3d at 8–10.

27. *See id.*

28. *See infra* Parts III–IV.

29. *See infra* Parts III–IV.

supports enhanced oil recovery operations.[30] Part II also discusses the fundamentals of royalty calculation, including the distinction between production and post-production activities.[31] Part III analyzes early cases addressing the ownership of gases injected into a reservoir and argues that Texas courts have wisely rejected the application of the *ferae naturae* theory to mineral ownership.[32] Scrutinizing the Texas Supreme Court's decision in *French v. Occidental Permian Ltd.*, Part IV contends that the decision is at odds with prior cases distinguishing production and post-production operations.[33] Part V examines another Texas Supreme Court case—*Heritage Resources, Inc. v. NationsBank*—and two other cases in which lessors unsuccessfully attempted to prohibit deductions of post-production expenses from their royalty.[34] Providing a remedy to the *French* decision, Part V.D specifically recommends certain clauses for lessors to negotiate into new oil and gas leases to effectively prevent post-production deductions.[35]

Although this Comment focuses on the impact of carbon dioxide injection on gas royalties, a basic understanding of oil production and royalty calculation is essential. Moreover, Texas courts' frequent reliance on public policy warrants a brief discussion on the state's policy of supporting enhanced oil recovery programs.[36]

II. GETTING THE LAST DROP: A GUIDE TO ENHANCED OIL RECOVERY, TEXAS PUBLIC POLICY, AND ROYALTY CALCULATIONS

A. Primary and Secondary Recovery

Oil and gas production occurs through one of three stages: primary recovery, secondary recovery, and tertiary (enhanced) recovery.[37] During the primary recovery stage, enough pressure exists in the reservoir "to push the oil from the reservoir into the well bore and then all the way to the surface."[38] As the pressure declines, oil must be brought to the surface using artificial lift, which requires the installation of a pump at the surface of the well.[39] Primary production in shale formations, "where the hydrocarbons will not

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30. *See infra* Part II.B.

31. *See infra* Part II.C.

32. *See infra* Part III.

33. *See infra* Part IV.

34. *See infra* Part V.

35. *See infra* Part V.D.

36. *See, e.g.*, Coastal Oil & Gas Corp. v. Garza Energy Tr., 268 S.W.3d 1, 16–17 (Tex. 2008) (noting in dicta that a trespass cause of action should not extend to subsurface hydraulic fracturing that causes drainage of gas partly "because no one in the industry appears to want or need the change"); R.R. Comm'n of Tex. v. Rowan Oil Co., 259 S.W.2d 173, 175 (Tex. 1953) (recognizing that prevention of waste and protection of correlative rights of all mineral owners are two well-established public policies in Texas).

37. JOHN S. LOWE ET AL., CASES AND MATERIALS ON OIL & GAS LAW 44–45 (6th ed. 2013).

38. VACLAV SMIL, OIL: A BEGINNER'S GUIDE 124 (2008).

39. *Id.*

flow naturally to a traditionally-drilled borehole," typically requires the use of horizontal drilling and hydraulic fracturing.[40]

As primary production continues, pressure in the reservoir declines, causing oil to remain in the pore spaces of the rock that forms the reservoir.[41] The decline in pressure continues until production ceases.[42] Up to 90% of the original oil in place remains trapped in rock pores after primary production.[43] Some of this oil may never be recovered.[44]

Assuming the operator does not abandon the well after primary production, secondary production begins.[45] Secondary recovery operations seek "to restore adequate reservoir pressure and to displace oil toward the well bore."[46] The most common method of achieving this goal is water flooding.[47] New injection wells push water into the reservoir.[48] The injected water acts "as a substitute for the lost reservoir pressure" and allows further recovery of oil.[49]

Although water flooding can recover as much oil as primary recovery, several factors can make secondary recovery operations ineffective.[50] For example, a rapid pressure decrease in the early stages of production can cause irreparable harm to the reservoir.[51] Moreover, reservoirs may have naturally occurring fractures and fissures that limit the flow of water, making a water flood inefficient.[52] Because of these limitations, more than half of the original oil in place is often left behind after secondary recovery.[53] Recovering the remaining oil from the reservoir requires enhanced or tertiary recovery methods.[54]

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40. LOWE ET AL., *supra* note 37, at 41. "Hydraulic fracturing . . . is a process in which fluid is injected into a well at very high pressures in order to either widen and deepen existing cracks or create new fractures in the tight [shale] formation." Christopher S. Kulander, *Environmental Effects of Petroleum Production: 2010–2011 Texas Legislative Developments*, 44 TEX. TECH L. REV. 863, 869 (2012). A mixture of sand and ceramic beads hold these cracks open, allowing oil and gas to flow more easily. *See Coastal Oil & Gas Corp.*, 268 S.W.3d at 6–7.

41. LOWE ET AL., *supra* note 37, at 44.

42. *Id.*

43. *How CO2-EOR Works*, NAT'L ENHANCED OIL RECOVERY INITIATIVE, http://www.neori.org/resources-on-co2-eor/how-co2-eor-works (last visited Oct. 20, 2015).

44. *See id.*

45. *Id.*

46. SMIL, *supra* note 38, at 129.

47. *Id.*

48. *How CO2-EOR Works*, *supra* note 43.

49. LOWE ET AL., *supra* note 37, at 45.

50. *How CO2-EOR Works*, *supra* note 43; *see* JACQUELINE LANG WEAVER, UNITIZATION OF OIL AND GAS FIELDS IN TEXAS: A STUDY OF LEGISLATIVE, ADMINISTRATIVE, AND JUDICIAL POLICIES 17–18 (2011) (discussing reservoir properties that can limit the success of secondary recovery operations).

51. *See* WEAVER, *supra* note 50 (listing improper production techniques as one factor in the limited success of secondary recovery operations).

52. *Id.*

53. LOWE ET AL., *supra* note 37, at 45.

54. *See id.*

B. Enhanced Oil Recovery: "The Art of Forcing Oil from Reluctant Reservoirs"[55]

Enhanced oil recovery methods include the injection of liquids or gases capable of changing the physical properties of the oil in the reservoir.[56] Specifically, these injectants must be able to change the oil's viscosity, allowing the oil to move out of the pore spaces and towards recovery wells.[57] Potential enhanced recovery methods include thermal, chemical, and miscible carbon dioxide recovery.[58] Petroleum engineers and geologists decide which enhanced recovery method to deploy for a particular reservoir after studying the technical data from the reservoir and conducting tests on core samples of the rock inside the reservoir.[59]

1. Carbon Dioxide Injection

Carbon dioxide injection is expected to "generate an additional 240 billion barrels of recoverable oil resources" after completion of secondary recovery.[60] Sometimes referred to as "miscible gas injection" or "miscible enhanced recovery" due to its ability to mix with and swell the oil, carbon dioxide injection is most often used in reservoirs containing low-viscosity light crude oil.[61] Once injected, the carbon dioxide mixes with the oil in the reservoir because the physical force that usually holds the two substances apart, known as interfacial tension, essentially disappears.[62]

To begin a carbon dioxide injection operation, the operator must deliver carbon dioxide to the field at sufficient pressure via pipeline.[63] Next, the carbon dioxide "is directed to injection wells strategically placed within the pattern of wells to optimize the areal sweep of the reservoir."[64] As carbon dioxide enters the reservoir, it becomes miscible with the oil, "forming a concentrated oil bank that is swept towards the producing wells."[65] During this process, the carbon dioxide mixes with natural gas in the reservoir, resulting in a stream of gas known as casinghead gas when produced from an

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55. GULF OIL CORP., AN ENHANCED RECOVERY PRIMER 1 (n.d.).
56. *See* LOWE ET AL., *supra* note 37, at 45 (stating that liquids or gasses injected during tertiary recovery lower the viscosity of the oil, allowing the oil to flow towards recovery wells).
57. *Id.*
58. *See id.* at 45–48
59. *Id.* at 45, 48.
60. *Id.* at 48.
61. *Id.* at 45; *see* SMIL, *supra* note 38, at 130 (referring to carbon dioxide injection as "miscible gas injection"); *see also How CO2-EOR Works*, *supra* note 43 (stating that injected carbon dioxide mixes with oil and causes the oil to swell).
62. NETL, CARBON DIOXIDE, *supra* note 22, at 5.
63. *Id.* at 6.
64. *Id.*
65. *Id.*

oil well.[66] The carbon dioxide is then "separated from the produced natural gas and recompressed for reinjection."[67] Carbon dioxide injection typically helps recover 4% to 15% of the original oil in place, although some projects utilizing new technology have reported as much as 22% recovery.[68]

Although the number of carbon dioxide injection projects has increased nationally, West Texas, the birthplace of this enhanced recovery method, remains its epicenter.[69] The Permian Basin of West Texas contains sixty-seven carbon dioxide injection projects that produce a combined total of 190,000 barrels of oil per day—equivalent to 70% of the nation's daily production from carbon dioxide projects.[70] Reservoirs in the Permian Basin are prime candidates for carbon dioxide injection for several reasons.[71] First, the reservoirs in this region have already undergone successful secondary water flooding recovery, a key indicator of success for carbon dioxide recovery projects.[72] Second, the Permian Basin's close proximity to natural deposits of carbon dioxide ensures lower costs and ample availability, both of which were significant factors in the increased use of carbon dioxide injection in the Permian Basin during the 1970s and 1980s.[73] Today, the primary sources of carbon dioxide for the Permian Basin are the Sheep Mountain and McElmo Dome deposits in Colorado and the Bravo Dome deposit in New Mexico.[74] Third, operators in West Texas are able to reduce costs by using existing pipeline infrastructure to enhance recovery in multiple reservoirs rather than in a single, isolated reservoir.[75] Moreover, the existence of large "anchor" reservoirs in proximity to smaller reservoirs allows operators to reduce the cost of carbon dioxide delivery to these smaller reservoirs, where enhanced recovery may otherwise be uneconomical.[76] The Permian Basin will continue to be a leader in enhanced recovery operations

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66. *Id.*; *see* French v. Occidental Permian Ltd., 440 S.W.3d 1, 6 (Tex. 2014); MARTIN & KRAMER, *supra* note 14, at 131–33 (defining *casinghead gas*).

67. NETL, CARBON DIOXIDE, *supra* note 22, at 6.

68. *Id.* at 14; *see also* INST. FOR 21ST CENTURY ENERGY, U.S. CHAMBER OF COMMERCE, CO2 ENHANCED OIL RECOVERY 3, http://www.energyxxi.org/sites/default/files/020174_EI21_EnhancedOil Recovery_final.pdf (last visited Oct. 20, 2015) (stating that carbon dioxide injection "has the potential to recover a further 15% to 20% of the original oil").

69. LOWE ET AL., *supra* note 37, at 46; NETL, CARBON DIOXIDE, *supra* note 22, at 9.

70. Al Pickett, *Permian's EOR Projects Lead the Way*, AM. OIL & GAS REP., Oct. 2012, at 138, 138, http://www.nxtbook.com/nxtbooks/aogr/2012_pbios/index.php?startid=138; Jesse Mullins, *The Future of Co2*, PB OIL & GAS (July 10, 2012), http://pbog.zacpubs.com/the-future-of-co2/.

71. *See* NETL, CARBON DIOXIDE, *supra* note 22, at 9 (describing two reasons why a large portion of the world's carbon dioxide injection projects are located in West Texas and southeastern New Mexico); *see also* LOWE ET AL., *supra* note 37, at 46 (describing West Texas's close proximity to natural carbon dioxide deposits in New Mexico and Colorado).

72. NETL, CARBON DIOXIDE, *supra* note 22, at 9.

73. *Id.* at 10; LOWE ET AL., *supra* note 37, at 46.

74. NETL, CARBON DIOXIDE, *supra* note 22. The increase in oil prices during the 1970s helped fund the development of pipeline infrastructure connecting the Permian Basin to natural carbon dioxide deposits in Colorado and New Mexico. INST. FOR 21ST CENTURY ENERGY, *supra* note 68.

75. NETL, CARBON DIOXIDE, *supra* note 22, at 10–11.

76. *Id.* at 11.

because production from carbon dioxide injection projects in the region is predicted to increase by more than 60% by 2020.[77]

2. Treated Like Royalty: How Texas Public Policy Supports Enhanced Oil Recovery

The Texas Legislature has enacted several laws to encourage full recovery of oil and gas resources, including statutes that prohibit waste and provide tax incentives for enhanced recovery operations.[78] In *Railroad Commission of Texas v. Manziel*, the Texas Supreme Court recognized that the state's voluntary unitization statute was designed to encourage secondary recovery of minerals, and that "[s]uch operations are primarily concerned with increasing the ultimate recovery of oil and gas and the prevention of waste."[79] Modern Texas statutes go further than just discouraging waste—they explicitly ban it.[80] For example, the Texas Natural Resources Code provides: "The production, storage, or transportation of oil or gas in a manner, in an amount, or under conditions that constitute waste is unlawful and is prohibited."[81] Broadly defined by the Texas Legislature, *waste* includes activities like operating a well at an inefficient gas–oil ratio, allowing surface and subsurface leaks, and producing in excess of market demand.[82]

In addition to prohibiting waste, Texas encourages enhanced recovery operations by offering tax incentives.[83] Texas, like thirty-five other states, imposes a severance tax, which is "[a] tax on the removal of minerals from the ground."[84] The standard severance tax for oil in Texas is 4.6% of the market value of the oil or 4.6 cents for each barrel of oil produced, whichever is greater.[85] Operators pay only a 2.3% tax rate, however, on oil recovered through an enhanced recovery project.[86] "Enhanced recovery project" has a broad definition, encompassing all projects that recover oil beyond primary

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77. *See* NAT'L ENERGY TECH. LAB., U.S. DEP'T ENERGY, NEAR-TERM PROJECTIONS OF CO2 UTILIZATION FOR ENHANCED OIL RECOVERY 10 (Apr. 7, 2014), http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Near-Term-Projections-CO2-EOR_april_10_2014.pdf (projecting that production in the Permian Basin from carbon dioxide enhanced recovery operations will increase from 186,000 barrels per day in 2012 to 301,000 barrels per day in 2020).

78. *See infra* notes 79–82 and accompanying text.

79. R.R. Comm'n of Tex. v. Manziel, 361 S.W.2d 560, 569 (Tex. 1962); *see also* Coastal Oil & Gas Corp. v. Garza Energy Tr., 268 S.W.3d 1, 34–35 (Tex. 2008) (Willett, J., concurring) (recognizing the Texas Legislature's "focus on maximizing recoverable reserves" of oil).

80. *See, e.g.*, TEX. NAT. RES. CODE ANN. § 85.045 (West 2014).

81. *Id.*

82. *Id.* § 85.046.

83. *See* TEX. TAX CODE ANN. §§ 202.052–.0545 (West 2015).

84. MARTIN & KRAMER, *supra* note 14, at 958; *see* Jacquelyn Pless, *Oil and Gas Severance Taxes: States Work to Alleviate Fiscal Pressures Amid the Natural Gas Boom*, NAT'L CONF. ST. LEGISLATURES, http://www.ncsl.org/research/energy/oil-and-gas-severance-taxes.aspx (last updated Feb. 2012).

85. TAX § 202.052(a).

86. *Id.* § 202.052(b).

recovery.[87] The legislature expressly included "miscible, chemical, [and] thermal" projects in its definition of *enhanced recovery project*.[88] A further 50% tax deduction is available if the enhanced recovery operation utilizes anthropogenic carbon dioxide.[89] To qualify for this additional reduction, the carbon dioxide utilized must be man-made rather than from natural deposits.[90] Thus, the effective severance tax for enhanced recovery projects utilizing man-made carbon dioxide is 1.15%.[91] Although the precise economic impact of these tax incentives is unclear, there is little doubt that tax incentives lower the cost of production for operators and encourage exploration and production.[92]

C. The Fundamentals of Royalty Calculation

1. The Standard Lessor's Royalty

In an oil and gas lease, royalty is the primary consideration paid by the lessee to the lessor.[93] Texas courts have generally defined a lessor's royalty as "the landowner's share of production, free of expenses of production."[94] It may be paid in kind or in money.[95] The lessor's royalty is represented as a fraction of production, most frequently one-eighth.[96]

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87. *Id.* § 202.054(a)(3).

88. *Id.*

89. *Id.* § 202.0545(a).

90. *See id.*; Christopher J. Miller, *Carbon Capture and Sequestration in Texas: Navigating the Legal Challenges Related to Pore Space Ownership*, 6 TEX. J. OIL GAS & ENERGY L. 399, 401–03 (2011) (discussing additional requirements that operations must meet to qualify for the anthropogenic carbon dioxide tax incentive); NETL, CARBON DIOXIDE, *supra*, note 22, at 11 (defining *anthropogenic* as "man-made").

91. *See* TAX § 202.0545(a) (providing an additional 50% reduction in the tax rate from the rate provided in § 202.052(b) for enhanced recovery projects).

92. *See* Michael M'Gonigle & Louise Takeda, *The Liberal Limits of Environmental Law: A Green Legal Critique*, 30 PACE ENVTL. L. REV. 1005, 1023 (2013) (stating that oil and gas tax incentives reduce the cost of production); *Texas Severance Tax Incentives: Past and Present*, RAILROAD COMMISSION TEX., http://www.rrc.state.tx.us/oil-gas/publications-and-notices/texas-severance-tax-incentives-past-and-present/ (last updated July 21, 2015) ("The reduction or elimination of state severance taxes provides an economic incentive to operators to undertake activities that produce oil and gas resources that otherwise might remain unrecovered.").

93. JOSEPH SHADE & RONNIE BLACKWELL, PRIMER ON THE TEXAS LAW OF OIL & GAS 52 (5th ed. 2013).

94. Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 121–22 (Tex. 1996) (citing Delta Drilling Co. v. Simmons, 338 S.W.2d 143, 147 (Tex. 1960)).

95. SHADE & BLACKWELL, *supra* note 93. An in-kind royalty clause obligates the lessee to deliver to the royalty owner his or her share of the physical production of oil and gas instead of paying the royalty owner the market value of production. *See* First Nat'l Bank in Weatherford v. Exxon Corp., 597 S.W.2d 783, 787 (Tex. Civ. App.—El Paso 1980), *aff'd*, 622 S.W.2d 80 (Tex. 1981); *see also* MARTIN & KRAMER, *supra* note 14, at 917–18 (discussing the legal consequences of whether royalty is paid in kind or in money).

96. MARTIN & KRAMER, *supra* note 14, at 917; *accord* SHADE & BLACKWELL, *supra* note 93.

In addition to royalty on oil, a lease will typically include a separate royalty on natural gas or casinghead gas.[97] Casinghead gas is "[g]as produced with oil in oil wells . . . as distinguished from gas produced from a gas well."[98] A complex process separates the liquefiable hydrocarbons contained in the casinghead gas.[99] Traditionally, leases containing a casinghead gas clause provided only a fixed annual payment for any gas recovered from the well, typically no more than $100 per year.[100] As the science of removing liquefiable hydrocarbons from casinghead gas improved, the inclusion of a casinghead gas royalty clause in traditional leases became economically more important.[101] Today, leases include a casinghead gas royalty clause that makes "royalty payable on casinghead gas produced and saved from an oil well."[102]

2. *Classifying Production and Post-production Operations*

Compared to other states, Texas has a well-defined line between production and post-production operations.[103] "Production costs are the expenses incurred in exploring for mineral substances and in bringing them to the surface."[104] These expenses are generally "not chargeable to the non-operating royalty interest."[105] All activities that take place after the oil and gas are severed from the land at the wellhead are post-production activities.[106] Thus, post-production activities "add value to production in its raw state at the location of the wellhead prior to a final sale."[107]

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97. *See, e.g.*, Hutchings v. Chevron U.S.A., Inc., 862 S.W.2d 752, 756–59 (Tex. App.—El Paso 1993, writ denied).

98. MARTIN & KRAMER, *supra* note 14, at 131.

99. *Id.*

100. *See id.* at 133.

101. *Id.*

102. *Id.*

103. *See* Jeffrey C. King, *The Compression of Natural Gas: Is It Production or Post-Production? Is It Deductible from Royalties? If So, How Much?*, 1 TEX. J. OIL GAS & ENERGY L. 36, 43 (2006) (stating that "[u]nlike Texas law, the Oklahoma view creates uncertainty and is fertile ground for litigation," with regard to classification of gas compression expenses); Edward B. Poitevent, II, *Post-Production Deductions from Royalty*, 44 S. TEX. L. REV. 709, 732 (2003) (stating that Texas case law provides certainty regarding royalty clauses because the clause's various formulations have defined meanings as a matter of law).

104. Parker v. TXO Prod. Corp., 716 S.W.2d 644, 648 (Tex. App.—Corpus Christi 1986, no writ); *see also* Byron C. Keeling & Karolyn King Gillespie, *The First Marketable Product Doctrine: Just What Is the "Product?"*, 37 ST. MARY'S L.J. 1, 88–89 (2005) (defining *production* as "the act of producing oil, gas, and other minerals" and stating that "'production' ceases once the lessee extracts oil or gas from the ground at the wellhead").

105. Cartwright v. Cologne Prod. Co., 182 S.W.3d 438, 444 (Tex. App.—Corpus Christi 2006, pet. denied); *see also* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 121–22 (Tex. 1996) ("Although [the landowner's royalty] is not subject to the costs of production, [it] is usually subject to post-production costs.").

106. *See Cartwright*, 182 S.W.3d at 444–45 ("Whatever costs are incurred *after* production of the gas or minerals are normally proportionately borne by both the operator and the royalty interest owners.").

107. Poitevent, II, *supra* note 103, at 714.

Post-production expenses include treatment costs to render the gas marketable,[108] compression costs,[109] dehydration costs,[110] and transportation costs.[111] These expenses are deductible from the value of production, unlike production expenses.[112] As the value of production decreases, so too does the value of royalty.[113] Texas law does, however, recognize the ability of lessees and royalty owners to contract around the general rules regarding post-production expense deductions.[114]

The distinction between production and post-production activities is particularly important with regard to enhanced oil recovery operations using carbon dioxide injection due to their complexity.[115] Once injected, the carbon dioxide commingles with the other gases in the reservoir, producing casinghead gas.[116] Although oil production is complete once the oil reaches the wellhead, casinghead gas must be further processed to extract its valuable natural gas liquids (NGLs) and to remove the previously injected carbon dioxide.[117] Although the extraction of the NGLs is undoubtedly considered a post-production process, the process of removing carbon dioxide from casinghead gas remained unclassified until the Texas Supreme Court's recent decision in *French v. Occidental Permian Ltd*.[118]

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108. *Heritage*, 939 S.W.2d at 122.

109. Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996).

110. Holbein v. Austral Oil Co., 609 F.2d 206, 209 (5th Cir. 1980) (interpreting Texas law); Le Cuno Oil Co. v. Smith, 306 S.W.2d 190, 193 (Tex. Civ. App.—Texarkana 1957, writ ref'd n.r.e.).

111. *Heritage*, 939 S.W.2d at 122.

112. *Id.* at 121–22; Cartwright v. Cologne Prod. Co., 182 S.W.3d 438, 444–45 (Tex. App.—Corpus Christi 2006, pet. denied); *see also* Poitevent, II, *supra* note 103, at 714 (explaining that post-production expenses are subtracted from the value of production, rather than being subtracted from royalty itself).

113. *See* Poitevent, II, *supra* note 103, at 714.

114. *Heritage*, 939 S.W.2d at 122 (citing Martin v. Glass, 571 F. Supp. 1406, 1410 (N.D. Tex. 1983), *aff'd*, 736 F.2d 1524 (5th Cir. 1984)).

115. *See* French v. Occidental Permian Ltd., 440 S.W.3d 1, 5–7 (Tex. 2014) (describing carbon dioxide injection programs as requiring specialized well equipment and being more expensive than a water flood); *see also* Shell W. E & P, Inc. v. Bd. of Supervisors of Pike Cty., 624 So. 2d 68, 69–72 (Miss. 1993) (describing a case involving carbon dioxide injection as "a highly technical, complex factual situation"); Occidental Permian Ltd. v. Helen Jones Found., 333 S.W.3d 392, 397 (Tex. App.—Amarillo 2011, pet. denied) (describing the carbon dioxide process as "a continuous cycle of injection, recovery, processing and re-injection").

116. *Helen Jones*, 333 S.W.3d at 397 ("The injected [carbon dioxide] becomes commingled with hydrocarbons in the producing formation and comes back to the surface along with the casinghead gas.").

117. *See, e.g.*, *French*, 440 S.W.3d at 6–7 (discussing the operator's desire to extract NGLs from the casinghead-gas stream).

118. *See* 3 EUGENE KUNTZ, LAW OF OIL & GAS §§ 39.4, 40.4 (1989) (explaining that the term *processing* is often used to describe various post-production operations, including the extraction of substances from gas).

III. OWNERSHIP OF INJECTED GAS: HOW TEXAS COURTS WISELY REJECTED APPLICATION OF *FERAE NATURAE* TO OIL & GAS

During the 1800s, the growth of the oil and gas industry forced courts across the nation to answer difficult questions regarding the ownership of these newly discovered minerals.[119] As the industry became more technologically advanced, the questions before the courts became more complex.[120] For example, once carbon dioxide is injected into a formation to enhance oil recovery, who owns the carbon dioxide?[121] Does it belong to the operator, who originally secured possession of the gas, transported it, and injected it into the formation?[122] Or does the operator lose possession of the carbon dioxide when it is injected, subjecting the gas to the rule of capture and obligating the operator to pay royalties on the carbon dioxide?[123] The Seventh Court of Appeals of Texas grappled with these questions in 2011 in *Occidental Permian Ltd. v. Helen Jones Foundation*.[124]

In arriving at an answer to these issues, the court relied primarily on two cases addressing possession of natural gas: *Lone Star Gas Co. v. Murchison* and *Humble Oil & Refining Co. v. West*.[125] Both of these Texas cases discussed and rejected the theory of minerals *ferae naturae*, a theory based on the flawed analogy between animals and minerals.[126] According to the theory of minerals *ferae naturae*, mineral owners lose their personal property interest in minerals when they inject the minerals into a reservoir.[127] The theory gained prominence as a result of its approval in two early cases: *Westmoreland & Cambria Natural Gas Co. v. De Witt* and *Hammonds v. Central Kentucky Natural Gas Co.*[128]

119. *See* Rance L. Craft, *Of Reservoir Hogs and Pelt Fiction: Defending the Ferae Naturae Analogy Between Petroleum and Wildlife*, 44 EMORY L.J. 697, 697–98 (1995) (discussing landowners' desire to determine their legal rights to oil and gas below their property and the lack of scientific and technical information available to courts during the 1800s).

120. *Id.*

121. *See Helen Jones*, 333 S.W.3d at 408–11.

122. *See id.*

123. *See id.*

124. *See id.*

125. *Id.*; *see* Humble Oil & Ref. Co. v. West, 508 S.W.2d 812, 817–19 (Tex. 1974); Lone Star Gas Co. v. Murchison, 353 S.W.2d 870, 875–78 (Tex. Civ. App.—Dallas 1962, writ ref'd n.r.e.).

126. *See West*, 508 S.W.2d at 817 (rejecting the theory of minerals *ferae naturae*); *Murchison*, 353 S.W.2d at 875–78 (same); *see also* Pierson v. Post, 3 Cai. 175, 179–80 (N.Y. Sup. Ct. 1805) (holding that a wild animal is considered property when mortally wounded or trapped such that it is deprived of its natural liberty).

127. Hammonds v. Cent. Ky. Nat. Gas Co., 75 S.W.2d 204, 206 (Ky. 1934); *see* Bruce M. Kramer & Owen L. Anderson, *The Rule of Capture—An Oil and Gas Perspective*, 35 ENVTL. L. 899, 932–33 (2005) (discussing the flaws in the *Hammonds* court's analogy between minerals and wild animals).

128. *Hammonds*, 75 S.W.2d at 205–06; Westmoreland & Cambria Nat. Gas Co. v. De Witt, 18 A. 724, 725 (Pa. 1889).

A. Ferae Naturae *and the Flawed Logic in Two Early Cases*

In the late 1800s, courts facing questions regarding possession of oil and gas did not have the scientific knowledge that today's courts enjoy.[129] Nor did these courts have any direct legal precedent on which to base their decisions.[130] This lack of information and precedent led courts to formulate "legal rules to govern oil and gas by drawing an analogy to a resource governed by a legal framework with which they were familiar: wild animals, or animals *ferae naturae*."[131]

The Supreme Court of Pennsylvania first analogized oil and gas to animals in *Westmoreland & Cambria Natural Gas Co. v. De Witt*.[132] The court noted several similarities between gas and animals: "They have the power . . . to escape without the volition of the owner," their fugacious nature is not limited to a particular tract of land, and they belong to the owner of the land on which they are located.[133] Most importantly, the court said that when gas and animals "escape[] and go into other land, or come under another's control, the title of the former owner is gone."[134]

More than forty years later, in *Hammonds v. Central Kentucky Natural Gas Co.*, the defendant used a reservoir to store gas it purchased from distant fields.[135] Hammonds, the plaintiff, owned an unleased portion of the field and sued Central Kentucky for trespass, seeking to recover money for Central Kentucky's unauthorized use of a reservoir beneath the plaintiff's property.[136] The court characterized the storing of natural gas in an underground reservoir as analogous to releasing a captured fox back into the forest or releasing a seized fish into a stream.[137] The owner of the captured fox or fish loses his or her property interest in the animal once it is released back into its natural habitat, according to the court's logic.[138] Similarly, Central Kentucky lost possession of the purchased gas when it injected the gas into the reservoir for storage.[139] The court determined that Central Kentucky was not liable for trespass because it did not own the gas when it crossed over into the subsurface of Hammonds's property.[140]

There are several inconsistencies and flaws in the minerals *ferae naturae* theory on which the *De Witt* and *Hammonds* courts relied so

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129. *See* Craft, *supra* note 119.
130. *See id.* at 707–08 (stating that courts developed property rules for oil and gas based on other areas of the common law).
131. *Id.* at 698.
132. *See De Witt*, 18 A. at 725; Kramer & Anderson, *supra* note 127, at 906–14.
133. *De Witt*, 18 A. at 725.
134. *Id.*
135. Hammonds v. Cent. Ky. Nat. Gas Co., 75 S.W.2d 204, 204 (Ky. 1934).
136. *Id.*
137. *Id.* at 206.
138. *See id.*
139. *See id.*
140. *See id.*

heavily.[141] First, the analogy between injecting gas into a reservoir for storage and a captured fox or fish being released back into its natural habitat is inaccurate.[142] As two oil and gas law commentators noted, "A more proper analogy would be to compare the injection of gas for storage to the confinement of a wild animal within a fenced enclosure."[143] Using this analogy, the gas remains the personal property of the injector because the reservoir has a well-defined boundary, similar to that of a fenced enclosure.[144]

Furthermore, the minerals *ferae naturae* theory fails to recognize the distinction between ownership of animals and ownership of minerals prior to original capture.[145] Under the ownership in place theory of oil and gas, which Texas has adopted, landowners own the minerals beneath their property and may sever the mineral estate from the surface estate.[146] Conversely, wild animals are regarded as belonging to the public or the state rather than any particular individual.[147] As the U.S. Supreme Court has recognized, members of the public have a right to create a personal property interest in wild animals through capture and possession, but the public does not enjoy that same right with respect to natural gas.[148] Rather, only the landowner has a right to reduce to possession the natural gas beneath his or her land.[149] Recognizing these flaws in the minerals *ferae naturae* theory, Texas courts have wisely rejected its application in this state.[150]

B. The Texas Trio: Three Cases Determining Ownership of Injected Gases

Lone Star Gas Co. v. Murchison presented the first opportunity for a Texas court to either accept or reject the minerals *ferae naturae* theory.[151] Before the Dallas Civil Court of Appeals, Murchison argued that Lone Star lost title to and possession of "extraneous gas it injected into a storage

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141. *See id.*; Westmoreland & Cambria Nat. Gas Co. v. De Witt, 18 A. 724, 726 (Pa. 1889); Lone Star Gas Co. v. Murchison, 353 S.W.2d 870, 876–80 (Tex. Civ. App.—Dallas 1962, writ ref'd n.r.e.) (criticizing the *ferae naturae* theory's application to minerals); Kramer & Anderson, *supra* note 127.

142. *See* Kramer & Anderson, *supra* note 127, at 932.

143. *Id.*

144. *See id.*

145. *See* Ohio Oil Co. v. Indiana, 177 U.S. 190, 209 (1900) (criticizing the *ferae naturae* analogy between animals and gas because wildlife is publicly owned when it is not captured, but natural gas is considered privately owned even when it has not been captured).

146. *See id.* at 208–09 (distinguishing between ownership of minerals and ownership of animals prior to capture); Elliff v. Texon Drilling Co., 210 S.W.2d 558, 561 (Tex. 1948) (stating that in Texas, "the landowner is regarded as having absolute title in severalty to the oil and gas in place beneath his land"); MARTIN & KRAMER, *supra* note 14, at 735–36 (discussing ownership in place theory).

147. State v. Bartee, 894 S.W.2d 34, 41–42 (Tex. App.—San Antonio 1994, no writ); *see Ohio Oil Co.*, 177 U.S. at 208–09 (distinguishing between ownership of minerals and ownership of animals prior to capture).

148. *Ohio Oil Co.*, 177 U.S. at 208–09.

149. *Id.*

150. *See infra* Part III.B (discussing Texas courts' rejection of the minerals *ferae naturae* theory).

151. Lone Star Gas Co. v. Murchison, 353 S.W.2d 870, 875–78 (Tex. Civ. App.—Dallas 1962, writ ref'd n.r.e.).

reservoir as the gas became like a wild animal, subject to capture."[152] The court first acknowledged that a personal property right vests in a person who produces natural gas.[153] That person does not relinquish their property right by simply injecting natural gas into a reservoir for storage.[154] The court held that there was no intent to abandon the natural gas when Lone Star injected the gas into a defined reservoir for the specific purpose of storage.[155] Not persuaded by the analogy between minerals and wild animals, the *Murchison* court stated that "[g]as has no similarity to wild animals."[156]

In *Humble Oil & Refining Co. v. West*, the Texas Supreme Court made definitive Texas's rejection of minerals *ferae naturae*.[157] In that case, royalty owners sought an injunction against Humble Oil to force it to pay royalties on natural gas stored inside a reservoir on the leased lands.[158] Humble Oil began using the reservoir for storage even though the reservoir was still producing native gas.[159] In denying the plaintiffs a royalty on the injected gas, the Court adopted the reasoning from *Murchison*, stating that "Humble's ownership of the gas as personal property is not altered either upon injection of the gas into the reservoir or upon later production of the gas."[160] The royalty interest only applied to native gas and did not implicate a royalty on extraneous gas.[161] Accordingly, the Court held that Humble Oil owed no royalties on production of extraneous gas previously injected for storage.[162]

The *Murchison* and *West* cases not only rejected the application of minerals *ferae naturae* theory in Texas, but also ensured that companies can continue to use underground reservoirs to store natural gas without fear of unintended royalty obligations.[163] Both decisions support Texas's public policy of limiting economic waste.[164] If the *Murchison* and *West* courts had held differently—that a party loses its personal property interest in gas when the gas is injected into a reservoir for storage—companies would have been forced to build expensive pipelines and man-made storage facilities instead

152. Occidental Permian Ltd. v. Helen Jones Found., 333 S.W.3d 392, 410 (Tex. App.—Amarillo 2011, pet. denied).

153. *Murchison*, 353 S.W.2d at 879.

154. *Id.*

155. *See id.*

156. *Id.*

157. *See* Humble Oil & Ref. Co. v. West, 508 S.W.2d 812, 817 (Tex. 1974) (citing with approval *Murchison*, 353 S.W.2d at 870).

158. *Id.* at 813.

159. *Id.* at 817.

160. *Id.*

161. *Id.*

162. *Id.* at 819.

163. *See id.*; Lone Star Gas Co. v. Murchison, 353 S.W.2d 870, 875–78 (Tex. Civ. App.—Dallas 1962, writ ref'd n.r.e.).

164. *See supra* Part II.B.2 (discussing Texas's public policy against waste); *see also* Owen Anderson, *Geophysical "Trespass" Revisited*, 5 TEX. WESLEYAN L. REV. 137, 173 n.158 (1999) (stating that courts have protected owners of injected gas from trespass claims partly to encourage efficient storage of gas).

of using natural reservoirs for storage.[165] Instead, Texas courts recognized the utility of underground storage and created a legal framework that today allows the state to be a leader in the underground storage of natural gas, based on the number of reservoirs and total storage capacity.[166] That legal framework is now codified in the Texas Natural Resources Code, recognizing the public policy benefits of underground storage of natural gas and designating the injected gas as the personal property of the injector.[167]

Although neither *Murchison* nor *West* addressed royalty obligations in the context of carbon dioxide injection, the Seventh Court of Appeals relied on both cases in *Occidental Permian Ltd. v. Helen Jones Foundation*—a case in which it decided whether a casinghead gas royalty clause includes royalty on extraneous carbon dioxide.[168] In *Helen Jones*, royalty owners sued the current lease operator for underpaid royalties on casinghead gas, including a claim for royalties on carbon dioxide injected into a reservoir to enhance oil recovery.[169] The royalty owners sought royalties on non-native carbon dioxide injected into the producing formation when the carbon dioxide subsequently commingled and produced with the casinghead gas stream.[170] After initial production from the lease declined, the operator implemented a water flood operation to enhance production.[171] Soon thereafter, the operator commenced a carbon dioxide injection operation "for the purpose of maintaining and enhancing production of oil."[172] As the court noted, the injected carbon dioxide "becomes commingled with hydrocarbons in the producing formation and comes back to the surface along with the casinghead gas."[173] To separate the carbon dioxide from the other hydrocarbons, the operator sent the casinghead gas to an on-site processing plant.[174] The operator then sold the hydrocarbons and reinjected the carbon dioxide into

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165. *See* Anderson, *supra* note 164; *see also* Alan Stamm, *Legal Problems in the Underground Storage of Natural Gas*, 36 TEX. L. REV. 161, 162–63 (1957) (discussing the critical role of underground storage during seasonal fluctuations of demand for natural gas and the financial impracticality of building pipelines to meet maximum consumer demand).

166. *See West*, 508 S.W.2d at 817–19; *Murchison*, 353 S.W.2d at 875–78; *Underground Natural Gas Storage Capacity–Total Number of Existing Fields*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/dnav/ng/ng_stor_cap_a_EPG0_SAD_Count_a.htm (last updated Aug. 31, 2015) (crediting Texas with thirty-seven underground storage fields, ranking as the state with the third-most number of fields); *Underground Natural Gas Storage Capacity–Total Storage Capacity*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/dnav/ng/ng_stor_cap_a_epg0_sac_mmcf_a.htm (last updated Aug. 31, 2015) (listing Texas as having the third-largest underground natural gas storage capacity by state).

167. TEX. NAT. RES. CODE ANN. §§ 91.172–.182 (West 2014).

168. *See West*, 508 S.W.2d at 817–19; Occidental Permian Ltd. v. Helen Jones Found., 333 S.W.3d 392, 407–11 (Tex. App.—Amarillo 2011, pet. denied); *Murchison*, 353 S.W.2d at 875–78.

169. *Helen Jones*, 333 S.W.3d at 407–11.

170. *Id.*

171. *Id.* at 397.

172. *Id.*

173. *Id.*

174. *Id.*

the reservoir.[175] Thus, the carbon dioxide followed "a continuous cycle of injection, recovery, processing and re-injection."[176]

Although the royalty owners conceded that the carbon dioxide is the operator's personal property before its injection, they contended that the operator lost possession of the carbon dioxide upon injection, making it susceptible to capture in the producing formation.[177] The royalty owners further argued that the operator had the right to "capture, or recapture," the carbon dioxide as provided in the leases and unitization agreements and that once the operator captured the carbon dioxide, it became subject to the operator's royalty obligation.[178] The court characterized the issue as "whether, under Texas law, the rule of capture operates to subject extraneous [carbon dioxide] injected and recovered by [the operator] to a royalty obligation under its leases."[179]

Helen Jones was a case of first impression for the Texas courts, as there was no prior case directly addressing "ownership of extraneous [carbon dioxide] injected into a formation" to enhance production.[180] Nevertheless, the court relied heavily on the *Murchison* and *West* cases, despite the imprecise analogy between stored natural gas and injected carbon dioxide.[181] The royalty owners failed to show the necessity of departing from the reasoning in *Murchison* and *West* because they did not distinguish the injection of carbon dioxide for enhanced oil production from the injection of natural gas for storage.[182] The court also recognized that the operator did not intend to abandon title to the carbon dioxide when it injected the gas into the reservoir and that, in fact, the operator's recycling and reinjection of the carbon dioxide was proof of its intent to maintain possession of the gas throughout the entire enhanced recovery process.[183] Thus, the court held that the injected carbon dioxide remained the personal property of the operator and that royalty owners were not entitled to royalty on the carbon dioxide that was subsequently produced as part of the commingled casinghead gas

175. *Id.*
176. *Id.*
177. *Id.* at 408–09.
178. *Id.*
179. *Id.* at 409. Texas courts have described the rule of capture as a doctrine entitling a landowner "to produce the oil and gas in place beneath his land, as well as the oil and gas which flows to the land as the result of physical conditions and natural laws relating to the migratory nature of oil and gas." *Id.* (quoting SWEPI, L.P. v. Camden Res., Inc., 139 S.W.3d 332, 341 (Tex. App.—San Antonio 2004, pet. denied) (internal citations omitted)).
180. *Id.*
181. *Id.* at 409–11; *see* Humble Oil & Ref. Co. v. West, 508 S.W.2d 812, 814–19 (Tex. 1974); Lone Star Gas Co. v. Murchison, 353 S.W.2d 870, 874–78 (Tex. Civ. App.—Dallas 1962, writ ref'd n.r.e.).
182. *Helen Jones*, 333 S.W.3d at 410; *see West*, 508 S.W.2d at 814–19; *Murchison*, 353 S.W.2d at 874–78.
183. *Helen Jones*, 333 S.W.3d at 411 (citing *Murchison*, 353 S.W.2d at 870).

stream.[184] Because the operator maintained its personal property ownership of the carbon dioxide, the rule of capture did not apply in this case.[185]

The decision in *Helen Jones* continued the Texas tradition of rejecting the doctrine of minerals *ferae naturae*.[186] Oil and gas operators should not overlook the importance of *Helen Jones*, however, because it was the first case to reject this theory in the context of enhanced recovery operations.[187] Most significantly, the court stated definitively that even in enhanced oil recovery operations, injected carbon dioxide remains the property of the operator.[188] Although this rule was well-reasoned by the Seventh Court of Appeals, it conflicts with the Texas Supreme Court's subsequent decision in *French v. Occidental Permian Ltd*.[189]

IV. UNRAVELING THE LAYERS OF THE *FRENCH* PASTRY: DISTINGUISHING PRODUCTION AND POST-PRODUCTION ACTIVITIES IN CARBON DIOXIDE OPERATIONS

After royalty owners recognized they could not obtain a royalty interest in carbon dioxide injected to enhance oil recovery, they attempted to maximize their royalty payments by limiting post-production expense deductions.[190] In *French v. Occidental Permian Ltd.*, royalty owners sued Occidental Permian (Oxy), the working interest owner, for underpayment of casinghead gas royalty, arguing that Oxy improperly deducted, as a post-production expense, the cost of separating carbon dioxide from casinghead gas.[191]

A. It's French *to Me: Who Pays to Remove Carbon Dioxide from Casinghead Gas?*

It is fitting that *French v. Occidental Permian Ltd.*, the most recent Texas case regarding royalty obligations in the context of enhanced recovery operations, started in Scurry County, Texas, the birthplace of carbon dioxide

184. *Id.* at 408–11.

185. *See id.* at 410–11.

186. *See id.* at 409–11; *see also West*, 508 S.W.2d at 814–19 (rejecting the minerals *ferae naturae* theory); *Murchison*, 353 S.W.2d at 874–78 (same).

187. *See Helen Jones*, 333 S.W.3d at 409 (stating there was no prior case law regarding "ownership of extraneous [carbon dioxide] injected into a formation" for enhanced oil recovery).

188. *See id.* at 410–11.

189. *See id.*; French v. Occidental Permian Ltd., 440 S.W.3d 1, 10 (Tex. 2014).

190. *See French*, 440 S.W.3d at 7 (discussing royalty owners' argument that the cost of separating carbon dioxide from casinghead gas is a production cost not deductible from the lessors' royalty); *Helen Jones*, 333 S.W.3d at 409 (rejecting lessor's claim for royalty on extraneous carbon dioxide injected for enhanced recovery operations).

191. *French*, 440 S.W.3d at 1–7. A working interest owner has the "exclusive right to exploit the minerals on the land." MARTIN & KRAMER, *supra* note 14, at 1147. A working interest is typically created through the execution of an oil and gas lease. *Id.*

injection.[192] The plaintiffs in *French* owned the royalty interests under two leases, the Fuller Lease and the Cogdell Lease.[193] The Fuller Lease required the lessee to pay a royalty equal to the market value of one-eighth of the casinghead gas sold or used.[194] The Cogdell Lease required the lessee to pay "a royalty of '[one-fourth] of the net proceeds from the sale'" of products manufactured and sold from the casinghead gas, after deducting manufacturing costs.[195] The royalty owners alleged that Oxy underpaid royalties on both leases because it deducted from the value of the casinghead gas the cost of separating carbon dioxide from the casinghead gas stream.[196]

After primary production declined, the lessee unitized the leases to implement secondary recovery operations, which began in 1954.[197] The Unitization Agreement granted the working interest owners complete discretion in determining how to conduct enhanced recovery operations.[198] Importantly, the Unitization Agreement stated that the royalty owners would bear the cost of such operations only if they were already obligated to pay such costs under the original leases.[199]

After water flooding became less effective, Oxy began carbon dioxide injection operations in 2001.[200] Because the injected carbon dioxide becomes commingled with the casinghead gas, Oxy needed to separate the carbon dioxide to reinject it into the reservoir.[201] To implement this process, the operator contracted with Kinder Morgan to build and manage a facility that could separate the carbon dioxide-laden casinghead gas.[202] The casinghead gas stream also included NGLs, such as ethane, propane, butane, pentane, and natural gasoline, all of which the operator could extract and sell.[203] In exchange for its services, Kinder Morgan received a monthly fee, plus 30% of the total NGLs produced from the separation process, as well as all of the residual gas.[204]

Oxy paid royalty owners a "royalty on 70% of the NGLs, but not on the 30% [it gave] to Kinder Morgan as in-kind compensation."[205] In essence, Oxy considered the in-kind compensation to Kinder Morgan for carbon

192. *French*, 440 S.W.3d at 1; *see supra* notes 18–19 and accompanying text.
193. *French*, 440 S.W.3d at 2.
194. *Id.*
195. *Id.* at 2–3.
196. *See id.* at 7.
197. *Id.* at 4.
198. *Id.*
199. *Id.* at 5.
200. *Id.* at 5–6.
201. *See id.* at 5–7.
202. *Id.* at 6–7.
203. *Id.* at 6. The Kinder Morgan plant also removed most of the hydrogen sulfide, a contaminant, from the casinghead gas. *Id.* at 6–7. The royalty owners conceded that removal of hydrogen sulfide was a post-production expense. *Id.* at 7.
204. *Id.* The residual gas could not be sold because of its high nitrogen content, but Kinder Morgan used the gas for a nearby electric generation facility. *Id.*
205. *Id.*

dioxide removal a post-production expense that must be shared by the operator and the royalty owners.[206] The royalty owners contended that "royalties must be based only on the value of the non-[carbon dioxide] gas, the 'native' gas, at the well."[207] The only deductions the royalty owners considered appropriate were processing costs unrelated to the removal of carbon dioxide.[208] In response, Oxy argued that "under both leases, the cost of removing [carbon dioxide] is a postproduction expense involved in extracting the NGLs that must be deducted from their market price in determining royalties."[209]

The royalty owners relied on the Texas Supreme Court's prior decision in *Humble Oil & Refining Co. v. West*.[210] The Court, however, rejected *West*'s applicability to this case, stating that "whether a royalty owner must share in the cost of separation [of carbon dioxide] was not in issue or addressed in *West*."[211] The Court also rejected the royalty owners' argument that the process of separating injected carbon dioxide from casinghead gas is similar to the process of separating injected water from oil in a secondary recovery water flooding operation, which is considered a production cost.[212] Separating water from oil is necessary to make the oil marketable after a water flood and necessary to reinject the water into the reservoir.[213] On the other hand, separating carbon dioxide from the casinghead gas is not necessary to continue oil production, according to the Court, because the gas can be reinjected directly without removing the carbon dioxide.[214] The royalty owners themselves recognized this distinction when they gave the operator the power to decide whether to reinject the entire casinghead gas stream or to process the casinghead gas stream to extract the NGLs and obtain a concentrated carbon dioxide stream.[215]

Had Oxy decided to reinject the casinghead gas stream without further processing, the royalty owners would not have received a royalty on any of the casinghead gas.[216] Because Oxy instead decided to process the casinghead gas to extract the NGLs and inject a fully concentrated stream of carbon dioxide, the royalty owners realized a substantial additional royalty from the marketing of the NGLs.[217] Ultimately, the Court decided that the royalty owners must share in the cost of carbon dioxide removal because they

206. *Id.*
207. *Id.* at 8–9.
208. *Id.* at 9.
209. *Id.*
210. *Id.*
211. *Id.*
212. *See id.* at 9–10.
213. *Id.*
214. *Id.* at 10.
215. *See id.*
216. *See id.*
217. *See id.* at 7 n.16.

gave the operator the discretion to decide whether to reinject the casinghead gas or process it and because the royalty owners substantially benefitted from the operator's decision to process the casinghead gas.[218]

B. A Bunch of Crêpe!: How French v. Occidental Permian Ltd. *Was Incorrectly Decided*

The Texas Supreme Court's decision in *French* was largely driven by public policy considerations. The Court described the consistent interpretation and application of conventional lease provisions as "important to industry stability."[219] The Court also noted that Oxy's decision to reinject a concentrated stream of carbon dioxide, rather than unprocessed casinghead gas, furthered the state's "policy of encouraging full recovery of hydrocarbons and precluding waste."[220] *French* provides predictability to oil and gas operators by clearly designating the cost of removing carbon dioxide from casinghead gas as a post-production expense chargeable to royalty owners.[221]

Despite the case's broad support for the Texas oil and gas industry and specifically, carbon dioxide injection operations, the Texas Supreme Court decided *French* incorrectly for several reasons. First, the Court's decision in *French* is irreconcilable with its prior decision in *Humble Oil & Refining Co. v. West* and the Seventh Court of Appeals' decision in *Occidental Permian Ltd. v. Helen Jones Foundation*.[222] In *West*, the Court recognized the value of underground gas storage and held that injected gas was not subject to a royalty when subsequently removed from the reservoir for commercial use.[223] Moreover, *Helen Jones* teaches that extraneous carbon dioxide, injected to enhance oil recovery, remains the personal property of the party injecting it.[224] Although agreeing that the carbon dioxide remains Oxy's personal property, the *French* Court allowed Oxy to include the extraneous carbon dioxide as part of casinghead gas for royalty valuation purposes.[225] The value of the casinghead gas is "far less" in its carbon dioxide-laden state than its native state, and this reduced value decreases Oxy's royalty obligations.[226] As the royalty owners argued, if the injected carbon dioxide belongs to Oxy, the casinghead gas royalty should be based on its native state,

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218. *Id.* at 10.
219. *Id.* at 8.
220. *Id.* at 10 n.32.
221. *See id.* at 10.
222. *See id.* at 9–10; Humble Oil & Ref. Co. v. West, 508 S.W.2d 812, 816–19 (Tex. 1974); Occidental Permian Ltd. v. Helen Jones Found., 333 S.W.3d 392, 408–11 (Tex. App.—Amarillo 2011, pet. denied).
223. *See West*, 508 S.W.2d at 816–19.
224. *See Helen Jones*, 333 S.W.3d at 408–11.
225. *French*, 440 S.W.3d at 9–10.
226. *Id.* at 9.

without the commingled carbon dioxide.[227] By permitting Oxy to retain ownership of the injected carbon dioxide and to devalue the casinghead gas by including substantial amounts of that same carbon dioxide, the Court allowed Oxy to have its cake and eat it too.[228]

Another reason extraneous carbon dioxide should not be included in the casinghead gas royalty valuation is because such inclusion fails to uphold the language of the leases. The gas royalty provisions in both leases applied only to gas "produced from" the leased land.[229] The injected carbon dioxide, however, is not produced from the leased lands; it is produced elsewhere and then transported to the reservoir for injection.[230] Moreover, the *French* Court failed to apply the statutory definition of *casinghead gas*, which is "any gas [or] vapor *indigenous* to oil stratum and produced from [the] stratum with oil."[231] The Texas Supreme Court previously held that the state's Natural Resources Code's definition of *casinghead gas* is incorporated into a lease when the parties themselves have failed to specifically define the term.[232] Because the leases in *French* failed to define *casinghead gas*, the Court's analysis should have focused on the statutory definition.[233] Based on that definition, extraneous carbon dioxide is not a part of the casinghead gas, for royalty purposes, because it is not "indigenous" to the reservoir.[234] Valuing the native casinghead gas, exclusive of the extraneous carbon dioxide, is thus the proper method of determining the amount of royalty due.

The Texas Supreme Court's decision in *French* is also inconsistent with prior Texas cases distinguishing production from post-production because the Court failed to adequately consider the true purpose of the carbon dioxide flood.[235] In classifying operations as either production or post-production, the purpose of the activity is a determinative factor.[236] For example, in *Parker v. TXO Production Corp.*, a Texas court of appeals held that the use of a compressor to move gas to producing wells was a production operation because its purpose was to "*increase production* from the wells."[237]

227. Petitioners' Brief on the Merits at 35 n.26, *French*, 440 S.W.3d 1 (No. 12-1002), 2013 WL 5409251.

228. *See French*, 440 S.W.3d at 8–10.

229. *Id.* at 2 n.4.

230. *Cf. id.* at 5 n.12 (indicating that Oxy paid 66 cents per mcf of carbon dioxide, implying that the carbon dioxide was produced off-lease and subsequently purchased and transported by Occidental Permian for injection).

231. TEX. NAT. RES. CODE ANN. § 86.002(10) (West 2014) (emphasis added).

232. Amarillo Oil Co. v. Energy-Agri Prods., Inc., 794 S.W.2d 20, 22 (Tex. 1990).

233. Petitioners' Brief on the Merits, *supra* note 227, at 35 (stating that the two leases in the case did not define *casinghead gas*).

234. *See* NAT. RES. § 86.002(10).

235. *See* Martin v. Glass, 571 F. Supp. 1406, 1415–16 (N.D. Tex. 1983), *aff'd*, 736 F.2d 1524 (5th Cir. 1984); *French*, 440 S.W.3d at 6–10; Blackmon v. XTO Energy, 276 S.W.3d 600, 604 (Tex. App.—Waco 2008, no pet.); Parker v. TXO Prod. Corp., 716 S.W.2d 644, 648 (Tex. App.—Corpus Christi 1986, no writ).

236. *See, e.g.*, *Martin*, 571 F. Supp. at 1415–16; *Parker*, 716 S.W.2d at 648.

237. *Parker*, 716 S.W.2d at 648.

Conversely, when insufficient pressure exists to move produced gas from the wellhead to a gathering pipeline, the use of a compressor is a post-production activity.[238]

In *French*, the operator injected carbon dioxide to increase reservoir pressure and thereby stimulate oil production.[239] As the Court even recognized, without the carbon dioxide program, "oil production would have declined to 200 barrels per day and would no longer have been economically viable, and more than half the oil in the reservoir would have been lost forever."[240] After the carbon dioxide was collectively produced with the casinghead gas, the operator could have reinjected all of the casinghead gas, which was "only about 85%" carbon dioxide.[241] Instead, because the "injection stream should be more highly concentrated" in carbon dioxide, Oxy chose to process the casinghead gas.[242] At trial, Oxy's witnesses admitted that the sole purpose of separating and reinjecting the carbon dioxide was to produce more oil.[243] The Court mischaracterized the purpose of separating the carbon dioxide by noting that the process was "not necessary for the continued production of oil" because all of the casinghead gas could have been reinjected.[244] In its analysis, however, the Court conflates purpose with necessity.[245] That an operation is not necessary for continued oil production does not change the purpose for which it is carried out.[246] The true purpose of injecting carbon dioxide and separating that carbon dioxide from the casinghead gas was to increase oil production.[247] Therefore, both activities ought to be classified as production operations, the costs of which are not chargeable to royalty owners.

V. MAKING *FRENCH* TOAST: HOW ROYALTY OWNERS CAN PROHIBIT POST-PRODUCTION DEDUCTIONS

Despite *French v. Occidental Permian Ltd.* allocating the cost of carbon dioxide removal as a post-production cost, future royalty owners entering into new oil and gas leases can avoid these costs and maximize their royalty payments by carefully and conscientiously drafting the royalty provisions in

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238. *See Martin*, 571 F. Supp. at 1415–16; *see also* Cartwright v. Cologne Prod. Co., 182 S.W.3d 438, 444–45 (Tex. App.—Corpus Christi 2006, pet. denied) (explaining that post-production costs include "compression costs to make [gas] deliverable into a purchaser's pipeline").

239. *See French*, 440 S.W.3d at 5–6.

240. *Id.* at 6. After Oxy began carbon dioxide injection, the unit produced about 5,800 barrels of oil each day. *Id.*

241. *Id.*

242. *Id.*

243. Petitioners' Brief on the Merits, *supra* note 227, at 22 n.20.

244. *French*, 440 S.W.3d at 10.

245. *See id.* at 8–10.

246. *See, e.g.*, Parker v. TXO Prod. Corp., 716 S.W.2d 644, 648 (Tex. App.—Corpus Christi 1986, no writ).

247. *See French*, 440 S.W.3d at 5–6; Petitioners' Brief on the Merits, *supra* note 227, at 22 n.20.

their leases.[248] Texas courts have long recognized the right of lessors and lessees to draft around judicially created rules.[249] Taking advantage of this right, however, has proved difficult for lessors seeking to prohibit all post-production cost deductions from their royalty.[250] The landmark *Heritage Resources, Inc. v. NationsBank* case from the Texas Supreme Court and two modern Fifth Circuit cases are illustrative of this difficulty.[251] A recent case decided by the Fourth Court of Appeals and affirmed by the Texas Supreme Court, however, demonstrates that the task is not impossible.[252] With these cases in mind, lessors can draft their leases to prevent operators from reducing their royalty with certain post-production expenses, including costs to remove extraneous carbon dioxide from casinghead gas.[253]

A. When "No Deductions" Really Means "With Deductions": Heritage Resources, Inc. v. NationsBank

In 1996, the Texas Supreme Court examined the implications of a royalty clause prohibiting post-production cost deductions in a lease requiring royalties on gas based on the "market value at the well."[254] The lease in *Heritage Resources, Inc. v. NationsBank* stated "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."[255] Royalty owners sued Heritage Resources, arguing that Heritage's deduction of transportation costs from royalty payments violated the express agreement of the parties.[256] Noting that words and phrases such as *royalty* and *market value at the well* have certain commonly understood meanings within the oil and gas industry, the

248. *See French*, 440 S.W.3d at 9–10; *see also* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 124 (Tex. 1996) (Owen, J., concurring) (recognizing that lessors and lessees "may allocate costs, including post-production or marketing costs, as they choose").

249. *See Heritage*, 939 S.W.2d at 122 (majority opinion); *see also French*, 440 S.W.3d at 8 ("Royalty owners and working interest owners are, of course, free to agree on what royalty is due, the basis on which it is to be calculated, and how expenses are to be allocated."); Cartwright v. Cologne Prod. Co., 182 S.W.3d 438, 444–45 (Tex. App.—Corpus Christi 2006, pet. denied) (recognizing that parties to a lease may modify the general rule that post-production expenses are proportionally borne by the operator and the royalty owners).

250. *See, e.g.*, Potts v. Chesapeake Expl., L.L.C., 760 F.3d 470, 476 (5th Cir. 2014) (applying Texas law) (holding that cost-free language in a point-of-sale lease did not prohibit post-production expense deductions); Warren v. Chesapeake Expl., L.L.C., 759 F.3d 413, 419 (5th Cir. 2014) (applying Texas law) (holding that a cost-free provision in an "at the well" lease addendum did not prohibit deduction of post-production expenses); *Heritage*, 939 S.W.2d at 122–24 (stating that a "no deductions" clause in an "at the well" lease did prevent deduction of post-production transportation expenses).

251. *See Potts*, 760 F.3d at 476; *Warren*, 759 F.3d at 419; *Heritage*, 939 S.W.2d at 122–23.

252. *See* Chesapeake Expl., L.L.C. v. Hyder (*Hyder I*), 427 S.W.3d 472, 477–78 (Tex. App.—San Antonio 2014), *aff'd*, No. 14–0302, 2015 WL 3653446, at *5 (Tex. June 12, 2015).

253. *See id.*; *e.g.*, *Potts*, 760 F.3d at 476; *Warren*, 759 F.3d at 419; *Heritage*, 939 S.W.2d at 122–23.

254. *Heritage*, 939 S.W.2d at 120.

255. *Id.* (emphasis added).

256. *Id.*

court defined *royalty* as the landowner's share of production, free of the costs of production, but subject to post-production costs, and defined *market value at the well* as "the price a willing seller obtains from a willing buyer."[257] Based on these definitions, the court construed the lease as requiring the lessee to determine the market value at the well by using either a comparable sales or a net-back method, and then multiplying that value by the royalty fraction defined in the lease.[258] This multiplication results in the value of the lessor's royalty.[259] The "no deductions" clause then prohibited any deductions from the value of the lessor's royalty.[260] The royalty owners' failure to provide evidence of comparable sales forced the court to use the net-back method to determine market value at the well.[261] Regardless of the method used, however, calculation of market value at the well necessarily required subtraction of reasonable post-production expenses from the gas value at the "point of sale."[262]

Using a narrow interpretation of the lease, the Court deemed the no-deductions clause as legal surplusage because it only restated existing Texas law that the lessee cannot pay the lessor less than the lessor's fractional share of the market value, even if the amount realized from the sale of the gas is less than the market value.[263] *Heritage* teaches that "[a]s long as 'market value at the well' is the benchmark for valuing the gas, a phrase prohibiting the deduction of post-production costs from that value does not change the meaning of the royalty clause."[264] Thus, for lessors to effectively prohibit post-production deductions from their royalty, they should avoid the phrase "at the well" altogether.[265] Leases with royalty valuation based on gross proceeds or amount realized are more compatible with a no deductions clause.[266] Calculating gross proceeds or amount realized does not inherently require the deduction of post-production expenses, unlike calculations of market value at the well.[267]

257. *Id.* at 121–22.
258. *Id.* at 122–23.
259. *See id.* at 122.
260. *Id.*
261. *See id.* at 122–23.
262. *See id.* at 130–31 (Owen, J., concurring).
263. *See id.* at 122–23 (majority opinion) (citing Tex. Oil & Gas Corp. v. Vela, 429 S.W.2d 866, 875–76 (Tex. 1968)).
264. *Id.* at 130 (Owen, J., concurring).
265. *See id.*; *see also* Poitevent, II, *supra* note 103, at 733 (encouraging lessors to use a gross-proceeds or amount-realized clause, instead of an at-the-well clause, to avoid post-production deductions).
266. *See, e.g.*, Comm'r of Gen. Land Office v. SandRidge Energy, Inc., 454 S.W.3d 603, 623–26 (Tex. App.—El Paso 2014, pet. filed) (holding that a lease based on gross proceeds and containing a cost-free clause prohibited post-production deductions); *see also* Poitevent, II, *supra* note 103, at 733.
267. *See* Bowden v. Phillips Petroleum Co., 247 S.W.3d 690, 699 (Tex. 2008) ("'Proceeds' or 'amount realized' clauses require measurement of the royalty based on the amount the lessee in fact receives under its sales contract for the gas." (citing Union Pac. Res. Grp. v. Hankins, 111 S.W.3d 69, 72 (Tex. 2003))); *Heritage*, 939 S.W.2d at 122–23 (majority opinion).

After the Texas Supreme Court's decision in *Heritage*, lessors and lessees faced difficulty in determining the precise language necessary to prohibit post-production deductions.[268] This difficulty is highlighted in a trilogy of recent cases involving Chesapeake Exploration.[269] In all three cases, the royalty owners thought they had a royalty free of post-production costs.[270] But as the Fifth Circuit recently decided in two of these cases, the applicable royalty provisions did not adequately change the general rule that a lessor's royalty is subject to post-production expense deductions.[271] In the third case, however, royalty owners prevailed in arguing that a "cost-free" clause effectively prohibited post-production deductions.[272]

B. *Continued Language Barriers:* Warren v. Chesapeake Exploration, L.L.C. *and* Potts v. Chesapeake Exploration, L.L.C.

In the first of two Fifth Circuit cases addressing the validity of clauses attempting to prohibit post-production expenses, *Warren v. Chesapeake Exploration, L.L.C.*, the lessors and lessee agreed to a gas royalty based on "the amount realized by Lessee, computed at the mouth of the well."[273] The lease also contained an addendum stating that the lessors' royalty would "be free of all costs and expenses related to" production and post-production operations.[274] Moreover, the addendum provided that the provisions therein would supersede the main lease in the event of an inconsistency between the two agreements.[275] In interpreting the royalty clause, the court characterized the "amount realized by Lessee, computed at the mouth of the well," as requiring the lessee to pay a royalty based on net proceeds, calculated at the well.[276] Citing *Judice v. Mewbourne Oil Co.*, a companion case to the Texas Supreme Court's decision in *Heritage*, the Fifth Circuit concluded that calculating net proceeds requires a lessee to deduct post-production costs.[277] The court then examined the impact of the cost-free provision in the addendum, but determined the provision did "not change the point at which

268. *See, e.g.*, Potts v. Chesapeake Expl., L.L.C., 760 F.3d 470, 476 (5th Cir. 2014) (applying Texas law); Warren v. Chesapeake Expl., L.L.C., 759 F.3d 413, 419 (5th Cir. 2014) (applying Texas law); *Hyder I*, 427 S.W.3d 472, 477–78 (Tex. App.—San Antonio 2014), *aff'd*, No. 14–0302, 2015 WL 3653446, at *5 (Tex. June 12, 2015).

269. *See Potts*, 760 F.3d at 476; *Warren*, 759 F.3d at 419; *Hyder I*, 427 S.W.3d at 477–78.

270. *See Potts*, 760 F.3d at 472; *Warren*, 759 F.3d at 414; *Hyder I*, 427 S.W.3d at 475.

271. *See Potts*, 760 F.3d at 476; *Warren*, 759 F.3d at 419.

272. *Hyder I*, 427 S.W.3d at 477–78.

273. *Warren*, 759 F.3d at 416 (emphasis omitted).

274. *Id.*

275. *Id.* at 418.

276. *Id.* at 417–18.

277. *Id.* (citing Judice v. Mewbourne Oil Co., 939 S.W.2d 133, 136 (Tex. 1996)); *see* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 127 (Tex. 1996) (Owen, J., concurring) (identifying *Judice* as a companion case).

all royalty is computed, which is the mouth of the well."[278] Thus, the cost-free provision in this case was similar to the no-deductions clause in *Heritage* as both clauses failed to effectively prohibit post-production deductions.[279] The key lesson from *Warren*, as Judge Owen (who authored the concurring opinion in *Heritage*) noted, is that the inclusion of "at the mouth of the well" undermines the success of a clause intended to preclude post-production royalty deductions.[280] If the *Warren* royalty clause had instead stated "amount realized," the court would undoubtedly have construed the royalty as being free from post-production deductions.[281]

Soon after the Fifth Circuit decided *Warren*, the court encountered a lease provision that changed the point of valuation from the wellhead to the point of sale.[282] In *Potts v. Chesapeake Exploration, L.L.C.*, royalty owners claimed Chesapeake miscalculated royalties because it deducted post-production costs in determining the value on which the royalty was based.[283] The lease fixed the royalty at the market value of the gas at the point of sale.[284] The lease also included a cost-free clause stating the royalty would be "free of all costs and expenses related to" production and post-production operations.[285] Despite moving the royalty valuation point away from the wellhead, which the lessors in *Heritage* and *Warren* failed to do, the court held that the cost-free clause in this lease was ineffective because the gas sales occurred at the wellhead.[286] The price paid by the Chesapeake affiliate that purchased the gas included deductions for post-production activities, but the court determined that such calculation was consistent with the meaning of market value at the well.[287] Judge Owen again relied on her concurrence in *Heritage*, stating that the "concept of 'deductions' of marketing costs from the value of the gas is meaningless when gas is valued at the well" because "[v]alue at the well is already net of reasonable marketing costs."[288]

Potts teaches an important lesson: Although a lease may include express language to change the location at which royalty is determined, a cost-free clause proscribing post-production deductions may still be ineffective if the

278. *Warren*, 759 F.3d at 418.
279. *See id.* at 417–18; *Heritage*, 939 S.W.2d at 123 (majority opinion).
280. *Warren*, 759 F.3d at 418; *see Heritage*, 939 S.W.2d at 124 (Owen, J., concurring).
281. *See Warren*, 759 F.3d at 417–18.
282. Potts v. Chesapeake Expl., L.L.C., 760 F.3d 470, 473 (5th Cir. 2014) (applying Texas law).
283. *Id.* at 474–75.
284. *Id.* at 473–74.
285. *Id.* at 474.
286. *Id.* at 474–75; *see Warren*, 759 F.3d at 417–18; Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 122–23 (Tex. 1996) (majority opinion).
287. *Potts*, 760 F.3d at 474–75. The royalty owners also questioned Chesapeake's use of an affiliate to sell the gas, but the court found no problems with Chesapeake's practice because it did not impact royalty calculation. *Id.* at 475–76.
288. *Id.* at 475 (quoting *Heritage*, 939 S.W.2d at 130 (Owen, J., concurring)).

operator sells the gas at the well.[289] The royalty owners in *Potts* attempted to follow then-Justice Owen's advice in *Heritage* to make clear their intent to have the lessee bear post-production expenses.[290] Chesapeake's decision to sell the gas at the wellhead, however, thwarted their pursuit of a royalty free of post-production deductions.[291]

C. *The Recipe for Success:* Chesapeake Exploration, L.L.C. v. Hyder

In *Chesapeake Exploration, L.L.C. v. Hyder (Hyder I)*, the lease provided the lessor a standard royalty on gas based on the "price actually received" by Chesapeake.[292] The Fourth Court of Appeals described the gas royalty as a "proceeds royalty," fixed on the amount of gas actually sold by Chesapeake.[293] The royalty was to be "free and clear of all production and post-production costs and expenses."[294] The lease also provided for a cost-free overriding royalty interest for wells located off the leased premises, based on "gross production."[295] Interestingly, the royalty clause in this case expressly stated the parties' agreement "that the holding in the case of *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118 (Tex. 1996) shall have no application to the terms and provisions of this Lease."[296] Chesapeake argued that the cost-free clause still allowed it to deduct from the lessor's royalty post-production expenses incurred between the point of delivery and the point of sale.[297] Interpreting the cost-free clause in the royalty owners' favor, the court noted that regardless of where Chesapeake incurred the post-production costs, it could not deduct such costs from the royalty.[298] The parties successfully modified the general rule that post-production costs are deductible from royalty.[299] Furthermore, the *Heritage* exclusion clause "reinforced" the court's conclusion that the parties intended to create a royalty free of post-production costs.[300] Using similar analysis, the court also construed the overriding royalty as being free from post-production deductions.[301]

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289. *See id.*
290. *See id.* at 476; *Heritage*, 939 S.W.2d at 131.
291. *See Potts*, 760 F.3d at 475–76.
292. *Hyder I*, 427 S.W.3d 472, 477–78 (Tex. App.—San Antonio 2014), *aff'd*, No. 14–0302, 2015 WL 3653446, at *5 (Tex. June 12, 2015).
293. *Id.* at 481–82.
294. *Id.* at 476 (emphasis omitted).
295. *Id.* at 478.
296. *Id.* at 477.
297. *Id.* at 476.
298. *Id.* at 476–78.
299. *See id.* at 477.
300. *Id.*
301. *See id.* at 478–80.

On appeal to the Texas Supreme Court (*Hyder II*), Chesapeake did not challenge the lower court's decision regarding the lessor's gas royalty.[302] Instead, it only challenged the court's holding regarding the overriding royalty.[303] In a 5–4 decision, the Texas Supreme Court affirmed, determining that the overriding royalty was also free of post-production deductions.[304] The Court, however, also confirmed, in dicta, that the lessor's royalty was free of post-production costs because it was a "proceeds lease"—the lease based the royalty on the price Chesapeake actually received for the gas, after it paid post-production expenses.[305] Both the majority and the dissenting opinions in the case indicated that the "free and clear" language in the gas royalty was surplusage because the "gas royalty is valued by sale price after post-production value has already been added."[306] This view is in conflict with the court of appeals' decision, which gave effect to the "free and clear" language.[307]

Lease clauses excluding the application of *Heritage* gained popularity after the Texas Supreme Court's controversial decision in that case.[308] *Hyder I*, however, was the first case in which a court actually addressed the impact of a *Heritage* exclusion clause.[309] Although the lease in *Hyder I* based the royalty on proceeds of sales rather than the market value at the well standard used in *Heritage*, the Fourth Court of Appeals appeared to give at least some weight to the clause as a factor in interpreting the cost-free provision.[310] The Texas Supreme Court, however, held that the *Heritage* disclaimer had no impact on its analysis of the royalty provisions.[311] It stated in *Hyder II* that "[a] disclaimer of [the *Heritage*] holding, like the one in this case, cannot free a royalty of postproduction costs when the text of the lease itself does not do so."[312] Justice Brown's dissenting opinion, however, indicated that the *Heritage* disclaimer could be viewed as a "belt-and-suspenders attempt to

302. Chesapeake Expl., L.L.C. v. Hyder (*Hyder II*), No. 14–0302, 2015 WL 3653446, at *2 n.18 (Tex. June 12, 2015).

303. *See id.* at *1.

304. *Id.* at *5.

305. *Id.* at *2.

306. *Id.* at *7 (Brown, J., dissenting).

307. *See id.* at *2 n.18 (majority opinion) (noting that the "court of appeals reasoned otherwise, relying on the 'free and clear' language to conclude that both the oil and gas royalties are free of postproduction costs").

308. *See* Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 123 (Tex. 1996) (majority opinion); Timothy D. Howell & David A. Palmer, *Observations on Recent Royalty Litigation in Energy*, TEX. LAW. (Sept. 11, 2014), http://www.texaslawyer.com/id=1202669715164/Observations-on-Recent-Royalty-Litigation-in-Energy?slreturn=20150106123238.

309. *See Hyder I*, 427 S.W.3d 472, 477–78 (Tex. App.—San Antonio 2014), *aff'd*, No. 14–0302, 2015 WL 3653446, at *5 (Tex. June 12, 2015).

310. *Id.*

311. *Hyder II*, 2015 WL 3653446, at *4–5.

312. *Id.*

ensure the 'free and clear' language is given effect despite its conflict with the oil royalty's market-value-at-the-well definition."[313]

For future royalty owners, *Hyder II* once again shows the benefits of having a lease based on the amount realized or gross proceeds.[314] Although the Texas Supreme Court indicated that the cost-free provision was unnecessary for a gas royalty based on proceeds, lessors drafting royalty provisions should still include such language because the Court's view on this issue has limited precedential value, and because the lower court in *Hyder I* did give weight to the free-and-clear provision.[315] Furthermore, mineral owners who are unable to negotiate a royalty based on proceeds or amount realized should incorporate a *Heritage* exclusion clause into their lease.[316] The *Heritage* exclusion clause, combined with a well-drafted cost-free or no-deductions clause, shows further proof of the parties' intent to create a royalty prohibiting post-production costs.[317]

D. Let's Start Drafting: Best Practices for Preventing Post-production Deductions from Royalty

When viewed collectively, the four cases highlighted above provide strong guidance for mineral owners seeking a lessor's royalty free of post-production expenses.[318] The key goal for lessors is to modify the general rule that a lessor's royalty is subject to its proportionate share of post-production expenses.[319] As prior case law indicates, achieving this goal requires careful drafting.[320]

Heritage Resources, Inc. v. NationsBank warns lessors to not use the phrase "market value at the well" while *Warren v. Chesapeake Exploration, L.L.C.* instructs lessors to avoid phrases like "amount realized at the well".[321] *Potts v. Chesapeake Exploration, L.L.C.* further instructs that even if the parties move the royalty valuation point from the wellhead to a to-be-determined point of sale, post-production expenses may still be

313. *Id.* at *7 (Brown, J., dissenting).

314. *See id.* at *2 (majority opinion) (noting that a proceeds lease is "sufficient in itself to excuse the lessors from bearing postproduction costs").

315. *See id.*; *Hyder I*, 427 S.W.3d at 477–78; Edwards v. Kaye, 9 S.W.3d 310, 314 (Tex. App.—Houston [14th Dist.] 1999, pet. denied) (observing that "[d]ictum is not binding as precedent under stare decisis").

316. *See supra* Part V.A–C.

317. *See supra* Part V.A–C.

318. *See supra* Part V.A–C.

319. *See Hyder I*, 427 S.W.3d at 477 (stating the parties successfully modified the general rule that royalty is subject to post-production deductions).

320. *See, e.g.*, Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 122–23 (Tex. 1996).

321. *See id.*; Warren v. Chesapeake Expl., L.L.C., 759 F.3d 413, 416–19 (5th Cir. 2014) (applying Texas law).

deducted if the point of sale is at the wellhead.[322] Thus, royalty owners should avoid the term *point of sale* for royalty valuation purposes.[323] The best royalty valuation phrase to avoid making a no-deductions clause legal surplusage is *price actually received* or *proceeds*.[324] The lease in *Chesapeake Exploration, L.L.C. v. Hyder* used *price actually received*.[325] A royalty based on the price or proceeds actually received by the lessee fixes the royalty on the amount of gas sold, rather than the amount delivered to a particular location, such as the wellhead.[326]

Second, prohibiting post-production deductions requires a comprehensive no-deductions clause.[327] The clause should include a non-exclusive list of prohibited post-production deductions.[328] Given the Texas Supreme Court's decision in *French v. Occidental Permian Ltd.*, this list should include the cost of conducting secondary recovery and enhanced oil recovery operations, such as the cost to separate carbon dioxide from casinghead gas.[329] The no-deductions clause in *Chesapeake Exploration, L.L.C. v. Hyder* provides a good starting point.[330] An ideal no-deductions clause, based on the one used in *Hyder* and specifically including costs to implement secondary and enhanced oil recovery operations, is provided below:

> The royalty reserved herein by [the lessor] shall be free and clear of all production and post-production costs and expenses, including but not limited to, production, gathering, separating, storing, dehydrating, compressing, transporting, processing, treating, marketing, delivering, or any other costs and expenses incurred between the wellhead and [the lessee's] point of delivery or sale of such share to a third party. *The lessor's royalty shall also be free and clear of all costs and expenses of or relating to secondary, tertiary, or enhanced oil recovery operations, including but not limited to, water flooding, thermal recovery, chemical injection, and carbon dioxide injection*.[331]

322. *See* Potts v. Chesapeake Expl., L.L.C., 760 F.3d 470, 473–76 (5th Cir. 2014) (applying Texas law).

323. *See id.*

324. *See* Poitevent, II, *supra* note 103, at 733 (advising royalty owners to use a gross-proceeds or amount-realized clause, instead of an at-the-well clause, to avoid post-production deductions). *But see supra* notes 305–07 and accompanying text.

325. *Hyder I*, 427 S.W.3d 472, 477–78 (Tex. App.—San Antonio 2014), *aff'd*, No. 14–0302, 2015 WL 3653446, at *5 (Tex. June 12, 2015).

326. *Id.* at 481–82.

327. *See supra* Part V.A–C (discussing four cases in which leases included a no-deductions clause).

328. *See supra* Part V.A–C.

329. *See* French v. Occidental Permian Ltd., 440 S.W.3d 1, 10 (Tex. 2014) (classifying the cost of removing injected carbon dioxide from casinghead gas as a post-production cost chargeable to a lessor's royalty).

330. *See Hyder I*, 427 S.W.3d at 476.

331. *See id.* (italicized language reflects Author's proposed revisions).

Royalty owners should also strongly consider adding a *Heritage* exclusion clause, especially if their royalty is based on market value at the well.[332] The *Heritage* exclusion clause may convince a court to give effect to a cost-free or no-deductions provision.[333] In construing an oil and gas lease, courts seek to uphold the intent of the parties, as expressed in the lease.[334] The *Heritage* exclusion clause would signal to the court the parties' intent to modify the general rule that royalty is subject to post-production deductions.[335] Lessors can look to *Hyder* once more for an example of an effective *Heritage* exclusion clause: "[Lessor] and [Lessee] agree that the holding in the case of *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118 (Tex. 1996) shall have no application to the terms and provisions of this Lease."[336]

A lease containing a royalty clause based on proceeds of actual sales, combined with a broad no-deductions clause and a *Heritage* exclusion clause, will effectively change the general rule in Texas that royalty owners must pay for their share of post-production expenses. This combination of clauses imposes an obligation on the lessee to bear the costs of all post-production activities, including enhanced oil recovery operations.

VI. CONCLUSION: ENSURING ENHANCED OIL RECOVERY OPERATIONS REMAIN FAIR FOR ROYALTY OWNERS

Enhanced oil recovery operations like carbon dioxide injection can change the financial prospects of a reservoir, its royalty owners, and nearby cities.[337] The story of the Kelly–Snyder Field and SACROC in Snyder, Texas, exemplifies the broad impacts of carbon dioxide injection programs.[338] By enacting statutes that prohibit waste and provide tax incentives for enhanced recovery operations, the Texas Legislature has made clear its support of activities that increase oil production.[339]

Judicial decisions in Texas have incorporated the state's public policy to create a legal framework that strongly favors the oil and gas industry.[340] In *Occidental Permian Ltd. v. Helen Jones Foundation*, a court of appeals correctly decided that an operator retains ownership of extraneous carbon

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332. *See id.* at 477 (recognizing the validity of a *Heritage* exclusion clause); *Hyder II*, No. 14–0302, 2015 WL 3653446, at *2 n.18 (Tex. June 12, 2015) (Brown, J., dissenting).

333. *See Hyder I*, 427 S.W.3d at 477.

334. Browning Oil Co. v. Luecke, 38 S.W.3d 625, 640 (Tex. App.—Austin 2000, pet. denied) (citing Heritage Res., Inc. v. NationsBank, 939 S.W.2d 118, 121 (Tex. 1996)).

335. *See Hyder I*, 427 S.W.3d at 477–78.

336. *Id.* at 477.

337. *See supra* Part I.

338. *See supra* Part I.

339. *See supra* Part II.B.2.

340. *See supra* Parts III–IV.

dioxide when the gas is injected to increase oil production.[341] More recently, the Texas Supreme Court in *French v. Occidental Permian Ltd.* heavily relied on the state's public policy in incorrectly holding that the cost of separating non-native carbon dioxide from casinghead gas is a post-production cost that can be deducted from a lessor's royalty.[342] The *French* decision demonstrates the dangers of judicial decisions based primarily on public policy, rather than existing case law.[343] When a lessee injects non-native carbon dioxide into a reservoir to increase oil production, the cost of separating that carbon dioxide from casinghead gas produced from the leased premises should be a production cost not chargeable to a lessor's royalty.[344]

In light of *French*, lessors entering into new oil and gas leases should modify the default rule that their royalty is subject to the costs of any post-production activities to increase their royalty revenues through the life of the lease. *Heritage Resources, Inc. v. NationsBank*, *Warren v. Chesapeake Exploration, L.L.C.*, and *Potts v. Chesapeake Exploration, L.L.C.* all illustrate unsuccessful efforts to change this industry custom.[345] *Chesapeake Exploration, L.L.C. v. Hyder* should give hope to lessors, however, because the parties in *Hyder* successfully created a royalty free of post-production deductions.[346] Drawing lessons from *Heritage*, *Warren*, *Potts*, and *Hyder*, lessors can ensure that enhanced oil recovery operations remain fair for them by negotiating leases with three essential provisions: a royalty clause based on proceeds of actual sales; a comprehensive no-deductions clause prohibiting post-production deductions, including costs of enhanced recovery operations; and a clause excluding the applicability of the holding in *Heritage*.[347] Despite the Texas Supreme Court's flawed decision in *French*, royalty owners can ensure that if carbon dioxide injection operations or other methods of enhanced oil recovery occur on their lease, they will not bear the costs of such activities. With the anticipated increase in carbon dioxide injection programs in Texas, preventing post-production deductions should be a priority for all lessors negotiating new oil and gas leases.[348]

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341. *See supra* Part III.B.
342. *See supra* Part IV.A–B.
343. *See supra* Part IV.B.
344. *See supra* Part IV.B.
345. *See supra* Part V.A–B.
346. *See supra* Part V.C.
347. *See supra* Part V.D.
348. *See supra* notes 60, 77 and accompanying text.